Transcript Exhibit(s)

Docket #(s): G-01551A-10-0458

Arizona Corporation Commission
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Exhibit # : AIC1-AIC3, ZWICK1, ZWICK2, NRDC1, NRDC2, RUCO1, RUCO2, RUCO3, RUCO4-RUCO16,

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To: Docket Control

Date: August 17, 2011

Re: Southwest Gas Corporation / Rates
G-01551A-10-0458
August 10, 12, and 15, 2011
Volumes I through III, Concluded

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL

Arizona Investment Council (AIC Exhibits)

1 through 3

Cynthia Zwick (Zwick Exhibits)

1 and 2

Natural Resource Defense Council (NRDC Exhibits)

1 and 2

Residential Utility Consumer Office (RUCO Exhibits)

1, 2, 3 (Administrative Notice), 4 through 16

Southwest Energy Efficiency Project (SWEEP Exhibits)

1 and 2

Southwest Gas Corporation (A Exhibits)

1 through 18

Please note, to comply with Docket Control's filing requirements, we removed Exhibits A-1 through A-13 from binders. We removed and made copies of any tabs included within the exhibits.

Staff (S Exhibits)

1, 3, 5 through 9, 11, 12

CORRECTIONS TO INDEX OF EXHIBITS

Please see attached corrected page 512. Under the column "No.", Line 17.5 has been corrected from RUCO-3 to RUCO-4. Line 18.5 has been corrected from RUCO-4 to RUCO-5. Only the column "No." needed correction. We apologize for the inconvenience.

EXHIBITS RETURNED TO PARTIES

Residential Utility Consumer Office (RUCO Exhibits)

17 Not admitted

EXHIBITS NOT UTILIZED
Not given to Court Reporter

Staff (S Exhibits)

10

CONFIDENTIAL EXHIBITS
Given to ACALJ Nodes

Staff (S Exhibits)

2 and 4

Copy to:

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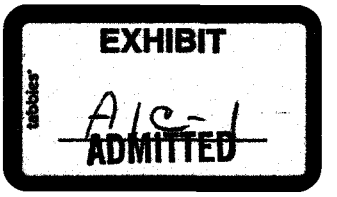

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.	DOCKET NO. G-01551A-10-0458

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Direct Testimony of

Daniel G. Hansen, Ph.D.

in Support of the Settlement Agreement

on Behalf of

Arizona Investment Council

July 29, 2011

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1. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Daniel G. Hansen. My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705.

Q. WHAT IS YOUR PROFESSION AND BACKGROUND?

A. I am a Vice President at Laurits R. Christensen Associates, Inc. I received a Ph.D. in Economics from Michigan State University in 1997, at which time I joined Laurits R. Christensen Associates, Inc. I have worked primarily with and for regulators, intervenors and the energy industry during my 14 years of consulting experience. In recent years, I have, on several occasions, analyzed and testified on some of the key issues raised in this docket. Specifically, in 2005, I conducted independent evaluations of Northwest Natural Gas's decoupling and weather normalization mechanisms in Oregon, as required by that Commission's orders approving the mechanisms. In 2007, I provided testimony on behalf of the Utah Division of Public Utilities regarding Questar Gas Company's decoupling mechanism. On behalf of Environment Northeast (a non-profit environmental organization), I provided testimony regarding a decoupling mechanism proposed by Connecticut Light & Power and also served on a panel before the Massachusetts Department of Public Utilities to discuss the merits of decoupling mechanisms (Docket No. 07-50). In 2009, I conducted an independent evaluation of decoupling mechanisms in place at New Jersey Natural Gas and South Jersey Gas. My resume is attached hereto as DGH-1.

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Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The Arizona Investment Council ("AIC") has retained Christensen Associates Energy Consulting, LLC, a subsidiary of Laurits R. Christensen Associates, Inc., to provide testimony regarding Alternatives A and B which are described on pages 6 to 14 of the Proposed Settlement Agreement (the "Settlement Agreement"), which was executed on July 15, 2011 by AIC, Southwest Gas Corporation ("Southwest Gas" or the "Company"), this Commission's Utilities Division Staff and other parties to this docket. AIC's position is that, while it can support the adoption of either Alternative A or B, it considers Alternative B to be a much superior result with several advantages over Alternative A. My testimony will explain why.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following this introductory section, the testimony is organized as follows:

- Section 2: Identification of the key differences between the alternatives;
- Section 3: Description of the reasons that Alternative B is superior to Alternative A;
- Section 4: Summary of the customer protections included in Alternative B; and
- Section 5: Summary of my recommendations.

2. KEY DIFFERENCES BETWEEN ALTERNATIVES A AND B

Q. WHAT IS THE MOST SIGNIFICANT DIFFERENCE BETWEEN ALTERNATIVES A AND B?

A. Alternative A contains a Lost Fixed Cost Recovery ("LFCR") mechanism, which compensates the Company only for lost revenues specifically linked to programs and measures designed to meet the Commission's required annual energy savings. In contrast, Alternative B contains a revenue per customer decoupling ("Decoupling") mechanism that adjusts rates to account for deviations between allowed and actual revenue per customer, even if the deviation cannot be directly tied to savings associated with a particular energy efficiency program. This difference is crucial. As I explain in Section 3, the Decoupling mechanism in Alternative B has a number of advantages relative to the LFCR mechanism proposed in Alternative A.

Q. WHAT ARE THE OTHER DIFFERENCES BETWEEN ALTERNATIVES A AND B?

A. There are three other significant differences between Alternatives A and B:

- **Rate case moratorium:** Alternative A has none, while under Alternative B, Southwest Gas has committed not to file a rate case prior to April 30, 2016 (Section 3.30).[1]
- **Allowed return on common equity:** 9.75 percent is allowed under Alternative A; 9.5 percent is allowed under Alternative B (Sections 3.16 and

[1] Parenthetical references are to the sections of the Settlement Agreement.

3.17). As a result, Alternative B's rate increase is approximately $2.3 million *less* than Alternative A.

- **Monitoring/reporting:** Alternative A has only an *annual* reset filing by the Company (Section 3.9) and an *annual* review by Staff of compliance with energy efficiency goals (Section 3.11), while Alternative B also includes *quarterly* filings of monthly bill customer impacts and *annual* reports. These quarterly and annual reports include a variety of components, such as monthly bill impacts by customer sectors and individual tariff, a listing of customer complaints, an analysis of compliance with annual energy efficiency goals, an analysis of usage differences between new and existing customers (including use per customer), comparisons of pre- and post-Decoupling usage levels and an analysis of Company activities that support new customer growth (Sections 3.21 to 3.23). Alternative B also requires that a detailed earnings test be completed on an annual basis to ensure that the Company is not earning more than its authorized return on common equity (Section 3.25).

Q. DO THE ALTERNATIVES SHARE ANY IMPORTANT COMPONENTS?

A. Yes, both alternatives include a weather-related component that adjusts current-month customer bills to account for bill changes due to deviations from normal winter weather conditions. However, as I describe in Section 3, the weather-related component functions much better in combination with Alternative B's Decoupling mechanism than it does in Alternative A, because Alternative B's approach eliminates concerns regarding errors in the normal weather definition.

Also, both alternatives commit Southwest Gas to meeting the requirements of the Energy Efficiency and Renewable Energy Resource Technology Portfolio Implementation Plan ("EE and RET Plan"). Annual energy savings will be at least 1,250,000 therms within nine months of Commission approval. In addition, the Settlement Agreement requires the Company's shareholders to contribute at least $1 million over the next five years to support low-income weatherization programs.

Finally, the Company has agreed to develop a customer outreach/education plan. While the primary goal of this program is to educate customers regarding the changes affiliated with the alternative (either A or B) approved by the Commission, it can also be used to inform them of the benefits associated with conservation and direct them toward resources that can help them become more energy efficient consumers.

3. REASONS THAT ALTERNATIVE B IS SUPERIOR TO ALTERNATIVE A

Q. WHICH ALTERNATIVE DOES AIC PREFER AND DO YOU RECOMMEND THE COMMISSION ADOPT?

A. I recommend the adoption of Alternative B, which I agree with AIC is superior to Alternative A, primarily for the following reasons:

- Decoupling provides a more complete solution to the Company's conservation incentive issues;
- Decoupling combines well with the weather-related component;
- Decoupling reduces contentiousness regarding the measurement of usage reductions; and

- Finally, Decoupling leads to improved bond ratings, which benefit all ratepayers by reducing the utility's borrowing costs and improving its access to capital.

I will now explain each of these reasons in detail.

Q. WHY IS DECOUPLING A MORE COMPLETE SOLUTION THAN LFCR TO THE COMPANY'S CONSERVATION ISSUES?

A. The LFCR in Alternative A only removes the Company's disincentive to support conservation efforts used to meet specific energy efficiency goals. In contrast, the Decoupling in Alternative B removes those same disincentives, but, as importantly, also removes the utility's disincentive to support conservation efforts for which the benefits are difficult to measure. In addition, unlike LFCR, Decoupling removes the utility's incentive to *increase* use per customer.

Q. WHAT KINDS OF CONSERVATION EFFORTS PRODUCE BENEFITS THAT ARE DIFFICULT TO MEASURE?

A. The most obvious category is customer outreach and education programs. A good example of this is a web site that offers conservation tips to customers who visit the site. While these tips may be effective in getting customers to reduce usage levels, it is very difficult to track which customers are visiting the site and, as importantly, the actions each customer takes based on the information they obtain. Because the LFCR only allows the Company to recover lost revenues directly associated with measured usage reductions, educational programs like these are unlikely to become part of the Company's efforts to encourage conservation. In contrast, under Alternative B's Decoupling,

Southwest Gas has every incentive to be creative across the board in structuring and implementing efficiency programs, because its ability to recover lost revenues will not be hampered by restrictive attribution and verification requirements.

Q. DR. JOHNSON'S DIRECT TESTIMONY ON RUCO'S BEHALF ATTACKS THE PREMISE THAT DECOUPLING REMOVES THE COMPANY'S INCENTIVE TO PROMOTE *INCREASES* IN CUSTOMER USAGE. DO YOU AGREE?

A. No. The financial incentive to increase customer usage under traditional rate design is obvious. In the absence of Decoupling, Southwest Gas improves its realized rate of return with each additional therm sold. Put another way, additional sales drive an increase in the Company's non-gas revenues regardless of whether there is an increase in non-gas costs. Decoupling replaces the link between *sales* and non-gas revenues with a link between *the number of customers* and non-gas revenues. Therefore, under Alternative B's Decoupling, Southwest Gas will have an incentive to increase the number of customers served, but will not have an incentive to increase the level of usage per customer.

Q. WHY DOES DECOUPLING COMBINE WELL WITH THE WEATHER-RELATED COMPONENT?

A. The weather-related component adjusts customer bills based on the difference between actual winter weather conditions and "normal" winter weather conditions, which are measured using a ten-year average of weather data. For example, in an unusually cold winter month, customer bills and utility revenues will be adjusted down by the weather-

related component to account for the fact that sales were higher than they would have been under "normal" weather conditions. However, a problem can arise when this type of weather adjustment is used as a stand-alone mechanism instead of in combination with a Decoupling mechanism such as AIC supports in Alternative B. Specifically, if the definition of normal weather is set incorrectly, the results of the weather-adjustment mechanism will be skewed toward either the utility or its ratepayers. One such instance of this occurring is described by Staff witness Dr. David Dismukes on pages 22-23 of his direct testimony. In that example, the Connecticut regulator discontinued a stand-alone weather-adjustment mechanism, because payments over a 15-year period were skewed toward the utility. The Connecticut results would not have been possible if the weather-adjustment mechanism had been combined with a Decoupling mechanism, as is the case with Alternative B.

Q. PLEASE EXPLAIN WHY THESE SKEWED PAYMENTS WOULD NOT HAVE OCCURRED IF THE WEATHER-RELATED COMPONENT WAS COMBINED WITH DECOUPLING AS IT IS IN ALTERNATIVE B.

A. Decoupling eliminates the potential for skewed weather-related adjustments, because it ensures that the utility receives the same annual level of revenue per customer regardless of the sales levels (and, by extension, weather conditions) that actually occurred. For example, if the normal winter weather definition is set five percent "too cold," the utility will tend to be paid five percent too much through the weather-related component. (Some years will be higher and some lower, depending on the weather in that particular year.) However, the Decoupling component's annual true-up (Section 3.20) will give

that five percent "surcharge" from the weather-related component back to customers through a rate reduction in the following year.

Therefore, when the weather-related component is combined with Decoupling, customers still benefit by an immediate reduction in the weather-induced variability of their bills, but the annual adjustment eliminates the possibility of overpayment to the utility due to any error in the definition of normal weather.

Q. COULD THE SKEWED PAYMENTS OCCUR IF THE WEATHER-RELATED COMPONENT IS COMBINED WITH ALTERNATIVE A'S LFCR MECHANISM?

A. Yes, because the LFCR does not true-up annual revenues in the same manner as Decoupling. If the definition of normal winter weather is set too cold (so that actual sales are consistently below "normal" sales), the utility will benefit from the weather-related component over time. Extending this to the example I gave in the previous answer, the Company would keep the five percent over-payment from the weather-related component under LFCR. This problem is present only under Alternative A's LFCR. Alternative B's Decoupling element eliminates the possibility that the utility will recover more revenue because the normal weather definition is set at too cold a level.

Q. HOW DOES DECOUPLING REDUCE CONTENTIOUSNESS REGARDING THE MEASUREMENT OF USAGE REDUCTIONS?

A. Under Decoupling, the utility receives the same test-year level revenue per customer regardless of the level of its sales or commodity throughput. Therefore, there's no need

to measure usage reductions in order to remove the utility's disincentive to promote conservation and energy efficiency ("EE"). Under Alternative B, the requirements are that the EE programs are cost effective and that the utility meets its Commission-required EE goals. Once these hurdles are cleared, the level of utility revenues is unaffected by *how much* Southwest Gas cleared the hurdle.

Conversely, under Alternative A, the LFCR requires the detailed measurement of program-induced usage reductions. Under the LFCR, the amount of the lost revenue payment to the utility depends directly upon the amount and cause of the measured usage reductions. To relate it back to the earlier analogy, the LFCR in Alternative A requires that we measure precisely the height the utility "jumped" and not merely a confirmation that the Company cleared the hurdle (as is the case with Decoupling and Alternative B). Therefore, protracted disputes regarding the measurement of program-induced usage reductions are highly likely to occur under Alternative A, adding to the costs of administering that alternative and discouraging the utility from pursuing or supporting EE programs for which the measurement and verification method of their effects is not assured.

Q. DOES DECOUPLING, AS CONTAINED IN ALTERNATIVE B, LEAD TO IMPROVED BOND RATINGS?

A. Yes. As Staff witness David Parcell indicates on page 15 of his direct testimony, Moody's recently upgraded Southwest Gas's bond rating from Baa3 to Baa2. Among the upgrade reasons cited in Mr. Parcell's excerpt of the Moody's report are "signs of improvements in Southwest's regulatory environment," which include approval of a

Decoupling mechanism in Nevada and the potential for the adoption of decoupling in Arizona because of the Commission's workshops which were underway last year when the Moody's upgrade occurred.

Q. HOW DO CUSTOMERS BENEFIT FROM AN IMPROVEMENT IN THE COMPANY'S BOND RATING?

A. The improved bond rating reduces the Company's borrowing costs, which leads to lower retail rates over time. It also improves Southwest Gas's access to capital for repairs, replacements and system improvements necessary for customers to get safe, reliable and adequate service.

4. SUMMARY OF CUSTOMER PROTECTIONS IN ALTERNATIVE B

Q. SOME CONSUMER GROUPS, INCLUDING THE AARP, HAVE SUGGESTED THAT POLICYMAKERS AND REGULATORS LIKE THE COMMISSION SHOULD ADOPT CONSUMER PROTECTIONS ALONG WITH THE APPROVAL OF DECOUPLING MECHANISMS. DOES ALTERNATIVE B, WHICH AIC SUPPORTS, CONTAIN SUCH CONDITIONS AND PROTECTIONS?

A. Yes, Alternative B addresses these concerns in a number of ways:

- Southwest Gas will expand its cost-effective EE programs and improve its customer outreach/education plans;
- Rate adjustments are limited in size and frequency;

- The Company's allowed return on equity ("ROE") is reduced to account for perceived (whether accurate or not) reductions in utility risk;
- Decoupling deferrals are subject to an earnings test that prevents the Company from earning more than its authorized ROE;
- The performance of the Decoupling mechanism will be regularly evaluated; and
- After each annual review, the Commission may set a hearing to determine whether the Decoupling mechanism should be suspended, terminated or modified.

Q. PLEASE DESCRIBE HOW ALTERNATIVE B COMMITS SOUTHWEST GAS TO SUPPORT THE EXPANSION OF COST-EFFECTIVE ENERGY EFFICIENCY PROGRAMS.

A. As I explained earlier in my testimony, both Alternatives A and B commit Southwest Gas to meeting the requirements of the EE and RET Plan, which includes annual energy savings of at least 1,250,000 therms within nine months of Commission approval (Sections 5.7 to 5.11). In addition, the Company's shareholders will commit $1 million to support low-income weatherization programs (Section 4.1). Finally, the Company has agreed to develop an outreach/education plan, which can also be used to inform customers of the benefits associated with conservation and direct them toward resources that can help them become more energy efficient (Section 3.31).

Q. PLEASE DESCRIBE THE LIMITS THAT ALTERNATIVE B PLACES ON THE SIZE AND FREQUENCY OF RATE ADJUSTMENTS.

A. Under the Settlement Agreement, rate increases associated with Decoupling are limited to an annual adjustment no greater than five percent of the non-gas portion of the rate (Section 3.29), or approximately 2.5 percent of the *total* rate at current rate levels. *No* limit is placed on the annual Decoupling-induced rate *decreases*. These provisions ensure that customer rates will remain stable and predictable after the adoption of Decoupling.

Q. DOES THE MONTHLY ADJUSTMENT FROM THE WEATHER-RELATED COMPONENT CHANGE YOUR CONCLUSION REGARDING THE STABILITY OF RATES UNDER ALTERNATIVE B?

A. No. To the contrary, the monthly bill adjustments from the weather-related component provide a benefit to customers by reducing the weather-induced variability in their bills. This adjustment, which occurs under both Alternatives A and B, is different from the annual Decoupling adjustment that is only included in Alternative B. Additionally, as described previously, the combination of the weather-related component and Alternative B's Decoupling provides extra consumer protection against faulty definitions of "normal" winter weather.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO THE COMPANY'S ALLOWED RETURN ON EQUITY CONTAINED IN ALTERNATIVE B.

A. As an initial matter, AIC does not believe there is any empirical evidence that supports or requires an adjustment to ROE simply because a Decoupling mechanism is adopted. However, it is my understanding that in negotiating the Settlement Agreement, the parties did, as part of the negotiation process, adopt different ROE figures for each alternative. Specifically, the allowed ROE is 9.50 percent under Alternative B, which is 25 basis points lower than the 9.75 percent under Alternative A.

The Settlement Agreement does not provide a specific rationale for the different ROE figures. However, a reduction in ROE is typically intended to account for reductions in the utility's risk that can occur because revenue decoupling removes variations in non-gas revenues due to customer responses to changing economic conditions or commodity prices. While the risk is not one-sided (e.g., the Company loses the opportunity to *increase* per-customer non-gas revenues when the economy is booming or commodity prices are falling), those who support a reduction to the ROE argue that it is an appropriate customer protection to reflect the reduced variability of utility non-gas revenues.

Q. PLEASE DESCRIBE THE REPORTING AND EVALUATION REQUIREMENTS CONTAINED IN ALTERNATIVE B.

A. There are both quarterly and annual reporting requirements (Sections 3.21 to 3.23). Each quarter, Southwest Gas is required to report on customer bill impacts (using a variety of measures) associated with the Decoupling mechanism. Each year, the Company must

prepare a filing that includes a variety of data, including: a listing of customer complaints (which will help ensure that the Company's service quality is not affected); a showing that its disincentives to support EE have been removed; compliance with required annual energy savings targets; a comparison of usage between new and existing customers; various analyses of changes in use per customer; an analysis of customer migration between tariffs; and an analysis of Company activities that support new customer growth.

Q. ARE THE COMPANY REPORTS SUBJECTED TO REGULAR SCRUTINY?

A. Yes, Staff will perform an annual review of Southwest Gas's filing, with a required contribution of $75,000 from Southwest Gas to obtain assistance in this review (Section 3.28). In addition, each annual review will be the subject of an Open Meeting during which the Commissioners may deliberate on the performance of the Decoupling mechanism (Section 3.24).

Q. DOES THE SETTLEMENT AGREEMENT PROVIDE THE COMMISSION WITH ANY RECOURSE IF IT IS NOT PLEASED WITH THE RESULTS OF THESE EVALUATIONS?

A. Yes. The Commission may set a hearing to consider the suspension, termination or modification of the Decoupling mechanism (Section 3.24). This ensures consumer protection if unexpected problems arise from implementation.

Q. DO YOU HAVE ANY CONCERNS ABOUT CUSTOMER-LEVEL INCENTIVES TO CONSERVE UNDER DECOUPLING?

A. No. Under Decoupling, customers continue to be financially incentivized to conserve. For example, when a customer reduces usage by one therm, there is an immediate financial benefit in the form of a bill reduced by that therm's full retail rate (which, according to the Statement of Rates available on the Company's web site,[2] is currently about $1.14 per therm for single-family residential customers). Under Decoupling, only the non-gas portion of this reduction (currently about 57 cents per therm) would be placed in a deferral account to be recovered through an adjustment the following year. This 57 cents is spread across *all* therms consumed in that year and is also subject to the five percent cap. Thus, it is highly unlikely that any customer would give up the immediate and larger financial benefits of a lower gas bill based on a concern that the utility may be able to recoup a tiny fraction of that lost revenue a year later.

Q. ON PAGES 15-16 OF HIS DIRECT TESTIMONY, DR. JOHNSON ARGUED THAT, WHILE YOUR PRECEDING ARGUMENT IS TECHNICALLY CORRECT, CUSTOMERS WILL NOT BE SUFFICIENTLY INFORMED TO UNDERSTAND IT AND MAY STILL PERCEIVE THAT THEIR INCENTIVE TO CONSERVE IS REDUCED. DO YOU AGREE WITH THIS OPINION?

A. No, for two reasons. First, his argument assumes that customers will understand enough about Decoupling to know that class-level conservation leads to increases in non-gas rates, but will not understand it well enough to be able to work out its effect on them.

[2] *See* http://www.swgas.com/tariffs/arizona_rates_and_tariffs.php.

This "customers are smart, but not smart enough" argument does not strike me as very plausible, particularly because the Settlement Agreement requires the Company to develop, and Staff to review and approve, a customer outreach/education program that will explain Decoupling to customers.

Second, rate changes allowed under Alternative B's Decoupling mechanism are smaller than the rate changes customers currently experience due to market changes in gas costs. For example, the largest increase permitted by the Settlement Agreement is five percent of the test-year non-gas revenues. Based on current single-family residential rates (per the schedule on the Company's web site), this would amount to an increase of approximately 2.9 cents per therm and would only increase the per-therm total rate from about $1.14 to $1.17. This is a very small amount compared to the changes in gas costs that customers regularly experience. For example, since 2006, the average annual change in gas costs (which I measured from August to August) was 8.4 cents per therm. That is, the average annual change in the gas cost has recently been nearly *three times* greater than the largest possible rate adjustment under Decoupling (using current rates). Because the magnitude of Decoupling-induced rate changes will be quite small relative to gas-cost-induced rate changes, it's likely customers will not even notice the effect of Decoupling on their bills.

Q. DO YOU HAVE ANY CONCERNS ABOUT DECOUPLING REDUCING THE COMPANY'S INCENTIVE TO OPERATE EFFICIENTLY?

A. No. Decoupling only affects revenues; it does not change the fact that the Company can, and remains incented to, improve its profitability by reducing its costs. In addition, the

Settlement Agreement contains a provision requiring Southwest Gas to reduce its annual expenses by $2.5 million beginning in 2012 (Section 5.20). This requires the Company to operate more efficiently and removes concerns (which I do not believe to be valid in the first place) that Decoupling will reduce the Company's incentive to operate efficiently.

Q. OPPONENTS OF DECOUPLING SOMETIMES CHARACTERIZE IT AS A NON-MARKET-BASED MEANS OF PAYING THE UTILITY MORE TO PRODUCE LESS. DO YOU AGREE WITH THIS CHARACTERIZATION?

A. No. Decoupling leads to the same amount of utility revenue as one would obtain by setting regulated rates based on marginal cost-based pricing principles found in economics. That is, under marginal cost-based pricing, all fixed costs would be recovered using fixed charges (e.g., the fixed monthly customer charge) and all variable costs (e.g., gas costs) would be recovered using volumetric (i.e., dollar per therm) rates. In the natural gas industry, this is known as Straight Fixed Variable ("SFV") pricing. Decoupling produces the same outcome as SFV, because the non-gas costs that are included in the Decoupling "true-up" mechanism are the same as the fixed costs that would be recovered through the fixed monthly customer charge in SFV pricing. As a result, under either Decoupling or SFV, the utility receives the same amount of non-gas revenue per customer per year, which covers the utility's fixed costs and eliminates its disincentive to promote conservation.

Q. COULD YOU PLEASE ELABORATE ON THE EQUIVALENCE OF STRAIGHT FIXED VARIABLE PRICING AND DECOUPLING?

A. Under SFV, utility non-gas revenues are collected solely through monthly customer charges. Therefore, the total amount of utility non-gas revenue in a given year under SFV is equal to: 12 x (the monthly customer charge) x (the number of customers served). Under Decoupling, the utility recovers a fixed amount of non-gas revenue per customer per year. Therefore, the total amount of utility non-gas revenue in a given year under Decoupling, including the revenue gained or lost through the true-up mechanism, is equal to: (the authorized non-gas revenue per customer per year) x (the number of customers served). In both cases, the amount of non-gas revenue is unrelated to the amount of gas that customers use. If the SFV rates and Decoupling mechanism are designed using the same information (i.e., using the same revenue requirement and test-year number of customers), the utility would recover the exact same amount of non-gas revenue per year using either method.

Q. IF DECOUPLING AND SFV RETURN THE SAME AMOUNT OF NON-GAS REVENUE FOR THE UTILITY, WHY IS DECOUPLING PREFERRED TO STRAIGHT FIXED VARIABLE PRICING?

A. Decoupling is preferred to SFV for two reasons. First, by raising the customer charge for fixed costs, SFV tends to produce especially large bill increases for low-use customers. It is believed that low-use customers are more likely to be low-income customers. Therefore, SFV is often rejected on fairness grounds. Decoupling does not introduce bill

impacts that differ by customer usage (and potentially income) levels. It simply adds a small adjustment factor to the current billing structure.

Second, SFV reduces the customer-level incentive to conserve, because the increase in the customer fixed monthly charge (which is required in order for the utility to recover fixed costs) must be matched by a decrease in the per-therm rate in order to hold the revenue requirement constant. But this reduction in the per-therm rate also reduces each customer's incentive to conserve. I have already described above why Decoupling does not affect the customer-level incentive to conserve.

Q. PLEASE EXPLAIN HOW DECOUPLING DOES NOT PAY THE UTILITY MORE TO PRODUCE LESS.

A. Under Decoupling, when customers reduce their usage levels, they will never pay the gas cost associated with the conserved therms, either in the current bill or through the Decoupling deferral mechanism. Decoupling compensates the utility only for reductions in *non-gas* (or fixed cost) revenues, which is reasonable, because the non-gas *costs* are not reduced when customers conserve (at least in the short run). That is, under Decoupling, when customers use less, it leads to a reduction in utility revenues that matches the reduction in utility costs.

5. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE SETTLEMENT AGREEMENT AND THE DECOUPLING ALTERNATIVES CONTAINED THEREIN?

A. I recommend that the Commission approve Alternative B, because it provides a more complete solution to the energy conservation issues than Alternative A. Its primary benefits relative to Alternative A are:

- Only Alternative B removes the incentive for the Company to *increase* usage per customer;
- Only Alternative B removes the Company's disincentive to support the full range of energy efficiency programs (rather than supporting only programs for which benefits are easily measured); and
- Only Alternative B eliminates the potential for revenues from the weather-related component to be skewed toward the utility or its customers because of errors in the definition of normal winter weather.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

EXHIBIT DGH-1

Daniel G. Hansen

RESUME

January 2011

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Academic Background:

Ph.D., Michigan State University, 1997, Economics
M.A., Michigan State University, 1993, Economics
B.A., Trinity University, 1991, Economics and History

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc. 2006-present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999-2005
Economist, Laurits R. Christensen Associates, Inc., 1997-1999
Research Assistant to David Neumark, 1995-1997
Instructor, School of Management, University of Michigan-Flint, spring 1996: MBA Business Economics

Professional Experience:

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

Major Projects:

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

Professional Papers:

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33-38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37-49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

Testimony and Reports before Regulatory Agencies:

Otter Tail Power Company, Minnesota Docket No. E-017/GR-10-239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09-04003: Testimony regarding a the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G-01551A-07-0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E-017/GR-07-1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07-50: Participation in a panel regarding an "Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources", on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07-07-01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

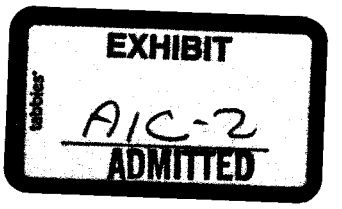
Questar Gas Company, Docket No. 05-057-T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.	Docket No. G-01551A-10-0458

Direct Testimony of

Gary Yaquinto

in Support of the Settlement Agreement

on Behalf of

Arizona Investment Council

July 29, 2011

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1. INTRODUCTION

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

A. Gary M. Yaquinto. I am the President of the Arizona Investment Council ("AIC"). Our offices are located at 2100 North Central Avenue, Phoenix, Arizona 85004.

Q. Please summarize your educational background and professional experience.

A. I earned B.S. and M.S. Degrees in Economics in 1974 from Arizona State University. In 2005, I received an MBA from the University of Phoenix. From 1975 to 1977, I was employed by the State of Wyoming as an economist responsible for evaluating the economic, fiscal and demographic effects of resource development in Wyoming. From 1977 to 1980, I was Chief Research Economist for the Arizona House of Representatives. From 1980 to 1984, I was employed as an economist in the consulting industry. Since 1984, I have worked in various capacities in government and the private sector in the area of utility regulation, including positions with the Utilities Division Staff of the Arizona Corporation Commission, a competitive local exchange telephone carrier and as a consultant. I have also served as the Chief Economist at the Arizona Attorney General's Office (2003-2005) and as the Director, Office of Strategic Planning and Budgeting, under Governor Janet Napolitano (2005-2006). I became the AIC President in December of 2006.

Q. What is the Arizona Investment Council and what is its mission?

A. The AIC is a non-profit association organized under Chapter 501(c)(6) of the Internal Revenue Code. AIC's membership includes approximately 6,000 individuals—many of

whom are debt and equity investors in Arizona utility companies and other Arizona businesses.

AIC's mission is to advocate on behalf of its members' interests before regulatory and legislative bodies. AIC also works with business leadership, policymakers, community leaders and educators to improve the investment climate in Arizona and to support the planning for and development of essential infrastructure to meet the needs of Arizona.

Q. What is the Arizona Investment Council's interest in this docket?

A. Southwest Gas Corporation ("Southwest Gas" or the "Company") must be positioned to attract capital on reasonable terms so that it can provide safe, reliable and adequate natural gas service to its customers while also maintaining its financial integrity. As the Company indicated in its Application and Direct Testimony filed with the Commission on November 12, 2010, its need for this rate increase primarily stems from declines in customer consumption and changes in the Company's cost of capital. A related and very important issue in this docket is Southwest Gas's decoupling proposal, which AIC views as a vital component in achieving the Commission's Energy Efficiency Standards ("EES") without depriving the Company of a realistic opportunity to recover its costs and earn a fair return. Both the Company's Application and the Settlement Agreement contain proposed rates and cost recovery mechanisms that AIC believes are fair, reasonable and in the public interest.

2. SETTLEMENT AGREEMENT

Q. Is AIC a signatory to the Settlement Agreement dated July 15, 2011 (the "Settlement Agreement")?

A. Yes. We participated with the other signatories in the discussions and negotiations which led to the execution of the Settlement Agreement by all but one of the intervenors in this case. I also participated in the meetings arranged by Southwest Gas to discuss technical aspects of the Company's Energy Efficiency Enabling Provision with parties to this docket.

Q. Generally, why does AIC support the Settlement Agreement?

A. The primary reason for AIC's support is the Settlement Agreement's inclusion of a decoupling mechanism. As explained by Staff witness David Parcell, Southwest Gas's debt rating was recently upgraded in response to the approval of a decoupling mechanism by the Public Utilities Commission of Nevada, as well as the anticipation that decoupling might also be approved by this Commission:

> The rating upgrade also recognizes signs of improvements in Southwest's regulatory environment where we remain cautiously optimistic about... potentially Arizona (55% of operating margins).[1]

An upgrade in rating is significant for the Company, its investors and its customers, because it generally leads to decreases in the costs of debt and an improvement in investor confidence. Without decoupling, Southwest Gas will be viewed as less financially stable and an inherently riskier investment by rating agencies, lenders and the

[1] Direct Testimony of David Parcell, p. 15, quoting Moody's May 27, 2010 upgrade report.

investment community, because the Company's ability to earn a fair rate of return and, specifically, to recover its fixed costs, will be subject to volumetric risks.[2]

Q. How does the Company's good credit rating benefit customers?

A. A lower cost of debt and improved access to capital—which are the byproducts of a favorable rating—benefit customers in the form of lower rates. They also help assure that Southwest Gas is better positioned to compete with other utilities and industries for the capital needed to get safe, reliable and adequate service to customers. Given the link between decoupling and the Company's credit rating, customers will benefit from the Commission's approval of a decoupling mechanism.

Q. The Settlement Agreement contains an Alternative A and Alternative B. Does AIC have a preference as to which alternative the Commission approves?

A. Yes. AIC supports the Decoupling mechanism contained in Alternative B and does not oppose Alternative A's Lost Fixed Cost Recovery mechanism. AIC does prefer Alternative B, because we believe it is the much better option for the Company, its investors and its customers. Additionally, in considering the alternatives presented in the Settlement Agreement, AIC strongly urges the Commission to adopt one of the alternatives (preferably Alternative B) in its *entirety*. Each alternative was crafted through a very careful and comprehensive negotiation process, such that the exclusion of any particular term from one of the alternatives would undermine the signatories' efforts and the compromises reached during the negotiations.

[2] *See* Direct Testimony of Theodore Wood, p. 7, l. 14 – p. 8, l. 4.

Q. Why does AIC prefer Alternative B?

A. Many of the reasons for AIC's support for Alternative B are described by our witness, Dan Hansen, in his concurrently-filed testimony. Simply put, AIC prefers Alternative B, because it is a better, more complete solution for addressing many of the impediments to achieving the EES as outlined in the Commission's December 29, 2010 Policy Statement. Also, from an investor perspective, the rate case moratorium provision combined with the decoupling in Alternative B reduces rate case cost and frequency and also reduces regulatory uncertainty—all of which are viewed favorably by the market.

Q. Are there any other aspects of the Settlement Agreement that AIC wants to highlight?

A. Yes. Section 1.8 of the Settlement Agreement outlines many customer and shareholder benefits, but there are a few provisions—in addition to AIC's preference for Alternative B's decoupling—that warrant particular attention. Although AIC believes the Company has done a good job of controlling costs, the Settlement Agreement requires Southwest Gas to further reduce annual expenses by an average of $2.5 million per year beginning in 2012. Southwest Gas's commitment to this level of additional cost reduction is commendable and benefits both shareholders and customers.

Additionally, in the interest of compromise and to reach settlement of the case, the parties agreed to commit $1 million of shareholder funds to finance a weatherization program for low-income customers. While shareholders are not usually called upon to fund such

programs, AIC agrees with low-income advocates and others that improved home insulation and other weatherization enhancements will create substantial benefits.

Finally, the fact that the Settlement Agreement was signed and is supported by a broad array of parties with differing interests is also a very positive signal to the markets concerning the Company, its regulators, customers and stakeholder groups.

3. RECOMMENDATION

Q. Mr. Yaquinto, what is AIC's recommendation for the Commission in relation to the Settlement Agreement?

A. The Settlement Agreement reflects an appropriate, productive balance among the often widely divergent views of the parties on a broad and challenging set of issues. In reaching that accord, we are confident that the Settlement Agreement, and especially its Alternative B, is in the best interest of all concerned. It is also very responsive to the Commission's Policy Statement on decoupling. It will give the Company a reasonable opportunity to recover its fixed costs and earn its authorized rate of return as, simultaneously, it meets the reduction in sales volumes required by the Commission's EES and the Settlement Agreement. We recommend the Commission enter its Order approving the Settlement Agreement with the inclusion of Alternative B in its entirety.

Q. Does that conclude your testimony?

A. Yes, it does.

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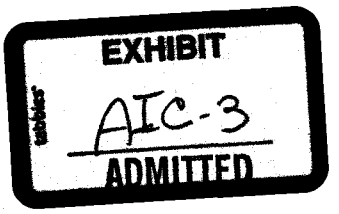


Q. PLEASE DESCRIBE THE LIMITS THAT ALTERNATIVE B PLACES ON THE SIZE AND FREQUENCY OF RATE ADJUSTMENTS.

A. Under the Settlement Agreement, rate increases associated with Decoupling are limited to an annual adjustment no greater than five percent of the non-gas portion of the rate (Section 3.29), or approximately 3.1 percent of the *total* rate at proposed rate levels. *No* limit is placed on the annual Decoupling-induced rate *decreases*. These provisions ensure that customer rates will remain stable and predictable after the adoption of Decoupling.

Q. DOES THE MONTHLY ADJUSTMENT FROM THE WEATHER-RELATED COMPONENT CHANGE YOUR CONCLUSION REGARDING THE STABILITY OF RATES UNDER ALTERNATIVE B?

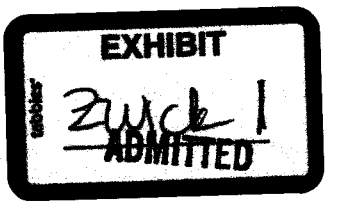
A. No. To the contrary, the monthly bill adjustments from the weather-related component provide a benefit to customers by reducing the weather-induced variability in their bills. This adjustment, which occurs under both Alternatives A and B, is different from the annual Decoupling adjustment that is only included in Alternative B. Additionally, as described previously, the combination of the weather-related component and Alternative B's Decoupling provides extra consumer protection against faulty definitions of "normal" winter weather.

This "customers are smart, but not smart enough" argument does not strike me as very plausible, particularly because the Settlement Agreement requires the Company to develop, and Staff to review and approve, a customer outreach/education program that will explain Decoupling to customers.

Second, rate changes allowed under Alternative B's Decoupling mechanism are smaller than the rate changes customers currently experience due to market changes in gas costs. For example, the largest increase permitted by the Settlement Agreement is five percent of the test-year non-gas revenues. Based on the proposed single-family residential rates (per the schedules filed by Staff), this would amount to an increase of approximately 5.6 cents per therm and would only increase the per-therm total rate from about $1.41 to $1.47. This is a very small amount compared to the changes in gas costs that customers regularly experience. For example, since 2006, the average annual change in gas costs (which I measured from August to August) was 8.4 cents per therm. That is, the average annual change in the gas cost has recently been nearly *fifty percent* greater than the largest possible rate adjustment under Decoupling. Because the magnitude of Decoupling-induced rate changes will be quite small relative to gas-cost-induced rate changes, it's likely customers will not even notice the effect of Decoupling on their bills.

Q. DO YOU HAVE ANY CONCERNS ABOUT DECOUPLING REDUCING THE COMPANY'S INCENTIVE TO OPERATE EFFICIENTLY?

A. No. Decoupling only affects revenues; it does not change the fact that the Company can, and remains incented to, improve its profitability by reducing its costs. In addition, the



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

Gary Pierce, Chairman
Bob Stump
Sandra D. Kennedy
Paul Newman
Brenda Burns

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	DOCKET NO. G-01551A-10-0458

DIRECT TESTIMONY OF CYNTHIA ZWICK

JUNE 10, 2011

RECEIVED
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AZ CORP COMMISSION
DOCKET CONTROL

Q. 1 Please state your name and address.

A. 1 My name is Cynthia Zwick and my address is 1940 E. Luke Avenue, Phoenix, Arizona 85016.

Q. 2 What is the purpose of your testimony?

A. 2 There are three reasons I am providing testimony in this case: 1) to urge the Commission to reject the rate increase proposal presented in this case as it relates to the Southwest Gas low-income customers, specifically rates G-10 and G-11, and to hold the low-income customers harmless from any rate increase at this time; 2) I am asking the Commission to require the Company to enhance its marketing of the availability of the discount rates so that more eligible families are enrolled in the discount program; and 3) I am asking the Commission to support the Low-Income Program: Smarter Greener Better Low-Income Energy Conservation.

Q. 3 What is your experience with low-income issues?

A. 3 I have served as a low-income advocate in Arizona since 2003, and have participated in rate cases since that time in order to ensure that the interests and impact of rate increases on the low-income community are heard and understood, and that there is a better understanding of the condition of poverty in the State of Arizona.

Q. 4 Would you please describe the low-income community in Arizona today?

A. 4 Let me start by saying that the poverty rate in Arizona is currently the second highest in the country, having increased significantly during the last two years, making the low-income community larger than ever. According to the United States Census Bureau, the Arizona poverty level is currently 21.2%. These numbers are more dramatic when considering the number of children living in poverty, which in Arizona is 1 in 5 children.

The income for a person living at 100% of the federal poverty level is $908 a month or $10,896 a year. For a family of four, the household income is $1,863 a month or $22,356 annually.

For the two Southwest Gas low-income customer programs, bill assistance and weatherization, the eligibility level is 150% of the federal poverty level, which is an income of $16,344 for an individual and $33,540 for a family of four.

Family self sufficiency has been exacerbated by the national and state economy, as high home foreclosure rates continue, and Arizona currently struggles with an unemployment rate of 9.3%, which is driving a new population into the community of low-income. Families that have lost their jobs have typically gone through any savings accumulated and have lost their health care coverage before seeking help from a Community Action Agency. Asking for financial assistance is never easy, and it is particularly difficult for families who have never before needed any assistance. By the time the request is made, the family income is already below 150% of the federal poverty level.

Governor Brewer has recognized the problems faced by unemployed families, and the slow recovery of the recession, and has called a special session of the legislature in order to extend the time within which someone seeking employment may receive unemployment benefits, in order to maintain basic expenses, such as the payment of utility bills, rent and the purchase of food. [1]

In order to qualify for the Southwest Gas discount program an individual or household income may not exceed 150% of the federal poverty level.

[1] "Governor Brewer calls special session on jobless benefits," www.azcentral.com/news/election; attached.

Q. 5 Arizona has received an increase in the amount of Low Income Home Energy Assistance (LIHEAP) funding over the past two years. Has this funding taken care of the problem for families?

A. 5 No, it has certainly helped, but unfortunately the need for assistance far exceeds the funds available. The families eligible for and receiving LIHEAP are also eligible for the Southwest Gas bill assistance, so these survey findings are important to note. The National Energy Assistance Directors' Association conducted a survey in April of 2009 of LIHEAP recipients and report the following:

- LIHEAP recipient households are likely to be vulnerable to temperature extremes;
- 39% of the homes had a senior in the household aged 60 or older
- 44% had a disabled household member
- 45% had a child 18 or younger
- 92% had a least one vulnerable household member

The study also provided information on challenges that these households faced:

- 36% were unemployed at some point during the previous year (this is an increase from the previous year's 29%)
- 82% had a serious medical condition, and
- 25% used medical equipment that requires electricity.

The survey also reported that many of the LIHEAP recipients faced significant medical and health problems in the past five years, partly as a result of high energy costs. Respondents reported the following:

- 30% went without food for at least one day
- 41% went without medical or dental care

- 33% did not fill a prescription or took less than the full dose of a prescribed medication, and
- 25% had someone in the home become sick because the home was too cold.
- An increase at the level being considered in this case renders these customers even more vulnerable.[2]

Q. 6 How much utility assistance funding did Southwest Gas receive for their customers?

A. 6 In state fiscal year 2010, based on a survey of our agencies distributing bill assistance funding from a variety of sources, including LIHEAP, Southwest Gas received $1,537,414.

Q. 7 Why is this information important or relevant in this case?

A. 7 These issues are important in this case for a couple of reasons. First, as previously stated, the need for bill assistance far outweighs the resources available for the families in need. In February, March and April, the City of Phoenix reported receiving 9,600, 11,000 and 12,400 calls for assistance respectively. These numbers are up by 2,000 calls from the previous year for the same months. They are able to serve 1 in 10 of those calling for help.

The proposed increase for low-income customers in this case is higher than for any other rate class at 15.93% for G-10 and 14.96% for G-11. A request for this percentage increase for this group of customers at any time, but particularly during the worst economic recession to hit the state in years, and to assign a higher rate to low-income customers than any other customer is, at best, irresponsible and insensitive.

[2] 2009 National Energy Assistance Directors' Association, 2009 National Energy Assistance Survey, Final Report, April 2009, attached.

Q. 8 Will an increase of this level result in more disconnections for Southwest Gas customers?

A. 8 I believe that without question more customers will either be disconnected from service due to an inability to pay their bills, or will simply opt to self-disconnect because their bills, already troublesome, will be impossible to pay.

The Company has provided information indicating that they disconnect more customers than any other major utility in the State, including APS and SRP. In 2008, they disconnected 68,423 customers (5,701/month), in 2009, 69,266 (5,772/month) and in the first eight months of 2010, 44,820 (5,602/month) customers. See the attached spreadsheet with the Southwest Gas disconnection data.[3]

Q. 9 What is an energy burden, and what is the energy burden in Arizona?

A. 9 An energy burden is essentially the percentage of a person's income that is used to pay their energy bill. As stated in the text of the Low-Income Program: Smarter Greener Better Low-Income Conservation document at page 55, "Energy expenses represent an economic drain on low-income communities. The DOE reports that, on average, low-income households typically spend 14 percent of their total annual income on energy, compared to 3.5 percent for other households." As this statement indicates, low-income families have a much higher energy burden than other customers – the lower the income the higher the energy burden, and the greater difficulty maintaining utility service.

Q. 10. You indicated in your response to Question 2, that you are also asking the Commission to require Southwest Gas to enhance its marketing of the availability of the discount rates so that more eligible families are enrolled in the discount program. Would you please explain this request?

---

[3] Southwest Gas, Disconnections, State fiscal year (June-July) for the years ending 2008, 2009 and 2010, attached.

A. 10 Yes. Mr. Aldridge's testimony states, on page 3, that Southwest Gas has over 976,000 customers in Arizona, nearly 54% of its total customer base. If we conclude that based on the Arizona poverty rate, that 20% of the Southwest Gas customers also fall into this category, 195,200 customers are likely financially challenged, if not living at the federal poverty level. The low-income rates calculated in this case by Mr. Gieseking, are based on the number of customers currently enrolled in the Company's bill assistance program, LIRA. That number is 37,729 customers. While I don't believe all 195,200 customers will ever enroll in this discount program, I do believe there are more who if properly informed, more than 19 percent of the eligible customers would take advantage of an opportunity to save money on their gas bill, on average 28% less than non low-income customers, as Mr. Gieseking states.

Communication about the program and increased enrollment will be a necessity if in fact this proposal for 15.93% and 14.96% increases for low-income customers is approved. Simply relying on bill stuffers and human service providers to get the word out is inadequate. Families who are struggling are still in the mainstream of our communities, and should be approached through more traditional communication and marketing vehicles, such as newspapers, magazine ads and radio.

Q. 11 You also state in your response to Question 2, that you support the Low-Income Program: Smarter Greener Better Low-Income Energy Conservation. Will you please explain your position?

A. 11 This program is Southwest Gas' weatherization program which has been operating successfully in concert with the other Arizona utility weatherization programs, the federal Weatherization Assistance Program and the funding provided by those entities. These

partnerships create access for eligible households, to more energy efficient homes. Without this program, low-income homes would not have a chance at becoming more efficient. Low-income families are challenged to pay utility bills, let alone have funds for weatherization and efficiency improvements or equipment replacement.

Q. 12 Why is energy efficiency important for and to the low-income community?

A. 12 Housing in which low-income families live, tends to be less efficient and of poorer quality than other homes in our community. Additionally, as previously stated, many residents of the low-income households are vulnerable, for a variety of reasons including age, disability, and overall health. This program provides funding for eligible households to weatherize their homes, making them energy efficient and safe during weather extremes, either cold or hot. Multi-family and rental properties are also eligible for weatherization with the approval of the landlord, and assuming other program criteria are met. Additionally, once weatherized, residents reduce their utility bills for many, many years, allowing them to stay current on their utility bills, and to use their income for other basic household necessities, like food, medication and rent or mortgage payments and education.

Q. 13 Who performs the weatherization work in Arizona?

A. 13 Most of the low-income weatherization work in Arizona is done by or through Community Action Association Weatherization programs. Each Agency employs Building Performance Institute (BPI) certified technicians, a requirement of the federal weatherization program, holds a general contractors license, and may employ local businesses to contract some of the work. The weatherization staff are highly skilled, and

use the building science and technology standards required by Southwest Gas for other programs in place or being proposed in this Docket.

Q. 14 What is the Savings to Investment (SIR) for the weatherization program?

A. 14 Southwest Gas indicates in their Low-Income Program: Smarter Greener Better Low-Income Energy Conservation documentation, that the program realizes an .83 cost effectiveness ratio. It is important to note, that Southwest Gas money is not used in stand-alone weatherization jobs. Meaning every home weatherized with Southwest Gas money leverages other weatherization funding in that home. This funding may be federal Weatherization Assistance Program funding, or it may be funding provided by one of the electric utilities in their service territory, and funding provided the agencies through the Home Energy Assistance Fund managed by the Arizona Community Action Association. When the Southwest Gas funds are leveraged with other fund sources, the SIR increases to 1.16 if health and safety measures are included in the home. The SIR increases to 1.37 if health and safety measures are not undertaken in the home.

Additionally, as stated in the Low-Income Program: Smarter Greener Low-Income Energy Conservation on page 55, "According to the DOE, when the energy and non-energy related benefits are combined, the cost-benefit ratio of energy reduction is $3.71 for every $1.00 invested in the program." The utility money is well- invested.

Q. 15 Would you please summarize your request of the Arizona Corporation Commission?

A. 15 Yes. Raising the rates on a class of customer who are struggling to survive, in larger numbers than ever before, during a time when the unemployment rate is extremely high and the prospects of employment remain very low is not reasonable, humane and/or socially responsible. Furthermore, raising the rates of low-income customers at a higher

percentage than any other Southwest Gas rate class defies logic and does not demonstrate by any measure fairness or reasonableness. Therefore, the proposal for the G-10 and G-11 rate increase must be rejected by this Commission.

There must be a significant increase in effective outreach and education to customers throughout the Southwest Gas service territory, through conventional means to increase the percentage of families enrolled in the discount program.

Finally, I support the Low-Income Program: Smarter Greener Better Low-Income Energy Conservation, as it is essential and critical to maintaining sustainable energy efficient homes for families, and reduces the long-term energy burden for those residents.

Q. 16 Does that conclude your testimony?

A. 16 Yes it does. Thank you for considering this request.

RESPECTFULLY SUBMITTED, June 10, 2011

By _____

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Gov. Brewer calls special session on extended jobless benefits

*by **Mary Jo Pitzl and Jahna Berry** - Jun. 8, 2011 09:57 PM*
The Arizona Republic

Gov. Jan Brewer has called the Legislature into a special session Friday to extend unemployment benefits for nearly 15,000 Arizonans.

It is an eleventh-hour bid to keep checks flowing for people who are scheduled to exhaust their unemployment payments after Friday. To help win votes from some reluctant lawmakers, Brewer late Wednesday included a provision in her proposal that would hold Arizona businesses harmless from an expected increase in job-related taxes.

The session could be a lifeline for 14,697 workers who have been on unemployment for at least 79 weeks. By making a change to state law, Arizona would qualify for federal dollars to extend those benefits to a maximum 99 weeks.

Lawmakers would need to make a change to allow the state to calculate its unemployment numbers over a three-year period instead of two years.

The unemployment benefit is $212 a week, before taxes. Arizona's unemployment rate is 9.3 percent.

The call for a session, to begin at 10 a.m. Friday, caps several weeks of arm twisting and negotiations between the governor and reluctant Republican lawmakers.

Many lawmakers have been philosophically opposed to the idea of people receiving 99 weeks of unemployment checks, believing it's a disincentive to seeking a job. But Brewer, who said she shares the same disbelief that people could spend nearly two years on the unemployment rolls, said the recession had forced record unemployment.

"We have to acknowledge there are forces at play here larger than the inability or unwillingness of some people to find work," she wrote in a guest column published Wednesday in *The Republic*.

The state Department of Economic Security, which administers the unemployment p rogram, said the consequences of nearly 15,000 people losing benefits at a time when the economy was still floundering would be dire.

"They are those who have had the most difficulty getting back into the workforce," said Mark Darmer, deputy assistant director of the Division of Employment and Rehabilitation Services.

Without the money, these people "will be scrambling to find ways to cover their

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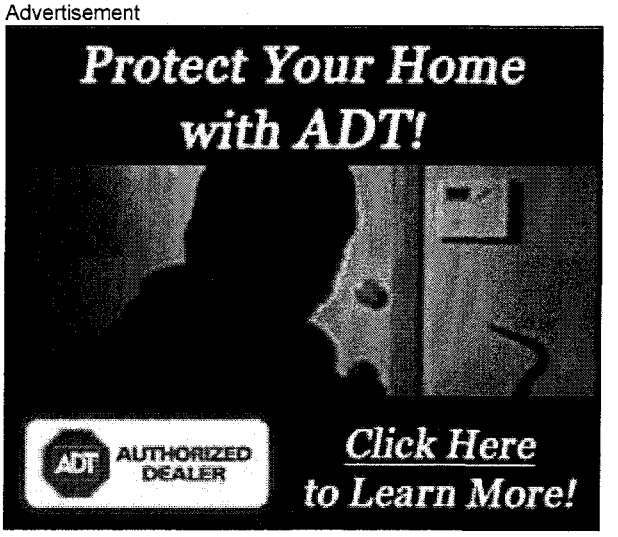

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minimal needs such as rent, utilities, basic needs that their families had," Darmer said.

The economic impact of the lost unemployment payments would also ripple throughout Arizona. If the extended benefits lapse, the state will lose the $3.2 million that flowed into the local economy each week as people cashed their checks, according to DES estimates. By the end of the year, those lost unemployment benefits would total $86.9 million.

The GOP leadership in the Legislature held out against a special session through Wednesday. Earlier in the day, House Speaker Andy Tobin, R-Paulden, said he might be able to muster enough support among the 40 Republicans he directs if the session included business tax breaks.

He suggested reviving two business-related bills Brewer had vetoed earlier this year.

Brewer rejected that. But in a bid to get as broad a consensus as possible, Brewer added a provision that would hold Arizona employers harmless from a bump-up in taxes that is expected to kick in July 1.

She also included two conditions that would be imposed on those collecting the extended benefits checks: that they actively seek work at least four days a week and that they take the first job offer they get that pays at least minimum wage.

Brewer spokesman Matthew Benson said the governor believed she has the two-thirds vote needed in both the House and Senate to pass the bill.

The governor has the support of minority Democrats, who tried to get the Legislature to extend the benefits in April, when lawmakers were still meeting in their regular session. House Minority Leader Chad Campbell, D-Phoenix, said the brinksmanship was regrettable and could have been avoided if lawmakers had acted two months ago.

On Wednesday, the Children's Action Alliance sent letters to all 90 lawmakers urging support. The letter detailed unemployment statistics for each member's district, noting, for example, the 25.3 percent rate in Yuma County, as reported by state officials.

The benefits would come without a tax increase, the letter noted.

"This is about spending our own federal dollars right here in Arizona," the letter states.

Republic reporter Ginger Rough contributed to this article.

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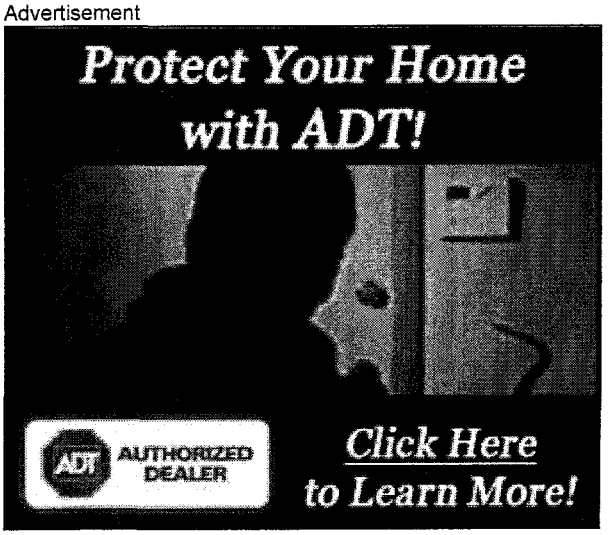

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NATIONAL ENERGY ASSISTANCE DIRECTORS' ASSOCIATION

2009 NATIONAL ENERGY ASSISTANCE SURVEY

Final Report
April 2009

The National Energy Assistance Directors' Association

The National Energy Assistance Directors' Association (NEADA) represents the state directors of the Low Income Home Energy Assistance Program (LIHEAP). NEADA is a nonprofit educational and policy organization based in Washington, DC. Its mission is to support the delivery of LIHEAP services by state agencies and programs.

This report has been prepared by APPRISE for NEADA under Grant No. 90XP0249 through the Administration for Children and Families (ACF), U.S. Department of Health and Human Services. The statements, findings, conclusions, and recommendations do not necessarily reflect the views of ACF.

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The study would not have been possible without the participation of the directors and staff at the state LIHEAP offices in:

California	Iowa	Montana	New York
Connecticut	Maine	North Carolina	Ohio
Delaware	Minnesota	New Mexico	Pennsylvania
Georgia			

Mark Wolfe
Executive Director
National Energy Assistance Directors' Association

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Executive Summary

The National Energy Assistance Directors' Association (NEADA), representing the state LIHEAP directors, received a grant through the Administration for Children and Families (ACF), U.S. Department of Health and Human Services to update the information about LIHEAP-recipient households that was collected in the 2003, 2005, and 2008 NEA Surveys. This survey documented changes in the affordability of energy bills, the need for LIHEAP, and the choices that low-income households make when faced with unaffordable energy bills.

The 2009 Survey included the 12 states that were included in the 2008 Survey and an oversample in Connecticut. Stratified samples of fiscal year 2009 LIHEAP recipients were chosen from each of the state LIHEAP databases. This report presents the findings from the 2009 NEA Survey and provides comparisons to the 2003 and 2008 NEA Surveys. The survey and report were prepared for NEADA by APPRISE.

During the period of study, low-income households across the country faced an increasingly difficult economic climate and continued to deal with high energy costs. The survey substantiated these issues – showing that 36 percent were unemployed at some point during the year and that 35 percent reported higher energy bills than the previous year. However, while the survey showed that LIHEAP recipients continued to face many challenges in meeting their energy needs, the prevalence of these problems did not increase as compared to the previous year. One important factor that improved the circumstances of low-income households with respect to their energy bills was the increase in the LIHEAP appropriation from $2.57 billion in FY 2008 to $5.1 billion in FY 2009. This resulted in greater average LIHEAP benefits and a greater percentage of eligible households served. Without this increased funding, we expect that we would have seen an increase in the prevalence of the problems studied in this report.

LIHEAP Recipient Households

The study confirmed that LIHEAP recipient households are likely to be vulnerable to temperature extremes.

- 39 percent had a senior in the household aged 60 or older.
- 44 percent had a disabled household member.
- 45 percent had a child 18 or younger.
- 92 percent had at least one vulnerable household member.

The study also provided information on challenges that these households faced.

- 36 percent were unemployed at some point during the previous year.
- 82 percent had a serious medical condition.
- 25 percent used medical equipment that requires electricity.

The recession had a big impact on this group in the past year. The percent who had been unemployed at some point during the year increased from 29 percent to 36 percent. LIHEAP recipients with income above 150 percent of the poverty level faced the greatest increase, from 17 percent who had been unemployed sometime in FY 2008 to 39 percent who had been unemployed sometime in FY 2009.

Energy Costs

LIHEAP recipients reported that they face high energy costs.

- 37 percent reported that their energy bills were more than $2,000 in the past year.
- Pre-LIHEAP energy burden averaged 16 percent and post-LIHEAP energy burden averaged 11 percent for these households, compared to 7 percent for all households in the U.S. and 4 percent for non low-income households in the U.S.[1]
- 35 percent said that their energy bills were higher than they had been in the previous year and 40 percent said that they were more difficult to pay than in the previous year.
- 60 percent of those who said that it was more difficult to pay their energy bills reported that the main reason was their financial situation.

LIHEAP benefits increased since the previous year due to the greater appropriation in FY 2009. Twenty-one percent had total LIHEAP benefits of more than $750 in FY 2009, compared to 12 percent in FY 2008.

Responses to High Energy Costs

Households reported that they took several actions to make ends meet.

- 36 percent closed off part of their home.
- 26 percent kept their home at a temperature that was unsafe or unhealthy.
- 20 percent left their home for part of the day.
- 33 percent used their kitchen stove or oven to provide heat.

Inability to Pay Energy Bills

Many LIHEAP recipients were unable to pay their energy bills.

- 49 percent skipped paying or paid less than their entire home energy bill.
- 35 percent received a notice or threat to disconnect or discontinue their electricity or home heating fuel.
- 12 percent had their electric or natural gas service shut off in the past year due to nonpayment.
- 27 percent were unable to use their main source of heat in the past year because their fuel was shut off, they could not pay for fuel delivery, or their heating system was broken and they could not afford to fix it.
- 17 percent were unable to use their air conditioner in the past year because their electricity was shut off or their air conditioner was broken and they could not afford to fix it.

Housing and Financial Problems

Many LIHEAP recipients had problems paying for housing in the past five years, due at least partly to their energy bills.

- 31 percent did not make their full mortgage or rent payment.
- 5 percent were evicted from their home or apartment.
- 4 percent had a foreclosure on their mortgage.
- 12 percent moved in with friends or family.
- 3 percent moved into a shelter or were homeless.

[1] Source: 2007 LIHEAP Notebook.

They faced other significant financial problems as well.

- 17 percent got a payday loan in the past five years.
- 2 percent were forced into bankruptcy in the past year.

Medical and Health Problems

Many of the LIHEAP recipients faced significant medical and health problems in the past five years, partly as a result of high energy costs. All of these problems increased significantly since the 2003 survey.

- 30 percent went without food for at least one day.
- 41 percent went without medical or dental care.
- 33 percent did not fill a prescription or took less than the full dose of a prescribed medication.
- 25 percent had someone in the home become sick because the home was too cold.

The Need for LIHEAP

Households reported enormous challenges despite the fact that they received LIHEAP. However, they reported that LIHEAP was extremely important.

- 64 percent of those who did not keep their home at unsafe or unhealthy temperatures said they would have done so if LIHEAP had not been available.
- 53 percent of those who did not have their electricity or home heating fuel discontinued said that they would have if it had not been for LIHEAP.
- 98 percent said that LIHEAP was very or somewhat important in helping them to meet their needs.

It is clear that many of these households will continue to need LIHEAP to meet their energy and other essential needs. 88 percent said that they have or plan to apply for LIHEAP in the next year.

I. Introduction

The National Energy Assistance Directors' Association (NEADA), representing the state LIHEAP directors, received a grant through the Administration for Children and Families (ACF), U.S. Department of Health and Human Services to update the information about LIHEAP-recipient households that was collected in the 2003, 2005, 2008, and 2009 NEA Surveys. This survey documented changes in the affordability of energy bills, the need for LIHEAP, and the choices that low-income households make when faced with unaffordable energy bills.

The 2009 NEA Survey selected a new sample of 2009 LIHEAP recipients to document changes in the need for LIHEAP and changes in the choices that low-income households make when faced with unaffordable energy bills. This report presents the findings from the 2009 NEA Survey and provides comparisons to the 2003 and 2008 NEA Surveys. The survey and report were prepared for NEADA by APPRISE.

A. Low Income Home Energy Assistance Program (LIHEAP)

The Low Income Home Energy Assistance Program (LIHEAP) is administered by the U.S. Department of Health and Human Services (HHS). The purpose of LIHEAP is "to assist low-income households, particularly those with the lowest incomes, that pay a high proportion of household income for home energy, primarily in meeting their immediate home energy needs." The LIHEAP statute defines home energy as "a source of heating or cooling in residential dwellings."[2]

Federal dollars for LIHEAP are allocated by the U.S. Department of Health and Human Services to the grantees (i.e., the 50 states, District of Columbia, 128 tribes and tribal organizations, and five insular areas) as a block grant. Program funds are distributed by a formula, which is weighted towards relative cold-weather conditions.

Program funds are disbursed to LIHEAP income-eligible households under programs designed by the individual grantees. Section 2605(b)(2) allows LIHEAP grantees to use two income-related standards in determining household eligibility for LIHEAP assistance:

- Categorical eligibility for households with one or more individuals receiving Temporary Assistance for Needy Families, Supplemental Security Income payments, Food Stamps, or certain needs-tested veterans' and survivors' payments, without regard for household income.

- Income eligibility for households with incomes that do not exceed the greater of an amount equal to 150 percent of the federal poverty level[3], or an amount equal to 60 percent of the state median income. Grantees may target assistance to poorer households by setting lower income eligibility levels. Grantees are prohibited from setting income eligibility levels lower than 110

[2] The statutory intent of LIHEAP is to reduce home heating and cooling costs for low-income households. However, information on total residential energy costs is more accessible and more apparent to LIHEAP-recipient respondents. Moreover, any reduction in home heating and cooling costs leads to a direct reduction in total residential energy costs. Therefore, this report addresses total residential energy costs.

[3] Most states use the 150 percent of federal poverty level maximum as the guideline. 150 percent of federal poverty in FY2008 is $16,245 for a single person and $33,075 for a family of four.

percent of the poverty level. Eligibility priority may be given to households with high energy burden or need.[4]

B. *2009 National Energy Assistance Survey*

The 2009 NEA Survey aimed to update the information about LIHEAP-recipient households that was collected in the 2003, 2005, and 2008 NEA Surveys. Stratified samples of 2009 LIHEAP recipients were selected to collect new information about the consequences of high energy bills for low-income households. The 2009 National Energy Assistance Survey collected the following information from LIHEAP-recipient households:

- Demographic, energy expenditure, and income information
- Healthy home behaviors
- History of LIHEAP participation
- Constructive actions taken to meet energy expenses
- Signs of unaffordable energy bills
- Health and safety consequences of unaffordable energy bills
- Effects of unaffordable energy bills on housing
- Changes in financial situation and affordability of home energy bills
- Impact and importance of LIHEAP benefits for recipient households

The 2009 Survey included the 12 states that were included in the 2008 Survey and a larger sample of CT LIHEAP recipients, as a result of additional funding that was allocated for a special study in CT. This report presents the national and regional results. A separate report presents the results for CT compared to the Northeast and the U.S. as a whole.

C. *Organization of the Report*

This report has six sections that follow this introduction.

- *Section II: Survey Methodology*: Presents the methodology used for sample selection, survey implementation, weighting, and survey response rates.

- *Section III: LIHEAP Recipients:* Presents demographic and income information LIHEAP-recipient households that completed the 2009 NEA Survey.

- *Section IV: Problems Faced By Low-Income Households in Meeting Their Energy Needs:* Presents information about actions that LIHEAP-recipient households take to meet their energy needs, household necessities, and health and wellness in the face of significant financial constraints.

- *Section V: The Need For LIHEAP:* Presents information about the impact and importance of LIHEAP on recipient households.

[4] Description of LIHEAP information obtained from "Low Income Home Energy Assistance Program. Report to Congress for Fiscal Year 2001." U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. Additional information regarding the LIHEAP program can be found on the World Wide Web at: http://www.acf.hhs.gov/programs/liheap/.

- *Section VI: Regional Analysis:* Presents analysis of the problems faced by low-income households in the Northeast, Midwest, West, and South.

- *Section VII: Conclusion:* Presents a summary of the key findings in this report.

II. Survey Methodology

This section describes the methodology for the 2009 NEA Survey, including procedures for sample selection, survey implementation, and weighting.

A. Survey Implementation

A survey advance letter was sent to the sample of selected LIHEAP recipients from the 13 participating states. This letter announced the survey, notified potential respondents that they might be called to participate in the survey, explained the purpose of the survey, and gave potential respondents the option to call the phone center to complete the survey at their convenience.

APPRISE retained TMR Group to conduct the telephone survey through its call center. A researcher from APPRISE trained TMR's employees on the survey instrument and monitored survey implementation. TMR's manager in charge of the survey instructed interviewers how to use the computerized version of the survey to record customer responses.

Interviewer training consisted of two hour-long sessions – one for daytime and one for evening interviewers. This training session provided interviewers with an overview of the project, purpose behind questions asked, and strategies to provide accurate clarification and elicit acceptable responses through neutral probing techniques.

Interviewer monitoring allowed APPRISE researchers to both listen to the way interviewers conducted surveys and see the answers they chose on the computerized data entry form. TMR's manager facilitated open communication between the monitors and interviewers, which allowed the monitors to instruct interviewers on how to implement the survey and accurately record customer responses.

Telephone interviews were conducted between November 16, 2009 and January 26, 2010. During this time period, 1,828 interviews were completed.

B. Sample Selection and Response Rates

LIHEAP recipients were selected from each of the 13 states chosen to participate in the survey. Because of a special congressional earmark for Connecticut, a special study was conducted for Connecticut. Table II-1 details the number of LIHEAP recipients selected to complete the survey, number of completed interviews, cooperation rates, and response rates for the national sample. Table II-1 presents the following information:

- **Number selected:** Initially, approximately 220 households were selected in each state, or for each district in Connecticut. Due to the expected interview response rate based off of the 2008 study, an additional sample of 180 was initially selected for New York. Because client telephone numbers were not provided in the Georgia LIHEAP database, an additional sample of 380 was selected. Due to the high number of non-interviews and unusable telephone numbers, an additional sample of 150 cases were selected for California, 30 for Iowa, 80 for New Mexico, and 80 for North Carolina. In Connecticut, an additional sample of 100 was selected for Districts 1-3 and an additional sample of 150 was selected for Districts 4-5. The final sample consisted of 5,240 cases.

- **Unusable:** There were 1844 cases deemed unusable because no one was present in the home during the survey who was able to complete the survey, or because phone numbers were missing, unavailable, disconnected, or incorrect. These households are not included in the denominator of the response rate or the cooperation rate. They are included in the denominator of the completed interview rate.

- **Non-Interviews:** There were 418 cases classified as non-interviews because the qualified respondent refused to complete the interview, or because the respondent asked the interviewer to call back to complete the interview at a later time, but did not complete the interview during the field period. These households are included in the denominator of the cooperation rate, the response rate, and the completed interview rate.

- **Unknown eligibility:** There were 1150 cases that were determined to have unknown eligibility to complete the interview, due to answering machines, no answers, and language barriers.[5] These households are not included in the denominator of the cooperation rate. They are included in the denominator of the response rate and the completed interview rate.

- **Completed interviews**: The completed interviews are households that were reached and that answered the full set of survey questions by telephone. In total, 1,828 interviews were completed.

- **Cooperation rate**: The cooperation rate is the percent of eligible households contacted who completed the survey. This is calculated as the number of completed interviews divided by the interviews plus the number of non-interviews (refusals plus non-completed call backs[6]). Overall, this survey achieved a 81 percent cooperation rate.

- **Response rate:** The response rate is the number of completed interviews divided by the number of completed interviews plus the number of non-interviews (refusals plus non-completed call backs) plus all cases of unknown eligibility (due to answering machines and language barriers). This survey attained a 54 percent response rate.

- **Completed Interview Rate:** The completed interview rate is the percentage of households selected that completed the survey. This survey attained a 35 percent completed interview rate.

Table II-1
Sample and Response Rates

	Total Sample Statistics
Number Selected	5,240
Unusable	1,844
Non-Interviews	418

[5] The telephone interview center conducted interviews with respondents with a language barrier who spoke Spanish. However, there were 187 cases in which an interview could not be completed due to a language barrier for a language other than Spanish. Eighty-three Spanish interviews were completed.

[6] Non-completed callbacks include respondents who asked the interviewer to call back at a later time to complete the interview, but did not complete the interview by the end of the field period.

	Total Sample Statistics
Unknown Eligibility	1,150
Completed Interviews	1,828
Cooperation Rate	81%
Response Rate	54%
Completed Interview Rate	35%

Table II-2 displays the number of interviews completed by state. The response rate ranged from 40 percent in California to 74 percent in North Carolina.

Table II-2
Number of Completed Interviews by State

State	Total Selected	Completed Interviews	Response Rate
California	370	106	40%
Connecticut	1700	530	44%
Delaware	220	102	62%
Georgia[7]	600	120	65%
Iowa	250	100	57%
Maine	220	115	64%
Minnesota	220	103	62%
Montana	220	106	65%
New Mexico	300	106	57%
New York[6]	400	111	49%
North Carolina[6]	300	114	74%
Ohio	220	102	61%
Pennsylvania	220	113	69%
TOTAL	5240	1828	54%

Table II-3 displays the number of interviews completed by CT district. The response rate ranged from 41 to 50 percent.

Table II-3
Connecticut Number of Completed Interviews by District

State	Total Selected	Completed Interviews	Response Rate
Connecticut D1	320	106	50%
Connecticut D2	320	111	47%

[7] Client telephone number was not provided in the GA LIHEAP datasets, and many numbers were missing from the NC and NY LIHEAP datasets. Manual look-ups were conducted for these households.

State	Total Selected	Completed Interviews	Response Rate
Connecticut D3	320	103	44%
Connecticut D4	370	107	41%
Connecticut D5	370	103	41%

C. *Weights*

Two sets of weights were used to ensure that state-level data represents each state and that the overall findings are representative of the national LIHEAP population. First, weights were applied within states. The purpose of these weights was to adjust for selection and response rate variation within poverty group and vulnerable status. A second set of weights was used so that the sum of the state weights was proportional to the strata size from which it was drawn. In the estimates presented in this report, the total weight, comprised of these two separate weights, is used. This results in a nationally representative sample of 2009 LIHEAP recipients.

III. LIHEAP Recipient Households

The 2009 National Energy Assistance Survey included a series of questions about household demographics. Table III-1 displays information on the number of household members. The table shows that 36 percent of LIHEAP recipients live in single person households and 57 percent have two or fewer household members.

Table III-1
Number of Household Members

Number of Household Members	Percent of Respondents
1	36%
2	21%
3	17%
4	11%
5	8%
6 or more	7%

Table III-2 displays information on the presence of vulnerable household members. The table shows that 39 percent have a senior in the home, 44 percent have a disabled household member, 45 percent have a child age 18 or younger, 23 percent have a child age five or younger, and 18 are single parent households.

Table III-2
Vulnerable Groups

	Household With Senior (Age 60 or older)	Household With Disabled	Household With Child (Age 18 or under)	Household With Young Child (Age 5 or under)	Single Parent Household[1]
Yes	39%	44%	45%	23%	18%
No	61%	56%	55%	77%	82%
Don't Know/ Refused	<1%	1%	<1%	<1%	0%

[1] Defined as households with only one adult residing with one or more children.

Table III-3 shows that 92 percent of LIHEAP recipients have at least one vulnerable household member.

Table III-3
Households With At Least One Vulnerable Member

	Percent of Respondents
At Least One Vulnerable Member	92%
No Vulnerable Members	8%

Respondents were asked whether they own or rent their home. Table III-4 shows that 46 percent of LIHEAP recipients own their homes.

Table III-4
Home Ownership

Home Ownership	Percent of Respondents
Own	46%
Rent	51%
Other	2%
Don't Know	<1%

Table III-5 displays the annual household income distribution for LIHEAP-recipient households. The table shows that 38 percent have income of less than or equal to $10,000 and only one percent have income above $40,000.

Table III-5
Annual Income

Annual Income	Percent of Respondents
≤ $ 10,000	38%
$ 10,001 - $ 20,000	41%
$ 20,001 - $ 30,000	16%
$ 30,001 - $ 40,000	4%
More than $ 40,000	1%

Table III-6A shows that 20 percent had income at or below 50 percent of the poverty level and 62 percent had income at or below the poverty level. Only 10 percent had income above 150 percent of the poverty level.

Table III-6A
Poverty Level

Poverty Level	Percent of Respondents
0%-50%	20%
51%-100%	42%
101%-125%	16%
126%-150%	12%
>150%	10%

Table III-6B displays the household poverty level by vulnerable group. The table shows that households with children and non-vulnerable households are more likely than households with seniors and with disabled members to have income at or below 50 percent of the poverty level.

Table III-6B
Poverty Level by Vulnerable Group

	Senior	Disabled	Child 18 or Younger	Child 5 or Younger	Single Parent Household[1]	Non-Vulnerable
Number of Respondents	757	788	778	362	299	152
0% - 50%	10%	17%	29%	36%	33%	28%
51% - 100%	43%	50%	39%	38%	41%	29%
101% - 150%	37%	25%	24%	18%	19%	28%
> 150%	10%	8%	9%	8%	8%	14%

[1] Defined as households with only one adult residing with one or more children.

Respondents were asked about the type of income and benefits received in the past year. Table III-7 shows that 31 percent reported that they received employment income, 37 percent said that they received retirement income, 40 percent reported that they received public assistance, and 61 percent reported that they received non-cash benefits, including food stamps or public housing.

Table III-7
Types of Income and Benefits Received

	Wages or Self-Employment Income	Retirement Income	Public Assistance	Non-cash benefits
Yes	31%	37%	40%	61%
No	68%	62%	58%	38%
Don't Know /Refused	1%	1%	2%	1%

Respondents were asked whether they had been unemployed at some time during the year. Table III-8A shows that 36 percent reported that they had been unemployed at some point during the past year. This compares to 31 percent in 2003 and to 29 percent in 2008.

Table III-8A
Unemployed During the Year

	2003	2008	2009
Yes	31%	29%	36%
No	69%	70%	63%
Don't Know / Refused	0%	1%	1%

Table III-8B displays the percent of respondents who were unemployed during the past year by vulnerable group. The table shows that households with children under 18 and non-vulnerable households were most likely to report that they had been unemployed. Fifty-four percent of each of these groups reported that they had been unemployed.

Table III-8B
Unemployed During the Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Yes	17%	28%	54%	54%
No	83%	72%	46%	42%
Don't Know / Refused	<1%	<1%	<1%	5%

Table III-8C displays the percent of respondents who reported that they had been unemployed in the past year by poverty level. The table shows that 58 percent of respondents with income at or below 50 percent of the poverty level reported that they had been unemployed, compared to 31 percent between 51 and 100 percent of poverty, 27 percent between 101 and 150 percent of poverty, and 39 percent above 150 percent of poverty.

Table III-8C
Unemployed During the Year
By Poverty Level

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Yes	58%	31%	27%	39%
No	41%	69%	73%	60%
Don't Know / Refused	1%	<1%	<1%	2%

Table III-8D displays the percent of households with income above 150 percent of poverty who were unemployed during the year, in 2003, 2008, and 2009. The table shows that there was a large increase in the percentage of these households who were unemployed in 2009, from the previous year. The percent increased from 17 percent to 39 percent.

Table III-8D
Unemployed During the Year
Poverty Level >150%

	2003	2008	2009
Number of Respondents	130	77	312
Yes	29%	17%	39%
No	71%	83%	60%
Don't Know / Refused	0%	0%	2%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Respondents were asked several questions about different medical conditions that members of their households had. Table III-9 shows that 46 percent had asthma, 21 percent had breathing-related conditions, 51 percent had heart disease, and 54 percent had allergies.

Table III-9A
Medical Conditions: Someone in the Household Had or Had Symptoms of These Medical Conditions

	Asthma or Symptoms of Asthma	Chronic Bronchitis, Emphysema, COPD	Hypertension, Heart Disease, Heart Attack, or Stroke	Allergies or Symptoms of Allergies
Yes	46%	21%	51%	54%
No	54%	78%	48%	45%
Don't Know/ Refused	1%	1%	1%	1%

Table III-9B displays the percent of respondents who had each of these medical conditions, by vulnerable group. The table shows that the rates of these conditions vary by vulnerable group. Disabled households are most likely to have asthma and breathing conditions. Seniors are most likely to have heart disease. Households with disabled members and households with children are most likely to have allergies.

Table III-9B
Medical Conditions: Someone in the Household Had, or Had Symptoms of These Medical Conditions By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Asthma or Symptoms of Asthma	42%	60%	49%	29%
Chronic Bronchitis, Emphysema, COPD	22%	35%	17%	12%
Hypertension, Heart Disease, Heart Attack, or Stroke	75%	66%	32%	40%
Allergies or Symptoms of Allergies	48%	66%	60%	34%

Table III-9C displays the percent of respondents who had medical conditions by poverty level. The table shows that there is not a clear relationship between poverty level and these symptoms.

Table III-9C
Medical Conditions: Someone in the Household Had, or Had Symptoms of These Medical Conditions By Poverty Level

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Asthma or Symptoms of Asthma	45%	49%	42%	44%
Chronic Bronchitis, Emphysema, COPD	18%	24%	22%	14%

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Hypertension, Heart Disease, Heart Attack, or Stroke	39%	54%	57%	48%
Allergies or Symptoms of Allergies	59%	55%	52%	46%

Table III-10A displays the percent of respondents who reported that they had any of these conditions. The table shows that 82 percent reported that someone in the household had at least one of these conditions.

Table III-10A
Medical Conditions: Someone in the Household Had, or Had Symptoms of Allergies, Asthma, Chronic Bronchitis, Emphysema, COPD, High Blood Pressure, Heart Disease, a Heart Attack, or Stroke

	Presence of Medical Condition
Yes	82%
No	17%
Don't Know/ Refused	<1%

Table III-10B shows the percent of respondents who reported any of these conditions by vulnerable group. The table shows that households with seniors and disabled household members were most likely to report these conditions. Ninety percent of households with a senior reported that they had one of these conditions and 94 percent with a disabled household member reported that they had one of these conditions.

Table III-10B
Medical Conditions: Someone in the Household Had, or Had Symptoms of Allergies, Asthma, Chronic Bronchitis, Emphysema, COPD, High Blood Pressure, Heart Disease, a Heart Attack, or Stroke By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Yes	90%	94%	77%	65%
No	10%	6%	23%	31%
Don't Know/Refused	0%	0%	<1%	4%

Table III-10C displays the percent of respondents who reported any of these conditions by poverty group. The table shows that households in the middle poverty level groups are more likely to have these conditions.

Table III-10C
Medical Conditions: Someone in the Household Had, or Had Symptoms of Allergies, Asthma, Chronic Bronchitis, Emphysema, COPD, High Blood Pressure, Heart Disease, a Heart Attack, or Stroke By Poverty Level

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Yes	76%	86%	84%	77%
No	23%	14%	15%	23%
Don't Know/Refused	1%	<1%	1%	1%

Table III-11 displays the percent of respondents who had a breathing condition and who needed to go to the hospital for the condition during the past year. This table shows that about one half of the households had asthma or another breathing problem, and about 19 percent had the condition and needed to go to the hospital for the condition.

Table III-11
Medical Conditions: Someone in the Household Had Asthma, Symptoms of Asthma, or had Chronic Bronchitis, Emphysema, or Chronic Obstructive Pulmonary Disease (COPD) And Needed to Go to the Hospital for This Health Problem in the Past Year

	Had Asthma, or Bronchitis, Emphysema, or COPD	Needed to Go to Hospital
Yes	49%	19%
No	50%	30%
Don't Know / Refused	1%	<1%
Does Not Have Condition	--	50%

Respondents were asked whether they use any medical equipment that requires the use of electricity. Table III-12A shows that 25 percent of respondents reported that they use such equipment.

Table III-12A
Someone in the Household Utilizes Necessary Medical Equipment that Uses Electricity

Someone in the Household Utilizes Necessary Medical Equipment that Uses Electricity	Percent of Respondents
Yes	25%
No	75%
Don't Know/Refused	<1%

Table III-12B displays the percent who reported the use of such medical equipment by vulnerable group. The table shows that 38 percent of households with a disabled member and 29 percent of households with

children reported that they use this equipment. Households that did not have vulnerable members were least likely to report the use of this equipment.

Table III-12B
Member of Household Utilizes Medical Equipment that Requires Electricity
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Yes	21%	38%	29%	9%
No	79%	62%	71%	86%
Don't Know / Refused	<1%	0%	0%	5%

Table III-13A displays the respondent's self-reported health condition. The table shows that despite the reported presence of the medical conditions displayed earlier, 37 percent said that they were very healthy, and 43 percent said that they were somewhat healthy. Only six percent said that they were very unhealthy.

Table III-13A
Respondent's Health Condition

Respondent's Health Condition	Percent of Respondents
Very Healthy	37%
Somewhat Healthy	43%
Somewhat Unhealthy	12%
Very Unhealthy	6%
Don't Know/Refused	1%

Table III-13B displays the respondent's health condition by vulnerable group. The table shows that households with disabled members were mostly likely to say that they were unhealthy. One third of respondents with disabled members said that they were somewhat or very unhealthy, 22 percent of respondents with seniors in the household, 11 percent of households with no vulnerable members, and nine percent of households with children said that they were somewhat or very unhealthy.

Table III-13B
Respondent's Health Condition
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Very Healthy	29%	23%	50%	39%
Somewhat Healthy	48%	42%	41%	46%
Somewhat Unhealthy	14%	20%	7%	8%
Very Unhealthy	8%	13%	2%	3%

	Senior	Disabled	Child Under 18	Non-Vulnerable
Don't Know/Refused	1%	2%	1%	4%

Table III-13C displays the respondent's health condition by poverty level. The table shows that there is not a significant relationship between poverty level and reported health condition.

Table III-13C
Respondent's Health Condition
By Poverty Level

	Poverty Level			
	0-50%	**51-100%**	**101-150%**	**>150%**
Number of Respondents	286	673	557	312
Very Healthy	41%	38%	36%	34%
Somewhat Healthy	42%	41%	45%	49%
Somewhat Unhealthy	11%	13%	13%	7%
Very Unhealthy	4%	7%	6%	9%
Don't Know / Refused	2%	1%	<1%	1%

Respondents were asked several questions about home behaviors and home conditions that could affect their health. Table III-14A shows that 21 percent of respondents reported that they smoke in the home.

Table III-14A
Healthy Homes: Someone Smokes Inside the House

Health Homes: Someone Smokes Inside the House	Percent of Respondents
Yes	21%
No	79%
Don't Know/Refused	<1%

Table III-14B displays the percent who reported that they smoke in the home by vulnerable group. Households with no vulnerable members and households with disabled members were most likely to report that they smoke in the home.

Table III-14B
Healthy Homes: Someone Smokes Inside the House
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Yes	15%	26%	18%	31%
No	85%	74%	82%	66%
Don't Know/Refused	0%	0%	0%	4%

Table III-14C displays the percent who smoke in the home by poverty level. The table shows that the percent does not vary by poverty level.

Table III-14C
Healthy Homes: Someone Smokes Inside the House
By Poverty Level

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Yes	19%	22%	20%	19%
No	80%	78%	80%	80%
Don't Know / Refused	1%	<1%	<1%	1%

Respondents were asked how often they use their bathroom exhaust when showering or bathing and how often they use their kitchen exhaust when cooking. Table III-15 shows that about half of the respondents said that they never use the bathroom exhaust or don't have one, and 39 percent said that they never use their kitchen exhaust or don't have one.

Table III-15
Healthy Homes: Members of Household Use Exhaust Fan

Members of Household Use Exhaust Fan	In Bathroom: When Showering or Bathing	In Kitchen: When Cooking
Always	30%	22%
Sometimes	11%	21%
Rarely	8%	16%
Never/Don't Have One	49%	39%
Don't Know/Refused	2%	1%

Respondents were asked whether they have had mold or pests in their home in the past year. Table III-16A shows that 23 percent reported that they had mold and 42 percent reported that they had pests.

Table III-16A
Healthy Home Issue: Mold or Pests in Home in Past Year

	Mold	Pests
Yes	23%	42%
No	76%	57%
Don't Know/Refused	1%	<1%

Table III-16B displays the percent of respondents who reported that they have mold or pests by vulnerable group. The table shows that households with children were more likely to report these problems.

Table III-16B
Healthy Homes Issue: Had Most or Pests in Home in Past Year
By Vulnerable Group

	Senior	Disabled	Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Mold	16%	24%	31%	20%
Pests	41%	44%	48%	40%

Table III-16C displays the percent of respondents who reported that they had mold or pests by poverty level. The table does not show a clear relationship between poverty group and these problems.

Table III-16C
Healthy Homes: Had Mold or Pests in Home in Past Year
By Poverty Level

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Mold	24%	22%	21%	28%
Pests	46%	40%	45%	38%

Table III-17 displays the presence of respiratory conditions by whether healthy home behaviors are practiced. The table shows that 57 percent of respondents who have someone smoke in the home have someone in the home with asthma, compared to 43 percent who do not and 39 percent have someone in the home with bronchitis, emphysema, or COPD compared to 16 percent who do not have someone who smokes in the home. The table also shows that respondents who use the bathroom and kitchen exhausts are somewhat less likely to have someone in the home with these medical conditions.

Table III-17
Presence of Respiratory Condition
By Healthy Home Conditions

	Asthma or Symptoms of Asthma	Chronic Bronchitis, Emphysema or COPD
	Yes	Yes
Smokes in Home	57%	39%
Does Not Smoke in Home	43%	16%
Uses Bathroom Exhaust	44%	20%

	Asthma or Symptoms of Asthma	Chronic Bronchitis, Emphysema or COPD
	Yes	Yes
Does Not Use Bathroom Exhaust	49%	23%
Uses Kitchen Exhaust	44%	20%
Does Not Use Kitchen Exhaust	49%	23%

Respondents were asked to report the primary fuel used to heat their home. Table III-18 shows that 43 percent use natural gas, 24 percent use electricity, 17 percent use fuel oil or kerosene, and 10 percent use LPG.

Table III-18
Primary Fuel Used for Home Heating

Primary Fuel Used for Home Heating	Percent of Respondents
Natural Gas	43%
Electricity	24%
Fuel Oil or Kerosene	17%
Bottled Gas (LPG or Propane)	10%
Wood	2%
Coal or Coke	<1%
Other Fuel	<1%
No Fuel Used	<1%
Solar Energy	0%
Don't Know/Refused	3%

Table III-19 shows that six percent of respondents have their heat included in their rent.

