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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
JUN 24 2011
DOCKETED BY

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 THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS; APPROVAL OF DEFERRED ACCOUNTING ORDERS; AND FOR APPROVAL OF AN ENERGY EFFICIENCY AND RENEWABLE ENERGY RESOUCE TECHNOLOGY PORTFOLIO IMPLEMENTATION PLAN.	DOCKET NO. G-01551A-10-0458 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY ON RATE DESIGN**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Staff Witness David E. Dismukes (Public) in the above-referenced matter.

A confidential version of David E. Dismukes Direct Testimony has also been provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge, and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 24th day of June, 2011.

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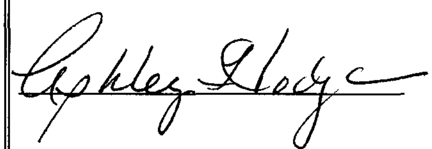

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
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BRENDA BURNS
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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

PUBLIC

DIRECT

TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

CONSULTING ECONOMIST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 24, 2011

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SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

I present testimony on three subjects regarding the Southwest Gas Corporation's ("Company") proposed: revenue decoupling mechanism, its proposed class cost of service study ("CCOSS"), and its proposed rate design. Staff recommends that the Arizona Corporation Commission ("Commission") reject the Company's proposed revenue decoupling mechanism. As an alternative, Staff recommends a lost fixed cost recovery ("LFCR") mechanism that is performance-based and would actively incent the Company to meet the Commission's energy efficiency goals, while holding the Company harmless for the revenue losses associated with meeting these energy efficiency goals. Staff recommends that the Commission modify several of the Company's CCOSS allocation factors particularly those associated with the allocation of plant investments. Staff also recommends that the Commission retain the existing level of customer charges for all customer classes and implement rates that adhere to generally-accepted rate design principles used in utility regulation.

INTRODUCTION

Q. Would you please state your name and business address?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana.

Q. Would you please state your occupation and current place of employment?

A. I am a Consulting Economist with the Acadian Consulting Group, LLC ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana, with additional staff in Los Angeles, California, and Fallon, Nevada.

Q. Do you hold any academic positions?

A. Yes. I am also a Full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I also hold an appointment as an Adjunct Professor in the E.J. Ourso College of Business Administration (Department of Economics), I am a co-director of the Coastal Marine Institute in the School of the Coast and the Environment, and I am a member of the graduate research faculty at LSU.

Q. Have you prepared any attachments to your testimony outlining your qualifications in energy and regulated industries?

A. Yes. Attachment 1 to my testimony provides my academic vita that includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. I have prepared 22 exhibits in support of my testimony.

Q. What is the purpose of your testimony?

A. I have been retained by the Arizona Corporation Commission ("ACC" or "Commission"), Utilities Division ("Staff") to provide an expert opinion on several policy and rate design proposals included in the rate filing made by Southwest Gas Corporation ("Southwest" or "Company"), before the Commission. My testimony will address the Company's revenue decoupling proposal, Class Cost of Service Study, and rate design proposals and tariff modifications.

Q. How is the remainder of your testimony organized?

A. My testimony is organized into the following sections:

- Summary of Recommendations
- Decoupling
- Class Cost of Service Study
- Rate Design
- Conclusions

SUMMARY OF RECOMMENDATIONS

Q. Would you please summarize your recommendations and conclusions regarding the Company's proposed revenue decoupling mechanism?

A. Yes. Staff recommends that the Commission should reject the Company's proposed revenue decoupling mechanism since:

- The proposed efficiency enabling provision ("EEP") mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the Company and its shareholders and onto ratepayers. Such a shifting of risk, without any corresponding mitigation or ratepayer protection measures will result in rates that are not fair, just, and reasonable.

- The inclusion of a weather component in the proposed EEP provides the Company with virtually free weather-related sales insurance without any corresponding benefit to ratepayers. Even if revenue decoupling is adopted, this aspect of the Company's EEP proposal should be rejected, without a showing of some corresponding benefit to ratepayers.