Table III-19
Heat included in Rent

Heat included in Rent	Percent of Respondents
Yes	6%
No/ Own Home	93%
Do Not Pay Rent	1%
Don't Know/Refused	<1%

Table III-20 displays the primary method of summer cooling. The table shows that 36 percent have use window or wall air conditioning, 26 percent use central air conditioning, and 24 percent use fans.

Table III-20
Primary Method of Summer Cooling

Primary Method of Summer Cooling	Percent of Respondents
Window or Wall Air Conditioning	36%
Central Air Conditioning	26%
Fans	24%
Evaporative or Swamp Cooling	2%
No Cooling Method Used	11%
Don't Know	<1%

IV. Problems Faced by Low-Income Households in Meeting Their Energy Needs

This section examines the financial challenges and difficult choices made the LIHEAP recipients to manage their total residential energy costs. Tables presented in this section may not total to 100 percent due to rounding.

A. Increased Utility Bills and Increased Need

Respondents were asked to report their annual energy costs. Table IV-1 shows that 37 percent of the respondents reported that their bills were over $2,000.

Table IV-1
Annual Total Residential Energy Costs

Annual Total Residential Energy Costs	Percent of Respondents
Less than $500	7%
$501 - $1,000	13%
$1,001 - $1,500	14%
$1,501 - $2,000	16%
Over $2,000	37%
Don't Know/Refused	14%

Table IV-2A displays the distribution of total LIHEAP benefits for 2008 and 2009 LIHEAP recipients. The table shows that benefits increased in FY 2009 due to the increased program funding. While 12 percent had total benefits of greater than $750 in 2008, 21 percent had total benefits of greater than $750 in 2009.

Table IV-2A
Total LIHEAP Benefits Distribution
Heating, Cooling, and Crisis Benefits

	Percent Received	
	2008	2009
Number of Respondents	1,256	1,828
≤ $100	9%	4%
$101-$250	27%	11%
$251-$500	40%	41%
$501-$750	13%	22%
$751-$1,000	7%	10%

	Percent Received	
	2008	2009
Number of Respondents	1,256	1,828
≥ $1,000	5%	11%

Note: 2009 statistically significant differences at the 95% level from 2008 are underlined.

Table IV-2B displays the distribution of LIHEAP heating benefits in FY 2008 and FY 2009. Heating benefits also increased.

Table IV-2B
LIHEAP Heating Benefits Distribution

	Percent Received	
Benefit Amount	2008	2009
Number of Respondents	1,256	1,828
≤ $100	6%	5%
$101-$250	25%	13%
$251-$500	39%	45%
$501-$750	11%	21%
$751-$1,000	6%	7%
≥ $1,000	3%	6%
Did Not Receive Heating Benefit	9%	4%

Note: 2009 statistically significant differences at the 95% level from 2008 are underlined.

Table IV-2C displays mean total LIHEAP benefits by poverty level. The table shows that households with income below 100 percent of the poverty level receive greater average benefit amounts.

Table IV-2C
Mean Total LIHEAP Benefits
Heating, Cooling, and Crisis Benefits
By Poverty Level

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Mean Benefit Received	$562	$570	$524	$478

Table IV-2D displays mean total LIHEAP benefits by vulnerable group. The table shows that households with young children have the greatest average benefits, followed by households with children under 18 and all single parent households. Households without vulnerable members receive the lowest average benefits.

Table IV-2D
Mean Total LIHEAP Benefits
Heating, Cooling, and Crisis Benefits
By Vulnerability Group

	Senior	Disabled	Under 18	Under 6	Single Parent	Non-Vulnerable
Number of Respondents	757	788	778	362	299	152
Mean Benefit Received	$548	$533	$578	$608	$560	$502

Table IV-2E displays the type of benefit received and the mean benefit level for 2008 and 2009. The table shows that a greater percentage of respondents received heating benefits and a greater percentage received crisis benefits in FY 2009 than in FY 2008. Mean benefits were also significantly greater in FY 2009 for all three types of benefits.

Table IV-2E
Type of LIHEAP Benefits and Mean Benefit Amounts

	2008 Survey			2009 Survey		
Type of Benefit	**# Received**	**% Received**	**Mean Benefit Received**	**# Received**	**% Received**	**Mean Benefit Received**
Heating	1144	91%	$388	1752	96%	$483
Cooling	13	1%	$218	37	2%	$231
Crisis	158	13%	$402	302	17%	$448

Note: 2009 statistically significant differences at the 95% level from 2008 are underlined.

Pre-LIHEAP energy burden was calculated by dividing the respondents energy costs by their total household income and post-LIHEAP energy burden was calculated by subtracting LIHEAP benefits from energy costs and then dividing these net energy costs by total household income. Table IV-3A shows that LIHEAP benefits had a big impact on the households' energy burden. Prior to receiving LIHEAP, 22 percent of households had an energy burden of 20 percent or more. After receiving LIHEAP, 12 percent had an energy burden that was this high. Additionally, LIHEAP benefits increased the percentage with burdens below five percent from 13 percent of recipients to 37 percent.

Table IV-3A
Total Residential Energy Burden

	Total Residential Energy Burden	
	Pre-LIHEAP	**Post-LIHEAP**
Number of Respondents	1533	1533
0-5%	13%	37%
6%-10%	32%	29%
11-15%	19%	17%
16-20%	15%	8%
21-25%	7%	4%
>25%	14%	7%

Table IV-3B displays pre and post LIHEAP average energy burdens by vulnerable group. The table shows that single parent households have the greatest pre-LIHEAP energy burdens, averaging 20 percent. LIHEAP benefits reduces mean energy burden by between four and six percentage points for all groups of households. While the pre-LIHEAP energy burden average ranged from 14 percent to 20 percent, the post-LIHEAP energy burden average ranged from nine percent to 14 percent.

Table IV-3B
Mean Total Residential Energy Burden
By Vulnerable Group

	All	Senior	Disabled	Child Under 18	Child Under 6	Single Parent	Non-Vulnerable
Number of Respondents	1533	630	665	678	308	261	117
Pre-LIHEAP Burden	16%	14%	17%	16%	17%	20%	16%
Post-LIHEAP Burden	11%	9%	11%	12%	12%	14%	10%

Table IV-3C displays the energy burden distribution by vulnerable group. The table shows that nearly 40 percent of each group have energy burdens that are below five percent after receipt of LIHEAP. However, there are still seven to twelve percent of all groups who have energy burden of more than 20 percent even after receipt of LIHEAP.

Table IV-3C
Residential Energy Burden Distribution
By Vulnerable Group

	Senior		Disabled		Child Under 18		Non-Vulnerable	
	Pre-LIHEAP	Post-LIHEAP	Pre-LIHEAP	Post-LIHEAP	Pre-LIHEAP	Post-LIHEAP	Pre-LIHEAP	Post-LIHEAP
Number of Respondents	630	630	665	665	678	678	117	117
0-5%	11%	37%	15%	36%	15%	38%	14%	39%
6%-10%	31%	30%	28%	25%	36%	29%	32%	26%
11-15%	23%	18%	18%	17%	17%	14%	15%	20%
16-20%	17%	8%	16%	10%	11%	7%	18%	5%
21-25%	8%	4%	9%	4%	5%	3%	7%	3%
>25%	10%	3%	15%	8%	16%	8%	14%	7%

Respondents were asked whether their energy bills had increased, decreased, or remained the same since the previous year. Table IV-4 shows that 35 percent said their bills had increased and 21 percent said their bills had declined.

Table IV-4
Change in Energy Bills

Change in Energy Bills	Percent of Respondents
Same	37%
Lower	21%
Higher	35%
Don't Know/Refused	8%

Respondents who said that their energy bills were higher were asked why they thought their bills had increased. Table IV-5 shows that 63 percent said it was because energy prices were higher, five percent said it was due to increased energy usage, and four percent said it was due to a colder winter.

Table IV-5
Why Energy Bills are Higher

Why Energy Bills are Higher	Percent of Respondents
Number of Respondents	660
Prices were Higher	63%
Increased Energy Usage	5%
Winter was Colder	4%
Summer was Warmer	2%
Energy Inefficient Home	2%
Health or Safety Reasons	2%
Bad Economy	1%
Moved to Different Home	1%
Added Members to Household	1%
Other	3%
Don't Know/Refused	16%

Respondents were also asked whether their financial situation had improved or worsened in the past year. Table IV-6A shows that 39 percent said their financial situation was worse and 12 percent said it was better than the past year.

Table IV-6A
Change in Financial Situation

Change in Financial Situation	Percent of Respondents
Same	47%
Worse	39%
Better	12%
Don't Know/Refused	1%

Table IV-6B examines responses to the change in financial situation by vulnerable group. The table shows that households with children were most likely to say that their financial situation had worsened, and households with senior members were least likely to say that their financial situation had worsened.

Table IV-6B
Change in Financial Situation
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Same	56%	47%	39%	47%
Worse	34%	40%	46%	39%
Better	9%	11%	13%	14%
Don't Know/ Refused	1%	1%	2%	1%

Respondents were asked whether they had a more or less difficult time paying their energy bills the past year, as compared to the previous year. Table IV-7A shows that 40 percent said they had a more difficult time and 13 percent said they had a less difficult time.

Table IV-7A
Change in Difficulty in Paying Energy Bills

Change in Difficulty in Paying Energy Bills	Percent of Respondents
Same	44%
More Difficult	40%
Less Difficult	13%
Don't Know/Refused	3%

Table IV-7B displays the change in difficulty paying energy bills by vulnerable group. The table shows that households with children were most likely to say they had a more difficult time and households with seniors were least likely to say they had a more difficult time.

Table IV-7B
Change in Difficulty in Paying Energy Bills

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Same	54%	41%	36%	40%
More Difficult	33%	44%	47%	43%
Less Difficult	10%	11%	14%	16%
Don't Know/ Refused	3%	4%	3%	2%

Respondents who said that they had a more difficult time paying their energy bills were asked why it was more difficult. Table IV-8A shows that 60 percent said it was due to a worse financial situation and 21 percent said it was due to an increased energy bill.

Table IV-8A
Reasons for Increased Difficulty in Paying Energy Bills

	Main Reason (Unprompted)
Number of Respondents	747
Lower Income/Lost Job/Worse Economic Situation	60%
Increased Energy Bill	21%
Increased Other Bills	7%
Increased Medical Expenses	4%
Increased Expenses/Cost of Living	3%
No/Less Energy Assistance	2%
Increased Rent	1%
Increased Property Taxes	<1%
Increased Prescription Drugs	<1%
Other	2%
Don't Know/Refused	1%

Table IV-8B compares responses for 2008 and 2009 and highlights the fact that households faced a rough time in FY 2009 more due to the financial climate than to increasing energy bills. Table IV-8B shows that 37 percent said they had increased difficulty paying their energy bills due to their economic situation in FY 2008 and 60 percent said they had increased difficulty paying their energy bills due to financial reasons in FY 2009. Conversely, households were much more likely to say the cause of their difficulty was their high bills in FY 2008 than in FY 2009.

Table IV-8B
Reasons for Increased Difficulty in Paying Energy Bills

	2008	2009
Number of Respondents	543	747
Lower Income/Lost Job/Worse Economic Situation	37%	60%
Increased Energy Bill	50%	21%

Note: Differences are statistically significant at the 99 percent level.

B. Signs of the Problem

Respondents were asked several questions about difficulties that they faced in meeting their energy needs during the past year. Table IV-9A shows that 73 percent of respondents said that

they worried about paying their home energy bill due to not having enough money to pay the bill during the past year.

Table IV-9A
Worried About Paying Home Energy Bill Due to Not Having Enough Money for the Energy Bill During Past Year

	Percent of Respondents
Almost Every Month	30%
Some Months	27%
1 or 2 Months	16%
Never / No	26%
Don't Know	<1%

Table IV-9B displays responses to this question by vulnerable group. The table shows that households with children and households without vulnerable members were most likely to say that they worried about paying their energy bill.

Table IV-9B
Worried About Paying Home Energy Bill Due to Not Having Enough Money for the Energy Bill During Past Year By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	20%	33%	38%	37%
Some Months	25%	27%	32%	28%
1 or 2 Months	14%	14%	17%	26%
Never / No	41%	25%	12%	10%
Don't Know	<1%	<1%	<1%	0%

Table IV-9C displays responses to whether the household worried about paying the home energy bill by poverty group. The table shows that households with income below 50 percent of the poverty level were most likely to say that they worried about paying their energy bill. Eighty-four percent of these households said that they worried about paying their energy bill.

Table IV-9C
Worried About Paying Home Energy Bill Due to Not Having Enough Money for the Energy Bill During Past Year By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Almost Every Month	36%	31%	26%	25%

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Some Months	30%	24%	29%	32%
1 or 2 Months	18%	17%	14%	16%
Never / No	15%	28%	31%	27%
Don't Know	<1%	<1%	<1%	<1%

Respondents were asked whether they reduced expenses for household necessities due to not having enough money to pay their energy bill during the past year. Table IV-10A shows that 78 percent said that they took this action.

Table IV-10A
Reduced Expenses for Household Necessities Due to Not Having Enough Money for the Energy Bill During the Past Year

	Percent of Respondents
Almost Every Month	41%
Some Months	27%
1 or 2 Months	10%
Never / No	21%
Don't Know	<1%

Table IV-10B shows that households with children and households without vulnerable members were most likely to report that they reduced expenses for household necessities. The table shows that 87 percent of households with children and 93 percent of households without vulnerable members said that they faced this problem.

Table IV-10B
Reduced Expenses for Household Necessities Due to Not Having Enough Money for the Energy Bill During the Past Year By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	32%	42%	47%	52%
Some Months	23%	28%	30%	31%
1 or 2 Months	12%	10%	10%	10%
Never / No	33%	20%	12%	7%
Don't Know	<1%	<1%	<1%	0%

Table IV-10C shows that households with income below 50 percent of poverty and households with income above 50 percent of poverty were most likely to say that they reduced expenses for household necessities. Eighty-four percent of those with income below 50 percent and 82 percent of those with income above 150 percent of poverty said that they reduced these expenses.

Table IV-10C
Reduced Expenses for Household Necessities Due to Not Having Enough Money for the Energy Bill During the Past Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Almost Every Month	49%	39%	36%	49%
Some Months	26%	26%	28%	26%
1 or 2 Months	9%	10%	13%	8%
Never / No	16%	25%	23%	17%
Don't Know / Refused	<1%	<1%	<1%	<1%

Respondents were asked whether they borrowed from a friend or relative to pay their home energy bill during the past year. Table IV-11A shows that 46 percent of respondents said that they needed to take this action.

Table IV-11A
Borrowed from a Friend or Relative to Pay Home Energy Bill Due to Not Having Enough Money for the Energy Bill During the Past Year

	Percent of Respondents
Almost Every Month	5%
Some Months	21%
1 or 2 Months	20%
Never / No	54%
Don't Know	<1%

Table IV-11B shows that households with no vulnerable members were most likely to report that they needed to take this action. Sixty-four percent of households without vulnerable members reported that they borrowed for a friend or relative to pay their energy bill in the past year.

Table IV-11B
Borrowed from a Friend or Relative to Pay Home Energy Bill Due to Not Having Enough Money for the Energy Bill During the Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	2%	5%	6%	6%
Some Months	13%	20%	27%	28%
1 or 2 Months	12%	18%	24%	30%
Never / No	73%	56%	43%	36%

	Senior	Disabled	Child Under 18	Non-Vulnerable
Don't Know	<1%	<1%	1%	0%

Table IV-11C shows that households with income below 50 percent of the poverty level were most likely to borrow from a friend or relative. The table shows that 61 percent of these households reported that they borrowed from a friend or relative, compared to about 40 percent of the other poverty groups.

Table IV-11C
Borrowed from a Friend or Relative to Pay Home Energy Bill Due to Not Having Enough Money for the Energy Bill During the Past Year
By Poverty Group

	Poverty Level			
	0-50%	**51-100%**	**101-150%**	**>150%**
Number of Respondents	286	673	557	312
Almost Every Month	7%	4%	3%	3%
Some Months	30%	20%	15%	21%
1 or 2 Months	24%	19%	18%	20%
Never / No	39%	56%	63%	56%
Don't Know / Refused	0%	<1%	<1%	<1%

Table IV-12 compares responses to questions about signs of unaffordable energy bills for the 2003, 2008, and 2009 surveys. The table shows that approximately the same percentage of respondents faced these problems in all three years.

Table IV-12
Signs of the Problem
Comparison of Survey Results

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	2,161	1,256	1,828
Worried About Paying Home Energy Bill	72%	72%	74%
Reduced Expenses for Household Necessities	78%	80%	79%
Borrowed From a Friend or Relative	46%	43%	46%

C. Responses to the Problem

This section examines how households have responded to the problem of unaffordable energy bills. Respondents were asked whether they closed off part of their home during the past year because they could not afford to heat or to cool it. Table IV-13A shows that 36 percent of respondents said that they took this action.

Table IV-13A
Closed Off Part of Home Because Could Not Afford to Heat or Cool It
Due to Not Having Enough Money for the Energy Bill During the Past Year

	Percent of Respondents
Almost Every Month	12%
Some Months	18%
1 or 2 Months	6%
Never / No	64%
Don't Know / Refused	<1%

Table IV-13B displays the percent of respondents who said that they closed off part of their home because they could not afford to heat or to cool it. The table shows that households with children were most likely to say that they took this action. Thirty-one percent of these respondents said that they closed off part of their home.

Table IV-13B
Closed Off Part of Home Because Could Not Afford to Heat or Cool It
Due to Not Having Enough Money for the Energy Bill During Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	13%	13%	9%	19%
Some Months	21%	20%	15%	19%
1 or 2 Months	5%	7%	7%	6%
Never / No	61%	60%	69%	57%
Don't Know/Refused	<1%	<1%	1%	0%

Table IV-13C shows that the percent of respondents who closed off part of their home does not vary by poverty level.

Table IV-13C
Closed Off Part of Home Because Could Not Afford to Heat or Cool It
Due to Not Having Enough Money for the Energy Bill During Past Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Almost Every Month	11%	11%	13%	13%
Some Months	17%	18%	17%	19%
1 or 2 Months	6%	7%	5%	5%
Never / No	65%	64%	64%	63%

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Don't Know	<1%	0%	<1%	<1%

Respondents were asked whether they kept their home at a temperature that they felt was unsafe or unhealthy due to not having enough money for the energy bill during the past year. The table shows that about one quarter of the respondents said that they took this action.

Table IV-14A
Kept Home at Temperature You Felt Was Unsafe or Unhealthy Due to Not Having Enough Money for the Energy Bill During Past Year

	Percent of Respondents
Almost Every Month	6%
Some Months	14%
1 or 2 Months	6%
Never / No	73%
Don't Know / Refused	1%

Table IV-14B shows that about one third of households with disabled members and one third of households with no vulnerable members said that they kept their home at an unsafe or unhealthy temperature.

Table IV-14B
Kept Home at Temperature You Felt Was Unsafe or Unhealthy Due to Not Having Enough Money for the Energy Bill During Past Year By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	5%	8%	5%	7%
Some Months	12%	17%	13%	18%
1 or 2 Months	4%	7%	8%	7%
Never / No	78%	67%	73%	67%
Don't Know/Refused	1%	1%	1%	0%

Table IV-14C shows that there is not much variation in the percent of households who kept their home at an unsafe or unhealthy temperature by poverty group.

Table IV-14C
Kept Home at Temperature You Felt Was Unsafe or Unhealthy Due to Not Having Enough Money for the Energy Bill During Past Year By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Almost Every Month	4%	7%	6%	6%
Some Months	16%	15%	11%	15%
1 or 2 Months	7%	7%	4%	7%
Never / No	71%	71%	78%	70%
Don't Know/Refused	<1%	<1%	1%	2%

Table IV-15A shows that twenty percent of respondents said that they left their home for part of the day because it was too hot or too cold in the past year.

Table IV-15A
Left Home for Part of the Day Because it was Too Hot or Too Cold Due to Not Having Enough Money for the Energy Bill During the Past Year

	Left Home for Part of the Day Because Home was Too Hot or Too Cold
Almost Every Month	1%
Some Months	9%
1 or 2 Months	10%
Never / No	79%
Don't Know / Refused	0%

Table IV-15B shows that there is not much variability by vulnerable group in this action.

Table IV-15B
Left Home for Part of the Day Because it was Too Hot or Too Cold Due to Not Having Enough Money for the Energy Bill During the Past Year By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	1%	2%	1%	1%
Some Months	7%	11%	10%	12%
1 or 2 Months	6%	10%	14%	14%
Never / No	86%	76%	75%	73%
Don't Know	0%	0%	0%	0%

Households with income below the poverty level are more likely to say that they left their home because it was too hot or too cold. Table IV-15C shows that 26 percent of those with income below 50 percent of the poverty level and 23 percent of those with income between 51 and 100 percent of the poverty level said that they took this action.

Table IV-15C
Left Home for Part of the Day Because it was Too Hot or Too Cold Due to Not Having Enough Money for the Energy Bill During Past Year By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Almost Every Month	0%	2%	1%	2%
Some Months	12%	10%	6%	6%
1 or 2 Months	14%	11%	9%	6%
Never / No	74%	77%	84%	86%
Don't Know	0%	<1%	<1%	<1%

Households sometimes take the dangerous action of using their kitchen oven or stove to provide heat when they cannot afford their energy bill. Table IV-16A shows that one third of respondents said that they took this action during the past year.

Table IV-16A
Used Kitchen Stove or Oven to Provide Heat Due to Not Having Enough Money for the Energy Bill During Past Year

	Percent of Respondents
Almost Every Month	2%
Some Months	15%
1 or 2 Months	16%
Never / No	67%
Don't Know	<1%

Table IV-16B shows that households without vulnerable members were most likely to report that they took this action. Forty-six percent of these households said that they used their kitchen stove or oven for heat in the past year.

Table IV-16B
Used Kitchen Stove or Oven to Provide Heat Due to Not Having Enough Money for the Energy Bill During the Past Year By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152

	Senior	Disabled	Child Under 18	Non-Vulnerable
Almost Every Month	2%	2%	3%	3%
Some Months	10%	19%	17%	20%
1 or 2 Months	13%	17%	18%	23%
Never / No	75%	61%	62%	53%
Don't Know/Refused	<1%	<1%	<1%	2%

Table IV-16C shows that households with income below 50 percent of poverty were most likely to report that they used their kitchen stove or oven to provide heat during the past year. Thirty-nine percent of these households said that they used their kitchen stove or oven for heat in the past year.

Table IV-16C
Used Kitchen Stove or Oven to Provide Heat Due to Not Having Enough Money for the Energy Bill During the Past Year By Poverty Group

	Poverty Level			
	0-50%	**51-100%**	**101-150%**	**>150%**
Number of Respondents	286	673	557	312
Almost Every Month	5%	2%	1%	1%
Some Months	18%	16%	12%	13%
1 or 2 Months	16%	16%	16%	13%
Never / No	61%	66%	70%	73%
Don't Know	0%	1%	<1%	<1%

Table IV-17 compares responses to these questions between the 2003, 2008, and 2009 surveys. The table shows that in FY 2009, respondents were less likely to close off their homes and they were less likely to leave their home for part of the day because they could not afford their energy bill.

Table IV-17
Responses to the Problem
Comparison of Survey Results

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	2,161	1,256	1,828
Closed Off Part of Home	39%	44%	36%
Kept Home at Temperature You Felt was Unsafe or Unhealthy	25%	28%	26%
Left Home for Part of the Day	24%	23%	20%
Used Kitchen Stove or Oven to Provide Heat	31%	33%	33%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

D. Inability to Pay Energy Bills

Respondents were asked several questions about the inability to pay their home energy bill. Table IV-18A shows that 49 percent of respondents said that they skipped paying or paid less than their entire home energy bill during the past year due to not having enough money to pay the bill.

Table IV-18A
Skipped Paying or Paid Less than Entire Home Energy Bill
Due to Not Having Enough Money for the Energy Bill During Past Year

	Percent of Respondents
Almost Every Month	11%
Some Months	21%
1 or 2 Months	17%
Never / No	50%
Don't Know	<1%

Table IV-18B shows that households with children were most likely to say that they skipped paying their home energy bill. Sixty-five percent of households with children said that they skipped paying their home energy bill.

Table IV-18B
Skipped Paying or Paid Less than Entire Home Energy Bill
Due to Not Having Enough Money for the Energy Bill During Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	6%	12%	15%	9%
Some Months	13%	19%	30%	27%
1 or 2 Months	12%	18%	20%	21%
Never / No	68%	51%	34%	43%
Don't Know/Refused	<1%	1%	1%	0%

Table IV-18C shows that households with income below 50 percent of the poverty level were most likely to say that they skipped paying the home energy bill. Sixty-two percent of these households said that they skipped paying their bill.

Table IV-18C
Skipped Paying or Paid Less than Entire Home Energy Bill
Due to Not Having Enough Money for the Energy Bill During the Past Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Almost Every Month	12%	12%	7%	13%
Some Months	29%	21%	17%	17%
1 or 2 Months	21%	16%	18%	14%
Never / No	37%	51%	57%	55%
Don't Know / Refused	<1%	<1%	<1%	<1%

Respondents were asked whether they received a notice or threat to disconnect or discontinue their electricity or home heating fuel due to not having enough money for the energy bill during the past year. The table shows that 35 percent said that they received a notice or threat.

Table IV-19A
Received Notice or Threat to Disconnect or Discontinue Electricity or Home Heating Fuel Due to Not Having Enough Money for the Energy Bill During the Past Year

	Percent of Respondents
Almost Every Month	5%
Some Months	12%
1 or 2 Months	18%
Never / No	64%
Don't Know	<1%

Table IV-19B shows the percent who received a threat of service termination by vulnerable group. The table shows that households with children were most likely to face this problem. Nearly half of these households received a notice or threat to disconnect or discontinue their service in the past year.

Table IV-19B
Received Notice or Threat to Disconnect or Discontinue Electricity or Home Heating Fuel Due to Not Having Enough Money for the Energy Bill During Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Almost Every Month	2%	5%	8%	6%
Some Months	6%	14%	16%	14%
1 or 2 Months	10%	19%	25%	16%
Never / No	81%	62%	50%	64%

	Senior	Disabled	Child Under 18	Non-Vulnerable
Don't Know	0%	<1%	<1%	0%

Table IV-19C shows that households with income below 50 percent of poverty were most likely to report that they received a notice or threat to disconnect or discontinue their electricity or home heating fuel. The table shows that 44 percent of these households said that they faced this problem in the past year.

Table IV-19C
Received Notice or Threat to Disconnect or Discontinue Electricity or Home Heating Fuel Due to Not Having Enough Money for the Energy Bill During the Past Year By Poverty Group

	Poverty Level			
	0-50%	**51-100%**	**101-150%**	**>150%**
Number of Respondents	286	673	557	312
Almost Every Month	8%	6%	3%	6%
Some Months	14%	13%	9%	12%
1 or 2 Months	22%	19%	15%	14%
Never / No	56%	62%	73%	68%
Don't Know / Refused	<1%	0%	<1%	1%

Table IV-20A shows that nine percent of respondents had their electricity shut off due to nonpayment, seven percent had their gas service shut off, and 12 percent had one of the two shut off during the past year.

Table IV-20A
Utility Service Was Shut Off Due to Nonpayment During the Past Year

	Percent of Respondents
Electricity	9%
Gas	7%
Electricity or Gas	12%

Table IV-20B displays the percent that had their utility service shut off by vulnerable group. The table shows that households with children were most likely to face these problems. Eighteen percent of households with children had their electricity or gas shut off due to nonpayment in the past year.

Table IV-20B
Utility Service Was Shut Off Due to Nonpayment During the Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Electricity	2%	9%	13%	9%
Gas	3%	8%	10%	9%
Electricity or Gas	5%	15%	18%	12%

Table IV-20C displays the percent of households who had utility service terminated by poverty group. The table shows that the lower poverty level households were most likely to have had their service terminated. Eighteen percent of households with income below 50 percent of the poverty level had their service terminated in the past year.

Table IV-20C
Utility Service Was Shut Off Due to Nonpayment During the Past Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Electricity	14%	9%	6%	3%
Gas	9%	8%	3%	4%
Electricity or Gas	18%	14%	8%	6%

Table IV-21A shows the percent of households who were unable to use their main source of heat during the past year. The table shows that 13 percent were unable to use their main source of heat due to the system being broken, 11 percent due to an inability to pay for a fuel delivery, and 11 percent due to an electric or gas service termination.

Table IV-21A
Unable to Use Main Source of Heat During the Past Year

	Percent of Respondents
Heating System Broken	13%
Unable to Pay for Fuel Delivery	11%
Gas or Electric Service Discontinued	11%
Any of the Three Reasons	27%

Table IV-21B displays the percent of respondents who said that they were unable to use their main source of heat during the past year by vulnerable group. The table shows that households with children were most likely to face this problem. Thirty-six percent of households with children could not use their main source of heat during the past year because their heating system was broken, they were unable to pay for a fuel delivery, or their gas or electric service was discontinued due to nonpayment.

Table IV-21B
Unable to Use Main Source of Heat During the Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Heating System Broken	11%	14%	16%	11%
Unable to Pay for Fuel Delivery	7%	13%	13%	15%
Gas or Electric Service Discontinued	5%	13%	17%	9%
Any of the Three Reasons	19%	31%	36%	27%

Table IV-21C displays the percent of respondents who were unable to use their main source of heat during the past year by poverty group. The table shows that households with income below the poverty level were most likely to face this problem. Thirty percent of households with income below the poverty level were unable to use their main source of heat at some point during the past year.

Table IV-21C
Unable to Use Main Source of Heat During the Past Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Heating System Broken	13%	13%	12%	11%
Unable to Pay for Fuel Delivery	11%	11%	9%	14%
Gas or Electric Service Discontinued	15%	13%	7%	7%
Any of the Three Reasons	30%	30%	21%	25%

Table IV-22A displays the percent of respondents who were unable to use their air conditioner during the past year because it was broken or they had their electric service discontinued for nonpayment. The table shows that 12 percent could not use their air conditioner because it was broken and eight percent could not use it because their electric service was discontinued. Seventeen percent could not use their air conditioner for one of those two reasons.

Table IV-22A
Unable to Use Air Conditioner During the Past Year

	Percent of Respondents
Air Conditioner Broken	12%
Electric Service Discontinued	8%
Either Reason	17%

Table IV-22B displays the percent of respondents who were unable to use their air conditioner in the past year by vulnerable group. The table shows that households with disabled members and households with

children were most likely to face this problem. Twenty-one percent of both of these groups were unable to use their air conditioner at some point during the past year because it was broken or their electric service was discontinued for nonpayment.

Table IV-22B
Unable to Use Air Conditioner During the Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Air Conditioner Broken	8%	15%	13%	11%
Electric Service Discontinued	4%	11%	11%	7%
Either Reason	11%	21%	21%	15%

Table IV-22C displays the percent of households who were unable to use their air conditioner during the past year by poverty group. The table shows that households in the lower poverty groups were most likely to face this problem. Twenty-five percent of households with income below 50 percent of poverty were unable to use their air conditioner at some point during the past year.

Table IV-22C
Unable to Use Air Conditioner During the Past Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Air Conditioner Broken	18%	11%	10%	9%
Electric Service Discontinued	12%	8%	5%	3%
Either Reason	25%	16%	13%	11%

Table IV-23A displays the percent of respondents who had to go without showers due to lack of hot water, had to go without hot meals due to lack of cooking fuel, or had to use candles or lanterns due to lack of lights. The table shows that seven to ten percent of respondents faced these problems.

Table IV-23A
Had to Go Without Showers, Hot Meals, or Lights During the Past Year

	Percent of Respondents
Had to Go Without Showers or Baths Due to Lack of Hot Water	10%
Had to Go Without Hot Meals Due to Lack of Cooking Fuel	7%
Had to Use Candles or Lanterns Due to Lack of Lights	8%

Table IV-23B displays the percent of respondents who had to go without showers, hot meals, or lights during the past year by vulnerable group. The table shows that households with children and households without vulnerable members were most likely to face these problems.

Table IV-23B
Had to Go Without Showers, Hot Meals, or Lights During the Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Had to Go Without Showers or Baths Due to Lack of Hot Water	5%	12%	13%	14%
Had to Go Without Hot Meals Due to Lack of Cooking Fuel	3%	8%	10%	10%
Had to Use Candles or Lanterns Due to Lack of Lights	4%	9%	12%	13%

Table IV-23C displays the percent of households who had these problems by poverty group. The table shows that households in the lower poverty groups are most likely to face these problems.

Table IV-23C
Had to Go Without Showers, Hot Meals, or Lights During the Past Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Had to Go Without Showers or Baths Due to Lack of Hot Water	14%	11%	5%	10%
Had to Go Without Hot Meals Due to Lack of Cooking Fuel	12%	8%	3%	6%
Had to Use Candles or Lanterns Due to Lack of Lights	14%	9%	5%	5%

Table IV-24A displays the percent of respondents who had their utility service shut off at the time of the survey. The table shows that two percent of respondents had their electricity or gas shut off.

Table IV-24A
Utility Service Shut Off at Time of Survey

	Percent of Respondents
Electricity	<1%
Gas	1%
Electricity or Gas	2%

Table IV-24B shows that three percent of households without vulnerable members had their electricity or gas service shut off at the time of the survey.

Table IV-24B
Utility Service Shut Off at Time of Survey
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Electricity	<1%	1%	1%	0%
Gas	1%	1%	2%	3%
Electricity or Gas	1%	2%	2%	3%

Table IV-24C shows that lower poverty group households are not significantly more likely to have their utility service shut off at the time of the survey.

Table IV-24C
Utility Service Shut Off at Time of Survey
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Electricity	<1%	1%	<1%	0%
Gas	2%	1%	1%	<1%
Electricity or Gas	2%	2%	1%	<1%

Table IV-25 compares the responses about service disruptions across the 2003, 2008, and 2009 surveys. The table shows that some of the rates are higher in 2009 than in 2003, but there has not been an increase in these problems in the past year.

Table IV-25
Inability to Pay Energy Bills During Past Year
Comparison of Survey Results

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	2,161	1,256	1,828
Skipped Paying or Paid Less than Entire Home Energy Bill	52%	47%	50%
Received Notice or Threat to Disconnect or Discontinue Electricity or Home Heating Fuel	38%	37%	36%
Electricity Shut off Due to Nonpayment	8%	9%	9%
Heating System Broken and Unable to Pay for Repair or Replacement	10%	13%	13%
Unable to Use Main Source of Heat Because Unable to Pay for a Fuel Delivery	10%	13%	11%
Unable to Use Main Source of Heat Because Utility Company Discontinued Gas or Electric Service Due to Nonpayment	11%	13%	11%

	2003 Survey	2008 Survey	2009 Survey
Unable to Use Air Conditioner Because it was Broken and Unable to Pay for Repair or Replacement	12%	12%	12%
Unable to Use Air Conditioner Because Utility Company Discontinued Electric Service Due to Nonpayment	6%	7%	8%
Had to Go Without Showers or Baths Due to Lack of Hot Water	9%	10%	10%
Had to Go Without Hot Meals Due to Lack of Cooking Fuel	5%	7%	7%
Had to Use Candles or Lanterns Due to Lack of Lights	8%	7%	8%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

E. Housing Problems

This section examines housing problems that respondents have faced in the past five years due to unaffordable energy bills. Table IV-26A shows that 31 percent skipped a mortgage payment, five percent were evicted, four percent had a mortgage foreclosure, twelve percent moved in with friends or family, and three percent moved into a shelter or were homeless.

Table IV-26A
Housing Problems Due to Energy Bills in the Past Five Years

	Percent of Respondents
Did not Make Full Rent or Mortgage Payment	31%
Evicted from Home or Apartment	5%
Had Mortgage Foreclosure	4%
Moved in With Friends or Family	12%
Moved into Shelter or Was Homeless	3%

Table IV-26B displays the results by vulnerable group. The table shows that households with children were most likely to face these problems. Forty-five percent of these households skipped a mortgage payment, eight percent were evicted, and 17 percent moved in with friends or family.

Table IV-26B
Housing Problems Due to Energy Bills in the Past Five Years
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Did not Make Full Rent or Mortgage Payment	16%	32%	45%	39%
Evicted from Home or Apartment	3%	5%	8%	3%
Had Mortgage Foreclosure	2%	4%	6%	2%
Moved in With Friends or Family	6%	12%	17%	15%
Moved into Shelter or Was Homeless	1%	4%	5%	3%

Table IV-26C displays the results by poverty group. The table shows that the lowest poverty group was most likely to face these problems.

Table IV-26C
Housing Problems Due to Energy Bills in the Past Five Years
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Did not Make Full Rent or Mortgage Payment	38%	35%	23%	28%
Evicted from Home or Apartment	8%	5%	3%	6%
Had Mortgage Foreclosure	6%	3%	3%	4%
Moved in With Friends or Family	20%	13%	6%	10%
Moved into Shelter or Was Homeless	5%	3%	3%	2%

Table IV-26D displays the percent of respondents with housing problems by whether or not they own their home. The table shows that respondents who do not own their homes were more likely to face these problems.

Table IV-26D
Housing Problems Due to Energy Bills in the Past Five Years
By Home Ownership

	Own Home	Does Not Own Home
Number of Respondents	826	990
Did not Make Full Rent or Mortgage Payment	27%	36%
Evicted from Home or Apartment	3%	7%
Had Mortgage Foreclosure	4%	3%
Moved in With Friends or Family	7%	16%
Moved into Shelter or Was Homeless	1%	6%

Table IV-27 compares results with respect to housing problems from the 2003, 2008, and 2009 surveys. The table shows that some of the housing problems have become somewhat more prevalent since the 2003 survey.

Table IV-27
Housing Problems During Past Five Years
Comparison of Survey Results

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	2,161	1,256	1,828
Did Not Make Full Rent or Mortgage Payment	28%	28%	31%

	2003 Survey	2008 Survey	2009 Survey
Evicted from Home or Apartment	4%	4%	5%
Moved in with Friends or Family	9%	11%	12%
Moved into Shelter or Was Homeless	4%	3%	3%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

F. Financial Problems

This section examines financial problems that respondents faced in the past five years due to their energy bills. Table IV-28A shows that 17 percent reported that they took out a payday loan and two percent reported that they filed for bankruptcy.

Table IV-28A
Financial Problems Due to Energy Bills
In the Past Five Years

	Percent of Respondents
Payday Loan	17%
Bankruptcy	2%

Table IV-28B displays the percent of respondents who had financial problems in the past five years due to unaffordable energy bills by vulnerable group. The table shows that households without vulnerable members were most likely to report that they obtained a payday loan.

Table IV-28B
Financial Problems Due to Energy Bills
In the Past Five Years
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Payday Loan	9%	17%	23%	27%
Bankruptcy	1%	3%	4%	1%

Table IV-28C displays the percent of respondents who had financial problems in the past five years due to unaffordable energy bills by poverty level. The table shows that households with income below 50 percent of the poverty level were most likely to report that they obtained a payday loan.

Table IV-28C
Financial Problems Due to Energy Bills
In the Past Five Years
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Payday Loan	21%	17%	16%	16%
Bankruptcy	3%	2%	2%	4%

G. *Medical and Health Problems*

This section examines the medical and health problems that respondents faced in the past five years due to unaffordable energy bills. Table IV-29A shows that 30 percent went without food for at least one day, 41 percent went without medical or dental care, 33 percent did not fill a prescription or took less than their full dose of prescribed medication, and 22 percent were unable to pay their energy bill due to medical expenses.

Table IV-29A
Medical and Health Problems Due to Energy Bills
In the Past Five Years

	Percent of Respondents
Went Without Food for at Least One Day	30%
Went Without Medical or Dental Care	41%
Didn't Fill Prescription or Took Less Than Full Dose	33%
Unable to Pay Energy Bill Due to Medical Expenses	22%

Table IV-29B examines medical and health problems by vulnerable group. The table shows that households without vulnerable members are most likely to go without food and to go without medical or dental care. Almost three quarters of this group said that they went without medical or dental care in the past five years.

Table IV-29B
Medical and Health Problems Due to Energy Bills
In the Past Five Years
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Went Without Food for at Least One Day	20%	36%	33%	49%

	Senior	Disabled	Child Under 18	Non-Vulnerable
Went Without Medical or Dental Care	29%	41%	45%	72%
Didn't Fill Prescription or Took Less Than Full Dose	26%	40%	37%	40%
Unable to Pay Energy Bill Due to Medical Expenses	16%	28%	26%	24%

Table IV-29C displays responses to questions about medical and health problems by poverty group. The table shows that there is not a strong relationship between poverty level and the presence of these problems.

Table IV-29C
Medical and Health Problems Due to Energy Bills
In the Past Five Years
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Went Without Food for at Least One Day	33%	33%	23%	30%
Went Without Medical or Dental Care	43%	40%	40%	42%
Didn't Fill Prescription or Took Less Than Full Dose	33%	33%	32%	35%
Unable to Pay Energy Bill Due to Medical Expenses	23%	23%	20%	25%

Table IV-30A displays the percent of respondents who didn't take prescribed medication by the presence of a serious medical condition. The table shows that 37 percent of households with a serious medical condition skipped taking their prescription medication, compared to 16 percent without a serious medical condition.

Table IV-30A
Didn't Fill Prescription or Took Less Than the Full Dose of
Prescribed Medicine Due to Energy Bills
In the Past Five Years
By Presence of Serious Medical Conditions

	Didn't Fill Prescription or Took Less Than the Full Dose of Prescribed Medicine	
	Household Member with Serious Medical Condition	No Household Member With Serious Medical Condition
Number of Respondents	1,509	307
Yes	37%	16%
No	63%	84%
Don't Know/ No Answer	<1%	0%

Table IV-30B displays the percent of respondents who skipped taking prescription medication by the presence of necessary medical equipment that uses electricity. The table shows that 45 percent of those with medical equipment skipped taking their medication, compared to 29 percent without the equipment.

Table IV-30B
Didn't Fill Prescription or Took Less Than the Full Dose of Prescribed Medicine due to Energy Bills
In the Past Five Years
By Presence of Necessary Medical Equipment the Uses Electricity

	Didn't Fill Prescription or Took Less Than the Full Dose of Prescribed Medicine	
	Necessary Medical Equipment That Uses Electricity	No Necessary Medical Equipment That Uses Electricity
Number of Respondents	448	1,364
Yes	45%	29%
No	55%	70%
Don't Know/ No Answer	<1%	<1%

Table IV-31A displays the percent of respondents who said that they were unable to pay their energy bill due to medical expenses by the presence of a serious medical condition. The table shows that 25 percent of those with a serious medical condition were unable to pay their energy bill and nine percent without a serious medical condition were unable to pay their energy bill due to medical expenses.

Table IV-31A
Unable to Pay Energy Bill Due to Medical Expenses
In the Past Five Years
By Presence of Serious Medical Conditions

	Unable to Pay Energy Bill Due to Medical Expenses	
	Household Member with Serious Medical Condition	No Household Member With Serious Medical Condition
Number of Respondents	1,509	307
Yes	25%	9%
No	74%	89%
Don't Know/ No Answer	1%	2%

Table IV-31B displays the percent of respondents who reported that they were unable to pay their energy bill due to medical expenses by the presence of medical equipment that uses electricity. The table shows that 34 percent of those with medical equipment said they were unable to pay their energy bill and 19 percent without medical equipment said they were unable to pay their energy bill due to medical expenses.

Table IV-31B
Unable to Pay Energy Bill due to Medical Expenses
In the Past Five Years
By Presence of Necessary Medical Equipment the Uses Electricity

	Unable to Pay Energy Bill due to Medical Expenses	
	Necessary Medical Equipment That Uses Electricity	No Necessary Medical Equipment That Uses Electricity
Number of Respondents	448	1,364
Yes	34%	19%
No	65%	81%
Don't Know/ No Answer	2%	<1%

Table IV-32A displays the percent of respondents who became sick and needed to go to the doctor or hospital because the home was too cold. The table shows that 17 percent became sick and needed to go to the doctor or hospital because the home was too cold, and three percent became sick and needed to go to the doctor or hospital because the home was too hot.

Table IV-32A
Someone in Household Became Sick Because Home was Too Cold or Too Hot
In the Past Five Years

	Became Sick	Became Sick and Needed to Go to the Doctor or Hospital
Home Was Too Cold	25%	17%
Home Was Too Hot	4%	3%

Table IV-32B displays the percent who became sick and needed to go to the doctor or hospital because the home was too cold by vulnerable group. The table shows that households without vulnerable members were most likely to become sick, but that households with disabled members, households with children and households with no vulnerable members were most likely to become sick and need to go to the doctor or hospital because the home was too cold.

Table IV-32B
Someone in Household Became Sick Because Home was Too Cold
In the Past Five Years
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Became Sick	15%	28%	31%	38%
Became Sick and Needed to Go to the Doctor or Hospital	10%	22%	22%	21%

Table IV-32C displays the percent of respondents with a serious medical condition who got sick because the home was too hot or too cold and need to go to the doctor or hospital. The table shows that 26 percent

of respondents with a serious medical condition became sick because their home was too hot or too cold and 18 percent needed to go to a doctor or to the hospital due to this illness.

Table IV-51
Household Member With Allergies, Asthma, Emphysema, or COPD, High Blood Pressure, Heart Disease, or Stroke Got Sick Because the Household was Too Hot or Too Cold and Needed to Go to the Doctor or Hospital In the Past Year

	Became Sick	Needed to Go to the Doctor or Hospital
Number of Respondents	1,509	1,509
Yes	26%	18%
No	74%	8%
Don't Know	<1%	0%
Did not Become Sick	--	74%

Table IV-33 displays the percent of respondents who became sick and needed to go to the doctor or hospital because the home was too hot or too cold in the 2003, 2008, and 2009 surveys. The table shows that the percentage who faced these problems was approximately the same in all three surveys.

Table IV-33
Someone in Household Became Sick Because Home was Too Hot or Too Cold And Had to Go to the Hospital in the Past Five Years Comparison of Survey Results

	2003		2008		2009	
	Became Sick	Needed to Go to the Doctor or Hospital	Became Sick	Needed to Go to the Doctor or Hospital	Became Sick	Needed to Go to the Doctor or Hospital
Number of Respondents	2,161		1,256		1,828	
Yes	24%	17%	26%	18%	26%	18%
No	75%	7%	74%	8%	74%	8%
Don't Know	1%	0%	<1%	0%	<1%	0%
Did not Become Sick	--	76%	--	74%	--	74%

Table IV-34A compares the percent of respondents with seniors in the household who had medical and health problems in the 2003 survey, the 2008 survey, and the 2009 survey. The table shows that a few of the indicators were higher than in the 2003 survey.

Table IV-34A
Medical and Health Problems During the Past Five Years
Comparison of Survey Results
By Vulnerable Group – Senior Member in Household

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	888	542	757
Went Without Food for At Least One Day	11%	24%	20%
Went Without Medical or Dental Care	29%	32%	29%
Did Not Fill Prescription or Took Less Than Full Dose	23%	31%	26%
Unable to pay Energy Bill Due to Medical Expenses	16%	15%	16%
Became Sick Because Home was Too Cold	11%	15%	15%
Became Sick Because Home was Too Hot	6%	5%	4%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Table IV-34B compares the percent of respondents with disabled household members who had medical and health problems in the 2003 survey, the 2008 survey, and the 2009 survey. The table shows that a few of the indicators were higher than in the 2003 survey.

Table IV-34B
Medical and Health Problems During the Past Five Years
Comparison of Survey Results
By Vulnerable Group – Disabled Member in Household

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	1,013	627	788
Went Without Food for At Least One Day	25%	39%	36%
Went Without Medical or Dental Care	39%	44%	41%
Did Not Fill Prescription or Took Less Than Full Dose	32%	42%	40%
Unable to pay Energy Bill Due to Medical Expenses	19%	26%	28%
Became Sick Because Home was Too Cold	29%	26%	28%
Became Sick Because Home was Too Hot	7%	9%	7%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Table IV-34C compares the percent of respondents with children who had medical and health problems in the 2003 survey, the 2008 survey, and the 2009 survey. The table shows that a few of the indicators were higher than in the 2003 survey.

Table IV-34C
Medical and Health Problems During the Past Five Years
Comparison of Survey Results
By Vulnerable Group – Child Under 18 in Household

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	919	503	778
Went Without Food for At Least One Day	28%	36%	33%
Went Without Medical or Dental Care	40%	48%	45%
Did Not Fill Prescription or Took Less Than Full Dose	34%	42%	37%
Unable to pay Energy Bill Due to Medical Expenses	24%	28%	26%
Became Sick Because Home was Too Cold	24%	28%	31%
Became Sick Because Home was Too Hot	9%	8%	4%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Table IV-34D compares the percent of respondents with no vulnerable household members who had medical and health problems in the 2003 survey, the 2008 survey, and the 2009 survey. The table shows that a few of the indicators were higher than in the 2003 and 2008 surveys. Households with no vulnerable members appear to have had the greatest increase in these problems since last year.

Table IV-34D
Medical and Health Problems During the Past Five Years
Comparison of Survey Results
By Vulnerable Group – No Vulnerable Members in Household

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	476	87	152
Went Without Food for At Least One Day	24%	32%	49%
Went Without Medical or Dental Care	49%	65%	72%
Did Not Fill Prescription or Took Less Than Full Dose	38%	47%	40%
Unable to pay Energy Bill Due to Medical Expenses	18%	13%	24%
Became Sick Because Home was Too Cold	21%	13%	38%
Became Sick Because Home was Too Hot	4%	3%	1%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

V. The Need For LIHEAP

This section examines the history of LIHEAP receipt, utility bill payment problems and payment arrangements, and the importance of LIHEAP in helping recipients meet their needs.

A. History of LIHEAP Receipt

Respondents were asked whether they had received LIHEAP benefits in the year prior to the survey. Since the survey sample was drawn from state LIHEAP databases of past year LIHEAP recipients, all respondents received LIHEAP in the past year. However, because LIHEAP is often paid directly on the household's utility bill, respondents are often not aware that they received these benefits. Table V-1A shows that only 86 percent of the respondents reported that they had received LIHEAP in the past year.

Table V-1A
Received LIHEAP During Past Year[8]

	Percent of Respondents
Yes	86%
No	12%
Don't Know	3%

Table V-1B displays the percent of respondents who reported that they received LIHEAP during the past year by vulnerable group. Households with no vulnerable members were more likely than some of the other groups to report that they received LIHEAP, perhaps because they are less likely to have received these benefits automatically through participation in another program.

Table V-1B
Received LIHEAP During Past Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Yes	83%	85%	87%	89%
No	13%	12%	10%	8%
Don't Know / Refused	4%	3%	2%	3%

Table V-1C displays the percent of respondents who reported that they received LIHEAP in the past year by poverty level. The table shows that all poverty groups have the same likelihood of being aware of benefit receipt.

[8] Interviewers used the name for the LIHEAP program particular to the state of the recipient interviewed. If the respondent was initially confused or did not recall the program based on the state-designated name, interviewers were trained to assist their memory by describing energy assistance benefits, and using the term energy assistance throughout the survey instead of the state-designated LIHEAP name.

Table V-1C
Received LIHEAP During Past Year
By Poverty Level

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Yes	86%	86%	86%	85%
No	12%	12%	11%	12%
Don't Know / Refused	2%	2%	4%	3%

Respondents were asked to report the number of times in the past five years that they received LIHEAP. Table V-2A shows that about one quarter said they only received benefits in one of the past five years, and about one quarter said that they received benefits in each of the past five years.

Table V-2A
Number of Years Received LIHEAP in the Past Five Years

Number of Years Received LIHEAP	Percent of Respondents
1	26%
2	18%
3	15%
4	8%
5	25%
Don't Know / Refused	8%

Table V-2B displays the number of years that respondents reported they received LIHEAP by vulnerable group. The table shows that households without vulnerable members are most likely to report that they only received benefits in one of the past five years and are least likely to report that they received LIHEAP in each of the past five years. These households appear to be more likely to be facing temporary financial problems.

Table V-2B
Number of Years Received LIHEAP
In the Past Five Years
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
1	22%	21%	30%	44%
2	13%	18%	22%	20%
3	16%	16%	15%	11%
4	8%	8%	8%	6%
5	31%	29%	19%	16%

	Senior	Disabled	Child Under 18	Non-Vulnerable
Don't Know / Refused	10%	8%	7%	3%

Table V-2C displays the number of years that respondents reported they received LIHEAP by poverty group. The table shows that households with income below 50 percent of poverty and households with income above 150 percent of poverty were most likely to report that they received LIHEAP in only one of the past five years.

Table V-2C
Number of Years Received LIHEAP In the Past Five Years
By Poverty Group

	Poverty Level			
	0-50%	**51-100%**	**101-150%**	**>150%**
Number of Respondents	286	673	557	312
1	34%	20%	28%	34%
2	21%	16%	17%	23%
3	10%	16%	18%	12%
4	7%	8%	9%	6%
5	20%	30%	25%	18%
Don't Know / Refused	8%	10%	5%	6%

Respondents were asked whether they applied or planned to apply for LIHEAP in the current year. The table shows that 88 percent reported that they did so.

Table V-3A
Applied or Plans to Apply for LIHEAP This Year

	Percent of Respondents
Yes	88%
No	9%
Don't Know	3%

Table V-3B shows that households with disabled members are most likely to report that they applied or plan to apply for LIHEAP in the current year.

Table V-3B
Applied or Plans to Apply for LIHEAP This Year
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	757	788	778	152
Yes	89%	91%	86%	86%
No	7%	7%	10%	14%
Don't Know	4%	3%	4%	1%

Table V-3C shows that households between 50 and 150 percent of the poverty level are most likely to report that they applied or plan to apply for LIHEAP this year.

Table V-3C
Applied or Plans to Apply for LIHEAP This Year
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	286	673	557	312
Yes	84%	90%	90%	83%
No	12%	7%	7%	13%
Don't Know	3%	3%	3%	4%

Table V-4 compares information about LIHEAP receipt in the 2003, 2008 and 2009 surveys. The table shows that respondents in 2009 were somewhat more likely than in 2003 to report that they received LIHEAP in each of the past five years and to report that they applied or plan to apply for LIHEAP this year.

Table V-4
LIHEAP Receipt
Comparison of Survey Results

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	2,161	1,256	1,828
Recalled Receipt of LIHEAP	84%	86%	86%
Percent That Reported They Received LIHEAP in Each of the Past Five Years	21%	26%	25%
Plans to Apply for LIHEAP This Year	83%	88%	88%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

B. Utility Payment

This section examines respondents' need for utility payment arrangements and resources available to assist them in preventing service termination. Table V-5 shows that 51 percent of

respondents tried to work out a payment arrangement in the past year, and 86 percent of those who tried to work out a payment arrangement were able to do so.

Table V-5
Payment Arrangement with Gas or Electric Company
In the Past Year

	2008 Survey		2009 Survey	
	Tried to Work Out Payment Arrangement	Was Able to Work Out Payment Arrangement	Tried to Work Out Payment Arrangement	Was Able to Work Out Payment Arrangement
Number of Respondents	1,256	682	1,828	976
Yes	54%	84%	51%	86%
No	45%	15%	48%	14%
Don't Know	1%	1%	1%	1%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Table V-6 shows that 56 percent of respondents who tried to make a payment arrangement contacted a fuel fund or social services agency for assistance, and 79 percent of those who applied for assistance received some form of assistance. Respondents were more likely to apply and received assistance in FY 2009 than in the previous year.

Table V-6
Contacted a Fuel Fund or Social Services Agency for Assistance
When Tried to Work Out a Payment Arrangement with Gas or Electric Company

	2008 Survey		2009 Survey	
	Contacted Fuel Fund or Social Services Agency	Fuel Fund or Social Services Agency Was Able to Help	Contacted Fuel Fund or Social Services Agency	Fuel Fund or Social Services Agency Was Able to Help
Number of Respondents	682	340	976	551
Yes	50%	72%	56%	79%
No	49%	25%	43%	18%
Don't Know	2%	4%	1%	3%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Table V-7 shows that 70 percent who tried to work out a payment arrangement with their utility applied for assistance from LIHEAP and 82 percent of those who applied for LIHEAP assistance received LIHEAP assistance. This is an increase from the previous year when only 75 percent of those who tried to work out a payment arrangement and applied for LIHEAP assistance received that assistance.

Table V-7
Applied for Assistance from LIHEAP
When Tried to Work Out a Payment Arrangement with Gas or Electric Company

	2008 Survey		2009 Survey	
	Applied for Assistance from LIHEAP	Received Assistance from LIHEAP	Applied for Assistance from LIHEAP	Received Assistance from LIHEAP
Number of Respondents	682	458	976	670
Yes	67%	75%	70%	82%
No	29%	22%	27%	16%
Don't Know	4%	2%	3%	2%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Table V-8 shows that 61 percent of those who tried to work out a payment arrangement received assistance that was sufficient to prevent service termination, 73 percent of those who applied for assistance received assistance that was sufficient to prevent service termination, and 86 percent of those who received assistance obtained assistance that was sufficient to prevent service termination.

Table V-8
Assistance from LIHEAP or Social Services Was
Sufficient to Prevent Termination of Gas or Electric Service

	2008 Survey	2009 Survey
Tried to Work Out Payment Arrangement		
Number of Respondents	682	976
LIHEAP Was Sufficient	54%	61%
Applied for Assistance		
Number of Respondents	541	794
LIHEAP Was Sufficient	69%	73%
Received LIHEAP or Social Services Assistance		
Number of Respondents	431	688
LIHEAP Was Sufficient	87%	86%

C. Problems that Would Have Been Faced in the Absence of LIHEAP

Respondents who said that they did not face some problems with their energy bills were asked whether they felt they would have faced such problems if LIHEAP assistance had not been available. Table V-9 shows that 76 percent said they would have worried about their energy bill if LIHEAP had not been available, 64 percent said they would have had to keep their home at an unsafe or unhealthy temperature if LIHEAP assistance had not been available, and 53 percent said they would have had their electricity or home heating fuel discontinued if LIHEAP assistance had not been available.

Table V-9
If LIHEAP Had Not Been Available, Problems that May Have Been Faced

	Worried About Paying Home Energy Bill	Kept Home at Unsafe or Unhealthy Temperature	Had Electricity or Home Heating Fuel Discontinued
Number of Respondents	389	1,134	1,175
Yes	76%	64%	53%
No	23%	32%	41%
Don't Know / Refused	1%	4%	6%

Table V-10 compares responses about problems that would have been faced in the absence of LIHEAP between 2003, 2008, and 2009. The table shows that respondents were more than in 2009 than in 2003 to say that they would have faced these problems.

Table V-10
If LIHEAP Had Not Been Available, Problems that May Have Been Faced
Comparison of Survey Results

	2003 Survey		2008 Survey		2009 Survey	
	Respondents	Percent of Respondents	Respondents	Percent of Respondents	Respondents	Percent of Respondents
Worried About Paying Home Energy Bill	511	66%	294	77%	389	76%
Kept Home at Unsafe or Unhealthy Levels	1,392	54%	761	63%	1,134	64%
Had Electricity or Home Heating Fuel Discontinued	1,555	48%	845	59%	1,175	53%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

D. LIHEAP Restored Heat

Respondents were asked whether LIHEAP helped to restore heat due to shutoff or broken equipment. The table shows that 12 percent said that LIHEAP restored heat due to a shutoff and seven percent said that LIHEAP restored heat due to broken equipment.

Table V-11
LIHEAP Helped to Restore Heat Due to Shutoff or Broken Equipment

	Restored Heat Due to Shutoff		Restored Heat Due to Broken Equipment	
	2008	2009	2008	2009
Yes	12%	12%	9%	7%
No	8%	6%	5%	5%
Don't Know	<1%	<1%	<1%	<1%
Did Not Experience Loss of Heat/or Did Not Receive LIHEAP	81%	81%	86%	87%

Note: 2009 statistically significant differences at the 95% level from 2008 are underlined.

E. Importance of LIHEAP

Respondents were asked to report how important LIHEAP was in helping them to meet their needs. Table V-12A shows that 93 percent of respondents said that LIHEAP was very important, an increase over the previous surveys.

Table V-12A
Importance of LIHEAP

	2003 Survey	2008 Survey	2009 Survey
Number of Respondents	957	1,082	1,537
Very Important	74%	90%	93%
Somewhat Important	6%	8%	5%
Of Little Importance	3%	1%	1%
Not At All Important	1%	1%	<1%
Don't Know / Refused	<1%	<1%	1%

Note: 2009 statistically significant differences at the 95% level from 2003 and 2008 are underlined.

Table V-12B shows that households with disabled members were most likely to say that LIHEAP was very important in helping them meet their needs.

Table V-12B
Importance of LIHEAP
By Vulnerable Group

	Senior	Disabled	Child Under 18	Non-Vulnerable
Number of Respondents	617	650	673	135
Very Important	91%	96%	93%	91%
Somewhat Important	6%	3%	5%	4%
Of Little Importance	1%	<1%	1%	4%
Not At All Important	<1%	<1%	0%	0%
Don't Know	1%	1%	<1%	0%

Table V-12C shows that households with income below 100 percent of the poverty level were most likely to say that LIHEAP was very important in helping them meet their needs.

Table V-12C
Importance of LIHEAP
By Poverty Group

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Number of Respondents	240	574	464	259
Very Important	95%	95%	92%	83%

	Poverty Level			
	0-50%	51-100%	101-150%	>150%
Somewhat Important	3%	4%	7%	9%
Of Little Importance	1%	1%	1%	6%
Not At All Important	0%	<1%	<1%	<1%
Don't Know	1%	1%	<1%	2%

VI. Regional Analysis

This section provides a regional analysis of some of the information that was presented in this report.

A. Demographic Characteristics

Table VI-1 displays the percent of respondents with children and the percent in single family households. The table shows that households in the northeast are most likely to include children.

Table VI-1
Presence of Children Under 18 and Single-Parent Households
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Percent with Children	49%	43%	39%	46%
Percent in Single-Parent Households	18%	19%	15%	16%

Table VI-2 displays the poverty level of LIHEAP recipients by region. The table shows that households in the Northeast are most likely to have income above 150 percent of the poverty level.

Table VI-2
Poverty Level
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
0%-50%	21%	18%	21%	23%
51%-100%	42%	39%	51%	40%
101%-150%	24%	34%	22%	31%
>150%	13%	9%	6%	6%

Table VI-3 shows that recipients in the West are most likely to have employment income, recipients in the South and West are most likely to have retirement income, recipients in the West are most likely to receive public assistance, and recipients in the South are most likely to receive non-cash benefits.

Table VI-3
Types of Income and Benefits Received
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318

	Northeast	Midwest	South	West
Wages or Self-Employment Income	32%	30%	27%	37%
Retirement Income	33%	41%	39%	35%
Public Assistance	40%	39%	36%	46%
Non-Cash Benefits	61%	55%	71%	62%

Table VI-4 displays the percent of respondents who were unemployed during the year. The table shows that LIHEAP recipients in the West were most likely to be unemployed.

Table VI-4
Unemployed During the Year
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Yes	33%	36%	37%	42%
No	65%	64%	63%	57%
Don't Know / Refused	2%	0%	<1%	1%

B. Energy Burden and Energy Bill Payment Problems

Table VI-5 displays mean pre and post-LIHEAP energy burden by region. The table shows that recipients in the West have lower energy burdens on average than those in the other regions.

TableVI-5
Mean Energy Burden
By Region

	Northeast	Midwest	South	West
Number of Respondents	715	255	299	264
Pre-LIHEAP	16%	16%	16%	14%
Post-LIHEAP	10%	12%	13%	8%

Table VI-6 shows that recipients in the Northeast and in the South were most likely to report that they worried about paying their home energy bill during the past year.

Table VI-6
Worried About Paying Home Energy Bill Due to
Not Having Enough Money for the Energy Bill
During Past Year
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318

	Northeast	Midwest	South	West
Almost Every Month	31%	28%	33%	31%
Some Months	31%	25%	28%	25%
1 or 2 Months	15%	15%	19%	17%
Never / No	23%	32%	20%	27%
Don't Know / Refused	<1%	0%	0%	<1%

Table VI-7 shows that recipients in the South were most likely to report that they borrowed from a friend or relative to pay their home energy bill during the past year. Fifty-six percent of LIHEAP recipients in the South reported that they did so.

Table VI-7
Borrowed from a Friend or Relative to Pay Home Energy Bill Due to Not Having Enough Money for the Energy Bill During Past Year By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Almost Every Month	4%	3%	8%	5%
Some Months	22%	17%	26%	21%
1 or 2 Months	21%	16%	22%	23%
Never / No	53%	63%	44%	51%
Don't Know / Refused	<1%	<1%	<1%	0%

Table VI-8 shows that LIHEAP recipients in the West and South were most likely to report that they left their home for part of the day because it was too hot or too cold.

Table VI-8
Left Home for Part of the Day Because it was Too Hot or Too Cold Due to Not Having Enough Money for the Energy Bill During Past Year By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Almost Every Month	1%	1%	1%	2%
Some Months	7%	7%	13%	13%
1 or 2 Months	12%	9%	10%	12%
Never / No	80%	83%	75%	73%
Don't Know / Refused	<1%	0%	0%	<1%

Table VI-9 shows that the percentage of respondents who reported that they used their kitchen oven or stove to provide heat in the past year ranged from 30 percent in the Midwest to 37 percent in the West.

Table VI-9
Used Kitchen Stove or Oven to Provide Heat
Due to Not Having Enough Money for the Energy Bill
During Past Year
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Almost Every Month	3%	2%	2%	4%
Some Months	15%	13%	19%	13%
1 or 2 Months	16%	15%	14%	20%
Never / No	66%	70%	65%	62%
Don't Know / Refused	1%	<1%	0%	<1%

Table VI-10 shows that respondents in the West were most likely to report that they skipped paying or paid less than their entire home energy bill during the past year.

Table VI-10
Skipped Paying or Paid Less than Entire Home Energy Bill
Due to Not Having Enough Money for the Energy Bill
During Past Year
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Almost Every Month	9%	9%	13%	16%
Some Months	24%	18%	22%	22%
1 or 2 Months	16%	19%	15%	19%
Never / No	50%	54%	50%	42%
Don't Know / Refused	<1%	<1%	<1%	0%

Table VI-11 shows that respondents in the Northeast, South, and West were more likely than those in the Midwest to report that they received a notice or threat to disconnect their electricity or home heating fuel in the past year.

Table VI-11
Received Notice or Threat to Disconnect or Discontinue Electricity or Home Heating Fuel Due to Not Having Enough Money for the Energy Bill During Past Year By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Almost Every Month	5%	5%	8%	4%
Some Months	14%	8%	16%	13%
1 or 2 Months	20%	18%	15%	19%
Never / No	61%	70%	62%	63%
Don't Know / Refused	<1%	0%	0%	<1%

Table VI-12 displays the percent of respondents who had their electricity and gas utility service terminated during the past year. The table shows that there is not much variation in service terminations by region.

Table VI-12
Utility Service Terminations During Past Year By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Electricity	10%	7%	9%	8%
Gas	7%	8%	6%	5%
Electricity or Gas	13%	11%	13%	11%

C. Housing, Health, and Medical Problems

Table VI-13 displays the percent who did not make their full rent or mortgage payment in the past five years. The table shows that respondents in the South were most likely to report this problem, and respondents in the Midwest were least likely to report this problem.

Table VI-13
Did Not Make Full Rent or Mortgage Payment Due to Energy Bills
In the Past Five Years
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Yes	33%	25%	37%	34%
No	66%	75%	62%	65%
Don't Know /Refused	1%	<1%	1%	1%

Table VI-14 displays the percent of respondents who reported that they went without food for at least one day in the past five years. The table shows that respondents in the West were most likely to report this problem.

Table VI-14
Went Without Food for at Least One Day Due to Energy Bills
In the Past Five Years
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Yes	29%	27%	30%	39%
No	71%	73%	70%	60%
Don't Know / Refused	<1%	0%	0%	<1%

Table VI-15 shows that respondents in the South and in the West were most likely to report that they went without medical or dental care due to their energy bills in the past five years.

Table VI-15
Went Without Medical or Dental Care Due to Energy Bills
In the Past Five Years
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Yes	37%	36%	51%	48%
No	63%	64%	48%	52%
Don't Know / Refused	<1%	<1%	<1%	0%

Table VI-16 shows that respondents in the South were most likely to report that they did not fill their prescription or took less than the full dose of a prescribed medication due to their energy bills in the past five years.

Table VI-16
Didn't Fill Prescription or Took Less Than the Full Dose of Prescribed Medicine Due to Energy Bills
In the Past Five Years
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Yes	33%	27%	43%	33%
No	66%	73%	56%	67%
Don't Know / Refused	1%	0%	<1%	<1%

Table VI-17 shows that respondents in the West were most likely to report that someone in the home became sick because the home was too cold and respondents in the Midwest were least likely to report this problem.

Table VI-17
Someone in Household Became Sick Because Home was Too Cold
In the Past Five Years
By Region

	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
Yes	26%	18%	27%	35%
No	73%	81%	73%	64%
Don't Know / Refused	1%	1%	1%	1%

D. LIHEAP Receipt

Table VI-18 displays the number of years that respondents reported they received LIHEAP in the past five years. The table shows that respondents in the West were most likely to report that they received LIHEAP in only one of the past five years and respondents in the Midwest were most likely to report that they received LIHEAP in each of the past five years.

Table VI-18
Number of Years Received LIHEAP
In the Past Five Years
By Region

	2009 Survey			
	Northeast	Midwest	South	West
Number of Respondents	869	305	336	318
1	27%	19%	30%	36%
2	20%	16%	16%	18%

	2009 Survey			
	Northeast	Midwest	South	West
3	16%	15%	12%	16%
4	7%	10%	7%	5%
5	21%	35%	17%	20%
Don't Know / Refused	7%	5%	17%	4%

VII. Conclusion

The 2009 NEADA study confirmed that LIHEAP recipient households are likely to be vulnerable to temperature extremes. They are likely to have seniors, disabled members, or children in the home. Over 90 percent of LIHEAP recipients had at least one of these vulnerable household members. The study also showed that these households face many challenges in addition to their energy bills, including unemployment, unhealthy home conditions, and medical issues.

Energy Costs

LIHEAP recipients reported that they faced high energy costs. Over one third of the respondents reported energy costs over $2,000 in the past year and 35 percent said that their energy bills had increased over the previous year. The majority of those who said that their energy bills were more difficult to pay, said that the increased difficulty was due to a worsened financial situation.

Responses to High Energy Costs

Households reported that they took several actions to make ends meet, including closing off part of the home and leaving the home for part of the day. Some of the actions were unsafe and could lead to injury or illness, such as keeping the home at a temperature that was unsafe or unhealthy or using the kitchen stove or oven to provide heat.

Inability to Pay Energy Bills

Despite the assistance that they received, many LIHEAP recipients were unable to pay their energy bills. Almost half of the respondents reported that they had skipped paying or paid less than their entire home energy bill in the past year and more than one third said that they received a notice or threat to disconnect or discontinue their electricity or home heating fuel.

Households went without utility service and sacrificed heating and cooling their home. Over ten percent had their electric or natural gas service shut off in the past year due to nonpayment. More than one quarter reported that they were unable to use their main source of heat in the past year because their fuel was shut off, they could not pay for fuel delivery, or their heating system was broken and they could not afford to fix it. Almost one fifth reported that they were unable to use their air conditioner in the past year because their electricity was shut off or their air conditioner was broken and they could not afford to fix it.

Housing and Financial Problems

Many LIHEAP recipients had problems paying for housing in the past five years, due at least partly to their energy bills. Over one quarter did not make their full mortgage or rent payment. Five percent were evicted from their home or apartment and four percent had a foreclosure on their mortgage.

They faced other significant financial problems as well, including taking out payday loans and going into bankruptcy.

Medical and Health Problems

Many of the LIHEAP recipients faced significant medical and health problems in the past five years, partly as a result of high energy costs. Nearly one third reported that they went without food, over 40

percent sacrificed medical care, and one quarter had someone in the home become sick because the home was too cold.

The Need for LIHEAP

Households reported enormous challenges despite the fact that they received LIHEAP. However, they reported that LIHEAP was extremely important. Many reported that they would have kept their home at unsafe or unhealthy temperatures and/or had their electricity or home heating fuel discontinued if it had not been for LIHEAP. Ninety-eight percent said that LIHEAP was very or somewhat important in helping them to meet their needs.

It is clear that many of these households will continue to need LIHEAP to meet their energy and other essential needs. Almost ninety percent said that they have or plan to apply for LIHEAP in the next year.

Appendix A: Survey Instrument

Applied Public Policy Research

APPRISE

Institute for Study and Evaluation

NEADA 2009 National Energy Assistance SURVEY
FINAL INSTRUMENT
November 2009

Screener

Hello. This is (INTERVIEWER) from TMR Research calling for (NAME) regarding the National Energy Assistance study.

{Interviewer Note: The goal is to conduct the survey with either (NAME) or that person's spouse/partner. If (NAME) is not home / unavailable, politely ask, "May I speak with the spouse or partner of (NAME)".}

You should have received a letter in the mail from the National Energy Assistance Directors' Association about this survey. I'm calling to ask you a few brief questions about your energy bills. In the survey, we will also talk about (**state specific LIHEAP name**). By (**state specific LIHEAP name**), we mean the home energy assistance benefits that your household received through your Community-Based Organization. Your responses will help us better understand the need for (**state specific LIHEAP name**) energy assistance, and the problems caused by high energy bills. All your responses will be kept confidential and will not affect your energy assistance benefits.

S1. {Interviewer: DO NOT READ, Whom are you speaking to?}

01 NAME
02 Spouse/Partner
03 Caretaker/Guardian
04 Other/Don't Know

[ASK if S1=04]
S2. When can I call back to speak with (NAME) or the spouse or partner of (NAME)? _____ WRITE DATE AND TIME FOR CALLBACK

S3. Did you receive (**STATE SPECIFIC LIHEAP NAME**) in the past 12 months?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

A. Experience with Energy Assistance

A1. In how many of the past 5 years have you received (**STATE SPECIFIC LIHEAP NAME**)?

01 ONCE
02 TWICE
03 THREE TIMES
04 FOUR TIMES
05 FIVE TIMES
07 DON'T KNOW
08 REFUSED

A2. Have you or will you apply for (**STATE SPECIFIC LIHEAP NAME**) this winter?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

B. Actions taken to meet energy expenses

Energy bills can take up a large part of a family's budget, and households often find it necessary to make choices about what bills they will pay or what needs they will meet. In this section of the survey, we ask some questions about actions that your household may have taken when it was difficult to meet all of your expenses.

In the past 5 years, have you or any member of your family taken any of the following actions or experienced any of the following due to your energy bills:

	01	02	07	08
1. Housing Problems				
B1. Didn't make full rent or mortgage payment?	YES	NO	DON'T KNOW	REFUSED
B2. Was evicted from home or apartment?	YES	NO	DON'T KNOW	REFUSED
B3. Had a foreclosure on your mortgage?	YES	NO	DON'T KNOW	REFUSED
B4. Moved in with friends or family?	YES	NO	DON'T KNOW	REFUSED
B5. Moved into a shelter or been homeless?	YES	NO	DON'T KNOW	REFUSED
	01	02	07	08
2. Financial				
B6. Got a payday loan to cover your expenses?	YES	NO	DON'T KNOW	REFUSED
	01	02	07	08
3. Other Expenses				
B7. Went without food for at least one day?	YES	NO	DON'T KNOW	REFUSED
B8. Went without medical or dental care?	YES	NO	DON'T KNOW	REFUSED
B9. Didn't fill a prescription or took less than the full dose of a prescribed medicine?	YES	NO	DON'T KNOW	REFUSED
	01	02	07	08
4. Utility Service and Health				
B10. Had someone in your household get sick because your home was too cold?	YES	NO	DON'T KNOW	REFUSED
B11. (Ask if B10=1, YES) Did someone in the household need to go to the doctor or hospital because of this illness?	YES	NO	DON'T KNOW	REFUSED
B12. Had someone in your household get sick because your home was too hot?	YES	NO	DON'T KNOW	REFUSED
B13. (Ask if B12=1, YES) Did someone in the household need to go to the doctor or hospital because of this illness?	YES	NO	DON'T KNOW	REFUSED
	01	02	07	08
5. Utility Payment				
B14. In the past year, have you tried to work out a payment arrangement with your gas or electric utility company?	YES	NO	DON'T KNOW	REFUSED
B15. (Ask if B14=1, YES) Were you able to work	YES	NO	DON'T KNOW	REFUSED

	out a payment arrangement?				
B16.	(Ask if B14=1, YES) Did you contact a fuel fund or social services agency for assistance at this time?	YES	NO	DON'T KNOW	REFUSED
B17.	(Ask if B16=1, YES) Was the fuel fund or social services agency able to help you?	YES	NO	DON'T KNOW	REFUSED
B18.	(Ask if B14=1, YES) Did you apply for assistance from **(STATE SPECIFIC LIHEAP NAME)** at this time?	YES	NO	DON'T KNOW	REFUSED
B19.	(Ask if B18=1, YES) Did you receive assistance from **(STATE SPECIFIC LIHEAP NAME)** at this time?	YES	NO	DON'T KNOW	REFUSED
B20.	(Ask if B19=1, YES or B17=1, YES) Was the **(STATE SPECIFIC LIHEAP NAME)** or social services assistance sufficient to prevent the utility from terminating your electric or gas service?	YES	NO	DON'T KNOW	REFUSED

C. Energy Insecurity Scale

In the past 12 months, did you almost every month, some months, only in 1 or 2 months, or never do the following because there wasn't enough money for your energy bill? (INTERVIEWER NOTE: IF ASKED, ALMOST EVERY MONTH MEANS 10 OR MORE MONTHS, AND SOME MONTHS MEANS 3 TO 9 MONTHS.)

		01	02	03	04	07	08
C1.	Did you worry that you wouldn't be able to pay your home energy bill?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C2.	Did you reduce your expenses for what you consider to be basic household necessities?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C3.	Did you need to borrow from a friend or relative to pay your home energy bill?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C4.	Did you skip paying your home energy bill or pay less than your whole home energy bill?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C5.	Did you have a supplier of your electric or home heating service threaten to disconnect your electricity or home heating fuel service, or discontinue making fuel deliveries?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C6.	Did you close off part of your home because you could not afford to heat or cool it?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C7.	Did you keep your home at a temperature that you felt was unsafe or unhealthy at any time of the year?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C8.	Did you leave your home for part of the day because it was too hot or too cold?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED
C9.	Did you use your kitchen stove or oven to provide heat?	ALMOST EVERY MONTH	SOME MONTHS	1 OR 2 MONTHS	NEVER/ NO	DON'T KNOW	REFUSED

		01	02	07	08
C10a.	In the past 12 months, was your electricity ever shut off because you were unable to pay your electric bill?	YES	NO	DON'T KNOW	REFUSED
C10b.	**ASK C10b if C10a=01, YES.** Is your electricity service shut off now?	YES	NO	DON'T KNOW	REFUSED
C10c.	In the past 12 months, was your natural gas ever shut off because you were unable to pay your gas bill?	YES	NO	DON'T KNOW	REFUSED
C10d.	**ASK C10d if C10c=01, YES.** Is your gas service shut off now?	YES	NO	DON'T KNOW	REFUSED

Was there ever a time during the past 12 months when you wanted to use your main source of heat, but could not for one or more of the following reasons?

		01	02	07	08
C11.	Your heating system was broken and you were unable to pay for its repair or replacement?	YES	NO	DON'T KNOW	REFUSED
C12.	You ran out of fuel oil, kerosene, LPG, propane, coal, or wood because you were unable to pay for a delivery?	YES	NO	DON'T KNOW	REFUSED
C13.	The utility company discontinued your gas or electric service because you were unable to pay your bill?	YES	NO	DON'T KNOW	REFUSED

(Ask C14 if C11=1, YES, OR C12=1, YES, OR C13=1, YES)

		01	02	07	08
C14.	Did (**STATE SPECIFIC LIHEAP NAME**) help you to restore use of your main source of heat?	YES	NO	DON'T KNOW	REFUSED

Was there ever a time during the past 12 months when you wanted to use your air conditioner, but could not for one or more of the following reasons?

		01	02	07	08
C15.	Your air conditioner was broken and you were unable to pay for its repair or replacement?	YES	NO	DON'T KNOW	REFUSED
C16.	The utility company discontinued your electric service because you were unable to pay your bill?	YES	NO	DON'T KNOW	REFUSED

(ASK C17-C19 IF C12=1, YES OR C13=1, YES, OR C16=1, YES, OR C10A=1, YES, OR C10C=1, YES)
Was there ever a time during the past 12 months when you had to do the following because the utility company discontinued your gas or electric service or because you ran out of fuel and could not pay for a delivery?

		01	02	07	08
C17.	Did you have to go without showers or baths because you didn't have hot water?	YES	NO	DON'T KNOW	REFUSED
C18.	Did you have to go without hot meals because you didn't have cooking fuel?	YES	NO	DON'T KNOW	REFUSED
C19.	Did you have to use candles or lanterns because you didn't have lights?	YES	NO	DON'T KNOW	REFUSED

(READ IF S3=1 AND [C1=4, NEVER OR C7=4, NEVER OR [C12=2, N0, AND C13=2, NO, AND C16=2, NO, AND C10A=2, NO, AND C10C=2, NO]]) ELSE SKIP TO C23
You stated that you did not face some of these problems that we asked about in the past year. In the next few questions we ask whether you think you may have had some of these problems if (**STATE SPECIFIC LIHEAP NAME**) assistance had not been available.

		01	02	07	08
C20.	(Ask if C1=4, NEVER) Would you have worried about paying your home energy bill if (**STATE SPECIFIC LIHEAP NAME**) assistance had not been available?	YES	NO	DON'T KNOW	REFUSED
C21.	(Ask if C7=4, NEVER) Would you have needed to keep your home at a temperature that you felt was unsafe or unhealthy at any time of the year if (**STATE SPECIFIC LIHEAP NAME**) assistance had not been available?	YES	NO	DON'T KNOW	REFUSED

		YES	NO	DON'T KNOW	REFUSED
C22.	(Ask if [C12=2, NO, AND C13=2, NO, AND C16=2, NO, AND C10A=2, NO, AND C10C=2, NO]) Would you have had your electricity or home heating fuel shut off or discontinued during a time when you needed it to heat or cool your home if (**STATE SPECIFIC LIHEAP NAME**) assistance had not been available?				

[DO NOT ASK C23 IF S3=2,7,8]

C23. How important has (**STATE SPECIFIC LIHEAP NAME**) been in helping you to meet your needs? (DO NOT READ LIST EXCEPT TO PROMPT)

01 VERY IMPORTANT (HAS MADE A VERY BIG DIFFERENCE)
02 SOMEWHAT IMPORTANT (HAS MADE A DIFFERENCE)
03 OF LITTLE IMPORTANCE (HAS MADE A SMALL DIFFERENCE)
04 NOT AT ALL IMPORTANT (NOT BIG ENOUGH BENEFIT TO HELP)
07 DON'T KNOW
08 REFUSED

D. Change in Circumstances

D1. How do your energy bills this year compare to those last year? (DO NOT READ LIST EXCEPT TO PROMPT) **VARY THE ORDER OF RESPONSES

01 SAME
02 LOWER
03 HIGHER
07 DON'T KNOW
08 REFUSED

(Ask D2 if D1=3 "Higher")

D2. Why do you think your energy bills are higher than last year? (DO NOT PROMPT. MARK ALL THAT APPLY.)

01 PRICES WERE HIGHER
02 WINTER WAS COLDER
03 SUMMER WAS WARMER
05 OTHER_____
07 DON'T KNOW
08 REFUSED

D3. How does your financial situation this year compare to last year? (DO NOT READ LIST EXCEPT TO PROMPT)
(OPTIONAL INTERVIEWER NOTE: I WOULD LIKE YOU TO THINK ABOUT HOW DIFFICULT IT IS TO PAY ALL YOUR BILLS WITH YOUR CURRENT INCOME, COMPARED TO HOW DIFFICULT IT WAS LAST YEAR.) **VARY THE ORDER OF RESPONSES

01 SAME
02 WORSE
03 BETTER
07 DON'T KNOW
08 REFUSED

D4. How difficult is it for you to pay your energy bills compared to last year? (DO NOT READ LIST EXCEPT TO PROMPT) **VARY THE ORDER OF RESPONSES

01 SAME
02 MORE DIFFICULT
03 LESS DIFFICULT
07 DON'T KNOW
08 REFUSED

(Ask D5 if D4=2, "More difficult")

D5. What do you feel is the main reason that it is more difficult to pay your energy bills this year? (DO NOT PROMPT.)

01 INCREASED ENERGY BILL
02 INCREASED OTHER BILLS
03 INCREASED PROPERTY TAXES
04 INCREASED RENT
05 INCREASED MEDICAL EXPENSES
06 INCREASED PRESCRIPTION DRUGS
07 LOWER INCOME/LOST JOB/WORSE ECONOMIC SITUATION
95 OTHER_____
97 DON'T KNOW
98 REFUSED

D6. Have unaffordable energy bills forced you into bankruptcy in the past 12 months?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

E. Healthy Homes

In this section of the survey, we will ask some general questions about the home and the household members.

E1. Does anyone smoke inside the house?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

E2. How often do you use your bathroom exhaust fan when you are showering or bathing?

01 Never/Don't have one
02 Rarely
03 Sometimes
04 Always
07 DON'T KNOW
08 REFUSED

E3. How often do you use your kitchen exhaust fan when you are cooking?

01 Never/Don't have one
02 Rarely
03 Sometimes
04 Always
07 DON'T KNOW
08 REFUSED

E4. Have you seen mold in your home in the past year?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

E5. Have you seen pests (cockroaches, ants, mice, rats. . .) in your home in the past year?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

E6. How do you rate the health of your household members overall?

01 VERY HEALTHY
02 SOMEWHAT HEALTHY
03 SOMEWHAT UNHEALTHY

04 VERY UNHEALTHY
07 DON'T KNOW
08 REFUSED

E7. Does anyone in the home have symptoms of asthma, including coughing, wheezing, shortness of breath, chest tightness, or phlegm production?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

E8. Does anyone in the home have chronic bronchitis, emphysema, or chronic obstructive pulmonary disease (COPD)?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

(Ask E9 if E7=1, YES OR E8=1, YES)
E9. Has anyone in the home gone to the emergency room or urgent care center for asthma, bronchitis, emphysema, or chronic obstructive pulmonary disease (COPD) in the past year?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

E10. Does anyone in the home have high blood pressure (hypertension), heart disease, heart attack, or stroke?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

E11. Does anyone in the home have allergies, or always seem to have a runny nose, wheezing, coughing, burning eyes, or headaches?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F. Demographics

F1. Do you own or rent your home?

01 OWN
02 RENT
03 OTHER_____
07 DON'T KNOW
08 REFUSED

F2. Including yourself, how many people normally live in this household? (Interviewer instruction: if someone asks if a child who is away at college should be included, instruct them that the child should only be included if he/she is listed as a dependent on the household's tax form.) (USE CODES 97 FOR 'DON'T KNOW' AND 98 FOR 'REFUSED')

_____ OCCUPANTS

F3. How many are 60 or older? (USE CODES 97 FOR 'DON'T KNOW' AND 98 FOR 'REFUSED')

_____ OCCUPANTS OVER AGE 60

F4. How many are 18 or under? (USE CODES 97 FOR 'DON'T KNOW' AND 98 FOR 'REFUSED')

_____ CHILDREN 18 OR UNDER

(ASK F5 IF F4 ≠ 0)

F5. How many are 5 or under? (USE CODES 97 FOR 'DON'T KNOW' AND 98 FOR 'REFUSED')

_____ CHILDREN 5 OR UNDER

F6. How many are disabled? (USE CODES 97 FOR 'DON'T KNOW' AND 98 FOR 'REFUSED')

_____ DISABLED OCCUPANTS

F7. Which fuel is used most for heating your home? (DO NOT READ LIST EXCEPT TO PROMPT)

01 GAS; FROM UNDERGROUND PIPES SERVING THE NEIGHBORHOOD
02 GAS: BOTTLED, TANK OR LPG, OR PROPANE
03 ELECTRICITY

04 FUEL OIL, KEROSENE, ETC.
05 COAL OR COKE
06 WOOD
07 SOLAR ENERGY
08 OTHER FUEL
09 NO FUEL USED
97 DON'T KNOW
98 REFUSED

[ASK IF F1 ≠ 01]
F8. Is heat included in your rent?

01 YES
02 NO
03 DO NOT PAY RENT
07 DON'T KNOW
08 REFUSED

F9. What is the main way that you cool your home on the hottest days of the summer? (DO NOT READ LIST EXCEPT TO PROMPT)

01 CENTRAL AIR CONDITIONER
02 WINDOW OR WALL AIR CONDITIONER
03 EVAPORATIVE COOLING OR SWAMP COOLERS
04 FANS
05 NONE
07 DON'T KNOW
08 REFUSED

F10. In the past 12 months, what was the cost of electricity, gas, and other fuels (oil, coal, kerosene, wood, etc.) for your home? (give option to provide monthly cost) (DO NOT READ LIST EXCEPT TO PROMPT.)

01 ≤$500
02 $501 - $1,000
03 $1,001 - $1,500
04 $1,501 - $2,000
05 $2001 OR MORE
07 DON'T KNOW
08 REFUSED

F11. In the past 12 months, did you not pay your home energy bill or not pay your bill in full because of expenses for medical bills or prescription medicine?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F12. In the past 12 months, did any member of your household have any necessary medical equipment that uses electricity?
(OPTIONAL INTERVIEWER NOTE: I WOULD LIKE YOU TO THINK ABOUT ANY NECESSARY MEDICAL EQUIPMENT THAT USES ELECTRICITY, SUCH AS AN OXYGEN MACHINE OR A NEBULIZER.)

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F13. In the past 12 months, did you or any member of your household receive employment income from wages and salaries or self-employment income from a business or farm?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F14. In the past 12 months, was any member of your household unemployed and looking for work?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F15. In the past 12 months, did you or any member of your household receive retirement income from Social Security or pensions and other retirement funds?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F16. In the past 12 months, did you or any member of your household receive benefits from Temporary Assistance for Needy Families (TANF), Supplemental Security Income (SSI), or general assistance or public assistance?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F17. In the past 12 months, did you or any member of your household receive Food Stamps or live in public or subsidized housing?

01 YES
02 NO
07 DON'T KNOW
08 REFUSED

F18. What is your household's annual income? (give option to provide monthly income) (DO NOT READ LIST EXCEPT TO PROMPT.)