- The EEP mechanism has been offered on a permanent basis and has no review or analysis period to assess its effectiveness or the emergence of any unanticipated consequences.

- The EEP mechanism is not accompanied or tied to any verifiable, performance-based energy efficiency goals and outcomes.

- The EEP mechanism is likely to make the Company whole for changes in sales that have nothing to do with its energy efficiency efforts.

Q. Would you please describe Staff's alternative proposal?

A. Yes. Should the Commission accept the need for decoupling, Staff recommends that the Commission approve the lost fixed recovery ("LFCR") performance-based mechanism that would actively incent the Company to meet the Commission's energy efficiency goals, while holding the Company harmless for the revenue losses associated with its energy efficiency efforts if it meets the Commission's goals. If the Company is correct that cost-effective energy efficiency programs result in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals. Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

Q. If the Commission adopts the Company's proposed revenue decoupling mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Company's decoupling mechanism is approved.

- Adoption of an annual earnings review and a refund of all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

- Adoption of a three year review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the decoupling mechanism is initiated. This review should include a regulatory presumption that any lost revenue recovery mechanism will be discontinued in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.

- A three year review process that includes: (1) an energy efficiency review; (2) a revenue deferrals and collections review if full decoupling is adopted by the Commission; (3) a customer usage analysis; and (4) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both the Company's proposal to reconcile actual-to-allowed revenue, an annual earnings surveillance report, and a reconciliation of the forecasted to actual per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The three year review should be conducted by a consultant selected by Staff and funded by the Company at a level of not more than $100,000 per review.

Q. If the Commission adopts Staff's alternative mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's proposed LCFR is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should be conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether the Commission adopts a full decoupling mechanism or the LFCR recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.
- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.
- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.

- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

Q. Would you please summarize Staff's Class Cost of Service Study recommendations?

A. Yes. Staff recommends that the Commission adopt the following alternative CCOSS allocation factors:

- Distribution mains should be allocated on a 50-50 basis with 50 percent of those investments being allocated to customers and the other 50 percent allocated on non-customer factors. This differs from the Company's proposal to allocate mains investment on a 50 percent demand/50 percent customer allocation basis.

- The non-customer component of the mains investment allocator should be divided on a 50-50 commodity-demand basis.

- Measuring and regulating equipment should be allocated on a 50 percent demand and 50 percent commodity basis, instead of the 50 percent customer and 50 percent demand allocation proposed by the Company.

- Maintenance of mains should be allocated on the basis of 50 percent customers, 25 percent demand, and 25 percent commodity, consistent with the plant account associated with these maintenance activities.

- Measuring and regulating equipment – industrial should be allocated to industrial customers only, as opposed to the Company's method which allocated these costs to all customers.

- The Commission should order the Company to include the special procurement gas customers served under Schedule G-30 in the CCOSS submitted in its next rate case.

- The Commission should order the Company to develop an accounting process that explicitly identifies customer class-specific Contributions in Aid of Construction ("CIAC") in such a manner that CIAC can be appropriately assigned to the classes that paid the CIAC.

- All CCOSS errors identified by the Company in response to Staff's discovery should be corrected including those associated with the allocation of services, meters, and customer installation expenses.

Q. Would you please summarize Staff's rate design recommendations?

A. Yes. Staff's rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average and distribute any of the remaining revenue deficiency across classes earning less than three times the proposed system average increase.

- Existing customer charges should be held at their current levels.

- The Company's existing uniform volumetric rate structure should be continued.

- Volumetric rates should be increased according to the results of Staff's alternative class cost of service model and the Staff's recommended revenue requirement.

- Staff recommends the Commission reject the Company's low income class rate design proposal and continue the existing 20 percent discount on the first 150 therms of winter usage.

- For the Company's Special Residential Gas Service for Air Conditioning rate, Staff recommends a gradual move towards a uniform volumetric rate for this class until such time that the Company can support a declining block rate with class-specific cost information.