01 ≤$5,000
02 $5,001 - $10,000
03 $10,001 - $15,000
04 $15,001 - $20,000
05 $20,001 - $25,000
06 $25,001 - $30,000
07 $30,001 - $35,000
08 $35,001 - $40,000
09 >$40,000
97 DON'T KNOW
98 REFUSED

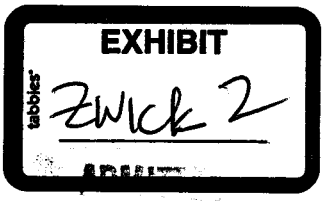
That was my last question. Thank you very much for your time and cooperation. Have a pleasant day/evening.

Southwest Gas

Disconnections

State fiscal year (June - July) for the years ending 2008, 2009 and 2010

DATE	AZ Total Comp	DATE	AZ Total Comp	DATE	AZ Total Comp	DATE	AZ Total Comp
2007		2008		2009		2010	
Jan	[redacted]	Jan	3039	Jan	1909	Jan	1951
Feb		Feb	2919	Feb	3820	Feb	3280
Mar		Mar	4126	Mar	5825	Mar	4525
Apr		Apr	4857	Apr	4744	Apr	4172
May		May	3325	May	3146	May	3195
Jun	2326	Jun	2792	Jun	2685	Jun	2744
Jul	2043	Jul	2543	Jul	2804	Jul	2933
Aug	1947	Aug	2184	Aug	3603	Aug	2844
Sept	1535	Sept	2175	Sept	3167	Sept	[redacted]
Oct	2332	Oct	2449	Oct	2806	Oct	
Nov	2232	Nov	1576	Nov	1957	Nov	
Dec	1524	Dec	2272	Dec	2040	Dec	
2007 Total	38962	2008 Total	68423	2009 Total	69266	2010 Total	44820
				Grand Total		221,471	



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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	DOCKET NO. G-01551A-10-0458

TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT

CYNTHIA ZWICK
July 28, 2011

Q.1. Please state your name for the record.

A.1. Cynthia Zwick

Q.2. Have you previously filed testimony in this case?

A.2. Yes. I filed direct testimony on June 10, 2011.

Q.3. What is the purpose of this additional testimony?

A.3. My testimony at this time is intended to articulate my support for the Settlement Agreement filed in this case.

Settlement discussions began in this case on June 28, 2011, with all parties receiving notice and an opportunity to participate. I was able to fully participate in this meeting in order to share my position and concerns about the case as originally filed.

Arizonans throughout the Southwest Gas (the Company) service territory continue to struggle to find jobs, to maintain their homes, to feed their families, in short to simply make ends meet, and maintain utility service. The parties signing the Settlement Agreement in this case have agreed that circumstances are such that in order to maintain the economic viability of the Company, ensure that low and formerly middle income families realize reasonable rates, are subject to fair practices and procedures, and have additional support available order to ensure consistent and continued gas service. These parties have entered into the agreement that is before the Commission.

The provisions in this case related to low-income customers that all settling parties have agreed to support the following provisions:

- Southwest Gas will enhance and increase the funding level of the Low Income Energy Conservation ("LIEC") weatherization program by

committing to make non-ratepayer funded contributions to the LIEC weatherization program each year for the next 5 years. The commitment shall result in a total contribution of at least $1 million;

- The demand-side management adjustor rate for the low-income residential rate schedules will not be increased above the rate currently collected, which is $0.00200 per therm;
- The Customer Owned Yard Line cost recovery mechanism ("CCRM") will consist of a per therm charge, and the CCRM will not apply to the low-income rate schedules;
- The proposed increase to the low-income residential rate schedules shall be mitigated by increasing the Low-Income Rate Assistance discount to 30 percent, from the current 20 percent for the first 150 therms in the winter months (November –April). This will result in an average monthly bill increase of either $0.70 (Alternative A) or $0.59 (Alternative B) depending upon the alternative selected by the Commission;
- Southwest Gas staff will meet with the Parties to the Docket within 45 days of the effective date of any order approving this Agreement to develop a plan to enhance customer education and outreach for its LIEC weatherization program.

My Direct Testimony did not address the central issue in this case, that of Decoupling, nor was I able to participate in the discussions related to this issue. Therefore I am not supporting one or the other Alternatives presented in this case. I

respect the expertise of all the Parties and the Commission and know that the best solution for Southwest Gas customers and the Company will be reached.

I offer my full support to the agreements reached with respect to the Low-Income issues listed above and thank the Parties to this Settlement for their considered position and urge the support of the Commission as well.

Q.4. Does this conclude your testimony?

A.4. Yes, it does.

RESPECTFULLY SUBMITTED this 29th day of July, 2011.

By _____
Cynthia Zwick
1940 E. Luke Avenue
Phoenix, AZ 85016

ORIGINAL and thirteen (13) COPIES of the Foregoing were filed with docket control this 29th day of July, 2011.

COPIES of the foregoing were emailed this 29th day of July, 2011 to:

Robin Mitchell
ACC Staff

Justin Brown
SW Gas Corporation

Daniel Pozefsky
RUCO

Tim Hogan
Center for Law in the Public Interest

Jeff Schlegl
SWEEP

Michael Patten
Roshka, DeWulf and Patten, PLC

Philip Dion
Tucson Electric Power

Michael Grant
Arizona Investment Council

Gary Yaquinto
Arizona Investment Council

NRDC
EXHIBIT 1

BEFORE THE ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY

OF

RALPH CAVANAGH

Q. Please state your name, address, and employment.

A. My name is Ralph Cavanagh. I am the Energy Program Co-Director for the Natural Resources Defense Council ("NRDC"), 111 Sutter Street, 20th Floor, San Francisco, CA 94104.

Q. Please outline your educational background and professional experience.

A. I am a graduate of Yale College and Yale Law School, and I joined NRDC in 1979. I am a member of the faculty of the University of Idaho's Utility Executive Course, and I have been a Visiting Professor of Law at Stanford and the University of California. From 1993-2003, I served as a member of the U.S. Secretary of Energy's Advisory Board, and I am now a member of the Department of Energy's Electricity Advisory Board. My current board memberships include the Bipartisan Policy Center, the Bonneville Environmental Foundation, the Center for Energy Efficiency and Renewable Technologies, the Renewable Northwest Project, and the Northwest Energy Coalition. I have received the Mary Kilmarx Award from the National Association of Regulatory Utility Commissioners (2007), the Heinz Award for Public Policy (1996) and the Bonneville Power Administration's Award for Exceptional Public Service (1986). I have not testified before the Arizona

Corporation Commission in at least two decades, but I was an invited participant in the workshops that preceded the Commission's adoption last December of its Final Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Final Policy Statement").

Q. On whose behalf are you testifying?

A. I am testifying for the Natural Resources Defense Council (NRDC).

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

A. My testimony supports the Southwest Gas Corporation's ("Southwest") proposal for a revenue-per-customer decoupling mechanism.

Q. Summarize your conclusions and recommendations.

A. Southwest has proposed an energy efficiency enabling provision (EEP) consisting of "a revenue per customer decoupling mechanism that is designed to eliminate the link between sales and revenues that currently exists with traditional rate designs, so that the existing financial disincentive associated with Southwest Gas's pursuit of cost-effective energy efficiency is eliminated."[1]

[1] Prepared Direct Testimony of Edward B. Gieseking, p. 12: 9-13.

The company's General Rate Case Application appropriately links that proposal to its significant role in achieving the Commission's appropriately ambitious Electric and Gas Energy Efficiency Standards.[2]

I conclude that the Southwest proposal is entirely consistent with the Commission's Final Policy Statement, and I recommend its approval. My testimony summarizes experience with comparable revenue decoupling mechanisms and responds to concerns commonly raised about them. Southwest's proposal would remove a potent disincentive to the company's engagement with all forms of energy efficiency progress, by ensuring that the Company recovers no more and no less than the fixed costs previously authorized by the Commission, notwithstanding any short-term fluctuations in natural gas use. My testimony also shows that efforts to link rate adjustments specifically to energy efficiency program impacts would have perverse consequences and impede statewide progress in achieving cost-effective savings.

My testimony anticipates and rebuts claims that approval of Southwest's proposal should be linked to reductions in its return on equity. I am aware of no evidence that decoupling mechanisms have reduced any

[2] Southwest Gas Corporation, Application, Docket No. G-01551A-10-0458) (Nov. 12, 2010), pp. 8-9.

utility's cost of capital, and customer benefits from the proposed mechanism are illustrated in the initial returns from a portfolio of proposed Southwest efficiency programs that "have an overall benefit-cost ratio of 1.68, with targeted annual savings of 2,451,00 therms."[3] Reducing the Company's authorized return on equity ("ROE") would undercut a principal rationale for the Commission's Final Policy Statement, which was to "encourage and enable aggressive use of demand side management programs and the achievement of Arizona's Electric and Gas Energy Efficiency Standards, which will benefit ratepayers and minimize utility costs."[4]

Q. What is the basis for your conclusion that Southwest's proposal is consistent with the Commission's Final Policy Statement?

A. Southwest has proposed a per-customer decoupling mechanism, which includes a monthly adjustment that "provide[s] immediate weather-related rate relief to customers following extreme weather events," followed by an annual adjustment "to true-up the difference between authorized and experienced non-gas revenues."[5] The

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[3] Application, note 2 above, at p. 8:16-17.

[4] Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314, p. 30 (Dec. 29, 2010).

[5] Testimony of Edward B. Gieseking, p. 3:5-9.

mechanism is designed to prevent over-earning, because "the Company will not be able to collect more revenue per customer than what the Commission authorizes in this rate case proceeding."[6] The scope of the mechanism is appropriately broad but not over-inclusive, covering "the rate schedules where Southwest Gas has, or expects to have, usage lowered as a result of energy efficiency programs and where a large amount of the fixed cost of service is recovered in variable charges."[7]

The Commission anticipated and encouraged all of these decoupling elements in its Final Policy Statement:

- "Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency . . ." [p. 30, item 3]

- "[N]on-fuel revenue per customer decoupling may be well suited for Arizona as it responds to customer growth and is better suited to address the issues associated with customer growth." [p. 30, item 4]

- "Adoption of decoupling . . . should not occur as a pilot, as this insufficiently supports demand side management efforts, discourages beneficial changes in rate design and is unlikely to encourage financial ratings improvements." [p. 30, item 5]

- "Full decoupling is preferable to partial decoupling ..." [p. 31, item 8]

- "Decoupling adjustments should occur at least on an annual basis; however, parties may propose more current adjustments as this may provide ratepayers

[6] Id., pp. 3-4.
[7] Id., p. 7:14-17.

with weather related relief following extreme events." [p. 31, item 10]

- "Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes." [p. 31, item 11]

Q. Describe experience with revenue decoupling elsewhere in the country.

A. Nationally, the count of states with decoupling for at least one utility stands at 14 for electricity and 22 for natural gas. In the West, Hawaii, California, Idaho and Oregon have adopted decoupling for at least one electric utility. California, Utah, Oregon, Washington and Wyoming have adopted natural gas decoupling mechanisms. New Mexico's Public Service Commission has left open "the determination of whether a decoupling mechanism should be approved or required for any utility," and the New Mexico Legislature has acknowledged the need to "identify regulatory disincentives or barriers for public utility expenditures on energy efficiency and load management measures and ensure that they are removed in a manner that balances the public interest, consumers' interests and investors' interests."[8]

Q. What about rate impacts of revenue decoupling?

[8] See Case No. 08-00024-UT, Final Order Repealing and Replacing 17.7.2 NMAC (2010), p. 10; Efficient Use of Energy Act, Section 62-17-5.F.

A. Neither revenue decoupling in general nor the Southwest proposal in particular add any additional costs to utility bills; they simply ensure that previously approved fixed costs are neither over- nor under-recovered. In terms of rate adjustments to achieve this objective, industry experience shows that effects are minimal in practice, with adjustments that go in both directions. A comprehensive industry-wide assessment (attached) found that, of 88 gas and electric rate adjustments from 2000-2009 under decoupling mechanisms, less than one-seventh involved increases exceeding 3 percent. (Refunds accounted for a much larger fraction.) Typical adjustments in utility bills "amount[ed] to less than $1.50 per month in higher or lower charges for residential gas customers and less than $2.00 per month . . . for residential electric customers."[9] That represents about a dime a day for the average household, which hardly seems like dangerous rate volatility, particularly since it sometimes comes in the form of a rebate - and serves only to ensure that the utility recovers no more and no less than the fixed costs of service that regulators have reviewed and approved.

Q. What do you say to those who are concerned that revenue decoupling reduces incentives to save energy,

[9] See Pamela Lesh, Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review, Electricity Journal (October 2009), p. 67.

by raising rates and depriving customers of rewards from consumption reductions?

A. Experience proves the opposite: revenue decoupling results in trivial rate adjustments that go both ways, and do not materially affect rewards for saving electricity and natural gas. As the Oregon Public Utility Commission found when it adopted a decoupling mechanism for Portland General Electric in January 2009, responding to analogous claims that decoupling would rob customers of the rewards of conservation: "We believe the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient." Oregon PUC Order No. 09-020, p. 28 (Jan. 2009). Finally, note that unlike so-called "fixed-variable rate designs" that load fixed costs into monthly customer charges, Southwest's proposal "does not establish a 'fixed bill' that would make customers indifferent to the amount of gas they use."[10]

Q. Explain your conclusion that approving Southwest's proposal should not result in an adjustment in its authorized return on equity.

[10] See Direct Testimony of Edward B. Gieseking, p. 6:17-18.

A. In this I am of course in part just echoing the Commission's conclusion in the Final Policy Statement: "Commitment to and early implementation of decoupling should precede significant decoupling-specific adjustments to cost of capital if a revenue per customer decoupling mechanism is approved for a utility."[11] The data that I just presented provide additional support for my recommendation: rate impacts this modest simply do not imply appreciable consequences for company-wide cost of capital, and I have seen no empirical evidence to the contrary. Indeed, in the specific context of natural gas utility decoupling, a March 2011 investigation by the Brattle Group reached the opposite conclusion:

> The findings of our analysis do not support the belief that utilities with decoupling have a lower cost of capital than utilities without decoupling. Contrary to what some might expect to find, at least on the basis of the opinions of certain intervenors and the (minority set of) judgments where commissions reduced allowed rates of return because of decoupling, we found that the estimated cost of capital for decoupled utilities was higher by a small but statistically significant amount (emphasis in original).[12]

Q. Why shouldn't the Commission amend the proposal so that adjustments track only natural gas savings attributable to the Company's energy efficiency programs?

---

[11] Final ACC Policy Statement, note 4 above, p. 31 [item 6].
[12] J. Wharton, M. Vilbert, R. Goldberg & T. Brown, The Impact of Decoupling on the Cost of Capital (Discussion Paper, The Brattle Group, March 2011), p. 2.

A. This would undercut the whole purpose of the mechanism, while introducing a whole new set of perverse incentives. It would reintroduce automatic penalties, in the form of reduced fixed-cost recovery, for all cost-effective natural gas savings not directly associated with Southwest's programs, even when the Company by action or inaction could make a material difference in prospects for those savings. It would create a powerful and perverse new incentive for the Company to promote programs that looked good on paper but delivered little or no savings in practice. And it would ensure adversarial discord over every savings calculation, since significant financial stakes would then hinge on the results. Finally, and most tellingly, adjustments keyed solely to adjudicated savings would mean automatic annual rate increases (unless the company was wholly ineffective), whereas decoupling adjustments can be either positive or negative (Southwest notes, for example, that its most recent Nevada decoupling adjustment "will return approximately $2 million to its customers."[13])

Q. But doesn't your recommendation mean paying Southwest for savings that it didn't help achieve?

A. No, because the proposed EEP doesn't "pay" Southwest any incremental amount for anything; it is simply

[13] Prepared Direct Testimony of Edward B. Gieseking, p. 9:5.

a mechanism that allows the company to receive no more and no less than the fixed-cost revenue requirement per customer that the Commission has reviewed and approved.

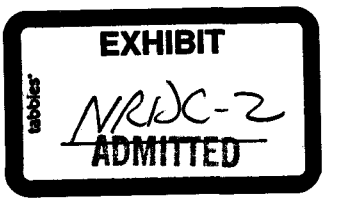
Q. Revenue decoupling has been criticized as "use less, pay more" and shifting risk to customers; do you believe those are valid concerns regarding Southwest's proposal?

A. No. As indicated earlier in my testimony, customers who find ways to use significantly less energy will not be appreciably affected by decoupling-induced rate adjustments, and of course a principal justification for the Commission's Energy Efficiency Standards is to reduce the costs of providing reliable energy services, with long-term savings to Southwest customers (in the form of reductions in the company's revenue requirements and fuel purchases) that revenue decoupling will not affect. As regards risk shifting, an appealing feature of Southwest's proposal is that it reduces risks for *both* customers and Southwest; customers get prompt relief from cost increases driven by extreme weather events, and Southwest avoids downside risk on recovery of its authorized fixed costs (although, as noted earlier, I do not view this as justification for a reduction in the company's ROE). Risk reduction is not a zero sum enterprise here.

Q. Does this conclude your testimony?

A. Yes.

NRDC
EXHIBIT 2



BEFORE THE ARIZONA CORPORATION COMMISSION

TESTIMONY

OF

RALPH CAVANAGH

ON THE SETTLEMENT AGREEMENT FILED WITH THE COMMISSION

DOCKET No. G-01551A-10-0458

Q. Please state your name, address, and employment.

A. My name is Ralph Cavanagh. I am the Energy Program Co-Director for the Natural Resources Defense Council ("NRDC"), 111 Sutter Street, 20th Floor, San Francisco, CA 94104.

Q. Have you filed testimony previously in this proceeding?

A. Yes, I filed Direct Testimony on behalf of NRDC in this proceeding through NRDC's attorney, Laura Sanchez, on June 23, 2011. My qualifications have not changed, and I continue to hold the views presented there in support of Southwest Gas Corporation's original proposal for a revenue-per-customer decoupling mechanism.

Q. What is the purpose of this additional testimony?

A. This additional testimony, submitted again on behalf of NRDC, presents my views on the Settlement Agreement submitted to the Commission in this proceeding by NRDC and other parties earlier in July.

Q. Summarize your conclusions and recommendations.

A. Southwest originally proposed an energy efficiency enabling provision (EEP) consisting of "a revenue per customer decoupling mechanism that is designed

to eliminate the link between sales and revenues that currently exists with traditional rate designs, so that the existing financial disincentive associated with Southwest Gas's pursuit of cost-effective energy efficiency is eliminated."[1] The company's General Rate Case Application appropriately linked that proposal to its significant role in achieving the Commission's Electric and Gas Energy Efficiency Standards, which NRDC strongly supports.[2]

I concluded in my Direct Testimony that the Southwest proposal was entirely consistent with the Commission's recent Final Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Final Policy Statement"),[3] and I recommended its approval. Alternative B of the Settlement Agreement retains the essential elements of the original Southwest proposal and I support its adoption, for reasons canvassed at length in my Direct Testimony. Alternative B would remove a potent disincentive to the company's engagement with all forms of energy efficiency progress, by ensuring that the Company recovers no more and no less than the fixed costs previously authorized by the Commission,

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[1] Prepared Direct Testimony of Edward B. Gieseking, p. 12: 9-13.
[2] Southwest Gas Corporation, Application, Docket No. G-01551A-10-0458) (Nov. 12, 2010), pp. 8-9.
[3] Docket Nos. E-00000J-08-0314 and G-000000C-08-0314(Dec. 29, 2011).

notwithstanding any short-term fluctuations in natural gas use.

However, as permitted by the express terms of the Settlement Agreement [Item 3.2], I recommend strongly against adopting its proposed Alternative A, which is characterized as "a partial revenue decoupling mechanism." Alternative A fails to break the linkage between Southwest's financial health and retail sales, and seeks instead simply to restore lost revenues associated with energy savings determined to have resulted from the utility's "achievement of the Commission's required energy savings." [Item 3.4] Key elements of Alternative A were effectively considered and rejected by the Commission itself in the Final Policy Statement, which was the centerpiece of my Direct Testimony (and was adopted unanimously less than seven months ago).

Q. If you oppose Alternative A, why did NRDC join the other parties to the Settlement Agreement?

A. The parties to the agreement agreed that the document would include both Alternatives A and B, and that parties other than Staff reserved the right to oppose one alternative and support the other. That is exactly what I am doing here.

Q. Why do you conclude that Alternative A is inconsistent with the Commission's Final Policy Statement?

A. Following Commission workshops in which I and many others participated, which canvassed partial decoupling options at length, the Commission's Policy Statement concluded [p. 31, Item 8] that "full decoupling is preferable to partial decoupling as it contributes to greater rate stability which would encourage improvements in financial ratings, is administratively more manageable, and offer opportunity for rate relief following extreme weather events."

I agree strongly with the Commission's conclusion to endorse full decoupling over "partial" variants, including the lost revenue recovery approach that is the centerpiece of Alternative A. Although I appreciate Alternative A's retention of the appealing weather adjustment from Southwest's original proposal [Item 3.4], I reemphasize my view that partial decoupling like that of Alternative A would undercut the whole purpose of the mechanism, while creating perverse incentives. It would reintroduce automatic penalties, in the form of reduced fixed-cost recovery, for all cost-effective natural gas savings not directly associated with savings determined to have been "achieved" by the Company, even when the Company by action or inaction could make a material difference in prospects for those savings (e.g., efficiency standards administered by government agencies, which can benefit greatly from

utility support; informal intervention by utility staff to encourage customer patronage of independent energy efficiency contractors; and effective public education campaigns with multiple participants including utilities). Alternative A would also create a powerful and perverse new incentive for the Company to promote programs that looked good on paper but delivered little or no savings in practice (because then Alternative A would deliver double recovery). And it would ensure adversarial discord over every savings calculation, since significant financial stakes would then hinge on the results.

Unlike full decoupling, Alternative A would leave unimpaired strong utility incentives to promote increased natural gas use, since (unlike Alternative B) Southwest would keep any per-customer fixed cost recovery in excess of that authorized by the Commission. Paying a utility bonuses for both increases in its per-customer natural gas sales and its "achieved" natural gas savings is the metaphorical equivalent of encouraging the CEO to drive with one foot on the brake and the other on the accelerator.

Finally, and most tellingly, adjustments keyed solely to adjudicated savings would mean annual rate increases (unless the company was wholly ineffective), whereas rate adjustments under full decoupling can be

either positive or negative (Southwest notes, for example, that its most recent Nevada decoupling adjustment "will return approximately $2 million to its customers."[4]) This point is worth underscoring: in sharp contrast to Alternative B, Alternative A virtually guarantees annual rate increases.

Q. But wouldn't adoption of Alternative B mean paying Southwest for savings that it didn't help achieve?

A. No, because unlike Alternative A, Alternative B doesn't "pay" Southwest any incremental amount for anything; it is simply a mechanism that allows the company to receive the fixed-cost revenue requirement per customer that the Commission has reviewed and approved.

Q. Would the adoption of Alternative B reduce risks for Southwest and shift risks to customers?

A. No. Under Alternative B Southwest would still face business and cost risks in its operations. Also, as I noted in my direct testimony, an appealing feature of Alternative B is that it reduces risks for *both* customers and Southwest; customers get prompt relief from cost increases driven by extreme weather events, and Southwest reduces its downside risk regarding under-recovery of its Commission-authorized fixed costs.

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[4] Prepared Direct Testimony of Edward B. Gieseking, p. 9:5.

Q. Does this conclude your testimony about the Settlement Agreement?

A. Yes.

ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures

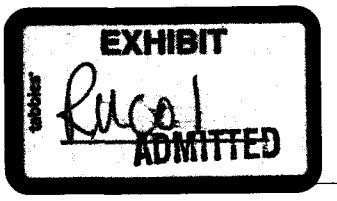
Introduction

Several factors underscore the need for increased energy efficiency in Arizona. Historically, Arizona has experienced high population growth and corresponding increases in demand for energy which has required significant investments in distribution, transmission and generation facilities and led to increased utility infrastructure and operational expenses.

While growth is anticipated to continue in the future, expanded demand side efforts, such as energy efficiency and demand response, can moderate rate pressures otherwise experienced from growth and reduce customer utility bills. Expansion of demand side management programs is cost effective, promotes price stability, mitigates exposure to volatile fuel prices, creates cost savings opportunities for customers and limits unnecessary load growth.

Since June 2008 the Commission, in this generic docket (08-0314) and subsequent Notice of Inquiry ("NOI"), has been investigating utility financial disincentives to energy efficiency and considering how it can address these issues and maximize energy efficiency efforts at Arizona's utilities.

On December 18, 2009, the Commission issued a Notice of Proposed Rulemaking on Electric Energy Efficiency, which adopted an energy efficiency requirement for Arizona's electric utilities. The proposed rules require cumulative annual energy savings of 22% by December 31, 2020 for Arizona's largest electric utilities. The proposed energy efficiency rules recognize potential utility disincentives to achieving the Energy Efficiency Standard ("EES") and include provisions providing for Commission review of



measures designed to address these disincentives in future rate cases. Similar energy efficiency rules are currently being developed for Arizona's gas utilities. On August 25, 2010, the Commission issued a Notice of Proposed Rulemaking on Gas Energy Efficiency, which adopted an energy efficiency requirement for Arizona's gas utilities to achieve cumulative annual energy savings of 6% by December 31, 2020.

Purpose

Properly addressing disincentives to energy efficiency is important to the Commission, the companies involved, and Arizona's utility consumers. Traditionally, Arizona's utilities have been disincented to vigorously utilize demand-side management programs to meet their resource needs. An internal conflict exists for utilities between sales growth and promotion of programs or technologies which reduce sales, as these sales offer the opportunity to recover fixed costs and earn profit; sales erosion may impact recovery of fixed costs and investment returns. To the degree to which utility fixed costs are recovered from volumetric sales, a net lost revenue and profit erosion effect exists which could act as a disincentive to utilities robustly seeking to implement energy efficiency measures. This utility disincentive to reduce sales discourages demand-side management programs which could ultimately benefit customers and minimize utility rates and customer utility bills.

In recognition of the need to fully utilize supply and demand side options for meeting resource needs in Arizona, the Commission has been considering alternate approaches it could adopt to spur the use of demand side programs. On February 23, 2010 the Commission issued a Notice of Inquiry to solicit input on utility disincentives and decoupling frameworks. The responses to the Notice of Inquiry led to Commission

Workshops on decoupling and a study by the Lawrence Berkeley National Laboratory ("LBNL") examining the potential impacts of energy efficiency savings goals and decoupling through 2030. The Regulatory Assistance Project also participated in and provided technical assistance during the Commission Workshops.

Description

A revenue decoupling mechanism is a ratemaking design which reduces or removes the linkage between sales and utility revenues and/or profits, reducing utility disincentives to the adoption of programs that benefit customers by saving energy, but which also contribute to sales erosion and under-recovery of authorized fixed costs. Several states have utilized decoupling as a means of bolstering their energy efficiency efforts and the American Recovery and Reinvestment Act of 2009 (ARRA) has asked participating states to consider general policies that ensure that utility financial incentives are aligned with helping customers use energy more efficiently. Arizona, in accepting ARRA funding, agreed to analyze and consider these policies.

Mechanically, revenue decoupling compares actual versus authorized revenues or revenues per customer over a period and either credits or collects any differences from customers in a subsequent period. This collection would include, among other things, revenue impacts associated with implementation of demand side programs.

States which have implemented revenue decoupling have addressed several issues within the decoupling design. Among the design and implementation issues are the application of the mechanism to all or only some customer classes; whether to include or exclude weather related sales fluctuations; and the frequency, nature, and allowed amount of true-ups or decoupling adjustments.

Revenue decoupling achieves the primary purpose of reducing utility disincentives to implementing demand side programs and reducing energy consumption. While decoupling alone does not directly lead to increases in utility promotion of energy efficiency, decoupling paired with energy efficiency requirements creates an effective environment for the implementation and promotion of demand side programs.

The Commission recognizes that alternative mechanisms to addressing utility disincentives may exist, such as implementation of fully-cost based rates, development of lost revenue mechanisms or incorporation of anticipated energy efficiency effects into rate case forecasts. While these measures address some utility disincentives, they can lead to significant bill impacts or prove complex and administratively challenging to implement.

The Commission believes that, properly structured, decoupling offers significant advantages over alternative mechanisms to addressing utility disincentives which furthers the utilization of demand-side resources.

DECOUPLING WORKSHOPS

The Commission conducted workshops in April, May, and June of 2010 to address issues raised by the Notice of Inquiry, stakeholder concerns and an analysis of energy efficiency goals and decoupling prepared by LBNL at the Commission's request.

April 15-16, 2010 Workshop

The April 15-16, 2010 workshops principally provided background information on decoupling and addressed stakeholder responses to the Notice of Inquiry, highlighting areas of agreement and issues which required further consideration.

Participants noted that the Commission's EES "...changes the landscape for energy efficiency in the state"[1] and that significant growth in energy programs results in "...growth in the impacts...."[2] Modest sales reductions, such as those likely to result from utility energy programs, were alleged to have significant impacts on utility earnings. Decoupling was identified as a means of holding revenues constant by fluctuating prices up and down in the opposite direction of sales changes.[3]

Among the issues identified regarding decoupling, parties spoke to the timing of true-ups, the benefits of full versus limited decoupling, and limitations or collars on the decoupling adjustments.[4] Extensive discussion centered on the effect of decoupling on utility risk and cost of capital, and whether recognition of the risk mitigation implied by decoupling could be synchronized with the adoption of decoupling. The Commission was cautioned that adoption of decoupling through a pilot program or limited term may not provide investors sufficient certainty to merit cost of capital benefits at the outset.[5] Explicit adoption of decoupling with a periodic review was identified as an alternative option to pilot adoption.[6]

Utility representatives spoke on behalf of Arizona Public Service Company ("APS"), Tucson Electric Power ("TEP"), Southwest Gas ("SWG"), and the Grand Canyon State Electric Cooperative Association ("GCSECA"). Utility representatives generally argued that decoupling, or similar mechanisms, were necessary to support the

[1] TR Vol I, Pg 15, 24-25.
[2] TR Vol I, Pg 30, 18-19.
[3] TR Vol I, Pg 68, 4-5.
[4] TR Vol I, Pgs 79-90.
[5] TR Vol II, Pg 164, 12-18; TR Vol II, Pg 170, 9-14.
[6] TR Vol II, Pg 187, 6-16.

Commission's energy efficiency requirements[7] and largely advocated a revenue per customer form of full decoupling.[8]

In supporting decoupling, utility representatives identified the need to align utility and customer interests,[9] the generation infrastructure that could be deferred as a result of decoupling, [10] environmental benefits which would result from deferral of future generation,[11] a heightened focus on operational expenses[12] and the likelihood of better and less expensive resource portfolios for customers in the long run.[13] Utilities preferred full decoupling to limited decoupling, for its administrative simplicity, stating that it would result in cost minimization and lessen adversarial hearings.[14]

In response to questions as to whether Arizona should engage in a broad approval of decoupling, utilities responded that a rulemaking would provide a framework and parameters but the expectation was that utilities would more fully address issues within a rate case proceeding.[15] When asked which time interval should be used to reconcile revenues - annual, semi-annual or quarterly - utilities supported at least annual reconciliation with several arguing in favor of more frequent adjustments allowing customers to receive offsets in the event of extreme weather events.[16]

In response to questions about how to control for excessive rate impacts associated with decoupling and whether a "dead-band" would be appropriate, utilities

[7] TR Vol II, Pg 198, 3-12; TR Vol II, Pgs 203, 18 through 204, 15; TR Vol II, Pg 213, 14-21; TR Vol II, Pgs 222, 25 through Pg 225, 13.
[8] TR Vol II, Pg 198, 14.
[9] TR Vol II, Pg 200, 17-18; Pg 205, 1-6.
[10] TR Vol II, Pg 201, 6-10.
[11] TR Vol II, Pg 201, 10-13.
[12] TR Vol II, Pg 223, 10-18.
[13] TR Vol II, Pg 207, 8-10.
[14] TR Vol II, Pgs 300, 10 through 303, 19.
[15] TR Vol II, Pgs 304, 13 through 305, 19.
[16] TR Vol II, Pgs 305, 20 through 311, 15.

supported a dead-band in concept and favored annual caps or a collar of at least three percent.[17]

The Residential Utility Consumer Office ("RUCO") indicated it is not opposed necessarily to decoupling, however it believed "...any recovery mechanism must, one, be cost effective; two, contain a detailed commitment to energy efficiency;...three, have a high degree of accountability and transparency; and four, have a cap on the amount that may be recovered."[18] Parties largely agreed with RUCO's position and believed planned and existing requirements under the Commission's EES addressed some of the expressed concerns.[19]

Commission Staff recognized impacts to utility fixed cost recovery from energy efficiency[20] and indicated a need to balance the incentives of the utilities wanting to sell more and policies asking customers to use less.[21] Staff further stated it believed it would be appropriate to adjust capital structures to the extent decoupling enhanced revenue stability.[22] In addressing decoupling, Staff indicated that Arizona's utility companies were unlikely to achieve the EES without some kind of cost recovery, whether decoupling or other form of rate recovery.[23]

Representatives for Arizonans for Electric Choice and Competition ("AECC") opposed decoupling, stating that any discussion would best be had in a general rate case[24] and arguing that industrial consumers were probably not a good target for revenue

[17] TR Vol II, Pgs 312, 10 through 315, 3.
[18] TR Vol II, Pgs 232, 22 through 233, 4.
[19] TR Vol II, Pgs 233, 12 through 234, 3; Pgs 234, 15 through 235, 11; Pg 236, 3-19; Pg 237, 2-13.
[20] TR Vol II, Pgs 254 line 25 through 255, line 3.
[21] TR Vol II, Pg 256, 20-23.
[22] TR Vol II, Pgs 259, 16 through 260, 3.
[23] TR Vol II, Pg 265, 3-15.
[24] TR Vol II, Pg 284, 5.

decoupling.[25] While AECC indicated its opposition to revenue decoupling, it further stated that if decoupling was adopted AECC would want to see clear and careful review on return on equity.[26]

Representatives for the Arizona Investment Council ("AIC") spoke in favor of decoupling, arguing that there are benefits that accrue to consumers from such a mechanism.[27] AIC further stated that the Commission must pay attention to energy efficiency programs to be able to reach out and get as many customers as possible engaged in conservation.[28]

Marshall Magruder noted that avoided costs could result for both utilities and consumers, from aggressive adoption of energy efficiency, where lower operational demands ease maintenance requirements.[29]

In concluding the meeting, specific questions were posed to utility representatives regarding appropriate decoupling designs. In response to questions as to whether Arizona should engage in a broad approval of decoupling, utilities responded that a rulemaking or policy statement would provide a framework and parameters but the expectation was that utilities would more fully address the adoption of decoupling within a rate case proceeding.[30] When asked which time interval should be used to reconcile revenues, annual, semi-annual or quarterly, utilities supported at least annual reconciliation with several arguing in favor of more frequent adjustments allowing customers to receive offsets in the event of extreme weather events.[31]

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[25] TR Vol II, Pg 284, 14-18.
[26] TR Vol II, Pg 286, 1-8.
[27] TR Vol II, Pg 294, 13-22.
[28] TR Vol II, Pg 296, 7-11.
[29] TR Vol II, Pgs 297, 13 through 298, 7.
[30] TR Vol II, Pgs 304, 13 through 305, 19.
[31] TR Vol II, Pgs 305, 20 through 311, 15.

In response to questions about how to control for excessive rate impacts associated with decoupling and whether a "dead-band" or collar would be appropriate, utilities supported a dead-band in concept and favored annual caps of at least three percent.[32] When asked whether changes to capital structure to reflect reduced risk were in order, utilities encouraged caution and a fuller record to develop the issue.[33] In addressing questions regarding appropriate reporting and evaluation, utilities and stakeholders responded that the reporting required under the energy efficiency rules was significant, however, additional information specifically related to decoupling would likely be needed.[34] In response to concerns raised about maintaining customer service standards, stakeholders and utilities asserted that decoupling would not minimize the focus on customer service and the energy efficiency rules would require the development of enhanced customer relationships and interaction.[35]

In response to questions regarding the reception of the investment community to decoupling, electric utilities responded that some concerns had been expressed regarding details and more specifically about how a decoupling mechanism would address growth.[36] SWG stated its discussions with ratings agencies indicated a positive reception for decoupling.[37]

In response to questions regarding application of decoupling to customer classes, APS indicated that there were merits to both class specific and aggregated mechanisms,[38]

[32] TR Vol II, Pgs 312, 10 through 315, 3.
[33] TR Vol II, Pgs 322, 2 through 329, 12.
[34] TR Vol II, Pgs 330, 14 through 336, 7.
[35] TR Vol II, Pgs 336, 11 through 344, 9.
[36] TR Vol II, Pg 344, 16-23; Pgs 345, 22 through 346, 4.
[37] TR Vol II, Pg 349, 19-25.
[38] TR Vol II, Pg 351, 6-12.

TEP expressed a preference for a by class mechanism,[39] and SWG expressed a preference for application to all classes.[40]

May 3, 2010 Workshop

The May 3, 2010 workshop principally addressed rate design issues associated with decoupling, common concerns raised regarding decoupling, impacts on participating and nonparticipating customers and a discussion of technical issues amongst participants.

It was argued that decoupling is a means of pursuing rate designs better structured to drive energy efficient outcomes. Stakeholders noted that decoupling "...allows the Commission to... set rates that are based on long-run marginal costs without creating the new revenue volatility for the utilities."[41] Energy efficiency benefits were identified where rates were based on long-run marginal costs.[42] Stakeholders stated that properly designed rates have resulted in dramatic conservation effects.[43] It was asserted that the Commission must ensure that its actions on rate design now and in the future must be internally consistent with energy efficiency programs and internally consistent with ratemaking treatment and decoupling, with each reinforcing the other and moving utilities in the same direction.[44]

Stakeholders highlighted common criticisms of decoupling, including that it is a different approach to ratemaking,[45] it could serve as a disincentive for a utility's management to control costs,[46] that it diminished risk for investors,[47] that it should

[39] TR Vol II, Pg 351, 16 through 352, 1.
[40] TR Vol II, Pg 352, 8-11.
[41] TR Vol III, Pg 369, 21-24.
[42] TR Vol III, Pgs 373, 25 through 374, 4.
[43] TR Vol III, Pg 407, 3-4.
[44] TR Vol III, Pg 376, 10-16.
[45] TR Vol III, Pg 411, 5-13.
[46] TR Vol III, Pgs 411, 25 through 412, 13.
[47] TR Vol III, Pgs 412, 14 through 413, 2.

require a demonstrated commitment to energy efficiency,[48] that it could diminish utility support for economic development,[49] and that energy efficiency savings are not necessarily being caused by utilities.[50]

Other concerns raised with respect to decoupling included the differences between new and existing customers in a decoupling design. With straight revenue per customer decoupling, new customers utilizing less gas or electricity than existing customers could drive upward rate pressure as rates for existing customers would need to make up the difference between revenues received at current rates from new customers and the allowed revenue per customer.[51] In response to this issue, some parties stated that decoupling models could adjust revenues per customer downward year by year to reflect what would happen in the absence of decoupling, or a bifurcated approach could be used for existing and new customers.[52]

Stakeholders addressed impacts of decoupling on customers who participated in energy efficiency programs and nonparticipating customers. For customers who adopted energy efficiency measures, decoupling slightly eroded some of the savings they received. [53] For nonparticipants, decoupling contributed to slight increases in rates.[54] Robust customer participation was identified as a means of addressing impacts to all customers, with particular focus on low income customers who could be most at risk.[55] Particular attention was paid to utility plans for scaling up programs, reaching as many

[48] TR Vol III, Pg 413, 3-13.
[49] TR Vol III, Pgs 413, 14 through 414, 14.
[50] TR Vol III, Pg 424, 4-13.
[51] TR Vol III, Pg 417, 2-1.
[52] TR Vol III, Pgs 418, 12 through 419, 2.
[53] TR Vol III, Pgs 426, 14 through 429, 4.
[54] TR Vol III, Pgs 426, 14 through 429, 4.
[55] TR Vol III, Pgs 429, 21 through 430, 13.

communities as possible and touching all customers with energy efficiency programs, so that the number of nonparticipants would be minimized.[56]

In response to questions regarding maintenance of service quality standards,[57] the utilities responded that service quality was being addressed in existing operations, but that the key consideration with respect to decoupling was establishing the appropriate performance benchmark that utilities would be required to achieve.[58]

In response to questions regarding opposition to decoupling by ratepayer advocates and the National Association of State Utility Consumer Advocates[59]("NASUCA"), parties recognized a need to explain to the public the policies that the Commission is adopting and implementing.[60] Utilities were encouraged to develop plans for communicating decoupling and energy efficiency to their customers.[61]

In response to questions regarding third party administration of energy efficiency, parties noted that the third party administrator model has been successful where implemented but was not necessarily superior to a utility based model.[62] Existing third party involvement was identified in the areas of measurement, evaluation and research.[63] It was suggested by some parties that utility administration of energy efficiency programs has largely been successful in Arizona and it was further noted that the regulatory compact accorded the Commission better opportunities to steer regulated utilities than with a third party administrator operating under a contract.[64]

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[56] TR Vol III, Pgs 435, 15 through 436, 20.
[57] TR Vol III, Pg 438, 4-23.
[58] TR Vol III, Pgs 437, 24 through 442, 13.
[59] TR Vol III, Pg 454, 10-22.
[60] TR Vol III, Pg 457, 20-25.
[61] TR Vol III, Pg 461, 13-25.
[62] TR Vol III, Pgs 466, 22 through 467, 18.
[63] TR Vol III, Pg 469, 18-21; Pg 472, 11-19.
[64] TR Vol III, Pg 471, 2-20.

In technical discussions, parties outlined decoupling models which could be appropriate for Arizona. Assuming revenue per customer decoupling, which was supported by many workshop participants: principal concerns revolved around the customer classes that would be affected, distribution of adjustments, rate design, accrual methodology, weather risk, caps on decoupling adjustments and whether new customers merited different treatment than existing customers.[65]

In response to the issue of treating new customers distinctly from existing customers, parties noted that one approach by a Washington utility was to leave new customers entirely out of the decoupling mechanism and apply adjustments solely to existing customers between rate cases.[66] Electric utilities noted little difference between new and existing customers[67] and remarked that the issue would likely be more pronounced for gas utilities. Parties suggested that further analysis was needed to examine whether any difference existed between new and old customers and whether such a difference required particular treatment.[68]

Parties raised concerns regarding the application of decoupling adjustments to customer classes, particularly with respect to industrial customers, arguing that some customer classes lacked enough homogeneity to lend themselves to revenue decoupling.[69] Others suggested that it may make sense for some industrial customers to be excluded as they make not contribute significantly to fixed recovery.[70] Some parties argued that application of decoupling adjustments may be inappropriate for small customer classes

[65] TR Vol III, Pgs 482, 2 through 483, 23.
[66] TR Vol III, Pgs 486, 3 through 488, 2.
[67] TR Vol III, Pgs 488, 17 through 490, 8.
[68] TR Vol III, Pg 493, 11-24.
[69] TR Vol III Pgs 494, 14 through 496, 15.
[70] TR Vol III Pg 499 19 through 21.

with fewer than one hundred customers.[71] Others asserted that decoupling should lean towards broad inclusion with participation from all customers through a certain demand level.[72] Recognizing the unique issues faced by individual utilities, some argued that these issues would best be dealt with on a utility-by-utility basis.[73]

Related to the customer class issue was the question of whether shortfalls or over recoveries should be spread evenly across classes or specifically within classes.[74] Parties noted that states have approached this issue in both ways; class distribution was seen as keeping costs and adjustments focused within a class but potentially leading to larger per unit adjustments, while across-class adjustments smoothed out overall impacts but potentially led to some level of subsidy between classes.[75] In addressing the distribution of adjustments among customer classes, parties noted that adjustment collars could minimize fluctuations and could be seasonally tailored where more current adjustments were utilized.[76]

Discussion segued into whether decoupling adjustments should be current, monthly, or annualized. Parties noted that further examination of the utilities' billing system infrastructure would be necessary to determine whether a utility's existing systems could functionally support more current adjustments.[77] In response to questions regarding administrative burdens, parties noted that monthly decoupling adjustments

[71] TR Vol III Pg 497, 11-22.
[72] TR Vol III, Pg 499, 3-18; Pg 502, 5-9.
[73] TR Vol III, Pgs 502, 22 through 503, 25; Pg 508 4-12.
[74] TR Vol III, Pg 513, 6-13.
[75] TR Vol III, Pgs 515, 22 through 516, 11.
[76] TR Vol III, Pgs 516, 19 through 518, 18.
[77] TR Vol III, Pg 521, 6-14.; 522, 4-16.

would likely require less work than fuel cost adjustments, as the data for the former would come directly from the billing systems.[78]

Parties addressed the ability of decoupling to facilitate improved rate designs that could encourage conservation and other goals.[79] Rate designs which solely utilized volumetric rates with no customer charges and use of inverted block rates were identified as concepts worthy of discussion.[80] While decoupling was recognized for facilitating rate designs, caution was urged, particularly if decoupling was adopted as a pilot and not a permanent mechanism.[81] Cooperatives were open to exploring changed rate designs, but expressed reluctance toward any elimination of customer charges.[82] If straight fixed/variable cost rates were adopted in lieu of decoupling, utility customer charges alone would range from $22 to $70 per month with additional charges for variable costs.[83]

In response to questions regarding adoption of a pilot program or implementation with review, RUCO noted it did not support decoupling, nor was RUCO opposed.[84] RUCO's stated concerns were the perception that decoupling adjustments were driven by factors other than utility efforts, such as weather, and impacts of decoupling on customers who implemented no energy efficiency measures.[85]

In response to questions about whether decoupling was appropriate for cooperatives, parties stressed the need for administrative simplicity, given the

[78] TR Vol III, Pg 523, 15-21.
[79] TR Vol III, Pg 525, 15-25.
[80] TR Vol III, Pg 526, 2-19.
[81] TR Vol III, Pg 526, 20-24; Pg 532, 1-9; Pg 533, 11-18.
[82] TR Vol III, Pg 529, 4-19.
[83] TR Vol III, Pgs 537, 23 through 538, 13.
[84] TR Vol III, Pg 545, 3-6.
[85] TR Vol III, Pgs 545, 7 through 546, 7.

cooperatives' more limited resources.[86] Parties remarked on the unique characteristics of rural cooperatives and noted that the cooperatives were beginning to implement programs and would need to be very aggressive in the future in order to comply with the EES.[87]

Echoing the cooperatives comments regarding administrative simplicity, parties reiterated that full decoupling offered more straightforward calculations than if weather and other non-efficiency related effects were removed.[88]

May 24, 2010 Workshop

The May 24, 2010 workshop focused on utility historical analyses of rates if decoupling had existed between 2000 and 2010, LBNL's preliminary analysis of the impact of the electric Energy Efficiency Standard and decoupling on APS and its customers, and follow-up on recommended decoupling designs and related issues.

APS presented a ten-year look back analysis that had been requested by Commissioners and noted that if decoupling had existed over that interval, customers would have experienced both refunds and surcharges of roughly one and a half percent.[89] Similar conclusions were reached whether the examination was based on an actual sales basis or a weather normalized approach, though the weather normalized approach produced slightly more revenue over the ten-year period.[90] APS analyzed a revenue per customer approach, modeling the fixed cost by class, excluding fuel costs, transmission costs, regulatory assets, special surcharges and system benefits from the calculation.[91] Parties noted that APS' findings underscored other research which contends that,

[86] TR Vol III, Pg 556, 7-18.
[87] TR Vol III, Pgs 558, 17 through 559, 8.
[88] TR Vol III, Pgs 560, 11 through 562, 13.
[89] TR Vol IV, Pgs 586, 21 through 587, 12.
[90] TR Vol IV, Pgs 587, 19 through 588, 2.
[91] TR Vol IV, Pg 589, 12-22.

nationally, decoupling mechanisms tend to result in adjustments that are less than three percent.[92]

TEP's decoupling calculations resulted in similar findings to APS, largely falling below three percent.[93] Similar results were identified for both UNS Electric and UNS Gas, as they stayed within a three percent cap; however, greater volatility was identified for UNS Gas.[94] In response to greater gas volatility, parties suggested that a larger collar or cap be utilized and that balances be allowed to carry forward if the collar is exceeded.[95]

SWG's decoupling calculations reflected modest customer impacts, with a minimum impact of $.86 to a maximum impact of $2.61, with an average of $1.53.[96] The company noted that the decoupling impact on a customer bill was relatively small in relation to the total customer bill.[97] While SWG acknowledged that the adjustments exceeded three percent, rising to nearly six percent in some cases, they argued that the dollar impact remained modest considering that the average gas bill was lower than the average electric bill.[98] In response, parties argued that consideration could be given to a larger cap for gas utilities.[99]

Following the utility presentations of their historical analyses, LBNL presented its preliminary analysis of APS with the implementation of the electric EES, with and without decoupling. LBNL's analysis examined "...future impacts of current resource plans and adopted policies of the Commission and strategies for dealing with energy

[92] TR Vol IV, Pg 595, 1-11.
[93] See June 9, 2010, TEP Decoupling Calculation Chart.
[94] TR Vol IV, Pg 605, 8-13; Pg 607, 21-24; Pg 609, 7-22.
[95] TR Vol IV, Pgs 609, 23 through 610, 9.
[96] TR Vol IV, Pg 613, 6-14.
[97] TR Vol IV, Pg 615, 8-11.
[98] TR Vol IV, Pg 621, 1-11.
[99] TR Vol IV, Pgs 622, 22 through 623, 14.

efficiency, utilities and their customers."[100] The LBNL analysis documented the benefits, costs and financial impacts on ratepayers and shareholders of achieving energy efficiency savings goals consistent with the Commission's EES, and the potential impact of a decoupling mechanism.[101]

The LBNL analysis began with establishing a business as usual case, based on publicly available information, where APS offers efficiency programs as if the EES was not enacted and continues on its preexisting savings path. This presumed APS would meet the annual energy savings targets in its 2010 Rate Settlement Agreement and thereafter meet a one percent annual energy savings target the 2010-2012 period covered in the APS rate case settlement.[102] Fuel and purchased power costs which were passed through to customers and nonfuel expenses, such as return of and on capital expenditures and O&M expenses for new generation and transmission and distribution resources, were expected to grow in excess of five percent per year.[103] Rate cases were assumed to be filed every three years or when capital expenditure budgets exceeded a billion dollars, rates were assumed to take effect two years from the time of filing, and compliance with the Renewable Energy Standard ("RES") was presumed.[104] In order to capture the full benefits of the energy efficiency measures installed in the business as usual case or under the standard, a 20-year planning horizon was utilized.[105]

The business as usual scenario reflected ten year savings of more than 600 megawatts of peak demand, and more than 43,000 gigawatt hours of energy savings over

[100] TR Vol IV, Pg 627, 15-18.
[101] TR Vol IV, Pg 631, 9-22.
[102] TR Vol IV, Pg 635, 2-17.
[103] Id.
[104] TR Vol IV, Pg 640, 11-23.
[105] TR Vol IV, Pg 642, 4-16.

the measure lifetimes, with net benefits of $943 million (present value at 4.0%).[106] Roughly a third of the projected energy savings and half the peak demand savings came from residential portfolio programs.[107] Among its assumptions, the business as usual case assumed growth in nominal operation and maintenance costs of 3.5 percent per year, fuel and purchased power budget growth of 6.8 percent per year, rate-base related cost (e.g., return on rate base, interest on debt, and depreciation) growth of 6.0 percent per year and retail sales growth of 2.2 percent a year.[108] Under the business as usual case, the analysis showed that APS is expected to under-earn relative to its authorized level in almost every year during the 20-year time horizon.[109]

Under the high energy efficiency scenario (i.e. to meet the EES), APS was assumed to offer energy efficiency and demand response programs to comply with the Commission's EES, with estimated program costs, measure lifetimes and on-peak/off-peak savings.[110] Energy efficiency program costs to the utility were estimated at about $35/MWh.[111] Up to 6,800 gigawatt hours of cumulative annual energy savings were expected to be achieved in 2020 with the Standard.[112]

Comparing the business as usual case to the high efficiency scenario demonstrated additional offsets to load growth.[113] Under the high efficiency scenario, annual retail sales growth drops from 2.2 percent to 1.1 percent and to about 1.4 percent growth in peak demand.[114] Following the ten-year EES, the 2021-2030 period was

[106] TR Vol IV, Pgs 647, 25 through 648, 15.
[107] TR Vol IV, Pg 651, 1-4.
[108] TR Vol IV, Pg 652, 4-21.
[109] TR Vol IV, Pg 656, 7-15.
[110] TR Vol IV, Pg 657, 9-24.
[111] TR Vol IV, Pgs 658, 25 through 659, 16.
[112] TR Vol IV, Pg 662, 10-15.
[113] TR Vol IV, Pg 662, 16-21.
[114] TR Vol IV, Pg 662, 22 through 663, 4.

assumed to resume normal underlying load growth of about 3 percent a year; this was done solely for modeling purposes.[115] The cost to meet the EES in 2020, including program administration, measure incentives and customer measure cost contributions, were projected to be about $41 per lifetime megawatt hour for the whole portfolio, and $55 per lifetime megawatt hour for the residential portfolio.[116] Achievement of the EES more than doubles the lifetime energy savings compared to the business as usual scenario, from about 43,000 gigawatt hours to 95,000 gigawatt hours and increases peak demand savings from 600 to more than 1,500 megawatts.[117] Total net resource benefits increased to $1.4 billion from $943 million (present value at 4.0%).[118] The Commission was cautioned to recognize the degree of variability in the numbers, which could increase or decrease projected benefits.[119] Variability could result from changes in assumed conditions, such as increased/decreased program costs or increased/decreased avoided costs.

The high efficiency scenario resulted in direct bill savings to ratepayers on the order of $4.6 billion between 2011 and 2030, compared to the business as usual case.[120] Bill savings were principally driven by utility plant deferrals and by reductions in utility fuel and purchased power budgets.[121] In response to questions about the potential impacts from avoided externalities, LBNL responded that the planning model was not well suited

[115] TR Vol IV, Pg 664, 16-21.
[116] TR Vol IV, Pg 665, 23 through 666, 4.
[117] TR Vol IV, Pg 667, 4-11.
[118] TR Vol IV, Pg 667, 7-11.
[119] TR Vol IV, Pg 669, 13-23.
[120] TR Vol IV, Pg 676, 2-8.
[121] TR Vol IV, Pg, 676, 24 through 678, 22.

for identifying those benefits;[122] however, LBNL re-emphasized that the identified benefits were conservative numbers.[123]

Following LBNL's presentation, the Commission continued discussion of recommended decoupling designs and rate related issues. In prior discussions, the Commission had taken up issues concerning customer classes, collars, types of deferrals, pilot programs and other issues.[124] AECC commented that decoupling could result in recession-induced rate increases and urged caution.[125] AECC further argued that the concept of "average customer" was best applicable to residential customers but made little sense for industrial customers.[126] Rather than utilizing decoupling, AECC advocated for adoption of projected test years to address some of the potential utility challenges.[127] AECC noted that other jurisdictions which had adopted decoupling segregated some or all nonresidential customers.[128] AECC's principal objections included a perceived risk shift between the utility and customers, through the incorporation of weather and other factors affecting electricity usage in the decoupling mechanism.[129]

In response to AECC's concerns, APS noted that no conclusions had been drawn regarding which customer classes would be involved in a decoupling mechanism, as this is a policy decision for the Commissioners; however, benefits would inure to all customers from deferred capacity.[130] With respect to the issue of weather risk, APS noted

[122] TR Vol IV, Pgs 717, 21 through 718, 2.
[123] TR Vol IV, Pg 720, 1-8.
[124] TR Vol IV, Pg 747, 7-11.
[125] TR Vol IV, Pg 748, 18-25.
[126] TR Vol IV, Pg 752, 5-16.
[127] TR Vol IV, Pgs 755, 22 through 756, 13.
[128] TR Vol IV, Pg 757, 1-5.
[129] TR Vol IV, Pgs 777, 18 through 778, 20.
[130] TR Vol IV, Pg 781, 5-17.

that the analysis demonstrated that APS would have been better off if weather effects were excluded, to the tune of $15 million.[131]

Stakeholders further noted that large customers, like mines, were typically excluded from decoupling mechanisms, largely because their operations would not be contributing to fixed cost recovery through variable charges.[132] As a result, these customers would not be making material impacts on the underlying problem decoupling addresses.[133] Others argued that there could be good reasons for excluding certain customer classes, but that the Commission should begin from the presumption that all customers should be included absent contrary evidence.[134] Commission staff recognized that each company presents a unique mix of customers which may require each company to figure out the best way to address those customers under a decoupling mechanism.[135]

Stakeholders highlighted different approaches used to address large utility customers, which included rate collars to minimize rate dislocation, use of a pure net lost revenue adjustment, and use of adjustments other than revenue per customer.[136]

June 10, 2010 Workshop

The June 10, 2010 workshop principally addressed LBNL's analysis of APS and TEP with the implementation of the EES, with and without decoupling.

LBNL examined the incremental benefits and costs of achieving higher levels of energy efficiency on ratepayers and utility shareholders.[137] The analysis addressed

[131] TR Vol IV, Pg 783, 14-23.
[132] TR Vol IV, Pg 789, 2-8
[133] TR Vol IV, Pg 789, 9-13.
[134] TR Vol IV, Pg 790, 13 through 791, 7.
[135] TR Vol IV, Pg 791, 9-15.
[136] TR Vol IV, Pg 793, 12 through 794, 23.
[137] TR Vol V, Pg 812, 3-10.

impacts to customer bills, rates, earnings and return on equity.[138] LBNL's approach included a long-term 20-year analysis, allowing stakeholders to better understand impacts from utilization of efficiency as a resource over a long-term.[139]

LBNL reiterated and finalized its preliminary findings for APS which LBNL had presented earlier at the May 24, 2010 workshop. For the business as usual case (with about one percent annual energy savings), LBNL identified about 43,000 gigawatt hours in total energy savings and 600 megawatts of peak demand savings, producing combined benefits of about $1.6 billion on a present value basis at a cost of about $730 million,[140] with net benefits of $946 million and a benefit/cost ratio around 2.[141] The high efficiency scenario, when compared to the business as usual case, reduced sales growth in half because of the EES.[142] When compared with the business as usual scenario, the energy efficiency scenario produced more than twice the total energy savings, a 150 percent increased in peak demand savings and a 50 percent improvement in net resource benefits.[143] LBNL identified net benefits, on a present value basis (4.0%) of $1.4 billion under the high efficiency scenario versus $946 million in the business as usual case.[144] The LBNL analysis also estimated that customer bill savings in the high efficiency case would be about $4.6 billion more than the bill savings achieved in the business as usual case.[145]

LBNL conducted a separate but similar analysis for TEP, examining energy efficiency impacts on customer bills and rates, the Company's earnings and return on

[138] TR Vol V, Pg 812, 10-13.
[139] TR Vol V, Pgs 813, 22 through 814, 4.
[140] TR Vol V, Pg 822, 7-17.
[141] TR Vol V, Pg 826, 20-21.
[142] TR Vol V, Pg 832, 13-21.
[143] TR Vol V, Pg 833, 1-5.
[144] TR Vol V, Pg 833, 18-20.
[145] TR Vol V, Pgs 835, 2 through 836, 8.

equity. While the TEP analysis made similar assumptions to those in the APS analysis, key differences included substantially lower growth rates for nonfuel costs[146] and two year intervals between rate case filings rather than three.[147]

For the TEP business as usual case, a one percent annual efficiency savings level was assumed, to be consistent with the APS business as usual case, though TEP's existing level of savings is at or about 0.4 percent per year.[148] Under the business as usual case (which included the one percent annual efficiency savings level), LBNL identified about 13,000 gigawatt hours of energy savings and 230 megawatts of peak demand reductions[149] with a value of $472 million (present value at 4.0%) in total net resource benefits.[150] Under the EES, TEP would achieve cumulative annual savings in excess of 2,000 gigawatt hours in 2020.[151] The EES flattened retail sales growth and dropped peak demand growth to half a percentage point.[152] Overall savings associated with the EES more than doubles total lifetime energy savings relative to the business as usual case of one percent savings (i.e, about 27,900 vs. 13,000 GWh), producing a 210 percent increase in peak demand levels and a 44 percent increase in net resource benefits.[153] The present value of customer bill savings totaled $570 million over the 20 year period between 2011-2030.[154]

Comparing the high efficiency scenario to the business as usual case revealed shareholder impacts of $38 million (present value at 4.0%) between 2011-2020, reducing

[146] TR Vol V, Pg 846, 13-18.
[147] TR Vol V, Pg 846, 20-22.
[148] TR Vol V, Pg 847, 5-19.
[149] TR Vol V, Pg 848, 5-13.
[150] TR Vol V, Pg 849, 2-10. Revised numerical value from LBNL Analysis, June 14 Update, Slide 30.
[151] TR Vol V, Pg 853, 3-6.
[152] TR Vol V, Pg 853, 16-20.
[153] TR Vol V, Pgs 853, 21 through 854, 2. Revised numerical value from LBNL Analysis, June 14 Update, Slide 35.
[154] LBNL Analysis, June 14 Update, Slide 38.

the utility's average return on equity by 46 basis points.[155] Incorporation of revenue per customer decoupling added $36 million (present value at 4.0%) to TEP earnings over the 10-year period, or 59 basis points to return on equity.[156] Decoupling resulted in a 0.7 percent increase to customer bills, or $70 million (present value at 4.0%) as compared to $570 million of projected ratepayer bill savings achieved under the EES.[157]

Combining results for TEP and APS, LBNL identified total resource net benefits on the order of about $2 billion without a decoupling mechanism in the high efficiency case with the EES, and approximately $670 million more in total net benefits than the business as usual case.[158] Customer bill savings totaled about $5.2 billion between the two utilities for the high efficiency scenario compared to the business as usual case, even after accounting for the rate increases.[159] Retail rates rose between 1 and 1.8 cents higher for APS and TEP respectively for the high efficiency case compared to the business as usual case.[160] Without decoupling, APS and TEP average utility return on equity decreased by about 50 basis points over the 10-year period compared to the business as usual case.[161] The inclusion of a decoupling mechanism added about 45 to 60 basis points to the utilities' return on equity.[162]

While LBNL's analysis revealed consistent results between APS and TEP, several assumptions drove distinct results. Assumed avoided costs were lower for APS than for TEP;[163] TEP utilized lower DSM program costs;[164] nonfuel cost growth assumptions

[155] TR Vol V, Pg 857, 16-23.
[156] TR Vol V, Pg 858, 6-11.
[157] TR Vol V, Pg 859, 1-24. Revised numerical value from LBNL Analysis, June 14 Update, Slide 42.
[158] TR Vol V, Pg 861, 15-21. Revised numerical value from LBNL Analysis, June 14 Update, Slide 44
[159] TR Vol V, Pg 861, 21-24.
[160] TR Vol V, Pg 862, 1-5. Revised numerical value from LBNL Analysis, June 14 Update, Slide 44.
[161] TR Vol V, Pg 862, 6-9.
[162] TR Vol V, Pg 862, 9-12.
[163] TR Vol V, Pg 863, 4-12

were higher for APS;[165] and APS forecasted higher retail sales, customer, and peak demand growth rates.[166] TEP noted that differences in avoided cost estimates were largely the result of whether the utility was long or short on resource capacity.[167] Parties noted that assumptions could change some of the total resource benefits; however, concerns about these benefits were dwarfed by net incremental customer bill savings of $5.2 billion (combined APS and TEP) over the business as usual case and $8.7 billion over a case with no energy efficiency savings.[168]

Parties clarified that the bill savings figures presented were net of rate impacts for energy efficiency programs and emphasized the need to address utility disincentives to align the interests of customers in saving energy and the interests of utilities in maintaining their rates of return.[169]

ISSUES

The Commission's extensive workshop process unearthed significant benefits for ratepayers and utilities and clarified stakeholder concerns. The Commission's analysis revealed that customer bill savings for APS and TEP from achieving the EES, including implementation of decoupling, would total $8.7 billion relative to a scenario in which no EES existed. Customer bill savings would total about $5.2 billion under the EES with decoupling when compared to a scenario in which the utilities only achieved one percent annual energy efficiency savings. The Commission further recognizes that decoupled utility companies would be foregoing overearning opportunities as decoupling would

[164] TR Vol V, Pg 863, 13-16.
[165] TR Vol V, Pg 863, 17-18.
[166] TR Vol V, Pg 863, 23-25.
[167] TR Vol V, Pg 872, 11-15.
[168] TR Vol V, Pgs 880 5 through 881, 15.
[169] TR Vol V, Pgs 883, 1 through 884, 17.

provide customers credits in the event of excess earnings. The savings and benefits of decoupling encourages the Commission to move forward with steps that support the Standard, including eliminating disincentives to the pursuit of energy efficiency.

Among the issues stakeholders raised in workshops were: the proper mechanism for aligning utility and customer incentives; whether differences between new and existing customers necessitated different treatment; whether adjustments to cost of capital should be undertaken; whether the Commission should adopt decoupling on a pilot or permanent basis; whether full or partial decoupling should be adopted; the appropriate timing for adjustments; applicability of decoupling across customer classes; whether adjustments would be blended across customer classes or segregated by class; and whether collars or caps on adjustments were necessary and the appropriate bandwidth for such collars or caps.

The Commission believes it is critical that utility disincentives to demand side management programs and energy efficiency be addressed. As stakeholders recognized, it is unlikely that the EES can be met without addressing financing disincentives and impacts to utilities' revenues and earnings. LBNL's analysis estimated that the utility bills of APS and TEP customers would be reduced by about $5.2 billion through compliance with the EES, relative to the business as usual case. Similar benefits are anticipated at other utilities. Absent achievement of the EES, APS and TEP ratepayers will unnecessarily pay between $5.2 billion and $8.7 billion in higher energy bills.

The Commission's workshops, while not limited to decoupling, demonstrated significant interest in decoupling as a means of addressing utility disincentives. Revenue per customer decoupling is uniquely suited for Arizona as it establishes a target revenue

per customer and responds to customer growth in between rate case cycles. While the target revenues per customer are established in traditional rate cases, revenues are allowed to increase with customer growth, better matching utility costs and revenues. As recognized in workshops, further analysis is necessary to determine whether new and existing customers should be expected to consume similar amounts, require similar infrastructure costs and generate similar revenues. If new customers, whether through decreased costs to serve or decreased usage, would bring in less revenue than existing customers, this dynamic must be considered.

Other proposals discussed in the workshops included fixed cost/variable cost pricing and mechanisms to address lost margin recovery. Though these and other proposals may be appropriate for some utilities, the Commission believes they have limited application. Fixed cost/variable pricing would result in larger customer charges, which impact low-income customers, and reduced variable charges, which discourages efficient energy use. Lost margin recovery mechanisms allow for recovery of margins attributable to decreased energy sales from energy efficiency programs; however, this mechanism may be subject to prolonged litigation, and would not allow for other beneficial actions on rate design or contribute to improved costs of capital.

Some stakeholders proposed that the Commission adopt decoupling as a pilot and refrain from broader adoption. The Commission believes that adoption of decoupling should occur in rate cases, with evaluation and review occurring after an initial three year period. This would demonstrate a stronger commitment to decoupling and better facilitates action on complimentary rate designs and on costs of capital. The Commission recognizes that Arizona's largest utilities, while improving, are not well-rated by

financial ratings agencies. The Commission believes it is important to send long-term signals and demonstrate commitment to decoupling before taking action on costs of capital. Adoption of decoupling on a pilot basis would not send appropriate signals and would not demonstrate the requisite commitment to eliminating financial disincentives to the adoption of energy efficiency.

Parties have argued that full decoupling may draw in effects from factors other than energy-efficiency, such as weather or economic effects. However, full decoupling is preferable as it enhances utility and customer billing stability, is administratively more manageable and would allow for rate relief during extreme weather events. Utility analyses indicated ratepayer benefits even if weather effects had been considered. With decoupling in place, these ratepayer benefits would have been directly distributed to customers rather than benefitting the utility. With respect to economic effects, utilities would be capable of filing rate cases or emergency rate increase requests with or without decoupling. The Commission believes a collar or cap on the size of decoupling adjustments appropriately addresses concerns raised by parties as it limits effects from extraordinary economic downturns or unforeseen circumstances.

Decoupling adjustments occur over periods of time, whether annually, quarterly or monthly. The Commission believes that more current adjustments respond better to extreme weather events and allow for ratepayer relief. Appropriate collars or caps on adjustments ensure that rates will not vacillate between periods. While annual adjustments may smooth and moderate changes, as a longer tine interval may dampen seasonal variations, they lack responsiveness to weather events.

ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures

POLICY STATEMENTS

1. Diversity and utilization of both demand and supply side options for meeting Arizona's energy resource needs is beneficial and should be actively pursued by Arizona utilities as a way of moderating capital expenses, encouraging greater flexibility, ensuring reliability, and minimizing rate impacts and customer energy bills.

2. Arizona utilities should pursue all cost-effective energy efficiency and demand side management resources, and should meet Arizona's Electric and Gas Energy Efficiency Standards of at least 22% electric energy savings and at least 6% gas savings by 2020.

3. Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency, as it establishes better certainty of utility recovery of authorized fixed costs and better aligns utility and customer interests. The Commission could also consider alternative methods for addressing utility financial disincentives. Some form of decoupling or alternative for addressing financial disincentives must be adopted in order to encourage and enable aggressive use of demand side management programs and the achievement of Arizona's Electric and Gas Energy Efficiency Standards, which will benefit ratepayers and minimize utility costs. These types of mechanisms offer short term and long term benefits: in the short term they allow for customer bill savings through increased energy efficiency, achieved through Commission-approved energy efficiency programs; in the long term they contribute to plant deferrals and may contribute to improvements in costs of capital.

4. While other decoupling models are appropriate in general, non-fuel revenue per customer decoupling may be well suited for Arizona as it responds to customer growth and is better suited to address the issues associated with customer growth. Utilities interested in revenue per customer decoupling must address whether new customers should be treated distinctly from existing customers.

5. Adoption of decoupling (or any other alternative mechanism that addresses utility disincentives to promoting energy efficiency) should not occur as a pilot, as this insufficiently supports demand side management efforts, discourages beneficial changes to rate design and is unlikely to encourage financial ratings improvements. In lieu of pilot adoption, an initial three-year review period should be utilized which allows for evaluation and redress of decoupling models and related issues. The initial review period should be within three years of adoption or until the company files its next rate case after a decoupling or alternative mechanism is approved. If Commission Staff is not able to conduct this review due to resource constraints, an independent evaluation contractor shall be hired by the utility.

6. Commitment to and early implementation of decoupling should precede significant decoupling-specific adjustments to cost of capital if a revenue per customer decoupling mechanism is approved for a utility. The review of the initial three-year period following adoption of revenue per customer decoupling should include analysis and discussion of possible adjustments to cost of capital to recognize any modified risk at the utilities, as well as benchmarking and comparisons to other utilities operating with revenue per customer decoupling.

7. Utilities are encouraged to develop customer rate designs that support energy efficiency and work well in tandem with decoupling (or alternative mechanisms). Utilities may propose preliminary rate designs for the initial three-year period, and the preliminary rate designs should be evaluated during the review of the initial period. Revisions to the preliminary rate designs based on the results of the review should be proposed for the subsequent period.

8. Full decoupling is preferable to partial decoupling as it contributes to greater rate stability which would encourage improvements in financial ratings, is administratively more manageable, and offers opportunities for rate relief following extreme weather events.

9. Weather normalization in the application of decoupling is discouraged because such normalization would reduce the size of decoupling surcredits to customers following an extreme weather event.

10. Decoupling adjustments should occur at least on an annual basis; however, parties may propose more current adjustments as this may provide ratepayers with weather related rate relief following extreme events.

11. Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes. Utilities should address any proposed distinct treatments and justify why certain customer classes may merit different treatment.

12. Decoupling adjustments should be blended and applied across customer classes to discourage dramatic changes experienced by any one class.

13. Decoupling adjustments applied in a manner to encourage energy efficiency are preferred, such as applying decoupling surcharges to rates and higher-usage blocks to encourage energy efficiency, and applying decoupling surcredits to reward customers who use less energy.

14. Collars or caps on decoupling adjustments should be designed to encourage gradualism, and to minimize the short-term effects on customers. If the decoupling adjustments are to occur on a monthly, quarterly, annual, or less-than-annual basis, the utility should propose a cap for the periodic decoupling adjustments. Customers should receive the full amount of any credit in a timely manner in the event that achieved

revenue per customer exceeds authorized revenue per customer. Therefore, it is not necessary to cap the amount of surcredit decoupling adjustments or credits to customers.

ORDER

A utility may file a proposal for decoupling or alternative mechanisms for addressing utility financial disincentives to energy efficiency, including revenue per customer decoupling, in its next general rate case. A utility filing such a proposal should address this policy statement in its filing and should use this policy statement as a guideline in development of its proposal.

Sincerely,

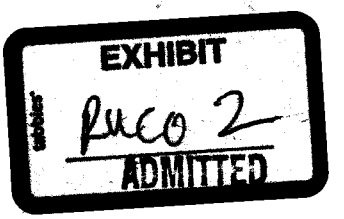
Kristin K. Mayes
Chairman

Gary Pierce
Commissioner

Sandra D. Kennedy
Commissioner

Paul Newman
Commissioner

Bob Stump
Commissioner



SOUTHWEST GAS CORPORATION

April 1, 2011

Ms. Michele Finical
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007-2996

Subject: Southwest Gas Corporation
2010 General Rate Case; Docket No. G-01551A-10-0458
Data Request No. ACC-STF-3

Dear Ms. Finical:

Enclosed please find a copy of Southwest Gas Corporation's response to Staff's data request Nos. 20 and 32 of the third set of data requests received in the above-referenced proceeding. The "CD" included, marked "FINAL", contains all the attachments pertaining to this set of data requests.

In addition, the attachments to data request no. 32 are considered Confidential and afforded protection under the protective agreements signed with the parties for this proceeding.

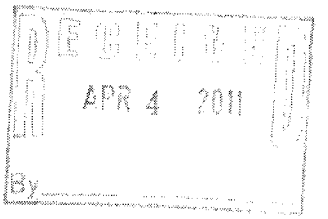
This completes the third set of data requests in the above-referenced proceeding.

If you have any questions, please contact me at (702) 876-7163.

Respectfully,

Debra S. Gallo by cmg

Debra S. Gallo, Director
Government & State Regulatory Affairs



Enclosures

c David and Kim Dismukes, Acadian Consulting Group

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SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-3
(ACC-STF-3-1 to ACC-STF-3-54)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 23, 2011

Request No. ACC-STF-3-32:

Provide a recast of the Company's financial results (this would include revenue, expenses, rate base, capital, return on equity, and return on rate base) for each of the years 2006 through 2010, assuming the Company's proposed revenue decoupling mechanism had been implemented in 2006 through 2010 and using 2005 as the base year. Please provide any and all workpapers supporting this response in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Respondent: Revenue Requirements

Response:

While the margin that would have been realized if the Company's proposed decoupling mechanism had been implemented in 2006 can be readily recast, recasting the Company's financial results, specifically debt expense and capital structure would require assumption and speculation on how the margin recovered through the decoupling mechanism would have been employed. A recast of return on equity and return on rate base, assuming the proposed decoupling mechanism, would also be highly speculative and cannot be determined with accuracy.

Notwithstanding, the Company has prepared two margin analyses in an attempt to provide information responsive to this request. Both analyses utilize recorded customer bills and volumes for the 48 months ended June 2010. All results are for the twelve months ended June 30 of the year indicated.

In the first analysis, the recast margin for the years ended June 2007 and 2008 are based on rates established in the Company's 2004 rate case with a test year ended August 2004 and a 347 therm residential average use. The recast margin for the years ended June 2009 and 2010 are based on rates established in the Company's 2007 rate case with a test year ended April 2007 and residential customer average annual use of 332 therms.

Margin ($Millions)				
	2007	2008	2009	2010
Recast Margin with Decoupling	352.6	360.3	374.5	386.6
Recast Margin w/o Decoupling	348.6	349.6	340.0	369.8
Annual Difference	4.0	10.7	34.5	16.8

The Company does not believe this analysis is a reasonable representation of what will likely occur on a pro forma basis since the billing determinants used to develop rates in the historical period were much higher than the normalized billing determinants used to develop rates in this proceeding.

Consequently, the Company has prepared a second analysis whereby it has recast the margin by applying the proposed rates in this proceeding to recorded customer bills and volumes for the 48 months ended June 2010.

Margin ($Millions)				
	2007	2008	2009	2010
Recast Margin with Decoupling	421.6	430.6	432.1	430.9
Recast Margin w/o Decoupling	458.9	459.4	417.2	446.3
Annual Difference	(37.3)	(28.8)	14.9	(15.4)

ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS TO
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458
February 23, 2011

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

STF – 3.27 State the amount of base revenue increase or decrease authorized by the Commission for any rate increase or decrease implemented in 2004, 2005, 2006, 2007, 2008 and 2009. For each rate change state the date the rate change was implemented by the Company, the return on equity and overall rate of return allowed by the Department, the capital structure used to develop the allowed rate of return, and state the test year associated with the rate change.

STF – 3.28 Please describe in detail any ratepayer protection mechanisms that SWG has included in its decoupling proposal.

STF – 3.29 Please provide the most recent S&P, Moody's, and Fitch credit ratings for the Company and its parent as well as those as of Dec. 31, 2010, Dec. 31, 2009, Dec. 31, 2008, and Dec. 31, 2007.

STF – 3.30 Please provide all rating agency and investor reports that address all negative financial pictures for the Company and/or its parent issued within the last five years.

STF – 3.31 For each month from July 2009 through June 2010, please provide the Company's actual return on equity and the return on equity that would have been realized had the proposed revenue decoupling mechanism been in place. Use the capital structure and appropriate cost rates for the twelve months ending June 30, 2010 in calculating the return on equity. Include in your response all supporting source documentation, work papers, and calculations. Please provide any and all workpapers supporting this response in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

STF – 3.32 Provide a recast of the Company's financial results (this would include revenue, expenses, rate base, capital, return on equity, and return on rate base) for each of the years 2006 through 2010, assuming the Company's proposed revenue decoupling mechanism had been implemented in 2006 through 2010 and using 2005 as the base year. Please provide any and all workpapers supporting this response in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

SOUTHWEST GAS CORPORATION
ARIZONA
DECOUPLING ADJUSTMENTS FOR THE TWELVE MONTHS ENDED JUNE 2007 THROUGH JUNE 2010
PROPOSED AND PREVIOUSLY AUTHORIZED RATES

Description	Rate Sch.	Twelve Months Ended June XXXX 2007	2008	2009	2010	4-Yr Total
Decoupling Adjustment Proposed Rates						
Residential	G-5	(27,471,068)	(22,615,311)	13,294,200	(11,222,500)	(48,014,678)
Multi-Family Residential GS	G-6	(896,679)	(405,511)	150,178	(183,177)	(1,335,189)
Single Family Low Income	G-10	(785,417)	(644,802)	360,058	(454,127)	(1,524,287)
Multi-Family Low Income	G-11	(89,525)	16,093	30,065	(19,580)	(62,946)
Special Residential	G-15	0	0	0	0	0
General Gas Service - Small	G-25S	(892,673)	(471,976)	74,495	(507,539)	(1,797,694)
General Gas Service - Medium	G-25M	(1,917,879)	(1,114,516)	599,341	(1,323,348)	(3,756,402)
General Gas Service - Large	G-25L	(5,247,355)	(3,561,870)	392,023	(1,711,212)	(10,128,414)
Total Decoupled Customers		(37,300,595)	(28,797,894)	14,900,361	(15,421,482)	(66,619,609)
Decoupling Adjustment Historic Rates						
Residential	G-5	6,896,718	10,435,455	26,972,698	11,042,141	55,347,011
Multi-Family Residential GS	G-6	527,773	948,760	719,372	330,667	2,526,572
Single Family Low Income	G-10	246,350	368,303	1,590,150	1,836,814	4,041,617
Multi-Family Low Income	G-11	(31,015)	42,300	49,983	41,068	102,336
Special Residential	G-15	(1,594)	(1,594)	10,139	13,987	20,938
General Gas Service - Small	G-25S	(681,236)	(356,111)	473,983	271,061	(292,302)
General Gas Service - Medium	G-25M	(1,312,301)	(557,756)	1,428,056	369,863	(72,137)
General Gas Service - Large	G-25L	(1,689,471)	(135,339)	3,229,806	2,872,132	4,277,128
Total Decoupled Customers		3,955,224	10,744,017	34,474,188	16,777,734	65,951,163

SOUTHWEST GAS CORPORATION
ARIZONA
DECOUPLING ADJUSTMENTS FOR THE TWELVE MONTHS ENDED JUNE 2007 THROUGH JUNE 2010
PREVIOUSLY AUTHORIZED HISTORIC RATES

Description	Rate Sch.	Twelve Months Ended June XXXX 2007	2008	2009	2010	4-Yr Total
Decoupling Adjustment Historic Rates						
Residential	G-5	6,896,718	10,435,455	26,972,698	11,042,141	55,347,011
Multi-Family Residential GS	G-6	527,773	948,760	719,372	330,667	2,526,572
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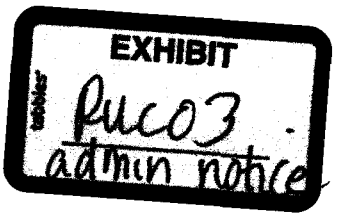

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

June 9, 2010

IN RE:	)	
	)	
PETITION OF PIEDMONT NATURAL GAS COMPANY, INC. TO IMPLEMENT A MARGIN DECOUPLING TRACKER (MDT) RIDER AND RELATED ENERGY EFFICIENCY AND CONSERVATION PROGRAMS	)	**DOCKET NO. 09-00104**

ORDER DENYING MARGIN DECOUPLING TRACKER RIDER

This matter came before Director Mary W. Freeman, Director Eddie Roberson and Director Kenneth C. Hill of the Tennessee Regulatory Authority (the "Authority" or "TRA"), the voting panel assigned to this docket, at a regularly scheduled Authority Conference held on January 25, 2010 for consideration of the *Petition of Piedmont Natural Gas Company, Inc. for Approval of Service Schedule No. 317 and Related Energy Efficiency Programs* ("*Petition*") filed on July 16, 2009. Through the *Petition*, Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company") is requesting approval to implement energy efficiency and conservation programs and a Margin Decoupling Tracker ("MDT") mechanism.

TRAVEL OF THE CASE

Subsequent to the filing of Piedmont's *Petition*, the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate") filed a *Complaint and Petition to Intervene* ("*Petition to Intervene*") on July 31, 2009. Piedmont filed *Piedmont Natural Gas Company, Inc.'s Opposition to the Complaint and Petition to Intervene by the Tennessee Consumer Advocate and Protection Division of the Attorney General* on August 10,

2009. The Consumer Advocate filed its response to the Company's opposition on August 21, 2009. At a regularly scheduled Authority Conference held on August 24, 2009, the panel voted unanimously to convene a contested case proceeding, to suspend the proposed tariff for ninety days, from September 1, 2009 to November 29, 2009, and to appoint the Authority's General Counsel or his designee to serve as Hearing Officer for the purpose of handling preliminary matters and preparing this matter for hearing before the panel.

The Hearing Officer issued an *Order Granting Intervention, Determining Issues, and Establishing Procedural Schedule* on October 13, 2009. On November 24, 2009, the Hearing Officer issued his *Order Granting Motion for Entry of a Protective Order and Modifying Procedural Schedule.* The *Notice of Hearing and Pre-Hearing Conference* was issued by the Hearing Officer on December 3, 2009, and the *Pre-Hearing Order* was issued on December 16, 2009.[1]

The parties undertook discovery, and subsequently Piedmont filed the Pre-filed Direct Testimony of David R. Carpenter, Russell A. Feingold, Steve Lisk and Frank Yoho on December 4, 2009. On the same day, the Consumer Advocate filed the Pre-Filed Direct Testimony of Terry Buckner, Christopher C. Klein and David Dismukes. On December 11, 2009, each of the Company's witnesses filed Pre-filed Rebuttal Testimony. The Company also filed the Pre-filed Rebuttal Testimony of David Dzuricky. The Consumer Advocate filed the Pre-filed Rebuttal Testimony of Terry Buckner on December 11, 2009.

[1] At the Pre-Hearing Conference held on December 14, 2009, the Hearing Officer informed the parties that Piedmont should have at least one of its witnesses prepared to address the Public Utility Regulatory Policies Act ("PURPA") standards as directed by the panel in Docket No. 09-00065. *Pre-Hearing Order*, p. 4 (December 16, 2009). *See also In re: Appropriateness of Implementation of PURPA Standard 5 (Energy Efficiency) and Standard 6 (Rate Design Modification) for Piedmont Natural Gas Company, Chattanooga Gas Company, and Atmos Energy Company*, Docket No. 09-00065, *Order Declining to Adopt Standards in Instant Case*, pp. 3-4 (January 11, 2010).

THE HEARING AND POST-HEARING FILINGS

The Hearing was held on December 17-18, 2009. Participating in the Hearing on behalf of the parties were the following respective counsel:

> Piedmont Natural Gas Company – **James H. Jeffries IV, Esq.** and **Brian Heslin, Esq.**, Moore & Van Allen PLLC, 100 North Tryon Street, Suite 4700, Charlotte, North Carolina 28202-4003; **Erin M. Everitt, Esq.**, Bass, Berry and Sims PLC, 150 Third Avenue South, Suite 2800, Nashville, Tennessee 37201.
>
> Consumer Advocate and Protection Division – **C. Scott Jackson, Esq.** and **Ryan L. McGehee, Esq.**, Office of the Attorney General, P.O. Box 20207, Nashville, TN 37202-0207.

The panel heard testimony from Company witnesses: Frank Yoho, Russell A. Feingold, David R. Carpenter, Steven L. Lisk and David Dzuricky. David E. Dismukes, Christopher C. Klein and Terry Buckner testified for the Consumer Advocate. No member of the public sought recognition during the Hearing, but various members of the public filed comments prior to the Hearing. Post-Hearing Briefs were filed on January 4, 2010.

ISSUES AND POSITIONS OF THE PARTIES

The Authority adopted five issues for determination in the case.[2] Additionally, the 2007 PURPA standards were considered by the Authority in this docket. The parties' respective positions on each issue and the 2007 PURPA standards are set out below.

Issue 1: **What is the appropriate mechanism, or financial incentive, to insure that Piedmont's financial incentives are aligned with the state's energy conservation policy set out in 2009 Public Act 531, Section 53?**[3]

Piedmont: Piedmont asserts that Service Schedule No. 317, which proposes the MDT mechanism, satisfies all the requirements of Tennessee policy set out in Tenn. Code Ann. § 65-4-126 to align the Company's financial incentives with the interests of its customers. According to the Company, the decoupling proposal accomplishes this by "trueing [sic] up" the recovery of

[2] *See Order Granting Intervention, Determining Issues, and Establishing Procedural Schedule* (October 13, 2009).
[3] This Public Act is codified at Tenn. Code Ann. § 65-4-126.

average per customer margin in a way that assures the Company will recover exactly the right amount of fixed costs from its residential customers as determined by the TRA in a rate case. Piedmont asserts that the mechanism is neutral in that both over and under recoveries are trued up. It notes that the benefits to customers from the mechanism include: protecting against over-recovery of margin when customer usage is higher than projected; maintaining usage-based rates as preferred by customers; preserving gas cost savings benefits for customers associated with conservation; extending the time periods between rate cases by eliminating margin erosion from lower per customer usage; and permitting the Company to promote energy efficiency and conservation programs that will save customers money in lower utility bills. Piedmont states that the design also makes sense because it allows the recovery of fixed costs on a fixed basis. Piedmont also notes that decoupling is supported by a number of legislative enactments, including Tenn. Code Ann. § 65-4-126, as well as by a number of trade groups.[4]

Piedmont asserts that the Consumer Advocate's criticisms of the MDT as neither valid nor compelling. The Company states that rather than shifting risk to customers as asserted by the Consumer Advocate, the MDT will eliminate risk for both customers and the Company. Piedmont states that its proposal offers consumer protective measures that effectively eliminate any potential incremental risk to customers. Piedmont proposes the following consumer protective measures: adoption of the MDT on a trial basis for the shorter of three years or until the Company files its next general rate case, a cap on earnings during the trial period, and full payment (without cost recovery) for the Company's energy efficiency programs during the same time period. Finally, Piedmont asserts that the Consumer Advocate's alternative proposal, that

[4] *Brief of Petitioner Piedmont Natural Gas Company, Inc. in Support of Approval of Proposed Service Schedule No. 317 and Related Energy Efficiency Programs*, pp. 10-13 (January 4, 2010) (hereinafter "*Piedmont's Brief*").

the Authority disapprove the MDT and retain the Company's existing rate structure, is inconsistent with Tenn. Code Ann. § 65-4-126.[5]

Consumer Advocate: The Consumer Advocate proposes a lost base revenue mechanism[6] to align the Company's financial incentives with encouraging consumers to become more energy efficient. With such a mechanism, the Company's financial incentives are aligned with customers by making the utility whole for lost revenue attributable solely to the utility's energy conservation efforts and provides an incentive if the efforts are successful in producing cost-effective and measurable results.[7]

According to the Consumer Advocate, the Company's proposed MDT is not just and reasonable because it is an arbitrary mechanism that will raise the rates of consumers while generating for the Company a financial windfall that is out of proportion with the insignificant revenue loss generated from conservation programs. The benefits to consumers from decoupling are unknown. The Company's proposed weatherization and equipment rebate programs are modest in impact and scope, and the Company's annual cost for these programs is not significant in comparison to its revenues. On the other hand, the benefits to the Company through the proposed MDT are substantial. Had the mechanism been in place since Piedmont's last rate case in 2003, Piedmont's revenues would have grown by $19 million. Further, if the proposal is approved, the Company's rates will increase by $1.9 million over the next twelve months while the cost of the proposed conservation programs would result in only $20,000 in revenue loss to the Company. The Consumer Advocate states that the theory behind Piedmont's decoupling proposal is that if its profits are no longer dependent on sales volume, it no longer has a

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[5] *Id.* at 14-16.

[6] A lost base revenue mechanism is a performance based mechanism that would allow the Company to recover its costs for energy conservation programs and recover non-gas revenues lost due to such programs. Additionally, the mechanism would allow the award of financial incentives for successful energy conservation programs. *Post-Hearing Brief of the Consumer Advocate*, p. 9 (January 4, 2010) (hereinafter "*Consumer Advocate's Brief*").

[7] *Consumer Advocate's Brief*, p. 9.

disincentive to encourage conservation. The Consumer Advocate asserts that there is no economic or academic treatise showing decoupling as a means or the only solution to encourage conservation.[8]

The Consumer Advocate further asserts that: 1) the evidence in the proceeding does not establish the need for decoupling; 2) one side-effect of decoupling is a weakening of the incentive for the utility to control costs; 3) Piedmont's proposed MDT does not comply with Tennessee's new conservation policy; and 4) the current regulatory framework and natural gas market provide the Company with sufficient financial incentive to encourage conservation. Should the Authority determine that a decoupling mechanism is warranted, the Consumer Advocate proposes that the Authority adopt the "Colorado Model," a decoupling mechanism substantially modified by the Colorado Public Utilities Commission to address concerns regarding the shift of risk to customers and maintenance of the incentive to the utility to control costs. The Consumer Advocate further notes that there are other safeguard modifications the Authority should consider if the Authority decides to adopt a decoupling mechanism, the safeguards proposed by Piedmont being insufficient.[9]

Issue 2: **If such mechanism or incentive is adopted, what is the appropriate customer usage level and/or margin to be used as the benchmark for Piedmont's proposed decoupling mechanism?**

Piedmont: The Company proposes to use four factors to true-up monthly actual normalized average per customer usage with the assumed normalized usage underlying the Company's approved volumetric rates. Piedmont further proposes to use the approved versions of these factors that were established in the Company's last rate case. One of the advantages of the MDT proposal is that it would extend the period of time between general rate cases. Because the expense of rate cases is largely borne by a utility's customers, Piedmont's customers would

[8] *Id.* at 11-12.
[9] *Id.* at 13-36.

benefit from avoiding unnecessary rate cases. Piedmont also asserts that because rate cases generally result in rate increases, it is not reasonable to adopt the Consumer Advocate's suggestion to convene a general rate case to implement the proposed MDT or to update three out of the four factors.[10]

Consumer Advocate: The Consumer Advocate asserts that in the event that the Authority adopts a decoupling mechanism, the determination of the appropriate benchmark for the mechanism is an essential element of that decision. Piedmont's proposal applies a benchmark from its last rate case in 2003. Applying that stale benchmark results in the undisputed financial impact of increasing Company revenues and raising the bills of residential customers by $1.9 million. The Consumer Advocate proposes that, at a minimum, a test year ending September 2009 is the most logical and sound benchmark available. The use of that test year would significantly lower the adverse financial impact on residential customers.[11]

Issue 3: Prior to implementing a decoupling mechanism, should Piedmont's earnings be evaluated?

Piedmont: The Company asserts that an earnings evaluation is not necessary prior to implementing the proposed MDT. The evidence presented by the Company at the hearing demonstrates that the Company has not been over-earning since its last rate case nor is it over-earning now. Piedmont's average annual rate of return for 2004-2008 was 8.43%, virtually identical to the rate of return of 8.42% approved in its last rate case in 2003. The 2009 rate of return was 7.47%, ninety-five basis points below its approved rate of return. Further, the Company projects that the overall rate of return would be less than 8% after implementation of

[10] *Piedmont's Brief*, pp. 20-23.
[11] *Consumer Advocate's Brief*, pp. 37-40.

the proposed MDT. Because the MDT mechanism is neutral in character, it cannot cause over-earnings.[12]

Consumer Advocate: The Consumer Advocate asserts that there is a need for a rate case prior to implementing a decoupling mechanism. The proposed decoupling mechanism tracks only one rate-making facet, the margin per customer based on the 2003 rate case settlement. This, by definition, is "single issue" ratemaking and is generally prohibited outside the context of a rate-making proceeding. The Consumer Advocate is concerned that the MDT will function more as a "bridge" between rate cases rather than encourage conservation. While Piedmont argues that rate cases are expensive for consumers, looking at such costs in context shows that the expenses from the 2003 rate case were amortized over three years and cost consumers roughly $100,000 annually. The Consumer Advocate argues that this figure pales in comparison to the $1.9 million Piedmont would receive within the next twelve months if the proposed MDT is approved.[13]

Issue 4: Does the implementation of a decoupling mechanism lower the business risk for Piedmont, thereby justifying an adjustment of its rate of return? If so, what method or evaluation tools should be utilized to quantify an appropriate adjustment to the rate of return?

Piedmont: Piedmont asserts that its business risk would not be lowered by the implementation of the MDT, and there is no justification to adjust its allowed rate of return on common equity. Even if the adjustment proposed by the Consumer Advocate (a 50 basis point reduction) was accepted, the Company argues that there is no starting point at which to make the calculation since there was no return on common equity set forth in the settlement agreement of the last rate case. Piedmont further argues that a number of factors make it not reasonably possible to conclude that the Company's overall business risk will be materially impacted by

[12] *Piedmont's Brief*, pp. 23-26.
[13] *Consumer Advocate's Brief*, pp. 40-43.

implementing the MDT or that its permissible return on common equity should be adjusted as a result. Finally, Piedmont states that the evidence indicates that Piedmont's overall return is well below its currently approved level and will remain so even after the adoption of the MDT.[14]

Consumer Advocate: The Consumer Advocate asserts that adoption of the decoupling mechanism will guarantee the Company's margin per customer and thereby reduce risk that Piedmont will fail to recover that margin. Applying a conservative estimate of 10% reduction in risk, the Consumer Advocate recommends that the Authority reduce Piedmont's allowable return on common equity by fifty basis points to offset the effect decoupling has on the Company's business risk.[15]

Issue 5: Should Piedmont be required to meet specific, verifiable, measurable energy efficiency goals and/or benchmarks for any approved conservation programs?

Piedmont: Piedmont states that its three proposed programs satisfy the policy requirements of Tenn. Code Ann. § 65-4-126: promoting timely cost recovery and timely earnings opportunities associated with cost-effective, measurable, and verifiable energy savings that sustain or enhance the ability of customers to use energy efficiently. Each of the programs is designed to help customers utilize energy more efficiently and is cost-effective as measured by one or more of the California Standard Practice Manual cost-effectiveness tests or by Piedmont's experience from implementing the programs in other states. Two of the three programs have built-in verification and measurement protocols. While the Customer Education program is not verifiable or directly measurable, it is potentially more cost-effective than the other two. Additionally, Piedmont has proposed not to seek either cost recovery or an earnings opportunity for these programs in the initial trial period.[16]

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[14] *Piedmont's Brief*, pp. 27-30.
[15] *Consumer Advocate's Brief*, pp. 46-47.
[16] *Piedmont's Brief*, pp. 30-31.

Piedmont asserts that the Consumer Advocate's criticism of the programs fails to acknowledge that the Company employed a consultant to analyze the programs and that the results of the analysis were positive. Neither did the Consumer Advocate recognize that the Company's low-income energy efficiency program was modeled on a successful federal program or that the Company has significant experience in implementing similar programs in North Carolina under the purview of the North Carolina Utilities Commission.[17]

Consumer Advocate: The Consumer Advocate asserts that Piedmont's proposed conservation programs are neither fully verifiable nor measurable and do not justify the implementation of a decoupling mechanism. Piedmont was not able to provide any Tennessee-specific estimates or data to quantify savings for the proposed weatherization program. According to the Consumer Advocate, Piedmont's analysis of the high efficiency equipment rebate program omitted a majority of the standard tests for such programs. Further, the Company did not attempt to provide any cost effectiveness testing for the proposed Consumer Education program.[18]

2007 PURPA STANDARDS

The 2007 Energy Act created the following new PURPA standards:

(5) Energy efficiency.--Each natural gas utility shall--

(A) integrate energy efficiency resources into the plans and planning processes of the natural gas utility; and

(B) adopt policies that establish energy efficiency as a priority resource in the plans and planning processes of the natural gas utility.

(6) Rate design modifications to promote energy efficiency investments.--

(A) In general.--The rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency.

(B) Policy options.--In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider--

[17] *Id.* at 30-33.

[18] *Consumer Advocate's Brief*, pp. 48-51.

> (i) separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer;
> (ii) providing to utilities incentives for the successful management of energy efficiency programs, such as allowing utilities to retain a portion of the cost-reducing benefits accruing from the programs;
> (iii) promoting the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives; and
> (iv) adopting rate designs that encourage energy efficiency for each customer class.
>
> For purposes of applying the provisions of this subtitle to this paragraph, any reference in this subtitle to the date of enactment of this Act shall be treated as a reference to the date of enactment of this paragraph.[19]

Piedmont: Piedmont asserts that it has addressed the first standard in that the proposed MDT separates fixed cost recovery from the variable volume of transportation and sales. The other rate design principles need further study and further examination in other dockets. The energy efficiency standards require further attention in future dockets.[20]

Consumer Advocate: In regard to the decoupling standard PURPA requires, the Consumer Advocate urges the TRA to reject the standard for the reasons stated during the proceeding. Further, the Authority should exercise caution in adopting the federal standards as doing so can weaken the discretion the state legislature has given the TRA to regulate public utilities.[21]

FINDINGS AND CONCLUSIONS

The panel made the following findings regarding the issues set out in this docket.[22] The panel first considered Issue Numbers 1 and 5.

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[19] 15 U.S.C. § 3203(b)(5)-(6).
[20] Transcript of Hearing, v. I, pp. 132-133 (December 17, 2009).
[21] *Consumer Advocate's Brief*, p. 52.
[22] Director Freeman made the motion that was the basis of the panel's actions. Director Roberson and Director Hill concurred with the motion. However, each Director made specific comments setting out their individual deliberations on the matter.

Issue 1: What is the appropriate mechanism, or financial incentive, to insure that Piedmont's financial incentives are aligned with the state's energy conservation policy set out in 2009 Public Act 531, Section 53?

Issue 5: Should Piedmont be required to meet specific, verifiable, measurable energy efficiency goals and/or benchmarks for any approved conservation programs?

As to these two issues, the panel found that Piedmont failed to present sufficient evidence to justify a need for a new financial incentive in order to comply with state and federal law regarding conservation while earning a just and reasonable rate of return. The Authority must be able to determine the benefit to consumers before permitting Piedmont an additional financial incentive.

The panel also found that Piedmont's decoupling mechanism proposal failed to meet the requirements of the Federal American Recovery and Reinvestment Act of 2009 and Tennessee's policy on energy conservation as set out in 2009 Public Act 531, Section 53. These laws require the implementation of cost-effective, measurable and verifiable efficiency savings in a way that sustains or enhances utility customers' incentives to use energy more efficiently. The conservation programs proposed by Piedmont lack specificity and measurements that would allow a determination as to whether conservation would actually be achieved.

Next, the panel considered Issue Numbers 2 and 3.

Issue 2: If such mechanism or incentive is adopted, what is the appropriate customer usage level and/or margin to be used as the benchmark for Piedmont's proposed decoupling mechanism?

Issue 3: Prior to implementing a decoupling mechanism, should Piedmont's earnings be evaluated?

The panel found that before the Authority can determine whether Piedmont's decoupling mechanism should be implemented, it is imperative that Piedmont's earnings be evaluated to insure that the Company does not exceed its approved rate of return. Because Piedmont's last

rate case was filed in 2003, the information pertaining to Piedmont's revenues is stale. The lack of current information makes it more appropriate for the Authority to consider Piedmont's proposal for a decoupling mechanism in the context of a rate setting proceeding. Evaluating Piedmont's request in a rate case would allow for the consideration of all factors relative to the Company's earnings, as well as, allow an evaluation of the potential impact on consumers before approving the implementation of a decoupling mechanism.

The panel next considered Issue Number 4.

Issue 4: Does the implementation of a decoupling mechanism lower the business risk for Piedmont, thereby justifying an adjustment of its rate of return? If so, what method or evaluation tools should be utilized to quantify an appropriate adjustment to the rate of return?

The panel found that the Authority is not in a position to examine the impact of a decoupling mechanism on Piedmont's business risk based on information that is seven years old. There are many different forms of decoupling, and each presents a different impact on revenue and business risks. There is no "one size fits all" formula for implementing a decoupler. The Authority must conduct a review of all current, relevant information pertaining to a Company's financial position and take into account many factors before determining the appropriate decoupling mechanism, if any, that should be implemented by a company.

After making these findings, the panel voted unanimously to deny Piedmont's *Petition* to implement the MDT and the accompanying tariff. The panel then considered the issue of whether the 2007 PURPA standards should be adopted for Piedmont. The panel found that the evidence in the record was insufficient to evaluate whether the PURPA standards concerning energy efficiency and rate design should be adopted for Piedmont. Thereafter, the panel voted unanimously that Piedmont should address the PURPA standards in its next general rate case or other proceeding Piedmont initiates with the Authority.

ADDITIONAL COMMENTS BY PANEL

Additionally, each Director provided individual comments related to the issues raised in this docket.

Director Freeman made the following remarks as a part of her deliberations:

> As a nation, we are becoming increasingly aware that we need to expand our energy sources. This can be done either by developing [new sources of energy] or by conserving our current sources and ideally, through both methods. We have to change our way of thinking and way of doing things in order to develop innovative and environmentally friendly energy solutions.
>
> I want to thank Piedmont for recognizing the importance of conservation and for trying to find ways to encourage consumers to conserve energy. I also want to thank the Consumer Advocate of the Attorney General's Office for intervening in this docket. And, finally, I would like to thank the TRA Staff for their diligence in analyzing the docket.
>
> Last year, Piedmont brought decoupling legislation before the General Assembly, and the General Assembly determined that more information was needed and chose to study the issue. With this [*Petition*], it is abundantly clear to me that Piedmont circumvented the Authority last year when it filed legislation in the General Assembly, and now, after the General Assembly expressed a desire to study the decoupling issue, Piedmont is attempting to circumvent the General Assembly by filing its [*Petition*] with the TRA. With that being said, we are where we are.
>
> This issue is before the Authority and we need to act prudently to insure that all relevant information is available to evaluate the effect of a decoupling mechanism on Piedmont's earnings. It is crucial that the Authority strike a balance between the rights of consumers and the right of the Company to earn a fair and reasonable rate of return.[23]

Although Director Roberson seconded Director Freeman's motion to deny the tariff and not to adopt the PURPA standards, he disagreed with some of her reasons and instead offered the following comments as a part of his deliberations:

> This petition is the first opportunity this Authority has had to address the statute enacted by the legislature last year establishing the state policy of promoting energy conservation by requiring the TRA in an appropriate proceeding to ensure that there is a proper alignment of regulated utilit[ies']

[23] Transcript of Deliberations, pp. 18-20 (January 25, 2010).

financial interest to promote said policy. The legislature established the policy but allowed the TRA wide latitude in how and when to implement it.

I will state that there is no reference to decoupling in the statute that was enacted.

I have reviewed the evidentiary record in this docket, and I believe that the company's existing [rate design] that was approved in the 2003 rate case, taken in isolation, has difficulty in meeting the statutory criteria for the proper alignment of the [C]ompany's financial incentives with helping customers use energy more efficiently. However, I do not believe that the [C]ompany's margin decoupling tracker does so either.

One concern I have [with this] mechanism is that it appears to eliminate or significantly reduce the positive effect of regulatory lag. In theory, regulatory lag provides an incentive for utilities to operate efficiently in order to maximize profits. For a monopoly, this concept is very important, and any new rate design adopted by the Authority for a monopoly should not forgo the benefits of this traditional ratemaking principle. Also the risk between utility and consumer needs to be more properly balanced.

It is my opinion that the margin decoupling tracker fails to provide adequate consumer safeguards. While I appreciate the [C]ompany's effort to address needed safeguards in Mr. Yoho's rebuttal testimony, I still believe it came up lacking.

I also do not believe this docket is the appropriate proceeding that the statute requires. To consider such a dramatic change in rate design as proposed by the [C]ompany, at a minimum, the TRA needs to have current usage and financial data from the [C]ompany and not data almost seven years old from a 2003 rate case where conservation was not considered. Testimony in this case and in my own observations and experience proves to me that much has changed and new facts must be considered.

In my opinion, a rate case would be a more appropriate proceeding because we would have access to up-to-date revenue, financial, customer account and usage data needed to make relevant and valid findings.

While rate cases are expensive, the comprehensive examination of a utility's finances is essential to ensure that a fair and balanced decision is rendered. Piecemeal ratemaking, as is proposed in this proceeding, can lead to the setting of rates based upon incomplete or inaccurate assumptions. Without question, the proposed tariff impacts residential rates and the [C]ompany's risks, which would be more appropriately considered in the context of the TRA's general ratemaking authority through a rate case.

A rate case would allow the Authority to consider alternative rate designs where sufficient consumer safeguards are in place. We could also consider ways to implement any required or needed changes incrementally to reduce any potential rate shock.

I am a true believer in energy conservation and strongly support the statute passed last year by the General Assembly. Energy conservation is good public policy, and the TRA can and should play an important role in encouraging all consumers to better conserve energy.

Achieving [comprehensive energy] conservation requires all participants -- consumers, the private sector, government, and utilities -- to buy in and promote the policy. I look forward to continuing work on implementing state policy.[24]

Director Hill made the following remarks as a part of his deliberations:

At the outset, I would like to say thank you to the TRA staff for the fine work that they've done as we've gone through this process.

And, I want to thank the staff and attorneys for Piedmont Natural Gas, as well as the Consumer Advocate and Protection Division of the Attorney General's Office for their hard work in preparing for this docket [and] for the frank discussion both sides offered to us during this time.

Specifically, I commend everyone for the professional manner in which they conducted themselves through the entire process.

Piedmont spent a great deal of its time, both on paper and during the hearing itself, arguing that Tennessee's recently adopted conservation policy codified in TCA 65-4-126 is a clear statement of policy strongly supporting decoupling.

I agree with the Consumer Advocate that this view is highly unwarranted. There is no evidence that decoupling is the only method by which to achieve the conservation goal set out by the legislature – that the ["]TRA seek to implement...a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently.["]

In fact, the decoupling plan presented by Piedmont may have the opposite effect. A customer's incentive to conserve is getting a lower bill in the mail. Under Piedmont's proposed rate structure, a consumer's usage may decrease – and I say may, because there's no evidence that Piedmont's proposed

[24] *Id.*at 25-28.

conservation programs will have any positive effect – but that consumer's bill may look the same as it did the month before and the month before that or nearly so.

The decoupling plan promoted by Piedmont may be an incentive for the utility to conserve since it will continue earning at a specific return on equity, but the consumers will have no incentive.

Piedmont argues that decoupling will assist in its continuing to earn its approved return. This reason is, as oft-repeated in its briefs and filings, as the previously mentioned conservation policy. If Piedmont were indeed losing profits because of declining usage, why has it not come to the TRA with a traditional rate case before now? Decline in customer usage is not a new trend. It's been going on for a couple of decades.

Piedmont attempts to argue that decoupling is neutral in character, but there's no evidence to support that. The utility points out that decoupling is considered by researchers to be reasonable and enjoys widespread acceptance.

While a number of states may have adopted decoupling, I believe that Tennessee's new conservation policy requires the TRA to look beyond a one-size fits all answer.

As it has been presented to me thus far, I cannot agree that decoupling is beneficial to consumers.

I would like to applaud Mr. Frank Yoho for his testimony regarding the fact that though his [C]ompany has a disincentive to promote conservation, it is simply doing the right thing by promoting conservation. I wholeheartedly agree that it is the right thing to conserve.

I appreciate the conservation programs that Piedmont proposed, but I am concerned that the programs were included as somewhat of a pot sweetener.

For example, Piedmont's weatherization program would only have helped approximately 40 customers a year. For a [C]ompany that serves about 150,000 in Tennessee, the offer seemed a bit lacking, to be only serving 40.

I do sympathize with the plight of Piedmont and other natural gas companies. I understand that competing with other suppliers, particularly electric, is not always a fair contest. Perhaps, then, utilities should look at how to change their business model instead of focusing so singularly on their profit margins.

While the Consumer Advocate attacks Piedmont for presenting its proposal as a sort of a type of "bail-out," I would like to point out that Piedmont does not need a bail-out. It is a well-run company and known to be highly efficient.

> These are difficult times, but I am encouraged by the strength of Piedmont and other utilities such as Piedmont. However, I cannot support a single-issue piecemeal ratemaking using stale numbers from 2003. I encourage Piedmont to address this issue in its next case.[25]

IT IS THEREFORE ORDERED THAT:

1. The *Petition of Piedmont Natural Gas Company, Inc. for Approval of Service Schedule No. 317 and Related Energy Efficiency Programs* is hereby denied.

2. The 2007 PURPA standards shall be addressed by Piedmont in its next general rate case or other proceeding Piedmont initiates with the Authority.

3. Any party aggrieved by the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within fifteen days from the date of this Order.

4. Any party aggrieved by the Authority's decision in this matter has the right to judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within sixty days from the date of this Order.

Mary W. Freeman, Director

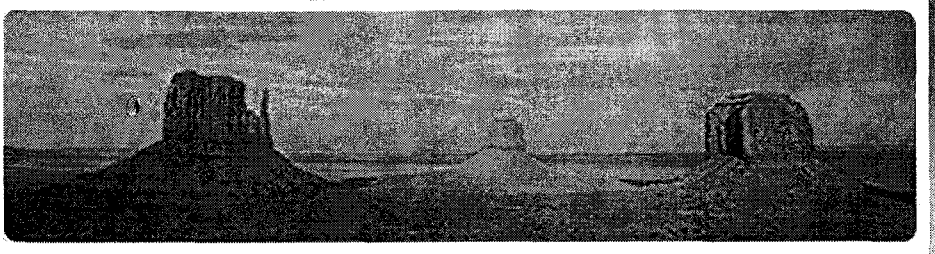
Eddie Roberson, Director

Kenneth C. Hill, Director

[25] *Id.* at 28-32.

EXHIBIT
RUCO 4
ADMITTED

SWEEP
SOUTHWEST ENERGY EFFICIENCY PROJECT



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Ruco-3

SOUTHWEST GAS NYSE-SWX

RECENT PRICE 39.06 | P/E RATIO 16.6 (Trailing: 16.8 Median: 18.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 2.7%

EXHIBIT Ruco 5 ADMITTED

TIMELINESS 3 Lowered 8/20/10
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 5/27/11
BETA .75 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+40%)	11%
Low	35	(-10%)	1%

Insider Decisions

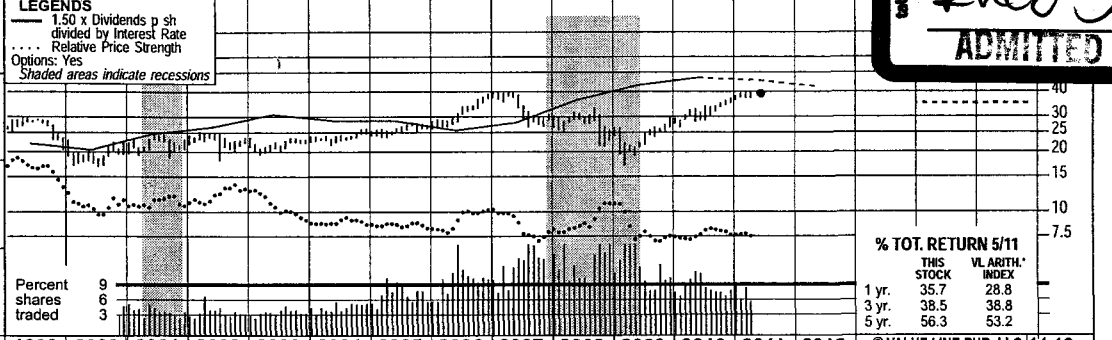
	J	A	S	O	N	D	J	F	M
to Buy	0	0	2	0	0	1	0	0	2
Options	0	0	4	0	2	3	2	0	7
to Sell	0	0	4	0	3	3	2	0	9

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	57	61	60
to Sell	76	75	80
Hld's(000)	32794	32710	33193

High:	23.0	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	29.5	37.3	40.6
Low:	16.9	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	17.1	26.3	36.1

LEGENDS
1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	35.7	28.8
3 yr.	38.5	38.8
5 yr.	56.3	53.2

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.14	*37.85*	*38.00*	Revenues per sh	*48.00*
2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.45	*6.55*	*6.90*	"Cash Flow" per sh	*7.80*
.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	*2.35*	*2.50*	Earnings per sh A	*3.00*
.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	*1.06*	*1.10*	Div'ds Decl'd per sh B■†	*1.25*
6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.72	*4.85*	*5.00*	Cap'l Spending per sh	*6.00*
14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.59	*27.95*	*29.15*	Book Value per sh	*34.00*
24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.60	*46.50*	*48.00*	Common Shs Outst'g C	*50.00*
NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89			Relative P/E Ratio	*1.00*
5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%			Avg Ann'l Div'd Yield	*2.8%*
1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	*1760*	*1825*	Revenues ($mill)	*2400*
37.2	38.6	38.5	58.9	48.1	80.5	83.2	61.0	87.5	104.0	*110*	*120*	Net Profit ($mill)	*150*
34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	*37.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	*6.3%*	*6.6%*	Net Profit Margin	*6.3%*
56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	*47.0%*	*46.0%*	Long-Term Debt Ratio	*45.0%*
39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	46.5%	50.9%	*53.0%*	*54.0%*	Common Equity Ratio	*55.0%*
1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2371.4	2292.0	*2450*	*2600*	Total Capital ($mill)	*3100*
1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	*3150*	*3250*	Net Plant ($mill)	*3600*
5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	5.4%	6.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	*8.5%*	*8.5%*	Return on Com Equity	*9.0%*
1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.1%	5.0%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
71%	70%	72%	49%	65%	42%	44%	63%	48%	44%	*45%*	*44%*	All Div'ds to Net Prof	*42%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $1122.7 mill. Due in 5 Yrs $275.0 mill.
LT Debt $1122.7 mill. LT Interest $72.0 mill.
(Total interest coverage: 3.2x) (48% of Cap'l)
Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/10 $505.6 mill.
Oblig. $708.9 mill.
Pfd Stock None

Common Stock 45,848,692 shs.
as of 4/29/11

MARKET CAP: $1.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	65.3	116.1	108.4
Other	352.3	329.8	281.9
Current Assets	417.6	445.9	390.3
Accts Payable	158.9	165.5	114.5
Debt Due	1.3	75.1	--
Other	314.0	356.4	363.2
Current Liab.	474.2	597.0	477.7
Fix. Chg. Cov.	251%	299%	314%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	5.0%	4.0%	*1.5%*
"Cash Flow"	3.5%	3.0%	*4.0%*
Earnings	3.5%	6.0%	*8.0%*
Dividends	1.0%	2.0%	*4.5%*
Book Value	4.5%	5.0%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	813.6	447.3	374.4	509.4	2144.7
2009	689.9	387.6	317.5	498.8	1893.8
2010	668.8	385.8	307.7	468.1	1830.4
2011	628.4	*365*	*300*	*466.6*	*1760*
2012	*650*	*375*	*310*	*490*	*1825*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.14	d.06	d.38	.71	1.39
2009	1.12	d.01	d.18	1.01	1.94
2010	1.42	d.02	d.11	.98	2.27
2011	1.48	*Nil*	*d.12*	*.99*	*2.35*
2012	*1.50*	*Nil*	*d.10*	*1.10*	*2.50*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.205	.215	.215	.215	.85
2008	.215	.225	.225	.225	.89
2009	.225	.238	.238	.238	.94
2010	.238	.250	.250	.250	.99
2011	.250	.265			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2010 margin mix: residential and small commercial, 86%; large commercial and industrial, 4%; transportation, 10%. Total throughput: 2.2 billion therms. Sold PriMerit Bank, 7/96. Has 4,802 employees. Off. & Dir. own 1.7% of common stock; BlackRock Inc., 8.6%; T. Rowe Price Associates, Inc., 7.2%; GAMCO Investors, Inc., 7.0% (3/11 Proxy). Chairman: James J. Kropid. CEO: Jeffrey W. Shaw. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have traded in a holding pattern over the past three months, following a healthy rebound over the past couple of years. The company posted lower revenues but higher share earnings for the March period.

Mixed performance will likely continue in the coming quarters. The natural gas utility operations will likely continue to experience softness in demand, though this should be partly offset by rate relief in California and modest customer growth. Elsewhere, the construction services subsidiary ought to further benefit from an increase in maintenance and replacement work. Overall, lower revenues will likely be offset by a decline in the cost of gas sold, and we expect a moderate share-net improvement for full-year 2011. Earnings should continue to advance in 2012, assuming utility demand picks up.

Efforts to procure rate relief ought to further benefit performance. Southwest has filed a general rate case in Arizona, requesting an increase in revenues of $73.2 million (roughly 9.3%). The company is also seeking a decoupled rate structure and several programs promoting energy efficiency. A decision on this matter is expected by early 2012. Southwest's focus on rate relief and improved rate design is important, as the company depends on such approved revenue increases to help it cope with rising operating costs and to provide compensation for investments in infrastructure.

Investors should be aware of several caveats. Southwest Gas will likely incur greater operating expenses as it continues to expand going forward. Moreover, warmer-than-normal temperatures during the winter months can result in lower profitability. Insufficient, or lagging, rate relief can also hurt performance.

These shares remain neutrally ranked for Timeliness. Looking further out, we anticipate solid improvement in revenues and share earnings at the company out to 2014-2016. This appears to be partly reflected in the present quotation, and the shares currently trade within our Target Price Range. Moreover, Southwest's dividend yield is below average for its industry group. Investors can probably find more-attractive opportunities elsewhere.

Michael Napoli, CFA *June 10, 2011*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due early August. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	75

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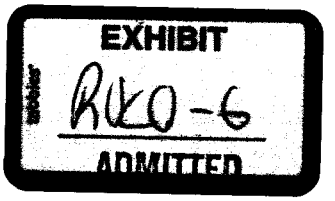
SOUTHWEST GAS CORPORATION



DOCKET NO. G-01551A-10-0458

DIRECT TESTIMONY

OF

BEN JOHNSON, Ph.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 10, 2011

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Appendix A: Qualifications

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. G-01551A-10-0458

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, I have prepared Schedules BJ-1 through BJ-7. These schedules were prepared under my supervision and are attached to my testimony.

Q. What is your purpose in making your appearance at this hearing?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of Southwest Gas Corporation's (SWG's) application for a rate increase. The purpose of my testimony is to present RUCO's revenue requirement recommendation for SWG in this proceeding, taking into account my analysis, as well as that of RUCO's rate of return witness Bill Rigsby.

Following this introduction, my testimony has seven sections. In the first section, I briefly summarize the background of this proceeding. In the second section, I discuss SWG's financial condition and credit ratings. In the third section I briefly summarize and discuss SWG's revenue requirement filing in general terms. In the fourth section, I discuss the rate base adjustments proposed by SWG and I present RUCO's recommendations with respect to those adjustments. In the fifth section, I discuss the income adjustments proposed by the Company and I present RUCO's recommendations with respect to each proposed adjustment. In the sixth section, I discuss the appropriate rate of return to be applied to a fair value rate base taking into account the testimony of RUCO witness Bill Rigsby concerning SWG's cost of capital. In the seventh and final section, I summarize my conclusions and recommendations.

I. Background

Q. Can you briefly discuss SWG's most recent rate case?

A. Yes. On August 31, 2007, SWG filed an application requesting an increase in rates. SWG requested a revenue increase of $57,546,205, and proposed an adjusted original cost rate base ("OCRB") of $1,069,743,402 and a fair value rate base of $1,392,895,487. [Decision 70665, p. 5] Staff and RUCO recommended revenue increases of $28,239,870 and $32,046,846, respectively. [Id.] Staff proposed an OCRB of $1,065,561,602, and a fair value rate base (FVRB) of $1,388,713,687. [Id.] RUCO proposed an OCRB of $1,089,082,745, and a FVRB of $1,463,404,389. [Id.] The evidentiary hearing was held on 7 days beginning June 16, 2008. The Commission determined that SWG had an OCRB of $1,066,107,826 and a FVRB of $1,389,259,911. [Id., p. 8] The Commission further determined that the Company was entitled to a revenue increase of $33,533,844, or 8.4% over adjusted test year revenues.[1] [Id.] The Commission ordered the new rates to become effective December 1, 2008. [Id., p. 60]

Q. Can you now briefly discuss the procedural background of this current case?

A. Yes. SWG's application for a rate increase was filed with the Commission on November 12, 2010. On December 13, 2010, Staff filed a Letter of Sufficiency in the docket indicating that SWG's' application had meet the sufficiency requirements of the Arizona Administrative Code. A Procedural Order was issued on January 11, 2011, setting an evidentiary hearing for September 12, 2011, establishing dates for testimony, and setting a deadline for motions to intervene. The procedural order also granted RUCO's motion to intervene.

1 The Commission determined SWG's adjusted test year revenues to be $399,234,678. [Id., p. 21]

Q. Can you now summarize SWG's Application?

A. Yes. SWG requests a $73.2 million rate increase. If granted, this would represent an increase of approximately 17.8% relative to the adjusted test year revenues (including the cost of gas). [Schedule A-1, Sheet 2] The proposed increase is an even larger percentage of the Company's operating margin (revenues after subtracting the cost of gas). The requested increase is based in part on sales and expenses during the test year, but it also reflects various adjustments to the actual test year results, including certain post-test year adjustments.

SWG is also requesting approval of two deferred accounting orders, and approval of its Arizona Energy Efficiency and Renewable Energy Resource Technology Portfolio Implementation Plan (EE and RET Plan).

> The EE and RET Plan is comprised of 10 energy efficiency and renewable energy resource technology (RET) programs that afford Southwest Gas' customers, including its low income customers, cost-effective opportunities and resources, education and training tools, all of which are designed to promote energy efficiency and conservation, and will result in lower energy bills for customers. [Application, p. 4]

Finally, SWG requests approval of its Energy Efficiency Enabling Provision (EEP). The proposed EEP is a revenue per customer decoupling mechanism which is intended to "better align utility and customer interests so Southwest Gas will be able to sharpen its focus on customer end-use efficiencies and the development of strategies to achieve the Standards established by the Commission". [Id., pp. 8-9] SWG's proposed EE and RET Plan and EEP will be discussed in my rate design testimony, which will be prefiled a few weeks after this testimony was prepared.

II. SWG Financial Situation and Credit Metrics

Q. What information does SWG provide regarding its financial condition?

A. In SWG's prior rate case, the Commission authorized an 8.86% rate of return on original cost rate base (OCRB). [Decision No. 70665, pp. 58-59] The Company claims, however, that during the test year on an adjusted basis, it earned a ROR of 6.06%. [Mashas Direct, p. 3]

> Southwest Gas' current rates and charges, which were approved by the Commission in Decision No. 70665 (December 24, 2008) are no longer sufficient to produce a reasonable return on the fair value of the Company's properties devoted to public service in the state of Arizona ... [Application, p. 4]

The Company has identified three "major factors" contributing to the alleged revenue deficiency: (1) a decline in residential consumption per customer, and the need to set rates based upon current usage levels; (2) a decline in general service customer consumption per customer, and the need to set rates based upon current usage levels; and (3) changes in the Company's cost of capital. [Id., pp. 4-5]

Q. To the extent SWG has not been earning its cost of capital, is this problematic?

A. While there is no expectation that earnings will exactly match a utility's cost of capital or its allowed rate of return, it is not in the public interest for the Company to achieve earnings that are far below its cost of capital or a fair rate of return – particularly if there is reason to anticipate this pattern will be sustained well into the future.

Q. Can you explain how Moody's and S&P rate the Company's credit?

A. Yes. As shown below, Moody's and S&P have established a series of tiers designated by alphanumeric codes to rate corporate securities.

S&P	Moody's
——Investment Grade——	
AAA	Aaa
AA+	Aa1
AA+	Aa2
AA-	Aa3
A+	A1
A+	A2
A-	A3
BBB+	Baa1
BBB	Baa2
BBB-	Baa3
——Speculative Grade——	
BB+	Ba1
BB	Ba2
BB-	Ba3
B+	B1
B	B2
B-	B3
CCC+	Caa1
CCC	Caa2
CCC-	Caa3
CC	
————In Default————	
SD	Ca
D	C

Q. Where does SWG currently fall relative to this list?

A. At the time SWG filed its testimony, the Company's debt obligations were rated Baa2 from Moody's and BBB from S&P, which is toward the bottom of the range of ratings that are commonly referred to as "Investment Grade." [Wood Direct, p. 5]

Q. How do these ratings compare to the ratings in effect during SWG's 2008 rate case?

A. On April 22, 2009 (a few months after SWG's last rate case), S&P upgraded the Company's unsecured bond rating from BBB- to BBB. [Id., p. 6] More than a year later, on May 27, 2010, Moody's followed suit, upgrading SWG's unsecured bond rating from Baa3 to Baa2. [Id.]

Q. Have there been any changes in the Company's debt ratings since SWG filed its testimony?

A. Yes. On April 27, 2011, S&P raised SWG's debt rating by one more notch, to BBB+.

Q. What is the rationale behind S&P and Moody's ratings for SWG, and the recent upgrades in those ratings?

A. According to the Company, the key factors for Moody's rating are "the improvement in the Company's regulatory environment due to authorized decoupling in Nevada and the prospect for approval of a decoupling mechanism in Arizona". [Id.] Likewise, S&P's positive outlook is "based on the assumption of adequate rate relief and improved regulatory support", according to SWG. [Id.]

Q. Do you agree that "improved regulatory support" through an approved decoupling mechanism was the primary factor behind the recent Moody's and S&P upgrades?

A. I agree that both rating agencies consider the Company's overall regulatory environment to be "improving", and that this factored into the Company's current ratings. However, I've not seen any indication the rating agencies are placing substantial weight on this particular policy issue, and other factors are obviously also contributing to the recent upgrades. For example, Moody's provided the following "ratings drivers" for SWG:

- Generally low business risk given dominance of regulated gas distribution operations
- Cautiously optimistic about signs of improvements in historically challenging regulatory environment
- Timely recovery of costs via PGA mechanisms
- Market diversity and high reliance on residential and commercial customers stabilize cash flows
- Moderate capital expenditure plan eases future financing needs
- Credit metrics appropriate for the rating

> [Moody's Investor Service, Credit Opinion: Southwest Gas Corporation, May 27, 2010, p. 1]

Moody's further explains:

> The upgrade follows improvements in Southwest's cash flow credit metrics which we believe will be sustained for the foreseeable future...As of March 31, 2010, the ratio of Southwest's last twelve month cash flow from operations excluding changes in working capital to debt, calculated in accordance with Moody's standard analytical adjustments, had improved to over 20% from approximately 16% for the year ended December 2006. Over the medium term, Moody's anticipates this metric will remain at a similar level. [Moody's Investor Service, Ratings Action: Moody's upgrades Southwest Gas Corp. -- Sr. Unsecured to Baa2, May 27, 2010, p. 1]

S&P summarizes their recent decision to upgrade SWG's rating as follows:

> We are raising our corporate credit senior unsecured ratings on U.S. natural gas distributor and construction services provider Southwest Gas Corp. to 'BBB+' from 'BBB' and revising the outlook to stable from positive. The ratings action reflects improved financial results, and our view that the business risk profile remains excellent given the utility's steady cash flow contribution. The stable outlook reflects our expectation that the company will maintain stable financial metrics. [Standard & Poor's, Research Update: Southwest Gas Corp.'s Ratings Are Raised To 'BBB+' On Good Financial Performance; Outlook Stable, April 27, 2011, p. 1]

Q. To what extent has the issue of decoupling been considered by the rating agencies?

A. Although the references are rather cryptic, both Moody's and the S&P mention decoupling in their recent reports. For example, Moody's states:

> The rating upgrade also recognizes signs of improvements in Southwest's regulatory environment where we remain cautiously optimistic about, primarily in Nevada (34% of operating margins) and potentially Arizona (55% of operating margins). In Nevada, the Public Utilities Commission of Nevada approved the company's request for the implementation of decoupling mechanism in its April 2009 general rate case, pursuant to the decoupling legislation approved in 2008. Furthermore, the Arizona Corporation Commission (ACC) has conducted a series of workshops in

> 2009 and 2010 to evaluate the possibility of implementing a decoupling mechanism in Arizona, and is currently reviewing related proposals submitted by utilities in its jurisdiction, including Southwest. [Moody's Investor Service, Ratings Action: Moody's upgrades Southwest Gas Corp. -- Sr. Unsecured to Baa2, May 27, 2010, p. 1]

Similarly, S&P states:

> We also factor a gradual reduction in the regulatory risks associated with the company's Arizona service territory into our rating. We expect resolution of the company's rate case before the Arizona Corporation Commission (ACC) in early 2012, where the company has requested a $73.2 million revenue increase (return on equity [ROE] of 11%) and regulatory mechanisms, including decoupling. [Standard & Poor's, Research Update: Southwest Gas Corp.'s Ratings Are Raised To 'BBB+' On Good Financial Performance; Outlook Stable, April 27, 2011, p. 1]

Q. Is there reason for the Commission to be worried about SWG's bond rating and credit metrics?

A. In recent years we have recently seen extreme swings in credit markets, triggered by relatively minor changes in the underlying facts. Once perceptions of the credit-worthiness of major institutions like Lehman Brothers or Wachovia turned a bit negative, the shift in perceptions began to feed on itself, leading to rapidly escalating atmosphere of fear and uncertainty, which in turn had very real consequences for these firms and others.

During a financial crisis or tight credit environment, even firms with a solid investment grade bond rating may find it more difficult than normal to issue additional debt or equity. A company with a debt rating toward the low end of the utility industry may find it difficult to fully fund future capital construction programs – bearing in mind that merely offering to pay higher than normal interest rates wouldn't necessarily solve the problem, since the very need to offer such high rates could be perceived as a sign of weakness, pushing away more risk-averse investors and making it harder to raise capital in the future.

SWG's credit ratings are two (Moody's) or three (S&P) notches above the threshold

between investment grade and "speculative" grade ratings, and Moody's and S&P have both offered a "stable" outlook for SWG, indicating that neither agency thinks a downgrade is likely in the foreseeable future. Under the circumstances, the Commission should be sensitive to the Company's bond ratings, but I don't believe it needs to be particularly worried about them.

Q. To what extent should SWG's credit ratings influence the Commission's analysis of the issues in this case?

A. The Commission has no direct control over bond ratings, and it would not be appropriate to skew its decisions in this proceeding toward a particular outcome in the hopes of further improving the Company's bond ratings. Fortunately, SWG's credit ratings do not appear to be in any danger of falling below investment grade levels.

In fact, there is reason to be hopeful that if economic conditions in the state improve, this trend may continue. Any further improvement in SWG's credit ratings could have a positive impact on the interest rates which would be paid by the Company when it needs to raise additional debt capital. In general, as bond ratings improve, the required interest on new issuances tends to decrease, which will can lead to lower costs for customers over the life cycle of the debt issuance.

The Company explains its belief that

> obtaining an "A" bond rating would provide the Company with a greater amount of financial flexibility. The Company would be able to attract capital at reasonable prices during both normal and turbulent market conditions, which have been recently experienced. [Woods Direct, p. 9]

I would agree that any further improvement in the Company's ratings could result in decreased costs associated with future capital improvements. However, as both S&P and Moody's have pointed out, the Company's future capital expenditure plans are moderate, and can be largely financed through internal cash flows. The benefit of any reduction in interest rates primarily

shows up when new debt is issued.

In any event, the Commission should not let the potential for a further improvement in the Company's credit ratings drive the results of this proceeding, nor should it cause the Commission to accept inappropriate ratemaking proposals in a misplaced effort to improve SWG's bond ratings. I believe a vigilant and appropriately balanced regulatory regime is ultimately in everyone's best interest. For regulation to work as intended, management of monopolies cannot be given a blanket promise of immediate, full recovery of any and all costs they have incurred, or anticipate incurring. The regulatory process should serve as a substitute for effective competition; thus, for example, it is appropriate to closely scrutinize the Company's application to identify a normalized level of reasonable, prudently incurred costs – costs which are appropriate for consideration in determining rates to be paid by customers – rather than simply passing through whatever cost levels are proposed by the Company in its filing.

III. SWG's Filing: An Overview

Q. Is SWG proposed revenue requirement based upon the actual test year results?

A. No. A substantial portion of the proposed rate increase can be traced to various proposed adjustments. For example, SWG has proposed to include in its rate base certain construction investments the Company describes as "Completed Construction Not Classified". This series of adjustments increases its proposed rate base by a total of $6,090,567. [Schedule B-1] Similarly, SWG has proposed numerous adjustments to its actual test year operating income. These adjustments collectively result in a $16,524,664 decrease in operating margin and a $10,157,812 increase in operating expenses prior to tax effects, relative to the actual, unadjusted test year results. After taxes, these adjustments translate into a $16,039,330 decrease in

calculated net operating income, relative to the actual income experienced during the test year. [Schedule A-1]

Q. Can you explain the concept of pro forma adjustments, in general terms?

A. Yes. Although terminology can vary, test year adjustments can be classified into various groups, based on the underlying purpose or theoretical basis for making the adjustment. For example, pro forma adjustments can be categorized into three major types: normalizations, annualizations and eliminations. Using this terminology and classification schema, normalization adjustments are typically made when the recorded test year operating revenues and expenses are believed to not be representative of a normal level for ratemaking purposes. Annualization adjustments are made to reflect a full 12-month revenue or expense level for items that were not in effect throughout the entire test year; typically this is done by applying end-of-test-year quantities to known and measurable prices and rates as of the end of the year. Eliminations are made to remove out-of-period or non- recurring transactions, or items that are not costs or revenues related to the provision of utility service.

Many of the Company's proposed "annualization" adjustments are designed to bring costs and revenue to an end-of-test year basis, while others update costs beyond the test year, to reflect the impact of additional investment, inflation or cost changes which weren't placed into service or didn't occur until after the test year. While making "annualization" adjustments for "known and measurable" cost increases is a popular method for dealing with the closely related problems of inflation and regulatory lag, this method tends to be arbitrary and controversial, particularly when attempts are made to select a cut-off date or annualization data that goes beyond the end of the test year. Regardless of how well known or measurable a particular cost change may be, it is difficult to achieve internal consistency and an appropriate "matching" of revenues and costs when the adjustments go beyond the test year.

Q. Can you elaborate on the "matching" principle, and RUCO's concerns about "known and measurable" adjustments?

A. Yes. RUCO recognizes that the Commission, as a matter of policy, has decided to rely upon a historical test year approach, rather than using a projected test year. However, RUCO believes it would be better policy to stay within the parameters of the historical test year, and to generally reject ad hoc adjustments stretching beyond the historical time period. In other words, if the Commission isn't satisfied with the result of using the historical test year, it should not assume that a long series of adjustments to the historical data will somehow "improve" upon, or overcome the weaknesses of, the historical test year. To the contrary, RUCO believes that an historical test year that is heavily adjusted tends to be arbitrary and subjective, and the end result may be a less reliable basis for setting rates than would be an appropriately developed and thoroughly validated projected future test year.

I recognize that this Commission, and other regulators, have long accepted the practice of modifying the historical test year in an attempt to solve concerns about the impact of inflation and other trends. However, adopting adjustments for "known and measurable" changes within and beyond the test year is an inherently difficult and controversial process. Should the Commission only consider "known and measurable" changes which occurred during the test year? Or, should the Commission go a few weeks, or perhaps as much as 6 months beyond the test year? These are vexing questions that are never answered the satisfaction of all concerned. While it is understandable why the Commission has sometimes gone beyond the end of the test year, in my opinion, this is not a good practice, nor is it the preferred solution to dealing with inflation, under-earnings, or allegations of attrition. Among other problems, as more and more adjustments pile up, stretching farther and farther beyond the test year, it becomes increasingly arbitrary to pick and choose adjustments, or to select a specific cutoff date. As well, the mismatch between revenues and expenses tends to become increasingly

severe, and it becomes harder to ensure that all of the adjustments are fully known and accurately measurable, and to ensure that the final result is a realistic and representative snapshot of the Company's actual operations – rather than a distorted hypothetical picture which is largely a function of the adjustment development and advocacy process.

To its credit, in its filing the Company mostly focuses on the actual test year, and many of its adjustments are relatively uncontroversial, at least in principle (e.g. it is better to base rates upon typical, rather than atypical, weather). However, the Company makes some important exceptions, in which it proposes adjustments that are calculated using various dates that go past the test year. No overarching principle has been put forward to justify the particular mix of adjustments and dates, and in my view the end result is not an improvement over an analysis which focuses on the Company's actual operating experience during the test year. There is no assurance that the end result of a series of post-test year adjustments will be reasonable, or representative of actual conditions that can reasonably be anticipated in the future.

Admittedly, some of the same criticisms can be applied to adjustments for "known and measurable" changes that occurred within the test year. But, once the line is crossed and adjustments are made beyond the end of the test year, the tendency is to pile up more and more adjustments, extending farther and farther beyond the test year. In turn, the entire exercise tends to degenerate into an arbitrary, ad hoc, and ultimately unsound process of picking and choosing items to be included in the adjustment process, as well as picking and choosing the specific dates to be used in developing each of the accepted adjustments. As well, the more one goes beyond the actual test year experience, the less confidence can be placed in the underlying premise that the test year represents a realistic, representative snapshot of the Company's actual revenues, costs, and income – undermining the fundamental rationale for using an historical test year approach in the first place.

Q. What is your recommendation concerning pro forma adjustments for "known and measurable" changes?

A. Rather than debating the merits of a long series of actual and potential "known and measurable" adjustments in isolation, one-by-one, or attempting to put forward an alternative ad hoc mixture of such adjustments, my general approach has been to start with a specific cut-off date, and to remove all of the proposed adjustments that are inconsistent with that cut-off date.

More specifically, I recommend using a June 30, 2010 cut off date, because this comes the closest to the Company's proposals while staying within the confines of the test year ending June 30, 2010. In other words, I recommend accepting proposals to adjust for wage increases and other changes which went into effect during the test year, but to reject all such adjustments to the extent they relate to changes which occurred after the end of the test year. For example, I recommend that the Commission only allow into rate base plant that has been placed in service on or before June 30, 2010.

It is worth noting that by choosing a specific adjustment cut-off date within the test year, and by disallowing adjustments for events that occurred after that date, the matching principle is better achieved, and a greater degree of internal consistency and discipline is imposed. Selecting a specific cutoff date is not as arbitrary an exercise as selecting individual adjustments to include or exclude on some arbitrary basis, like whether there is adequate precedent for that particular type of adjustment, whether enough is "known" about the change in question, or whether the calculations were sufficiently precise and reliable. Any specific cutoff date will sometimes work for, and sometimes work against, the Company's favor. Some potential adjustments will relate to events beyond the cutoff date that, if they were allowed, would have the effect of increasing the calculated revenue requirement, but other potential adjustments will have the opposite effect – potentially reducing the calculated revenue requirement.

IV. Rate Base Adjustments

Q. Can you now briefly explain how SWG develops its adjusted Original Cost Rate Base?

A. Yes. SWG begins with the recorded levels of Gas Plant in Service as of the the end of the test year. This consists of $2.25 billion of Arizona-specific plant and $101.3 million in system allocated plant. [Schedule B-1] SWG then subtracts $955.2 million in accumulated depreciation and amortization, resulting in $1.4 billion Net Plant in Service. SWG then modifies this amount to account for "other rate base items". First, SWG adds $10.2 million to account for working capital [Id.] Next, SWG removes $62 million in customer advances, $48.5 million in customer deposits, and $230.7 million in deferred taxes – amounts that represent funds provided by customers, rather than investors. [Id.] The net result is a test year rate base of $1.068 billion. [Id.]

Q. Does SWG make any adjustments to its test year rate base?

A. Yes. As I mentioned earlier, SWG adjusts Gas Plant in Service (GPIS) by adding and removing various amounts related to Completed Construction Not Classified (CCNC). First, SWG adds tangible plant expenditures that were made during the test year, for plant that was not booked to GPIS until after the test year. [Mashas Direct, p. 21] The gas plant included in this step of this adjustment "was either in-service at the end of the test year or shortly thereafter". [Id.] These plant balances were included in Construction Work in Progress (CWIP) at the end of the test year. [Id.] SWG argues that none of this plant is revenue producing. [Id.] The result of this portion of the adjustment is a $2.8 million increase to rate base. [Schedule B-1]

Second, SWG modifies system allocable intangible plant by removing "all projects with an amortization period expiring March 31, 2011 or earlier from rate base," and adding "estimated amounts for projects to be closed to plant prior to March 31, 2011 to rate base". [Id.,

p. 22] The result of this portion of the adjustment is a $3.3 million increase to rate base. [Schedule B-1] The total effect of this CCNC adjustment is a $6.09 million increase to test year rate base. [Id.]

Q. When was the tangible plant portion of this adjustment placed into service?

A. Although the underlying expenditures were made during the test year, during the discovery process SWG disclosed that many of the associated plant items were not placed into service until after the test year. [See, SWG response to Staff DR 6-7(a) and included attachment] Of the 40 tangible plant projects included in this adjustment, 9 projects totaling $576,000 involved plant that was apparently placed into service during the test year, but the investment was not transferred to GPIS until a later date. [Id.] Another 29 projects, totaling $2.1 million, involved plant that was not placed into service until after the test year. The last of these projects was placed into service on January 14, 2011. [Id.] The remaining 2 projects, totaling $110,000 were removed by SWG during the discovery process because they involved "work orders that have not closed". [Id.]

Q. Do you agree with this portion of the CCNC adjustment?

A. No. In effect, SWG is attempting to include CWIP in rate base – albeit construction that was completed shortly after the test year. The Commission has explained that CWIP is generally not allowed in rate base, except under extraordinary circumstances. [See, Decision 70360, p. 8] For example, in Decision 70360, UNSE was denied inclusion of CWIP because UNSE was not faced with an extraordinary situation. [Id.] The Commission further noted that UNSE achieved a return on its CWIP investment during the test year through the accrual of AFUDC; it noted that allowing CWIP in rate base tends to undermine the balancing of test year revenues and expenses; and it pointed out that regulatory lag can be both a benefit and determent to UNSE.

[Id.] In the alternative, UNSE requested post test year plant be included in rate base. [See, Id.] With regard to UNSE's alternative post test-year plant request, the Commission concluded that "post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP". [Id., p. 9]

In my opinion, the appropriate policy is to use AFUDC to compensate the Company for its investment in construction projects before they are completed and transferred into plant in service, and there is no need to make an exception to this policy. This approach provides a more consistent and conceptually sound approach to rate making. It is a policy that provides a clear delineation between the period when construction is occurring and the period when an investment is in service and providing benefits to customers. And, it is a policy that better balances the interests of customers and stockholders, as well as one that better balances the interests of different generations of customers. I recommend the Commission reject the Company's proposed adjustment, because it deviates from this sound policy, and it does so under ordinary – not extraordinary – circumstances.

Q. Can you please elaborate on the reason why you recommend rejection of this proposal?

A. Yes. While the Company describes these investments as not producing revenues, this is irrelevant at best, and misleading at worst. The effect of including these construction projects in rate base would certainly not be revenue neutral – it would increase the rate base, and if it were approved, this proposal would increase revenues received by the Company and the bills paid by customers. More importantly, there is nothing extraordinary about these investments; these assets are not unlike many other assets that are routinely acquired by utilities in the ordinary course of business, benefiting both existing and future customers. I am not questioning whether these investments are worthwhile, but whether they require extraordinary post-test year treatment. I see no evidence that special treatment is warranted for the items that

were not placed into service during the test year.

The Commission should bear in mind that even if the proposed adjustment is rejected, the Company will be adequately compensated for its investment. For instance, during the test year it received AFUDC on this investment. While AFUDC treatment ends once the property is placed into service, that doesn't mean customers won't be compensating the Company for its investment. To the contrary, these projects are taking place in the ordinary course of business, and the Company receives substantial cash flows from customers as compensation for these sorts of costs – both in terms of recovering its cost of capital, and in terms of payments from customers as compensation for depreciation – cash flows that provide funds that can be used to replace existing plant and invest in projects that may or may not directly and immediately contribute to growth in the Company's revenues. To the extent any specific investments are not sufficiently offset through depreciation, reduced operating expenses, or increased revenues, any associated income shortfall will be short lived, since the investments will be included in Gas Plant in Service, and thus will be included in the rate base that is calculated in future rate cases.

In general, RUCO believes it is inappropriate to modify the historical test year for some, but not all, of the impacts of post-test year events. Among other reasons, it is impossible to know precisely how specific assets will impact the Company's operating costs. In some cases, new investments may enhance safety, making it feasible to reduce maintenance and other operating costs. In some cases, costs may decline as a direct or indirect result of new construction, as older equipment is reinforced or replaced with new plant additions that increase reliability, reduce the need to incur extraordinary labour costs to provide safe and reliable service, or make it feasible to maintain adequate pressure at lower cost.

It isn't feasible to analyze all of the repercussion and implications of each investment made during the test year – nor is there any need to do so when an appropriate test year is established and used on a consistent basis, since it is reasonable to assume that the test year

represents a reasonable representation of future conditions, where all factors – both good and bad – are taken into consideration. There is no justification for violating the matching principle which is a fundamental underpinning of the historical test year approach to ratemaking, by selectively reaching beyond the test year include the cost of new construction projects, while ignoring other things that occur after the test year, including the continued decline in net plant in service through the accumulation of additional depreciation, as well as the benefit of operating cost decreases and efficiency increases which will occur after the test year.

In sum, as a matter of sound public policy, as long as the Commission continues to use an historical test year, it should reject proposals to include in rate base investments which were not actually completed and placed into service during the test year. I believe it is preferable to adopt a uniform, consistent cut-off based on the end of the test year. Accordingly, I recommend only accepting the portion of this proposed adjustment which relates to the items which were placed into service during the test year. As shown on Schedule BJ-2, this portion of the proposed adjustment increases rate base by $575,976.

Q. Do you agree with the intangible portion of SWG's CCNC adjustment?

A. No. SWG is adjusting its rate base for intangible plant additions that were not anticipated to be in service until as much as 10 months after the end of the test year, and for intangible plant projects with an amortization period expiring as much as 10 months after the end of the test year. I have excluded this portion of the adjustment for the same reasons that I excluded the post test year tangible plant portion of this adjustment.

V. Income Adjustments

Q. Let's discuss SWG's proposed income adjustments. Can you begin by commenting on SWG's first income adjustment?

A. Company witness Mashas states that witness A. Brooks Congdon covers SWG Adjustment No. 1 (as well as Adjustment No. 2). However, Mr. Congdon primarily discusses the Company's cost of service study, and he does not specifically address Adjustment No. 1. In any event, SWG's first income adjustment, "Revenues and Volumes" appears to primarily be intended to adjust the test year non-gas revenues (margin) to reflect 12 months of consumption under "normal" weather conditions. Witness Cattanach explains Adjustment No. 1 is actually the composite result of five different sets of adjustments:

> After compiling the recorded number of bills and therms for the test year, Southwest Gas made the following adjustments in order to derive the adjusted test year billing determinants: (1) billing adjustments; (2) customer specific volume annualizations; (3) customer reclassifications; (4) weather normalizations; (5) customer annualizations. ... The purpose of the five adjustments is to ensure that Southwest Gas's test year number of bills and volumes accurately reflect a full 12 months of consumption under normal weather conditions for the development of revenues and proposed rates. [Cattanach Direct, pp. 2-3]

Q. How does SWG describe these five sets of adjustments?

A. The billing adjustments involved adjusting monthly consumption for customer bills, to correct "significant billing anomalies". [Id., p. 3]

> This adjustment is necessary to ensure that the monthly adjusted volumes accurately reflect actual test year consumption. Otherwise, distorted monthly values would reduce the reliability of the regression analysis associated with the weather normalization adjustments ... [Id.]

The volume annualization adjustments were performed to "reflect a full year of consumption for each active customer (excluding residential and small commercial customers) billed during June

2010". [Id.] Additional consumption was estimated for months during the test year "where a new customer was not on-line or was clearly in a start-up phase". Consumption was removed for customers who discontinued service during the test year. [Id., pp. 3-4]

The customer reclassification adjustments move certain customers between rate schedules, to reflect a full 12 months of usage under the correct rate schedule that was applicable at the end of the test year. According to SWG, reclassification adjustments do not impact the overall number of bills or volumes for the test year. [Id., p. 4]

The weather normalization adjustments involve adjusting heat sensitive consumption per customer "to provide an accurate representation of monthly test year volumes under normal weather conditions". [Id., p. 4] According to SWG, actual billing cycle heating degree days during the test year were 7.1 percent colder than "normal" in Tucson, and 6.6 percent colder than "normal" in Phoenix. [Id.] To develop the "normal" number of heating degree days, SWG used a ten-year average for the 120 months ended June 2010, adjusted for outliers. The net result of the weather normalization adjustments was a decrease in test year volumes of 16,064,337 therms. [Id., p. 6]

The customer annualization adjustments were made by comparing the number of customers in the last month of the test year to the same month of the prior year. The customer growth was then

> prorated across the test year in declining intervals with 11/12ths of the adjustment in the first month of the test year (July 2009), 10/12ths in the second month (August 2009) and so forth. Adjustments to annualize volumes were made by multiplying the monthly customer additions by the respective monthly weather-adjusted average use per customer. Customer and volume adjustments are then added to the weather-normalized monthly bills and volumes to produce annualized test year monthly bills and volumes. [Id., p. 7]

Q. What was the overall net effect of these five sets of adjustments?

A. SWG's test year operating margin was $427,436,762 as recorded on in its account records. [Schedule C-1, Sheet 1] After making these five adjustments, SWG computed an adjusted test year margin of $410,912,098. [Schedule H-2, Sheet 8] The $16,524,664 difference is reflected in the proposed revenue requirement calculations through its proposed Adjustment No. 1.

Q. Schedule C-2 shows a $423,844,760 reduction in revenues for Adjustment No. 1. Why is that?

A. Since SWG calculated adjusted margin, Adjustment No. 1 also includes a reduction in revenues to exclude actual test purchased gas cost of $407,320,096. These gas costs are subsequently added back through Adjustment No. 2.

Q. What is your conclusion regarding these adjustments?

A. These types of adjustments are fairly common in ratemaking proceedings, and they are generally consistent with the underlying purpose of using a historical test year, which is simply a device for analyzing the normal level of revenues and costs which can be expected in the future. However, I do have some concerns about the proposed calculations. In particular, it seems odd to replace the actual test year results with hypothetical calculations based upon "normal" weather based on just ten years of data. Since weather patterns can vary widely from one year to the next, it is not unreasonable to attempt to "normalize" the test year based on typical weather conditions. But, it would be more appropriate to develop such calculations based upon a longer time period than just the past 10 years – since even a ten year period can be warmer, or cooler, than normal.

Q. What was actual weather like during the test year?

A. According to data supplied by SWG, there were 1,542 heating degree days in Tuscon during the test year, and 951 heating degree days in Phoenix during the twelve months ended June 2010. [SWG Response to RUCO DR 6-1 and included attachment] Heating degree day (HDD) is a standard measurement of the demand for energy needed to heat a home or business. Heating degree days are defined relative to a base temperature - typically the outside temperature above which a building needs no heating. For example, if the baseline temperature is 65 degrees, and the average ambient (outside) temperature during a given day is 55, that day will result in a calculated HDD of 10. HDD can be added over time; for instance, the HDD for each day during a month can be summed, to arrive at the total HDD for a particular month, and the process can be repeated for all 12 months to develop the total HDD for a given year. In turn, the HDD-based estimate of the heating requirements during any given 12 month period can be compared to the analogous number for a "normal" year, to determine the extent to which heating demand during the time period in question was larger or smaller than normal.

Q. Have you compared the Heating Degree days during the test year to those proposed by the Company, based upon an adjusted 10-year average?

A. Yes. As shown in the table below, the Company started with the 10-year average, which it then adjusted to remove certain alleged "outliers", resulting in a claimed "normal" level of 1,440 HDD for Tuscon, and 904 HDD for Phoenix. [Id.] The actual test year HDD for Tucson was 102 HDD greater than SWG's proposed "normal" HDD based on its proposed adjusted 10-year average; a difference of 7.1%. Similarly, during the test year the HDD for Phoenix was 59 HDD greater than SWG's proposed 10-year adjusted average, a difference of 6.6%.

Q. Do you agree with the Company's approach to this issue?

A. No. I agree the test year was a bit colder than normal, and I agree it would be reasonable to adjust the test year based upon a reasonable measure of "normal" weather. However, I don't agree with the specific calculations put forth by the Company. First, I think 10 years is too short a period to develop a reliable estimate of normal weather. Second, the proposed adjustment to remove supposed "outliers" has the effect of distorting the calculations, pushing the so-called "normal" measure of HDD farther from a true norm.

The problem is shown in the table below:

	Tucson CHDD	Test Year Difference	Phoenix CHDD	Test Year Difference
Test Year	1,542		951	
SWG Adjusted 10-Year Average	1,440	7.1%	892	6.6%
10-Year Average	1,458	5.8%	904	5.1%
15-Year Average	1,450	6.3%	922	3.1%
20-Year Average	1,444	6.7%	924	2.8%
25-Year Average	1,438	7.2%	922	3.1%
30-Year Average	1,465	5.2%	923	3.0%

Source: SWG Response to RUCO DR 6-1

As shown in the table, the unadjusted 10 year average for Tucson was 1,458 HDD – just slightly higher than the 15 year average of 1,450, the 20 year average of 1,444 and the 25 year average of 1,438. The unadjusted 10 year average is a bit lower than the 30 year average of 1,465. I would argue that a 10 year period is too short to consistently provide a reliable estimate of "normal" weather. The Company apparently agrees, since it felt compelled to adjust the actual 10 year data to remove certain alleged "outliers." Whatever the merits of their reasoning, the end result is not appropriate – their proposed adjustment to the data results in numbers that are clearly not normal – particularly for Phoenix. More specifically, the Company is proposing to replace the 10 year average with an adjusted figure of 892 HDD for Phoenix,

which is lower than the actual 10, 15, 20, 25 and 30 year averages.

The unadjusted test year data reflects the impact of gas sales attributable to the actual HDD of 1,542 and 951 in Tucson and Phoenix respectively. When compared to other time periods, it is apparent that the test year was somewhat colder than normal – but the extent of the discrepancy varies, depending on the specific time period used for the evaluation. For instance, the test year HDD were 5.8% and 5.1% colder than the unadjusted 10 year average, for Tucson and Phoenix, respectively. However, the test year HDD were 6.7% and 2.8% colder than the unadjusted 20 year average, for Tucson and Phoenix, respectively.

In essence, the data confirms that the test year was a bit colder than "normal" and thus people in Phoenix and Tucson undoubtedly used somewhat more gas than "normal" during the test year. However, the Company is going too far with its proposed adjustment, creating an unrealistic picture of a test year in which the weather was unusually warm and balmy during the winter, creating hypothetical condition in which people use relatively little gas. The effect of this proposal is to spread the Company's test year operating costs over an artificially small volume of gas, translating into higher than appropriate proposed rates. If approved, this will allow the Company to recover its revenue requirement over an artificially low volume of gas – one which is lower than the actual volume used during the test year, as well as one that is lower than the volume which will likely occur in future years – assuming weather patterns in the future are similar to the actual long term averages reflected in the above table.

Q. If the Commission wants to adjust the test year to reflect normal weather, what time period do you recommend be used to develop the adjustment?

A. I recommend using the 30-year average. This provides better, more stable measure of "normal" weather. However, I would not object to using a somewhat shorter time period, such as the 20-year average. Either way, I recommend relying on the actual, unadjusted historical data for the

time period in question, thereby avoiding the need to debate whether or not particular bits of data represent an anomaly, which justifies removal from the data as an "outlier". As well, with a longer time period, even if someone insists on removing outliers, the impact of this step will be relatively modest, since you are working with a larger body of data, in which any one outlier will have relatively limited impact.

Q. Have you estimated the impact of revising Adjustment No. 1 to reflect the use of a more appropriate measure of "normal" weather, based upon a longer time period than ten years?

A. Yes. I have estimated the impact of using a 30-year weather average, rather than the Company's adjusted 10-year average. As shown on Schedule BJ-5 column (A), my estimate for this adjustment works out to $420,471,656. Keep in mind that this adjustment is calculated residually. It is the difference between test year gross revenues and adjusted margin. The adjusted margin of $414,285,202 is shown Schedule BJ-4, column (C). The adjusted margin was estimated using the 30-year weather average, and compares to SWG's adjustment margin of $410,912,098.

Q. Can you now discuss SWG's second income adjustment - Purchased Gas Cost?

A. Yes. As I just mentioned, this adjustment simply adds back recorded test year purchased gas costs, and is consistent with the methodology used to develop Adjustment No. 1. Accordingly, I have included this adjustment on Schedule BJ-5.

Q. Can you now discuss SWG's third income adjustment - Labor/Loading Annualization?

A. Yes. This adjustment consists of a $7,852,483 increase to operating expenses. [Schedule C] This adjustment includes a salary annualization component for all employees with salaries in

effect at the end of the last pay period beginning prior to June 30, 2010, and a similar labor loadings annualization component. The adjustment also includes "an estimated 1.5 percent general wage increase to be effective in June 2011, along with additional wage increases as a result of within-grade movement during the twelve months subsequent to the end of the test year." [Aldridge Direct, pp. 6-7]

Q. What is your conclusion regarding this adjustment?

A. I disagree with the portion of this adjustment that is based upon pay increases that went into effect after the end of the test year. Accordingly, I have incorporated a similar adjustment in my revenue requirement analysis which excludes the portions of the Company's proposed adjustment attributable to the post test-year wage increases. This modified adjustment results in a $5,707,094 increase to operating expenses, as shown on BJ-7, page 1 in column (C), rather than the $7.9 million increase proposed by the Company.

Q. Can you now discuss SWG's fourth income adjustment - Call Center and Support Allocation and Annualization?

A. SWG explains there are two parts to this adjustment. One part allocates a portion of the call center and customer support costs (which are incurred on a systemwide basis) to Arizona customers. The other part is an annualization adjustment, to reflect the impact of contract employees who were present at the end of the test year, "to synchronize with the number of Company call center employees at the end of the test year". [Id., p. 9] This adjustment increases operating expenses by $690,350. [Schedule C-2] SWG proposed a similar adjustment in its previous rate case; it doesn't seems to have been disputed by the parties, and apparently was accepted by the Commission. I have included it in my recommended revenue requirements, as shown on BJ-7, page 1 in column (D).

Q. Can you now discuss SWG's fifth income adjustment - Cost of Service Analysis?

A. This adjustment results in a $252,777 increase in operating expenses. [Schedule C-2] This appears to be something of a catch-all adjustment which includes: 1) the removal of certain costs for which SWG is not requesting recovery; 2) an adjustment to ensure "a full year's worth of expense is reflected, no more and no less"; 3) annualization of certain items with significant cost changes; and 4) removal of material, non-recurring costs. [Aldridge Direct, p. 10]

Q. What do you conclude regarding this adjustment?

A. The process by which SWG calculated this adjustment is not entirely clear to me, and I have not studied it in depth. However, the adjustment does not seem to go beyond the end of the test year and it appears reasonable based on the provided description. I have included it in my recommended revenue requirements, as shown on BJ-7, page 1 in column (E).

Q. Can you now discuss SWG's sixth income adjustment - Employee Vehicle Compensation?

A. This adjustment reduces operating expenses by $227,232. [Schedule C-2] The adjustment removes from test year expenses the cost of Company vehicles related to personal use by employees. [Aldridge Direct, p. 11]

Q. What do you conclude regarding the vehicle compensation adjustment?

A. This adjustment appears reasonable, and I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 1 in column (F).

Q. Can you now discuss SWG's seventh income adjustment - Uncollectible Expense Annualization?

A. SWG explains:

> Adjustment No. 7 annualizes the recorded amounts in Account 904, Uncollectibles Expenses, to reflect the test year net closing bill write-offs as a percentage of gross revenues. The write-off percent applied to present revenues determines the annualized amount, which is then compared to the recorded uncollectible expense to determine the adjustment amount. [Aldridge Direct, p. 11]

The proposed adjustment consists of a $436,181 increase to operating expenses. [Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. The write off percent the Company is using is 0.2543%, which appears to be reasonable, and is consistent with the Company's historical experience.

Q. Can you now discuss SWG's eighth income adjustment - Leak Survey and Repair?

A. This adjustment reduces operating expenses by $178,871. The adjustment reduces test year accelerated leak survey and leak repair expense related to Aldyl A and Aldyl HD pipe. SWG states that this adjustment is consistent with prior Commission decisions. [Aldridge Direct, p. 11]

Q. What is your conclusion regarding this adjustment?

A. I have not studied this adjustment in depth, but it appears reasonable. I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 1 in column (H).

Q. Can you now discuss SWG's ninth income adjustment - Injuries and Damages?

A. SWG explains: "Adjustment No. 9 adjusts the recorded self-insured accruals charged to Account 925 (Injuries and Damages) during the test year to a normalized level". [Id.] The

Company uses a ten-year average of self-insured amounts to normalize its injuries and damages expense. [Id. p. 13] The effect of the adjustment is a $689,621 increase in operating expenses. [Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. By using a 10 year average of self-insured accruals, SWG's approach is generally consistent with the methodology approved by the Commission in the Company's last rate case. The Commission explained: "We agree with Staff that the 10-year normalization of recorded injuries and damages expenses for Southwest Gas is an appropriate means of calculating the Company's likely pro forma expenses for the period rates will be in effect from this case". [Decision 70665, p. 14]

However, in that case the Staff recommended, and the Commission approved, the removal of one extraordinary item. The claim involved an incident in 2005 when a leaking gas fire severely burned several people, and resulted in a $10 million settlement paid by SWG. [Id., p. 13] Staff argued that the payment represented an abnormal expense that was not likely to be experienced in the future. [Id., p. 14] The Commission agreed: "We believe Staff has presented a reasonable analysis of the issue by excluding the costs for what appears to be an extraordinary event that occurred in 2005, but is not likely to occur on a going-forward basis". [Id.]

I conclude that injuries and damages expense should again be calculated in the manner approved by the Commission in Decision 70665, using a long term average that excludes the extraordinary payment made in 2005. During the discovery process, SWG recalculated its injuries and damages expense (Account 925) in a manner consistent with Staff's approach in the prior rate case. [See, ACC-STF-6-12 Injuries and Damamges.xlsx, provided in response to Staff DR 6-12] As shown on those calculations, SWG's injuries and damages expense during the test year was $7,229,013. These total Account 925 expenses include the reserve for self insurance,

as well workman's comp expenses, legal and other costs. The Company proposed $7,918,534 for Account 925, resulting in SWG's $689,621 pro forma adjustment. Using Staff's methodology from the prior case, SWG calculated $7,411,513 for Account 925, which would require a $182,500 adjustment to the test year injuries and damages expense, rather than the $689,621 adjustment requested by the Company. As shown on Schedule BJ-5, I have included this smaller adjustment in my revenues requirements analysis.

Q. Can you now discuss SWG's tenth income adjustment - American Gas Association (AGA) Dues?

A. SWG adjusts its AGA dues expense by removing $16,324, which is the portion of the dues allocated to Arizona that SWG estimates is attributable to AGA's lobbying efforts. [Aldridge Direct, p. 14] The adjustment is based on an estimate that 6.09% of AGA's budget is used to fund lobbying efforts. [See, Schedule C-2, Adjustment No. 10, Sheet 1]

Q. What is your conclusion regarding this adjustment?

A. I disagree with SWG's exclusion of just 6.09% of AGA dues. This exclusion is not sufficient, in my opinion. I say this for two primary reasons. First, a large, but indeterminate, portion of AGA's activities are designed to influence government policy, both directly (supporting industry lobbying and public relations efforts with respect to Congress and various State and Federal agencies) and indirectly (through various types of policy studies and research which support those efforts). The Company has focused on a narrow subset of this overall range of activities – those which are most directly related to influencing legislation, but the entire range of activities is primarily the responsibility of, and for the benefit of, stockholders.

Second, this organization's activities would continue whether or not SWG or any other Arizona utility belongs to the organization, or contributes to the budget for these activities.

Thus, it is hard to say these costs are necessary for the Company to incur, or that membership offers any significant benefits to the Company's ratepayers. Taking both of these problems into account, I recommend that ratepayers be required to bear no more than a reasonable portion of these dues.

Q. What percentage of AGA dues did the Commission allow in SWG's previous rate case?

A. The Commission accepted Staff's recommendation to disallow 40% of AGA dues as a reasonable approximation of the amount for which ratepayers receive no benefit. [Decision 70665, p. 12] Staff's recommendation was based on two NARUC sponsored "Audit Reports of the Expenditures of the AGA", as well as information provided in AGA's 2007 and 2008 budgets. [See, Smith Direct, Docket No. G-01551A-07-0504, p. 42] As explained by the Commission:

> Staff claims that its recommended 40-percent disallowance is consistent with a March 2005 NARUC Audit Report that quantified AGA function categories that Staff believes should not be paid by ratepayers. The categories cited by Staff are: Public Affairs (24.13 percent); Corporate Affairs and International (10.54 percent); half of General Counsel and Corporate Secretary (2.6 percent); and Marketing (2.37 percent). (Id. at RCS-2, Sched. C-6.) Staff contends that the 39.64-percent total represented by these activities supports its recommended disallowance. Moreover, according to Mr. Smith, based on the 2007 and 2008 AGA budgets, the recommended dues disallowance would be 13.29 percent and 46.19 percent, respectively. [Decision 70665, p. 12]

Q. Did SWG provide any recent AGA budget information that would allow a similar computation as those provided by Staff in the prior rate case?

A. Yes. During the discovery process, SWG provided AGA's actual and forecasted expenditures for 2009 and 2010, respectively.

AGA Categories of Expenses	2009	Percent	2010 (forecast)	Percent
Public Affairs	$6,087,552	22.98%	$6,143,000	23.87%
Policy, Planning & Regulatory Affairs	4,277,647	16.15%	4,427,000	17.20%
Market Development	-	0.00%	-	0.00%
Corporate Affairs	2,880,397	10.87%	2,354,000	9.15%
Operations & Engineering Management	5,474,235	20.67%	5,085,000	19.76%
Industry Finance & Administrative	1,027,748	3.88%	1,129,000	4.39%
General Counsel	1,172,072	4.42%	1,067,000	4.15%
General and Administrative	5,569,647	21.03%	5,535,000	21.50%
Total	$26,489,298	100.00%	$25,740,000	100.00%

Summing the percentages for Public Affairs, Corporate Affairs, and half of General Counsel results in a 36.07% and 35.08% disallowance based on 2009 and 2010 data, respectively. Based on this data, I conclude that 35% is a reasonable estimate of the amount of dues that should not be born by ratepayers. Accordingly, I have removed 35% of AGA dues, which results in an Arizona-specific adjustment of $93,815, as Shown on Schedule BJ-5.

Q. Can you now discuss SWG's eleventh income adjustment - Paiute Pipeline/SGTC Annualization?

A. Yes. The adjustment consists of a $44,593 increase to expenses. [Schedule C-2] SWG explains:

> Adjustment No. 11 annualizes the system allocable A&G amounts allocated to Paiute through the MMF allocation methodology, the insurable property factor, and the rent revenue that Southwest Gas receives from Paiute for the test year ended June 30, 2010. [Aldridge Direct, pp. 17-18]

SWG states that the methodology used for this adjustment is the same as the methodology it used in previous rate cases. [Id., p. 18] The analogous adjustment made by SWG in it's last rate case was not discussed by the Commission in Decision 70665. Therefore, it appears that a similar adjustment has been implicitly approved by the Commission.

Q. What is your conclusion regarding this adjustment?

A. Although I have not studied this adjustment in depth, it appears reasonable, and I have included it in my analysis, as shown on Schedule BJ-5.

Q. Can you now discuss SWG's twelfth income adjustment - Rate Case Expense?

A. Yes. This adjustment increases operating expenses by the estimated costs of this rate case, including printing, postage, court reporting, noticing, publication, travel and outside consultants, amortized over a three year period. [Id.] The $33,386 adjustment is the difference between the computed amortization amount and the amount of rate case expense from the prior proceeding which was amortized on the Company's books during the test year. [Id.] This adjustment is consistent with the methodology used by SWG in the last rate case, which appears to have been implicitly approved by the Commission.

Q. What is your conclusion regarding this adjustment?

A. This adjustment appears reasonable, and I have included it in my analysis, as shown on Schedule BJ-5.

Q. Can you now discuss SWG's thirteenth income adjustment - Depreciation and Amortization Expense Annualization?

A. Yes. This adjustment consists of a $3,135,177 increase to operating expenses. [Schedule C-2]

> Adjustment No. 13 annualizes depreciation and amortization expense based on adjusted plant in service at June 30, 2010, using currently approved depreciation rates. ...This adjustment is necessary to synchronize the depreciation and amortization expense with the plant in service at the end of the test year, as adjusted. ... [P]lant that is placed in service or retired after the beginning of the test year has a partial year's depreciation expense recorded on the books of the Company. ...This adjustment... is consistent with the methodology approved by the

Commission in the Company's previous rate cases. [Aldridge Direct, pp. 18-19]

Q. What is your conclusion regarding this adjustment?

A. The general approach used by SWG seems reasonable, and I have included a similar adjustment in my analysis. However, in calculating my recommended adjustment, I used my recommended adjusted plant balances. As I explained previously, the latter amounts exclude certain post test-year additions and retirements proposed by SWG. As shown on Schedule BJ-5, my adjustment increases operating expenses by $2,481,107, which is substantially lower than SWG's proposed $3,135,177 adjustment.

Q. Can you now discuss SWG's fourteenth income adjustment - Property Tax Annualization?

A. Yes. SWG annualizes property taxes on the Company's adjusted investment in plant and materials as of the end of the test year. [Aldridge Direct, p. 20] The company estimated "full cash value" by adding materials and supplies to, and subtracting transportation equipment and land rights from, its adjusted test year net plant in service. "The estimated cash value is then multiplied by the 2011 assessment rate of 20 percent to determine the assessed value". [Id.] SWG multiplies the resulting assessed value by the currently effective property tax rate of 10.1263 percent to determine the annualized property tax expense. [Id.] This adjustment increases operating expenses by $1,457,495. [Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. I disagree with using the 2011 assessment ratio, because this goes too far beyond the test year. Property tax reform legislation passed in 2005 reduced the assessment ratio on class one property (business) from 25% to 20% over a ten-year period. [An Explanation of Arizona Property Taxes, 2010 Edition, p. 4] Legislation passed during the 2007 legislative session

accelerated the reduction in the class one assessment ratio from a ten year phase down to six years. [Id.] The assessment ratio was reduced to 22% for 2009, 21% for 2010, and 20% for 2011 and later years. [Id.] I have developed an alternative adjustment, as shown on BJ-7, using the 21% 2010 ratio, rather than the 20% 2011 ratio proposed by SWG. Further, my recommended adjustment is based upon my recommended net plant in service amount as of the end of the test year (June 30, 2010), rather than the post-test year adjusted net plant amount proposed by SWG.

As shown on Schedule BJ-5, my recommended adjustment results in a $2,730,392 increase to operating expenses, as compared with the Company's proposed adjustment, which increases operating expenses by $1,457,495. This is a good illustration of one of the points I mentioned earlier in my testimony. In this case, if the Company's proposed post-test year adjustment were allowed, it would substantially reduce the calculated revenue requirement. No one would dispute that the change in the assessment ratio is "known" or that the impact is "measurable." But, I believe the proposed adjustment should be rejected because it relates to changes which occurred after the test year, consistent with my recommendations concerning other adjustments which should also be limited to events which occurred before the end of the test year.

Q. Can you now discuss SWG's fifteenth income adjustment - Interest on Customer Deposits?

A. Yes. This adjustment consists of a $292,612 increase to operating expenses. [Schedule C-2] SWG explains:

> Adjustment No. 15 synchronizes interest expense on customer deposits with the amount of customer deposits used as a rate base reduction. The customer deposit balance used as a rate base reduction is multiplied by the customer deposit rate of six percent to determine the adjusted interest on customer deposit balance expense. The difference between the

adjusted amount and the recorded amount is the adjustment. Consistent with prior Commission decisions, interest expense is treated as an above-the-line expense. [Aldridge Direct, p. 20]

Q. What is your conclusion regarding this adjustment?

A. This type of adjustment is appropriate, in order to include the cost of interest on customer deposits (since this isn't included in the cost of capital and rate of return calculations), and to synchronize the level of interest on customer deposits with the end of the test-year rate base, and other adjustments that are tied to this cut off date. Accordingly, I recommend the Commission approve this adjustment. I have incorporated this adjustment into Schedule BJ-5.

Q. Can you now discuss SWG's sixteenth adjustment - Surcharge Adjustment?

A. This adjustment is intended to remove from base rates expenses that are recovered through various surcharges. [Aldridge Direct, p. 21] The adjustment results in a $3,798,881 reduction to operating expenses. [Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. This adjustment is necessary to prevent double recovery of expenses associated with R&D, TRIMP and Demand Side Management programs, since these expenses are being recovered through separate surcharges. I have included it in developing my recommended revenue requirements, as shown on Schedule BJ-5.

Q. Are there any other expense related adjustments you would like to discuss?

A. Yes. I would like to discuss several adjustments related to certain SWG incentive compensation and retirement plans. SWG has several retirement plans. The Company's Employee Investment Plan (EIP) is a 401(k) plan under which SWG provides matching contributions equal to one-half the deferred amount up to 7 percent of their annual salary. [SWG Response to Staff DR 1-50, p. 3] Officers are not eligible for matching contributions under the EIP. [Id.] SWG's

Defined Benefit Retirement Plan (DBRP), is a retirement plan with benefits based on an employee's years of service, up to a maximum of 30 years, and the 12-month average of the employee's highest five consecutive years salaries, excluding bonuses, within the final ten years of service. [Id. p. 2] The DBRP is available to all employees. [Id.] SWG's Executive Deferral Plan (EDP), is only available to executives at the vice president level and above. [Id.] Under the EDP, executives may defer up to 100 percent of their annual compensation and 100 percent of the cash portion of their variable at-risk compensation. The Company provides matching contributions similar to contributions made under the Company's 401(k) plan. [Id.] Finally, SWG provides a Supplemental Executive Retirement Plan (SERP) to executives. SWG explains:

> Benefits from the plan, when added to the benefits received under the basic retirement plan, will equal 60 percent of annual compensation for senior executives, and 50 percent of annual compensation for all other officers. Annual compensation is defined as the 12-month average of the highest 36 months of salary. [Id.]

SWG's incentive compensation plans include the Management Incentive Plan (MIP), the Restricted Stock/Unit Plan (RSUP), the Aspire program (Aspire), and the Going the Extra Mile (GEM) program. [Id., pp. 3-5] The MIP provides compensation based on certain goals and performance objectives. [Id., p. 3] The MIP is based on performance on four measures: customer satisfaction, customer-to-employee ratio, return on equity, and operating costs. [Id.] "Forty percent of the total award earned under the MIP is paid in cash immediately following the financial close of the most recent calendar year. The remaining 60 percent is issued as performance shares and vest three years in the future". [Id.] The MIP is measured as a percentage of base salary and varies by title, ranging from 10% for key management employees, to 115% for the CEO. [Id.] The MIP is only available to executives and upper-level management.

SWG's RSUP replaced the Company's Stock Incentive Plan in 2007. [Id., p. 4] The RSUP is only available to officers and other key management employees. The dollar amount of the award under the RSUP is "converted to restricted share units using the market price on the date such awards are approved by the Company's Board of Directors". [Id.]

Aspire is only available to salaried employees who do not qualify for the MIP. [Id.] To qualify, an employee must be recommended in writing by an officer of the Company. Awards range from $2,500 to $7,500 and are granted to individuals "who go significantly above and beyond their job responsibilities with substantial contributions toward the overall betterment of Southwest Gas, as well as demonstrate dedication to the goals and philosophy of the Company". [Id., p. 5]

GEM is similar to Aspire, but is tailored towards "non-exempt" (non-salaried) employees. Employees nominated are evaluated on: productivity; customer service; innovation; leadership; and, character. [Id.] The number of employees who may be recognized each year is limited to one hundred non-exempt employees Company-wide. "The number of awards allocated to each jurisdiction is determined by the number of non-exempt employees in that jurisdiction as a percent of the total non-exempt employee population company wide". [Id.]

Q. How has the Commission traditionally handled retirement plans in SWG rate cases?

A. The Commission has disallowed 100% of SERPs expenses in prior SWG rate cases. In SWG's previous rate case, SWG argued that the Company's SERP was "vital to the Company's attraction and retention of highly-skilled employees, which ultimately benefits customers". [See, Decision 70665, p. 17] Staff and RUCO argued that the Commission had disallowed SERPs expenses in prior cases involving SWG, UNS Gas, UNS Electric, and APS, and that SERPs were not necessary costs since high-ranking officers were already fairly compensated through their salaries and an array of benefits. [See, Id.] The Commission quoted the following

from previous rate cases:

> [Wle 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 SEW, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the sttempt to make these executives "whole" in the sense o€ 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. [Id., pp. 17-18, quoting from SWG Decision 68497, p. 19]
>
> [Tlhe issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so. shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Case rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SEW costs. [Id., p. 18, quoting from UNS Decision 70011, p. 28]

The Commission concluded that no material factual differences existed in SWG's prior rate case that would require a departure from past decisions on this issue, and denied the inclusion of SERP expenses in rates. [Id., pp. 17-18]

Q. What do you conclude regarding SWG's SERP expenses?

A. I conclude that SWG's SERP's expenses should once again be disallowed. As with SWG prior rate case, there are no material differences that would justify a departure from past precedent. During the discovery process, SWG was asked to identify the amount of SERP expense including in its filing. [See, RUCO DR 4-3 and Staff DR 17-1] SWG estimates that $1,725,839

in SERP expenses are included in its filing. [SWG response to Staff DR 17-1 and included attachment] However, SWG explains:

> The precise amount of SERP requested for recovery is impacted by numerous calculations within the cost of service model, including cash working capital and the labor loading allocations. The attached spreadsheet, which does not reproduce every calculation within Southwest Gas' cost of service model, but shows the largest components, shows an impact of approximately $1.73 million. Any changes to the allocation methods, charged labor amounts, or cash working capital components will impact the exact amount of SERP requested for recovery in Arizona. [Id.]

As shown on Schedule BJ-5, I have included an adjustment which removes the Company's estimated test year SERPs expenses. This adjustment results in a $1,725,839 decrease to operating expenses.