- Staff agrees with the Company proposal to separate the Large General Service class. However, the Commission should reject the Company's customer and delivery charge proposals for the Large-1 and Large-2 General Service classes. Instead, Staff recommends that the Commission decrease the customer charge of the Large-1 General Service class to $120 per month and examine further decreases in the Company's next rate case. Staff also recommends the Commission increase the customer charge of the Large 2 General Service class to $240 per month.

- Staff recommends that the Commission order the Company to close the Small Essential Agriculture tariff to all new customers.

- Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural gas consumption decisions. Staff recommends the Commission order the Company to evaluate alternative rate designs, including an inclining block rate structure for residential and commercial customers, in the next rate case. Each alternative rate design proposal offered by the Company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

- Staff recommends the Commission adopt the Company's proposed change for Rate Schedule No. B-1.

- Staff recommends that the Commission order the Company to either (a) discontinue collecting advances and CIAC that result in a return on equity that is more than 50 basis points above the allowed return, or (b) demonstrate that the Incremental Cost Model filed in this case, and used to estimate these advances, are not representative of the final advances and CIAC collected from customers.

DECOUPLING

A. Introduction

Q. What are Staff's general recommendations regarding the Company's proposed revenue decoupling mechanism?

A. Staff recommends that the Commission reject the Company's proposed revenue decoupling mechanism.

Q. What was the rationale for the Company's proposal?

A. The Company effectively bases its proposal on the assertion that regulation is ineffective in balancing the risks and rewards associated with energy efficiency investments.[1] According to the Company, traditional regulation has a number of inherent flaws that challenge its ability to promote energy efficiency and recover its revenue requirement.[2]

Q. How does revenue decoupling deviate from common regulatory principles?

A. Utility regulation is based upon a principle, developed over the past century, commonly referred to as the "regulatory compact," that defines the relationship and expectations between regulated companies and their regulators. This relationship gives regulated utilities a specific service territory and an opportunity, but not a guarantee, to earn a reasonable rate of return on, and recovery of, their prudently-incurred investments. In return, regulated utilities are obligated to provide safe, reliable, and economic service to their ratepayers at rates that are fair, just, and reasonable. Full decoupling, like Southwest's proposal, however, differs from this principle by creating an almost guaranteed revenue requirement for the Company with little to no market incentives or discipline for efficient service, and without mitigation or ratepayer protection measures.

Q. Does Staff agree with the Company's argument that its proposed EEP will better align its incentives with those of its customers?

A. No, particularly since this argument tends to overstate the financial impacts that are claimed to arise from the promotion of utility-sponsored energy efficiency. Lost base revenues associated with energy efficiency are only one of several factors that can

[1] Direct Testimony of Edward B. Gieseking, p. 5.
[2] Direct Testimony of Edward B. Gieseking, p. 7.

influence total sales revenues. Other factors include, but are not entirely limited to price, weather, and income. As a result, full revenue decoupling, as proposed by Southwest, can lead to bill surcharges for revenue changes that have nothing to do with utility-sponsored energy efficiency programs.

B. Revenue decoupling mechanisms and the proposed EEP

Q. Has the ACC issued a policy statement supportive of revenue decoupling?

A. Yes. This Policy Statement[3] is the outcome of several rounds of comments and workshops held throughout 2010. The investigation itself was the result of issues raised during the course of setting energy efficiency standards for electric utilities (December 19, 2009) and jurisdictional gas utilities (August 2010) during roughly the same period of time.

Q. What was the outcome of this workshop process?

A. The Commission issued a Policy Statement and Report at the conclusion of this process. The Report, which precedes the Policy Statement, summarizes the workshop process, identifies the parties participating in the workshop, and highlights various parties' positions. The Policy Statement itself consists of three pages and 13 specific policy bullet points.