Q. How has the Commission traditionally handled incentive compensation plans in SWG rate cases?

A. In the past, the Commission has disallowed 50% of SWG's MIP expenses, and 100% of SWG's other executive stock-based incentive plans. In SWG's prior rate case, the Company argued that annual variable pay was "less than the market average compared to other western utilities, including Pinnacle West and UniSource". [See, Id., p. 15] Staff and RUCO argued that the MIP goals benefit both ratepayers and stockholders, and that certain criteria primarily benefit stockholders. [See, Id.] The Commission noted that in several earlier rate cases, it had disallowed 50% of MIPs expenses "on the basis that such programs provide lpproximately equal benefits to shareholders and ratepayers because the performance goals relate to Financial performance and cost containment goals as well as customer service elements. [Id. p. 16] The Commission quoted from its decision in an earlier SWG rate case, in which it concluded:

> In Decision No. 64 172, the Commission adopted Staffs recommendation

> regarding MIP expenses based on Staffs claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staffs 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 Staffs equal sharing recommendation to be a reasonable resolution. [Id., quoting Decision 68487, p. 18]

With regard to other stock incentive plans, the Commission held:

> On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs elated to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted n the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. [Id., p. 16, f.n. 4]

Q. What do you conclude regarding SWG's incentive compensation plans?

A. I conclude that there has been no change in facts or circumstances that would require a deviation from the Commission's established practice of disallowing 50% of SWG's MIP expenses, and 100% of other executive stocked-based incentive compensation. SWG's MIP goals still include criteria that primarily benefit stockholders. Further, a significant portion of MIP compensation is in the form of stock. As the Commission has noted, when the value of incentive compensation is tied to the value of the Company's stock price, there is the potential for a conflict with customer service goals, and ratepayers should be required to pay for such executive compensation.

Q. What amount of MIP expense is SWG seeking to recover in this proceeding?

A. During the discovery process, SWG was asked to identify the amount of all incentive compensation included in its revenue deficiency analysis. [See, RUCO DR 4-2] SWG replied: "The amounts of incentive compensation are embedded into total labor costs, and cannot be separately identified by a cell reference to any tab in the file 2010 Arizona Deficiency.xlsx". [SWG reply to RUCO DR 4-2] However, in response to another data request, SWG provided the amount of incentive compensation recorded during the test year. [See, SWG response to Staff DR 17-2] SWG is requesting recovery of $3,536,498 in MIP expenses in this proceeding. [SWG response to Staff DR 17-2, and included attachment] As shown on Schedule BJ-5, I have included an adjustment to remove 50% ($1,768,249) from operating expenses.

Q. What amount of other (non-MIP) executive stocked-based incentive compensation is SWG seeking to recover in this proceeding?

A. As I explained earlier, the Commission disallowed 100% of SWG SIP expenses in the prior rate case. SIP has been replaced with SWG's RSUP program. SWG has included $1,033,831 in RSUP expenses in this proceeding. [Id.] Accordingly, as shown on Schedule BJ-5, I have included an adjustment which reduces operating expenses by $1,033,831.

VI. Fair Value Rate of Return

Q. Can you begin your discussion of the fair value rate of return (FVROR) by explaining how SWG developed its request?

A. SWG started by calculating the difference between its proposed OCRB and FVRB. [Hevert Direct, p. 52] SWG then "weighted the OCRB using the Company's proposed capital structure weighting, which includes the debt and equity component of the OCRB, and the appreciation in

the value of the assets which, when added to the OCRB, results in the FVRB". [Id.] The Company applied its cost of debt to the debt component of the OCRB, its proposed ROE to the equity component of the OCRB, and 50% of an estimate of the risk free rate of return to the difference between FVRB and OCRB. [Id., pp. 52-53] The Company estimated the nominal risk free rate of return by averaging the short-term projected yield on 30-year Treasury bonds and the long-term projected yield on the 30-year Treasury bonds. [Id. p. 53] This nominal risk free rate was then adjusted by the rate of inflation. [Id.] SWG estimated the inflation rate by averaging the Blue Chip Financial Forecast estimate of the long term change in CPI for 2017 through 2020, and the EIA Annual Energy Outlook estimate of the change in CPI for the period from 2010 through 2035. [Id.] The Company's calculations result in a cost rate of 1.24% to be applied to the difference between OCRB and FVRB.

Q. The Commission's traditional method of calculating a rate of return for application to a fair value rate base has been heavily litigated in recent years. Can you briefly explain how that recent litigation began?

A. On September 30, 2005 the Commission issued Decision No. 68176 granting a rate increase to Chaparral City Water Company. ("Chaparral") In accordance with longstanding precedent, the Commission multiplied the weighted average cost of capital (WACC) by the original cost rate base (OCRB) to estimate the needed operating income. [Decision 68176, pp. 26-28] The Commission then divided that required level of operating income by the fair value rate base (FVRB) to arrive at a fair rate of return. [Id., p. 28] The fair rate of return was then applied to the FVRB to determine operating income for rate making purposes. Chaparral subsequently filed an appeal with the Arizona Court of Appeals that, among other things, has resulted in the Commission rethinking its approach to developing the rate of return it applies to the FVRB.

Q. Did the Court of Appeals address the methodology for determining a fair rate of return?

A. Yes. First, the court recognized that the Arizona Constitution gives the Commission "exclusive and plenary" authority to prescribe rates for public utilities within the state. [Chaparral City Water Company v. ACC, 1 CA-CC 05-0002, Memorandum Decision, p. 5] However, the court also noted that the state Constitution specifically requires the Commission to ascertain the "fair value" of the utility's property. [Id., p. 6]. Article 15, Section 14 of the Arizona Constitution states:

> The corporation commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein; and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.

The court stated that this provision has been interpreted as requiring the Commission to determine the fair value of the utility's property, and to use that finding as the rate base in setting rates. [Id., citing Simms v. Round Valley Light & Power Co., 294 P. 2nd at 382] The court noted that the Arizona Constitution does not define fair value, but stated that it is "generally recognized as being based on both original cost and reproduction cost". [Id., p. 4, f.n. 4]

On appeal, Chaparral argued that operating income should be determined by multiplying the FVRB by the rate of return, and that "the rate of return is generally equal to a utility's weighted cost of capital". [See, Id., p. 7] The Commission responded by asserting that it was not bound to use the weighted average cost of capital as the rate of return to be applied to FVRB. The court agreed, stating:

> If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology. [Id., p. 13]

The court also noted that "rates of return vary, depending upon the type of rate base used". [Id., p. 7, f.n. 5] However, the Court of Appeals found that the Commission's method for determining operating income ignored fair value rate base, in violation of the Arizona Constitution.

> Here, the Commission determined Chaparral City's operating income based on the OCRB and then mathematically calculated a corresponding rate of return had the income been based on the FVRB. Under this method, Chaparral City's operating income, and therefore its revenue requirements and rates, were based not on the fair value of its property, but on its OCRB, which does not comport with the Arizona Constitution. [Id., p. 12]

Accordingly, the court remanded the matter to the Commission for further determination.

Q. What did the Commission decide on remand?

A. On July 28, 2008, the Commission issued Decision No. 70441, in which it stated:

> Our previous method was a shorthand method of ensuring that inflation would only influence one piece of the ratemaking formula - the rate of return. However, the Court of Appeals has made it clear that, under our constitution, the "inflation component" belongs in the FVRB. Accordingly, in order to avoid over-counting the effect of inflation, it is necessary for us to ensure that the rate of return does not also carry an inflation component. [Decision No. 70441, p. 33]

The Commission noted that there are many methods that could be used to determine an appropriate FVROR, including the methods advocated by Staff and RUCO in the Chaparral case. [Id., p. 34] Staff's method "adjusts the cost of capital to reflect the cost of the portion of the capital structure that is funded by neither debt nor equity, but exists due to inflation". [Id.] RUCO's method "analyzes the inflation contained in the estimates of cost of equity and adjusts the cost of capital to eliminate the inflation component". [Id.] Ultimately, the Commission used

a method similar to the one I recommended on behalf of RUCO, but with a significant modification, which limited its scope. [Id.]

Q. Can you describe the method that was recommended by RUCO in the Chaparral remand case?

A. Yes. As I explained in that proceeding, in jurisdictions where the rate base is entirely based on original cost data, it is common practice to apply a rate of return which is based upon the weighted average cost of capital, derived in large part using accounting data (e.g. debt and equity amounts; embedded interest rates). In contrast, where the rate of return will be applied to the current value of the utility's property, a lower return is appropriate – one that provides the utility with an opportunity to recover its actual capital costs, without overcompensating for inflation.

A rate of return that is fair to both customers and stockholders can be derived from the weighted average cost of capital by simply subtracting an amount related to the rate of inflation, thereby preventing a double counting of compensation for inflation. For example, assume the weighted average cost of capital is 7.50%, and the relevant inflation rate is 2.5%, then a fair return on the fair value rate base would be 5.00%, or thereabouts.

Q. Why is it appropriate to remove inflation from the rate of return?

A. A typical cost of capital, which includes inflation, cannot be applied to the fair value rate base because this would result in a double counting of inflation. A fair value valuation of the rate base tends to be higher than an original cost valuation, because it also reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Economists have long recognized that inflation and other factors which increase the value of an investment will significantly impact an investment's expected return. In turn, these factors

affect the present value of the investment. To fully understand this relationship, it is necessary to realize that growth in the value of an investment is a component of the total return achieved by the investor. Indeed, for many so-called growth stocks which pay little or no dividends, virtually the entire return received by the investor results from growth in the market value of the stock (capital gains). The same principle applies to the value of rental property in areas where real estate prices (and/or rents) are escalating – investors will take into account the anticipated growth in the value of their investment – similar to the way growth stocks are evaluated.

Similarly, if the income being generated by a particular investment is expected to grow over time (e.g. rents are increasing), that will tend to push up the current market value of an investment. Investors will accept a lower current return from an investment, if they have reason to believe the return will increase over time.

The current market value of an investment is determined by the net effect of multiple factors, including the current annual income or return (in dollars), expected changes in that income or return, and expected changes in the value of the investment. Thus, real estate investors in areas where demand is growing will often purchase property with an extremely low or negative current cash return, because they anticipate profiting from future growth. Similarly, investors might construct a new office building, despite the fact that the rent payments during the first few years will actually be less than their direct expenses (interest, utilities, taxes, etc.), indicating a negative current level of return – if they expect rents, and/or the value of the property, to increase sufficiently in the future. Investors take into account all aspects of anticipated returns, including past and future trends in market rents, as well as anticipated growth in the value of the building. If the growth expectations are strong enough, investors will accept extremely low or negative returns during the early years, because they anticipate earning an adequate return over the entire life cycle of their investment.

Since the dollar magnitude of the fair value rate base is larger than an original cost rate

base, reflecting past growth in the value of the utility's property, and since the future income stream can reasonably be expected to increase in the future, due to inflation and other factors which tend to push up property values as time passes, a 5.00% return on fair value is likely to provide investors with as large a total return (over time) as a 7.50% return applied to an original cost rate base. The exact amounts received by investors may differ somewhat, and they certainly will differ during any specific year, but the key point is that investors will have as strong an opportunity to recover their capital costs and to earn a competitive return through the application of a 5.00% return on an escalating estimate of fair value as with a 7.50% return on the original cost. The regulatory goal of simulating the effects of competitive markets, and compensating investors for the impact of inflation, can be achieved either way.

Q. Can you explain in greater detail why a fair rate of return applied to a fair value rate base is less than the percentage return which would normally be applied to an original cost rate base?

A. Yes. If the return is going to be fair to customers as well as to stockholders, it must be lower than the weighted average cost of capital. The same percentage figure cannot be appropriate for application to both the original cost and to the replacement cost of the utility's property, unless these two cost measures happen to be nearly the same.

Another way of seeing why this conclusion is valid is to start with the competitive market result, which is widely accepted as the appropriate standard for utility regulation in nearly all jurisdictions, regardless of whether they use original cost or fair value in developing their rate base calculations. Utilities in Arizona and other states are all competing for investment capital that is being provided in a national market. If the same percentage rates of return were applied to fair value rate bases in Arizona as are applied to original cost rate bases in all other jurisdictions, it is self evident that Arizona investors would be overcompensated.

If the same cost of capital were applied to a fair value rate base as is applied to original cost rate bases in other jurisdictions, Arizona utilities would be provided with an opportunity to earn windfall profits, in comparison with the treatment of utilities in other states, where firms are only given the opportunity to earn a normal, competitive return.

While the Arizona Constitution requires use of a fair value rate base, and that may influence the specific rate of compensation provided to any specific utility during any specific year, it is not necessary or appropriate to provide Arizona utilities with earnings that consistently exceed those earned, on average, by utilities in other states (or which consistently exceed the earnings of the average unregulated firm which operates in competitive markets, adjusted for differences in risk). Yet just such a consistent differential would occur if the same rate of return were applied to fair value in Arizona and to original cost in other jurisdictions.

Aside from differences in risk, the long term average compensation provided to utility investors in Arizona should be roughly equivalent to that paid to investors in other enterprises – assuming comparable levels of risk. Investors in Arizona and in other states should all be given a reasonable opportunity to earn a normal return – a return which is consistent with competitive market levels.

I made that last statement in terms of the long term average, because there could be differences in timing, due to differences in the rate base valuation methodology. The return on investment provided in a fair value rate jurisdiction might be somewhat lower in the initial years, and higher in the later years of any given investment, relative to the timing of the returns received in an original cost jurisdiction, just as investors in growth stocks receive more of their return in later years, as dividends increase, or upon sale of the stock. While the year-to-year pattern of cash flows might differ somewhat depending on the specific rate base methodology, the overall long term average level of compensation paid to investors should be very similar, regardless of whether the rate base is based upon original cost, or fair value.

Consistent with this line of reasoning, it is clear that the appropriate magnitude of the difference between the appropriate rate of return in an original cost jurisdiction and the fair rate of return in a fair value jurisdiction is closely related to the rate of growth in the utility's fair value rate base relative to the original cost of its property. The more rapidly fair value is growing relative to original cost, the less need there is to immediately provide a high level of current income in the form of high percentage return for application to the fair value rate base. This is exactly what we observe in the stock market, where investors are satisfied with relatively lower levels of current income and dividends in growth industries, where the value of the stock and the anticipated future level of dividends are expected to grow over time.

Q. Can you now describe the modified method the Commission used in the Chaparral case?

A. The Commission held:

> Although we believe that the cost of debt may reflect the effects of inflation, we are not convinced that the evidence presented in this proceeding is developed sufficiently to make that determination with certainty. Accordingly, while we agree with RUCO that the WACC should be adjusted to remove the inflation component, we believe that the appropriate adjustment in this case is to adjust only the cost of equity component of the WACC. [Id., pp. 36-37]

The Commission used a "conservative" inflation estimate of 2.00%, but it only removed the inflation component from the cost of equity component of the WACC. [Id., p. 37]

Q. Has the Commission's approach to FVROR evolved since the Chaparral remand case?

A. Yes. The Commission issued an order in SWG's prior rate case on December 24, 2008; several months after the Chaparral remand order. [Decision 70665] The Commission used an approach which was similar to a method proposed by Staff during the Chaparral remand proceeding, and similar to the methodology used by SWG in this proceeding, although the numbers differed.

Specifically, the Staff proposed applying 50% of the risk free rate to the difference between OCRB and FVRB. [See. Id., pp. 30-31] the Staff estimated a risk free rate of 2.50%, and recommended applying one half of this rate (1.25%) to the FVRB increment. [See, Id., p. 31] The Commission accepted the methodology, but adopted a lower return:

> Based on the record before us, we believe that Staffs alternative FVRB recommendation is appropriate, with a slight modification. Although we agree with Staff that it should not be necessary to provide the Company with any additional return on the increment between OCRB and FVRB, because that increment is not financed with investor-supplied funds, we find that applying a 1.00 percent return on the fair value increment is appropriate under the facts of this case and properly accounts for the effect of inflation. [Id., p. 32]

On October 21, 2009, the Commission issued an order in another Chaparral rate case, Docket No. W-02113A-07-0551. In that proceeding Staff recommended a different approach, reducing the WACC by a factor related to inflation. [See, Decision 71308, p. 39] According to the Commission, Staff used the 2.4 percent difference between the spot yields on a 20-year Treasury and a 20-year TIPS as a proxy for expected inflation. [Id., p. 43] "Because one half of the FVRB includes OCRB, which does not include inflation, Staff adjusted the 2.4 percent inflation factor by one-half, resulting in an inflation adjustment to the WACC of 1.2 percent". [Id., pp. 43-44] The Commission noted that there are many methods that could be used to determine an appropriate FVROR. [Id., p. 40] The Commission concluded that Staff's method to apply a downward adjustment for inflation to both the equity and debt components of the WACC "is a reasoned and sound approach to determining a FVROR that equitably balances the needs of the Company and its ratepayers, and results in the setting of just and reasonable rates". [Id., p. 49]

On September 30, 2010, the Commission issued an order in UNS Electric's most recent rate case, Docket No. E-04204A-09-0206. In that proceeding I testified on behalf of RUCO and

illustrated several methods the Commission could use to develop an appropriate FVROR. I recommended the Commission place the most weight on an approach that subtracted an inflation component from both the cost of equity and cost of debt, but that did not reduce that inflation component by 50%. The Commission agreed, concluding that

> an unadjusted inflation factor should be subtracted from the entire WACC, to afford appropriate recognition to the fact that inflation exists in both the debt and equity components of the Company's capital structure, and that reconstruction cost estimates likely exceed the rate of inflation ... [Decision 71914, pp. 49-50]

To my knowledge, this is the most recent decision in which the Commission has dealt with these issues.

Q. Can you elaborate on why it would be inappropriate to cut the inflation component in half?

A. Yes. As I explained in the UNSE case, while it is true that reproduction cost is only given half weight in developing the FVRB, reproduction cost does not escalate at the inflation rate; to the contrary, reproduction costs tend to grow faster than the rate of inflation, because they don't fully consider the favorable impact of technological changes, increasing economies of scale, and other sources of increased efficiency and cost savings – factors which tend to hold back the pace at which prices escalate over time.

Technological improvements and other sources of cost savings are one of the reasons why the Commission doesn't rely entirely on reproduction cost in developing fair value, and instead weights reproduction cost with original cost. As well, it's important to realize that technological improvements and other sources of cost savings are considered in developing most measures of inflation. In other words, most measures of inflation are relatively low percentage figures, because they take into account the beneficial effects of technological

changes and other sources of cost savings which ameliorate or offset other factors which tend to push up reproduction costs.

Q. If the Commission again decides to remove inflation from the WACC in developing a fair return on fair value, what estimate of inflation would you suggest using?

A. This is a matter of judgment; the Commission can exercise sound discretion in determining the most appropriate inflation factor to subtract from the weighted average cost of capital. In making this decision, I recommend that the Commission review and consider several of the data series that are publicly available. In particular, I recommend the Commission consider the data published by the Bureau of Labor Statistics for the annual rate of change in the Gross Domestic Product Deflator, as well as annual changes in consumer prices and various measures of producer prices. The following table summarizes historical changes in each of these inflation measures.

Year	GDP Implicit Price Deflator	CPI All Items	PPI All Comm.	PPI Finished Goods	PPI Mat. and Comp. for Const.
1979	8.3%	11.3%	12.6%	11.1%	10.1%
1980	9.1%	13.5%	14.1%	13.5%	8.4%
1981	9.4%	10.4%	9.2%	9.3%	7.2%
1982	6.1%	6.2%	2.0%	4.0%	2.1%
1983	4.0%	3.2%	1.2%	1.6%	2.8%
1984	3.8%	4.4%	2.4%	2.1%	2.7%
1985	3.0%	3.5%	-0.5%	0.9%	1.6%
1986	2.2%	1.9%	-2.9%	-1.4%	0.7%
1987	2.9%	3.6%	2.6%	2.1%	1.6%
1988	3.4%	4.1%	4.0%	2.5%	5.7%
1989	3.8%	4.8%	5.0%	5.1%	4.5%
1990	3.9%	5.4%	3.6%	4.9%	1.3%
1991	3.5%	4.2%	0.2%	2.1%	1.3%
1992	2.4%	3.0%	0.6%	1.2%	1.6%
1993	2.2%	3.0%	1.5%	1.2%	4.3%
1994	2.1%	2.6%	1.3%	0.6%	3.5%
1995	2.1%	2.8%	3.6%	1.9%	4.0%
1996	1.9%	2.9%	2.3%	2.6%	1.1%
1997	1.8%	2.3%	-0.1%	0.4%	2.0%
1998	1.1%	1.5%	-2.5%	-0.9%	0.2%
1999	1.5%	2.2%	0.8%	1.8%	1.4%
2000	2.2%	3.4%	5.8%	3.7%	1.2%
2001	2.3%	2.8%	1.1%	2.0%	-0.1%
2002	1.6%	1.6%	-2.3%	-1.3%	0.5%
2003	2.2%	2.3%	5.3%	3.2%	1.5%
2004	2.8%	2.7%	6.2%	3.6%	8.3%
2005	3.3%	3.4%	7.3%	4.9%	6.1%
2006	3.3%	3.2%	4.7%	3.0%	6.7%
2007	2.9%	2.9%	4.8%	3.9%	2.2%
2008	2.2%	3.8%	9.8%	6.3%	6.7%
2009	0.9%	-0.3%	-8.8%	-2.6%	-1.2%
2010	1.0%	1.6%	6.8%	4.2%	1.4%

Shown are average annual changes in the Gross Domestic Product Implicit Price Deflator (GDP Deflator); the familiar Consumer Price Index or CPI for "all consumer items"; the Producer Price Index, or PPI, for "all commodities"; the analogous PPI for "finished goods"; and the PPI for Materials and Components for Construction.

The annual change in any one measure of inflation can vary widely from one year to the next; as well there are variations between the various data series. However, by calculating averages over extended time periods, it is readily apparent that the average rate of inflation tends to fluctuate in a much tighter range, and that the differences between these various inflation measures are not extreme. As shown in the table below, I have calculated averages for 12 different time periods. The averages include time periods of 30 years, 25 years, 20 years, 15 years, 10 years, and 5 years ending in 2008 and 2010. As shown, these averages cover a fairly wide range. Several of the most important series (the GDP deflator and the CPI) averaged about about 2.1% to 2.4% during several historical time periods, including the recent five year period of 2006-2010, as well as the 25 year period ending in 2010. I believe this 2.1% to 2.4% range is an appropriate one for the Commission to use in evaluating historical inflation patterns for consideration in establishing the fair rate of return to apply to Chaparral's fair value rate base.

Date Range	GDP Implicit Price Deflator	CPI All Items	PPI All Comm.	PPI Finished Goods	PPI Mat. and Comp. for Const.
1979-2008	3.4%	4.1%	3.5%	3.2%	3.4%
1981-2010	2.9%	3.3%	2.5%	2.4%	2.8%
1984-2008	2.6%	3.1%	2.6%	2.3%	2.8%
1986-2010	2.1%	2.4%	2.8%	2.3%	2.5%
1989-2008	2.4%	3.0%	3.0%	2.5%	2.9%
1991-2010	2.2%	2.6%	2.4%	2.1%	2.6%
1994-2008	2.2%	2.7%	3.2%	2.4%	3.0%
1996-2010	2.1%	2.4%	2.8%	2.3%	2.5%
1999-2008	2.4%	2.8%	4.4%	3.1%	3.5%
2001-2010	2.2%	2.4%	3.5%	2.7%	3.2%
2004-2008	2.9%	3.2%	6.6%	4.3%	6.0%
2006-2010	2.1%	2.2%	3.5%	3.0%	3.1%

Q. The data you just discussed is strictly historical. Should the Commission also consider expectations regarding future levels of inflation?

A. Yes, although the most logical starting point is historical inflation data, it's important to also consider anticipated future rates of inflation. Interestingly, both backward and forward views of inflation are closely related. In fact, the historical data series are some of the best, most detailed and most objective information available for estimating future inflation rates – and this information is highly relevant to consideration of future inflation, since investors will often assume the future will be similar to the past, even though various differences are likely to occur, due to changes in monetary policy, fluctuations in the business cycle, and other changes over time. Succinctly stated, in evaluating a fair return to provide to investors, the Commission should consider both past and future inflation rates – giving some consideration to investor expectation concerning future inflation, as well as some consideration of the inflation rates which have already contributed to increases in the value of the utility's property.

Q. Are you aware of any published data series that are indicative of the future inflation rate expectations of investors?

A. Yes. A useful measure of investor inflation expectations can be derived by comparing the yields on Treasury Inflation-Protected Securities (TIPS) and other securities issued by the Treasury Department with similar liquidity and duration. TIPS are bonds issued by the U.S. Treasury which are sometimes called "linkers", because they are "linked" to the actual rate of inflation.

TIPS are issued twice a year, in January and July. The principal amount that is paid back to the holder upon maturity is periodically increased, based on the CPI-All Consumer Items. Like most government bonds, the TIPS coupon rate (percentage return) is constant, but these particular securities are unique because they generate an increasing flow of interest payments. TIPs pay interest twice a year, based upon a fixed rate that is multiplied by the inflation-adjusted principal. The end result is that investors are protected against inflation both with respect to the value of their investment, and with respect to the income they receive. Thus, for example, if the interest rate on a TIP Security is 5%, its cost is $100, and cumulative total amount of inflation from the time of issuance until maturity is 20%, the value of the investment would increase to $120 at maturity. The 5% interest rate would be applied to the increasing principal amount, eventually reaching the level of 5% of $120 – approximately 20% more than the initial payment level.

At maturity, the securities are redeemed at the greater of their inflation-adjusted principal or the original par amount at the time they were issued. TIPS provide yet another example that illustrates one of the key points in my testimony – that the percentage rate of return earned by an investment that grows in value over time will normally be lower than the analogous return paid on an investment that does not grow over time. The fact that these securities offer significantly different percentage returns is further proof of this fundamental point. But, these securities are also of interest because they provide useful insights into investor

expectations concerning inflation.

It is well established in the academic literature that the difference between the yield on a TIP and the yield on a comparable government security that is not linked to inflation can be used to estimate investors' future inflation expectations. In the following table, I present average daily yields on 10 year TIPs and average yields on analogous bonds, for the years 2003 through 2010. I have also calculated the average differences in the yields for the two types of securities. As shown, the average differences range from a low of 1.60% in 2009, to a high of 2.48% in 2005 and 2006.

Year	Value TIPS	Value Bond	Difference
2004	1.83	4.27	2.44
2005	1.82	4.29	2.48
2006	2.31	4.80	2.48
2007	2.29	4.64	2.35
2008	1.76	3.67	1.90
2009	1.66	3.26	1.60
2010	1.15	3.22	2.07
2011	1.05	3.36	2.31
Averages			
2004-2010	1.83	4.02	2.19
2006-2010	1.84	3.92	2.08
2008-2010	1.53	3.38	1.86

Averaging the entire array of annual average differences indicates the overall average level of future expected inflation during this time period was about 2.19%. Averaging the data over just the most recent three year period, from 2008 through 2010, suggests inflation expectations have dipped somewhat, averaging just 1.86%. However, it appears this drop in inflation expectations may have been only temporary. The most recent data – from the first part of 2011 – is within the historical range of 2.1% to 2.4%, which I mentioned earlier.

Q. Assuming the Commission adopts the approach it used in the recent UNSE case, what would be a reasonable inflation rate to use as an offset to the weighted average cost of capital?

A. Given current economic uncertainties, I recommend the Commission choose an inflation rate that is conservative – one that falls toward the low end of the historical data, and is reasonably consistent with the recent level of investor expectations concerning future inflation rates. Admittedly, there is a good chance that inflation will accelerate in the future, depending on how quickly and successfully the Federal Reserve Board is at unwinding its recent policy of holding down short term interest rates and aggressively expanding the nation's money supply, I don't think it would be appropriate to incorporate this upside potential into the fair value rate of return calculations in this proceeding. Instead, I recommend the Commission use a conservative inflation factor of 2.1%, which is at the lower end of the historical data discussed earlier, and comfortably within the recent range of investor expectation for future inflation, as indicated by the TIPS data I just discussed.

Q. How does your recommended inflation rate compare with SWG's estimate of inflation?

A. It is more conservative. For purposes of calculating the risk free rate of return, SWG estimated an inflation rate of 2.47%

Q. Can you illustrate your recommended approach, and how it compares to the results of SWG's FVROR analysis?

A. As shown in the table below, applying a 2.1% adjustment factor to the weighted average cost of capital results in a fair rate of return of 6.08%. This compares to a FVROR of 7.50% using the Company's methodology.

RUCO

Type of Capital	Amount	Percent	Cost Rate	Inflation Component	Modified Cost Rate	Weighted Avg. Cost Rate
Common Equity	611,263,103	50.15%	9.00%	2.10%	6.90%	3.46%
Long Term Debt	607,500,000	49.85%	7.35%	2.10%	5.25%	2.62%
Total	1,218,763,103	100.00%				6.08%

SWG

Type of Capital	Amount	Percent	Cost Rate	Inflation Component	Modified Cost Rate	Weighted Avg. Cost Rate
Common Equity	561,545,431	38.55%	11.00%	0.00%	11.00%	4.24%
Long Term Debt	512,155,202	35.16%	8.34%	0.00%	8.34%	2.93%
FVRB Increment	382,816,834	26.28%	1.24%	0.00%	1.24%	0.33%
Total	1,456,517,467	100.00%				7.50%

VII. Conclusions and Recommendations

Q. Can you now please briefly summarize your recommendations?

A. Yes. The effect of my recommendations, as well as Bill Rigsby's cost of capital analysis, is set forth on Schedule BJ-1 of my exhibit. If the Commission were to accept these RUCO recommendations, the original cost rate base would be $1,067,667,709 and the RCND rate base would be $1,833,301,376. The fair value rate base would be $1,450,484,543, assuming the Commission follows its traditional 50/50 weighting of original cost and RCND. These figures compare to the Company's rate base proposals of $1,073,700,633, $1,839,334,300, and $1,456,517,467, for original cost, RCND and fair value, respectively.

If the Commission were to accept all of my recommendations, after taking into account my recommended pro forma adjustments, the test year operating income would be $70,561,890, which compares to the Company's proposed operating income of $65,065,829. If the Commission were to adopt RUCO witness Rigsby's 9.00% estimate of the cost of equity, his overall weighted average cost of capital of 8.18%, and my corresponding recommended fair

rate of return on fair value rate base of 6.08%, the required operating income would be approximately $88.2 million. This analysis suggests a test year operating income deficiency of $17,627,571. This compares to the Company's calculated income deficiency of $44,145,700.

Q. What increase in revenues is implied by this income deficiency calculation?

A. Applying the Company's gross revenue conversion factor to this test year income deficiency results in a base rate revenue increase of approximately $29.2 million. This compares to the Company's proposed revenue increase of $73.2 million.

Q. Does this conclude your testimony, prefiled on June 10, 2011?

A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory

commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

Canada—Department of Communications
Hillsborough County Property Appraiser
Provincial Governments of Canada
Sarasota County Property Appraiser
State of Florida—Department of General Services
United States Department of Justice—Antitrust Division
Utah State Tax Commission

Regulated Firms

Alabama Power Company
Americall LDC, Inc.
BC Rail
CommuniGroup
Florida Association of Concerned Telephone Companies, Inc.
LDDS Communications, Inc.
Louisiana/Mississippi Resellers Association
Madison County Telephone Company
Montana Power Company
Mountain View Telephone Company
Nevada Power Company
Network I, Inc.
North Carolina Long Distance Association
Northern Lights Public Utility
Otter Tail Power Company
Pan-Alberta Gas, Ltd.
Resort Village Utility, Inc.
South Carolina Long Distance Association

Stanton Telephone
Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

Other Private Organizations

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

SOUTHWEST GAS CORPORATION
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SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
ACC JURISDICTIONAL REVENUE REQUIREMENTS

DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-1

LINE NO.	DESCRIPTION	(A) RUCO ORIGINAL COST	(B) RUCO RCND	(C) RUCO FAIR VALUE
1	ADJUSTED RATE BASE	$1,067,667,709	$1,833,301,376	$1,450,484,543
2	ADJUSTED OPERATING INCOME	70,561,890	70,561,890	70,561,890
3	CURRENT RATE OF RETURN (L2 / L1)	6.61%	3.85%	4.86%
4	REQUIRED OPERATING INCOME (L5 * L1)	87,335,219		88,189,460
5	REQUIRED RATE OF RETURN	8.18%		6.08%
6	OPERATING INCOME DEFICIENCY (L4 - L2)	16,773,329		17,627,571
7	GROSS REVENUE CONVERSION FACTOR	1.6579		1.6579
8	REVENUE REQUIREMENT	$27,808,502		**$29,224,749**

REFERENCES:
COLUMN (A): RUCO SCHEDULES BJ-2, BJ-5, BJ-6, SWG SCHEDULE C-3
COLUMN (B): RUCO SCHEDULES BJ-3
COLUMN (C): JOHNSON TESTIMONY, SWG SCHEDULE C-3

SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
ORIGINAL COST RATE BASE

DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-2

LINE NO.	DESCRIPTION	(A) Balance at End of Test Period	(B) RUCO Adjustments	(C) RUCO Adjusted
1	GROSS UTILITY PLANT IN SERVICE			
	Direct	$2,252,566,706	$575,976	$2,253,142,682
	System Allocable	101,255,058	-	101,255,058
	Total Gas Plant	$2,353,821,764	$575,976	$2,354,397,740
2	Less: Accumulated depreciation & amortization	955,200,740		955,200,740
3	NET UTILITY PLANT IN SERVICE	**$1,398,621,024**	**$575,976**	**$1,399,197,000**
	DEDUCTIONS:			
8	Customer advances for construction	(62,033,165)		(62,033,165)
9	Customer deposits	(48,475,278)		(48,475,278)
10	Accumulated Deferred Income Taxes	(230,694,907)		(230,694,907)
11	TOTAL DEDUCTIONS	**$(341,203,349)**		**$(341,203,349)**
	ADDITIONS:			
12	Allowance for working capital	$9,674,058		9,674,058
15	TOTAL ADDITIONS	**$9,674,058**		**$9,674,058**
16	TOTAL ORGINAL COST RATE BASE	**$1,067,091,733**	**$575,976**	**$1,067,667,709**

REFERENCES:
COLUMN (A): SWG SCHEDULE B-1
COLUMN (B): SWG ADJUSTMENT 17, AS MODIFIED BY RUCO
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
RCND RATE BASE

DOCKET NO. G-01551
SCHEDULE BJ-3

LINE NO.	DESCRIPTION	(A) Balance at End of Test Period	(B) RUCO Adjustments	(C) RUCO Adjusted
1	GROSS UTILITY PLANT IN SERVICE			
	Direct	$3,731,878,011	$575,976	$3,732,453,987
	System Allocable	109,795,518	-	109,795,518
	Total Gas Plant	$3,841,673,528	$575,976	$3,842,249,504
2	Less: Accumulated depreciation & amortization	1,556,335,737		1,556,335,737
3	NET UTILITY PLANT IN SERVICE	**$2,285,337,791**	**$575,976**	**$2,285,913,767**
	DEDUCTIONS:			
8	Customer advances for construction	(62,033,165)		(62,033,165)
9	Customer deposits	(48,475,278)		(48,475,278)
10	Accumulated Deferred Income Taxes	(351,778,007)		(351,778,007)
11	TOTAL DEDUCTIONS	**$(462,286,449)**	**$-**	**$(462,286,449)**
	ADDITIONS:			
12	Allowance for working capital	$9,674,058		9,674,058
15	TOTAL ADDITIONS	**$9,674,058**		**$9,674,058**
16	TOTAL ORGINAL COST RATE BASE	**$1,832,725,400**	**$575,976**	**$1,833,301,376**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-3
COLUMN (B): COMPANY SCHEDULE C-2, ADJUSTMENT 17, AS MODIFIED BY RUCO
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
OPERATING INCOME

DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-4

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	A+B (C) RUCO AS ADJUSTED TOTAL COMPANY
1	OPERATING REVENUES	$834,756,858	$(420,471,656)	$414,285,202
2	GAS COST	407,320,096	(407,320,096)	-
3	TOTAL MARGIN	427,436,762	(13,151,560)	414,285,202
	OPERATING EXPENSES:			
4	Other Gas Supply	$1,080,748	$44,279	$1,125,027
5	Distribution	$96,282,901	$2,980,810	$99,263,712
6	Customer Accounts	$31,334,890	$2,147,254	$33,482,145
7	Customer Information	$1,296,429	$(100,317)	$1,196,112
8	Sales	$58,740	$(58,740)	$-
	Administrative and General			
9	Direct	$5,944,630	$261,150	$6,205,780
10	System Allocable	$56,860,171	$(3,440,027)	$53,420,145
	Depreciation and Amortization			
11	Direct	$90,832,850	$2,131,366	$92,964,216
12	System Allocable	$5,333,983	$349,741	$5,683,724
13	Regulatory Amortizations	$4,083,462	$(3,798,881)	$284,581
14	Other Taxes	$25,746,383	$2,769,463	$28,515,846
15	Interest on Customer Deposits	$2,615,905	$292,612	$2,908,517
16	Income Taxes	$24,860,511	$(6,187,002)	$18,673,509
17	Total Expenses	$346,331,603	$(2,608,290)	$343,723,312
18	NET INCOME	81,105,159	$(10,543,270)	$70,561,890

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C1, UNADJUSTED
COLUMN (B): BJ-5, P3
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
OPERATING INCOME ADJUSTMENTS

DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-5
PAGE 1 OF 3

	DESCRIPTION	Revenues and Volumes (A)	Purchased Gas Cost (B)	Labor / Loading Annualization (C)	Call Center and Support Allocation and Annualization (D)	Cost of Service Analysis (E)	Employee Vehicle Compensation (F)	Uncollectible Expense Annualization (G)	Leak Survey and Repair (H)	Injuries and Damages (I)
1	OPERATING REVENUES	$(420,471,656)	$-	$-	$-	$-	$-	$-	$-	$-
2	GAS COST	-	(407,320,096)	-	-	-	-	-	-	-
3	TOTAL MARGIN	(420,471,656)	407,320,096	-	-	-	-	-	-	-
	OPERATING EXPENSES:									
4	Other Gas Supply	$-	$-	$44,279	$-	$-	$-	$-	$-	$-
5	Distribution	$-	$-	$3,239,547	$-	$(19,076)	$(60,789)	$-	$(178,871)	$-
6	Customer Accounts	$-	$-	$1,059,874	$690,350	$(60,073)	$-	$457,103	$-	$-
7	Customer Information	$-	$-	$26,543	$-	$(126,860)	$-	$-	$-	$-
8	Sales	$-	$-	$-	$-	$(58,740)	$-	$-	$-	$-
	Administrative and General									
9	Direct	$-	$-	$45,265	$-	$-	$-	$-	$-	$182,500
10	System Allocable	$-	$-	$1,291,587	$-	$11,971	$(166,443)	$-	$-	$(0)
	Depreciation and Amortization									
11	Direct	$-	$-	$-	$-	$-	$-	$-	$-	$-
12	System Allocable	$-	$-	$-	$-	$-	$-	$-	$-	$-
13	Regulatory Amortizations	$-	$-	$-	$-	$-	$-	$-	$-	$-
14	Other Taxes	$-	$-	$-	$-	$-	$-	$-	$-	$-
15	Interest on Customer Deposits	$-	$-	$-	$-	$-	$-	$-	$-	$-
16	Income Taxes									
17	Total Expenses	$-	$-	$5,707,094	$690,350	$(252,777)	$(227,232)	$457,103	$(178,871)	$182,500
18	NET INCOME	(420,471,656)	407,320,096	(5,707,094)	(690,350)	252,777	227,232	(457,103)	178,871	(182,500)

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C-2, ADJUSTMENT 1, AS MODIFIED BY RUCO
COLUMN (B): COMPANY SCHEDULE C-2, ADJUSTMENT 2
COLUMN (C): COMPANY SCHEDULE C-2, ADJUSTMENT 3, AS MODIFIED BY RUCO
COLUMN (D): COMPANY SCHEDULE C-2, ADJUSTMENT 4
COLUMN (E): COMPANY SCHEDULE C-2, ADJUSTMENT 5
COLUMN (F): COMPANY SCHEDULE C-2, ADJUSTMENT 6
COLUMN (G): COMPANY SCHEDULE C-2, ADJUSTMENT 7
COLUMN (H): COMPANY SCHEDULE C-2, ADJUSTMENT 8
COLUMN (I): COMPANY SCHEDULE C-2, ADJUSTMENT 9, AS MODIFIED BY RUCO

	DESCRIPTION	American Gas Association ("AGA") Dues (J)	Paiute Pipeline/SGTC Annualization (K)	Rate Case Expense (L)	Depreciation and Amortization Expense Annualization (M)	Property Tax Annualization (N)	Interest on Customer Deposits (O)	Surcharge Adjustment (P)
1	OPERATING REVENUES	$-	$-	$-	$-	$-	$-	$-
2	GAS COST	-	-	-	-	-	-	-
3	TOTAL MARGIN	-	-	-	-	-	-	-
	OPERATING EXPENSES:							
4	Other Gas Supply	$-	$-	$-	$-	$-	$-	$-
5	Distribution	$-	$-	$-	$-	$-	$-	$-
6	Customer Accounts	$-	$-	$-	$-	$-	$-	$-
7	Customer Information	$-	$-	$-	$-	$-	$-	$-
8	Sales	$-	$-	$-	$-	$-	$-	$-
	Administrative and General							
9	Direct	$-	$-	$33,386	$-	$-	$-	$-
10	System Allocable	$(93,815)	$44,593	$-	$-	$-	$-	$-
	Depreciation and Amortization							
11	Direct	$-	$-	$-	$2,131,366	$-	$-	$-
12	System Allocable	$-	$-	$-	$349,741	$-	$-	$-
13	Regulatory Amortizations	$-	$-	$-	$-	$-	$-	$(3,798,881)
14	Other Taxes	$-	$-	$-	$-	$2,769,463	$-	$-
15	Interest on Customer Deposits	$-	$-	$-	$-	$-	$292,612	$-
16	Income Taxes							
17	Total Expenses	$(93,815)	$44,593	$33,386	$2,481,107	$2,769,463	$292,612	$(3,798,881)
18	NET INCOME	93,815	(44,593)	(33,386)	(2,481,107)	(2,769,463)	(292,612)	3,798,881

REFERENCES:
COLUMN (J): COMPANY SCHEDULE C-2, ADJUSTMENT 10, AS MODIFIED BY RUCO
COLUMN (K): COMPANY SCHEDULE C-2, ADJUSTMENT 11
COLUMN (L): COMPANY SCHEDULE C-2, ADJUSTMENT 12
COLUMN (M): COMPANY SCHEDULE C-2, ADJUSTMENT 13, AS MODIFIED BY RUCO
COLUMN (N): COMPANY SCHEDULE C-2, ADJUSTMENT 14, AS MODIFIED BY RUCO
COLUMN (O): COMPANY SCHEDULE C-2, ADJUSTMENT 15
COLUMN (P): COMPANY SCHEDULE C-2, ADJUSTMENT 16

	DESCRIPTION	SERP (Q)	MIP (R)	Other Stock-Based Compensation (S)	Total Adjustments (T)
1	OPERATING REVENUES				$(420,471,656)
2	GAS COST				$(407,320,096)
3	TOTAL MARGIN				$(13,151,560)
	OPERATING EXPENSES:				
4	Other Gas Supply				$44,279
5	Distribution				$2,980,810
6	Customer Accounts				$2,147,254
7	Customer Information				$(100,317)
8	Sales				$(58,740)
	Administrative and General				
9	Direct				$261,150
10	System Allocable	$(1,725,839)	$(1,768,249)	$(1,033,831)	$(3,440,027)
	Depreciation and Amortization				
11	Direct				$2,131,366
12	System Allocable				$349,741
13	Regulatory Amortizations				$(3,798,881)
14	Other Taxes				$2,769,463
15	Interest on Customer Deposits				$292,612
16	Income Taxes				
17	Total Expenses	$(1,725,839)	$(1,768,249)	$(1,033,831)	$(2,677,671)
18	NET INCOME	1,725,839	1,768,249	1,033,831	(10,473,889)

REFERENCES:
COLUMN (Q): COMPANY RESPONSE TO RUCO DR 4-3 AND STAFF DR 17-1
COLUMN (R): COMPANY RESPONSE TO STAFF DR 17-2
COLUMN (S): COMPANY RESPONSE TO STAFF DR 17-2

SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
COST OF CAPITAL

DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-6

LINE NO.	TYPE OF CAPITAL	(A) PERCENT	(B) COST RATE	(C) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	50.15%	9.00%	4.51%
2	TOTAL DEBT	49.85%	7.35%	3.66%
3	TOTALS	100.00%		8.18%

REFERENCES:
WAR-1

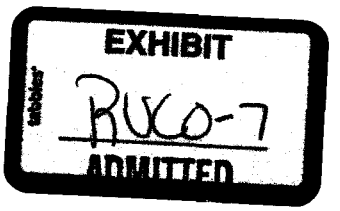
SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
OPERATING INCOME ADJUSTMENT: SYNCHRONIZE INCOME TAXES

DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-7

LINE NO.	DESCRIPTION	TOTAL COMPANY AMOUNT	REFERENCE
	FEDERAL INCOME TAXES:		
1	OPERATING INCOME BEFORE INCOME TAXES	$89,235,399	SCHEDULE BJ-4, LINE 3 – (LINES 4 THROUGH 13)
	LESS:		
2	ARIZONA STATE TAX	3,492,105	LINE 11
3	INTEREST EXPENSE	39,119,078	NOTE (a)
4	FEDERAL TAXABLE INCOME	46,624,216	LINE 1 - LINES 2 & 3
5	FEDERAL INCOME TAX RATE	32.561%	COMPANY SCHEDULE C3
6	FEDERAL INCOME TAX EXPENSE	15,181,404	LINE 4 X LINE 5
	STATE INCOME TAXES:		
7	OPERATING INCOME BEFORE INCOME TAXES	89,235,399	LINE 1
	LESS:		
8	INTEREST EXPENSE	39,119,078	LINE 17
9	STATE TAXABLE INCOME	50,116,321	LINE 7 - LINE 8
10	STATE TAX RATE	6.968%	COMPANY SCHEDULE C3
11	STATE INCOME TAX EXPENSE	3,492,105	LINE 9 X LINE 10
12	TOTAL INCOME TAXES	18,673,509	LINE 6 + LINE 11
13	INCOME TAXES PER COMPANY	24,860,511	SCHEDULE BJ-4
14	ADJUSTMENT	$(6,187,002)	LINE 12 - LINE 13

NOTE (a)
INTEREST SYCHRONIZATION

15	ADJUSTED RATE BASE	$1,067,667,709	SCHEDULE BJ-2
16	WEIGHTED COST OF DEBT	3.66%	SCHEDULE BJ-6
17	INTEREST EXPENSE	$39,119,078	



SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-10-0458

DIRECT RATE DESIGN TESTIMONY

OF

DR. BEN JOHNSON

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 24, 2011

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Appendix A: Qualifications

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. G-01551A-10-0458

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Are you the same Ben Johnson that filed revenue requirements testimony on June 10, 2011?

A. Yes, I am.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, Schedules BJ-8 through BJ-10, which are attached to my testimony, were prepared under my supervision.

Q. What is the nature of this testimony?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of Southwest Gas Corporation's (SWG's) application for a rate increase. The purpose of this testimony is to present RUCO's rate design recommendations.

Q. How is your rate design testimony organized?

A. Following this introduction, my testimony has six sections. In the first section, I briefly discuss the background of the rate design phase of the proceeding. In the second section, I summarize SWG's cost of service methodology and rate design proposals. In the third section, I discuss revenue decoupling and SWG's proposed "Energy Efficiency Enabling Proposal." In the fourth section, I discuss fully allocated class cost of service study, with a particular focus on the issue of whether it is appropriate to allocate fixed costs on a per-customer basis. In the fifth section, I discuss the Company's proposed revenue distribution and offer some suggestions for an alternative approach. In the sixth section, I critique the Company's proposed residential rates, and recommend some changes to the Company's rate design.

Q. Can you please briefly summarize your conclusions and recommendations?

A. Yes. I recommend the Commission reject the Company's decoupling proposal, because it will result in an unjustified increase in future cash flows from customers to stockholders, by guaranteeing the recovery of revenues lost when customers conserve energy while allowing the Company to continue to retain the benefit of revenue and cash flow increases when the number of customers increases, regardless of whether or not system costs increase. This change in future cash flows swamps any purported benefits, but I also disagree with the validity of many of these claimed benefits, for reasons I set forth in my testimony. If the Commission wants to continue to investigate the decoupling concept, I recommend the focus be narrowed to the weather component, where there is a greater chance for the benefits to outweigh the problems.

Turning to SWG's cost of service study, I disagree with the Company's approach to allocating its fixed and sunk costs. The Company advocates allocating these costs based on the number of customers in each class. This places an inordinate share of the system costs onto the residential class. The fixed costs in question are incurred for the purpose of distributing gas to customers; rather than allocating them based on the number of customers, I recommend allocating them based on gas usage. More specifically, I recommend using a "average and peaks" method, giving 50% weight to peak demand, and giving 50% weight to the annual volume of gas distributed to each class (rather than the number of customers).

Similarly, I disagree with the Company's contention that its fixed costs should be recovered through the fixed monthly customer charge. This is not consistent with sound economic pricing principles, and it is inconsistent with important policy objectives related to economic efficiency, energy conservation, and inter-customer equity.

I recommend the Commission consider implementing a seasonal rate structure, to be more consistent with cost causation principles, better encourage energy efficiency, and help improve inter-customer equity. To ameliorate the resulting increase in month-to-month bill

volatility, the Commission could introduce a bill smoothing option, in which customers could opt to pay the gas company a relatively fixed amount each month, based on one-twelfth their anticipated annual gas usage, plus small account-specific true-ups as necessary over the course of the year to ensure that each customer pays the same total amount over the course of the year, regardless of whether or not they select this billing option.

Finally, I disagree with the Company's proposal to expand its low income discount to include very high volumes of gas usage. This proposal would increases the total amount other customers are paying to help low income customers, and it would exacerbate the problem of sending weak energy-conservation signals to low income customers.

I. Background

Q. Can you briefly discuss SWG's most recent rate case?

A. Yes. On August 31, 2007, SWG filed an application requesting an increase in rates. SWG requested a revenue increase of $57,546,205. [Decision 70665, p. 5] Staff and RUCO recommended revenue increases of $28,239,870 and $32,046,846, respectively. [Id.] The Commission determined that the Company was entitled to a revenue increase of $33,533,844, or 8.4% over adjusted test year revenues.[1] [Id.] The Commission did not directly address the Company's class cost of service studies, but did reach conclusions regarding SWG's major rate design proposals.

First, the Commission rejected SWG's proposed decoupling mechanisms, deciding instead to further investigate decoupling through a generic docket. [Id., p. 41] Second, the Commission rejected SWG's proposed volumetric rate design ("VRD"), which would result in smaller users paying a greater percentage of non-gas costs and a smaller percentage of gas costs

1 The Commission determined SWG's adjusted test year revenues to be $399,234,678. [Id., p. 21]

than under traditional rate design, larger users paying a smaller percentage of nongas costs and a greater percentage of gas costs. [Id, pp. 43-44] The Commission concluded that the VRD is "simply an alternative method of enabling the Company to collect more of its margin costs through a shifting of risk from the Company to ratepayers.". [Id., p. 44] Third, the Commission rejected SWG's proposal to adopt an increase in the residential single-family basic monthly charge from the current $9.70 to $12.80, and its parallel proposal to increase the basic monthly charge for other customer classes. [Id., p. 44-46] Instead, the Commission accepted Staff's proposal, which included a smaller increase in the residential monthly customer charge to $10.70 and elimination of the declining block rate structure. [Id., p. 46]

II. SWG's Cost of Service and Rate Design Proposals

Q. Can you briefly summarize SWG's proposals in this phase of the proceeding, beginning with its cost of service study?

A. Yes. The underlying foundation for SWG's proposed rate design and revenue distribution was a class cost of service study (CCOSS). The CCOSS was developed using a three-step process in which test year accounting costs were first functionalized, by grouping costs with similar purposes or functions. The functionalized costs were then classified into capacity-related, volume-related or customer-related costs. Finally, the functionalized and classified costs were allocated to specific service classes using various allocation factors. [Congdon Direct, p. 3]

Q. Can you expain the "functionalization", "classification" and "allocation" steps in a little more detail?

A. Yes. In the natural gas industry, the major functions are production, storage, transmission and distribution. SWG explains: "Southwest Gas' functionalization follows the FERC uniform

system of accounts. Southwest Gas has no production, storage or transmission facilities in its Arizona service areas". [Id.] Under this schema, its only other costs – administrative and corporate overhead costs – are not interpreted as a separate function, but are dealt with at a later stage in the cost allocation process.

Having concluded that essentially all of its costs were supporting the distribution function, the Company then "classified" certain of its costs as capacity-related, presumably on the theory that these costs are primarily a function of the level of peak demand on the system. Other costs were classified as volume-related, based on the reasoning that they are directly affected by the overall volume of gas usage by customers. Other costs that were classified as being customer-related, on the basis that these were costs of "simply providing customers with access to Southwest Gas' system, including the related meter reading and billing expenses". [Id.]

The final step, "allocation," involves applying percentage factors to spread the costs to particular customer classes and rate schedules. The Company explains this was accomplished through the development of:

> allocation factors that appropriately quantify each customer class' relative contribution to Southwest Gas' cost of providing service. Capacity or demand-related allocations are based on relative customer class demands. Commodity allocations are based on relative customer class annual natural gas consumption. Customer allocations are related to the number of customers in each class weighted to recognize cost variations in providing service, such as meter and service cost and billing expenses. [Id., pp. 3-4]

Q. Can you now summarize SWG's rate design methodology?

A. Company witness Gieseking addresses the major aspects of SWG's proposed rate design. These aspects include: the Company's decoupling proposal, which it calls its Energy Efficiency Enabling Provision; its residential rate design methodology; and, its general service rate design

methodology.

Q. What is the Energy Efficiency Enabling Provision?

A. The Company's proposed energy efficiency enabling provision (EEP) is a revenue per customer decoupling mechanism "that is designed to eliminate the link between sales and revenues that currently exists with traditional rate designs ..." [Gieseking Direct, p. 2] The result of such a provision, according to the Company, would be to disassociate SWG's financial performance from the amount of gas it delivers to its customers. [Id.]

> [T]he Company is proposing the EEP to better align utility and customer interests so Southwest Gas will be able to sharpen its focus on customer efficiencies and the development of strategies to achieve the gas energy efficiency standards established by the Commission. [Id.]

SWG has requested implementation of the EEP in part to mitigate current and expected declines in consumption per customer. [Cattanach Direct, p. 10] The EEP would only apply to the residential, and small, medium and large general service customer classes. [Gieseking Direct, p. 7] It would not apply to: Transportation Eligible General Service and Street Lighting; Small Essential Agricultural, Airconditioning, Water Pumping, Electric Generation and Gas Service for Compression; or, Special Contract customers. [Id., pp. 7-8] I discuss SWG's proposed EEP in greater detail in the next section of my testimony.

Q. Can you now summarize the reasoning which underlies SWG's residential rate design proposal?

A. Yes. With regard to residential rate design, Mr. Gieseking explains:

> Southwest Gas considered the following objectives in designing the residential rates proposed in this application: 1) the fair and equitable recovery of costs; 2) rates that work well in tandem with the EEP; 3) customer acceptance and understandability; and 4) the effect of the rate

> design on the promotion of the Company's energy efficiency and conservation efforts. [Gieseking Direct, p. 8]

SWG claims: "Almost 100% of Southwest Gas' cost of providing service is fixed and does not increase or decrease when customer consumption changes". [Id., p. 9] If these costs are recovered through variable charges, the Company contends it "will not recover the full cost of providing service from low use customers, and will recover more from high use customers than it cost to provide them service". [Id.]

By this line of reasoning, SWG could argue for virtually eliminating its per-therm charges (aside from passing through the cost of purchased gas), and in favor of charging nearly all customers roughly the same amount per month – regardless of whether they only use gas for cooking, whether they also use it for water heating, or whether they also use it for heating. Similarly, based upon this reasoning that all-costs-are fixed and its corollary that fixed costs should be recovered on a per-customer basis, the Company could try to charge the same price per month to supply gas to a small studio apartment in a high rise building in the city as it charges to supply gas to a six bedroom home on a two acre lot in the suburbs. In fact, the same logic could even be used to charge roughly the same amount for heating the small apartment as it charges for heating a large grocery store, or even a 10-story office building – if the grocery store or office building is served by a single meter, so the entire building is counted as one customer, while the apartment is metered separately, so it is counted as a single customer as well.

Of course, in this proceeding, SWG is not taking its approach all the way to its logical conclusion. In fact, it is not proposing to increase its basic monthly service charge, nor is it proposing to reduce its per-therm charges toward zero. But this is apparently a concession on the Company's part, related in part to its desire to have its revenue decoupling proposal adopted. Mr. Gieseking explains:

> Without the revenue stability provided by the EEP, Southwest Gas deemed it necessary to seek recovery of a portion of its customer and demand-classified revenue requirement deficiency in the monthly basic service charge (BSC). In this proceeding, because of the revenue stability provided by the EEP, Southwest Gas is proposing to recover the entire revenue deficiency in variable charges... [Id., p. 7]
>
> The basic service charges are unchanged and the entire residential revenue deficiency is recovered in the variable charge, which will facilitate providing customers an incentive to be more energy efficient. [Id., p. 10]
>
> Southwest Gas is proposing to retain the monthly basic service charge and single commodity charge of its current rate design, and simply adjust the commodity rates to recover the proposed residential revenue requirement. [Id.]

Q. Are there some changes included in SWG's residential rate design proposal?

A. Yes. For instance, SWG is proposing a change to its residential low income discount. The current discount only applies to the first 150 therms of monthly consumption. SWG proposes to expand the discount to apply it to all low-income residential consumption during the winter months of November through April. [Id., p. 11]

Also, SWG proposes to tie the summer season residential air conditioning rate under Schedule No. G-15 (Special Residential Gas Service for Air Conditioning) to the air-conditioning rate provided under Schedule No. G-40 (Air Conditioning Gas Service). Apparently there are only a "very small number" of customers taking this service, so SWG has very little cost data associated with it. "Therefore the distribution rate calculated for Schedule G-40 is being utilized as a proxy for the cost of providing this service to residential customers with installed natural gas cooling equipment". [Id., p. 12]

Q. Can you briefly summarize key aspects of SWG's general service rate design proposal?

A. Yes. SWG proposes to modify its Large General Service schedule "in order to better align the recovery of margin with the costs of providing service..." [Id.] Currently, this schedule applies to customers that use between 7,201 and 180,000 therms per year. [Id.] SWG proposes to split the Large General Service class into two separate classes, with applying to customers that use more 7,200 and up to 50,000 therms per year, and the other applying to customers that use more than 50,000 and up to 180,000 therms per year. [Id.] SWG asserts that such a split is justified by its cost of service study. [Id.]

III. Revenue Decoupling

Q. Let's turn to the next section of your testimony. Can you describe SWG's decoupling proposal in a little more detail?

A. Certainly. SWG explains that its proposed EEP is comprised of two components; a "weather-related" component and an "annual true-up" component. [Gieseking Direct, p. 3] Both components involve the money the Company receives from customers for the recovery of costs other than the cost of purchased gas – what can be described as the Company's "operating margin" or its "non-gas revenues."

Under the weather component, during each winter billing cycle actual weather will be compared to the average weather used in setting rates, and customer bills will be adjusted accordingly. [Id.]

> The weather-related component will be provided through an adjustment to winter bills when actual weather during the billing cycle differs from the average weather used in the calculation of rates. In the event of an extreme cold weather event, customers will receive an immediate real-time benefit as there will be a downward adjustment to their bill. [Id.]

The annual true-up component will compare actual non-gas revenues to authorized non-gas revenues, resulting in adjustments to rates, and thus to the following year's revenues, as necessary to move revenues toward the authorized level. Authorized revenue in this context is defined as the Commission-authorized monthly revenue per customer multiplied by the total number of customers billed for service during the month. [Id.] In effect, if this proposal is accepted the Company will be allowed to recover the revenue requirement per-customer that is approved in this case, multiplied times the number of customers served in future years. This has two very significant effects: First, it shields the Company from the potential loss of revenues that occurs when customers buy more efficient appliances or adjust their thermostats – and reduction in revenues attributable to conservation is canceled out (after a lag) through an upward adjustment in the rate per therm, in order to maintain a constant level of revenue per-customer. Second, it allows the Company to increase its revenues to the extent more customers join its system. In a sense, this is a heads-we-win, tails-we-win system, since it stops the erosion of revenues which occurs when usage per customer decreases, while assuring continuation of the offsetting growth in revenues which occurs as the number of customers grows.

Under the Company's proposal, a deferral account will accumulate each month, and a true-up will be computed once a year, on a per-therm basis, by dividing the accumulated deferred account balance by the previous 12 months sales volume. [Id.] The adjusted rate is effective for the subsequent 12 months.

Q. Can you briefly summarize the benefits to stockholders of SWG's decoupling proposal?

A. The Company points to two primary benefits. First, the Company estimates that absent adoption of the EEP, the Commission's energy efficiency goals will shift recovery of approximately $2.4 million of non-gas costs from customers to shareholders. The Company's

EEP would eliminate this alleged phenomena, to the benefit of its shareholders (due to higher payments from customers than would otherwise occur absent adoption of the decoupling proposal). [SWG response to RUCO DR 2-11] Second, decoupling will benefit shareholders by reducing year-to-year volatility in non-gas revenue attributable to weather fluctuations. [Id.]

Q. Does the Commission's recent Decoupling Policy Statement require the approval of some form of decoupling in this case?

A. That is not my understanding. The order adopting the Policy Statement authorizes utilities to file decoupling proposals in their next rate case. [Id., p. 32] However, neither the order nor the Statement seem to require the Commission to approve such proposals. Rather, the Statement sets forth the Commission's preferences regarding the structure of any decoupling program, and providing some guidelines for utilities' to use in developing their decoupling proposals.

While the Commission has acknowledged a concern with financial disincentives, it has not committed to using decoupling, nor has it slammed the door shut on discussion of problems that might arise if decoupling were approved. In fact, the Commission specifically reserves the option to "consider alternative methods for addressing utility financial disincentives". [Id., p. 30]

Q. Did the Company propose a decoupling mechanism in its prior rate case?

A. Yes. The Company proposed revenue decoupling in Docket No. G-01551A-07-0504. In that docket, SWG claimed that its ongoing revenue instability was due primarily to two factors: declining usage per residential customer; and, variations in margin due to weather. [See, Decision 70665, p. 35] The Company proposed two decoupling mechanisms: one to recover the non-gas portion of customer bills based on weather-adjusted volumes (WNAP); and another to recover or refund differences between actual and weather-adjusted non-gas revenues

(RDAP). [Id., pp. 34-35] The Commission rejected the proposal.

> We are not persuaded that the decoupling mechanisms proposed by Southwest Gas in this proceeding should be adopted. Both Staff and RUCO have raised valid concerns regarding the Company's proposals, and we believe that consideration of revenue decoupling through the pending generic docket is the appropriate method of addressing those issues. As indicated in the Company's last rate case, "[decoupling mechanisms] should be fully explored as part of a broader investigation of usage volatility and margin recovery." [Id., pp. 40-41]

The Commission was particularly concerned that decoupling could "provide a disincentive to customers to undertake conservation efforts, because they would be required to pay for gas they did not use". [Id., p. 41] The Commission was also troubled by "providing the Company with what is effectively a guaranteed method of recovering authorized revenues", and by "shifting a significant portion of the Company's risk to ratepayers". [Id.] Rather than approve the decoupling proposal, the Commission opted instead to pursue the issue in a generic docket. [Id.]

Q. Can you briefly summarize the major problems you see with SWG's decoupling proposal?

A. First, the Company's decoupling proposal weakens the incentive customers, builders and developers currently have to be more energy efficient, by sending the message to customers that reduced usage will lead to higher rates, so the more they conserve the more they will pay per therm. Second, SWG's decoupling proposal may lead to a decreased incentive for SWG to contain costs, the opportunity for over-earnings and excessive rates will be increased, and there will be a loss of regulatory oversight which, when combined with the reduced incentive to minimize costs, could ultimately lead to higher costs and higher rates (over and above the increase in rates that will result from the decoupling mechanism itself).

Q. I'd like to discuss each of these points with you in detail. But first, do you agree with the

core premise that customers will benefit from decoupling through lower gas bills, resulting from "enhanced conservation and energy efficiency efforts"?

A. No – because I do not agree that revenue decoupling will achieve the intended purpose of increasing conservation or energy efficiency.

As a theoretical matter, perhaps the Company has a disincentive to promote energy efficiency, and it has an incentive to try to encourage customers to use energy in a profligate manner. However, I have not seen any evidence that the Company has responded to these incentives. For instance, I haven't heard about any advertising programs to discourage customers from installing more insulation, or encourage them to delay the purchase of new, energy efficient appliances. Absent any evidence that the Company is acting on these incentives (or disincentives) or any evidence the incentives are causing real (not imagined) problems, I question the wisdom of embarking on such a massive restructuring of the existing regulatory regime. Even if the Company responds in small ways to these disincentives, or it doesn't try hard enough to encourage its customers to use energy more efficiently, I am not convinced that these disincentives are significant, or need to be changed.

To the contrary, I think the most important incentives are not those faced by the Company's management, but the ones faced by the Company's customers, as well as real estate developers and builders in its service area. These are the people who are actually making the key decisions concerning what type and amount of insulation to install in new buildings, what appliances to replace, what appliances to install, what type of energy to use, and so forth. And, the Company's decoupling proposal does nothing to improve upon or strengthen the incentives facing those individuals – the customers, builders and developers. In fact, the decoupling proposal could very likely have the unintended consequence of weakening the incentives and price signals that are sent to these key decision makers – an adverse change that could swamp any benefits that might arise from changing the incentives facing the Company.

Q. Can you please elaborate on how decoupling could weaken the incentives for customers to be more energy efficient?

A. For customers as a whole, the decoupling program will reduce the benefits obtained from more energy efficient decisions – with rates automatically increasing as per-customer usage declines, customers as a group will not get the same short term benefit they currently receive as a reward fro increased energy efficiency. After the next annual true up, the per unit cost of gas will increase under decoupling – so that the harder customers work at their conservation efforts, the higher rates will increase during the annual true up. In effect, much of the economic gains currently being achieved through conservation will automatically be shifted from the customers back to the utility on an annual basis. Needless to say, for customers as a whole, this suggests that decoupling reduces the economic incentive to conserve.

Of course, a specific customer who reduces their energy usage will still receive an immediate benefit from a lower bill – but other customers will be burdened with higher bills, after the annual true up takes place. Given this disconnect between the individual and the group, it could be argued that the cost / benefit ratio for individual customers will not be greatly worsened by decoupling. But, what if the distinctions between immediate and eventual effects, and the distinctions between individual and group effects are not clearly and adequately communicated through the media? Even if the media do a good job trying to explain decoupling, what if these subtle distinctions are lost on the average consumer, who has plenty of other things to think about? What if customers, builders and developers simply hear that the Commission has adopted a revenue decoupling system, and (correctly) understand that to mean that the way utility rates have been fundamentally changed in ways that ensure that reduced energy usage will automatically result in higher rates after a one year lag?

Many customers may not study the issue in enough detail to realize exactly how the decoupling program works, but they will have the vague understanding that under the new

system, as usage does down rates go up. If so, they may react to this change by deciding it isn't worth the bother to make costly investments for the sake of conservation. Why invest in more costly insulation or more efficient appliances, if reductions in usage lead to higher rates down the road? When trying to decide whether to purchase a new appliance, or to put off that costly purchase for a few more years, they may vaguely remember reading something about decoupling, and think that the gas savings from a more efficient appliance will eventually be taken away (which is true, in the aggregate), so they may think – why waste money on the more energy efficient option? If this is their reaction, their vague understanding of decoupling could tip the scales away from making the purchase, or cause them to pay more attention to other features, or a lower price point, which in turn may lead them to select a different, less efficient appliance.

Under these circumstances, it strikes me as very unwise to simply assume that the Company will suddenly change its behavior in ways that significantly increase the rate at which per customer usage declines, or to simply assume that customers will be oblivious to the change. To the contrary, it seems at least as likely that decoupling will lead to less conservation, not more conservation, by sending the message to customers that reduced usage will lead to higher rates, so the more they conserve the more they will pay per therm.

Its important to realize that the Company only plays an indirect role in conservation decisions. Even if changes in the incentive structure were to change management's behavior (and I've seen no evidence that it will), management necessarily plays a secondary role in all of this. Publicity concerning the decoupling program, and any resulting adverse change in customer attitudes toward energy conservation could far outweigh any potential impact from improving management's attitude. On balance, there is every reason to worry that the actual impact of decoupling will be to slow the rate at which customers, builders and developers adopt more energy efficient technologies, and take other actions to conserve energy.

Q. Didn't the Commission imply in its Decoupling Policy Statement that decoupling can lead to a reduction in infrastructure investment?

A. The Commission stated:

> Historically, Arizona has experienced high population growth and corresponding increases in demand for energy which has required significant investments in distribution, transmission and generation facilities and led to increased utility infrastructure and operational expenses. While growth is anticipated to continue in the future, expanded demand side efforts, such as energy efficiency and demand response, can moderate rate pressures otherwise experienced from growth and reduce customer utility bills. Expansion of demand side management programs ... limits unnecessary load growth. [ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, p. 1]

However, it is important to keep in mind that SWG is a gas distribution company. It's infrastructure investment will continue to primarily be driven by decisions by local governments (installing or authorizing new roads) and real estate developers (expanding into the desert) which lead to the physical expansion of the distribution system. Decisions by builders (whether to install gas or electric appliances) and customers (whether or not to use natural gas as a source of energy) will have at most a secondary or tertiary impact on the Company's infrastructure investment – unlike electric utilities, where energy conservation by existing customers can result in the deferral or avoidance of the need to build costly new generating plants and transmission lines.

Q. The focus of the Company's concern seems to be the loss in revenues that results from reduced usage per customer. Does the Company explain what has caused this long term trend?

A. Yes. According to SWG, the decline in residential use per customer has been primarily caused by efficiency improvements in homes and appliances. [Cattanach Direct, p. 9] Newly constructed homes tend to be better insulated, and designed for greater energy efficiency; along

with a long term trend toward more efficient gas appliances for new and existing customers, this has led to a continuing trend toward declining residential usage. [Id., pp. 9-10]

Q. Does the Company expect this trend to continue?

A. Yes. SWG anticipates a continued decline in consumption per customer, due to "the continued emphasis on energy conservation to reduce energy expenditures and greenhouse gas emissions". [Id., p. 10]

Q. What is your view of these trends?

A. Over the past several decades, as customers have built more efficient, better insulated homes, they have been rewarded with lower utility bills. Customers have responded to higher global energy costs by adjusting their thermostats, replacing appliances with newer, more energy-efficient equipment, and installing more insulation (or moving into a new home that is better insulated); in each case they are rewarded with lower monthly bills.

The financial rewards customers receive from increasing their energy efficiency is a part of the normal market process; this is one of the prime drivers of the downtrend in usage. Customers are rewarded when they purchase less of a virtually any product or service. Admittedly, this normal market phenomena may seem unattractive to the Company – because it places downward pressure on the Company's earnings per share. However, from a public policy perspective, this downward pressure is a good thing. It pressures management to try to offset the impact of this trend by constantly looking for ways to cut costs and increase operational efficiency. If it can keep pace with the increases in efficiency and reductions in cost that are being achieved by its customers, it can sustain its earnings and postpone or avoid the need for rate cases.

While the pressures may be uncomfortable, they have not been excessive or extreme,

nor are these pressures contrary to what we often observe in unregulated markets. When customers find ways to reduce their use of a particular product or service, providers in that industry are pressured to cut costs or increase efficiency, and if they fail to successfully respond to these pressures they risk losing market share, a decline in profits or, in the worst case they will be driven out of business as the number of industry participants shrink.

There is another important point which needs to be kept in mind: the downward trend in per-customer gas usage is largely outside the Company's control. The incentive structure facing the Company's management is unlikely to have much impact on this trend, regardless of whether or not decoupling is adopted. The trend has been driven by price sensitivity in response to upward trends in worldwide energy prices, as well as by federal mandates intended to encourage conservation and reduce reliance on foreign oil. Even if the decoupling proposal were rejected and the Company were to respond by encouraging customers to leave their windows open during cold winter nights, I doubt it would have any impact on the trend.

Q. Does the Company benefit from any offsetting trends?

A. Yes. SWG has experienced an upward trend in the number of customers it serves. The following table shows the average annual number of residential customers from 1998 through 2010 (excluding low-income customers). As shown, the number of residential customers was rapidly increasing in each and every year until 2008, when the real estate bubble popped. Cumulatively, the average number of residential customers increased 39.2% over this time period.

Year	Average Customers	Percent Change	Cumulative Change
1998	613,012		
1999	640,776	4.5%	4.5%
2000	673,567	5.1%	9.6%
2001	699,857	3.9%	13.5%
2002	720,061	2.9%	16.4%
2003	744,408	3.4%	19.8%
2004	785,673	5.5%	25.4%
2005	825,650	5.1%	30.4%
2006	864,201	4.7%	35.1%
2007	891,515	3.2%	38.3%
2008	897,585	0.7%	39.0%
2009	897,265	0.0%	38.9%
2010	899,808	0.3%	39.2%

Source: SWG response to Staff DR 3-25

While no one can know for sure whether, or when, this long trend will resume, the fundamentals haven't changed. People have long shown a desire to move to the Sun Belt, and there is every reason to anticipate the baby boom generation will follow suit. Significantly, this important cohort will be entering the prime retirement age brackets over the next decade or so. For instance, those borne in 1946 are turning 65 this year, and those borne in 1960 will be turning 67 in 2027.

Q. Do you have any data that shows the extent to which the increase in the number of customers using gas has offset the decrease in per customer usage?

A. Yes. The following table shows the same average annual customer counts as the table above, the average annual usage for those customers on a per-customer basis, the total annual usage (average customers multiplied by average usage), the annual change in total usage, and the cumulative change in total usage. As shown, changes in annual total residential usage have fluctuated, ranging from a 14.4% increase in 2004 to an 11.5% decrease in 2009. Cumulatively, total residential usage (excluding low income customers) has increased nearly 5% from 1998 to

2010 – despite the impact of the recession and the recent slowing of migration into the state.

Year	Average Customers	Average Usage	Total Usage	Percent Change	Cumulative Change
1998	613,012	442.8	271,441,714		
1999	640,776	381.6	244,520,122	-9.9%	-9.9%
2000	673,567	379.8	255,820,747	4.6%	-5.3%
2001	699,857	382.5	267,695,303	4.6%	-0.7%
2002	720,061	353.0	254,181,533	-5.0%	-5.7%
2003	744,408	330.8	246,250,166	-3.1%	-8.8%
2004	785,673	358.7	281,820,905	14.4%	5.6%
2005	825,650	320.7	264,785,955	-6.0%	-0.4%
2006	864,201	309.2	267,210,949	0.9%	0.5%
2007	891,515	321.6	286,711,224	7.3%	7.8%
2008	897,585	319.4	286,688,649	0.0%	7.8%
2009	897,265	282.7	253,656,816	-11.5%	-3.7%
2010	899,808	306.1	275,431,229	8.6%	4.8%

Q. Is customer growth significant?

A. Yes. Even without a rebound in the economy or a resumption of population growth, the Company could benefit from customer growth over the next decade, since there a very significant number of unserved potential customers in SWG's Arizona service territory. For example, the U.S. Census Bureau estimates that as of 2009 there were 1,589,242 housing units in Maricopa County (Phoenix), and 428,564 housing units in Pima County (Tuscon). Comparing the total number of households to the total number of residential customers, it is readily apparent that some households are not using natural gas, and thus SWG could benefit from a shift in customer preferences toward natural gas as an energy source.

As well, SWG's Arizona service territory contains numerous unoccupied houses – including homes that were built during the real estate bubble, which currently stand empty, but will undoubtedly be purchased and occupied at some point in the future, after the economy strengthens and prices stabilize.

And, of course, the underlying appeal of Tucson and Phoenix remain unchanged – the

beautiful scenery, warm weather, lively culture, moderate taxes, and other fundamentals which have contributed to inward migration are all factors that remain intact. In fact, as noted a moment ago, the underlying demographics of the baby boom generation suggests the Company's Arizona service territory could experience another substantial wave of population growth once the baby boom generation reaches retirement age – a wave that could continue for the next decade or more.

Q. Do you agree with the claim that customers will benefit from capping SWG's revenue per customer to a specific dollar amount authorized by the Commission?

A. No. It's hard to see how switching from a regulatory system in which rates are capped to one in which revenues per customers are capped can be seen as a benefit to customers – particularly in the context of a gradual, long term trend toward reduced usage per customer – a trend that has directly benefited customers, and indirectly benefited them by creating pressure on management to increase efficiency and cut costs in an effort to ameliorate the impact of that trend, and avoid the need to file rate cases. over the years.

It isn't completely clear to me exactly what SWG is arguing with regard to capping revenues per customer. But, perhaps it is arguing that decoupling will provide less of an opportunity to over-earn (since the Company frames this issue in terms of limiting revenues per customer to a specific dollar amount). If so, it is being disingenuous at best. SWG will still be able to earn more than its authorized rate of return between rate cases, and in fact the opportunity to over-earn between rate cases will actually increase, because the trajectory of cash flows will shift in its favor. Rates per therm will automatically be increased once a year, in response to reductions in usage per customer, without having to wait to consider the impact of that reduction in the context of a full rate case, where other factors, including technological improvements, productivity improvements, and growth in the number of customers, would also

be taken into consideration. By automatically increasing rates in an expedited proceeding, based upon a narrow consideration of just one aspect of the overall picture (declining usage per customer), the opportunity for over-earnings and excessive rates will actually be increased, rather than decreased.

Q. Do you agree that customers will benefit through a decrease in rate case frequency?

A. No. It is true that decoupling may lead to fewer rate cases, but this isn't necessarily a benefit. At a minimum, the savings in reduced rate case expense must be weighed against the loss of regulatory oversight and the weakened incentive for management to minimize costs between rate cases. Under decoupling, the trajectory in cash flows over time will clearly be more favorable from managements perspective – it will be easier to maintain or boost earnings per share without necessarily having to struggle to minimize costs and increase efficiency, because rates will be automatically increased once a year to offset the decline in per-customer usage, and revenues will continue to increase as customers growth occurs. In fact, if growth in the number of customers resumes its historic pace, and technological progress and industry-wide and economy-wide productivity improvements continue as they have historically, management may find that it can keep earnings robust between rate cases without having to work very hard to contain costs. If anything, its main concern may be to ensure that earnings do not grow so rapidly as to trigger the unwanted scrutiny of an over-earnings rate review.

Q. Do you agree that customers will benefit from decoupling because SWG will have a stronger incentive to cut costs?

A. No. Whenever management cuts costs, the immediate beneficiaries are stockholders. Customers eventually share in the benefit, but only after a lag, when a rate case occurs. To the extent decoupling automatically increases per-unit rates between rate cases, and extends the

period between rate cases, there will be less pressure on management to cut costs as I explained earlier. But, to the extent cost cutting does occur, the benefits will be retained by stockholders for a longer period of time (assuming a longer lag between rate cases). In fact, management's main concern may shift away from the need to occasionally request a rate increase to the need to avoid the unwanted scrutiny of an over-earnings rate review.

If rate cases are less frequent, because rates are automatically increased by the decoupling mechanism, there will be fewer opportunities for customers to share in the benefits of any cost reductions and efficiency gains achieved by management – so it's hard to see how any alleged incentive for management to cut costs could translate into much benefit for customers.

Q. What about the potential for a reduction in capital costs?

A. If decoupling reduces the volatility of the Company's revenues and income, and this translates into lower business risks, lower equity costs, and lower interest rates paid by SWG when it raises debt capital, and those risk and cost reductions are eventually reflected in rates, customers may eventually benefit. This possibility was highlighted in the Commission's decoupling Policy Statement, which states:

> The review of the initial three-year period following adoption of revenue per customer decoupling should include analysis and discussion of possible adjustments to cost of capital to recognize any modified risk at the utilities, as well as benchmarking and comparisons to other utilities operating with revenue per customer decoupling. [ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, p. 2]

However, it will be difficult to measure the change in risk, and any estimate will be controversial and subject to the criticism that it is too speculative. Even if the data strongly supports a finding that equity costs have declined, I doubt the Company will concede the point,

and the issue will undoubtedly be controversial. Therefore, I am not optimistic that customers will fully share in the benefits of any reduction in risk, or in the cost of debt and equity, if the decoupling proposal is accepted.

In any event, whatever benefit might occur with regard to the cost of capital, the benefits could be more than offset if decoupling leads to an increase in the size of the Company's rate base – due to a phenomena known as the AJ effect. It's important to realize that decoupling will not eliminate management's incentive to take actions which cause the Company to grow, and to invest in ways that allow it to expand its rate base – incentives that are particularly strong if the authorized rate of return is greater than the Company's true cost of capital. If, for example, a utility is allowed to earn 9.0% percent on new investments, but it can raise capital at a cost of 8.25% percent, it can increase shareholder wealth (and justify higher management salaries and bonuses) by increasing its capital investment and rate base as much as feasible. The reason is simple – every thousand dollars of additional investment will cost $82.50 per year, but that same investment will earn $90.00 per year.

Q. Can you briefly elaborate on this problem?

A. Yes. Rate-regulated utilities are not guaranteed they will earn the allowed return, but they are legally entitled to the *opportunity* to earn the approved fair rate of return, which must be sufficient to at least cover their cost of capital. In practice, the allowed rate of return will almost always exceed the actual cost of capital because setting the rate of return below the cost of capital would be contrary to various legal standards, and because a regime in which rates of return are less than the cost of capital would ultimately be unsustainable in practical terms – because utilities would encounter difficulty in raising capital, which would jeopardize their ability to provide safe and reliable service to the public. Under decoupling, SWG will continue to have an incentive to expand its operations and to invest in new plant. Decoupling will not

eliminate management's desire to grow the size of its operation, or to invest in new facilities, in order to increase the size of the rate base. To the extent the trajectory of future cash flows is improved and the frequency of rate cases is diminished, the incentive for over-investment, and ultimately higher rates may be a problem which grows, rather than diminishes, as a result of decoupling.

Q. What do you recommend the Commission do regarding SWG's decoupling proposal?

A. I recommend the Commission reject the proposal for the reasons I have just given. I recognize that the Commission has expressed an interest in decoupling, and that the issues surrounding decoupling are not unique to SWG, or even to Arizona. However, I see no pressing need to adopt any form of decoupling at this time; instead, the Commission could continue to investigate the issues in other pending rate proceedings, and if necessary it could even use explore the issues further in another generic proceeding.

If the Commission still wants to consider some form of decoupling, despite all of the concerns I have raised, I recommend it focus on weather decoupling, and scrutinize the proposal very carefully to ensure that it does not increase the risk of SWG over-earning. The same weather fluctuations which lead to significant variations in SWG's earnings can also lead to drastic swings in customer bills from month to month and year to year. During unusually cold winter months, both customer bills and the Company's earnings will be unusually high. The weather adjustment component of the decoupling proposal will have the salutary effect of reducing rates immediately after unusually cold weather, effectively rebating the excess payments back to customers, smoothing out he Company's earnings as well as the revenue burden of the average customer.

In this regard, I agree with the Commission's conclusion that weather decoupling can benefit both utilities and customers by "enhanc[ing] utility and customer billing stability".

[ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, p. 29] Both customer's and stockholders would benefit from the changes wrought by the weather decoupling proposal – the reduction in weather related billing volatility will make earnings more stable and predictable for stockholders, and it will make it easier for customer to budget for their gas consumption – a benefit that will be particularly significant for those of modest means who are living on a fixed income.

IV. Fully Allocated Embedded Costs

Q. Let's turn to the next section of your testimony. Can you provide a brief description of fully allocated embedded cost studies, and explain what they measure?

A. Certainly. Fully allocated cost of service studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the rate of return earned from each class. Many of these costs are either joint or common costs not directly attributable to any one customer class; therefore, they must be allocated by a formula. This opens the door to subjective judgments, and the results of the study tend to depend heavily on the particular allocation formulas chosen by the analyst.

Because they are based upon embedded costs, these studies do not report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" is not necessarily the actual expense that a particular group of customers imposes on the system. Nevertheless, cost of service studies have long been used by this Commission and other regulators as a tool that can assist with the process of developing electric and gas rates. As long as their limitations are recognized, and reasonable allocation formulas are employed, fully allocated cost studies can help the Commission in determining an appropriate distribution of the revenue requirement amongst the various

customer classes.

Q. Can the judgment and arbitrariness be eliminated, if the analyst is completely unbiased and if sufficient effort is applied to the task?

A. No. Embedded cost allocation studies are simply a technique for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At best, these studies provide a yardstick for judging whether or not each customer class is paying an appropriate share of the joint and common costs. The real question is whether the yardstick is reasonably straight and true, or whether it is bent to favor particular classes at the expense of others.

The problem lies neither with the people performing the studies nor with the amount of effort and resources devoted to the analysis. Rather, it is inherent in the very concept of allocating embedded costs. To a large degree, these costs are the result of external factors (e.g. the configuration of roads within the Company's service territory) as well as management and engineering decisions which reflect many different considerations. These external factors, management decisions, and engineering judgments are completely outside the control of individual customers or customer classes, and the costs that are influenced by these factors, decisions and judgments cannot be unambiguously traced to individual customers or customer classes. To the extent the Commission wants to pursue the goal of insuring that each customer class pays the costs that it causes, it simply isn't possible to achieve this goal by allocating historical accounting costs.

Even when the actions of particular customer classes do influence the costs in question, the linkage is largely indirect, and is obscured by the passage of time. For instance, various customer decisions have influenced the management decisions and engineering judgments that determined the distribution system investments and related operating costs that were incurred

during the test year. However, these customer influences are almost entirely traceable to actions (and anticipated actions) by customers that occurred years ago, when the distribution lines serving today's customers were originally planned and constructed.

In truth, the cause and effect links between today's customers (or the customers present during the test year) and costs incurred during the test year are inherently impossible to measure using the techniques that are available for developing an embedded cost of service study. All of the various alternative allocation formulas rely upon statistics relating to the test year, and none of them can possibly reflect with exactness the historic relationships of cause and effect that explain the embedded accounting costs reflected in the test year data.

For these and other reasons, there is no "perfect" formula for allocating most, if not all, of the costs incurred by SWG, particularly the cost of distribution mains. Some cost allocation experts will sometimes imply their approach is the "true" answer, and that any significantly different approach is a heresy not to be condoned. I disagree with that viewpoint. There is a substantial body of economic literature which convincingly demonstrates that there is no "correct" method for allocating joint and common costs, and any attempt to locate the perfect method will ultimately prove fruitless.

Aside from the long lags that typically occur between when costs are planned, contracted, and incurred and when those costs are recovered through rates, there is another fundamental problem. Most of the Company's embedded costs are not caused by the actions of particular customers or customer classes; rather they are incurred by management based upon an evaluation of the needs of the system as a whole. Thus it isn't feasible, or meaningful, to rely entirely on an evaluation of causal relationships in deciding on the most reasonable allocation method.

Consider, for example, a hypothetical investment in distribution mains for which 20% of the cost can be directly and meaningfully traced to decisions by customers concerning whether

to use natural gas or electricity for heating, and the specific appliances and insulation they choose to install in their homes and places of business. The remaining 80% of this hypothetical investment is entirely attributable to factors like the geography of the Company's service territory, and the arrangement of roads and streets that have been constructed by local government over the course of decades. Under these circumstances, it would not necessarily be reasonable to allocate 100% of the investment solely on the basis of any specific statistics related to customer classes, when such a small fraction of the total costs is logically and directly traceable to customer decisions. Furthermore, given time lags involved and the impossibility of identifying and measuring causative factors precisely, even the small fraction of the cost which is attributable to customer decisions might be misinterpreted and traced to the wrong classes.

The requirement in a fully allocated cost-of-service study that all costs be allocated, regardless of how ambiguous the causal relationship with the service in question, produces results that are defined by the particular allocation methodology selected, rather than by established economic costing principles. Thus, any number of widely different estimates of "cost" could be produced for a given service category, merely by changing the allocation procedure. One study might show a particular customer category earning an above-average rate of return, while another study of the same company might show a negative return for that same category. The allocation scheme is pivotal. These allocation decisions are highly judgmental and (not surprisingly) controversial in regulatory proceedings where fully allocated studies are introduced--particularly where the joint costs are a very substantial fraction of the firms total costs.

Q. Can you describe the allocation approach used by SWG?

A. SWG allocates distribution mains and other "fixed" costs based on a 50/50 weighting of peak demand and the number of customers. SWG explains:

> The distribution system of Southwest Gas is designed and constructed to serve customers' peak demands. The CCOSS should reflect the underlying factors driving costs on the Company's system, which in the case of distribution mains is serving customers and their collective peak load requirements. Commodity-related requirements are by nature fully accommodated by the Company's peak demand planning criteria and, in effect, become a byproduct of the planning criteria.
>
> A commodity-based allocation of distribution mains does not reflect that sizing the distribution system to meet peak day demand provides the capacity needed to meet customers' annual throughput. Arizona Commission Decision No. 64172, issued in Southwest Gas Docket No. G-01551A-00-0309 ET AL., supported Arizona Commission Staff's methodology of allocating half the cost of distribution mains on number of customers and half on demand, as Southwest has proposed in this case. [SWG response to Staff DR 3-37]

Q. How does SWG develop the demand portion of its allocation methodology?

A. In SWG's view, peak usage is the main factor used by the engineers when making system design decisions, such as the diameter of the pipes. However, they don't have hourly or even daily peak demand data to use for the allocation process, so they are substituting January gas volume data, which is effectively serving as a proxy for peak demand. When asked to provide historical peak daily usage statistics, SWG responded:

> Southwest Gas does not have individual customer or customer class peak day demands. Southwest Gas uses each class' coincident peak month throughput to allocate costs in the class cost of service study. [SWG response to Staff DR 19-4]

Similarly,

> Southwest Gas does not have daily demand data by customer class and performs its demand analyses and allocations using monthly demand data. [SWG response to Staff DR 19-5]

For most customer classes, SWG uses monthly data for January, presumably on the theory that January was the coldest month of the test year, and the main reason demand varies over time is

the impact of weather fluctuations. By focusing on class usage in relative percentage terms during the month with the coldest weather and largest volume of gas distributed, the Company is arriving at relatively percentages that roughly parallel the results they would obtain if they had class-specific demand data during the system peak hour.

Q. Do you agree with SWG's cost allocation approach?

A. No. I disagree with the Company's way of viewing the costs in question, as well as the specific allocation methodology it has adopted. The fundamental problem is that so many of the costs are what economists would describe as "fixed" costs – they do not change much from day to day or even from year to year. Over the long run these costs do vary to some degree with respect to anticipated levels of peak demand, but this variation is not nearly as significant from an economic perspective as the Company suggests it is from an engineering perspective. And, the problem is even more severe with respect to the Company's rationale for using customers statistics to allocate much of the costs.