Q. Did the ACC recognize that specific revenue decoupling guidelines were best determined in a general rate case?

A. Yes. While the ACC Policy Statement generally supports some type of revenue decoupling, the Commission also recognizes, as did most parties at the ACC's workshops,

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[3] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures. Docket Nos. E-00000J-08-0314 and G-00000C-08-0314. December 29, 2010.

that specific policies and proposals, as well as potential alternatives, can and should be considered within the context of a specific rate case proceeding. The Workshop Summary explicitly notes that:

> In response to a question 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 specific rate case proceeding.

Later, the ACC, in the Workshop Summary noted:

> The Commission believes that adoption of decoupling should occur in rate cases, with evaluation and review occurring after an initial three year period.

In the formal Policy Statement itself, the Commission notes that utilities may file a proposal for decoupling or an alternative mechanism for addressing disincentives, in its next general rate case.[4] The ACC did not adopt, require, nor mandate revenue decoupling, leaving the ultimate decision regarding revenue decoupling, and the merits of specific decoupling proposals, to be addressed in utility-specific rate cases.

Q. Did the Policy Statement recognize that alternatives to revenue decoupling could also be examined?

A. Yes. While the ACC Policy Statement offers a number of positive assertions about the use of revenue decoupling as a policy mechanism to address perceived utility disincentives to energy efficiency, it also clearly recognizes that decoupling is not the only

[4] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures. Docket Nos. E-00000J-08-0314 and G-00000C-08-0314. December 29, 2010, p. 32.

policy option available to regulators. For instance, in Policy Statement Number 3, the ACC explicitly notes that it:

> ...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 [energy efficiency goals].

In Policy Statement Number 5, the ACC notes:

> Adoption of decoupling (or any other alternative mechanisms that addresses utility disincentives to promoting energy efficiency) should not occur as a pilot, as this insufficiently supports demand side management efforts.

In Policy Statement Number 7, the ACC notes:

> Utilities are encouraged to develop customer rate designs that support energy efficiency and work well in tandem with decoupling (or alternative mechanisms).

Thus, the ACC Policy Statement clearly recognizes that common revenue decoupling is not the only mechanism that can support utility efforts in promoting energy efficiency and that it was open to the consideration of "alternative mechanisms."

C. Overview of the Company's EEP Proposal

Q. How would the Company's decoupling mechanism work?

A. Southwest proposes to implement revenue decoupling on a revenue per customer ("RPC") basis. An RPC-based mechanism is a common form of revenue decoupling that starts with the determination of an allowed RPC, typically derived from the outcome of a concurrent rate proceeding. The allowed (test year) revenue requirement, divided by the total number of test year customers is then utilized as the allowed RPC for future revenue decoupling reconciliation purposes. Future decoupling reconciliations compare actual RPC (actual revenues collected per the actual number of customers in the same reconciliation period) to allowed RPC to determine a per customer revenue deficiency or surplus. This per customer difference is then multiplied by the number of actual customers in the reconciliation period to arrive at a total revenue deficiency or surplus. This deficiency or surplus is divided by reconciliation period sales to develop a per therm surcharge or credit that will be applied to the upcoming twelve-month recovery period.

Q. Would ratepayers be subject to a single or a multiple decoupling reconciliation process under the Company's EEP?

A. Ratepayers would be subjected to multiple reconciliations.[5] For instance, the first set of decoupling reconciliations would be done on a monthly basis, and assess a surcharge or credit for weather-related deviations in heating season usage. The second set of decoupling reconciliations would be conducted at the end of the year, would true up the difference between actual and allowed revenues discussed earlier, and assess this difference on monthly bills for the upcoming 12 months.