It is true, in one sense, that a distribution system is designed and constructed to serve customers' peak demands – but it is even more fundamentally true that a distribution system involves fixed costs that are incurred for the purpose of distributing gas to customers. Unless the total anticipated volume of gas is large enough, and the service of distributing that gas to customers is valuable enough, customers will not connect to the gas system even if it is built, and they will instead rely on other alternatives, like propane and electricity. While peak demand may be the focus of the engineering design phase, at a more fundamental level it is clear that management's investment decisions are not primarily driven by peak demands, but rather by the anticipated economic value of the system over its entire life cycle – something which is primarily a function of the anticipated volume of gas that will be distributed by the system. The anticipated volume of gas sold is ultimately what is important (which in turn

depends on the attractiveness of this energy source compared to others), rather than the number of customers or the hourly pattern of usage (peak volumes).

Of course, a portion of the system costs does vary as a function of the peak demand, and this variation is the focus of much of the engineering planning process. As a result, it is fair to say that the incremental cost of installing larger pipes rather than smaller ones is a function of peak demand. And, another small portion of the costs will vary as a function of the number of customer locations (but not the number of customers, per se). For instance, the incremental cost of installing service lines to connect each customer location to the nearest distribution main is a function of the number of buildings connected to the system. However, strictly speaking, even the cost of service lines doesn't necessarily vary directly with the number of customers. Rather, the cost of service lines is primarily a function of the configuration of buildings – how many buildings are served, and how far back the building is located, relative to the distribution main that passes by the property.

A single service line can connect a single large apartment building, a quadraplex, or a individual house to the distribution system. The size of the respective service lines to serve these buildings might vary, but if the costs do vary, the variation will primarily be a function of the anticipated peak demand and overall volume of gas (a larger pipe will be installed if it is anticipated that a lot of gas will be used by the customer or customers served by the line). However, neither the design of the service line, nor its cost is purely a function of the number of customers. This can easily be seen by thinking about two simple hypothetical examples. Consider a 4,000 square foot Quadraplex and a 4,000 square foot single family home. If the anticipated consumption is the same for both buildings, the cost of the service line might be identical – yet one building could contain as many as four customers, while the other would have no more than one customer.

The central role of gas consumption, and the relative insignificance of the number of

customers can be even more dramatically illustrated by considering a hypothetical building containing 30 apartments. The decision to install a service line to the building, and the size of the service line, will depend upon decisions made by the original owner or developer of the building – whether he anticipates the occupants will be using electricity for all of their energy needs, or will be using gas for some of their requirements. Suppose he decides to use electricity for everything except water heating; in that case, the developer or owner will still need to decide whether to install a centralized system that provides hot water circulating throughout the building, or install a separate water heater in each apartment, and whether to use solar, natural gas or propane to heat the water. All of these decisions will be driven by anticipations concerning energy usage over the life cycle of the investment decisions – including his perceptions concerning convenience, cost effectiveness, and other factors relating to the relative merits of each energy choice.

What is striking about this hypothetical example is not only that the cost of serving the building is largely a function of decisions made based on an evaluation of the merits of natural gas relative to alternative energy sources, but also that the costs are almost entirely independent of the number of customers in the building. Aside from the cost of metering and billing, there is very little difference in the costs the Company will incur to provide gas service to an apartment building where the landlord purchases gas for the entire building through a single customer account, or the same building using the same amount of gas, where each apartment is connected to an individual meter.

In evaluating the relative merits of different approaches, I believe it is important for the Commission to give adequate recognition to the basic product being sold by SWG: gas energy. Any allocation method that slights the importance of the most fundamental measure of the Company's output (therms of gas) should be viewed with skepticism. Where there is no clear cause-and-effect relationship between customer actions and costs, therm sales provides a

reasonable basis for allocation, because they closely reflect the benefits received by each class from the investments and expenses in question. From an economic standpoint it is clear that utilities does not build a distribution system merely to meet peak demand. Rather, these investments are made in anticipation of distributing gas – unless gas is viewed favorably relative to other energy sources (there is strong enough demand for gas), customers will not connect to the system, and ultimately the system itself would not exist.

Q. You mentioned most of the costs being allocated would be described by economists as fixed costs. Can you please explain more concerning how economists view the costs that are relevant to this discussion?

A. Yes. Common costs are incurred when production processes yield two or more outputs. They are often common to the entire output of the firm but can be common to just some of the outputs produced by the firm. An increase in production of any one good will tend to increase the level of common costs; however, the increase will not necessarily be proportional. The costs of producing several products within a single firm may be less than the sum of the analogous costs that would be incurred if each of the products were produced separately.

A joint cost is a specific type of common cost--one incurred when production processes yield two or more outputs in fixed proportions. A classic example arises in the joint production of leather and beef. Although cattle feed is a necessary input for the production of both gloves and hamburgers, there is no economically meaningful way to separate out the feed costs that are required to produce each. If the quantity of leather and beef is reduced, there will be a savings in the amount of cattle feeding costs, but it is impossible to say how much of this change in cost results from the change in the quantity of leather and how much from the change in the quantity of beef.

An allocated cost is a joint or common cost that has been divided among the firm's

different customers or products, in accordance with a particular formula or the judgments of a cost analyst. Economic theory demonstrates that there is no inherently correct method of allocating joint costs among the various joint products. Purchasers of each of the joint products will bear some share of the joint costs, in relative proportions that are determined by the relative strength of demand in the various markets, rather than by some arbitrary allocation formula.

Fixed costs are simply those elements of the firm's total cost which do not increase as the volume of output increases. The difference between fixed costs and sunk costs is that the former can be reduced or eliminated if the firm is willing to exit the market entirely (e.g., by converting its equipment over to another purpose). In contrast, sunk costs cannot be avoided or changed even by discontinuing production entirely; thus, they are considered irrelevant for most economic decisions. A simple example of a fixed cost is the cost of owning a factory building; as long as the building is in use as a factory, its costs are unavoidable (and they do not vary with the volume of output produced by the factory). However, if the firm discontinues production, and sells the building to someone who converts it to another use, it will avoid the costs of ownership. Hence, the cost is fixed, but it is not sunk because the building can be readily converted to another purpose.

A simple example of a sunk cost is the cost of writing a novel. Once this cost is incurred, it cannot be avoided, reduced, or eliminated, regardless of whether or not the novel is published, or how many copies are sold. Stated another way, sunk costs are irretrievable once the decision to incur them is implemented. From that time forward, they are completely irrelevant to any pricing, production, or other economic decisions that must be made.

Q. How do these concepts relate to the issues in this proceeding?

A. In attempting to analyze prices relative to costs, joint costs create considerable difficulty and controversy. The classic solution favored in regulatory proceedings is to allocate a reasonable

share of the joint costs to each of the joint products. Unfortunately, as economic theory demonstrates, there is no unequivocally correct way to allocate these costs among the various services.

The costs of installing and operating a gas distribution system are almost entirely common costs – as should be apparent from the fact that numerous customers are all served using a common system – and it is difficult to disentangle the cost of serving one customer from the cost of serving another customer. Looking more closely at the definition of common costs given earlier, it is apparent that if the volume of gas distributed to any single customer increases, to the extent this increases the overall cost of building and operating the system, the increase in costs will will not necessarily be proportional. To the contrary, the costs of providing gas service to multiple customers (or customer classes) within a single firm will tend to be substantially less than the sum of the analogous costs that would be incurred if each customer (or customer class) were served separately. In other words, gas distribution system enjoy economies of scale and scope.

Because of the pervasive impact of economies of scale and scope, there is no unambiguous "cost causative" method available for allocating the fixed costs of the distribution system. The most that can be hoped for is an allocation method that produces reasonable and equitable results.

In the gas industry, the cost of installing pipes is a sunk cost: once the pipe is in place, no future decision will alter those installation costs, or allow them to be not incurred. If the company is able to salvage some of the material involved, the salvageable portion of the pipe cost would be considered a fixed cost, but not sunk. However, the labor needed to engineer and install the facilities is irretrievable. Therefore, once the labor costs of installation have been incurred, they are irrelevant to future decisions about the appropriate price level for the service or services that utilize the pipe.

In the calculation of marginal or incremental cost, fixed and sunk costs are canceled out in the computations. This is one of the most distinctive attributes of the economist's concept of marginal cost, setting this concept apart from more conventional notions of average or total cost. The reason for this distinctive treatment is straightforward: since fixed and sunk costs do not change with the volume of output, they have no direct impact on the level of marginal cost, which is the change in total cost associated with a change in output.

Q. Can you relate this discussion of joint and common costs to the issue of whether the Commission should allocate SWG's fixed costs giving 50% weight to peak demand and 50% weight to the number of customers?

A. Yes. I don't disagree with the portion of SWG's cost allocation approach which allocates 50% of the system costs on the basis of peak demand. There are additional costs incurred in order to install a larger main that is capable of handling more gas during peak hours. The design and cost of the system is influenced by anticipated future peak usage of each main, and thus it is reasonable to give some weight to peak demand statistics. However, I strongly disagree with the decision to give 50% weight to the number of customers, and the failure to give any weight whatsoever to gas usage – which is the factor that largely controls the decision to build or expand the system in the first place.

In other words, anticipated peak demand influences the size of the pipes, which increases the cost of the pipes (albeit less than proportionally to the increase in demand). Hence, I don't object to allocating 50% of the costs on the basis of peak usage data. However, However, a distribution system has many of the characteristics of a "joint" cost in the classic sense. To a large extent, system costs are a function of the number of miles of streets served, and not a function of the level of peak demand or the number of customers who are, or will be, connected to the system. For instance, the cost of opening a trench and installing a pipe of even

minimum size is substantial – and this minimum system cost closely fits the classic definition of a "joint" cost, since it doesn't vary with output, but rather with the number of miles of pipe that needs to be installed.

In competitive markets, to the extent common costs vary with output, they are recovered in the same manner as direct costs--they directly affect the marginal cost of producing each service, and thus directly influence prices. (In competitive markets, prices tend to equilibrate towards marginal cost). Joint costs, on the other hand, have no impact on marginal cost, and thus do not directly determine prices in competitive markets.

In competitive markets, joint costs are never recovered entirely from consumers of one of the joint products, to the exclusion of the others; rather, the costs are shared by both groups of consumers, with the respective proportions depending upon the relative strength of demand. The stronger the demand, the greater the share of joint costs that will be borne by the respective product, service, or customer group.

Q. You've explained why you disagree with the Company's proposed method of allocating fixed or sunk system costs. Can you now briefly explain the approach you recommend using instead?

A. Yes. I recommend using the "average and peaks" allocation method. More specifically, I recommend giving 50% weight to peak demand, like the Company, but instead of giving the remaining 50% weight to the number of customers, I recommend using total annual gas volume, instead. My recommended approach recognizes that the primary purpose of the system is to provide energy used by its customers, and thus it gives considerable weight to energy usage (total gas usage). However, my approach also recognizes that it is less costly to serve customers who use energy more uniformly throughout the year. Thus, for example, it is less costly to provide gas to heat water for a home or office than it is to provide gas to heat the home

or office itself (due to wide variations in temperatures over the course of the year). Logically, both total gas usage and peak demand should be considered during the allocation process, and this is what I recommend doing. To the extent a cost allocation method is supposed to reflect the factors which "cause" costs, it makes sense to give some consideration to coincident peak data, as well as the total volume of gas used during the course of the test year.

Q. Have you developed any estimates of the impact of following your recommendation?

A. Yes, I have. For illustrative purposes, I developed an alternative set of cost of service results giving 50% weight to peak demand and 50% weight to gas usage. For ease of development and comparison, these calculations are based on the Company's revenue requirement filing, and thus the calculated returns are substantially lower than would be computed if I had started with RUCO's revenue requirement calculations.

As shown on Schedule BJ-8, relative to the Company's study, the major residential classes and the small general service class show higher returns, and the medium and large General Service classes show lower returns, as shown in the following table (which summarizes key results from Schedule BJ-8):

	Company	RUCO
Single-Family Residential	2.32%	4.84%
Multi-Family Residential	1.50%	7.30%
Small General	10.98%	17.30%
Medium General	8.16%	4.51%
Large-1 General	17.33%	6.41%

My recommended allocation method generates rates of return of 4.84% and 7.30% for the single-family and multi-family residential classes, respectively. These compare to returns of

2.32% and 4.84% for these two classes under the Company's approach.

My proposed allocation methodology results in an overall rate of return of 17.30%, 4.51% and 6.41% for the Small, Medium and Large-1 General Service classes, respectively. These compare to returns of 10.98%, 8.16% and 17.33%, respectively, for these classes under the Company's approach.

V. Revenue Distribution

Q. Let's turn to the fourth section of your testimony. What factors do you think should be considered in developing the interclass revenue distribution?

A. I recommend giving some consideration to the cost of service results. However, as a policy matter, I think it is important to note that other factors can also be important in developing a fair and reasonable revenue distribution, including historical rate relationships, ability to pay, relative risk, and demand or market conditions (including the extent of competition that might exist).

It is sometimes argued that the revenue burden should be distributed among the classes based entirely upon the results of a particular class cost-of-service study, at least as a goal. This argument has grown in popularity as "cost-based" ratemaking has come into vogue. However, I fundamentally disagree with this philosophy, particularly when it is tied to a single embedded cost allocation study. Valid cost-of-service studies can provide a useful starting point in developing the overall revenue distribution; but even if the cost study itself isn't controversial, the ultimate determination of rate spread should be tempered by consideration of other factors, such as the ones I just enumerated.

Any proposal to move away from the existing rate relationships should be implemented gradually. This is particularly important in a case like the present one, where there is relatively

little information available to evaluate how the various allocation methods react to changing weather and economic conditions, and thus little is known about how the various class returns react to changing conditions in the future. While I strongly believe the approach I am recommending is superior to the one proposed by the Company, I recognize that the latter approach was recommended by the Staff and accepted by the Commission in the prior case. I would hope the Commission will be persuaded by the merits of the alternative approach I have recommended – but even if the Commission accepts this change in methodology, I believe the resulting shift in the revenue distribution should be introduced gradually.

I also believe that the revenue distribution should not be designed merely to track the results of a particular cost-of-service study, regardless of how well founded that study may be. Instead, thought should be given from the outset to the potential hardships imposed on particular classes, historical relationships among the classes, and other elements of interclass equity. Moreover, the Commission should recognize that efforts to achieve uniform class rates of return are mostly fruitless. Even if a consistent COS methodology is employed from case to case, fluctuations in weather, economic conditions, and other variables can easily produce absolute fluctuations in the class rates of return of 1%-4% or even more, defeating such any attempt at perfect uniformity. If an above-average increase is imposed in one case (because a class appears to earning less than the average return), a below-average increase may appear appropriate for that same class in the next case, simply because of minor fluctuations in economic conditions or usage patterns – even if the underlying methodology is not changing. Of course, where changes in the costing methodology are involved, the class returns can fluctuate by even wider margins, due simply to differences in allocation techniques.

Given the inherent instability and subjectivity of the various allocations, the goal of absolute uniformity in class rates of return can probably never be achieved. Such an effort is an attempt to hit a moving target, and that very effort can potentially conflict with important policy

objectives, like rate continuity, gradualism and stability.

Q. How has the Company proposed to distribute its proposed revenue increase among the various customer classes?

A. The Company is proposing different percentage increases for the various customer classes. It developed a methodology which moves the individual customer classes toward a uniform rate of return, but it ameliorated the impact and simplified the resulting percentage increases in various ways. SWG explains:

> Some rate classes show a rate-of-return below the system average, sometimes referred to as under performing, and some classes show a rate-of-return above the system average, sometimes referred to as over performing. Southwest Gas' methodology takes this rate-of-return difference into consideration by distributing more of the requested rate relief to underperforming classes and limiting the distribution to classes that are over performing. The purpose of this methodology is to move customer class' rate-of-return towards the system average rate-of-return. [SWG response to RUCO DR 10-1]

More specifically, SWG performed the following steps: 1) Customer classes whose rate-of-return was greater than 3 times the proposed system average rate-of-return were excluded from the deficiency distribution; 2) Customer classes whose rate-of-return was less than the system average rate-of-return received a deficiency distribution of up to 1.25 times the system average margin increase, but no more than an amount necessary to bring the class rate-of-return to the system average; and, 3) The remaining deficiency after step 2 was distributed to customer classes on an equal percent of margin. [Id.]

While the Company's approach was rather convoluted, the final result was about the same as if they simply decided to exempt some customers from any increase, decided to increase the rates paid by a few classes by approximately 23.3%, and decided to increase the remaining classes by about a third as much – 7.47%.

The variations in the proposed increases reflect the Company's intent to move towards greater uniformity of rates of return pursuant to its cost-of-service study. For instance, under the Company's allocation methodology the Residential classes are supposedly earning about half the system average rate of return, while the General Service class is supposedly earning far more than the system average. This discrepancy in the allocated cost results explains why the Company is proposing to increase Residential rates by roughly three times the amount it is proposing to increase General Service rates, as can be seen in the following table:

Class	Return Present Rates	Return Proposed Rates	Margin Change
Residential Gas Service	2.33%	5.77%	23.29%
General Gas Service	12.16%	13.74%	7.47%
Air Conditioning Gas Service	16.08%	17.93%	7.47%
Street Lighting Gas Service	1.78%	4.12%	23.34%
Compression on Customer's Premises	12.71%	14.26%	7.47%
Electric Generation Gas Service	8.87%	10.15%	7.47%
Small Essential Agriculture User Gas Service	10.36%	11.75%	7.47%
Natural Gas Engine Gas Service	23.95%	23.84%	0.00%
Total Sales	4.47%	5.77%	17.81%

Source: Schedules G-1, G-2, H-1

Q. What is your reaction to SWG's proposed revenue distribution?

A. I disagree with the Company's proposed revenue distribution both because some of the proposed increases are too extreme and because it is based upon cost allocation results which are fundamentally unsound. For example, residential rates would be subjected to an overall increase of 23.29%, and Single Family Low Income customers would see a 29.21% increase in their rates. [Schedule H-1, Sheet 2] I disagree with both of these proposals, because the percentage increases are much too extreme, and because they are based on a fundamentally

invalid premise: that the Residential class is not currently paying its fair share of the revenue burden.

With a more appropriate allocation approach, in which a small apartment is not asked to share the same share of the burden as a large house, a hotel, a grocery store or an office building, a very different conclusion is reached. The Residential classes are shown to generate returns which are close to, or a bit higher than, the system average return during the test year.

Of course, the specific returns earned by each class depend in large part on the assumptions and allocation techniques used in a specific cost-of-service study. Different conclusions are reached when a different allocation study is used as a benchmark for evaluating the rate relationships.

Q. Have you developed an alternative revenue distribution approach which you are recommending for the Commission to consider?

A. Yes. I have developed an alternative methodology which gives considerable weight to historic rate relationships, while also giving substantial consideration to my recommended class cost of service results.

Specifically, starting with the results of my cost of service study, I looked at the classes with rates of return significantly above or below the system average. In order to avoid inter-class inequities, and in recognition of the fact that cost allocation studies are not perfectly precise, I believe that none of the classes should receive percentage rate increases that differ dramatically from the overall system average. Instead, I recommend increasing the rates paid by these classes by slightly more, or less, than the system average (as appropriate), thereby moving the class returns toward the average, without making futile attempt to move toward complete uniformity of returns.

My specific recommendations are as follows: First, the following rate schedules have

returns that are substantially lower than the system average of 4.47%: Gas Service for Air Conditioning (-0.88%), Large 2 - General (1.46%), Transportation Eligible (0.81%), Street Lighting (2.35%), Compression on Customer Premises (1.12%), Electric Generation Gas Service (-1.48%), Small Essential Agricultural (1.75%), and Natural Gas Engine Service (2.21%). Since these classes are generating below-average returns, I recommend increasing their rates by a moderately higher percentage than the overall system average increase.

Second, the following rate schedules have returns that are substantially higher than the system average of 4.47%: Multi-Family Residential (7.30%), Master Metered Mobile Home Park (6.68%), Small General (17.30%), and Large 1 - General (6.41%). Since these customers are generating above-average returns, I recommend increasing their rates by somewhat less than the overall system average increase.

Third, the following rate schedules have returns that are relatively similar to the system average of 4.47%: Single Family Residential (4.84%) and Medium General (4.51%). Since they are currently earning returns that are fairly close to the system average, no deviation from the system average is necessary or appropriate.

For convenience, my specific recommendations are summarized in greater detail in the last column of Schedule BJ-9. For comparison purposes, all of these calculations are based on the Company's requested revenue requirement. The actual rate changes that I recommend be applied to each class could be substantially less, of course, since it will depend on the overall revenue requirement which is ultimately approved by the Commission.

VI. Residential Rate Design and Miscellaneous Tariff Issues

Q. Let's turn to the last section of your testimony. What other rate design issues do you wish to discuss?

A. I would like to discuss fixed costs and customer charges, discuss the possibility of seasonal rates, and comment on SWG's proposed rates for low income customers.

Q. Let's discuss fixed costs and customer charges. What does SWG say about these issues?

A. As I mentioned earlier, the Company states that one of the primary objectives of its residential rate design was "the fair and equitable recovery of costs." SWG contends that almost 100% of its non-gas costs are fixed, and that it is unfair or inequitable to recover these fixed costs through variable charges. It contends that recovering fixed costs through variable charges leads to under-recovery from low use customers and over-recovery from high use customers.

Although SWG is not proposing dramatic changes to its current rate design, the argument its is making would justify drastically increasing the fixed monthly rate, and greatly reducing or eliminating its existing per-therm (variable) rates. Although the reasoning is a bit ambiguous, the Company seems to be implying that its proposal to leave the monthly charge unchanged in this case is tied to its request for approval of its EEP. "[B]ecause of the revenue stability provided by the EEP, Southwest Gas is proposing to recover the entire revenue deficiency in variable charges..." [Gieseking Direct, p. 7] SWG further explains:

> The cost of service rate design principle, that economic efficiency is maximized when the fixed and variable costs of service are recovered through associated fixed and variable charges, supports the retention of at least the current level monthly basic service charge, if not an increased monthly fixed charge. However, in consideration of other rate design goals, Southwest Gas is not proposing an increase in the monthly basic service charge at this time. Please also refer to the attached Excel file. [SWG response to Staff DR 3-47]

Q. Does SWG quantify the exact amount of costs that it considers fixed?

A. In response to data requests seeking clarify or support the "almost 100%" figure, SWG referred to Schedule G-4.

> The Company's class cost of service study shows that $7,442,314 out of $1,456,517,468, or 0.5%, of total rate base is associated with commodity-related functions (Line 34 of Schedule G-3, sheets 1-14). In addition the study shows that only $2,023,257 out of $136,804,420, or 1.5%, of the Total O&M expense is associated with commodity-related functions (Line 55 of Schedule G-4). [SWG response to Staff DR 13-5]

Essentially, the Company is arguing that its distribution system is fixed once it is installed – not varying with the volume of gas that moves through the system. Needless to say, I don't necessarily disagree with that conclusion – I made a similar point earlier in my testimony in arguing that the great majority of the costs of a natural gas distribution system are either fixed or sunk, once the investment is made. And, even during the planning phase, before investments are made, a large fraction of the costs are determined by the configuration of the road network and the positioning of buildings relative to that network.

Q. Do you agree with SWG's argument that fixed costs should be recovered on a flat monthly-per customer basis, or its corollary, that only costs that are strictly variable should be recovered through the price of gas-- in other words, all customers should pay about the same amount per month regardless of how much gas they use?

A. No. In fact, I would argue quite the opposite – that many of the customer charges are already higher than necessary or appropriate. Not only are further increases not warranted at this time, it would be preferable to shift away from flat per-month charges toward higher rates per unit of gas used.

When customer charges are set at reasonable levels, they are an acceptable rate-design tool for recovering a portion of a regulated utility's costs. However, the Company's current customer charges are already far higher than the marginal cost of connecting an additional customer to the system. These charges are not justified by marginal cost considerations, but rather they are an attempt to recover "fixed" costs on a "fixed" per-month, per-customer basis. I

strongly disagree with this approach because it is not a sound application of economic pricing principles, and it is inconsistent with important policy objectives related to economic efficiency, energy conservation, and inter-customer equity.

There are several problems with high customer charges. First, and most obviously, holding all else constant, higher customer charges tend to encourage gas consumption and discourage energy conservation, while lower customer charges will discourage energy usage and encourage greater energy efficiency.

Second, higher customer changes place a heavy burden on low use customers, for whom this is a major element of their gas bill. This rate design unduly burdens customers who do not own a large number of gas appliances, those who set the thermostat at a low level during the winter, those who rely on electricity to heat their home, and those who, for whatever reason, use the Company's system only to a minimal extent. It is not logical, equitable, or efficient to demand that a low use customers pay as much per month as high use customers. The illogic of the Company's position would have been self-evident if they had taken their reasoning to its logical extreme, and argued that a customer living in a small studio apartment in a densely populated urban area, should pay the exact same amount per month for use of the distribution system as someone living in a 6,000 square foot home in the suburbs. The illogic is even more obvious if one realizes that if the Company's reasoning were fully accepted and implemented, the monthly price would be the same regardless of whether the customer only uses gas for cooking and water heating, or whether they also use the gas for heating. In fact, by this reasoning, a residential customer might end up paying the same price per month as a hotel, an office building, or a retailer.

Third, the Company's customer charges are not based upon sound economic costing and pricing principles. Instead, they are based upon an inherently arbitrary embedded cost allocation approach, which happens to allocate substantial portions of the Company's

distribution investment and operating expenses on the basis of the number of customers in each class, regardless of whether or not these items directly vary in response to decisions by customers to join or leave the system. Even if the Commission were to disagree with the reasoning I set forth earlier in my testimony, and to conclude that there is no better way to assign some of these costs than on the basis of the number of customers, that doesn't mean the resulting allocated numbers are a valid justification for determining what portion of the revenue requirement should be recovered through a fixed monthly charge, and what portion should be recovered through the volumetric rates. Allocation techniques that are deemed acceptable for one purpose are not necessarily appropriate or acceptable for another purpose.

Q. Can you elaborate on your first point?

A. Yes. Customer charges have a negative effect similar to that of declining block rates, in which rates drop as the level of usage increases. In general, such rate structures make small-volume users pay a higher average rate per therm than large-volume users and tend to present customers with a relatively low marginal per-therm rate for increased usage. This has several undesirable effects: it imposes excessive rates on low-volume users, including those who are most successful in limiting their energy usage, and it tends to discourage energy conservation. A relatively high customer charge works in much the same way. It translates into relatively low therm rates; as a result, it sends price signals that make it seem less costly to consume additional energy, providing relatively little reward for those customers who buy more efficient appliances, install additional insulation, adjust the thermostat to lower levels in the winter, or take other steps to reduce their gas consumption.

The following example in the table below illustrates this point. The costs are based on the Company's proposed single-family residential rates, which include a $10.70 customer charge and a commodity charge of $1.44649 per therm.

	5 Therms	20 Therms	50 Therms	100 Therms
Customer Charge	$10.70	$10.70	$10.70	$10.70
Commodity Charge	7.23	28.93	72.32	144.65
Total	$17.93	$39.63	$83.02	$155.35
Total per Therm	$3.586	$1.981	$1.660	$1.553
		0.45		0.57

Source: Schedule H-4, Sheet 1

As shown, a customer using 5 therms during a given month would incur a total bill of $17.93 under the proposed rates. Thus, he would pay an average of about $3.59 per therm. In comparison, a customer who uses 20 therms would pay an average price of approximately $1.98 per therm, or roughly 45% less than the rate per therm paid by the smaller customer. Similarly, the customer using 50 therms will pay approximately 54% less per them than the customer using 5 therms in a given month. Finally, the customer using 100 therms will pay approximately 57% less per them than the customer using 5 therms in a given month.

In essence, a high customer charge tends to create an effective discount on the average rate per therm paid by large-volume users relative to the rate paid by low volume users, and it confronts customers with a marginal price which is lower than would be the case if a lower customer charge were applied. In my view, this pricing pattern runs directly counter to the policy goal of encouraging energy conservation, and this disadvantage outweighs any putative benefit from better tracking someone's preferred view of allocated costs.

Q. Have you analyzed the methods by which the Company allocates costs to the customer charge?

A. Yes. The great majority of the costs that are used to support this rate element are not actually variable or marginal costs that are directly attributable to decisions by customers to join or leave

the system. Rather, they are fixed or sunk costs that are largely determined by the configuration of roads and buildings in the Company's service area. In my view, a customer charge makes the most sense when it is used to collect the variable costs of metering, billing, and collecting the monthly bill. Other so called "customer costs" can and should be recovered through volumetric rates.

Q. Can you please elaborate on the costs that you believe are appropriately recovered through a fixed monthly fee?

A. I believe that the most meaningful definition of customer costs for pricing purposes is a narrow one. Preferably, a customer charge should only include those costs which are closely related to the number of customers served each month, so that the customer charge would be closely tied to the actual cost savings realized when a customer joins or leaves the system. This approach is economically sound, it avoids the imposition of excessive burdens on low-volume customers, and it tends to encourage energy conservation.

This recommendation entails a relatively narrow definition of customers costs. Specifically, I believe that only accounts 901-903 and possibly 586, 905, and 907-910 should be included in the calculation of the fixed monthly rate element (customer charge). This closely matches the costs which are directly related to a customer's decision to join or leave the system and which therefore are most appropriate to recover through a fixed monthly fee which is incurred when a customer joins the system, and which can only be avoided if the customer leaves the system.

Q. Have you analyzed the company's customer costs, based on your preferred definition?

A. Yes. Schedule 10 of my exhibit presents an analysis of those costs that I believe can properly be recovered through the customer charge. Schedule 10 shows that SWG's customer accounts

expenses (accounts 901-903) totaled $30,593,032 for the year ending June 30, 2010. Dividing the total monthly costs by the adjusted test year number of bills reveals that the expense per customer is $2.61 per month.

This figure is a reasonable estimate of the Company's variable direct cost per customer, per month--the cost which is most directly related to the number of customers present on the system during any particular month. I am not suggesting that the customer charge be immediately reduced from $10.70 to less than $3.00 per month – but this analysis of the relevant costs suggests that some movement in that direction would be appropriate in this case.

Q. To the extent they are not recovered through a fixed monthly fee, how should the company's joint and common costs be recouped?

A. In my opinion, the fixed costs of the system are most appropriately recovered in the same way that most unregulated businesses recover these sorts of overhead costs--through customer payments for value received. Most competitive firms do not charge monthly dues for the right to be a customer. Instead, by far the most common practice is to build their overhead costs into the prices of the goods and services they sell.

For instance, a retailer typically recovers overhead costs from his retail mark-up, not from a flat monthly fee charged customers for simply shopping in his store, or a per-visit fee for walking through the door. Similarly, customers generally do not pay a fixed monthly fee for the right to buy a car when they need one. All of the auto manufacturers' and auto dealers' overhead costs are recovered in the price of the cars actually sold to customers. Even book and music clubs recover their overhead costs through actual sales transactions – despite the fact that these firms incur additional costs with every additional customer who joins or stays on their system. The fixed costs of maintaining customer accounting records and sending monthly mailings to each customer are normally recovered strictly on the basis of the books, and music that is

actually purchased – rather than a flat fee imposed on customers regardless of how little or how much benefit they gain from the service.

Let me hasten to add that there are exceptions – situations where competitive firms impose fixed monthly or annual charges regardless of actual purchases. For instance, some credit card companies use this pricing method for some of their card offerings. But, such charges are relatively rare in unregulated markets, even for firms with relatively high levels of fixed costs in comparison to their variable costs. For instance, airports and airlines both have substantial fixed costs unrelated to the number of customers who fly. Even though it might be feasible, they do not assess a flat fee to every person who enters the airport in order to recover those costs. Nor do airports or airlines charge a fixed fee for the right to fly, regardless of whether or not a person chooses to fly during a particular month. Instead, these fixed overhead costs are recovered as and when tickets are sold.

In all of these examples, customers who buy more pay a higher portion of the firm's total overhead costs than the customers who buy less, but they also receive a proportionately greater benefit. No one complains that this practice is unfair or unreasonable. Applying the same logic to the pricing policies of gas and electric utilities, it is reasonable to recover most overhead costs through the rates charged for the use of gas and electricity. This pricing method imposes overhead costs on customers in proportion to their actual consumption of energy, which I believe is wholly appropriate and consistent with standard practice in most competitive markets.

From my perspective as an economist, the reason customer charges or equivalent fees typically do not survive in competitive markets is clear: customers find them objectionable, because they are not directly associated with the benefits the receive when the service is actually rendered. Unlike regulated utilities, none of the other entities just discussed (retail stores, gas stations, book clubs, and airlines) have sufficient monopoly power to impose this non-intuitive and potentially inequitable form of pricing on their customers. Hence, in most

unregulated markets normal market forces lead firms to recover their overhead costs in the price of the goods and services actually consumed--even though the underlying costs do not vary directly with sales volume and even though some of the costs in question may vary with the number of customers.

Q. Even if the Commission were to again adopt the cost allocation method proposed by the Company, which allocates numerous investment-related costs in proportion to the number of customers in each class, do you nevertheless oppose recovery of those costs through monthly customer charges?

A. Yes. Neither economics nor public policy requires that gas rates be tied directly to the results of fully allocated cost-of-service studies. Such studies are at best a tool which can assist regulators in evaluating the appropriate distribution of revenues among customer classes. Even if someone believes it is logical to allocate the same share of certain costs to a hotel as would be allocated to a residence, merely because they are fixed or sunk costs, that allocation should not determine or control the final pricing decisions. Other factors can and should be considered. Two long-recognized policy goals are particularly pertinent to this issue: the promotion of inter-customer equity and the encouragement of energy conservation. The former objective implies that small consumers should pay less than large customers, considering differences in their ability to pay, as well as differences in the aggregate value they receive from using the system. Few would argue that a single family residence should be taxed the same amount as a hotel; by the same reasoning, they should not be asked to pay the same amount toward the fixed costs of the natural gas system they both use.

Likewise, high fixed monthly rates do not promote the longstanding goal of energy conservation. Strictly speaking, conservation will be encouraged by setting a relatively high price per therm – even if that means setting a customer charge which is below what someone

believes is the actual level of customer costs.

Q. What did the Commission conclude regarding customer charges in SWG's prior rate case?

A. In the prior rate case, SWG proposed raising various customer charges as an alternative to its decoupling proposal. [See, Decision 70665, p. 44] Other parties expressed a preference for an increase customer charge in lieu of decoupling, or as a way of ameliorating the impact of eliminating declining block rates. The Commission agreed to increase the customer charge, but not as drastically as proposed by SWG. [Id., p. 46]

> The Company's proposed 32-percent increase in the residential customer charge would diminish the ability of many customers to control their gas bills by engaging in conservation and would undermine the gradualism concept in setting rates. As we stated in the Company's last rate case, "[wle 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." (Decision No. 68487 at 38.) [Decision No. 70665, p. 47]

Q. What do you recommend the Commission do regarding customer charges in this proceeding?

A. I recommend the Commission recognize that, contrary to the impression given in the prior case, fixed costs do not need to be recovered through a fixed monthly fee in order to be consistent with sound pricing principles. To the contrary, there are valid reasons to recover most fixed costs through volumetric charges – including the fact that an analogous pricing pattern is observed in most unregulated markets.

Going one step further, I recommend that the Commission consider modestly lowering SWG's customer charges for all of the reasons I mentioned above. This outcome would be a further step in the direction established in the previous case when declining block rates were

eliminated. It would serve the same purpose as the Company's revenue decoupling proposal, (encouraging encourage energy conservation), but without the deleterious effects of that proposal, which I explained earlier in my testimony.

Q. Let's discuss a few other aspects of the Company's rate design, beginning with seasonality. Are SWG's rates the same throughout the year?

A. Yes. Aside from the purchased gas recovery rates, all of the Company's rates are constant throughout the year. Customers pay the same monthly charge and the same rate per therm during the summer as during the winter, completely ignoring seasonal cost variations. The existing rate design ignores the fact it is more costly to deliver gas during the peak winter months than it is during the summer months, when the system is relatively little used. The incremental cost of going from a small pipe to a large pipe is largely attributable to the additional usage which occurs during winter months, when heating demand is strongest. Since extra costs are incurred to accommodate the higher level of demand which occurs during the peak winter months, it would not be unreasonable to vary rates, so that somewhat higher rates are charged during the winter.

Q. Is it practical to introduce an element of seasonality into the Company's rate structure?

A. Yes. In fact, unlike real-time pricing and other complex innovations that this Commission has recently authorized on a pilot basis, seasonal rates would be relatively simple, predictable and easy for customers to understand. It can be as simple as charging higher rates per therm during winter months, and lower rates during the remaining months of the year.

Q. Aside from greater consistency with the manner in which costs are incurred, are there other pros and cons to introducing seasonality into the Company's rate structure?

A. Yes. On the positive side of the ledger, seasonal rates could have the salutary effect of further encouraging energy efficiency, and improving inter-customer equity. The goal of encouraging energy conservation would potentially be enhanced by strengthening the connection customers see between increases in their gas usage during the winter and the higher monthly bills they receive from the Company. This would reinforce the message that consumption matters, and that actions they take to reduce their gas consumption can potentially save them money.

On the negative side of the ledger, seasonal rates would not be popular with some customers. Customers' bills already increase during the winter as a result of greater gas usage, and there would undoubtedly be some customers who would be displeased to see any further increase in the volatility of their winter bill amounts. This could be a significant problem if nothing is done to ameliorate the volatility, and particularly if the changeover to seasonal rates were not explained well.

Q. Is there anything that could be done to achieve the potential benefits of seasonal rates, without adversely affecting customers who are living on a fixed monthly budget?

A. Yes. In addition to introducing a degree of seasonality to the rate design, the Commission could also introduce a bill smoothing option, in which customers could opt to pay the gas company a fixed amount each month, based on one-twelfth their anticipated annual gas usage. Under this optional program, they would clearly see on their bill the cost of gas used that month, the amount extra they are paying into their account during the summer (as an advance on future use), or the amount they are drawing down from their account during the winter months (thereby recouping amounts previously paid into their account during the summer months).

Done correctly, a bill smoothing option would provide customers with the best of both worlds – monthly bill stability and strong price signals that emphasize how much more it costs to use large amounts of gas (in the winter) compared to what it costs to use just a little gas

(during the summer). These strong price signals would encourage customers to think more deeply about the option of upgrading their appliances, installing a more efficient heating system, or adding more insulation to their home or business. And, they would provide customers who are living on a relatively fixed salary or retirement income with the added convenience of more easily budgeting for their gas usage.

Q. Can you now explain the Company's low income proposal?

A. Yes. As I mentioned earlier, SWG proposes to increase the low income discount by applying it to all low-income residential consumption during the winter months of November through April. [Id., p. 11] The current discount is 20%, and applies to the first 150 therms per month during the winter season. The Company is proposing to provide a 20% discount on all winter season use. [SWG response to Staff DR 25-1]

Q. Do you agree with this aspect of the Company's rate design proposals?

A. No. Adequate justification has not been provided for increasing the discount above the first 150 therms. There are at least two problems with this proposal. First, it increases the total amount other customers are paying to help low income customers. While this discount program is serves a useful public purpose, it is not cost-free. While it's natural to visualize only upper income customers paying for this support, the reality is that middle and working class customers are also paying for this program. In this regard, it is important to realize that the current economic difficulties, including severe dislocations in the housing market have placed many different types of customers, including many members of the middle class, in a position of unexpected economic distress. It is not at all clear that someone who is undergoing genuine hardship during these difficult economic times should subsidize the cost of someone who uses unusually large amounts of gas, merely because the latter

customer happens to have an income level falling below the cut-off, whereas they happen to have income above the cut-off.

And, it's important to remember that any definition of "low income" customers is somewhat arbitrary. It is unavoidably the case that some customers who are just above the income cut-off are effectively subsidizing those with very similar incomes, who happen to be just below the cut-off. Anything that is done to expand the magnitude of the low income discount program will have a tendency to exacerbate this problem.

Second, increasing the application of the discount to include even very high levels of winter usage exacerbates the problem of sending weak energy-conservation signals to low income customers.

Q. Do you have any other concerns with the structure of the low income discount program?

A. Yes. As explained by SWG, the commodity discount is allocated to all non-discounted residential customers – and only to those customers. [SWG response to Staff DR 3-48] To the extent SWG offers discounts to low-income customers, I fail to see the logic of insisting that the cost of that program be borne entirely by the residential customer class.

Q. What do you recommend the Commission do regarding SWG's low-income discount?

A. I recommend not expanding the scope of the discount; it should continue to be limited to the first 150 therms per month. Second, I recommend the Commission require all customer classes to contribute equitably toward the cost of this program, rather than continuing to impose the full cost only on residential customers who do not qualify for the discount.

Q. Does this conclude your rate design testimony pre-filed on June 24, 2011?

A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory

commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

Canada—Department of Communications
Hillsborough County Property Appraiser
Provincial Governments of Canada
Sarasota County Property Appraiser
State of Florida—Department of General Services
United States Department of Justice—Antitrust Division
Utah State Tax Commission

Regulated Firms

Alabama Power Company
Americall LDC, Inc.
BC Rail
CommuniGroup
Florida Association of Concerned Telephone Companies, Inc.
LDDS Communications, Inc.
Louisiana/Mississippi Resellers Association
Madison County Telephone Company
Montana Power Company
Mountain View Telephone Company
Nevada Power Company
Network I, Inc.
North Carolina Long Distance Association
Northern Lights Public Utility
Otter Tail Power Company
Pan-Alberta Gas, Ltd.
Resort Village Utility, Inc.
South Carolina Long Distance Association

Stanton Telephone
Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

Other Private Organizations

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458
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SOUTHWEST GAS CORPORATION **DOCKET NO. G-01551A-10-0458**
ADJUSTED TEST YEAR ENDED JUNE 30, 2010 **SCHEDULE BJ-8**
ALLOCATION METHODOLOGY COMPARISON
50/50 PEAK AND CUSTOMERS VS. 50/50 PEAK AND GAS USAGE
RATES OF RETURN AT PRESENT RATES

LINE NO.	Customer Class	Peak and Customers ROR	Peak and Usage ROR
1	Single Family Residential	2.32%	4.84%
2	Multi Family Residential	1.50%	7.30%
3	MMMHP	15.66%	6.68%
4	Small General	10.98%	17.30%
5	Medium General	8.16%	4.51%
6	Large-1 General	17.33%	6.41%
7	Large-2 General	7.64%	1.46%
8	Transportation Eligible	12.37%	0.81%
9	Air Conditioning	16.08%	-0.88%
10	Street Lighting	1.78%	2.35%
11	Compression on Customer's Premises	12.71%	1.12%
12	Electric Generation	8.87%	-1.48%
13	Small Essential Agricultural	10.36%	1.75%
14	Natural Gas Engines	23.95%	2.21%
15	**Total**	**4.47%**	**4.47%**

SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
RECOMMENDED REVENUE DISTRIBUTION
ASSUMING PROPOSED REVENUE REQUIREMENT

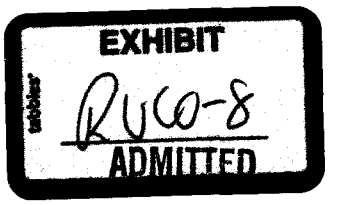
DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-9

LINE NO.	Customer Class	Current Margin	Recommended Increase Percent	Recommended Increase Dollars	Recommended Margin
1	Single-Family Residential Gas Service	$260,896,069	7.10%	$18,531,597	$279,427,666
2	Multi-Family Residential Gas Service	$6,914,441	4.26%	$294,682	$7,209,123
3	Single-Family Low Income Residential Gas Service	$8,921,577	7.10%	$633,705	$9,555,282
4	Multi-Family Low Income Residential Gas Service	$676,150	4.26%	$28,816	$704,966
5	Special Residential Gas Service for Air Conditioning	$58,822	14.21%	$8,356	$67,178
6	Master Metered Mobile Home Park Gas Service	$863,947	4.26%	$36,820	$900,767
	General Gas Service				
7	Small	$7,908,814	4.26%	$337,061	$8,245,875
8	Medium	$22,579,171	7.10%	$1,603,811	$24,182,982
9	Large-1	$43,845,416	4.26%	$1,868,619	$45,714,035
10	Large-2	$11,254,459	14.21%	$1,598,821	$12,853,280
11	Transportation Eligible	$21,689,599	14.21%	$3,081,249	$24,770,848
12	Optional Gas Service	$4,024,536	4.26%	$171,519	$4,196,055
13	Air Conditioning Gas Service	$82,169	14.21%	$11,673	$93,842
14	Street Lighting Gas Service	$53,386	14.21%	$7,584	$60,970
	Compression on Customer's Premises				
15	Residential	$17,094	14.21%	$2,428	$19,522
16	Small	$24,227	14.21%	$3,442	$27,669
17	Large	$818,366	14.21%	$116,258	$934,624
18	Electric Generation Gas Service	$2,982,640	14.21%	$423,717	$3,406,357
19	Small Essential Agriculture User Gas Service	$727,284	14.21%	$103,319	$830,603
20	Natural Gas Engine Gas Service	$1,713,984	14.21%	$243,491	$1,957,475
21	Total Sales and Full Margin Transportation	$396,052,151		$29,106,969	$425,159,120
22	Special Contract Service	$2,763,591	4.26%	$117,780	$2,881,371
23	Other Operating Revenue	$12,096,356	0.00%	$-	$12,096,356
24	Total Arizona Revenue	$410,912,098		$29,224,749	$440,136,847
25	Total Margin Requirement			$29,224,749	
26	Over/(Under) Requirement			$(0)	

SOUTHWEST GAS CORPORATION
ADJUSTED TEST YEAR ENDED JUNE 30, 2010
ALTERNATIVE CUSTOMER CHARGE CALCULATIONS

DOCKET NO. G-01551A-10-0458
SCHEDULE BJ-10

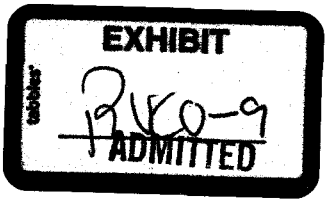
LINE NO.		Amount
	CUSTOMER ACCOUNTS EXPENSES	
1	901-Supervision	$2,543,953
2	902-Meter Reading Expense	1,964,231
3	903-Cust Records & Coll Exp	26,084,848
4	Customer Costs	$30,593,032
5	Test Year Adjusted Number of Bills	$11,738,902
6	Customer Charge (Line 10/Line 11)	$2.61



SWG-11 Please provide all studies and data that support the statement on page 26, lines 11-13 of Dr. Johnson's prepared direct testimony that: "However, the Company is going too far with its proposed adjustment, creating an unrealistic picture of a test year in which the weather was unusually warm and balmy during the winter, creating hypothetical condition in which people use relatively little gas." Specifically, please provide all weather and non-weather studies and data that indicate the adjustment to the test year reflects weather that was "unusually warm and balmy during the winter".

RESPONSE: (Johnson)

The quoted statement is supported by data provided by SWG in response to RUCO data request 6-1. That data shows that for Tucson SWG developed an adjusted 10-year average heating degree day value of 1,440. Although that value is put forward as representing "normal" it is lower than the actual heating degree days during the majority of the previous 30 years. Similarly, SWG developed an adjusted 10-year average heating degree day value for Phoenix of 892. Although that value is put forward as representing "normal" it is lower than the actual heating degree days during 20 of the previous 30 years. As well, the heating degree day values put forward by SWG as allegedly "normal" are lower than the historical averages actually experienced in Tucson during the past 10, 11, 12, 13, 14, 15,16, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29 and 30 year periods. The one (partial) exception to this lopsided pattern: the 1440 figure equals the 17 year average. Similarly, the heating degree day values put forward by SWG as allegedly "normal" are lower than the historical averages actually experienced in Phoenix during the past 10, 11, 12, 13, 14, 15,16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29 and 30 year periods. There are no exceptions – the supposed "normal" figure advocated by SWG is abnormal in comparison with every one of these historical time periods, ranging from 10 through 30 years in duration.



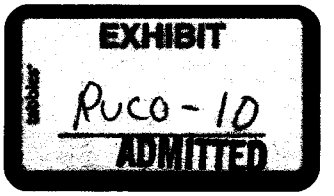
SOUTHWEST GAS CORPORATION
ARIZONA RATE CASE 2010
HISTORICAL WEATHER DATA & LONG TERM NORMAL
JULY 1980 - JUNE 2010

12 Months Ending June	Tucson CHDD	Phoenix CHDD	Long Term Average	Tucson CHDD	Phoenix CHDD		
1981	1,317	662		1,465	923	30 Year Average	30
1982	1,488	874		1,470	932		29
1983	1,875	1,110		1,470	934		28
1984	1,598	826		1,455	928		27
1985	1,740	1,166		1,449	932		26
1986	1,212	786		1,438	922	25 Year Average	25
1987	1,564	916		1,447	928		24
1988	1,429	997		1,442	928		23
1989	1,403	943		1,443	925		22
1990	1,452	928		1,444	925		21
1991	1,491	907		1,444	924	20 Year Average	20
1992	1,437	820		1,442	925		19
1993	1,470	947		1,442	931		18
1994	1,337	930		1,440	930		17
1995	1,400	1,062		1,447	930		16
1996	1,116	737		1,450	922	15 Year Average	15
1997	1,458	965		1,474	935		14
1998	1,880	1,266		1,475	932		13
1999	1,449	984		1,441	905		12
2000	1,271	829		1,441	898		11
2001	1,862	1,208		1,458	904	10 Yr Average	10
2002	1,479	902					
2003	1,341	692		1,440	892	Company Proposed	
2004	1,506	932				Adjusted 10 Yr Average	
2005	1,508	896					
2006	1,194	780					
2007	1,505	974					
2008	1,448	982					
2009	1,192	731					
2010	1,542	951					

COUNT		
Company	18	20
RUCO	14	16

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-10-0458



TESTIMONY IN OPPOSITION TO PROPOSED SETTLEMENT AGREEMENT OF JULY 15, 2011

OF

BEN JOHNSON, Ph.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 29, 2011

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. G-01551A-10-0458

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Are you the same Ben Johnson that filed revenue requirements testimony on June 10, 2011 and rate design testimony on June 24, 2011?

A. Yes, I am.

Q. What is the nature of this testimony?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of Southwest Gas Corporation's (SWG's) application for a rate increase. The purpose of this testimony is to explain why RUCO objects to the proposed settlement agreement ("Proposed Settlement", or "Settlement") filed by the Commission Staff and other parties on July 15, 2011.

Q. How is your testimony organized?

A. Following this introduction, my testimony has four sections. In the first section, I briefly discuss the procedural background of this proceeding, focusing on events that have occurred after the parties filed their direct testimony. In the second section, I briefly summarize some key provisions of the Proposed Settlement. In the third section, I explain RUCO's objections to the Proposed Settlement. In the final section I present my conclusions and recommendations.

Q. Can you please briefly summarize RUCO's position concerning the Settlement?

A. Yes. RUCO objects to the Proposed Settlement, primarily because of the provisions concerning decoupling. While the Settlement differs somewhat from the Company's originally filed proposal, it is not significantly better – in fact, it would be fair to analogize the Settlement modifications to the decoupling proposal as being largely cosmetic when complete rejection, or drastic modifications were needed. Accordingly, I recommend the Commission reject the Settlement as filed. It should tell the parties to negotiate drastic changes to the Settlement or

resubmit it without the decoupling provisions, or the Commission should issue an order ruling on the issues in this proceeding based upon the filed evidence, and as part of that ruling it should reject the various decoupling proposals.

I. Background

Q. Can you briefly discuss what has transpired since the parties filed revenue requirements and rate design testimony in this proceeding?

A. Yes. On June 21, 2011, SWG filed a Notice of Settlement Discussions inviting all parties to participate. Settlement discussions began on June 28, 2011, and RUCO participated in the settlement discussions until it became clear that the other parties were insisting upon including decoupling as part of the Settlement – despite the fact that this is a highly controversial issue which RUCO believes needs to be fully litigated. The Settlement does not craft an approach which would resolve the concerns set forth in my testimony concerning decoupling, which was filed in this proceeding on June 24, 2011 behalf of RUCO.

II. Summary of Proposed Settlement Agreement

Q. Can you briefly summarize the proposed settlement filed on July 15, 2011?

A. Yes. The proposed agreement puts forth two alternative revenue requirements, tied to two different decoupling alternatives. "Alternative A" includes a Lost Fixed Cost Recovery (LFCR) component and a weather component. This

> partial revenue decoupling mechanism permits Southwest Gas to recover lost base revenues attributable to achievement of the Commission's required annual energy savings and to adjust customer bills each month

> when actual weather during the billing cycle differs from the average weather used in the calculation of rates. [Proposed Settlement, para. 3.4]

Under Alternative A, the initial LFCR surcharge will be set at $0.00213 per therm, based on the assumption that the Company will achieve 100% of the Commission's required annual energy savings. The amount recovered through the surcharge would be trued up on an annual basis to actual lost base revenues caused by energy efficiency. If the Company fails to meet 100% of the required energy savings, the difference between the 100% it was allowed to collect and the actual lost revenue would be refunded to customers during the next annual reconciliation process. If SWG exceeds the 100% energy efficiency goal,

> the Company will be permitted to recover, through the surcharge, in the following year the difference between the 100 percent collected from customers and the actual amount of the lost base revenues associated with attaining energy savings greater than 100 percent of the year's goal, as limited by the Commission's required annual energy savings. [Id., para. 3.7]

Under Alternative A, the weather component will be incorporated through a monthly true-up to winter bills. "When actual weather during the billing cycle differs from the average weather used in the calculation of rates there will be either an upward or downward adjustment to the customers' bill.". [Id., para. 3.10]

Under Alternative A, the Company will be authorized to increase rates by an amount designed to increase revenues by $54,927,101, based upon an authorized return on common equity capital of 9.75%, and a Fair Value Rate of Return (FVROR) of 7.02% on Fair Value Rate Base (FVRB). The latter calculations are apparently based upon one the approaches offered by the Staff in its direct testimony concerning FVROR. [Id., p. 3.3] SWG would not be subject to any rate case moratorium under Alternative A.

Alternative B is similar to Alternative A, except that it includes an even more drastic or comprehensive decoupling mechanism which is described as "full" decoupling. This more

extreme decoupling approach is coupled with an overall revenue increase of $52,607,414, a return on common equity capital of 9.50%, and a fair value rate of return of 6.92% on FVRB (again using Staff's fair value methodology). [Id., para. 3.17] Under the "full" decoupling mechanism, rates will adjust to reflect any and all differences between authorized revenues per customer and actual revenues per customer. This is the mechanism largely the same as the one originally proposed by SWG in its Application. Alternative B includes the same weather component as included under Alternative A. Under Alternative B, SWG would be prohibited from filing a general rate case application prior to April 30, 2016. [Id., para. 3.30]

Q. Can you now briefly describe some of the other provisions included in the proposed settlement?

A. The parties to the settlement will be filing testimony simultaneously with this filing, and I assume they will explain in some detail how they arrived at the specific provisions set forth in the Settlement Agreement, so I will not make any attempt to fully summarize those details. However, I would like to briefly mention a few items. First, the settling parties agreed to a capital structure comprised of 47.70 percent long-term debt and 52.30 percent common equity, and an embedded cost of debt of 8.34% [Id., paras. 5.2-5.3] Second, the settling parties agreed to an OCRB for the test year ending June 30, 2010 of $1,070,115,558, a RCND rate base of $1,835,749,225, and a fair value rate base of $1,452,932,391. [Id., paras. 5.4-5.6] Third, the settling parties agreed to a base rate revenue allocation resulting in an equal percentage increase among all customer classes, with the exception of low income customers, who would not share in any of the burden of the rate increase. [Id., para. 5.36]

III. Response to Proposed Settlement Agreement

Q. Why did RUCO decide not to join the settlement?

A. As I alluded to a moment ago, RUCO was troubled by the insistence by other parties that the Settlement include revenue decoupling. As explained in my originally filed testimony, I am not convinced that decoupling will actually accomplish its stated purpose of encouraging energy efficiency and conservation. To the contrary, it may actually have the unintended consequence of discouraging customers from conserving energy. Furthermore, decoupling will tend to force customers to pay higher rates, increasing the Company's cash flows and profits, at the expense of consumers. RUCO could not, and does not, understand why other parties insisted upon embarking into such risky, uncharted waters, nor why they insisted upon imposing a resolution to this controversial issue as part of the Settlement, nor why they were so reluctant to have it be fully litigated before the Commission.

Q. Can you explain RUCO's opposition to the revenue decoupling provisions in greater detail?

A. The revenue decoupling provision contained in Alternative B is essentially the same as the original proposal included by SWG in its application. For a full discussion of RUCO's concerns with Alternative B, I refer the Commission to my previously filed testimony. The decoupling mechanism in Alternative A is not quite as extreme, since it is intended to be limited to revenues that are lost as a result of SWG's compliance with the Commission's energy savings goals. It is not clear exactly how Alternative A will be implemented, nor how the Commission will determine the extent to which changes in per-customer usage are "attributable to achievement of the Commission's required annual energy savings," the extent to which this achievement is attributable to the Company's efforts, or the manner in which offsetting factors (e.g. the impact

of changes in economic conditions or changes in consumer attitudes) will be accounted for in determining how to implement Alternative A.

However, both provisions have certain elements in common. As I explained in my previously filed testimony, Alternatives A and B will both benefit SWG's shareholders, while customers will receive little or no net benefit. Both alternatives will shift significant non-gas costs from shareholders to customers. Alternative B will also have the effect of reducing year-to-year volatility in non-gas revenues and profits. While both provisions are clearly beneficial to shareholders, they are not so attractive from the perspective of customers, and they are both fraught with risks for customers – if for no other reason than because they involve a fundamental uppending of the regulatory system, with substantial unknown consequences.

Yet, there is no evidence showing that the alleged existing "disincentives" for SWG to promote energy efficiency are actually influencing the Company's behavior in any way – much less that the negative impact of these alleged disincentives is significant enough to justify a complex, risky overhaul of the entire regulatory schema. The stated purpose of decoupling is to encourage energy conservation, yet the proposed decoupling provisions will weaken the incentives customers, builders and developers currently have to be more energy efficient. If the Commission adopts decoupling it will be sending the message to customers that future reductions in usage will automatically lead to higher rates per therm. In other words, the more consumers conserve, the more they are going to be forced to pay per therm. To the extent consumers learn about decoupling, and understand this linkage between efforts to conserve and higher rates, the more severe the risk is that decoupling will have the opposite effect as the one that is intended – it may actually have the effect of discouraging consumers from conserving, thereby offsetting the beneficial impact of efforts by the Company and this Commission to accelerate the long term trend toward greater energy efficiency and conservation.

Q. Can you elaborate on the first major problem you mentioned?

A. Decoupling is based in part on the theory that the Company has a disincentive to promote energy efficiency, and it has an incentive to try to encourage customers to use energy in a profligate manner. However, I am not aware of any evidence that the Company has responded to these incentives. Without any evidence that these supposed "disincentives" are causing problems, it would be unwise for the Commission to embark on such a massive restructuring of the existing regulatory regime.

Q. Can you please elaborate on the second major problem - how decoupling could weaken the incentives for customers to be more energy efficient?

A. As I explained in greater detail in my rate design testimony, the decoupling program will reduce the benefits obtained from more energy efficient decisions – with rates automatically increasing as per-customer usage declines, customers as a group will not get the same short term benefit they currently receive as a reward for increased energy efficiency. After the next annual true up, the per unit cost of gas will increase under decoupling – so that the more customers conserve, the higher rates will increase.

Q. What is the danger to the ratepayer if decoupling discourages customers from conserving, resulting in less energy efficiency?

A. At least under Option B, the Company will receive higher revenues due to decoupling, and customers will be paying higher bills, yet the end result may be little or no net improvement in efficiency and thus insufficient benefits, or no benefits, for ratepayers even over the long term. In other words, customers will be paying permanently higher rates without a commensurate benefit in the form of lower gas usage and improved efficiency.

Q. The settlement includes a provision requiring cost cutting; will this benefit customers?

A. Not necessarily. The proposed settlement includes a provision requiring SWG to reduce its expenses on an annual basis by an average of $2.5 million per year beginning in 2012 and continuing through the end of the test year in the Company's next general rate case. [Id., para. 5.20] It is not clear how this reduction will be measured, or how the Commission will differentiate between cost reductions attributable to this provision and cost reductions which would occur in the ordinary course of business. Regardless, it is important to remember that costs are reduced, the immediate beneficiaries are stockholders. True, customers eventually share in the benefit of cost reductions, but this occurs after the cost reductions show up in a test year and are reflected in a new set of rates established in a rate case. Because the Settlement will automatically increase per-unit rates between rate cases, it will bolster the Company's cash flow and income, and extend the time period between rate cases. In turn, this will put less pressure on management to cut costs. The requirement for $2.5 million per year in cost cutting may offset or ameliorate this problem, but to the extent rates will be increasing and costs will be decreasing, it is far from clear whether, or when, consumers will benefit. To the contrary, the benefits of the $2.5 million in cost reductions will be retained by stockholders until the next rate case, and with the benefit of automatically increasing rates attributable to decoupling, the period between rate cases will presumably be longer than it would otherwise have been. The delay in any potential sharing of the benefits of the $2.5 million in cost reductions is even more obvious under Alternative A, which includes a rate case moratorium.

Q. You've made clear that RUCO's primary objection to the Settlement relates to the decoupling issue. Are there any other issues you would like to briefly discuss?

A. Yes. There are two issues I'd like to briefly mention, although they are relatively minor. To put these issues into perspective, please consider the following table, which compares the

Alternative A and Alternative B revenue requirements in the Settlement to the amounts originally recommended by the Company, Staff and RUCO:

	Revenue Requirement
SWG	$73.2M
Staff	$54.9M
Alternative A	$54.9M
Alternative B	$52.6M
RUCO	$29.2M

As this table indicates, the Settlement revenue requirement is roughly midway between the Company's request and RUCO's recommendation – and it is approximately the same as Staff's recommendation. In and of itself, this is not disturbing, since it is not uncommon for the Commission's findings on revenue requirement to be somewhere in the middle of the range of options presented in the evidence. Howevever RUCO is troubled by two specific aspects of the Settlement. First, the revenue requirements were supposedly developed using Staff's recommended Fair Value Rate of Return (FVROR) methodology, but in reality the Settlement relies upon the less appropriate of two methods offered by the Staff in its direct testimony – a method which is clearly inferior to the one I recommended in my testimony. Second, the revenue requirements incorporate an erroneous measure of "normal" weather, as proposed by the Company, without correcting the errors which I pointed out in my testimony.

Q. Can you explain RUCO's concerns regarding the FVROR method?

A. Yes. According to the Settlement, the FVROR was purportedly developed using the methodology proposed by Staff in its revenue requirement testimony. This is not true – or, at best is misleading. In his direct testimony, Staff witness David Parcell recommended including

the increment between fair value rate base and original cost rate base in the proposed capital structure, and applying a cost of zero to this increment. He explains:

> Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards. [Parcells Direct, p. 50]

Using this methodology, Staff witness Parcell developed a FVROR of 6.69%. He further concluded:

> Applying this 6.69 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB. [Id., pp. 50-51]

Mr. Parcell also developed an alternative approach to developing the FVROR, but this was not his preferred methodology,l and it was only offered for use in the event "the Commission determine[s] that there should be a specific return (greater than zero) applied to the FVRB Increment". [Id., p. 51] Under Mr. Parcell's alternative approach, half the rate of inflation (estimated to be 1.25%) would be applied to the fair value increment.

In summarizing the parties' positions filed on direct, the Settlement provides:

> Staff agreed with the Company's capital structure and embedded cost of long-term debt, but recommended a cost of common equity capital of 9.75 percent and a FVROR of 7.02 percent using a 1.25 percent inflation-adjusted risk-free return on the fair value increment (differential between FVRB and OCRB). [Proposed Settlement, para. 2.2]

The language in the Settlement suggests it is based upon the FVROR methodology

recommended by Staff, yet it is actually using an approach the Staff offered as a fallback or compromise position, to be used only in the event that the Commission determines some level of cost needs to be applied to the fair value increment. The Commission has made no such determination in this case, and there is nothing in the Settlement that justifies using this approach. The parties could just as easily, and far more appropriately, used the methodology adopted in Docket No. E-04204A-09-0206, as I recommended in my testimony. This approach would be more theoretically sound than the one used in the Settlement, while yielding a result that falls between the one recommended by Mr. Parcell and the one used in the Settlement.

Q. Can you briefly elaborate on the FVROR methodology you are recommending, and how it compares to the approach used in the Settlement?

A. I would refer the Commission to my direct testimony for an in depth explanation of my recommended approach, and the underlying theory that supports its use. In essence, I recommended subtracting the rate of inflation component from both the cost of equity and cost of debt. This is the methodology adopted by the Commission in UNS Electric's most recent rate case, Docket No. E-04204A-09-0206. [See, Decision 71914, pp. 49-50]

As shown in the table below, using the 9.50% cost of equity recommended by RUCO witness Rigsby in his settlement testimony, and the capital structure and debt costs assumed in the Settlement, results in a FVROR of 6.85%, rather than 6.92% as calculated in the Settlement:

RUCO Approach – Using Settled Capital Structure

Type of Capital	Amount	Percent	Cost Rate	Inflation Component	Modified Cost Rate	Weighted Avg. Cost Rate
Common Equity	561,545,431	52.30%	9.50%	2.10%	7.40%	3.87%
Long Term Debt	512,155,202	47.70%	8.34%	2.10%	6.24%	2.98%
Total	1,073,700,633	100.00%				6.85%

Thus, this difference in methodology results in a difference in the FVROR of .07%. By way of further illustration, I would note that if the Commission were to adopt a 9.75% cost of equity, as set forth in the Settlement in the context of Alternative A, using the more appropriate methodology I recommend FVROR would be 6.98%, rather than 7.02% as put forth in the Settlement, a difference of just .04%.

Q. The end result of using a theoretically sound methodology is not greatly different than the end result adopted in the Settlement. Why are you even raising this issue?

A. As I stated earlier, the primary reason RUCO objects to the Settlement is because of the provisions concerning decoupling. However, the FVROR methodology is also an important issue – one which is still somewhat in flux, and one that has wide implications for future proceedings. There is no logical reason to adopt Staff's fallback alternative, when a more theoretically sound approach is available – particularly when that theoretically sound methodology has previously been adopted by the Commission, and its adoption in this case would not drastically change the overall revenue requirement agreed upon by the settling parties.

Q. Can you discuss RUCO's second minor concern, relating to weather normalization?

A. Yes. The proposed settlement apparently incorporates SWG's proposed "Revenues and Volumes" adjustment, including SWG's so-called "weather normalization" calculations. This component of the revenue requirement calculations is intended to adjust the test year non-gas revenues (margin) to reflect 12 months of consumption under supposedly "normal" weather conditions. Properly developed, this is unobjectionable. The problem is that SWG developed it's interpretation of the "normal" number of heating degree days, using a relatively brief ten-year average (for the 120 months ended June 2010), incorporating an adjustment for alleged

"outliers" which greatly distorts the final result.

As I explained in my direct testimony, it isn't logical to replace the actual test year results with hypothetical calculations based upon supposedly "normal" weather data that is based on just ten years of data. Since weather patterns can vary widely from one year to the next, it is not unreasonable to attempt to "normalize" the test year based on a long term average, but even a ten year period can be a bit warmer, or cooler, than normal. The Company tried to compensate for this problem by providing an adjustment to remove supposed "outliers" from the 10 years of data, but the effect of this step was to greatly distort their calculations, pushing the so-called "normal" measure of HDD away from a true norm.

During the discovery process, SWG provided certain data in response to RUCO data request 6-1. That data shows that for Tucson SWG developed an adjusted 10-year average heating degree day value of 1,440. That value is put forward as supposedly representing some sort of "normal" weather, but in reality it is a purely hypothetical calculation which is lower than the actual heating degree days during the majority of the previous 30 years. Similarly, SWG developed an adjusted 10-year average heating degree day value for Phoenix of 892. Although that value is put forward as representing "normal," in reality it a distorted calculation which reflects fewer heating degree days than actually occurred during 20 of the previous 30 years.

In fact, the heating degree day values used in the Settlement far from "normal" -- as indicated by the fact that they are lower than the historical averages actually experienced in Tucson during the past 10, 11, 12, 13, 14, 15,16, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29 and 30 year periods. The one (partial) exception to this lopsided pattern: the 1440 figure happens to match the 17 year average. Similarly, the heating degree day values used in the Settlement are lower than the historical averages actually experienced in Phoenix during the past 10, 11, 12, 13, 14, 15,16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29 and 30 year

periods. There are no exceptions – the supposed "normal" figure advocated by SWG is so abnormal it is lower than the actual data for every one of these historical time periods, spanning the entire range from 10 to 30 years in duration.

This not only distorts the revenue requirement, it ensures that the weather decoupling calculations will be invalid. Regardless of how hot or cold the actual weather turns out to be in any given month or year, if the Settlement is accepted customers will be forced to pay artificially high rates, based upon hypothetical weather conditions that are supposedly "normal" but in reality are warmer than normal.

IV. Conclusions and Recommendations

Q. What do you recommend the Commission do regarding the proposed settlement agreement?

A. I recommend the Commission reject the Settlement for the reasons I have just given. I recognize that the Commission has expressed an interest in decoupling, and that the issues surrounding decoupling are not unique to SWG, or even to Arizona. However, I see no pressing need to adopt any form of decoupling at this time. Instead, the Commission should continue to investigate decoupling in the context of individual rate proceedings, in which there is an opportunity to fully litigate the issue, and to explore the pros and cons in the context of specific utilities.

If the Commission is inclined to approve the settlement, I strongly recommend it do so only if the parties to the Settlement accept certain modifications. First, I recommend the Commission remove the decoupling provisions. If the Commission feels some further concession to the Company will be necessary if the decoupling provisions are rejected, I

recommend increasing SWG's flat monthly customer charges to $11.85 per month, rather than freezing this rate element at its current level of $10.70 (as the Company proposed) or reducing this rate element (as I originally recommended, on behalf of RUCO). Second, I recommend the Commission modify the revenue requirement to reflect a more theoretically sound FVROR methodology, and a valid measure of "normal" weather, based upon the 30 year average data (eliminating any need to adjust for alleged "outliers.")

Q. It is your recommendation that the Commission reject decoupling. Is it RUCO's position that the Commission should reject decoupling in principle and/or modify its policy on decoupling?

A. No. My analysis is limited to the facts and circumstances applicable to this particular case. As Ms. Jerich testifies in her testimony, RUCO has some general concerns about how effective decoupling will be in achieving the intended goal of energy conservation, but the agency recognizes that decoupling does have some attractive attributes, and a well formulated decoupling policy could potentially be in the ratepayers' best interest under appropriate circumstances. If the Commission is going to experiment with decoupling, it makes sense to wait for an appropriate set of circumstances – unlike the situation in this case. For the reasons I have stated, in addition to the reasons stated in Ms. Jerich's testimony, decoupling is not an appropriate solution in this case, but that does not preclude the possibility that decoupling might be more beneficial and appropriate under a different set of circumstances (e.g. for an electric utility).

Q. In your direct case, you offered a decoupling proposal. Why is RUCO not recommending that proposal at this time?

A. That portion of my direct testimony case, was offered as a potential alternative if the Commission determined that decoupling should be adopted for this Company. Subsequent to that filing, RUCO has come to the conclusion there is not enough interest in this potential compromise to merit offering it in this filing. Instead, I have suggested the possibility of further increasing the fixed monthly customer charge as an alternative to decoupling.

Q. In your direct testimony, you expressed concerns that SWG's customer charges were already higher than would be cost-justified. Why are you suggesting RUCO's willingness to move further away from cost-based rates, if decoupling is rejected?

A. RUCO is offering this suggestion in the spirit of compromise. RUCO recognizes that SWG is seeking decoupling in part because this would help maintain or boost its cash flows and income in the face of a trend towards energy conservation, and to reduce the volatility of its revenues and income in the face of wide fluctuations in weather conditions. While a further increase in the monthly customer charge is not cost-justified, a modest increase can reasonably be justified as an effort to help mitigate two of the concerns that are motivating the Company to seek decoupling.

A modestly higher customer charge would change the trajectory of future cash flows and income in the presence of a continued trend toward energy conservation, and it would help reduce volatility in the Companys' revenue and income in the face of changing weather conditions. Thus RUCO is offering this suggestion as a compromise – it is not cost-justified, but it is less objectionable than the decoupling provisions included in the proposed Settlement.

Q. Have you estimated the impact of changing the revenue requirements in the Settlement to reflect the use of a more appropriate FVROR methodology, and the use of the 30 year average for "normal" weather?

A. Yes. I was not provided with a copy of the workpapers underlying the Settlement, so I instead used a copy of the workpapers filed with Staff's direct testimony to estimate these impacts. More specifically, using a Return on Equity of 9.50% but a FVROR of 6.85% based on RUCO's methodology, and replacing the inappropriately adjusted 10 year average weather data with the unadjusted 30 year average weather data, I estimate the $52.6 million revenue requirement set forth in the Settlement would be reduced to approximately $44.6 million.

Q. In summary, what is RUCO's proposed resolution of the issues in this case?

A. In the spirit of compromise, and in recognition of the efforts by other parties to resolve the issues through the proposed Settlement, RUCO is willing to accept all elements of the Settlement except for the three issues I've discussed in this testimony: decoupling, fair value methodology, and weather normalization. Accordingly, RUCO recommends the Commission reject the Settlement as filed, but resolve the issues in this proceeding in accordance with the provisions of the Settlement with these exceptions: reject decoupling, calculate the FVROR using the methodology adopted in Docket No. E-04204A-09-0206, and normalize weather based upon the unadjusted 30 year average. I estimate this will result in a revenue requirement of approximately $44.6 million. Finally, in an effort to alleviate to some degree the financial concerns which underly the Company's preference for decoupling, I recommend increasing SWG's flat monthly customer charges to $11.85 per month, notwithstanding the fact that this would push this rate further above a cost-justified level.

Q. Will you be filing additional schedules to this testimony??

A. Yes. RUCO recently asked me to prepare one or more schedules showing the impact of RUCO's recommendations on residential rates. Once I have had an opportunity to prepare this analysis, RUCO intends to provide it to the Commission and other parties. If possible, this will be done prior to the hearing in this case, and RUCO anticipates asking permission to introduce the schedules into evidence.

Q. Does this conclude your testimony pre-filed on July 29, 2011?

A. Yes, it does.

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-10-0458

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 10, 2011

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INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to my direct testimony further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations based on my analysis of Southwest Gas Corporation's ("SWG" or the "Company") application for a permanent increase in rates ("Application").

Q. Is this your first case involving SWG?

A. No. I've testified in the last two SWG rate cases that have come before the ACC.

Q. Briefly describe SWG and the Company's filing.

A. SWG is a local distribution company ("LDC") based in Las Vegas, NV, and is publicly-traded on the New York Stock Exchange ("NYSE"). The Company is the dominant provider of natural gas distribution services in the state of Arizona, and provides service to customers in Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma counties. SWG also provides natural gas in the states of California and Nevada. The Company's last rate increase was approved in Decision No. 70665, dated December 24, 2008. SWG filed its Application with the ACC on November 12, 2010. The Company has chosen the operating period ended June 30, 2010 for the test year ("Test Year") in this proceeding. SWG is seeking a revenue increase of $73.2 million, or 17.8 percent, over adjusted test year revenues of $410,9 million which will result in a 7.50 percent return on SWG's fair value rate base of $1.5 billion. According to

the Company's Application, the proposed increase would raise the current average monthly winter residential bill of $58.10 by $9.01 to $67.11 or a 15.5 percent increase. The present average monthly summer residential bill of $24.07 would increase by $2.54 to $26.61 or 10.55 percent. In addition to seeking a permanent increase in rates, SWG is also requesting approval of an Energy Efficiency Enabling Provision ("EEP"), which is a general decoupling methodology that will allow SWG to collect, from the Company's ratepayers, lost revenues attributable to declining sales due to conservation and energy efficiency programs.

Q. Has SWG elected to perform a reconstruction cost new less depreciation study in this case?

A. Yes. SWG elected to perform a reconstruction cost new less depreciation ("RCND") study and is proposing a fair value rate base ("FVRB") that is an average of the Company's original cost rate base ("OCRB") and its RCND rate base for ratemaking purposes. For this reason RUCO is recommending a fair value rate of return ("FVROR") to be applied to SWG's FVRB.

Q. Please explain your role in RUCO's analysis of SWG's Application.

A. I reviewed SWG's Application and performed a cost of capital analysis to determine an original cost rate of return ("OCROR") on the Company's invested capital. In addition to my recommended capital structure, my

direct testimony will present my recommended cost of common equity (the Company has no preferred stock) and my recommended cost of long-term debt. The recommendations contained in this testimony are based on information obtained from Company responses to data requests, SWG's Application, and from market-based research that I conducted during my analysis.

Q. Will you also be testifying on RUCO's recommended FVROR to be applied to SWG's FVRB?

A. No. That aspect off the case will be addressed in the direct testimony of Ben Johnson, Ph.D. of Ben Johnson Associates. Dr. Johnson has testified as an expert witness for RUCO on FVROR issues in several prior cases before the ACC (most notably on the Chaparral City Water Company remand proceeding) and has extensive knowledge on Arizona's constitutionally mandated fair value requirement. Dr. Johnson was also retained by RUCO to testify on the required revenue, rate base and rate design issues in this proceeding. Dr. Johnson's rate design testimony, which is scheduled to be filed on June 24, 2011, will present RUCO's recommendation on the Company-proposed EEP.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case and will present RUCO's OCROR recommendation.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into five sections. First, the introduction I have just presented and second, a summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of return for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate within which the Company is operating. Fourth, I will discuss my recommended capital structure, my recommended cost of long-term debt and my recommended weighted average cost of capital which represents the OCROR. Fifth, I will comment on the Company's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.00 percent cost of equity capital. This 9.00 percent figure falls on the high side of the range of results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies. My 9.00 percent cost of equity capital is 200 basis points lower than the 11.00 percent cost of equity capital being proposed by the Company and is 165 basis points higher than my recommended cost of long-term debt.

Capital Structure – I am recommending that the Commission adopt a capital structure comprised of 50.15 percent common equity and 49.85 percent long-term debt as opposed to the Company-proposed capital structure which is comprised of approximately 52.30 percent common equity and 47.70 percent long-term debt.

Cost of Long-Term Debt – I am recommending that the Commission adopt a cost of long-term debt of 7.35 percent, which is 99 basis points lower than the company-proposed 8.34 percent cost of debt. My recommended cost of long-term debt is based on information provided by SWG in a

response to ACC Staff Data Request 2.22 and reflects the impact of debt retirements and new bond issuances since the end of the Test Year.

Weighted Average Cost of Capital – Based on the results of my recommended capital structure, I am recommending an 8.18 percent weighted average cost of capital ("WACC") for SWG, which is the weighted cost of my recommended costs of common equity and long-term debt and also represents my recommended OCROR in this case. This 8.18 percent OCROR is the basis for RUCO's recommended FVROR that will be presented in Dr. Johnson's testimony.

Q Why do you believe that RUCO's recommended 8.18 percent WACC is an appropriate rate of return for the Company to earn on its invested capital?

A. The 8.18 percent WACC figure that I am recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return

adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as BVWC, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your final recommended cost of equity capital for BVWC?

A. I am recommending a cost of equity of 9.00 percent. My recommended 9.00 percent cost of equity figure falls on the high side of the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded LDCs. The results of my DCF and CAPM analyses are summarized on page 2 of my Schedule WAR-1.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate the Company's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the

investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine the Company's cost of equity capital.

...

Q. In determining the rate of future dividend growth for the Company, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[1]

[1] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated

funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[2] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six

[2] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

percent.[3] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common

[3] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

...

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[4] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and

[4] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,
b = the earnings retention ratio,
r = the return on common equity,
s = the fraction of new common stock sold that accrues to a current shareholder, and
v = funds raised from the sale of stock as a fraction of existing equity.

and $v = 1 - [(BV) \div (MP)]$

where: BV = book value per share of common stock, and
MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior SWG rate case[5], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for SWG was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

[5] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group comprised of eight LDCs.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of the Company?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although SWG is publicly-traded on the NYSE, SWG's Arizona operations are not. Because of this situation, I used the aforementioned proxy that includes eight publicly-traded LDCs with similar risk characteristics to SWG in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

...

Q. What criteria did you use in selecting the natural gas LDC's included in your proxy for the Company?

A. Each of the LDCs in my sample are tracked in the Value Line Investment Survey's ("Value Line") natural gas Utility industry segment. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment A of my testimony contains Value Line's most recent evaluation of the natural gas proxy group that I used for my cost of common equity analysis.

Q. What companies are included your natural gas proxy?

A. The eight natural gas LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("AGL"), Atmos Energy Corp. ("ATO"), Laclede Group, Inc. ("LG"), New Jersey Resources Corporation ("NJR"), Northwest Natural Gas Co. ("NWN"), Piedmont Natural Gas Company ("PNY"), South Jersey Industries, Inc. ("SJI") and WGL Holdings, Inc. ("WGL").

Q. Are these the same LDC's that you have used in prior rate case proceedings?

A. Yes, I have used these same LDC's in prior rate cases including the most recent UNS Gas, Inc. proceeding.[6] However, in those prior proceedings I also included another natural gas provider known as Nicor, Inc. Nicor, Inc.

[6] Docket No. G-04204A-06-0463

is currently being acquired by AGL Resources, Inc. Since Nicor, Inc.'s stock price is now being driven by the aforementioned acquisition, I did not believe it should be included in my proxy group.

Q. Are these same LDCs included in the proxy used by SWG's witness?

A. Yes. However SWG's witness, Mr. Robert V. Hevert also included Nicor, Inc., in his analysis which would have been conducted prior to the December 7, 2011 announcement of the merger between AGL and Nicor, Inc.

Q. Briefly describe the regions of the U.S. served by the natural gas LDC's that make up your sample proxy.

A. The LDC's listed above provide natural gas service to customers in the Middle Atlantic region (i.e. NJI which serves portions of northern New Jersey, SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast and South Central portions of the U.S. (i.e. AGL which serves Virginia, southern Tennessee and the Atlanta, Georgia area and PNY which serves customers in North Carolina, South Carolina and Tennessee), the South, deep South and Midwest (i.e. ATO which serves customers in Kentucky, Mississippi, Louisiana, Texas, Colorado and Kansas, LG which serves the St. Louis area), and the Pacific Northwest (i.e. NWN which serves Washington state and Oregon).

Q. Please explain your DCF growth rate calculations for the sample LDCs used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the LDCs included in the sample for an historical 5-year observation period from the beginning of 2006 to the end of 2010. Schedule WAR-5 also includes Value Line's projected 2011, 2012 and 2014-16 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the sample LDC's.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use AGL as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 11 and 12) to multiply AWR's earned return on common equity by its earnings retention ratio for each year in the 2006 to 2010 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As

shown on Schedule WAR-5, Page 1, AGL's average internal growth rate of 5.24 percent over the 2006 to 2010 time frame reflects an up and down pattern of growth that ranged from a low of 4.79 percent in 2008 to a high of 6.02 percent during 2006. Value Line is predicting that growth will increase steadily from 5.33 percent in 2010, to 5.73 percent by the end of the 2014-16 time frame. After weighing Value Line's projections on earnings and dividend growth, I believe that a 5.50% rate of internal growth is reasonable for AGL (Schedule WAR-4, Page 1 of 2).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that the number of shares outstanding for AGL increased from 77.70 million to 78.00 million from 2006 to 2010. Value Line is predicting that this level will increase from 78.50 million in 2011 to 80.50 million by the end of 2016. Based on this data, I believe that a 0.65 percent growth in shares is not unreasonable for AGL (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for AGL is 5.70 percent (5.50 percent internal growth + 0.20 percent external growth) and is shown on Page 1 of Schedule WAR-4.

...

Q. What is the average DCF dividend growth rate estimate for your sample utilities?

A. The average DCF dividend growth rate estimate for my sample is 5.42 percent as displayed on page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate estimates on your sample companies compare to the growth rate data published by Value Line and other analysts?

A. Schedule WAR-6 compares my growth estimates with the five-year projections of analysts at both Value Line and Zacks Investment Research, Inc. ("Zacks") (Attachment B). My 5.42 percent estimate exceeds Zacks' average long-term EPS projection of 4.31 percent but is 10 basis points lower than Value Line's growth projection of 5.52 percent (which is an average of EPS, DPS and BVPS). My 5.42 percent estimate is 29 basis points lower than the 5.71 percent average of Value Line's historical growth results and 8 basis points lower than the 5.50 percent average of the growth data published by both Value Line and Zacks. My 5.42 percent growth estimate is 113 basis points higher than Value Line's 4.29 percent 5-year compound historical average of EPS, DPS and BVPS. The estimates of analysts at Value Line indicate that investors are expecting somewhat lower growth rates from the natural gas utility industry in the future. On balance, I would say my 5.42 percent estimate

is a good representation of the growth projections that are available to the investing public.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's June 10, 2011 Ratings and Reports Natural Gas Utility industry update. I then divided those figures by the eight-week average daily adjusted closing price per share of the appropriate utility's common stock. The eight-week observation period ran from April 11, 2011 to June 3, 2011, and the average dividend yield was 3.80 as exhibited on Schedule WAR-3.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the LDCs included in your sample?

A. As shown on Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.22 percent for the LDCs included in my sample.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[7], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[8] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification.

[7] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[8] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM is that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\ ß\ (\ r_m - r_f\ )\ ]$$

where:

k	=	the expected return of a given security,
r_f	=	risk-free rate of return,
ß	=	beta coefficient, a statistical measurement of a security's systematic risk,
r_m	=	average market return (e.g. S&P 500), and
$r_m - r_f$	=	market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

...

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments (Attachment C) will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[9] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my

[9] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yield on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated April 22, 2011 through June 10, 2011 (Attachment C). This resulted in a risk-free (r_f) rate of return of 1.91 percent.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2010 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of intermediate-term government bonds for the same eighty-four year period. The market risk premium (r_m - r_f) that results by using the geometric mean of these inputs is 4.50 percent (9.90% - 5.40% = 4.50%). The market risk premium that results by using the arithmetic mean calculation is 6.40 percent (11.90% - 5.50% = 6.40%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of June 10, 2011 for the LDCs in my proxy. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDCs included in my sample ranged from 0.60 to 0.75 with an average beta of 0.66.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 4.87 percent. My calculation using an arithmetic mean results in an average expected return of 6.11 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	9.22%
CAPM	4.87% – 6.11%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 4.87 percent to 9.22 percent. My final recommended cost of common equity figure is 9.00 percent.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.00 percent cost of equity capital proposed by the Company is 200 basis points higher than the 9.00 percent cost of equity capital that I am recommending.

Q How did you arrive at your final recommended 9.00 percent cost of common equity?

A. My recommended 9.00 percent cost of common equity falls on the high side of the range of estimates obtained from my DCF and CAPM analyses. As I will discuss in more detail in the next section of my testimony, my final estimate takes into consideration current interest rates (as the cost of equity moves in the same direction as interest rates), and the current state of the national and state economies. My final estimate also takes into consideration a general belief among economists and market analysts that the U.S. Federal Reserve will begin raising interest rates as the economy improves (although there is no firm estimate as to when that may occur). I also took into consideration information on Arizona's current rate of unemployment in making my final cost of equity estimate.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks

that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please describe your analysis of the current economic environment.

A. My analysis begins with a review of the economic events that have occurred between 1990 and the present in order to provide a background on how we got to where we are now. It also describes how the Board of Governors of the Federal Reserve System ("Federal Reserve" or "Fed") and its Federal Open Market Committee ("FOMC") used its interest rate-setting authority to stimulate the economy by cutting interest rates during recessionary periods and by raising interest rates to control inflation during times of robust economic growth. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve, then chaired by noted economist Alan Greenspan, lowered its benchmark

federal funds rate[10] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

[10] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000. Over the next ten years, the FOMC continued to stimulate the economy and keep inflation in check by raising and lowering the federal funds rate.

Q. How did the U.S. economy fare between 2001 and 2007?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Disappointing economic data releases, since the beginning of

2001, preceded the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon which are now regarded as a defining point during this economic slump. From January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times in order to stimulate growth. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent during a period in which the economic picture turned considerably brighter as both Inflation and unemployment fell, wages increased and the overall economy, despite continued problems in housing, grew briskly.[11]

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers, and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief. As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of

[11] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates. Once again, the Fed managed to engineer a soft landing.

Q. What has been the state of the economy since 2007?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the beginning of what is now being referred to as the Great Recession; the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[12] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible

[12] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through its open market operations) into the credit markets.[13] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [14] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than

[13] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[14] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[15] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street

[15] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[16]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another 50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008.

Q. What is the current rate of inflation in the U.S.?

A. As can be seen on Schedule WAR-8, the current rate of inflation is at 3.20 percent according to information provided by the U.S. Department of Labor's Bureau of Labor Statistics.[17]

...

[16] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

[17] http://www.bls.gov/news.release/cpi.nr0.htm

Q. Has the Fed raised interest rates in anticipation of higher inflation?

A. No. Despite encouraging signs of recovery, with the exception of recent higher prices for food and oil, the FOMC has not raised interest rates to date. Furthermore, during the first week of November 2010, Chairman Bernanke announced plans to buy $600 billion of U.S. government bonds over the next eight months in order to drive down long-term interest rates and encourage more borrowing and growth.[18] During its March 15, 2011 meeting, the FOMC unanimously voted to press on with its $600 billion bond-buying plan despite a considerably more upbeat assessment of the economy and the job market. In a prepared statement, the FOMC announced that "The economic recovery is on a firmer footing, and overall conditions in the labor market appear to be improving gradually." However, the rate-setting body of the Fed also reiterated its pledge to keep interest rates, currently near zero, at very low levels for an extended period.[19]

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected the yields on Treasury Instruments and benchmark interest rates?

A. As can be seen on Schedule WAR-8, current Treasury yields are considerably lower than corresponding yields that existed during the year

[18] Hilsenrath, Jon, "Fed Fires $600 Billion Stimulus Shot" The Wall Street Journal, November 4, 2010

[19] da Costa, Pedro and Mark Felsenthal, "Fed says economic recovery on firmer footing," MSNBC, March 15, 2011

2000 and U.S. Treasury instruments, are for the most part, still at historically low levels. As can be seen on the first page of Attachment C, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has remained steady at 0.75 percent since March of 2010.

As of June 1, 2011, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have dropped from their June 2010 levels. Longer term yields including the 5-year, 10-year and 30-year have all fallen from levels that existed a year ago. Only the 30-year Zero rate saw a 5 basis point increase since June 2010 (Attachment C, Value Line Selection & Opinion page 2193). The prime rate has remained constant at 3.25 percent over the past year, as has the benchmark federal funds rate discussed above. A previous trend, described by former Chairman Greenspan as a "conundrum"[20], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists. The 5-year Treasury yield, used in my CAPM analysis, has decreased 54 basis points from 2.13 percent, in June 2010, to 1.59 percent as of June 1, 2011.

[20] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

Q. What are the current yields on utility bonds?

A. Referring again to Attachment C, as of June 1, 2011, 25/30-year A-rated utility bonds were yielding 5.14 percent (28 basis points lower than a year ago) and 25/30-year Baa/BBB-rated utility bonds were yielding 5.69 percent (down 34 basis points from a year earlier).

Q. What is the current outlook for the economy?

A. Value line's analysts had this to say in the June 10, 2011 edition of Value Line's Selection and Opinion publication:

> **Recent sluggishness aside, we still expect second-quarter GDP growth to narrowly push past the tepid 1.8% gain recorded during the first three months of this year.** Our sense is that gross domestic product growth may edge up to 2.5%, or so, in the current period, as the effects of Japan's earthquake and the harsh winter storms that blanketed so much of our nation fade. We also look for the recent moderation in the price of oil and other key commodities to encourage a still-reticent consumer to gradually pick up the spending pace.

Value Line's analysts went on to explain

> **Even so, our optimism has been tempered by less-than-compelling recent data,** which include declining durable goods orders, unrelenting softness in housing, some developing listlessness in consumer confidence, and slowing growth in manufacturing. Our feeling is that some of these problems will start to fade after midyear, although even then, we no longer sense that GDP growth will move beyond 3% in the final half.

Value Line's analysts also stated

> **We are a little more optimistic about 2012,** and believe that the up cycle will broaden to incorporate the still-troubled housing market by then. For now, a bottoming-out process is the best we see ahead for housing in 2011. Our 2012 economic model calls for modestly better housing numbers and GDP growth of just over 3%.

Value Line's analysts went on to say

> **Meanwhile, the Federal Reserve is likely to continue its support for the economy,** even as it prepares to conclude its quantitative easing, or QE2, monetary stimulus program late this month. Our sense is that the lead bank will not move to tighten the reins by raising interest rates for another six months to a year. But for now, we do not see a new stimulus, or QE3, endeavor being forthcoming. Even here though, our certainty is less than it has been.

Q. How are LDCs such as SWG faring in the current economic environment?

A. In the June 10, 2011 quarterly update on the natural gas utility industry Mr. Richard Gallagher stated the following:

> The weakness in the U.S. economy continues to affect this group's results. On point, the lackluster housing market remains a challenge. In fact, one key measure for this sector, housing starts, declined 10.6% in in April. This suggests demand will probably continue to be weak in the near term. Moreover, tight consumer spending has led to customer conservation. These factors, along with low natural gas prices, will likely continue to pressure revenues for the foreseeable future. What's more, low interest rates have led to an unfavorable rate environment, which has hurt these utilities returns of late.
>
> The primary appeal of these utility stocks is their above-average dividend yields. Indeed, the average yield for this group is about 3.6%, which is well above the *Value Line* median. Most notably, *NiSource, AGL Resources* and *Laclede Group* all offer particularly attractive dividend yields in this sector.

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit the hardest during the Great Recession and has lagged during the current recovery.[21] During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona is currently ranked third in the nation behind California and

[21] Beard, Betty, "Recession hit Arizona hardest" The Arizona Republic, March 6, 2011

Nevada (all areas that SWG operates in) in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties.[22]

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information displayed on the website of the Arizona Department of Administration's Office of Employment and Population Statistics[23], Arizona's jobless rate stood at 9.30 percent in April 2011 which is down from 10.10 percent in April 2010. As of June 3, 2011, nationwide unemployment remained unchanged at 9.10 percent according to the U.S. Bureau of Labor Statistics.[24] So Arizona's unemployment rate is slightly higher than the national average.

Q. After weighing the economic information that you've just discussed, do you believe that the 9.00 percent cost of equity capital that you have estimated is reasonable for SWG?

A. I believe that my recommended 9.00 percent cost of equity capital, which is 331 basis points higher than the current 5.69 percent yield on a

[22] http://www.realtytrac.com/trendcenter/

[23] Arizona Department of Administration's Office of Employment and Population Statistics http://www.workforce.az.gov/

[24] U.S. Bureau of Labor Statistics Economic News Release dated June 3, 2011 http://www.bls.gov/news.release/empsit.nr0.htm

Baa/BBB-rated utility bond, will provide SWG with a reasonable rate of return on invested capital when data on interest rates (that are low by historical standards), the current state of the economy, current rates of unemployment (both nationally and in Arizona), and the Fed's ability to keep inflation in check are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of equity analysis has produced such a return. As can be seen in Attachment D, my recommended 9.00 percent cost of common equity exceeds Value Line's projected 2011 and 2012 8.50 percent return on book common equity for SWG. Further, my recommended 9.00 percent cost of common equity matches Value Line's 9.00 percent return on book common equity for SWG over the 2014-2016 time frame.

CAPITAL STRUCTURE AND COST OF DEBT

Q. Please describe the Company-proposed capital structure.

A. The Company-proposed capital structure is comprised of approximately 52.30 percent common equity and 47.70 percent long-term debt.

Q. How does the Company-proposed capital structure compare with the capital structures of the LDCs that comprise your sample?

A. The Company-proposed capital structure, comprised of 52.30 percent equity capital is somewhat lower in equity than the capital structures of the LDCs in my sample, which had an average of 56.80 percent common equity, and would be perceived by investors as having slightly higher risk overall. SWG's 47.70 percent level of long-term debt is somewhat higher than the average of 43.10 percent in my sample and would be perceived as having a slightly higher level of financial risk. Overall I would say that SWG's capital structure is well balanced and the Company has improved its equity position since its last rate case proceeding.

Q. What capital structure are you recommending for SWG?

A. I am recommending a capital structure comprised of 50.15 percent common equity and 49.85 percent long-term debt which is slightly different from the Company-proposed capital structure.

Q. What is the difference between your recommended capital structure and the Company-proposed capital structure?

A. My recommended capital takes into consideration debt refinancing and bond issuances that occurred after the end of the Company's Test Year (Exhibit 2).

Q. What cost of long-term debt are you recommending for SWG?

A. I am recommending that the Commission adopt a cost of debt of 7.3 percent which is 99 basis points lower than the Company-proposed cost of debt of 8.34 percent.

Q. How did your determine your recommended cost of debt?

A. I based my recommended cost of debt on information that was provided by SWG in its response to ACC Staff data request 2.21 (Exhibit 1) which reflects the impact of debt refinancing and bond issuances noted above.

COMMENTS ON THE COMPANY-PROPOSED COST OF EQUITY CAPITAL

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The Company's cost of capital witness, Mr. Hevert, is recommending a cost of common equity of 11.00 percent. His 11.00 percent cost of common equity is 200 basis points higher than the 9.00 percent cost of common equity that I am recommending.

Q. What models and methods did Mr. Hevert use to arrive at his proposed cost of common equity for the Company?

A. Mr. Hevert used both the DCF and CAPM models. Mr. Hevert relies on both the constant growth DCF model that I relied on and a multi-stage version of the DCF model. He also employed a bond yield plus risk premium analysis which I did not rely on since it is a variation on CAPM.

Q. Please describe the methods used by Mr. Hevert and the results produced by his constant growth DCF model?

A. Mr. Hevert relied on growth estimates from analysts at Value Line, Zacks and First Call. He also relied on 30, 90 and 180 day averages of closing stock prices for the inputs to his constant DCF models.

Q. What were the results of Mr. Hevert's constant growth DCF model?

A. Mr. Hevert's constant growth model produced results ranging from 7.43 percent to 9.71 percent.

Q. What results did Mr. Hevert's obtain from his multi-stage DCF model?

A. Mr. Hevert's obtained multi-stage DCF model results ranging from a low of 10.08 percent to a high of 10.66 percent.

Q. How do Mr. Hevert's DCF results compare with the results that you obtained from your DCF analysis?

A. Mr. Hevert's results from both his DCF models range from 7.43 percent to 10.66 compared to my DCF result of 9.22 percent. The mean average of all of his DCF results is 9.50 percent which is 28 basis points higher than the 9.22 percent that I obtained from my constant growth model.

Q. What types of inputs did Mr. Hevert use in the standard Sharpe Litner CAPM model?

A. Mr. Hevert conducted two analyses using the Sharpe Litner CAPM model, one using a Sharpe Ratio derived market risk premium input of approximately 9.89 percent and another which used an ex-ante approach derived market risk premium input of approximately 9.38 percent as opposed to my risk premiums ranging from 4.50 percent to 6.40 percent. He then performed two separate analyses relying on a current average 30-year treasury yield of 3.75 percent and a near-term projected 30-year treasury yield of 4.22 percent as opposed to my 8-week average yield of 1.91 percent on a 5-year Treasury instrument. Each of these analyses used historical betas which averaged 0.67 and betas that were recalculated by Mr. Hevert that averaged 0.88 as opposed to my average beta of 0.66.

Q. How do the results of Mr. Hevert's CAPM analyses compare to the results of your CAPM analyses?

A. Mr. Hevert's CAPM analysis produced results ranging from 10.41 percent to 12.93 percent. As opposed to my CAPM results which ranged from 4.87% to 6.11%.

Q. What concerns do you have with the market risk premium inputs used by Mr. Hevert in his CAPM models?

A. I believe that the market risk premiums that Mr. Hevert developed for his CAPM models are clearly excessive and are not reasonable based on historical averages. I believe that the historical 4.50 percent to 6.40 percent market risk premiums that I have relied on are much more reasonable given the fact that they take into account the broad range of economic conditions that this country has experienced since 1926.

Q. Do you agree with Mr. Hevert's use of recalculated betas?

A. No. Mr. Hevert believes that recalculated betas are necessary because of market volatility during the recent financial crises. I disagree with this rationale because it infers that betas should be adjusted downward during good economic times. Simply put, beta is intended to be reflective of how sensitive a given security is to current market conditions and is central to CAPM. To adjust betas in the manner that Mr. Hevert has essentially undermines the theory behind the CAPM model.

Q. Please explain the differences in your risk free rates of return.

A. I relied on an 8-week average yield of 1.91 percent on a 5-year treasury instrument whereas Mr. Hevert relied on a current average of the yield on a 30-year Treasury bond and near-term projections of a 30-year Treasury bond.

Q. Do you agree with Mr. Hevert's reliance on 30-year Treasury instruments?

A. No. Investor owned utilities do not file for rates every thirty years. .As I stated earlier in my testimony, the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument more closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

Q. How did Mr. Hevert arrive at his final 11.00 percent cost of common equity for the Company?

A. Mr. Hevert's proposed 11.00 percent cost of common equity represents his own judgment and relies on the results on the averages of estimates he obtained from his various models.

...

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Hevert or any other witness for SWG constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on SWG?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase
UNS Electric, Inc.	E-04204A-06-0783	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase
Arizona Public Service Company	E-01345A-08-0172	Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase
Arizona Water Company	W-01445A-08-0440	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Black Mountain Sewer Corporation	SW-02361A-08-0609	Rate Increase
Global Utilities	SW-02445A-09-0077 et al.	Rate Increase
Litchfield Park Service Company	SW-01428A-09-0104 et al.	Rate Increase
UNS Electric, Inc.	E-04204A-09-0206	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-08-09-0257	Rate Increase
Arizona-American Water Company	W-01303A-09-0343	Rate Increase
Bella Vista Water Company	W-02465A-09-0411 et al.	Rate Increase
Chaparral City Water Company	W-02113A-10-0309	Reorganization
Qwest Communications International	T-04190A-10-0194 et al.	Merger
CenturyLink, Inc.	T-04190A-10-0194 et al.	Merger
Goodman Water Company	W-02500A-10-0382	Rate Increase

EXHIBIT 1

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-2
(ACC-STF-2-1 to ACC-STF-2-47)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-2-21:

Please indicate if the Company has refinanced the $200 million of long-term debt maturing in February of 2011, as cited on page 16.

Respondent: Treasury

Response:

In December 2010, the Company issued $125 million, 4.45% Senior Notes, due 2020 and in February 2011, the Company issued $125 million 6.10% Senior Notes, due 2041. Of the total amount issued, $75 million of the 4.45% Senior Notes and $125 million of the 6.10% Senior Notes was used to repay the $200 million, 8.375% Notes that matured on February 15, 2011.

EXHIBIT 2

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-2
(ACC-STF-2-1 to ACC-STF-2-47)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-2-22:

Please indicate the cost of debt to Southwest Gas, relative to that shown on Schedule D-1, for any debt retirements and/or new debt issuances subsequent to June 30, 2010.

Respondent: Treasury

Response:

The pro forma cost of debt at June 30, 2010, adjusted for debt retirements and new issuances is 7.35%, which is 99 basis points lower than the actual cost of debt of 8.34% (8.34 - 7.35 = 0.99).

ATTACHMENT A

The Natural Gas Utility Industry has fallen to the bottom quartile of our Timeliness Ranking spectrum. A difficult economic environment, low gas prices, and customer conservation will likely be the story here for the foreseeable future. In turn, these companies continue to search for ways to improve their business prospects. Despite their efforts, near-term prospects will probably remain uninspiring until the economic recovery is further along. All told, this sector's main appeal is its above-average dividend yield.

Regulation

Rate cases are an important theme for members of this industry. These companies are regulated by state commissions that determine the return on equity that can be achieved. A positive or negative decision in rate cases can have an meaningful impact on these businesses and, as a result, their stock prices. There are a few notable rate cases pending. Prospective investors should look out in the following pages for any utilities that have cases pending before making any investment decisions.

Macroeconomic Environment

The weakness in the U.S. economy continues to affect this group's results. On point, the lackluster housing market remains a challenge. In fact, one key measure for this sector, housing starts, declined 10.6% in April. This suggests demand will probably continue to be weak in the near term. Moreover, tight consumer spending has led to customer conservation. These factors, along with low natural gas prices, will likely continue to pressure revenues for the foreseeable future. What's more, low interest rates have led to an unfavorable rate environment, which has hurt these utilities' returns of late.

Other Operating Factors

Often, these companies utilize a variety of strategies to improve their results. Establishing tight cost controls is important given this group's business structure. Furthermore, these utilities have started to look for acquisitions that can create further cost savings. For example, *AGL Resources* is awaiting approval for its purchase of *Nicor*. The combined entity would be the largest gas distributor in the United States and would benefit from various cost synergies.

INDUSTRY TIMELINESS: 76 (of 98)

Another factor that weighs on this industry is unseasonable weather. Warmer- or colder-than-normal weather can impact natural gas prices. Conservative investors should probably look for utilities that hedge this risk via weather-adjusted rate mechanisms. Additionally, it is worth noting that the sector is currently entering its off season as heating demand will be generally limited over the next few months.

Also, many of these companies have invested in non-regulated operations, which are not dictated a return on equity by the aforementioned state commissions. These operations offer a higher potential for returns, but also add greater risk to the profits of these otherwise stable utilities. However, when natural gas prices are unfavorable, as they are now, these businesses help to buoy profits.

Energy-efficiency programs have become an increasingly important theme here, too. Governments have been advocating these initiatives as a way to promote conservation without impacting profitability in this industry. We expect greater emphasis on these programs in the years ahead.

Dividends

The primary appeal of these utility stocks is their above-average dividend yields. Indeed, the average yield for this group is about 3.6%, which is well above the *Value Line* median. Most notably, *NiSource*, *AGL Resources*, and *Laclede Group* all offer particularly attractive dividend yields in this sector.

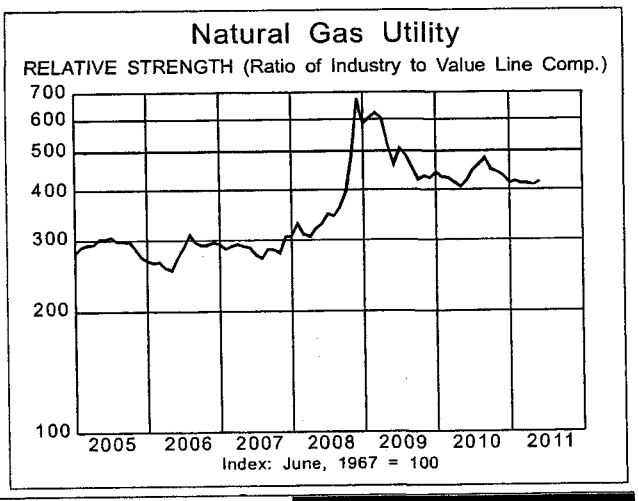
Conclusion

The Natural Gas Utility Industry is not ranked favorably for Timeliness. Thus, investors interested in stock appreciation in the year ahead would do better to look elsewhere. Longer term, these businesses should rebound due to an improved economic environment and more-favorable natural gas pricing. Therefore, we think conservative investors with an eye toward the 2014-2016 time frame will find a few issues here that offer worthwhile total return potential.

Richard Gallagher

Composite Statistics: Natural Gas Utility

2007	2008	2009	2010	2011	2012		14-16
38528	44207	34909	34089	*36250*	*42500*	Revenues ($mill)	*50250*
1562.4	1694.2	1677.6	1769.4	*2250*	*2130*	Net Profit ($mill)	*2415*
33.9%	35.7%	33.8%	34.0%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
4.1%	3.8%	4.8%	5.2%	*6.2%*	*5.0%*	Net Profit Margin	*4.8%*
50.4%	50.6%	49.9%	46.7%	*52.0%*	*51.0%*	Long-Term Debt Ratio	*54.0%*
49.5%	49.4%	50.1%	53.3%	*48.0%*	*49.0%*	Common Equity Ratio	*46.0%*
32263	32729	33974	33144	*33250*	*35500*	Total Capital ($mill)	*43000*
33936	35342	37292	39294	*40250*	*42250*	Net Plant ($mill)	*50500*
6.5%	6.8%	6.5%	6.9%	*6.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
9.8%	10.5%	10.0%	10.0%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
9.8%	10.5%	10.0%	10.0%	*10.0%*	*10.0%*	Return on Com Equity	*10.5%*
3.7%	4.3%	3.8%	4.0%	*4.0%*	*3.5%*	Retained to Com Eq	*4.5%*
62%	59%	61%	61%	*61%*	*60%*	All Div'ds to Net Prof	*61%*
16.6	13.9	12.8	14.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
.88	.83	.85	.90			Relative P/E Ratio	*.85*
3.7%	4.2%	4.8%	4.3%			Avg Ann'l Div'd Yield	*4.6%*
336%	358%	381%	402%	*400%*	*375%*	Fixed Charge Coverage	*400%*



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AGL RESOURCES NYSE-AGL

RECENT PRICE 41.11 | P/E RATIO 13.1 (Trailing: 14.4 Median: 13.0) | RELATIVE P/E RATIO 0.79 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 3/11/11
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 4/1/11
BETA .75 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+60%)	15%
Low	50	(+20%)	9%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	1	0	0	0	0
to Sell	0	0	2	0	1	0	0	0	0

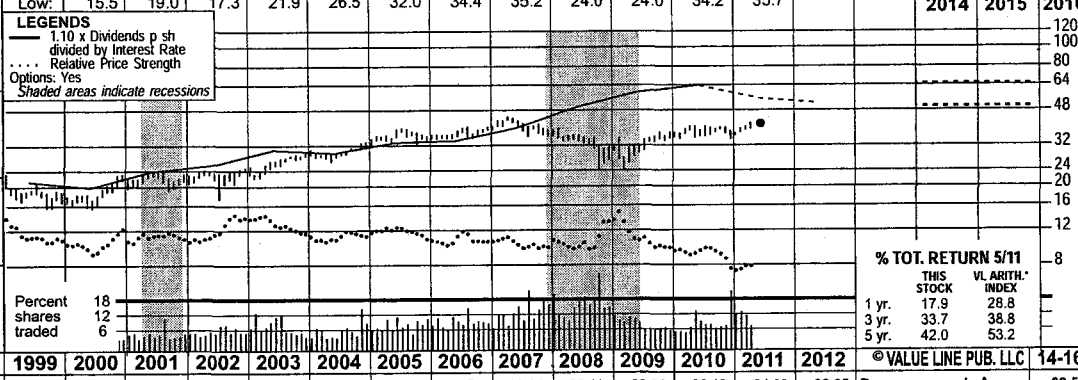
Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	109	134	103
to Sell	96	95	129
Hld's(000)	46899	48498	48137

	High:	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	42.3
	Low:	15.5	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	35.7

LEGENDS
1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions

Target Price Range 2014 | 2015 | 2016



% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.9	28.8
3 yr.	33.7	38.8
5 yr.	42.0	53.2

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	*31.60*	*32.65*	Revenues per sh [A]	*38.50*
2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	*5.25*	*5.45*	"Cash Flow" per sh	*6.05*
1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	*3.15*	*3.30*	Earnings per sh [A B]	*3.75*
1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	*1.80*	*1.84*	Div'ds Decl'd per sh [C■]	*1.96*
2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	*4.80*	*5.20*	Cap'l Spending per sh	*6.30*
10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	*24.95*	*26.50*	Book Value per sh [D]	*31.60*
55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	*78.50*	*79.00*	Common Shs Outst'g [E]	*80.50*
12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.79			Relative P/E Ratio	*1.00*
6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%			Avg Ann'l Div'd Yield	*3.5%*
1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	*2480*	*2580*	Revenues ($mill) [A]	*3100*
82.3	103.0	132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	*250*	*260*	Net Profit ($mill)	*300*
40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	*10.1%*	*10.1%*	Net Profit Margin	*9.7%*
61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	*53.0%*	*50.0%*	Long-Term Debt Ratio	*41.0%*
38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	*47.0%*	*50.0%*	Common Equity Ratio	*59.0%*
1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	*4160*	*4190*	Total Capital ($mill)	*4345*
2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	*4660*	*4735*	Net Plant ($mill)	*5100*
6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	*7.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	*12.5%*	*12.5%*	Return on Shr. Equity	*12.0%*
12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	*12.5%*	*12.5%*	Return on Com Equity	*12.0%*
4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	*5.5%*	*5.5%*	Retained to Com Eq	*5.5%*
65%	52%	53%	49%	52%	52%	58%	60%	57%	57%	*57%*	*56%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $2199.0 mill. **Due in 5 Yrs** $600.0 mill.
LT Debt $2173.0 mill. **LT Interest** $140.0 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $95.0 mill.
Pension Assets-12/10 $344.0 mill. **Oblig.** $531.0 mill.

Pfd Stock None

Common Stock 78,258,498 shs.
as of 4/28/11

MARKET CAP: $3.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	26	24	85
Other	1974	2138	1502
Current Assets	2000	2162	1587
Accts Payable	237	184	161
Debt Due	602	1032	26
Other	933	1212	1126
Current Liab.	1772	2428	1313
Fix. Chg. Cov.	472%	475%	820%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	6.0%	5.5%	3.0%
"Cash Flow"	6.5%	6.0%	4.0%
Earnings	9.0%	4.5%	5.0%
Dividends	5.0%	7.5%	3.0%
Book Value	7.0%	5.5%	6.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1012	444.0	539.0	805.0	2800.0
2009	995.0	377.0	307.0	638.0	2317.0
2010	1003	359.0	346.0	665.0	2373.0
2011	878.0	*400*	*400*	*802*	*2480*
2012	*1170*	*360*	*350*	*700*	*2580*

Calendar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.16	.30	.28	.97	2.71
2009	1.55	.26	.16	.91	2.88
2010	1.73	.17	.29	.81	3.00
2011	1.59	*.25*	*.35*	*.96*	*3.15*
2012	*1.60*	*.40*	*.45*	*.85*	*3.30*

Calendar	QUARTERLY DIVIDENDS PAID [C■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.41	.41	.41	.41	1.64
2008	.42	.42	.42	.42	1.68
2009	.43	.43	.43	.43	1.72
2010	.44	.44	.44	.44	1.76
2011	.45	.45			

BUSINESS: AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas. The utilities have more than 2.3 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in non-regulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. BlackRock Inc. owns 7.9% of common stock; off./dir., less than 1.0% (3/11 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

The acquisition of Nicor remains AGL Resources' main focus. The transaction, announced in December, 2010, is progressing on schedule. The SEC has approved the filed registration statement, and antitrust clearance has been received. The merger looks to be quite beneficial for the company, providing considerable economies of scale. The company hopes to use Nicor's expertise in the Midwest and Chicago area to gain a greater hold in the market, adding considerably to the existing customer base. Furthermore, the integration of Nicor's storage facilities is slated to reduce operating costs and provide expansion opportunities. The merger should result in a considerable boost to both top and bottom lines over the 3 - to 5 -year pull.

AGL Resources is likely to perform well in 2011. Favorable rate rulings and expansion projects should result in solid top- and bottom-line performances.

The company continues to diversify geographically. It increased its investment during the quarter in South Star Energy, a multistate natural gas provider, from 70% to 85%. AGL Resources is now looking at other investments, though no concrete details are known.

Rate cases and expansion projects remain earnings drivers. Due to favorable rulings, rate cases in Georgia and Tennessee are slated to provide a boost to the bottom line. The company is currently focusing on rate cases in Virginia, with plans to file a case in Florida, as well. The Golden Triangle project also remains a key driver, with the expansion of Caravan 2 progressing on schedule. The endeavor is key in increasing storage levels and expanding the customer base in the long term. This should provide a boost to earnings for the 2014-2016 period.

Long-term prospects appear bright. Any stress on earnings caused by AGL's supply glut, as well as low natural gas prices, is likely to be more than offset by revenues from mergers, expansion projects, and favorable rate cases.

Income investors might find this neutrally ranked issue of interest. This stock has a high dividend yield, with the possibility of increased payouts. Thus, total return potential appears worthwhile.

Sahana Zutshi *June 10, 2011*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late July.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2010: $418 million, $5.35/share.
(E) In millions.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	95

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ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 33.35 | P/E RATIO 13.6 (Trailing: 14.8 / Median: 14.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 2/25/11
SAFETY 2 Raised 12/16/05
TECHNICAL 3 Raised 4/8/11
BETA .70 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	30	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	0	0
to Sell	0	1	0	0	3	0	0	1	1

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	90	102	97
to Sell	106	100	107
Hld's(000)	50893	51197	50750

	High:	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.3
	Low:	14.3	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	31.3

LEGENDS
1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions

Target Price Range 2014 | 2015 | 2016

% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.4	28.8
3 yr.	40.8	38.8
5 yr.	56.9	53.2

Percent shares traded: 12 / 8 / 4

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

CAPITAL STRUCTURE as of 3/31/11
Total Debt $2159.7 mill. **Due in 5 Yrs** $1240.0 mill.
LT Debt $1807.3 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.2x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $18.2 mill.
Pfd Stock None
Pension Assets-9/10 $301.7 mill.
Oblig. $407.5 mill.
Common Stock 90,329,899 shs.
as of 4/29/11
MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	111.2	132.0	153.2
Other	717.7	743.2	830.9
Current Assets	828.9	875.2	984.1
Accts Payable	207.4	266.2	423.7
Debt Due	72.7	486.2	352.4
Other	457.3	413.7	301.9
Current Liab.	737.4	1166.1	1078.0
Fix. Chg. Cov.	416%	440%	435%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	9.5%	3.0%	*1.0%*
"Cash Flow"	4.0%	5.5%	*4.0%*
Earnings	5.0%	4.0%	*5.0%*
Dividends	2.0%	1.5%	2.0%
Book Value	6.5%	5.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	1657.5	2484.0	1639.1	1440.7	7221.3
2009	1716.3	1821.4	780.8	650.6	4969.1
2010	1292.9	1940.3	770.2	786.3	4789.7
2011	1157.0	1617.3	*820*	*805.7*	*4400*
2012	*1255*	*1740*	*850*	*805*	*4650*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	.82	1.24	d.07	.02	2.00
2009	.83	1.29	.02	d.17	1.97
2010	1.00	1.17	d.03	.02	2.16
2011	.81	1.40	*.06*	*.03*	*2.30*
2012	*.97*	*1.35*	*.06*	*.02*	*2.40*

Calendar	QUARTERLY DIVIDENDS PAID C Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.32	.32	.32	.325	1.29
2008	.325	.325	.325	.33	1.31
2009	.33	.33	.33	.335	1.33
2010	.335	.335	.335	.34	1.35
2011	.34	.34			

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
	35.36	22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	*48.35*	*50.55*	Revenues per sh A	*64.75*
	3.03	3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	*4.85*	*5.10*	"Cash Flow" per sh	*5.55*
	1.47	1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	*2.30*	*2.40*	Earnings per sh A B	*2.70*
	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	*1.36*	*1.38*	Div'ds Decl'd per sh C■	*1.45*
	2.77	3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	*6.45*	*6.75*	Cap'l Spending per sh	*7.65*
	14.31	13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	*26.10*	*27.50*	Book Value per sh	*30.10*
	40.79	41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	*91.00*	*92.00*	Common Shs Outst'g D	*105.00*
	15.6	15.2	13.4	15.9	16.1	13.5	15.9	13.6	12.5	13.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
	.80	.83	.76	.84	.86	.73	.84	.82	.83	.84			Relative P/E Ratio	*.85*
	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%			Avg Ann'l Div'd Yield	*4.1%*
	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	*4400*	*4650*	Revenues ($mill) A	*6800*
	56.1	59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	*210*	*220*	Net Profit ($mill)	*285*
	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	*38.5%*	*38.5%*	Income Tax Rate	*40.5%*
	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	*4.8%*	*4.7%*	Net Profit Margin	*4.2%*
	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*49.0%*
	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	*55.0%*	*55.0%*	Common Equity Ratio	*51.0%*
	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	*4315*	*4600*	Total Capital ($mill)	*6200*
	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	*5100*	*5400*	Net Plant ($mill)	*6400*
	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	*9.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	*9.0%*	*8.5%*	Return on Com Equity	*9.0%*
	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
	79%	82%	70%	77%	73%	63%	65%	65%	68%	62%	*59%*	*58%*	All Div'ds to Net Prof	*53%*

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2010 gas volumes: 323 MMcf. Breakdown: 59%, residential; 32%, commercial; 6%, industrial; and 3% other. 2010 depreciation rate 3.3%. Has around 4,915 employees. Officers and directors own 1.4% of common stock (12/10 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Coming off a disappointing first quarter, Atmos Energy's share net jumped almost 20% in the March interim. (Fiscal 2011 ends on September 30th.) The natural gas distribution segment was aided by higher rates in such states as Texas, Louisiana, and Kentucky. But results here were constrained a bit by an 11% decline in throughput, reflecting warmer temperatures. Meanwhile, the regulated transmission and storage unit benefited from lower operating expenses and revenues from filings under the Texas Gas Reliability Infrastructure Program. Diminished per-unit transportation margins were somewhat of an offset here.

For the full fiscal year, the bottom line stands to advance about 6%, to $2.30 a share. That's based partly on our assumption that the natural gas utility and regulated transmission and storage unit continue to perform nicely. Next year, share earnings may increase at a similar rate, to $2.40, as we look for a further expansion of operating margins.

The company intends to sell its non-core natural gas distribution assets in Missouri, Iowa, and Illinois to an affiliate of Algonquin Power & Utilities Corp. The estimated $124 million in proceeds would be used to support growth initiatives in such key states as Texas and Louisiana. Pending regulatory approvals, the transaction is expected to close in fiscal 2012.

We expect unspectacular results for the company over the 2014-2016 period. The utility is one of the country's biggest natural gas-only distributors. Also, the unregulated units, especially pipelines, possess healthy overall growth prospects. Lastly, management may resume its successful strategy of purchasing less efficient utilities and shoring up their profitability via expense-reduction initiatives, rate relief, and aggressive marketing efforts. But excluding future acquisitions, due to many uncertainties, annual share-net growth may be in the mid-single-digit range over the 3- to 5-year horizon.

The good-quality equity's dividend yield is a bit higher than the average gas utility stock tracked by *Value Line*. Further increases in the payout, though modest, seem likely.

Frederick L. Harris, III *June 10, 2011*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; Q2 '11, 5¢. Next egs. rpt. due early Aug. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	90

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LACLEDE GROUP NYSE-LG

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
37.61	15.4 (Trailing: 15.4 Median: 14.0)	0.93	4.4%

VALUE LINE

TIMELINESS 3 Raised 11/19/10
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 4/1/11
BETA .60 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	13%
Low	40	(+5%)	6%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	
to Sell	0	0	0	0	0	0	1	0	

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	54	49	52
to Sell	53	62	58
Hld's(000)	10165	10026	10275

	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3	37.8	40.0
High:	17.5	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	29.3	30.8	36.3

LEGENDS
1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions

Target Price Range 2014 | 2015 | 2016

128 96 80 64 48 40 32 24 16 12

Percent shares traded 7.5 5 2.5

% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.0	28.8
3 yr.	7.0	38.8
5 yr.	39.0	53.2

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	*71.10*	*73.90*	Revenues per sh	*86.55*
2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	*4.20*	*4.40*	"Cash Flow" per sh	*5.20*
1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	*2.45*	*2.55*	Earnings per sh A B	*3.05*
1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	*1.61*	*1.65*	Div'ds Decl'd per sh C■	*1.80*
2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	*2.70*	*2.80*	Cap'l Spending per sh	*3.15*
13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	*26.00*	*26.60*	Book Value per sh D	*31.15*
17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	*22.50*	*23.00*	Common Shs Outst'g E	*26.00*
15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.5*
1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87			Relative P/E Ratio	*1.05*
6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%			Avg Ann'l Div'd Yield	*3.8%*
1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	*1600*	*1700*	Revenues ($mill) A	*2250*
30.5	22.4	34.6	36.1	40.1	50.5	49.8	57.6	64.3	54.0	*55.0*	*58.5*	Net Profit ($mill)	*80.0*
32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	*35.5%*	*36.0%*	Income Tax Rate	*36.5%*
3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	*3.4%*	*3.4%*	Net Profit Margin	*3.5%*
49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
574.1	546.6	605.0	737.4	707.9	798.9	784.5	876.1	906.3	899.9	*975*	*1020*	Total Capital ($mill)	*1350*
602.5	594.4	621.2	646.9	679.5	763.8	793.8	823.2	855.9	884.1	*915*	*960*	Net Plant ($mill)	*1300*
6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	*9.5%*	*9.5%*	Return on Com Equity	*10.0%*
1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
83%	113%	74%	73%	72%	59%	63%	56%	53%	64%	*66%*	*65%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $364.3 mill. **Due in 5 Yrs** $155.0 mill.
LT Debt $364.3 mill. **LT Interest** $20.0 mill.
(Total interest coverage: 4.0x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/10 $240.9 mill.
Oblig. $398.4 mill.

Pfd Stock None
Common Stock 22,408,718 shs.
as of 4/28/11

MARKET CAP: $850 million (Small Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	74.6	86.9	23.0
Other	294.2	327.3	328.1
Current Assets	368.8	414.2	351.1
Accts Payable	72.8	95.6	96.8
Debt Due	129.8	154.6	--
Other	96.5	83.7	92.3
Current Liab.	299.1	333.9	189.1
Fix. Chg. Cov.	420%	391%	400%

ANNUAL RATES (of change (per sh))	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	11.5%	7.0%	*Nil*
"Cash Flow"	4.5%	7.5%	*3.5%*
Earnings	6.0%	7.5%	*2.5%*
Dividends	1.5%	2.5%	*2.5%*
Book Value	4.5%	7.0%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	504.0	747.7	505.5	451.8	2209.0
2009	674.3	659.1	309.9	251.9	1895.2
2010	491.2	635.3	324.5	284.0	1735.0
2011	444.2	543.8	*326*	*286*	*1600*
2012	*465*	*625*	*348*	*262*	*1700*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	.99	1.39	.41	d.14	2.64
2009	1.42	1.40	.31	d.22	2.92
2010	1.03	1.26	.21	d.07	2.43
2011	1.05	1.25	*.23*	*d.08*	*2.45*
2012	*1.05*	*1.31*	*.30*	*d.11*	*2.55*

Calendar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.365	.365	.365	.365	1.46
2008	.375	.375	.375	.375	1.50
2009	.385	.385	.385	.385	1.54
2010	.395	.395	.395	.395	1.58
2011	.405	.405			

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 630,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Therms sold and transported in fiscal 2010: .97 mill. Revenue mix for regulated operations: residential, 68%; commercial and industrial, 24%; transportation, 2%; other, 6%. Has around 1,700 employees. Officers and directors own approximately 8% of common shares (1/11 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group's utility unit, Laclede Gas, enjoyed a decent rise in profits during the first half of fiscal 2011 (ends September 30th), versus the year-ago figure. That was brought about, in part, by a rate hike that went into effect on September 1, 2010. Furthermore, operating costs were lower, reflecting effective collections efforts and expense-containment initiatives.

But the performance of Laclede Energy Resources was disappointing. Indeed, margins were lower, due to narrower regional price differentials (given a less-than-optimal economic environment). Unfortunately, it seems that difficult business conditions will continue a while longer.

In all, share net may only be about flat for the full fiscal year, as continued strength of Laclede Gas is offset by further weakness in Laclede Resources. But the bottom line stands to perk up some in fiscal 2012, perhaps to $2.55 a share, assuming further expansion of operating margins. (We expect the recent storms in Missouri to have minimal impact on the company's results.)

Prospects over the 2014-2016 time frame are not exciting. Annual growth in the customer base for the natural gas distributor will probably remain sluggish. (In fact, the number of customers in fiscal 2010 was only around 1,000 more than in fiscal 2000.) Laclede Energy Resources seems to have promising potential, but it has contributed just a small portion to total profits, on a historical basis. As a result, consolidated annual share-earnings advances may only be in the mid-single-digit range over the 3- to 5-year horizon. A significant acquisition could brighten things, but management appears to be satisfied with the way things are at this juncture.

The good-quality equity's dividend yield compares favorably to the average of all natural gas utility stocks covered by *Value Line*. The payout should continue to be well covered by the company's earnings. But future hikes will probably be moderate, given Laclede Gas' unexciting long-term prospects. Meanwhile, these shares' Timeliness rank stands at 3 (Average).

Frederick L. Harris, III *June 10, 2011*

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	80

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '10: $487.1 mill., $21.85/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

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NEW JERSEY RES. NYSE-NJR

RECENT PRICE 46.08 | P/E RATIO 17.1 (Trailing: 17.9 / Median: 15.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 4 Lowered 3/11/11
SAFETY 1 Raised 9/15/06
TECHNICAL 3 Raised 4/1/11
BETA .65 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	5%
Low	40	(-15%)	Nil

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	3	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	60	65	67
to Sell	64	56	57
Hld's(000)	23366	24033	23545

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
High:	19.8	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4	44.1	46.3								
Low:	16.1	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	30.0	33.5	40.2								
	11.36	13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.63	72.62	90.74	62.34	63.81	*70.10*	*74.00*	Revenues per sh [A]	*80.90*
	1.42	1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	3.16	3.28	*3.55*	*3.80*	"Cash Flow" per sh	*4.25*
	.86	.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	2.40	2.46	*2.65*	*2.85*	Earnings per sh [B]	*3.20*
	.68	.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	1.24	1.36	*1.44*	*1.48*	Div'ds Decl'd per sh [C] ■	*1.60*
	1.18	1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	1.81	2.09	*1.95*	*2.00*	Cap'l Spending per sh	*2.00*
	6.47	6.73	6.92	7.26	7.57	8.29	8.80	8.71	10.26	11.25	10.60	15.00	15.50	17.28	16.59	17.53	*18.75*	*19.45*	Book Value per sh [D]	*24.15*
	40.03	40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.61	42.06	41.59	41.36	*41.00*	*40.00*	Common Shs Outst'g [E]	*40.00*
	11.8	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
	.79	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.96			Relative P/E Ratio	*.95*
	6.7%	5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%			Avg Ann'l Div'd Yield	*3.6%*
	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	2592.5	2639.3	*2875*	*2960*	Revenues ($mill) [A]	*3235*
	52.3	56.8	65.4	71.6	74.4	78.5	65.3	113.9	101.0	102.4	*110*	*115*	Net Profit ($mill)	*130*
	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	27.1%	37.6%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	3.9%	3.9%	*4.0%*	*4.0%*	Net Profit Margin	*4.0%*
	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	39.8%	37.2%	*37.0%*	*39.0%*	Long-Term Debt Ratio	*34.0%*
	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	60.2%	62.8%	*63.0%*	*61.0%*	Common Equity Ratio	*66.0%*
	706.2	732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	1144.8	1154.4	*1220*	*1275*	Total Capital ($mill)	*1465*
	743.9	756.4	852.6	880.4	905.1	934.9	970.9	1017.3	1064.4	1135.7	*1160*	*1180*	Net Plant ($mill)	*1255*
	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	9.7%	9.8%	*10.0%*	*10.0%*	Return on Total Cap'l	*9.5%*
	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.1%	*14.5%*	*15.0%*	Return on Shr. Equity	*13.5%*
	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.1%	*14.5%*	*15.0%*	Return on Com Equity	*13.5%*
	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	7.2%	6.8%	*6.5%*	*7.0%*	Retained to Com Eq	*6.5%*
	59%	56%	51%	49%	50%	50%	64%	40%	50%	52%	*54%*	*51%*	All Div'ds to Net Prof	*50%*

Percent shares traded: 12, 8, 4

Target Price Range 2014 | 2015 | 2016: 80, 60, 50, 40, 30, 25, 20, 15, 10, 7.5

% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.7	28.8
3 yr.	53.8	38.8
5 yr.	82.2	53.2

LEGENDS
1.40 x Dividends p sh divided by Interest Rate
Relative Price Strength
3-for-2 split 3/02
3-for-2 split 3/08
Options: Yes
Shaded areas indicate recessions

CAPITAL STRUCTURE as of 3/31/11
Total Debt $589.8 mill. Due in 5 Yrs $544.5 mill.
LT Debt $430.0 mill. LT Interest $11.7 mill.
Incl. $14.6 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/10 $150.5 mill. Oblig. $244.5 mill.
Pfd Stock None

Common Stock 41,370,942 shs.
as of 5/2/11
MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	36.2	.9	76.4
Other	648.0	784.1	633.2
Current Assets	684.2	785.0	709.6
Accts Payable	44.4	47.3	44.6
Debt Due	149.9	178.9	159.8
Other	361.9	479.6	380.8
Current Liab.	556.2	705.8	585.2
Fix. Chg. Cov.	711%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	12.0%	1.5%	*2.0%*
"Cash Flow"	6.0%	6.0%	*4.0%*
Earnings	8.5%	8.5%	*4.0%*
Dividends	5.0%	7.5%	*4.5%*
Book Value	8.5%	10.0%	*6.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	811.1	1178	1000	827.1	3816.2
2009	801.3	937.5	441.1	412.6	2592.5
2010	609.6	918.4	479.8	631.5	2639.3
2011	713.2	977.0	*510*	*674.8*	*2875*
2012	*735*	*1000*	*530*	*695*	*2960*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	1.31	1.86	d.10	d.39	2.70
2009	.77	1.71	.03	d.12	2.40
2010	.66	1.55	.28	d.03	2.46
2011	.71	1.62	*.30*	*.02*	*2.65*
2012	*.75*	*1.67*	*.35*	*.08*	*2.85*

Calendar	QUARTERLY DIVIDENDS PAID [C E ■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.253	.253	.253	.253	1.01
2008	.267	.28	.28	.28	1.11
2009	.31	.31	.31	.31	1.24
2010	.34	.34	.34	.34	1.36
2011	.36	.36			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 490,310 customers at 9/30/10 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2010 volume: 150 bill. cu. ft. (5% interruptible, 39% residential and commercial and electric utility, 56% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2010 dep. rate: 2.2%. Has 887 empls. Off./dir. own about 1.5% of common (12/10 Proxy). Chrmn., CEO & Pres. : Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources is on pace to log solid top- and bottom-line gains this year. This ought to be supported by customer growth at the New Jersey Natural Gas (NJNG) unit. Thus far in 2011, NJNG has added 3,070 new customers, as natural gas continues to maintain its price advantage over other home heating fuels in NJNG's service territory. Further contributions will likely stem from the Midstream Asset division, which focuses on storage and pipelines.

Meanwhile, the NJR Clean Energy Ventures division is benefiting from solar project startups. That unit has already placed two rooftop applications into service, that generate about two megawatts of power. It also has two similar projects planned for completion this summer. And another 3.6 megawatt ground-mounted facility is slated to be in service this fall. Aside from generating green power, these facilities qualify for investment tax credits, which should lower NJR's effective tax rate down the road.

Accelerated infrastructure projects (AIP) augur well for longer-term prospects. AIP-phase I is comprised of 14 projects, of which seven have been completed. The remainder are expected to be done by the end of summer. Additionally, AIP-phase II was recently approved, and contains another nine projects to help ensure the safety, integrity, and reliability of NJR's system. These investments are expected to add over $60 million to the company's asset base, which could lead to a rate case filing down the road.

The balance sheet is improving. The company's cash reserved skyrocketed to more than $75 million since the beginning of the year. At the same time, the debt load has remained relatively constant.

These shares may appeal to income-seeking, conservative investors, thanks to an above-average dividend yield, Highest Safety rank, top mark for Price Stability, and good Financial Strength. Meanwhile, since our March review, the equity has advanced about 10% in price. This move places NJR's quotation inside our Target Price Range, which may limit capital appreciation potential. Also, the stock is ranked to lag the broader market averages in the coming year.

Bryan J. Fong *June 10, 2011*

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	50

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late July.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2010: $454.6 million, $10.99/share.
(E) In millions, adjusted for splits.

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N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 45.17 | P/E RATIO 19.2 (Trailing: 17.2 Median: 17.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 4 Lowered 5/13/11
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Raised 5/20/11
BETA .60 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+45%)	13%
Low	50	(+10%)	6%

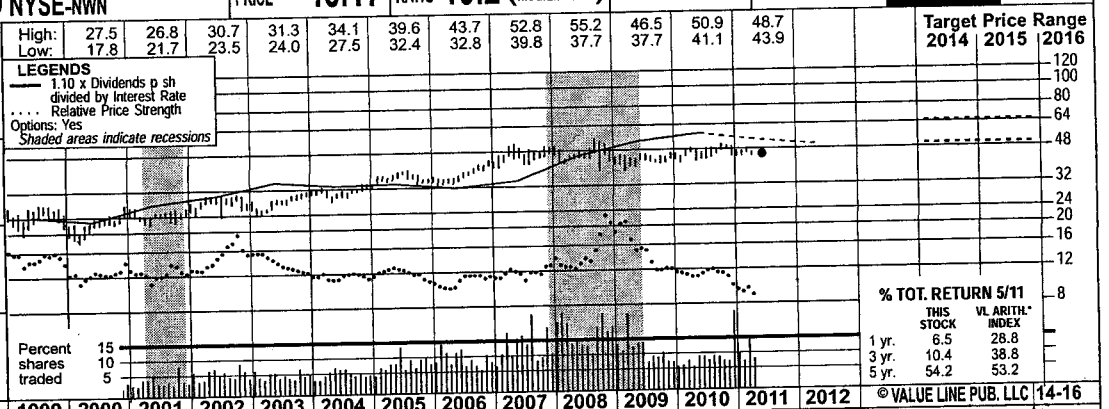
Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	3	0	0	0	0	0	0
to Sell	0	3	4	0	0	1	2	0	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	63	74	53
to Sell	59	56	73
Hld's(000)	15723	15297	15073

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.45	34.20	37.30	Revenues per sh	49.35
	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.15	5.20	5.60	"Cash Flow" per sh	6.75
	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.35	2.80	Earnings per sh A	3.40
	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.74	1.78	Div'ds Decl'd per sh B■	1.90
	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.30	3.75	5.20	Cap'l Spending per sh	9.65
	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	25.95	27.15	28.95	Book Value per sh	34.65
	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.67	26.75	26.80	Common Shs Outst'g C	26.95
	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.9	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	17.0
	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.10			Relative P/E Ratio	1.15
	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.8%			Avg Ann'l Div'd Yield	3.3%
	650.3	641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	915	1000	Revenues ($mill)	1330
	50.2	43.8	46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	65.0	75.0	Net Profit ($mill)	90.0
	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	31.4%	30.0%	30.0%	Income Tax Rate	30.0%
	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.0%	7.5%	Net Profit Margin	7.0%
	43.0%	47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.5%	43%	40%	Long-Term Debt Ratio	33%
	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.5%	57%	60%	Common Equity Ratio	67%
	880.5	937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1294.8	1275	1300	Total Capital ($mill)	1385
	965.0	995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1930	2035	Net Plant ($mill)	2530
	6.9%	5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	5.6%	6.5%	7.0%	Return on Total Cap'l	8.0%
	10.0%	8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	9.0%	9.5%	Return on Shr. Equity	10.0%
	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	9.0%	9.5%	Return on Com Equity	10.0%
	3.5%	1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.5%	3.5%	Retained to Com Eq	4.5%
	67%	79%	72%	69%	63%	59%	52%	59%	56%	61%	74%	63%	All Div'ds to Net Prof	56%



Target Price Range 2014 | 2015 | 2016
120
100
80
64
48
32
24
20
16
12
8

% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.5	28.8
3 yr.	10.4	38.8
5 yr.	54.2	53.2

CAPITAL STRUCTURE as of 3/31/11
Total Debt $788.1 mill. Due in 5 Yrs $200 mill.
LT Debt $551.7 mill. LT Interest $38.5 mill.

(Total interest coverage: 7.0x)

Pension Assets-12/10 $219 mill. Oblig. $337.3 mill.

Pfd Stock None

Common Stock 26,672,812 shares

MARKET CAP $1.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	8.4	3.5	3.5
Other	319.8	326.8	277.2
Current Assets	328.2	330.3	280.7
Accts Payable	123.7	93.2	71.8
Debt Due	137.0	267.4	236.4
Other	131.9	107.6	114.7
Current Liab.	392.6	468.2	422.9
Fx. Chg. Cov.	395%	495%	745%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	8.5%	9.5%	6.0%
"Cash Flow"	4.0%	7.0%	4.5%
Earnings	6.0%	9.5%	4.5%
Dividends	2.0%	3.5%	3.5%
Book Value	3.5%	4.0%	6.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	387.7	191.3	109.7	349.2	1037.9
2009	437.4	149.1	116.9	309.3	1012.7
2010	286.5	162.4	95.1	268.1	812.1
2011	323.1	190	130	271.9	915
2012	340	190	160	310	1000

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.62	.08	d.38	1.25	2.57
2009	1.78	.12	d.25	1.18	2.83
2010	1.64	.26	d.28	1.11	2.73
2011	1.53	.03	d.30	1.09	2.35
2012	1.78	.18	d.45	1.29	2.80

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.355	.355	.355	.375	1.44
2008	.375	.375	.375	.395	1.52
2009	.395	.395	.395	.415	1.60
2010	.415	.415	.415	.435	1.68
2011	.435	.435			

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 668,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. BlackRock Inc. owns 7.9% of shares; officers and directors, 1.5% (4/11 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

We have reduced our earnings estimates for Northwest Natural Gas. The one-time charge relating to Oregon's Senate Bill 408 and Senate Bill 967, as well as the upswing in expenses for the Gill Ranch project, has caused us to revise our forecasts down to $2.35 and $2.80 for 2011 and 2012, respectively.

Senate Bill 967 is expected to put considerable stress on earnings for the year. This was introduced on March 29th and was designed to repeal Senate Bill 408. The latter was an unusual state tax, which had distorted utility earnings, increasing them in good years and lowering them in bad ones. Since Northwest benefited from the bill in 2010, it had to take a one-time charge, to reverse the income booked last year. This action will bite into earnings in 2011.

The company has filed a major rate case in Oregon, its first such case since 2003. Management plans for this to be its primary focus this year and into 2012. In a best-case scenario, this whould provide a considerable boost to the bottom line over the 2014-2016 period. Also. . .

There are several major prospects on the horizon. The joint venture with Encana, to develop natural gas reserves in Wyoming, remains on schedule. These reserves are slated to increase Northwest's supply over a 30-year period. Also, the Palomar project is on its way to being resolved. In March, the initial application was withdrawn from the Federal Energy Regulatory Commission, but a new application is slated to be filed in its place in the near future. The changes include eliminating the troublesome western section of the pipeline, as well as rerouting the eastern section for greater efficiency. Northwest has decided to remain on board with the new project, and plans to begin negotiations with potential shippers by the end of this year, or the beginning of 2012. Should this project progress on schedule, and without major hindrances, it would likely provide a considerable boost to the bottom line by mid-decade.

There are better options in the industry. This untimely stock has below average long-term appreciation potential. That said, the dividend yield is slightly above the industry average.

Sahana Zutshi *June 10, 2011*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢. Next earnings report due late July.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	95

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PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 31.47 | P/E RATIO 19.5 (Trailing: 20.3 / Median: 17.0) | RELATIVE P/E RATIO 1.18 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Raised 5/20/11
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 4/29/11
BETA .65 (1.00 = Market)

2014-16 PROJECTIONS

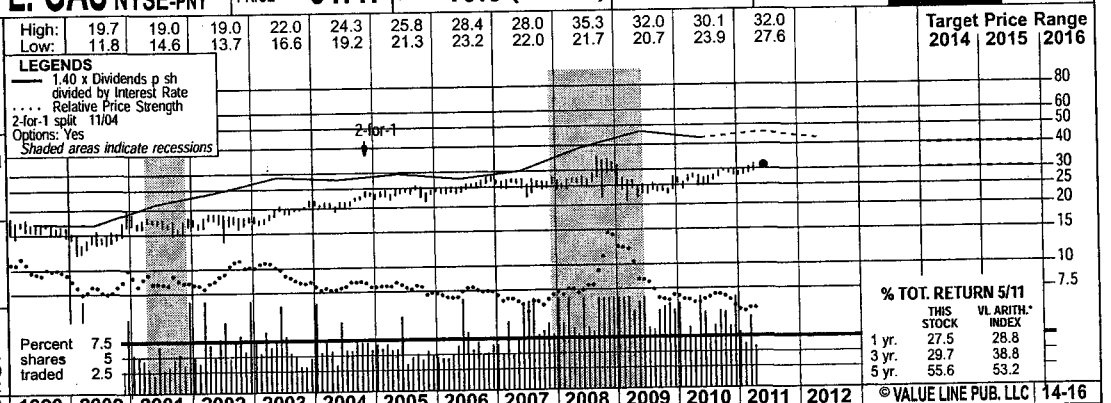
	Price	Gain	Ann'l Total Return
High	40	(+25%)	10%
Low	30	(-5%)	3%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	1	0	1

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	87	99	74
to Sell	81	75	89
Hld's(000)	33260	31677	31082



Target Price Range 2014 | 2015 | 2016

% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.5	28.8
3 yr.	29.7	38.8
5 yr.	55.6	53.2

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	*21.90*	*22.90*	Revenues per sh [A]	*26.10*
1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	*3.00*	*3.15*	"Cash Flow" per sh	*3.45*
.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	*1.60*	*1.70*	Earnings per sh [AB]	*1.90*
.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	*1.15*	*1.19*	Div'ds Decl'd per sh [C■]	*1.31*
1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	1.76	2.75	*4.40*	*2.80*	Cap'l Spending per sh	*2.95*
6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	*13.65*	*14.05*	Book Value per sh [D]	*15.05*
57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.27	72.28	*71.50*	*71.00*	Common Shs Outst'g [E]	*68.00*
13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	15.4	17.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.08	*Value Line*		Relative P/E Ratio	*1.20*
5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
1107.9	832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	*1565*	*1625*	Revenues ($mill) [A]	*1775*
65.5	62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	*115*	*120*	Net Profit ($mill)	*130*
34.6%	33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	*7.3%*	*7.5%*	Net Profit Margin	*7.3%*
47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	*42.0%*	*41.0%*	Long-Term Debt Ratio	*40.5%*
52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	*58.0%*	*59.0%*	Common Equity Ratio	*59.5%*
1069.4	1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	*1675*	*1700*	Total Capital ($mill)	*1720*
1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	*2450*	*2500*	Net Plant ($mill)	*2650*
7.9%	7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	*8.0%*	*8.5%*	Return on Total Cap'l	*8.5%*
11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	*12.0%*	*12.0%*	Return on Shr. Equity	*12.5%*
11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	*12.0%*	*12.0%*	Return on Com Equity	*12.5%*
3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
75%	83%	74%	66%	68%	74%	70%	69%	64%	72%	*72%*	*70%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $1047.4 mill. Due in 5 Yrs $160.0 mill.
LT Debt $671.9 mill. LT Interest $50.2 mill.
(LT interest earned: 4.1x; total interest coverage: 3.5x)

Pension Assets-10/10 $228.3 mill. Oblig. $211.0 mill.

Pfd Stock None

Common Stock 71,783,740 shs.
as of 3/1/11
MARKET CAP: $2.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	7.6	5.6	20.1
Other	505.6	322.2	490.3
Current Assets	513.2	327.8	510.4
Accts Payable	115.4	115.7	179.6
Debt Due	366.0	302.0	375.5
Other	118.8	80.9	98.8
Current Liab.	600.2	498.6	653.9
Fix. Chg. Cov.	316%	323%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	7.0%	3.5%	*1.5%*
"Cash Flow"	5.5%	5.0%	*3.0%*
Earnings	5.0%	5.0%	*3.0%*
Dividends	4.5%	4.5%	*3.5%*
Book Value	5.0%	3.5%	*3.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2008	788.5	634.2	354.7	311.7	2089.1
2009	779.6	455.4	180.3	222.8	1638.1
2010	673.7	472.9	211.6	194.1	1552.3
2011	652.1	*487.9*	*220*	*205*	*1565*
2012	*665*	*505*	*235*	*220*	*1625*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2008	1.12	.66	d.10	d.18	1.49
2009	1.10	.73	d.10	d.06	1.67
2010	1.14	.65	d.13	d.13	1.55
2011	1.16	*.66*	*d.10*	*d.12*	*1.60*
2012	*1.17*	*.69*	*d.06*	*d.10*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID [C■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.24	.25	.25	.25	.99
2008	.25	.26	.26	.26	1.03
2009	.26	.27	.27	.27	1.07
2010	.27	.28	.28	.28	1.11
2011	.28	.29			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 960,801 customers in North Carolina, South Carolina, and Tennessee. 2010 revenue mix: residential (48%), commercial (28%), industrial (7%), other (17%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 64.4% of revenues. '10 deprec. rate: 3.2%. Estimated plant age: 9.3 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,788 employees. Off./dir. own about 1.5% of common stock, State Street; 6.4% (1/11 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas is off to a decent start this year. We look for revenues to advance in the low single-digit range during 2011. This ought to reflect weaker natural gas pricing and customer conservation. However, PNY has been working to offset these trends by gaining new customers. In fact, it grew its core business by about 2,850 additional accounts during the first quarter. Meanwhile, the upside of lower natural gas pricing is a decrease in carrying costs for storage purchases, which has been helping to widen margins. One other drag on profits is the decreased ownership interest in Southstar Energy Holdings. That divestiture took place during the first quarter of 2010, so it wasn't a huge contributing factor. Nonetheless, it did boost the bottom line a bit last year. All told, we think the company will log a decent earnings advance of about 3% this year.

Meantime, the overall financial position is in good shape. Cash reserves advanced more than threefold, to $20 million, during the January period. Meanwhile, the long-term debt load has remained relatively flat. In January, the board completed its buyback agreement that resulted in the repurchase of 800,000 shares of stock. We look for this trend to continue and think further buybacks will bolster share net down the road. What's more, a recent 3.6% increase in the quarterly dividend adds to PNY's appeal.

Capital projects augur well for prospects. Multiple gas-fired power generation sites are being constructed to provide power to Progress Energy and Duke Energy in North Carolina. Those facilities are progressing well and on schedule.

Earnings advances may begin to pick up momentum next year. This ought to stem from customer growth and a pickup in both residential conversions and commercial additions. This may be an early sign of improvements at the residential new construction market, which has performed poorly for some time.

These shares may appeal to income-oriented investors, thanks to an attractive dividend yield. Meantime, conservative accounts can take comfort in the Above-Average Safety rank and top mark for Price Stability.

Bryan J. Fong *June 10, 2011*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '97, (2¢); '10, 41¢. Next earnings report due early Aug. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid mid-January, April, July, October. ■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2010: $14.8 million, 21¢/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

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SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 55.97 | P/E RATIO 18.4 (Trailing: 19.7, Median: 15.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Lowered 10/15/10
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Raised 5/13/11
BETA .65 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+15%)	7%
Low	50	(-10%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	0	0	0	1	0	0	5

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	60	61	58
to Sell	50	72	68
Hld's(000)	18334	17983	17863

	High:	15.1	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8	54.2	58.0
	Low:	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0	37.2	51.9

LEGENDS
1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: Yes
Shaded areas indicate recessions

Target Price Range 2014 | 2015 | 2016

% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.2	28.8
3 yr.	60.8	38.8
5 yr.	143.4	53.2

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	28.37	30.97	*30.95*	*32.80*	Revenues per sh	*39.70*
1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.48	3.72	4.21	*4.50*	*4.85*	"Cash Flow" per sh	*6.05*
.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.38	2.70	*3.05*	*3.35*	Earnings per sh A	*4.10*
.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.22	1.36	*1.48*	*1.60*	Div'ds Decl'd per sh B ■	*2.00*
2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	3.67	5.59	*4.85*	*5.45*	Cap'l Spending per sh	*7.35*
7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	18.24	19.08	*20.95*	*21.90*	Book Value per sh C	*26.45*
21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.61	29.73	29.80	29.87	*31.00*	*32.00*	Common Shs Outst'g D	*34.00*
12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.08			Relative P/E Ratio	*.95*
7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%			Avg Ann'l Div'd Yield	*3.5%*
837.3	505.1	696.8	819.1	921.0	931.4	956.4	962.0	845.4	925.1	*960*	*1050*	Revenues ($mill)	*1350*
26.8	29.4	34.6	43.0	48.6	72.0	61.8	67.7	71.3	81.0	*95.0*	*105*	Net Profit ($mill)	*140*
42.2%	41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	*25.0%*	*30.0%*	Income Tax Rate	*30.0%*
3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	*9.9%*	*10.0%*	Net Profit Margin	*10.4%*
57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	*39.5%*	*39.0%*	Long-Term Debt Ratio	*38.0%*
35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	*60.5%*	*61.0%*	Common Equity Ratio	*62.0%*
516.2	512.5	608.4	675.0	710.3	801.1	839.0	848.0	856.4	910.1	*1075*	*1150*	Total Capital ($mill)	*1450*
607.0	666.6	748.3	799.9	877.3	920.0	948.9	982.6	1073.1	1193.3	*1250*	*1325*	Net Plant ($mill)	*1500*
6.9%	7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	*10.0%*	*10.0%*	Return on Total Cap'l	*10.5%*
12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	*14.5%*	*15.0%*	Return on Shr. Equity	*15.5%*
12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	*14.5%*	*15.0%*	Return on Com Equity	*15.5%*
3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	*7.5%*	*7.5%*	Retained to Com Eq	*8.0%*
76%	62%	57%	52%	50%	37%	48%	49%	51%	50%	*48%*	*49%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $603.9 mill. **Due in 5 Yrs** $420.0 mill.
LT Debt $401.4 mill. **LT Interest** $24.0 mill.
(Total interest coverage: 6.2x)

Pension Assets-12/10 $120.6 mill. **Oblig.** $167.5 mill.

Pfd Stock None

Common Stock 29,953,094 common shs.
as of 5/2/11

MARKET CAP: $1.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	3.8	2.4	3.3
Other	364.6	421.4	345.4
Current Assets	368.4	423.8	348.7
Accts Payable	123.9	165.2	154.4
Debt Due	231.7	362.1	202.5
Other	123.2	113.2	99.9
Current Liab.	478.8	640.5	456.8
Fix. Chg. Cov.	585%	532%	571%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	4.0%	1.0%	*4.5%*
"Cash Flow"	8.0%	9.5%	*8.0%*
Earnings	10.5%	9.5%	*9.0%*
Dividends	5.5%	8.5%	*8.5%*
Book Value	10.5%	8.0%	*6.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	348.1	135.8	210.4	267.7	962.0
2009	362.2	134.5	127.1	221.6	845.4
2010	329.3	151.6	160.7	283.5	925.1
2011	331.9	*165*	*170*	*293.1*	*960*
2012	*380*	*180*	*185*	*305*	*1050*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.32	.26	.04	.67	2.27
2009	1.46	.15	d.06	.83	2.38
2010	1.49	.24	.10	.87	2.70
2011	1.63	*.30*	*.15*	*.97*	*3.05*
2012	*1.70*	*.35*	*.20*	*1.10*	*3.35*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	--	.245	.245	.515	1.01
2008	--	.270	.270	.568	1.11
2009	--	.298	.298	.628	1.22
2010	--	.330	.330	.695	1.36
2011	--	.365			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 347,725 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '10: residential, 44%; commercial, 21%; cogeneration and electric generation, 12%; industrial, 23%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 650 employees. Off./dir. control 1.0% of common shares; Black Rock Inc., 8.3% (4/11 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Telephone: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have been trading in a holding pattern since the beginning of the year, following a healthy advance in 2010. The company has posted solid results in recent periods, though the stock appears to have gotten ahead of itself somewhat.

Prospects look favorable for utility South Jersey Gas. SJG should continue to experience modest customer growth, despite softness in the housing construction market. Natural gas remains the fuel of choice within the utility's service territory. This business should continue to benefit from customer interest in converting from other fuel sources to natural gas. Moreover, rate relief should serve to offset cost pressures for the utility.

The company's retail energy operations should also continue to perform well. Demand for renewable and natural gas-fired energy projects will probably remain strong. For the remainder of the year, the company has projects under construction that will produce an additional 19 megawatts of generation capacity, bringing the total capacity from its projects to roughly 64 megawatts. Energenic, South Jersey's joint-venture energy project business, has agreed to provide the energy at the Revel resort complex in Atlantic City. Energenic's $160 million project will be in place to serve Revel when it opens in mid-2012.

Performance may improve somewhat at the wholesale energy business. This business has suffered from thin industry-wide storage spreads. Some weakness here may well continue, though this line's natural gas marketing activities have been shifted and expanded to take advantage of opportunities in the Marcellus Shale.

We anticipate favorable comparisons in the coming quarters. We expect top-line growth of about 4% for full-year 2011. Profit margins will likely widen, and we look for share-net growth of roughly 13%.

This stock is neutrally ranked for Timeliness. We anticipate steady growth through 2014-2016. Moreover, this issue earns high marks for Price Stability and Earnings Predictability. This appears to be partly reflected in the present quotation, and total return potential is unimpressive for the coming years.

Michael Napoli, CFA *June 10, 2011*

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	85

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $2.10; '08, $2.58; '09, $1.94; '10, $2.22. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31; '09, ($0.44); '10, ($0.47). Excl gain (losses) from discont. ops.: '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Egs. may not sum due to rounding. Next egs. report due in August. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2010: $248.4 mill., $8.32 per shr. (D) In mill., adj. for split.

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WGL HOLDINGS NYSE-WGL

RECENT PRICE 39.25 | P/E RATIO 18.2 (Trailing: 17.9 Median: 15.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 4 Lowered 5/13/11
SAFETY 1 Raised 4/2/93
TECHNICAL 3 Raised 6/10/11
BETA .65 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	35	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	1	0	0	0
Options	3	2	1	1	1	0	0	0	0
to Sell	4	4	1	1	2	0	0	1	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	76	87	83
to Sell	76	75	83
Hld's(000)	32221	31020	31550

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
High:	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	40.0	39.7								Target Price Range 2014 2015 2016
Low:	21.8	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0	35.6								
	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	*54.60*	*56.85*	Revenues per sh [A]	*59.20*
	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	*3.95*	*4.30*	"Cash Flow" per sh	*4.55*
	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	*2.10*	*2.35*	Earnings per sh [B]	*2.65*
	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	*1.55*	*1.59*	Div'ds Decl'd per sh [C] ■	*1.71*
	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	*2.45*	*2.45*	Cap'l Spending per sh	*2.40*
	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.89	22.82	*23.50*	*24.20*	Book Value per sh [D]	*27.15*
	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	*51.00*	*51.00*	Common Shs Outst'g [E]	*52.00*
	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.95			Relative P/E Ratio	*1.00*
	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%			Avg Ann'l Div'd Yield	*4.2%*
	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	*2785*	*2900*	Revenues ($mill) [A]	*3075*
	89.9	55.7	112.3	98.0	104.8	96.0	102.9	122.9	128.7	115.0	*110*	*120*	Net Profit ($mill)	*140*
	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	*3.9%*	*4.1%*	Net Profit Margin	*4.5%*
	41.7%	45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	*34.5%*	*34.0%*	Long-Term Debt Ratio	*32.5%*
	56.3%	52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	*64.0%*	*64.5%*	Common Equity Ratio	*66.0%*
	1400.8	1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1687.7	1774.4	*1875*	*1915*	Total Capital ($mill)	*2150*
	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	*2425*	*2510*	Net Plant ($mill)	*2775*
	7.9%	5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	*7.0%*	*7.5%*	Return on Total Cap'l	*7.5%*
	11.0%	7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	*9.0%*	*9.5%*	Return on Com Equity	*10.0%*
	3.8%	NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	*2.5%*	*3.0%*	Retained to Com Eq	*3.5%*
	67%	112%	56%	65%	62%	69%	66%	57%	57%	67%	*74%*	*67%*	All Div'ds to Net Prof	*64%*

LEGENDS
1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions

% TOT. RETURN 5/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.8	28.8
3 yr.	28.3	38.8
5 yr.	69.3	53.2

CAPITAL STRUCTURE as of 3/31/11
Total Debt $682.7 mill. Due in 5 Yrs $194.2 mill.
LT Debt $614.9 mill. LT Interest $39.4 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x)
Pension Assets-9/10 $1,215.8 mill. Oblig. $678.1 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 51,226,263 shs. as of 4/30/11

MARKET CAP: $2.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	7.9	8.9	190.0
Other	675.6	708.4	730.3
Current Assets	683.5	717.3	920.3
Accts Payable	213.5	225.4	292.7
Debt Due	266.5	130.5	67.8
Other	154.6	188.2	249.8
Current Liab.	634.6	544.1	610.3
Fix. Chg. Cov.	533%	536%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	9.0%	4.0%	*1.5%*
"Cash Flow"	4.0%	1.5%	*1.0%*
Earnings	4.0%	2.5%	*1.5%*
Dividends	2.0%	2.5%	*2.5%*
Book Value	4.0%	5.0%	*3.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	751.6	1020.0	464.7	391.9	2628.2
2009	826.2	1040.9	427.0	412.8	2706.9
2010	727.4	1056.6	459.7	465.2	2708.9
2011	795.9	1017.2	*481.9*	*490*	*2785*
2012	*825*	*1045*	*510*	*520*	*2900*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2008	.96	1.66	.06	d.24	2.44
2009	1.03	1.65	.11	d.25	2.53
2010	1.01	1.64	d.07	d.29	2.27
2011	1.02	1.53	*d.10*	*d.35*	*2.10*
2012	*1.08*	*1.61*	*d.04*	*d.30*	*2.35*

Calendar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.34	.34	.34	.34	1.36
2008	.34	.36	.36	.36	1.42
2009	.36	.37	.37	.37	1.47
2010	.37	.378	.378	.378	1.50
2011	.378	.39			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,073,722 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. Black Rock Inc. owns 9.2% of common stock; Off./dir. less than 1% (1/11 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted lackluster financial results for the March period. Indeed, the top line declined about 3.5% over that time frame, due to weaker contributions from the Regulated Utility segment. This stemmed from unfavorable changes in the consumption patterns of its natural gas customers. However, this was partially offset by greater earnings contributions at the Retail Energy Marketing and Design-Build Energy System divisions. Still, on balance, WGL's second-quarter bottom line declined almost 7%, to $1.53 a share. And we look for an annual earnings decline this year. But financial results ought to begin to rebound in 2012.

Rate cases and capital projects, augur well for prospects. The company recently received approval to raise its rates in Maryland. The proposed increase ought to boost annual revenues by about $30 million from that region, and is slated to go into effect this November. Meanwhile, WGL was also granted a favorable ruling by the Virginia commission to go ahead with a multiyear $115 million accelerated pipeline-replacement program. This should boost the distribution system's reliability and safety.

Investments in green energy projects may also bear fruit down the road. WGL has announced an additional 1.7 megawatts worth of solar projects for this year. When combined with existing ventures, the company has a stake in about 4.5 megawatts of clean renewable energy. These moves should also provide the company with federal energy tax credits.

Meanwhile, the financial position is solid. Cash reserves have skyrocketed to a seasonal high of $190 million. At the same time, the long-term debt load inched higher but at a much slower clip of about 4%, to $615 million. What's more, the board recently approved a 3.2% hike in the quarterly dividend, to $0.39 a share.

These shares may appeal to income-seeking investors, thanks to an above-average dividend yield, Highest Safety rank, and top mark for Price Stability. Meantime, in the event of a market correction, shares of WGL ought to be minimally affected as evidenced by the below-market Beta of .65. But they are ranked to lag the broader markets in the year ahead.

Bryan J. Fong *June 10, 2011*

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	95

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes non-recurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late July. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available. (D) Includes deferred charges and intangibles. '10: $580.4 million, $11.48/sh. (E) In millions, adjusted for stock split.

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ATTACHMENT B

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AGL RESOURCES INC (NYSE)

Scottrade

AGL	41.20	+0.01	(0.02%)	Vol. 220,610	15:08 ET

AGL Resources principal business is the distribution of natural gas to customers in central, northwest, northeast and southeast Georgia and the Chattanooga, Tennessee area through its natural gas distribution subsidiary. AGL's major service area is the ten county metropolitan Atlanta area.

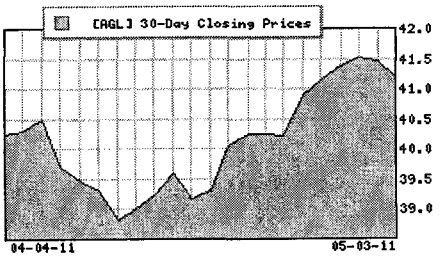
General Information

AGL RESOURCES
TEN PEACHTREE PLACE
ATLANTA, GA 30309
Phone: -
Fax: 404-584-3945
Web: http://www.aglresources.com
Email: scave@aglresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/11
Next EPS Date	07/28/2011

Price and Volume Information

Zacks Rank	2
Yesterday's Close	41.19
52 Week High	41.96
52 Week Low	34.21
Beta	0.45
20 Day Moving Average	338,833.19
Target Price Consensus	42



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.18	4 Week	0.38
12 Week	9.29	12 Week	6.70
YTD	14.90	YTD	6.79

Share Information		Dividend Information	
Shares Outstanding (millions)	77.98	Dividend Yield	4.37%
		Annual Dividend	$1.80
Market Capitalization (millions)	3,212.08	Payout Ratio	0.00
Short Ratio	11.38	Change in Payout Ratio	0.00
Last Split Date	12/04/1995	Last Dividend Payout / Amount	02/16/2011 / $0.45

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.27	Current (1=Strong Buy, 5=Strong Sell)	2.13
Current Year EPS Consensus Estimate	3.15	30 Days Ago	2.13
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.13
Next EPS Report Date	07/28/2011	90 Days Ago	2.13

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.10	vs. Previous Year	-5.78%	vs. Previous Year	-12.46%
Trailing 12 Months:	13.96	vs. Previous Quarter	89.53%	vs. Previous Quarter:	32.03%
PEG Ratio	3.27				

Price Ratios		ROE		ROA	
Price/Book	1.75	03/31/11	-	03/31/11	-
Price/Cash Flow		12/31/10		12/31/10	

	8.08		12.98		3.40
Price / Sales	1.43	09/30/10	13.19	09/30/10	3.50
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/11	-	03/31/11	-	03/31/11	-
12/31/10	0.89	12/31/10	0.63	12/31/10	10.02
09/30/10	0.79	09/30/10	0.47	09/30/10	10.27
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/11	-	03/31/11	-	03/31/11	-
12/31/10	16.43	12/31/10	16.43	12/31/10	23.52
09/30/10	17.35	09/30/10	17.35	09/30/10	23.28
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/11	-	03/31/11	-	03/31/11	-
12/31/10	2.98	12/31/10	0.91	12/31/10	47.68
09/30/10	2.87	09/30/10	0.83	09/30/10	45.49

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ATMOS ENERGY CORP (NYSE)

Scottrade

ATO	34.61	▲0.41	(1.20%)	Vol. 120,903	14:02 ET

Atmos Energy Corporation distributes and sells natural gas to residential, commercial, industrial, agricultural and other customers. Atmos operates through five divisions in cities, towns and communities in service areas located in Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Missouri, South Carolina, Tennessee, Texas and Virginia. The Company has entered into an agreement to sell all of its natural gas utility operations in South Carolina. The Company also transports natural gas for others through its distribution system.

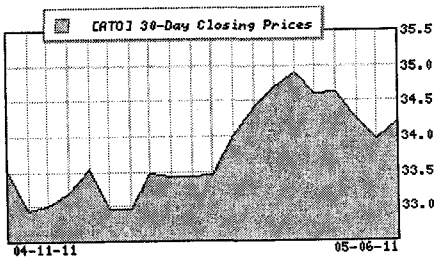
General Information

ATMOS ENERGY CP
-
-, - -
Phone: -
Fax: -
Web: -
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/11
Next EPS Date	08/10/2011

Price and Volume Information

Zacks Rank	2
Yesterday's Close	34.20
52 Week High	35.25
52 Week Low	25.86
Beta	0.52
20 Day Moving Average	224,307.25
Target Price Consensus	33.7



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.18	4 Week	0.28
12 Week	2.09	12 Week	1.25
YTD	9.62	YTD	2.86

Share Information

Shares Outstanding (millions)	90.65
Market Capitalization (millions)	3,100.20
Short Ratio	9.60
Last Split Date	05/17/1994

Dividend Information

Dividend Yield	3.98%
Annual Dividend	$1.36
Payout Ratio	0.61
Change in Payout Ratio	-0.02
Last Dividend Payout / Amount	02/23/2011 / $0.34

EPS Information

Current Quarter EPS Consensus Estimate	0.09
Current Year EPS Consensus Estimate	2.30
Estimated Long-Term EPS Growth Rate	4.50
Next EPS Report Date	08/10/2011

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.89
30 Days Ago	2.89
60 Days Ago	2.89
90 Days Ago	2.89

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.85	vs. Previous Year	-8.28%	vs. Previous Year	-16.65%
Trailing 12 Months:	15.34	vs. Previous Quarter	64.20%	vs. Previous Quarter:	39.78%
PEG Ratio	3.30				

Price Ratios **ROE** **ROA**

Price/Book	1.31	03/31/11	8.87 03/31/11	2.94
Price/Cash Flow	7.25	12/31/10	9.52 12/31/10	3.17
Price / Sales	0.72	09/30/10	9.23 09/30/10	3.11
Current Ratio		**Quick Ratio**	**Operating Margin**	
03/31/11	0.91	03/31/11	0.70 03/31/11	4.68
12/31/10	0.86	12/31/10	0.63 12/31/10	4.66
09/30/10	0.75	09/30/10	0.48 09/30/10	4.38
Net Margin		**Pre-Tax Margin**	**Book Value**	
03/31/11	7.50	03/31/11	7.50 03/31/11	26.19
12/31/10	6.52	12/31/10	6.52 12/31/10	25.16
09/30/10	6.99	09/30/10	6.99 09/30/10	24.16
Inventory Turnover		**Debt-to-Equity**	**Debt to Capital**	
03/31/11	12.01	03/31/11	0.76 03/31/11	43.22
12/31/10	13.40	12/31/10	0.79 12/31/10	44.27
09/30/10	13.07	09/30/10	0.83 09/30/10	45.38

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LACLEDE GROUP INC (NYSE)

Scottrade

LG	38.42	-0.23	(-0.60%)	Vol. 71,445	15:06 ET

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

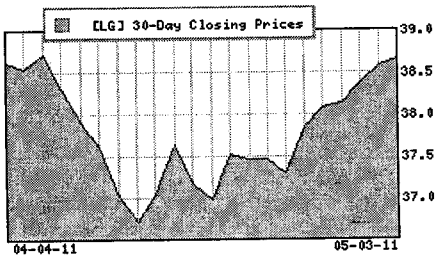
General Information

LACLEDE GRP INC
720 OLIVE ST
ST LOUIS, MO 63101
Phone: -
Fax: 314-421-1979
Web: http://www.thelacledegroup.com
Email: investorservices@lacledegas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/11
Next EPS Date	07/22/2011

Price and Volume Information

Zacks Rank	2
Yesterday's Close	38.65
52 Week High	39.99
52 Week Low	31.65
Beta	0.08
20 Day Moving Average	65,142.10
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	0.29	4 Week	-1.49
12 Week	-0.82	12 Week	-3.16
YTD	5.77	YTD	-3.15

Share Information		Dividend Information	
Shares Outstanding (millions)	22.39	Dividend Yield	4.19%
		Annual Dividend	$1.62
Market Capitalization (millions)	865.18	Payout Ratio	0.67
Short Ratio	10.21	Change in Payout Ratio	0.05
Last Split Date	03/08/1994	Last Dividend Payout / Amount	03/09/2011 / $0.41

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.22	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.45	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	3.00	60 Days Ago	3.00
Next EPS Report Date	07/22/2011	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.80	vs. Previous Year	0.00%	vs. Previous Year	-14.41%
Trailing 12 Months:	15.97	vs. Previous Quarter	17.14%	vs. Previous Quarter:	22.42%
PEG Ratio	5.27				

Price Ratios		ROE		ROA	
Price/Book	1.52	03/31/11	9.92	03/31/11	2.96

Price/Cash Flow	9.17	12/31/10
Price / Sales	0.54	09/30/10
Current Ratio		
03/31/11	-	03/31/11
12/31/10	1.39	12/31/10
09/30/10	1.24	09/30/10
Net Margin		
03/31/11	-	03/31/11
12/31/10	4.83	12/31/10
09/30/10	4.68	09/30/10
Inventory Turnover		
03/31/11	-	03/31/11
12/31/10	13.41	12/31/10
09/30/10	14.62	09/30/10
	9.84	12/31/10
	9.83	09/30/10
Quick Ratio		
03/31/11	-	03/31/11
12/31/10	0.97	12/31/10
09/30/10	0.84	09/30/10
Pre-Tax Margin		
03/31/11	-	03/31/11
12/31/10	4.83	12/31/10
09/30/10	4.68	09/30/10
Debt-to-Equity		
03/31/11	-	03/31/11
12/31/10	0.66	12/31/10
09/30/10	0.68	09/30/10
		2.95
		2.91
Operating Margin		
		03/31/11
		12/31/10
		09/30/10
Book Value		
		03/31/11
		12/31/10
		09/30/10
Debt to Capital		
		03/31/11
		12/31/10
		09/30/10

	3.38
	3.18
	3.07
	-
	24.51
	24.02
	-
	39.91
	40.48

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NEW JERSEY RES (NYSE)

Scottrade

NJR	44.50	▲0.66	(1.51%)	Vol. 106,324	14:03 ET

NJ RESOURCES is an exempt energy svcs holding company providing retail & wholesale natural gas & related energy services to customers from the Gulf Coast to New England. Subsidiaries include: (1) N J Natural Gas Co, a natural gas distribution company that provides regulated energy & appliance services to residential, commercial & industrial customers in central & northern N J. (2) NJR Energy Holdings Corp formerly NJR Energy Svcs Corp & (3) NJR Development Corp, a sub-holding company of NJR, which includes the Company's remaining unregulated operating subsidiaries.

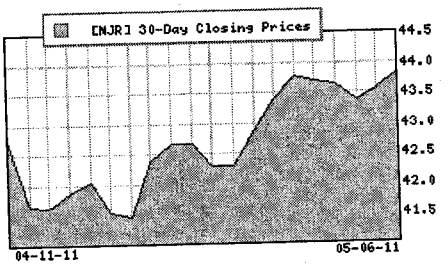
General Information

NJ RESOURCES
-
-, - -
Phone: -
Fax: -
Web: -
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/11
Next EPS Date	08/10/2011

Price and Volume Information

Zacks Rank	
Yesterday's Close	43.84
52 Week High	45.59
52 Week Low	34.07
Beta	0.20
20 Day Moving Average	151,621.20
Target Price Consensus	46



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.45	4 Week	1.53
12 Week	7.14	12 Week	6.25
YTD	1.69	YTD	-4.57

Share Information		Dividend Information	
Shares Outstanding (millions)	41.42	Dividend Yield	3.28%
Market Capitalization (millions)	1,815.72	Annual Dividend	$1.44
Short Ratio	14.01	Payout Ratio	0.56
Last Split Date	03/04/2008	Change in Payout Ratio	0.02
		Last Dividend Payout / Amount	03/11/2011 / $0.36

EPS Information

Current Quarter EPS Consensus Estimate	0.21
Current Year EPS Consensus Estimate	2.58
Estimated Long-Term EPS Growth Rate	4.00
Next EPS Report Date	08/10/2011

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.50
30 Days Ago	2.50
60 Days Ago	2.50
90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.97	vs. Previous Year	4.55%	vs. Previous Year	6.39%
Trailing 12 Months:	17.13	vs. Previous Quarter	130.00%	vs. Previous Quarter:	37.00%
PEG Ratio	4.24				

Price Ratios	
Price/Book	2.45
Price/Cash Flow	13.39
Price / Sales	0.65

Current Ratio	
03/31/11	-
12/31/10	1.09
09/30/10	1.11

Net Margin	
03/31/11	3.49
12/31/10	4.61
09/30/10	6.52

Inventory Turnover	
03/31/11	7.51
12/31/10	8.34
09/30/10	8.34

ROE	
03/31/11	14.49
12/31/10	13.92
09/30/10	13.91

Quick Ratio	
03/31/11	-
12/31/10	0.65
09/30/10	0.63

Pre-Tax Margin	
03/31/11	3.49
12/31/10	4.61
09/30/10	6.52

Debt-to-Equity	
03/31/11	-
12/31/10	0.59
09/30/10	0.59

ROA	
03/31/11	4.14
12/31/10	4.05
09/30/10	4.14

Operating Margin	
03/31/11	3.80
12/31/10	3.77
09/30/10	3.86

Book Value	
03/31/11	-
12/31/10	17.86
09/30/10	17.61

Debt to Capital	
03/31/11	-
12/31/10	36.96
09/30/10	37.15

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NORTHWEST NAT GAS CO (NYSE)

Scottrade

NWN	45.09	▲ 0.48	(1.08%)	Vol. 49,580	14:02 ET

NW Natural is principally engaged in the distribution of natural gas.The Oregon Public Utility Commission (OPUC) has allocated to NW Natural as its exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the fertile Willamette Valley and the coastal area from Astoria to Coos Bay. NW Natural also holds certificates from the Washington Utilities and Transportation Commission (WUTC) granting it exclusive rights to serve portions of three Washington counties bordering the Columbia River.

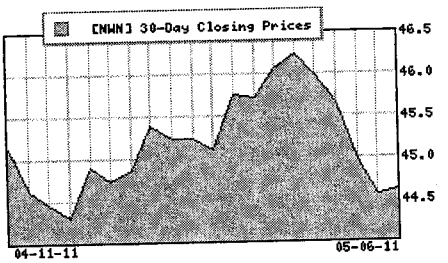
General Information

NORTHWEST NAT G
-
-, - -
Phone: -
Fax: -
Web: -
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/11
Next EPS Date	08/10/2011

Price and Volume Information

Zacks Rank	
Yesterday's Close	44.61
52 Week High	50.86
52 Week Low	41.90
Beta	0.31
20 Day Moving Average	114,048.75
Target Price Consensus	47.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.83	4 Week	-2.71
12 Week	-1.65	12 Week	-2.46
YTD	-4.00	YTD	-9.92

Share Information		Dividend Information	
Shares Outstanding (millions)	26.67	Dividend Yield	3.90%
Market Capitalization (millions)	1,189.70	Annual Dividend	$1.74
Short Ratio	12.96	Payout Ratio	0.66
Last Split Date	09/09/1996	Change in Payout Ratio	0.08
		Last Dividend Payout / Amount	04/27/2011 / $0.44

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.18	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	2.59	30 Days Ago	2.25
Estimated Long-Term EPS Growth Rate	4.60	60 Days Ago	2.25
Next EPS Report Date	08/10/2011	90 Days Ago	2.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.21	vs. Previous Year	-6.71%	vs. Previous Year	12.76%
Trailing 12 Months:	17.03	vs. Previous Quarter	37.84%	vs. Previous Quarter:	20.49%
PEG Ratio	3.72				

Price Ratios | **ROE** | **ROA**

Price/Book	1.64	03/31/11	10.04	03/31/11	2.78
Price/Cash Flow	8.63	12/31/10	10.56	12/31/10	2.93
Price / Sales	1.40	09/30/10	10.95	09/30/10	3.07
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/11	0.66	03/31/11	0.54	03/31/11	8.23
12/31/10	0.71	12/31/10	0.53	12/31/10	8.95
09/30/10	0.56	09/30/10	0.35	09/30/10	8.73
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/11	13.80	03/31/11	13.80	03/31/11	27.12
12/31/10	15.04	12/31/10	15.04	12/31/10	26.02
09/30/10	14.46	09/30/10	14.46	09/30/10	25.41
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/11	7.69	03/31/11	0.76	03/31/11	43.27
12/31/10	6.85	12/31/10	0.85	12/31/10	46.05
09/30/10	7.34	09/30/10	0.88	09/30/10	46.70

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PIEDMONT NAT GAS INC (NYSE)

Scottrade

PNY	31.12	▼-0.34	(-1.08%)	Vol. 133,337	15:11 ET

Piedmont Natural Gas Co, Inc., is an energy and services company engaged in the transportation and sale of natural gas and the sale of propane to residential, commercial and industrial customers in North Carolina, South Carolina and Tennessee. The Company is the second-largest natural gas utility in the southeast. The Company and its non-utility subsidiaries and divisions are also engaged in acquiring, marketing and arranging for the transportation and storage of natural gas for large-volume purchasers, and in the sale of propane to customers in the Company's three-state service area.