Q. Would the Company be made whole for changes in sales created by the weather?

A. Yes. The second component of the Company's revenue decoupling mechanism includes a true-up for weather-related differences in usage during its heating season months.[6] Ratepayers would be assessed a charge (or credit) if the prior month's weather was warmer (or colder) than normal. Here, "normal" weather is defined as the rolling ten year

[5] Direct Testimony of Edward B. Gieseking, p. 3.
[6] Direct Testimony of Edward B. Gieseking, p. 3.

average of the observed heating degree days ("HDDs").[7] Weather normalized usage for each customer is estimated as the difference in HDDs (actual to normal) times the statistically-estimated average response that customers tend to exhibit when HDDs are varied. The Company estimates this average weather response, or weather sensitivity, for single family residential customers as being 0.16. In other words, a one HDD deviation from average weather tends to result in a 0.16 therm increase in usage, holding other factors constant.[8]

Q. Has the Company included any customer protection mechanisms in its proposed EEP?

A. None that are comparable to those included in the revenue decoupling mechanisms of other states. The Company is not proposing to subject its revenue decoupling mechanisms to a future review and evaluation; its mechanism is not tied to successfully meeting the Commission's energy efficiency goals; and the proposal sets a rate cap at a relatively high percentage.

Q. Has the Company provided any "back-casts" that show the impact that revenue decoupling would have on customer bills had it been previously adopted?

A. Yes. The Company provided calculations showing the impact of decoupling as if it had been in place from 2007 through 2010 in response to Staff Data Request 3-32. This information revealed that for the residential classes, the Company would have collected additional revenue ranging from $7.6 million in 2007 to $29.3 million in 2009. In total,

[7] A heating degree day ("HDD") is a measure that relates temperature to energy demand. One HDD is defined as the difference in average daily temperatures to a reference temperature of 65 degrees. If the average temperature is equal to or greater than 65 degrees, there are no HDDs for that day. If the average temperature is lower than 65 degrees, then each degree lower is counted as an HDD. See National Oceanic and Atmospheric Administration, National Weather Service, Internet website: http://nws.noaa.gov/glossary/.
[8] Response to Staff Data Request ACC-STF-3-6

for the four years, Southwest would have collected an additional $62.0 million from residential customers if its rates had been decoupled. The average annual decoupling collections would have amounted to six percent of residential test year revenue. Further, for residential customers, the Company estimates surcharges in each of the four years, dispelling any notion that the rate impacts from revenue decoupling would have been symmetrical.

Q. What were the estimated impacts for the other customer classes?

A. Smaller impacts are indicated from the general service classes. If decoupling had been in place over the past four years, the Company would have collected an additional $3.9 million from customers with an annual average surcharge of close to $1 million, or one percent of test year revenue. Although the Company estimates that there would have been a total revenue increase for the entire general service class, the small and medium general service customers would have witnessed rate decreases with decoupling.

D. Rationale for Decoupling

Q. What are the purported disincentives to utilities to promote energy efficiency?

A. Some energy efficiency advocates, as well as many (but not all) utilities, argue that current regulatory pricing practices discourage utility-sponsored energy efficiency programs. These supporters note that energy efficiency reduces sales thereby reducing a utility's ability to recover its fixed costs. One of the primary reasons for the Company's revenue decoupling proposal is to address its claims that there is a mismatch between the financial interests of its customers and its shareholders regarding energy efficiency.[9]

[9] Direct Testimony of Edward B. Gieseking, p. 5.

Q. How does revenue decoupling address this claimed disincentive?

A. The general premise behind revenue decoupling is that it removes the relationship between the collection of a utility's revenue requirement and its sales, thereby removing the disincentives to pursue end user efficiency programs. For instance, under the Company's revenue decoupling approach, changes in sales revenues would be compared with benchmark revenue amounts.

Q. Are sales decreases due to energy efficiency the only source of differences between test year (allowed) and actual revenues?

A. No. There are a variety of other reasons why retail sales and revenues in any given year can differ from the test year amount. These impacts are usually much larger than sales losses created by energy efficiency programs. Consider that test year retail sales and revenues in a rate case are usually based upon a "typical" year and as such, are based upon typical factors such as the weather, the economy, and prices, among other things. In any given year, the actual performance of the economy may differ from the test year. Weather may be colder or warmer than the historical normal weather trends included in the test year, and other factors may occur in any given year that impact sales differently than what was anticipated in the test year determination. The differences in sales created by weather, the economy, commodity prices, and other factors usually account for greater changes in revenue than those resulting from utility-sponsored energy efficiency programs.