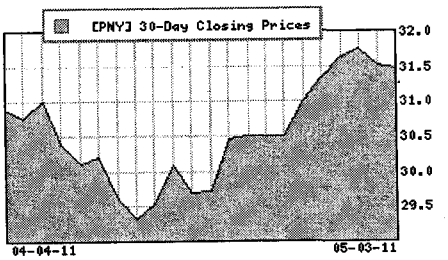
General Information

PIEDMONT NAT GA
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28233
Phone: -
Fax: 704-365-3849
Web: http://www.piedmontng.com
Email: investorrelations@piedmontng.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	October
Last Reported Quarter	04/30/11
Next EPS Date	06/07/2011

Price and Volume Information

Zacks Rank	2
Yesterday's Close	31.46
52 Week High	32.00
52 Week Low	24.50
Beta	0.26
20 Day Moving Average	207,969.34
Target Price Consensus	28.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.28	4 Week	0.47
12 Week	10.93	12 Week	8.31
YTD	12.52	YTD	4.73

Share Information		Dividend Information	
Shares Outstanding (millions)	71.78	Dividend Yield	3.69%
		Annual Dividend	$1.16
Market Capitalization (millions)	2,258.32	Payout Ratio	0.00
Short Ratio	14.55	Change in Payout Ratio	0.00
Last Split Date	11/01/2004	Last Dividend Payout / Amount	03/23/2011 / $0.29

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.67	Current (1=Strong Buy, 5=Strong Sell)	3.38
Current Year EPS Consensus Estimate	1.58	30 Days Ago	3.38
Estimated Long-Term EPS Growth Rate	4.80	60 Days Ago	3.43
Next EPS Report Date	06/07/2011	90 Days Ago	3.43

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.97	vs. Previous Year	1.75%	vs. Previous Year	-3.22%
Trailing 12 Months:	20.17	vs. Previous Quarter	1,066.67%	vs. Previous Quarter:	235.92%
PEG Ratio	4.19				

Price Ratios		ROE		ROA	
Price/Book	2.24	04/30/11	-	04/30/11	-
Price/Cash Flow	10.59	01/31/11	11.31	01/31/11	3.67
Price / Sales	1.48	10/31/10	11.31	10/31/10	3.65
Current Ratio		**Quick Ratio**		**Operating Margin**	
04/30/11	-	04/30/11	-	04/30/11	-
01/31/11	0.78	01/31/11	0.62	01/31/11	7.36
10/31/10	0.66	10/31/10	0.44	10/31/10	7.21
Net Margin		**Pre-Tax Margin**		**Book Value**	
04/30/11	-	04/30/11	-	04/30/11	-
01/31/11	11.99	01/31/11	11.99	01/31/11	14.02
10/31/10	15.06	10/31/10	15.06	10/31/10	13.38
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
04/30/11	-	04/30/11	-	04/30/11	-
01/31/11	11.84	01/31/11	0.66	01/31/11	39.82
10/31/10	11.93	10/31/10	0.70	10/31/10	41.05

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SOUTH JERSEY INDS INC (NYSE)

Scottrade

SJI	53.00	▲0.23	(0.44%)	Vol. 48,702	13:07 ET

South Jersey Inds Inc. is engaged in the business of operating, through subsidiaries, various business enterprises. The company's most significant subsidiary is South Jersey Gas Company (SJG). SJG is a public utility company engaged in the purchase, transmission and sale of natural gas for residential, commercial and industrial use. SJG also makes off-system sales of natural gas on a wholesale basis to various customers on the interstate pipeline system and transports natural gas.

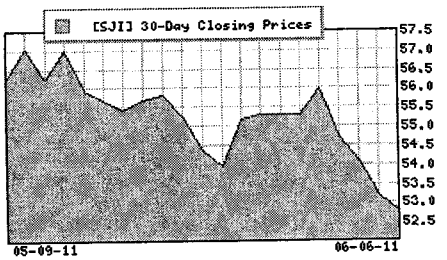
General Information

SOUTH JERSEY IN
1 SOUTH JERSEY PLAZA ROUTE 54
FOLSOM, NJ 08037
Phone: 609-561-9000
Fax: 609-561-8225
Web: http://www.sjindustries.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/11
Next EPS Date	08/04/2011

Price and Volume Information

Zacks Rank	2
Yesterday's Close	52.77
52 Week High	58.03
52 Week Low	41.96
Beta	0.30
20 Day Moving Average	113,944.45
Target Price Consensus	59.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.14	4 Week	-1.75
12 Week	-2.84	12 Week	-2.06
YTD	-0.09	YTD	-2.57

Share Information		Dividend Information	
Shares Outstanding (millions)	29.95	Dividend Yield	2.77%
		Annual Dividend	$1.46
Market Capitalization (millions)	1,580.62	Payout Ratio	0.51
Short Ratio	21.14	Change in Payout Ratio	-0.01
Last Split Date	07/01/2005	Last Dividend Payout / Amount	03/08/2011 / $0.37

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.29	Current (1=Strong Buy, 5=Strong Sell)	1.50
Current Year EPS Consensus Estimate	3.00	30 Days Ago	1.80
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	1.67
Next EPS Report Date	08/04/2011	90 Days Ago	1.57

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.57	vs. Previous Year	9.40%	vs. Previous Year	0.80%
Trailing 12 Months:	18.58	vs. Previous Quarter	87.36%	vs. Previous Quarter:	17.09%
PEG Ratio	-				

Price Ratios	ROE	ROA

Price/Book	2.58	03/31/11	14.89	03/31/11	4.34
Price/Cash Flow	12.54	12/31/10	14.42	12/31/10	4.22
Price / Sales	1.70	09/30/10	14.34	09/30/10	4.32
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/11	0.76	03/31/11	0.70	03/31/11	9.19
12/31/10	0.66	12/31/10	0.55	12/31/10	8.75
09/30/10	0.58	09/30/10	0.41	09/30/10	9.22
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/11	12.73	03/31/11	12.73	03/31/11	20.42
12/31/10	10.72	12/31/10	10.72	12/31/10	19.08
09/30/10	11.28	09/30/10	11.28	09/30/10	18.62
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/11	10.02	03/31/11	0.66	03/31/11	39.68
12/31/10	9.14	12/31/10	0.60	12/31/10	37.36
09/30/10	7.65	09/30/10	0.51	09/30/10	33.88

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WGL HLDGS INC (NYSE)

Scottrade

WGL	38.85	▲0.66	(1.73%)	Vol. 130,026	14:03 ET

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

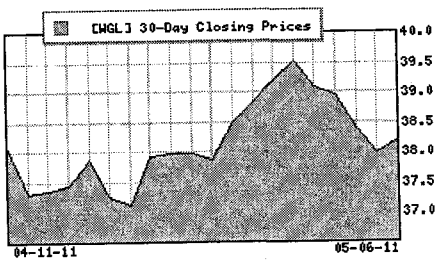
General Information

WGL HLDGS INC
-
-, - -
Phone: -
Fax: -
Web: -
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/11
Next EPS Date	08/10/2011

Price and Volume Information

Zacks Rank	2
Yesterday's Close	38.19
52 Week High	N/A
52 Week Low	32.75
Beta	0.26
20 Day Moving Average	151,953.20
Target Price Consensus	39



% Price Change		% Price Change Relative to S&P 500	
4 Week	-0.75	4 Week	-1.64
12 Week	1.41	12 Week	0.57
YTD	6.77	YTD	0.19

Share Information		Dividend Information	
Shares Outstanding (millions)	51.11	Dividend Yield	4.06%
		Annual Dividend	$1.55
Market Capitalization (millions)	1,952.01	Payout Ratio	0.69
Short Ratio	18.69	Change in Payout Ratio	0.06
Last Split Date	05/02/1995	Last Dividend Payout / Amount	04/06/2011 / $0.39

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	-0.09	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	2.05	30 Days Ago	2.25
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.25
Next EPS Report Date	08/10/2011	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.59	vs. Previous Year	-6.71%	vs. Previous Year	-3.73%
Trailing 12 Months:	17.44	vs. Previous Quarter	50.00%	vs. Previous Quarter:	27.81%
PEG Ratio	3.54				

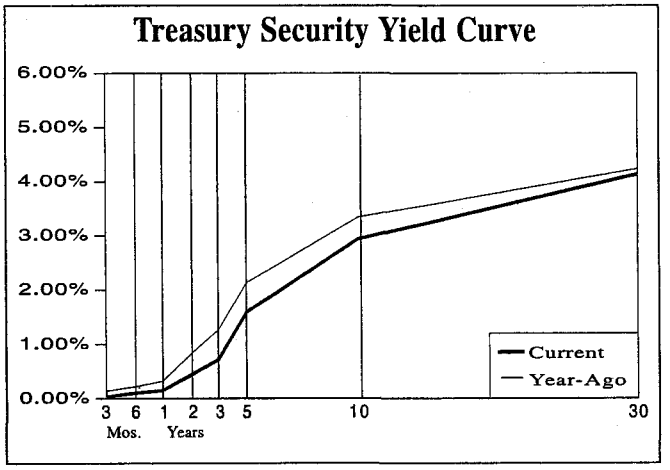
Price Ratios **ROE** **ROA**

Price/Book	1.54	03/31/11	9.35	03/31/11	3.01
Price/Cash Flow	9.10	12/31/10	9.82	12/31/10	3.17
Price / Sales	0.71	09/30/10	9.86	09/30/10	3.22
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/11	1.51	03/31/11	1.37	03/31/11	4.11
12/31/10	1.30	12/31/10	1.00	12/31/10	4.19
09/30/10	1.32	09/30/10	0.83	09/30/10	4.25
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/11	7.91	03/31/11	7.91	03/31/11	24.73
12/31/10	7.74	12/31/10	7.74	12/31/10	23.53
09/30/10	6.82	09/30/10	6.82	09/30/10	22.68
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/11	11.28	03/31/11	0.49	03/31/11	32.24
12/31/10	11.69	12/31/10	0.53	12/31/10	34.15
09/30/10	11.71	09/30/10	0.51	09/30/10	33.41

ATTACHMENT C

Selected Yields

	Recent (6/01/11)	3 Months Ago (3/2/11)	Year Ago (6/02/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.18	0.24	0.38
3-month LIBOR	0.25	0.31	0.54
Bank CDs			
6-month	0.27	0.21	0.42
1-year	0.45	0.29	0.70
5-year	1.70	1.76	2.08
U.S. Treasury Securities			
3-month	0.04	0.12	0.14
6-month	0.10	0.15	0.22
1-year	0.15	0.23	0.32
5-year	1.59	2.17	2.13
10-year	2.94	3.47	3.34
10-year (inflation-protected)	0.68	0.90	1.31
30-year	4.14	4.56	4.24
30-year Zero	4.51	4.91	4.46



	Recent (6/01/11)	3 Months Ago (3/2/11)	Year Ago (6/02/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.89	2.75	1.73
FHLMC 5.5% (Gold)	2.44	3.33	1.26
FNMA 5.5%	2.40	3.24	1.21
FNMA ARM	2.51	2.63	2.97
Corporate Bonds			
Financial (10-year) A	4.29	4.75	4.89
Industrial (25/30-year) A	5.14	5.56	5.42
Utility (25/30-year) A	5.14	5.69	5.56
Utility (25/30-year) Baa/BBB	5.69	6.08	6.03
Foreign Bonds (10-Year)			
Canada	2.99	3.34	3.38
Germany	2.99	3.20	2.66
Japan	1.16	1.28	1.28
United Kingdom	3.25	3.64	3.55
Preferred Stocks			
Utility A	5.58	5.77	6.00
Financial A	6.20	6.54	6.63
Financial Adjustable A	5.53	5.53	5.53
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.52	4.95	4.28
25-Bond Index (Revs)	5.38	5.57	4.84
General Obligation Bonds (GOs)			
1-year Aaa	0.26	0.40	0.32
1-year A	1.09	1.22	1.19
5-year Aaa	1.33	1.82	1.67
5-year A	2.53	2.76	2.54
10-year Aaa	2.73	3.20	3.02
10-year A	4.22	4.37	4.06
25/30-year Aaa	4.41	4.72	4.41
25/30-year A	5.91	6.25	5.51
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.87	5.18	4.75
Electric AA	5.19	5.30	4.77
Housing AA	5.83	6.28	5.62
Hospital AA	5.31	5.59	5.13
Toll Road Aaa	5.07	5.34	4.75

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/18/11	5/4/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1502022	1433322	68700	1388703	1201785	1110422
Borrowed Reserves	15373	16908	-1535	18822	29166	44696
Net Free/Borrowed Reserves	1486649	1416414	70235	1369881	1172619	1065726

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/16/11	5/9/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1922.1	1914.7	7.4	15.7%	14.1%	12.9%
M2 (M1+savings+small time deposits)	8994.5	8984.1	10.4	5.1%	5.0%	4.9%

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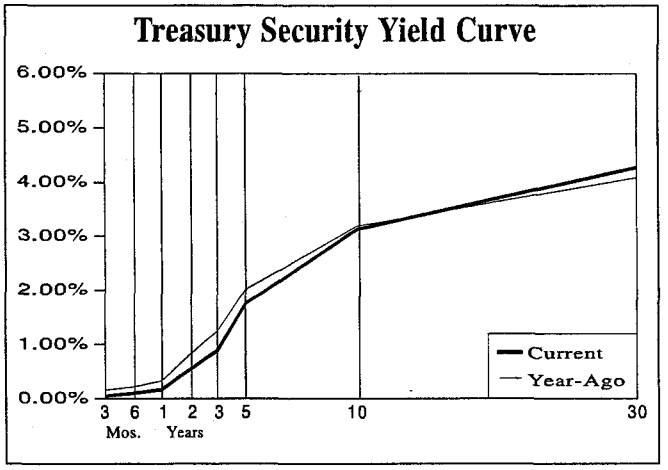
Selected Yields

	Recent (5/25/11)	3 Months Ago (2/23/11)	Year Ago (5/26/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.17	0.23	0.36
3-month LIBOR	0.25	0.31	0.54
Bank CDs			
6-month	0.27	0.21	0.42
1-year	0.45	0.29	0.70
5-year	1.70	1.65	2.12
U.S. Treasury Securities			
3-month	0.05	0.12	0.16
6-month	0.10	0.15	0.22
1-year	0.17	0.24	0.33
5-year	1.76	2.17	2.02
10-year	3.13	3.49	3.19
10-year (inflation-protected)	0.77	0.97	1.25
30-year	4.28	4.58	4.09
30-year Zero	4.63	4.94	4.30



	Recent (5/25/11)	3 Months Ago (2/23/11)	Year Ago (5/26/10)
Mortgage-Backed Securities			
GNMA 5.5%	2.05	2.78	1.51
FHLMC 5.5% (Gold)	2.58	3.36	1.05
FNMA 5.5%	2.53	3.27	1.07
FNMA ARM	2.60	2.66	3.01
Corporate Bonds			
Financial (10-year) A	4.45	4.73	4.67
Industrial (25/30-year) A	5.26	5.57	5.23
Utility (25/30-year) A	5.30	5.66	5.40
Utility (25/30-year) Baa/BBB	5.81	6.07	5.82
Foreign Bonds (10-Year)			
Canada	3.08	3.33	3.26
Germany	3.05	3.14	2.65
Japan	1.13	1.26	1.22
United Kingdom	3.33	3.67	3.56
Preferred Stocks			
Utility A	5.34	5.79	5.96
Financial A	6.49	6.07	6.84
Financial Adjustable A	5.52	5.52	5.52
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.55	5.10	4.27
25-Bond Index (Revs)	5.40	5.60	4.86
General Obligation Bonds (GOs)			
1-year Aaa	0.25	0.37	0.32
1-year A	1.07	1.21	1.16
5-year Aaa	1.33	1.85	1.66
5-year A	2.53	2.80	2.54
10-year Aaa	2.84	3.36	3.00
10-year A	4.21	4.43	3.99
25/30-year Aaa	4.40	4.80	4.36
25/30-year A	5.91	6.25	5.46
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.87	5.23	4.74
Electric AA	5.19	5.37	4.72
Housing AA	5.82	6.36	5.62
Hospital AA	5.31	5.60	5.08
Toll Road Aaa	5.07	5.38	4.72

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/18/11	5/4/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1502023	1433323	68700	1388703	1201785	1110422
Borrowed Reserves	15371	16908	-1537	18822	29166	44696
Net Free/Borrowed Reserves	1486652	1416415	70237	1369881	1172619	1065726

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/9/11	5/2/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1914.7	1937.1	-22.4	12.0%	7.2%	12.2%
M2 (M1+savings+small time deposits)	8984.2	8992.8	-8.6	5.0%	5.0%	5.0%

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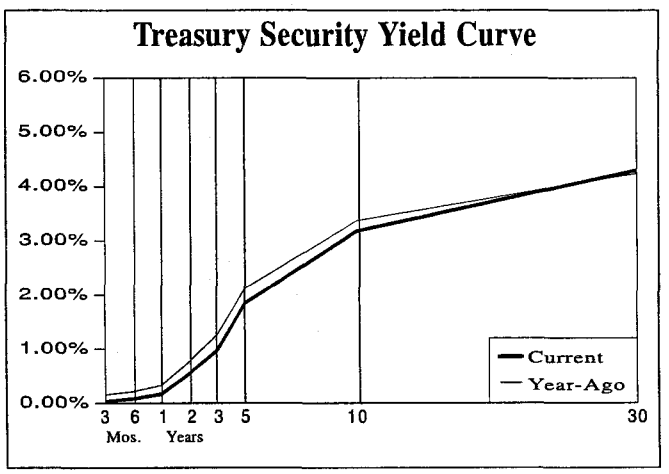
Selected Yields

	Recent (5/18/11)	3 Months Ago (2/16/11)	Year Ago (5/19/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.16	0.31	0.33
3-month LIBOR	0.27	0.31	0.48
Bank CDs			
6-month	0.27	0.21	0.25
1-year	0.45	0.29	0.43
5-year	1.71	1.65	1.99
U.S. Treasury Securities			
3-month	0.04	0.11	0.16
6-month	0.08	0.15	0.22
1-year	0.17	0.27	0.33
5-year	1.85	2.35	2.12
10-year	3.18	3.62	3.37
10-year (inflation-protected)	0.78	1.25	1.29
30-year	4.30	4.68	4.24
30-year Zero	4.63	5.01	4.46
Mortgage-Backed Securities			
GNMA 6.5%	2.05	2.96	1.70
FHLMC 6.5% (Gold)	2.60	3.51	1.14
FNMA 6.5%	2.53	3.45	1.19
FNMA ARM	2.60	2.66	3.01
Corporate Bonds			
Financial (10-year) A	4.52	4.85	4.74
Industrial (25/30-year) A	5.25	5.65	5.37
Utility (25/30-year) A	5.30	5.77	5.53
Utility (25/30-year) Baa/BBB	5.79	6.15	5.93
Foreign Bonds (10-Year)			
Canada	3.23	3.50	3.40
Germany	3.12	3.24	2.77
Japan	1.16	1.36	1.30
United Kingdom	3.39	3.81	3.66
Preferred Stocks			
Utility A	5.71	5.79	6.01
Financial A	6.48	6.07	6.56
Financial Adjustable A	5.52	5.52	5.52



	Recent (5/18/11)	3 Months Ago (2/16/11)	Year Ago (5/19/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.61	5.29	4.32
25-Bond Index (Revs)	5.41	5.67	4.90
General Obligation Bonds (GOs)			
1-year Aaa	0.25	0.38	0.37
1-year A	1.10	1.16	1.20
5-year Aaa	1.34	1.95	1.76
5-year A	2.53	2.87	2.70
10-year Aaa	2.84	3.52	3.12
10-year A	4.21	4.52	4.09
25/30-year Aaa	4.43	4.94	4.39
25/30-year A	5.95	6.25	5.46
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.91	5.33	4.74
Electric AA	5.19	5.48	4.74
Housing AA	5.86	6.42	5.64
Hospital AA	5.35	5.71	5.08
Toll Road Aaa	5.07	5.46	4.72

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/4/11	4/20/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1433322	1474432	-41110	1330196	1163742	1092180
Borrowed Reserves	16908	17930	-1022	19864	31461	47019
Net Free/Borrowed Reserves	1416414	1456502	-40088	1310332	1132281	1045161

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/2/11	4/25/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1937.1	1916.9	20.2	8.9%	19.9%	12.3%
M2 (M1+savings+small time deposits)	8992.6	8964.5	28.1	5.7%	4.9%	5.1%

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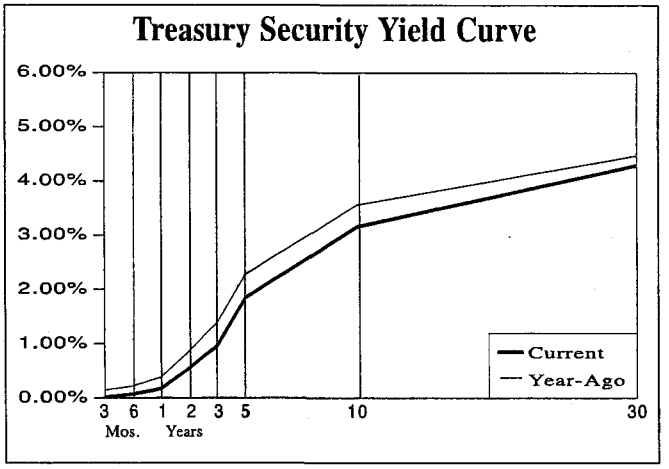
Selected Yields

	Recent (5/11/11)	3 Months Ago (2/09/11)	Year Ago (5/12/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.15	0.31	0.32
3-month LIBOR	0.26	0.31	0.43
Bank CDs			
6-month	0.28	0.21	0.25
1-year	0.46	0.29	0.43
5-year	1.71	1.65	1.99
U.S. Treasury Securities			
3-month	0.02	0.13	0.15
6-month	0.07	0.16	0.22
1-year	0.17	0.29	0.38
5-year	1.85	2.33	2.28
10-year	3.16	3.65	3.57
10-year (inflation-protected)	0.64	1.20	1.25
30-year	4.30	4.71	4.48
30-year Zero	4.66	5.02	4.75
Mortgage-Backed Securities			
GNMA 5.5%	2.25	3.17	2.04
FHLMC 5.5% (Gold)	2.70	3.78	1.73
FNMA 5.5%	2.60	3.68	2.28
FNMA ARM	2.60	2.66	3.01
Corporate Bonds			
Financial (10-year) A	4.51	4.94	4.87
Industrial (25/30-year) A	5.26	5.67	5.55
Utility (25/30-year) A	5.33	5.82	5.72
Utility (25/30-year) Baa/BBB	5.78	6.22	6.10
Foreign Bonds (10-Year)			
Canada	3.22	3.45	3.60
Germany	3.13	3.31	2.94
Japan	1.13	1.34	1.31
United Kingdom	3.44	3.87	3.85
Preferred Stocks			
Utility A	6.18	5.80	6.02
Financial A	6.47	6.06	6.74
Financial Adjustable A	5.51	5.51	5.51



	Recent (5/11/11)	3 Months Ago (2/09/11)	Year Ago (5/12/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.69	5.25	4.29
25-Bond Index (Revs)	5.45	5.63	4.89
General Obligation Bonds (GOs)			
1-year Aaa	0.28	0.39	0.39
1-year A	1.15	1.16	1.19
5-year Aaa	1.48	1.96	1.82
5-year A	2.59	2.87	2.73
10-year Aaa	2.96	3.57	3.16
10-year A	4.24	4.54	4.13
25/30-year Aaa	4.48	4.97	4.40
25/30-year A	6.01	6.26	5.47
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.98	5.35	4.75
Electric AA	5.24	5.48	4.75
Housing AA	5.91	6.44	5.65
Hospital AA	5.45	5.71	5.09
Toll Road Aaa	5.17	5.48	4.73

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/4/11	4/20/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1433323	1474433	-41110	1330196	1163742	1092180
Borrowed Reserves	16908	17930	-1022	19864	31461	47019
Net Free/Borrowed Reserves	1416415	1456503	-40088	1310332	1132281	1045161

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/25/11	4/18/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1917.0	1888.7	28.3	12.7%	14.5%	13.0%
M2 (M1+savings+small time deposits)	8964.7	8940.7	24.0	6.3%	4.7%	4.9%

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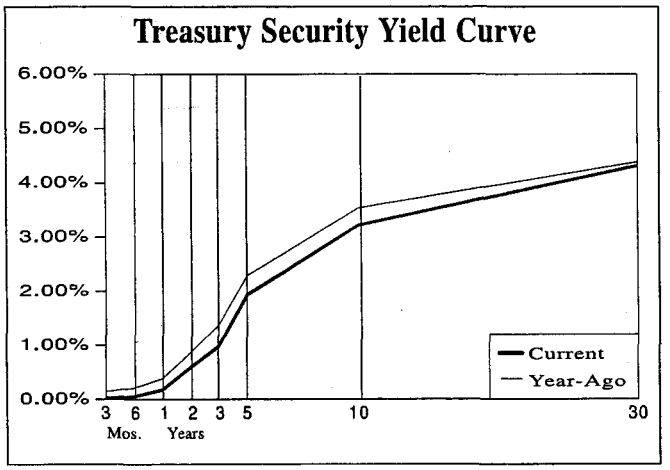
Selected Yields

	Recent (5/04/11)	3 Months Ago (2/02/11)	Year Ago (5/05/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.22	0.25	0.25
3-month LIBOR	0.27	0.31	0.36
Bank CDs			
6-month	0.28	0.30	0.25
1-year	0.46	0.48	0.43
5-year	1.71	1.59	1.99
U.S. Treasury Securities			
3-month	0.02	0.15	0.15
6-month	0.06	0.17	0.21
1-year	0.18	0.26	0.38
5-year	1.94	2.09	2.29
10-year	3.22	3.48	3.54
10-year (inflation-protected)	0.66	1.02	1.27
30-year	4.32	4.62	4.39
30-year Zero	4.66	4.96	4.62



	Recent (5/04/11)	3 Months Ago (2/02/11)	Year Ago (5/05/10)
Mortgage-Backed Securities			
GNMA 5.5%	2.56	3.06	2.45
FHLMC 5.5% (Gold)	2.90	3.45	1.96
FNMA 5.5%	2.81	3.27	2.50
FNMA ARM	2.53	2.66	3.01
Corporate Bonds			
Financial (10-year) A	4.48	4.86	4.80
Industrial (25/30-year) A	5.26	5.63	5.42
Utility (25/30-year) A	5.39	5.78	5.59
Utility (25/30-year) Baa/BBB	5.84	6.18	6.03
Foreign Bonds (10-Year)			
Canada	3.12	3.38	3.54
Germany	3.30	3.26	2.86
Japan	1.21	1.23	1.29
United Kingdom	3.80	3.76	3.82
Preferred Stocks			
Utility A	6.06	5.79	5.59
Financial A	6.47	6.05	6.68
Financial Adjustable A	5.51	5.50	5.51
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.86	5.25	4.37
25-Bond Index (Revs)	5.51	5.61	4.91
General Obligation Bonds (GOs)			
1-year Aaa	0.31	0.39	0.38
1-year A	1.17	1.17	1.19
5-year Aaa	1.57	1.90	1.80
5-year A	2.67	2.82	2.73
10-year Aaa	3.10	3.51	3.16
10-year A	4.35	4.50	4.12
25/30-year Aaa	4.58	4.92	4.42
25/30-year A	6.04	6.24	5.51
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.07	5.33	4.74
Electric AA	5.26	5.48	4.77
Housing AA	5.95	6.41	5.65
Hospital AA	5.55	5.69	5.13
Toll Road Aaa	5.24	5.46	4.73

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/20/11	4/6/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1474433	1431443	42990	1274154	1131440	1078169
Borrowed Reserves	17930	19196	-1266	21035	33743	49335
Net Free/Borrowed Reserves	1456503	1412247	44256	1253120	1097698	1028833

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/18/11	4/11/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1888.6	1883.8	4.8	8.2%	12.3%	10.9%
M2 (M1+savings+small time deposits)	8940.6	8928.2	12.4	3.6%	4.5%	5.1%

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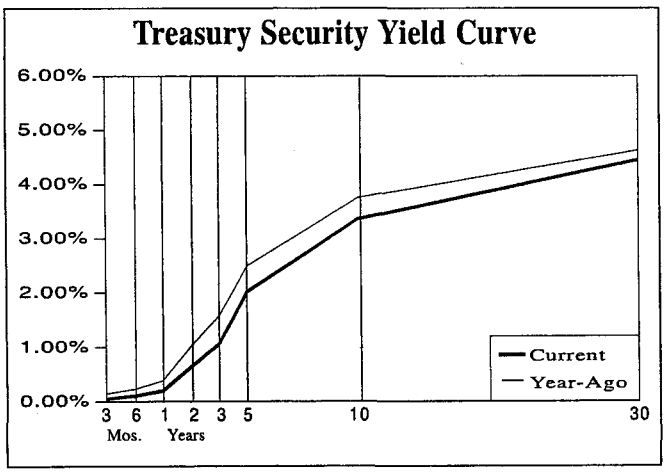
Selected Yields

	Recent (4/27/11)	3 Months Ago (1/26/11)	Year Ago (4/28/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.24	0.27	0.22
3-month LIBOR	0.27	0.30	0.34
Bank CDs			
6-month	0.28	0.31	0.25
1-year	0.46	0.49	0.43
5-year	1.71	1.65	1.99
U.S. Treasury Securities			
3-month	0.05	0.15	0.15
6-month	0.11	0.17	0.23
1-year	0.20	0.26	0.38
5-year	2.02	1.99	2.50
10-year	3.36	3.42	3.76
10-year (inflation-protected)	0.77	1.03	1.37
30-year	4.45	4.59	4.63
30-year Zero	4.79	4.93	4.89
Mortgage-Backed Securities			
GNMA 5.5%	2.72	2.90	2.25
FHLMC 5.5% (Gold)	2.94	3.19	1.88
FNMA 5.5%	2.87	3.06	2.41
FNMA ARM	2.62	2.72	2.76
Corporate Bonds			
Financial (10-year) A	4.68	4.73	4.99
Industrial (25/30-year) A	5.40	5.52	5.66
Utility (25/30-year) A	5.53	5.64	5.77
Utility (25/30-year) Baa/BBB	5.95	6.10	6.23
Foreign Bonds (10-Year)			
Canada	3.27	3.31	3.67
Germany	3.29	3.19	3.04
Japan	1.22	1.24	1.29
United Kingdom	3.57	3.69	3.94
Preferred Stocks			
Utility A	5.65	5.79	6.21
Financial A	6.46	6.52	6.64
Financial Adjustable A	5.50	5.50	5.50



	Recent (4/27/11)	3 Months Ago (1/26/11)	Year Ago (4/28/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.98	5.41	4.37
25-Bond Index (Revs)	5.54	5.66	4.93
General Obligation Bonds (GOs)			
1-year Aaa	0.27	0.41	0.38
1-year A	1.13	1.28	1.16
5-year Aaa	1.66	1.91	1.79
5-year A	2.75	2.96	2.77
10-year Aaa	3.28	3.60	3.16
10-year A	4.41	4.49	4.13
25/30-year Aaa	4.75	5.06	4.44
25/30-year A	6.07	6.27	5.51
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.15	5.46	4.79
Electric AA	5.28	5.57	4.77
Housing AA	5.97	6.44	5.70
Hospital AA	5.60	5.75	5.15
Toll Road Aaa	5.29	5.60	4.73

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/20/11	4/6/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1474421	1431443	42978	1274152	1131439	1078168
Borrowed Reserves	17930	19196	-1266	21035	33743	49335
Net Free/Borrowed Reserves	1456491	1412247	44244	1253117	1097696	1028833

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/11/11	4/4/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1883.7	1903.6	-19.9	14.3%	9.8%	10.8%
M2 (M1+savings+small time deposits)	8928.1	8922.4	5.7	5.2%	4.3%	4.8%

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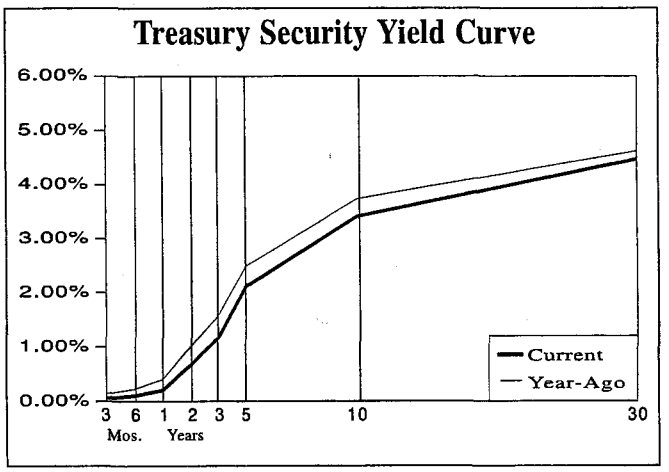
Selected Yields

	Recent (4/20/11)	3 Months Ago (1/19/11)	Year Ago (4/21/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.17	0.27	0.22
3-month LIBOR	0.27	0.30	0.31
Bank CDs			
6-month	0.29	0.30	0.25
1-year	0.47	0.48	0.43
5-year	1.71	1.60	1.99
U.S. Treasury Securities			
3-month	0.06	0.15	0.15
6-month	0.11	0.18	0.23
1-year	0.21	0.25	0.40
5-year	2.12	1.93	2.49
10-year	3.41	3.34	3.74
10-year (inflation-protected)	0.78	0.93	1.40
30-year	4.47	4.53	4.62
30-year Zero	4.79	4.87	4.87
Mortgage-Backed Securities			
GNMA 5.5%	2.85	2.38	2.24
FHLMC 5.5% (Gold)	3.07	3.03	1.86
FNMA 5.5%	2.99	2.89	2.42
FNMA ARM	2.62	2.72	2.76
Corporate Bonds			
Financial (10-year) A	4.71	4.78	5.03
Industrial (25/30-year) A	5.45	5.57	5.61
Utility (25/30-year) A	5.57	5.72	5.76
Utility (25/30-year) Baa/BBB	6.03	6.15	6.19
Foreign Bonds (10-Year)			
Canada	3.33	3.24	3.72
Germany	3.31	3.11	3.08
Japan	1.24	1.27	1.34
United Kingdom	3.58	3.64	4.02
Preferred Stocks			
Utility A	5.59	5.79	5.92
Financial A	6.45	6.04	6.59
Financial Adjustable A	5.49	5.49	5.49



	Recent (4/20/11)	3 Months Ago (1/19/11)	Year Ago (4/21/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.06	5.39	4.43
25-Bond Index (Revs)	5.58	5.60	4.96
General Obligation Bonds (GOs)			
1-year Aaa	0.33	0.39	0.43
1-year A	1.18	1.32	1.16
5-year Aaa	1.74	1.90	1.83
5-year A	2.81	3.00	2.86
10-year Aaa	3.37	3.58	3.22
10-year A	4.49	4.54	4.22
25/30-year Aaa	4.80	5.18	4.44
25/30-year A	6.12	6.31	5.51
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.19	5.56	4.79
Electric AA	5.32	5.57	4.77
Housing AA	6.01	6.42	5.73
Hospital AA	5.65	5.73	5.15
Toll Road Aaa	5.33	5.63	4.76

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/6/11	3/23/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1431443	1366438	65005	1207727	1094946	1064070
Borrowed Reserves	19196	19926	-730	24841	36026	51802
Net Free/Borrowed Reserves	1412247	1346512	65735	1182886	1058920	1012268

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/4/11	3/28/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1904.9	1903.8	1.1	17.1%	13.8%	13.2%
M2 (M1+savings+small time deposits)	8923.7	8897.5	26.2	5.4%	4.4%	4.7%

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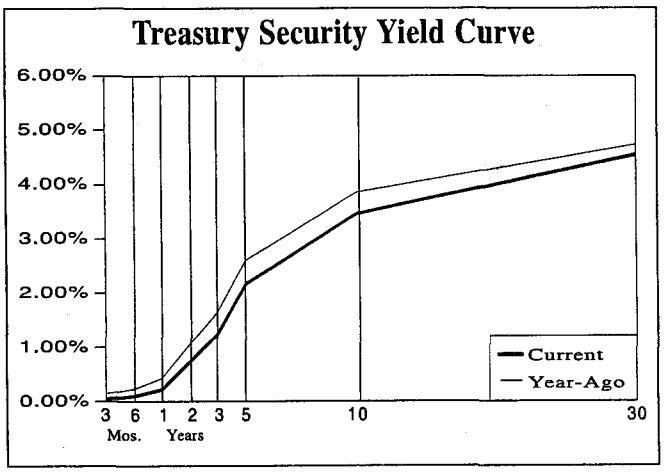
Selected Yields

	Recent (4/13/11)	3 Months Ago (1/12/11)	Year Ago (4/14/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.23	0.27	0.20
3-month LIBOR	0.28	0.30	0.30
Bank CDs			
6-month	0.29	0.30	0.25
1-year	0.47	0.48	0.43
5-year	1.71	1.57	1.99
U.S. Treasury Securities			
3-month	0.05	0.14	0.15
6-month	0.10	0.17	0.23
1-year	0.22	0.26	0.43
5-year	2.17	1.98	2.60
10-year	3.46	3.37	3.86
10-year (inflation-protected)	0.84	0.93	1.51
30-year	4.54	4.53	4.73
30-year Zero	4.88	4.86	4.99



	Recent (4/13/11)	3 Months Ago (1/12/11)	Year Ago (4/14/10)
Mortgage-Backed Securities			
GNMA 5.5%	2.97	2.61	2.52
FHLMC 5.5% (Gold)	3.32	3.14	1.83
FNMA 5.5%	3.22	2.99	2.14
FNMA ARM	2.62	2.72	2.76
Corporate Bonds			
Financial (10-year) A	4.72	4.80	5.22
Industrial (25/30-year) A	5.52	5.58	5.76
Utility (25/30-year) A	5.66	5.77	5.89
Utility (25/30-year) Baa/BBB	6.05	6.17	6.35
Foreign Bonds (10-Year)			
Canada	3.37	3.26	3.71
Germany	3.44	3.05	3.14
Japan	1.32	1.18	1.38
United Kingdom	3.71	3.64	4.03
Preferred Stocks			
Utility A	5.83	5.79	5.99
Financial A	6.44	6.03	6.60
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.04	5.08	4.45
25-Bond Index (Revs)	5.61	5.44	4.96
General Obligation Bonds (GOs)			
1-year Aaa	0.34	0.41	0.43
1-year A	1.20	1.28	1.18
5-year Aaa	1.83	1.79	1.87
5-year A	2.89	2.92	2.85
10-year Aaa	3.46	3.38	3.30
10-year A	4.62	4.38	4.27
25/30-year Aaa	4.86	4.94	4.45
25/30-year A	6.13	5.97	5.51
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.19	5.31	4.81
Electric AA	5.34	5.30	4.79
Housing AA	6.16	6.13	5.75
Hospital AA	5.65	5.43	5.15
Toll Road Aaa	5.33	5.35	4.78

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/6/11	3/23/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1431446	1366438	65008	1207727	1094946	1064070
Borrowed Reserves	19196	19926	-730	24841	36026	51802
Net Free/Borrowed Reserves	1412250	1346512	65738	1182886	1058920	1012268

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/28/11	3/21/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1903.6	1891.8	11.8	14.4%	14.8%	11.2%
M2 (M1+savings+small time deposits)	8897.3	8898.4	-1.1	2.8%	3.9%	4.4%

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ATTACHMENT D

SOUTHWEST GAS NYSE-SWX

RECENT PRICE 39.06 | P/E RATIO 16.6 (Trailing: 16.8 Median: 18.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Lowered 8/20/10
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 5/27/11
BETA .75 (1.00 = Market)

2014-16 PROJECTIONS

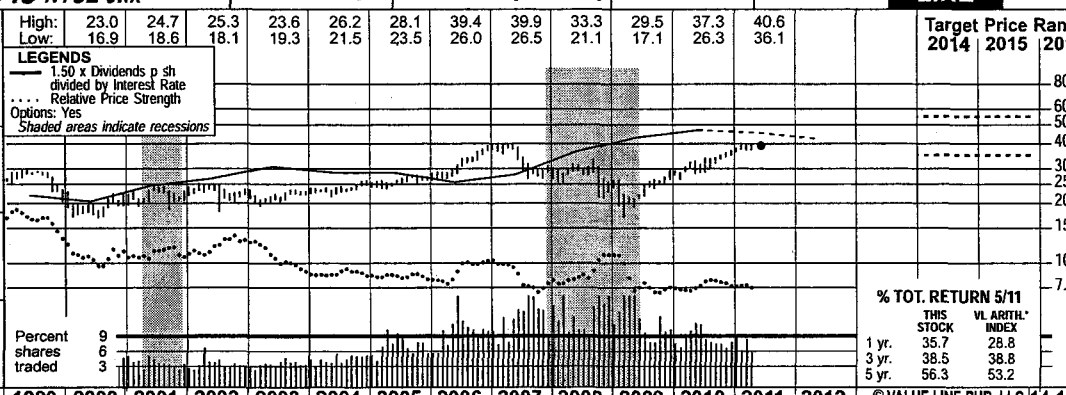
	Price	Gain	Ann'l Total Return
High	55	(+40%)	11%
Low	35	(-10%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	2	0	0	1	0	0	2
Options	0	0	4	0	2	3	2	0	7
to Sell	0	0	4	0	3	3	2	0	9

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	57	61	60
to Sell	76	75	80
Hld's(000)	32794	32710	33193



1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.14	*37.85*	*38.00*	Revenues per sh	*48.00*
2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.45	*6.55*	*6.90*	"Cash Flow" per sh	*7.80*
.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	*2.35*	*2.50*	Earnings per sh A	*3.00*
.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	*1.06*	*1.10*	Div'ds Decl'd per sh B■†	*1.25*
6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.72	*4.85*	*5.00*	Cap'l Spending per sh	*6.00*
14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.59	*27.95*	*29.15*	Book Value per sh	*34.00*
24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.60	*46.50*	*48.00*	Common Shs Outst'g C	*50.00*
NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89			Relative P/E Ratio	*1.00*
5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%			Avg Ann'l Div'd Yield	*2.8%*
1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	*1760*	*1825*	Revenues ($mill)	*2400*
37.2	38.6	38.5	58.9	48.1	80.5	83.2	61.0	87.5	104.0	*110*	*120*	Net Profit ($mill)	*150*
34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	*37.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	*6.3%*	*6.6%*	Net Profit Margin	*6.3%*
56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	*47.0%*	*46.0%*	Long-Term Debt Ratio	*45.0%*
39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	46.5%	50.9%	*53.0%*	*54.0%*	Common Equity Ratio	*55.0%*
1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2371.4	2292.0	*2450*	*2600*	Total Capital ($mill)	*3100*
1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	*3150*	*3250*	Net Plant ($mill)	*3600*
5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	5.4%	6.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	*8.5%*	*8.5%*	Return on Com Equity	*9.0%*
1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.1%	5.0%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
71%	70%	72%	49%	65%	42%	44%	63%	48%	44%	*45%*	*44%*	All Div'ds to Net Prof	*42%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $1122.7 mill. **Due in 5 Yrs** $275.0 mill.
LT Debt $1122.7 mill. **LT Interest** $72.0 mill.
(Total interest coverage: 3.2x) (48% of Cap'l)
Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/10 $505.6 mill.
Oblig. $708.9 mill.

Pfd Stock None

Common Stock 45,848,692 shs.
as of 4/29/11

MARKET CAP: $1.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	3/31/11
Cash Assets	65.3	116.1	108.4
Other	352.3	329.8	281.9
Current Assets	417.6	445.9	390.3
Accts Payable	158.9	165.5	114.5
Debt Due	1.3	75.1	--
Other	314.0	356.4	363.2
Current Liab.	474.2	597.0	477.7
Fix. Chg. Cov.	251%	299%	314%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	5.0%	4.0%	*1.5%*
"Cash Flow"	3.5%	3.0%	*4.0%*
Earnings	3.5%	6.0%	*8.0%*
Dividends	1.0%	2.0%	*4.5%*
Book Value	4.5%	5.0%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	813.6	447.3	374.4	509.4	2144.7
2009	689.9	387.6	317.5	498.8	1893.8
2010	668.8	385.8	307.7	468.1	1830.4
2011	628.4	*365*	*300*	*466.6*	*1760*
2012	*650*	*375*	*310*	*490*	*1825*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.14	d.06	d.38	.71	1.39
2009	1.12	d.01	d.18	1.01	1.94
2010	1.42	d.02	d.11	.98	2.27
2011	1.48	*Nil*	*d.12*	*.99*	*2.35*
2012	*1.50*	*Nil*	*d.10*	*1.10*	*2.50*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.205	.215	.215	.215	.85
2008	.215	.225	.225	.225	.89
2009	.225	.238	.238	.238	.94
2010	.238	.250	.250	.250	.99
2011	.250	.265			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2010 margin mix: residential and small commercial, 86%; large commercial and industrial, 4%; transportation, 10%. Total throughput: 2.2 billion therms. Sold PriMerit Bank, 7/96. Has 4,802 employees. Off. & Dir. own 1.7% of common stock; BlackRock Inc., 8.6%; T. Rowe Price Associates, Inc., 7.2%; GAMCO Investors, Inc., 7.0% (3/11 Proxy). Chairman: James J. Kropid. CEO: Jeffrey W. Shaw. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have traded in a holding pattern over the past three months, following a healthy rebound over the past couple of years. The company posted lower revenues but higher share earnings for the March period.

Mixed performance will likely continue in the coming quarters. The natural gas utility operations will likely continue to experience softness in demand, though this should be partly offset by rate relief in California and modest customer growth. Elsewhere, the construction services subsidiary ought to further benefit from an increase in maintenance and replacement work. Overall, lower revenues will likely be offset by a decline in the cost of gas sold, and we expect a moderate share-net improvement for full-year 2011. Earnings should continue to advance in 2012, assuming utility demand picks up.

Efforts to procure rate relief ought to further benefit performance. Southwest has filed a general rate case in Arizona, requesting an increase in revenues of $73.2 million (roughly 9.3%). The company is also seeking a decoupled rate structure and several programs promoting energy efficiency. A decision on this matter is expected by early 2012. Southwest's focus on rate relief and improved rate design is important, as the company depends on such approved revenue increases to help it cope with rising operating costs and to provide compensation for investments in infrastructure.

Investors should be aware of several caveats. Southwest Gas will likely incur greater operating expenses as it continues to expand going forward. Moreover, warmer-than-normal temperatures during the winter months can result in lower profitability. Insufficient, or lagging, rate relief can also hurt performance.

These shares remain neutrally ranked for Timeliness. Looking further out, we anticipate solid improvement in revenues and share earnings at the company out to 2014-2016. This appears to be partly reflected in the present quotation, and the shares currently trade within our Target Price Range. Moreover, Southwest's dividend yield is below average for its industry group. Investors can probably find more-attractive opportunities elsewhere.

Michael Napoli, CFA *June 10, 2011*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next eqs. report due early August. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	75

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SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458
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SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
COST OF CAPITAL SUMMARY

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SCHEDULE WAR - 1
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WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 607,500,000	49.85%	7.35%	3.66%
2	Common Equity	$ 611,263,103	50.15%	9.00%	4.51%
3	Total Capitalization	$ 1,218,763,103	100.00%		
4	**WEIGHTED AVERAGE COST OF CAPITAL**				**8.18%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): TESTIMONY WAR
COLUMN (C): TESTIMONY WAR
COLUMN (D): COLUMN (B) x COLUMN (C), LINE 4; LINE 1 + LINE 2

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
COST OF CAPITAL SUMMARY

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR-1
PAGE 2 OF 2

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.22%	SCHEDULE WAR-2, COLUMN (C), LINE 13
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	4.87%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE
5	CAPM - ARITHMETIC MEAN ESTIMATE	6.11%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE
6	**AVERAGE OF CAPM ESTIMATES**	**5.49%**	(SUM OF LINES 6 THRU 9) ÷ 4
7	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.35%**	(SUM OF LINES 2 AND 6) ÷ 2
8	**FINAL COST OF COMMON EQUITY ESTIMATE**	**9.00%**	TESTIMONY WAR

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AGL	AGL RESOURCES, INC.	4.46%	+	5.70%	=	10.16%
2	ATO	ATMOS ENERGY CORP.	4.07%	+	4.13%	=	8.21%
3	LG	LACLEDE GROUP, INC.	4.30%	+	4.62%	=	8.92%
4	NJR	NEW JERSEY RESOURCES CORPORATION	3.27%	+	6.61%	=	9.88%
5	NWN	NORTHWEST NATURAL GAS CO.	3.87%	+	4.08%	=	7.95%
6	PNY	PIEDMONT NATURAL GAS COMPANY	3.76%	+	3.76%	=	7.51%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	2.63%	+	10.69%	=	13.32%
8	WGL	WGL HOLDINGS, INC.	4.05%	+	3.74%	=	7.79%
9	**AVERAGE**						**9.22%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
DIVIDEND YIELD CALCULATION

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AGL	AGL RESOURCES, INC.	$1.80	/	$40.32	=	4.46%
2	ATO	ATMOS ENERGY CORP.	$1.36	/	$33.38	=	4.07%
3	LG	LACLEDE GROUP, INC.	$1.62	/	$37.65	=	4.30%
4	NJR	NEW JERSEY RESOURCES CORPORATION	$1.44	/	$43.98	=	3.27%
5	NWN	NORTHWEST NATURAL GAS CO.	$1.74	/	$44.97	=	3.87%
6	PNY	PIEDMONT NATURAL GAS COMPANY	$1.16	/	$30.87	=	3.76%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	$1.46	/	$55.50	=	2.63%
8	WGL	WGL HOLDINGS, INC.	$1.56	/	$38.55	=	4.05%
9	**AVERAGE**						**3.80%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/10/2011
COLUMN (B): EIGHT WEEK AVERAGE OF ADJUSTED CLOSING PRICES FROM 04/11/2011 TO 06/03/2011
STOCK QUOTES OBTAINED THROUGH YAHOO! FINANCE WEB SITE - HISTORICAL QUOTES (http://finance.yahoo.com).
COLUMN (C): COLUMN (A) DIVIDED BY COLUMN (B)

NOTE:
CLOSING STOCK PRICES ARE ADJUSTED FOR DIVIDENDS AND STOCK SPLITS.

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AGL	AGL RESOURCES, INC.	5.50%	+	0.20%	=	5.70%
2	ATO	ATMOS ENERGY CORP.	3.75%	+	0.38%	=	4.13%
3	LG	LACLEDE GROUP, INC.	4.00%	+	0.62%	=	4.62%
4	NJR	NEW JERSEY RESOURCES CORPORATION	6.60%	+	0.01%	=	6.61%
5	NWN	NORTHWEST NATURAL GAS CO.	4.00%	+	0.08%	=	4.08%
6	PNY	PIEDMONT NATURAL GAS COMPANY	3.75%	+	0.01%	=	3.76%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	7.80%	+	2.89%	=	10.69%
8	WGL	WGL HOLDINGS, INC.	3.50%	+	0.24%	=	3.74%
9	**NATURAL GAS LDC AVERAGE**						**5.42%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH		(B)		(C) EXTERNAL GROWTH (sv)
1	AGL	AGL RESOURCES, INC.	0.65%	x	{ [((1.62) + 1) / 2] - 1 }	=	0.20%
2	ATO	ATMOS ENERGY CORP.	2.75%	x	{ [((1.28) + 1) / 2] - 1 }	=	0.38%
3	LG	LACLEDE GROUP, INC.	2.75%	x	{ [((1.45) + 1) / 2] - 1 }	=	0.62%
4	NJR	NEW JERSEY RESOURCES CORPORATION	0.01%	x	{ [((2.35) + 1) / 2] - 1 }	=	0.01%
5	NWN	NORTHWEST NATURAL GAS CO.	0.25%	x	{ [((1.66) + 1) / 2] - 1 }	=	0.08%
6	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((2.26) + 1) / 2] - 1 }	=	0.01%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	3.50%	x	{ [((2.65) + 1) / 2] - 1 }	=	2.89%
8	WGL	WGL HOLDINGS, INC.	0.75%	x	{ [((1.64) + 1) / 2] - 1 }	=	0.24%
9	**AVERAGE**						**0.55%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/10/2011
COLUMN (C): COLUMN (A) x COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
DIVIDEND GROWTH COMPONENTS

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 5
PAGE 1 OF 2

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	AGL	AGL RESOURCES, INC.	2006	0.4559		13.20%		6.02%	20.71	77.70	
2			2007	0.3971		12.70%		5.04%	21.74	76.40	
3			2008	0.3801		12.60%		4.79%	21.48	76.90	
4			2009	0.4028		12.50%		5.03%	22.95	77.54	
5			2010	0.4133		12.90%		5.33%	23.24	78.00	
6			GROWTH 2006 - 2010					5.24%	5.50%		0.10%
7			2011	0.4286		12.50%		5.36%		78.50	0.64%
8			2012	0.4424		12.50%		5.53%		79.00	0.64%
9			2014-16	0.4773		12.00%		5.73%	6.00%	80.50	0.63%
10											
11	ATO	ATMOS ENERGY CORP.	2006	0.3700		9.80%		3.63%	20.16	81.74	
12			2007	0.3402		8.70%		2.96%	22.01	89.33	
13			2008	0.3500		8.80%		3.08%	22.60	90.81	
14			2009	0.3299		8.30%		2.74%	23.52	92.55	
15			2010	0.3796		9.20%		3.49%	24.16	90.16	
16			GROWTH 2006 - 2010					3.18%	5.00%		2.48%
17			2011	0.4087		9.00%		3.68%		91.00	0.93%
18			2012	0.4250		8.50%		3.61%		92.00	1.02%
19			2014-16	0.4630		9.00%		4.17%	4.50%	105.00	3.09%
20											
21	LG	LACLEDE GROUP, INC.	2006	0.4093		12.50%		5.12%	18.85	21.36	
22			2007	0.3723		11.60%		4.32%	19.79	21.65	
23			2008	0.4356		11.80%		5.14%	22.12	21.99	
24			2009	0.4760		12.40%		5.90%	23.32	22.17	
25			2010	0.3539		10.10%		3.57%	24.02	22.29	
26			GROWTH 2006 - 2010					4.81%	7.00%		1.07%
27			2011	0.3429		9.50%		3.26%		22.50	0.94%
28			2012	0.3529		9.50%		3.35%		23.00	1.58%
29			2014-16	0.4098		10.00%		4.10%	5.00%	26.00	3.13%
30											
31	NJR	NEW JERSEY RESOURCES CORPORATION	2006	0.4866		12.60%		6.13%	15.00	41.44	
32			2007	0.3484		10.10%		3.52%	15.50	41.61	
33			2008	0.5889		15.70%		9.25%	17.28	42.06	
34			2009	0.4833		14.60%		7.06%	16.59	41.59	
35			2010	0.4472		14.10%		6.30%	17.53	41.36	
36			GROWTH 2006 - 2010					6.45%	10.00%		-0.05%
37			2011	0.4566		14.50%		6.62%		41.00	0.00%
38			2012	0.4807		15.00%		7.21%		40.00	0.00%
39			2014-16	0.5000		13.50%		6.75%	6.00%	40.00	0.00%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/10/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
DIVIDEND GROWTH COMPONENTS

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SCHEDULE WAR - 5
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LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	NWN	NORTHWEST NATURAL GAS CO.	2006	0.4085		10.90%		4.45%	22.01	27.24	
2			2007	0.4783		12.50%		5.98%	22.52	26.41	
3			2008	0.4086		10.90%		4.45%	23.71	26.50	
4			2009	0.4346		11.40%		4.95%	24.88	26.53	
5			2010	0.3846		10.50%		4.04%	25.95	26.67	
6			GROWTH 2006 - 2010					4.78%	4.00%		-0.53%
7			2011	0.2596		9.00%		2.34%		26.75	0.30%
8			2012	0.3643		9.50%		3.46%		26.80	0.24%
9			2014-16	0.4412		10.00%		4.41%	6.50%	26.95	0.21%
10											
11	PNY	PIEDMONT NATURAL GAS COMPANY	2006	0.2578		11.00%		2.84%	11.83	74.61	
12			2007	0.2929		11.90%		3.49%	11.99	73.23	
13			2008	0.3087		12.40%		3.83%	12.11	73.26	
14			2009	0.3593		13.20%		4.74%	12.67	73.27	
15			2010	0.2839		11.60%		3.29%	13.35	72.28	
16			GROWTH 2006 - 2010					3.64%	3.50%		-0.79%
17			2011	0.2813		12.00%		3.38%		71.50	-1.08%
18			2012	0.3000		12.00%		3.60%		71.00	-0.89%
19			2014-16	0.3105		12.50%		3.88%	3.00%	68.00	-1.21%
20											
21	SJI	SOUTH JERSEY INDUSTIES, INC.	2006	0.6260		16.30%		10.20%	15.11	29.33	
22			2007	0.5167		12.80%		6.61%	16.25	29.61	
23			2008	0.5110		13.10%		6.69%	17.33	29.73	
24			2009	0.4874		13.10%		6.38%	18.24	29.80	
25			2010	0.4963		14.20%		7.05%	19.08	29.87	
26			GROWTH 2006 - 2010					7.39%	8.00%		0.46%
27			2011	0.5148		14.50%		7.46%		31.00	3.78%
28			2012	0.5224		15.00%		7.84%		32.00	3.50%
29			2014-16	0.5122		15.50%		7.94%	6.50%	34.00	2.62%
30											
31	WGL	WGL HOLDINGS, INC.	2006	0.3041		10.30%		3.13%	18.86	48.89	
32			2007	0.3445		10.30%		3.55%	19.83	49.45	
33			2008	0.4221		11.60%		4.90%	20.99	49.92	
34			2009	0.4190		11.60%		4.86%	21.89	50.14	
35			2010	0.3392		9.90%		3.36%	22.82	50.54	
36			GROWTH 2006 - 2010					7.39%	8.00%		0.83%
37			2011	0.2619		9.00%		2.36%		51.00	0.91%
38			2012	0.3234		9.50%		3.07%		51.00	0.45%
39			2014-16	0.3547		10.00%		3.55%	3.50%	52.00	0.57%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/10/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
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COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
GROWTH RATE COMPARISON

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 6

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) VALUE LINE PROJECTED DPS	(C) VALUE LINE PROJECTED BVPS	(D) VALUE LINE HISTORIC EPS	(D) VALUE LINE HISTORIC DPS	(D) VALUE LINE HISTORIC BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) 5 - YEAR COMPOUND HISTORY DPS	(F) 5 - YEAR COMPOUND HISTORY BVPS
1	AGL	5.70%	4.00%	5.00%	30.00%	6.00%	4.50%	7.50%	5.50%	8.93%	2.48%	4.43%	2.92%
2	ATO	4.13%	4.50%	5.00%	2.00%	4.50%	4.00%	1.50%	5.00%	3.79%	1.94%	1.55%	4.63%
3	LG	4.62%	3.00%	2.50%	2.50%	5.00%	7.50%	2.50%	7.00%	4.29%	0.63%	2.91%	6.25%
4	NJR	6.61%	4.00%	4.00%	4.50%	6.00%	8.50%	7.50%	10.00%	6.36%	7.10%	9.10%	3.97%
5	NWN	4.08%	4.60%	4.50%	3.50%	6.50%	9.50%	3.50%	4.00%	5.16%	3.82%	4.85%	4.20%
6	PNY	3.76%	4.80%	3.00%	3.50%	3.00%	5.00%	4.50%	3.50%	3.90%	4.90%	3.97%	3.07%
7	SJI	10.69%	-	9.00%	8.50%	6.50%	9.50%	8.50%	8.00%	8.33%	2.35%	10.27%	6.01%
8	WGL	3.74%	5.30%	1.50%	2.50%	3.50%	2.50%	2.50%	5.00%	3.26%	4.01%	2.67%	4.88%
9				4.31%	7.13%	5.13%	6.38%	4.75%	6.00%		3.40%	4.97%	4.49%
10	AVERAGES	5.42%	4.31%		5.52%			5.71%		5.50%		4.29%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/10/2011
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/10/2011
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 9
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/10/2011

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
CAPM COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 7
PAGE 1 OF 2

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL						(A)									(B) EXPECTED RETURN
		k	=	r_f	+	[	ß	x	(	r_m	-	r_f	)	]	=	
1	AGL	k	=	1.91%	+	[	0.75	x	(	9.90%	-	5.40%	)	]	=	5.29%
2	ATO	k	=	1.91%	+	[	0.70	x	(	9.90%	-	5.40%	)	]	=	5.06%
3	LG	k	=	1.91%	+	[	0.60	x	(	9.90%	-	5.40%	)	]	=	4.61%
4	NJR	k	=	1.91%	+	[	0.65	x	(	9.90%	-	5.40%	)	]	=	4.84%
5	NWN	k	=	1.91%	+	[	0.60	x	(	9.90%	-	5.40%	)	]	=	4.61%
6	PNY	k	=	1.91%	+	[	0.65	x	(	9.90%	-	5.40%	)	]	=	4.84%
7	SJI	k	=	1.91%	+	[	0.65	x	(	9.90%	-	5.40%	)	]	=	4.84%
8	WGL	k	=	1.91%	+	[	0.65	x	(	9.90%	-	5.40%	)	]	=	4.84%
9	**NATURAL GAS LDC AVERAGE**						0.66									**4.87%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 04/22/2011 THROUGH 06/10/2011 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2010 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PERI THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2011 YEARBOOK.

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
CAPM COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 7
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AGL	k	=	1.91%	+ [	0.75	x	(	11.90%	-	5.50%	)]	=	6.71%
2	ATO	k	=	1.91%	+ [	0.70	x	(	11.90%	-	5.50%	)]	=	6.39%
3	LG	k	=	1.91%	+ [	0.60	x	(	11.90%	-	5.50%	)]	=	5.75%
4	NJR	k	=	1.91%	+ [	0.65	x	(	11.90%	-	5.50%	)]	=	6.07%
5	NWN	k	=	1.91%	+ [	0.60	x	(	11.90%	-	5.50%	)]	=	5.75%
6	PNY	k	=	1.91%	+ [	0.65	x	(	11.90%	-	5.50%	)]	=	6.07%
7	SJI	k	=	1.91%	+ [	0.65	x	(	11.90%	-	5.50%	)]	=	6.07%
8	WGL	k	=	1.91%	+ [	0.65	x	(	11.90%	-	5.50%	)]	=	6.07%
9	**NATURAL GAS LDC AVERAGE**					0.66								**6.11%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 04/22/2011 THROUGH 06/10/2011 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2010 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAM THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2011 YEARBOO

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	CURRENT	3.20%	1.80%	3.25%	0.75%	0.00% - 0.25%	0.04%	4.51%	5.14%	5.69%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 06/10/2011
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 06/10/2011
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

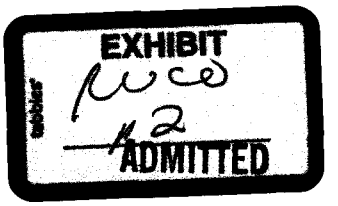
SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 9

AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES

LINE NO.		AGL	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	NWN	PCT.
1											
2											
3	DEBT	$ 1,673.0	47.7%	$ 1,809.6	45.4%	$ 364.3	47.0%	$ 428.9	37.2%	$ 591.7	46.1%
4											
5	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
6											
7	COMMON EQUITY	1,836.0	52.3%	2,178.3	54.6%	411.3	53.0%	725.5	62.8%	693.1	53.9%
8											
9	TOTALS	$ 3,509.0	100%	$ 3,987.9	100%	$ 775.6	100%	$ 1,154.4	100%	$ 1,284.8	100%
10											
11											
12										NATURAL GAS LDC	
13		PNY	PCT.	SJI	PCT.	WGL	PCT.			AVERAGE	PCT.
14											
15	DEBT	$ 671.9	41.0%	$ 340.0	37.4%	$ 592.9	33.4%			$ 809.0	43.1%
16											
17	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	28.2	1.6%			$ 3.5	0.2%
18											
19	COMMON EQUITY	964.9	59.0%	570.1	62.6%	1,153.4	65.0%			1,066.6	56.8%
20											
21	TOTALS	$ 1,636.9	100%	$ 910.1	100%	$1,774.4	100%			$ 1,879.1	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS



SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-10-0458

TESTIMONY IN OPPOSITION TO PROPOSED SETTLEMENT AGREEMENT OF JULY 15, 2011

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 29, 2011

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INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes. On June 10, 2011, I filed direct testimony with the Commission on RUCO's recommended cost of capital for SWG.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's revised cost of equity capital, which is part of RUCO's proposed alternative ("Proposed Alternative") to the proposed SWG settlement agreement ("Agreement") that was entered into by SWG, ACC Staff and various other parties to the case. The Agreement was filed on July 15, 2011.

Q. Is RUCO a signatory to the Agreement?

A. No. RUCO is not a signatory to the Agreement[1]. My testimony provides support for the recommendations of RUCO witness Ben Johnson, Ph.D. and Jodi Jerich, who are filing testimony in opposition to the Agreement.

[1] Signatories to the Agreement include Southwest Gas Corporation, the Utilities Division of the Arizona Corporation Commission, Arizona Investment Council, Southwest Energy Efficiency Project, National Resources Defense Council and Ms. Cynthia Zwick.

REVISED COST OF EQUITY RECOMMENDATION

Q. What revised cost of equity is RUCO recommending in its Proposed Alternative to the Agreement?

A. RUCO is recommending a cost of equity of 9.50 percent in its Proposed Alternative to the Agreement.

Q. How does RUCO's revised cost of equity compare to the cost of equity that you recommended in your direct testimony?

A. RUCO's revised 9.50 percent cost of equity is 50 basis points higher than the 9.00 percent cost of equity that I recommended in my direct testimony.

Q. How does RUCO's revised 9.50 percent cost of equity compare with the cost of equity contained in the Settlement Agreement?

A. RUCO's revised 9.50 percent cost of equity is equal to the 9.50 percent return on equity ("ROE") under Alternative B of the Agreement, and is 25 basis points lower than the 9.75 percent ROE under Alternative A of the Agreement.

Q. Please compare the costs of equity that were recommended by the Company, ACC Staff and RUCO prior to the filing of the Agreement.

A. The costs of equity that were recommended by the Company, ACC Staff and RUCO prior to the filing of the Agreement were as follows:

Company	11.00%
ACC Staff	9.75%
RUCO	9.00%

Q. Why Is RUCO recommending a cost of equity that is 50 basis points higher than RUCO's 9.00 litigation recommendation?

A. RUCO is offering a higher cost of equity in the spirit of compromise. RUCO's revised cost of equity is being offered as part of an alternative to the Agreement that is now before the Commission.

Q. Do you believe that the 9.50 percent cost of equity, being offered in the spirit of compromise, is reasonable given the results of your cost of equity analysis?

A. Yes. After comparing the range of results of my cost of equity analysis with the range of results obtained by ACC Staff's cost of capital witness; Mr. David C. Parcel, I believe that RUCO's revised 9.50 percent cost of equity is reasonable. RUCO's revised 9.50 percent cost of equity is 28 basis points higher than the 9.22 percent high end of the range of results that I obtained in my cost of equity analysis, and is 42 basis points higher than the 9.08 percent mid-range of cost of equity estimates obtained by Mr. Parcel. RUCO's revised 9.50 percent cost of equity is 25 basis points lower than Mr. Parcel's final recommended cost of equity estimate of 9.75 percent that is part of Alternative A of the Agreement.

Q. Does RUCO's Proposed Alternative adopt the proposed capital structure and cost of debt contained in the Agreement?

A. Yes. Again in the spirit of compromise, RUCO's Proposed Alternative to the Agreement adopts the proposed capital structure and cost of debt contained in the Agreement.

FINAL RECOMMENDATION

Q. What is your final recommendation?

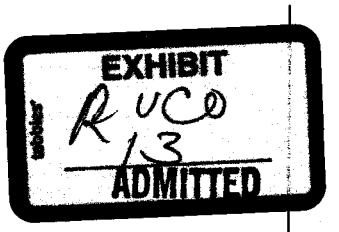
A. I am recommending that the Commission adopt the revised 9.50 percent cost of equity that is part of RUCO's Proposed Alternative to the Agreement.

Q. Does your silence on any of the provisions of the Agreement constitute your acceptance of those provisions?

A. No, it does not.

Q. Does this conclude your testimony?

A. Yes, it does.



BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
CHAIRMAN
BOB STUMP
COMMISSIONER
SANDRA D. KENNEDY
COMMISSIONER
PAUL NEWMAN
COMMISSIONER
BRENDA BURNS
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	Docket No. G-01551A-10-0458

NOTICE OF ERRATA

The Residential Utility Consumer Office ("RUCO") hereby files this Notice of Errata in the above-referenced matter. Attached is William A. Rigsby's revised Schedule WAR-5, page 2 of 2, of his direct testimony.

RESPECTFULLY SUBMITED this 15th day of June, 2011.

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES of the foregoing filed this 15th day of June, 2011 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/ mailed this 15th day of June, 2011 to:

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By Ernestine Gamble
Ernestine Gamble

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED JUNE 30, 2010
DIVIDEND GROWTH COMPONENTS

DOCKET NO. G-01551A-10-0458
SCHEDULE WAR - 5
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	NWN	NORTHWEST NATU	2006	0.4085		10.90%		4.45%	22.01	27.24	
2			2007	0.4783		12.50%		5.98%	22.52	26.41	
3			2008	0.4086		10.90%		4.45%	23.71	26.50	
4			2009	0.4346		11.40%		4.95%	24.88	26.53	
5			2010	0.3846		10.50%		4.04%	25.95	26.67	
6			GROWTH 2006 - 2010					4.78%	4.00%		-0.53%
7			2011	0.2596		9.00%		2.34%		26.75	0.30%
8			2012	0.3643		9.50%		3.46%		26.80	0.24%
9			2014-16	0.4412		10.00%		4.41%	6.50%	26.95	0.21%
10											
11	PNY	PIEDMONT NATUR/	2006	0.2578		11.00%		2.84%	11.83	74.61	
12			2007	0.2929		11.90%		3.49%	11.99	73.23	
13			2008	0.3087		12.40%		3.83%	12.11	73.26	
14			2009	0.3593		13.20%		4.74%	12.67	73.27	
15			2010	0.2839		11.60%		3.29%	13.35	72.28	
16			GROWTH 2006 - 2010					3.64%	3.50%		-0.79%
17			2011	0.2813		12.00%		3.38%		71.50	-1.08%
18			2012	0.3000		12.00%		3.60%		71.00	-0.89%
19			2014-16	0.3105		12.50%		3.88%	3.00%	68.00	-1.21%
20											
21	SJI	SOUTH JERSEY INI	2006	0.6260		16.30%		10.20%	15.11	29.33	
22			2007	0.5167		12.80%		6.61%	16.25	29.61	
23			2008	0.5110		13.10%		6.69%	17.33	29.73	
24			2009	0.4874		13.10%		6.38%	18.24	29.80	
25			2010	0.4963		14.20%		7.05%	19.08	29.87	
26			GROWTH 2006 - 2010					7.39%	8.00%		0.46%
27			2011	0.5148		14.50%		7.46%		31.00	3.78%
28			2012	0.5224		15.00%		7.84%		32.00	3.50%
29			2014-16	0.5122		15.50%		7.94%	6.50%	34.00	2.62%
30											
31	WGL	WGL HOLDINGS, IN	2006	0.3041		10.30%		3.13%	18.86	48.89	
32			2007	0.3445		10.30%		3.55%	19.83	49.45	
33			2008	0.4221		11.60%		4.90%	20.99	49.92	
34			2009	0.4190		11.60%		4.86%	21.89	50.14	
35			2010	0.3392		9.90%		3.36%	22.82	50.54	
36			GROWTH 2006 - 2010					3.96%	5.00%		0.83%
37			2011	0.2619		9.00%		2.36%		51.00	0.91%
38			2012	0.3234		9.50%		3.07%		51.00	0.45%
39			2014-16	0.3547		10.00%		3.55%	3.50%	52.00	0.57%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/10/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-10-0458

TESTIMONY IN OPPOSITION TO PROPOSED SETTLEMENT AGREEMENT OF JULY 15, 2011

OF

JODI A. JERICH

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 29, 2011

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INTRODUCTION

Q. Please state your name, occupation and business address for the record.

A. My name is Jodi Jerich. I am the Director of the Arizona Residential Utility Consumer Office (RUCO). My business address is 1110 W. Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Governor Brewer appointed me to serve as the Director of RUCO in February 2009. The Arizona State Senate found my qualifications met the statutory requirements found in Arizona Revised Statutes §40-462 and confirmed my appointment. As Director, I oversee and approve all testimony and briefs filed by RUCO. In consultation with my staff, I direct the public policy decisions of the office.

From 2003 through 2005, I was employed at the Arizona Corporation Commission as the Policy Advisor to Corporation Commissioner Mike Gleason. In that role, I advised the Commissioner on matters coming before

the Commission. I was actively involved in the utility policy-making decisions of that Commissioner's office.

Except for the time I was employed by the Commission, from 1997 through 2008, I was employed at the Arizona House of Representatives. I held several positions during my tenure, eventually becoming Chief of Staff and Counsel to the Majority Caucus. Relevant to the question at hand, I advised Legislators on matters involving water, energy, Commission jurisdiction and utility security.

In 2006, when Governor Janet Napolitano appointed Barry Wong to fill the Commission seat vacated by Commissioner Marc Spitzer's appointment to the Federal Energy Regulatory Commission (FERC), I took a leave of absence from the Legislature for a short time in order to assist Commissioner Wong establish his office.

Finally, I am a Phi Beta Kappa graduate of Indiana University. I also have a law degree from Indiana University and am a member of the Arizona and Tennessee bars.

In my position as RUCO Director, I have filed testimony detailing RUCO's position on numerous matters in several dockets.

Q. Have you filed testimony previously in this docket?

A. No.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to explain why RUCO is not a signatory to the Proposed Settlement Agreement.

Q. Does RUCO have an alternative proposal to the decoupling mechanism(s) proposed in the settlement agreement?

A. Yes. In the spirit of compromise, RUCO offers a "third" option for the Commission's consideration. I will briefly summarize RUCO's proposal later in my testimony and Dr. Johnson will provide the details.

Q. Have you, in your capacity as Director of RUCO, signed proposed settlement agreements in the past?

A. Yes. As Director on behalf of RUCO, I have signed settlement agreements in other rate cases. During my tenure as RUCO's Director, RUCO supported the settlement agreements in the most recent APS rate case

(Docket No D-01345A-08-0172) and the Qwest/Century Link merger (Docket No. T-04190A-10-0194).

Q. What is RUCO's philosophy regarding settlements?

A. RUCO supports the settlement process. RUCO will work hard to find a compromise position but must walk away from the negotiating table when the results of a settlement are not in the best interests of residential ratepayers. And that is what happened here.

Q. Do you believe the settlement process in this rate case was open and transparent and did RUCO fully participate in the settlement negotiations?

A. Yes. RUCO fully participated in the settlement process. However, RUCO is not able to support the proposed Settlement Agreement because RUCO believes it is not in the best interests of ratepayers. RUCO is the only party that is not a signatory to the proposed Settlement Agreement.

Q. Please summarize why RUCO opposes the Proposed Settlement?

A. RUCO finds the Proposed Settlement is not in the best interest of residential ratepayers for the following reasons:

1. The Proposed Settlement provides two alternative decoupling mechanisms for the utility – full decoupling and almost full decoupling. After careful reflection, RUCO finds that neither proposed decoupling mechanism for this utility, at this time, is in the best interest of residential ratepayers.
2. RUCO believes that the utility is in a financially healthy position with strong credit metrics as discussed in detail in Dr. Ben Johnson's Direct Testimony and a decoupling mechanism is not necessary to preserve the financial health of the utility.
3. Staff witness Dr. David Dismukes states in his Direct Testimony that ***Southwest Gas would have collected an additional $62 million from residential customers if its rates had been decoupled from 2007-2010***. This equates to six percent of residential test year revenue. (page 16, lines 17-22, page 17, lines 1-6)
4. There is significant public opposition to a decoupling mechanism.[1] As Director, I am very sensitive to the strong opposition to decoupling from the very people RUCO represents. The concept of a decoupling

[1] A cursory review of this docket shows that literally hundreds of ratepayers have communicated their opposition to a decoupling mechanism in this rate case.

mechanism is a complex one. The public is concerned that decoupling will result in higher rates regardless of conservation. In the absence of further education and greater customer outreach, it is very likely that decoupling will result in less conservation – the exact opposite of the purpose of decoupling. Furthermore, the first utility to be authorized a decoupling mechanism will need to provide significant consumer education and outreach to its customers. And in light of how poorly the utility communicated with customers during the outages on its system in Southern Arizona this past winter, frankly, this utility may not be the best company to shoulder this responsibility.

5. A decoupling mechanism in this case does not achieve one of the primary purposes of a decoupling mechanism. A primary reason for a decoupling mechanism is to delay building additional utility infrastructure – such as additional generating capacity. That compelling reason for a decoupling mechanism is not present for this utility. Southwest Gas, a distribution utility, merely supplies natural gas to customers. The utility's need to build additional infrastructure is predicated upon the growth of its customers. Reduced consumption by existing customers will not defer new infrastructure. There is no correlation between energy efficiency or conservation efforts from existing customers with Southwest Gas' need to expand its distribution system when new customers come on line in its service territory.

6. The unique structure of this proposed Settlement Agreement is troubling for RUCO. For the first time in my recollection of Settlement Agreements, the settling parties offer more than one proposal for the Commission's consideration. A settling party can prefer one option over the other and can even oppose one of the options as long as it supports the other option. Ultimately, that party must support the Commission's decision even if it is for an option that party does not support. Where there is so much at stake, it is doubtful that RUCO could ever support a settlement structured this way. Even if RUCO could support one option, RUCO could not give its tacit approval to another option RUCO does not support, particularly when the options address decoupling.

Q. Does RUCO oppose a decoupling mechanism in principle?

A. No. RUCO continues to have concerns about how effective decoupling will be in achieving the intended objective of encouraging reduced consumption of natural gas. However, we recognize the potential for developing a decoupling mechanism that is in the best interest of residential ratepayers as well as the utility. At this time, in this case, given current economic conditions and current ratepayer opposition, we don't believe either of the decoupling mechanisms put forward in the Settlement should be adopted. However, that does not mean RUCO is unalterably opposed to decoupling.

Q. Is there a time in the future when RUCO might support a decoupling mechanism?

A. Yes. RUCO is not foreclosed to the possibility of a decoupling mechanism for other utilities, or for Southwest Gas at a later time if the decoupling mechanism makes sense and the circumstances warrant it.

Q. In a nutshell, what arguments does RUCO find persuasive for decoupling?

A. The focus of decoupling should be to the benefit of the ratepayer while holding the utility financially harmless. RUCO believes it is in the interests of consumers to delay building additional infrastructure because the costs of new infrastructure would most likely raise rates higher than the adjustments made through a decoupling mechanism. That is definitely to the benefit of the customer. But instead, here we have just the opposite. Under the decoupling mechanism(s) offered in the proposed settlement, the benefit is purely for the utility with no benefit for the ratepayer.

Q. Please explain.

A. Under a well-constructed decoupling mechanism, the utility would implement robust and cost effective energy efficiency programs and the individual ratepayers would use less energy and enjoy a reduced monthly bill. Reduced consumption would result in the delay the need to build new and very expensive generation, transmission and other infrastructure. A decoupling mechanism would hold the utility harmless for the reduced consumption and allow it to cover its fixed costs. In the end, the revenue paid for by the ratepayers through the decoupling mechanism would be vastly outweighed by the deferred costs to build new generation and corresponding infrastructure.

Q. **Why isn't that the case here?**

A. No amount of reduced consumption will defer infrastructure growth because the need for new infrastructure is based entirely on building new distribution facilities to service new customers, and not to meet the needs of existing customers due to increased consumption. Here, ratepayers who do reduce their natural gas usage do not get to enjoy the full savings of their efforts. And those customers who either choose to not reduce their consumption or who have already reduced their consumption as far as they will see their

bills increase through the decoupling mechanism. And all of this will not defer new infrastructure.

Q. Does RUCO offer an alternative to the two options offered in the proposed Settlement Proposal?

A. Yes. In the spirit of compromise, RUCO offers a "third" option for the Commission's consideration. It is a slightly modified version of the proposed Settlement Agreement's Option B except for the following changes:

1. In lieu of a decoupling proposal, RUCO recommends shifting a portion of the revenue requirement into the fixed monthly rate. The fixed monthly rate would increase to $11.85 from $10.70.
2. Instead of a 10-year weather normalization period, RUCO proposes what it believes to be a more accurate 30-year weather normalization period.
3. Instead of the FVROR methodology used in the settlement agreement, RUCO recommends the FVROR methodology explained in Dr. Johnson's Direct Testimony.
4. All other components would be the same including the 9.50% ROE, capital structure and inclusion of post test year plant.

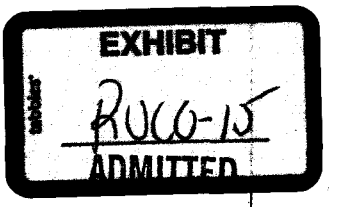
The details of RUCO's third option is addressed in greater detail in Dr. Johnson's testimony in response to the proposed Settlement Agreement.

	Option A	Option B	RUCO Option
ROE	9.75%	9.50%	9.50%
Revenue Increase	$54.9M	$52.6M	$44.6M
FVROR	7.02%	6.92%	6.85%
Mechanism to compensate utility for lost fixed costs	Almost full decoupling with no cap	Full decoupling with 5% cap	No decoupling Shift more revenue into fixed monthly rate
Weather normalization period	10 years	10 years	30 years
Low Income programs	Yes	Yes	Agrees with Settlement
Commitment to energy efficiency	Yes	Yes	Agrees with Settlement
Rate Case moratorium	None	5 years	None

Q. Does that conclude your testimony?

A. Yes.

EXHIBIT
RUCO-15
ADMITTED



BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	Docket No. G-01551A-10-0458

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby files its revised schedules in the above-referenced matter. Attached please find the revised revenue schedules of Dr. Ben Johnson, and revised testimony of Dr. Johnson and Jodi Jerich, incorporating the changes.

RESPECTFULLY SUBMITED this 10th day of August, 2011.

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES
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of August, 2011 with:

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Phoenix, Arizona 85007

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By Ernestine Gamble
Ernestine Gamble

Southwest Gas Corporation
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule A Revised per RUCO
Page 1 of 1

Line No.	Description	Reference	SWG Proposed Original Cost (A)	SWG Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (Alt. 1) (D1)	Staff Proposed Fair Value (Alt. 2) (D2)	Difference Fair Value (E) = D2 - B
1	Adjusted Rate Base	Sch. B	$ 1,073,700,633	$ 1,456,517,468	$ 1,070,116,558	$ 1,452,933,391	$ 1,452,933,391	$ (3,584,077)
2	Rate of Return	Sch. D	9.73%	7.50%	9.08%	6.69%	6.85%	
3	Operating Income Required		$ 104,483,741	$ 109,211,529	$ 97,139,081	$ 97,139,081	$ 99,525,937	$ (9,685,592)
4	Net Operating Income Available	Sch. C	$ 67,105,572	$ 67,105,572	$ 70,833,429	$ 70,833,429	$ 70,833,429	$ 3,727,857
5	Operating Income Excess/Deficiency		$ 37,378,169	$ 42,105,957	$ 26,305,652	$ 26,305,652	$ 28,692,508	$ (13,413,449)
6	*Gross Revenue Conversion* Factor	Sch. A-1	1.6579	1.6579	1.6579	1.6579	1.6579	1.6579
7	Overall Revenue Requirement		$ 61,969,266	$ 69,807,465	$ 43,612,140	$ 43,612,140	$ 47,569,309	$ (22,238,156)
8	Additional revenue requirement on Fair Value	Line 7		$ 7,838,200 (B - A)		$ - (D1 - C)	$ 3,957,169 (D2 - C)	

Notes and Source
Cols. A & B taken from SWG filing, Schedule A-1
SWG Schedule A-1 does not carry the Company's Original Cost calculations in its Schedule A-1, column c, through to a revenue requirement amount.

Southwest Gas Corporation
Adjusted Net Operating Income

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C Revised per RUCO
Page 1 of 1

Incorporating 30 Year Normal Weather Data

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Revenues	**$ 414,285,202**	$ -	**$ 414,285,202**
2	Gas Cost		$ -	$ -
3	Total Margin	$ 414,285,202	$ -	$ 414,285,202
	Operating Expenses			
4	Other Gas Supply	$ 1,138,145	$ -	$ 1,138,145
5	Distribution	$ 100,579,868	$ 625,094	$ 101,204,963
6	Customer Accounts	$ 33,881,272	$ -	$ 33,881,272
7	Customer Information	$ 1,205,135	$ -	$ 1,205,135
8	Sales	$ -	$ -	$ -
	Administrative and General			
9	Direct	$ 6,339,402	$ (4,160,309)	$ 2,179,093
10	System Allocable	$ 58,786,097	$ (2,451,994)	$ 56,334,103
	Depreciation and Amortization			
11	Direct	$ 93,057,028	$ (17,099)	$ 93,039,929
12	System Allocable	$ 6,244,982	$ (115,257)	$ 6,129,725
13	Regulatory Amortizations	$ 284,581	$ -	$ 284,581
14	Other Taxes	$ 27,203,877	$ (138,360)	$ 27,065,517
15	Interest on Customer Deposits	$ 2,908,517	$ -	$ 2,908,517
16	Income Taxes	$ 15,550,726	**$ 2,530,068**	$ 18,080,794
17	Total Operating Expenses	$ 347,179,630	$ (3,727,857)	$ 343,451,773
18	Net Operating Income	$ 67,105,572	$ 3,727,857	$ 70,833,429

Notes and Source

Col. A: SWG filing, Schedule C-1, page 1 of 18, colume e
Col. B: Staff Schedule C.1

Q. Have you estimated the impact of changing the revenue requirements in the Settlement to reflect the use of a more appropriate FVROR methodology, and the use of the 30 year average for "normal" weather?

A. Yes. I was not provided with a copy of the workpapers underlying the Settlement, so I instead used a copy of the workpapers filed with Staff's direct testimony to estimate these impacts. More specifically, using a Return on Equity of 9.50% but a FVROR of 6.85% based on RUCO's methodology, and replacing the inappropriately adjusted 10 year average weather data with the unadjusted 30 year average weather data, I estimate the $52.6 million revenue requirement set forth in the Settlement would be reduced to approximately $47.6 million.

Q. In summary, what is RUCO's proposed resolution of the issues in this case?

A. In the spirit of compromise, and in recognition of the efforts by other parties to resolve the issues through the proposed Settlement, RUCO is willing to accept all elements of the Settlement except for the three issues I've discussed in this testimony: decoupling, fair value methodology, and weather normalization. Accordingly, RUCO recommends the Commission reject the Settlement as filed, but resolve the issues in this proceeding in accordance with the provisions of the Settlement with these exceptions: reject decoupling, calculate the FVROR using the methodology adopted in Docket No. E-04204A-09-0206, and normalize weather based upon the unadjusted 30 year average. I estimate this will result in a revenue requirement of approximately $47.6 million. Finally, in an effort to alleviate to some degree the financial concerns which underly the Company's preference for decoupling, I recommend increasing SWG's flat monthly customer charges to $11.85 per month, notwithstanding the fact that this would push this rate further above a cost-justified level.

The details of RUCO's third option is addressed in greater detail in Dr. Johnson's testimony in response to the proposed Settlement Agreement.

	Option A	Option B	RUCO Option
ROE	9.75%	9.50%	9.50%
Revenue Increase	$54.9M	$52.6M	~~$44.6M~~ **$47.6 M**
FVROR	7.02%	6.92%	6.85%
Mechanism to compensate utility for lost fixed costs	Almost full decoupling with no cap	Full decoupling with 5% cap	No decoupling Shift more revenue into fixed monthly rate
Weather normalization period	10 years	10 years	30 years
Low Income programs	Yes	Yes	Agrees with Settlement
Commitment to energy efficiency	Yes	Yes	Agrees with Settlement
Rate Case moratorium	None	5 years	None

Q. Does that conclude your testimony?

A. Yes.

RUCO-16

State	Utility	Docket No. & Date	Outcome	Approved ROE	Credit rating prior to rate case	Credit rating after rate case	
Indiana	So. Indiana Gas & Electric	Cause No. 43839 April 27, 2011	Denies decoupling to electric utility	10.40%	2010 Moody's: A1 (stable) S&P: A (stable)	2011 Moody's: A1 (stable) S&P: A (stable)	
Tennessee	Piedmont Natural Gas	Docket No. 09-00104 June 9, 2010	Denying margin decoupling tracker rider	N/A (not a rate case)	2009 Moody's: A3 (stable) S&P: A (stable)	2011 Moody's: A3 (stable) S&P: A (stable)	
Nebraska	Source Gas	App. No. NG-0060 March 9, 2010	Denies decoupling b/c no e.e. program proposed but acknowledges declining use	9.6%	2009 Moody's: n/a S&P: n/a	2011 Moody's: Ba1 S&P: BBB	
Nebraska	Aquila	Appl. No. NG-0041 July 24, 2007	Denies "revenue normalization adjustment" Approves DSMAC-like surcharge	10.4%	2006 Moody's: Baa3 (negative) S&P: BBB- (stable) Fitch n/a	2011 Moody's: Baa3 (stable) S&P: BBB- (stable) Fitch BBB- (stable)	

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EXHIBIT
RUCO-16

Montana	NorthWestern Energy	Docket No. D2007.7.82 Order No. 7046i June 30, 2011	Denies decoupling for natural gas (in the end decoupling w/d for electric utility	10.25%	2010 Moody's: A3 (stable) S&P: BBB+ (stable) Fitch BBB+ (stable)	2011 Moody's A2 (stable) S&P: A- (stable) Fitch A- (stable)	
Connecticut	Connecticut Natural Gas	Docket No., 08-12-06 June 30, 2009	Denies decoupling and increases fixed charges to address lost fixed costs	9.31%	2008 [1] Moody's: n/a S&P: n/a	2011 [2] Moody's: Baa2 (stable) S&P: BBB (stable)	
Connecticut	Connecticut Light & Power	Docket No. 09-12-06 June 30, 2010	Denies decoupling and continued rate design of more fixed costs in non-sales charges	9.4%	2009 Moody's A2 (stable) S&P BBB+ (stable) Fitch A- (stable)	2011 Moody's Baa1 (stable) S&P BBB+ (CW-Positive) Fitch BBB (positive	
Connecticut	Yankee Gas	Docket No. 10-12-02 June 29, 2011	No decoupling mechanism offered. Utility offered rate design to shift more fixed costs out of volumetric rates	8.83%	2010 Moody's: n/a S&P: n/a Fitch n/a	2011 Moody's: Baa2 (stable) S&P: BBB+ (stable) Fitch n/a	

[1] Owned by Iberdrola S.A. prior to November 2010
[2] Acquired by UIL Holdings Corp. in November 2010

Rhode Island	National Grid	Docket No. 3943 January 29, 2009	No decoupling Weather normalization adjustment, declining block rates and future TY for known reductions in consumption.	10.5%	2008 Moody's A-3 (negative) S&P A- / A-2 (stable)	2011 Moody's A-3 / --- (stable) S&P A- / A-2 (stable)	