Q. What factors have motivated renewed interest in revenue decoupling?

A. Revenue decoupling attained a new level of interest around 2004 to 2005 due to (1) past increases in natural gas prices which have impacted overall usage and (2) the significant acceleration of state-driven energy efficiency ("EE") goals and targets. Exhibit DED-1 presents a map that shows EE goals that many states have recently adopted hoping to attain demand reduction levels by as much as 15 to 20 percent by 2015.

Q. Are natural gas and electric utilities facing similar usage trends?

A. No. Natural gas utilities, including Southwest in this proceeding, have suggested an additional motivation for promoting revenue decoupling associated with decreasing residential usage per customer ("UPC") over the past several years.[10] Electric utilities have not been facing similar decreasing UPC trends. In fact, electric utilities have seen UPC trends that generally move in opposite directions from those seen in the natural gas industry. The chart in Exhibit DED-2 compares overall U.S. electric and natural gas UPC trends over the past 19 years. While electric UPC has been generally increasing over this same period, natural gas UPC has been generally decreasing.

Q. What level of lost base revenue can be expected for Southwest as a result of meeting the Commission's energy efficiency goals?

A. Exhibit DED-3 shows the Company's historic and forecasted annual lost base revenues that are created by the Commission's annual energy efficiency goals. These lost base revenues do not exceed 0.7 percent of forecasted base revenues in any given year.

Q. What factors are influencing UPC if energy efficiency savings are not significantly impacting utility revenues?

A. A number of factors influence sales including weather, income, commodity prices, as well as structural usage changes created by new and more efficient appliance standards. More recently, the recession and its consequences of unemployment and belt tightening have

[10] Direct Testimony of Robert A. Mashas, pp. 4, 6-7; Direct Testimony of James L. Cattanach, p. 10.

contributed to a reduction in usage by customers. As noted earlier, natural gas commodity prices have changed dramatically over the past eight years starting during the winter of 2000-2001 and particularly in the aftermath of Hurricanes Katrina and Rita in 2005. These collective changes have had considerable impacts on recent changes in total residential UPC.

Q. How does the promotion of market transformation programs impact sales?

A. Market transformation is commonly associated with informational and educational programs designed to change consumer perceptions about energy use and efficiency. Education, however, is a long-term proposition and the results of these market transformation programs will likely be embedded (and difficult to separate) from the trend in usage per customer.

E. Revenue Decoupling and Weather Normalization

Q. Why has the Company's revenue decoupling mechanism included an adjustment for weather?

A. The Company's request appears to be based upon the fact that a weather adjustment opportunity was discussed, and eligible for future consideration, in the Commission's prior Policy Statement.[11] The Company suggests that the weather normalization adjustment ("WNA") component of its revenue decoupling mechanism is designed to provide immediate relief to customers from extreme weather events.[12] However, a close examination of past weather trends shows that the Company and its shareholders would have attained greater relief from this mechanism than ratepayers.

[11] Arizona Corporation Commission, "ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures," p. 32

[12] Response to Data Request RUCO-2-10.

Q. What are the common arguments that utilities have offered for WNA mechanisms?

A. Utility justifications for WNAs typically rest upon two premises. The first is that the regulatory process is deficient and unable to set rates correctly since actual sales and revenues are almost certain to never coincide. The second is that changes in sales are inherently risky, and the Company should be insulated from this risk by a true-up mechanism that allows it a level of revenues that is unaffected by weather.

Q. Does Staff agree with the premise that weather risk is symmetrical?

A. No. On some occasions, utilities, in making WNA proposals, will make the claim that weather risk is symmetrical and that WNA mechanisms can serve as a balancing mechanism between customers and utilities. That is not the case in this proceeding as the Company has not attempted to make this claim. The typical utility argument justifying the implementation of a WNA mechanism is that these mechanisms will effectively "institutionalize" long run weather trends: in some periods, rates will be increased due to warmer-than-normal temperatures and in other periods, rates will decrease to reflect colder-than-normal temperatures. Under this logic, in the long run, the colder-than-normal cycles will offset the warmer-than-normal cycles, resulting, on average, in a zero gain to either party (e.g., utility, ratepayers).

Q. Do these mechanisms tend to be symmetric?

A. Usually not and the degree of asymmetry inherent in the mechanism will in large part be a function of how the mechanism is constructed, the time period between rate cases, and the weather cycles under which the mechanisms are evaluated. It is quite possible that these mechanisms can be pure risk-shifting mechanisms placing greater weather-related sales risk on customers and away from utilities and their shareholders.

Q. Have any regulatory commissions revised their approval of a WNA because of this risk asymmetry?

A. Yes. The Connecticut DPUC noted that WNA clauses are not symmetrical in the benefits shared between the utility and ratepayer. In a recent Southern Connecticut Gas Company ("Southern") decoupling proceeding, the utility noted that it has received significantly greater benefits than ratepayers over a 15 year period. The DPUC noted that "Southern received a total of $43.6 million in net WNA revenue" over a 15 year period and that the utility's "ROE has benefitted significantly."[13] Exhibit DED-4 provides a table, based upon data developed by Southern, that was cited by the DPUC as providing evidence regarding asymmetric WNA benefits accruing to the utility.

Q. Did the Connecticut DPUC draw any conclusions from this analysis?

A. Yes. The DPUC noted:

> The WNA has not performed as the Department had believed it would when its continuation was allowed in the 2000 Decision. To date, the WNA has been <u>one-sided in favor of the Company</u>. As stated earlier, the Department was of the belief that the ROE would be reduced in future years and that the <u>revenue flows would average out over the 30-year normal weather period</u>. The WNA is now half-way through the 30-year averaging period and <u>neither has happened</u>. The 85 basis point average bonus to the ROE has now increased to 93 basis points and the Company is nearly $44 million better off with the WNA than without. Further, what was deemed an "accident of history" by the Department in the 2000 Decision has actually continued on a trend of warmer than normal weather in 12 of the 15 years since the WNA was established. Unless the weather pattern turns colder than normal for the majority of the remaining years of the 30-year cycle, the revenue flows will have little or no opportunity to average-out, and the benefit between ratepayers and the Company will not equalize as expected. Because there is no guarantee that the current weather

[13] Application of the Southern Connecticut Gas Company for a Rate Increase. Connecticut Department of Public Utility Control. Docket No. 08-12-07. Order Dated July 17, 2009, emphasis added.

> trend will reverse itself, the Department finds that <u>continuing the WNA would not be in the public interest</u>.
>
> Consequently, the Department hereby abolishes Southern's WNA. Effective with new rates, Southern is directed to cease applying the WNA to customer bills. The Department reserves for a future proceeding any determination regarding the historic operation and financial impact on the company and ratepayers of the WNA.[14]

Q. Does Staff think weather-related risk is symmetrical under the Company's proposal?

A. No, based on to the information included in the Company's application and testimony. Under the status quo, the Company would continue to deal with the risk of any potential losses (or gains) in sales associated with changes in weather. The Company itself has repeatedly noted that this is a risk that somehow compromises its ability to earn its revenue requirement and represents a fundamental shortcoming in its interpretation of traditional regulation.[15] Thus, approval of the Company's proposal would be a net shifting of risk away from itself and onto customers.

Q. Are the historic weather trends symmetrical in the Company's service territory?

A. No. Exhibit DED-5 shows that the difference between actual heating degree days and normal heating degree days ("normals") for the residential rate class (G-5) has been consistently skewed against ratepayers in samples based upon 3, 5, 7, and 10-year periods ending January 2011.

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[14] Application of the Southern Connecticut Gas Company for a Rate Increase. Connecticut Department of Public Utility Control. Docket No. 08-12-07. Order Dated July 17, 2009, emphasis added.
[15] Direct Testimony of Theodore K. Wood, p. 7.

Q. Is the historic usage change resulting from these biased differences significant?

A. Yes. Exhibit DED-6 shows that the usage from these warmer-than-normal biases was relatively significant over the 3, 5, 7, and 10-year sample periods.

Q. Is a WNA component required as part of a decoupling mechanism?

A. No, and a number of states that have adopted revenue decoupling mechanisms, such as Colorado, Idaho, Michigan, Minnesota and Washington, have explicitly done so without a weather adjustment component.

Q. Would Staff recommend approval of a WNA if these weather trends were exactly symmetrical?

A. No, since there would be no need for a WNA. A symmetrical WNA would balance revenue losses with gains over the long run, rendering the need for a WNA moot.

F. Washington Utilities and Transportation Commission's ("WUTC") Evaluation of Decoupling

Q. What mechanisms did the WUTC define as being appropriate and associated with the "direct" actions of utility energy efficiency efforts?

A. The WUTC states that it will only consider a "limited decoupling mechanism," in the context of a general rate case, and conditioned any consideration of a limited decoupling proposal entirely upon a utility's level of energy efficiency achievement:

> The Commission remains receptive to recovery of lost margin attributable to company-sponsored conservation programs and company-sponsored education and information programs. The Commission generally will not consider approving mechanisms that permit recovery of lost margin not attributable to a company's conservation efforts, such as conservation not supported by a utility's above–stated conservation efforts, customer-

initiated fuel substitution and other responses to price elasticity, or increased stringency of energy or building codes and standards.[16]

G. Staff's Alternative Recommendations

Q. Can Staff please explain its alternative recommendation?

A. Yes. One of the problems with true revenue decoupling is that by decoupling revenues and costs from sales, revenue decoupling can also decouple a primary determinant of performance from rates. If left unchecked, rates may start to reflect accumulated inefficiencies and potentially over-capitalization. There are alternative methods, however, that can preserve the traditional performance/rate relationship by tying any lost fixed cost recovery amounts to energy efficiency savings.

Q. Can you explain how this lost fixed cost recovery ("LFCR") mechanism would work?

A. Yes. A LFCR mechanism would tie the Company's performance in its energy efficiency efforts to potential lost base revenue recovery. If Southwest is correct, that the deployment of cost-effective energy efficiency results in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals.[17] Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

[16] In the Matter of the Washington Utilities and Transportation Commission's Investigation into Energy Conservation Incentives. Washington State Utilities and Transportation Commission. Docket-100522. Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed their Conservation Targets. November 4, 2010.

[17] Direct Testimony of Edward B. Gieseking, p. 7

Q. How would the LFCR be collected from customers?

A. The LFCR would be a separate surcharge included on each customer's bill, much like a gas adjustment surcharge.

Q. How would this mechanism work?

A. The mechanism would effectively allow the Company to recover its first year lost base revenues that could arise as if 100 percent of its first year energy efficiency goals were achieved. Using the Staff recommended rates and the Company's 2011 energy efficiency saving goal of 2,281,000 therms, Staff estimates 2011 lost base revenues to be approximately $1,313,481. Dividing this amount by applicable 2010 therms of 615,748,565 yields a 2011 surcharge of $0.00213 per therm.

Q. How would the next reconciliation work?

A. The Company would be allowed to recover, through a per unit surcharge, the total amount of the anticipated 2012 lost base revenues assuming it achieves 100 percent of its 2011 energy efficiency savings. This amount would be trued-up to actual lost base revenue in the April 2013 reconciliation process. If the Company does not meet 100 percent of its 2012 energy savings goals, the difference between the 100 percent it was allowed to collect and the actual lost revenue would be refunded to ratepayers during the 2013 reconciliation process. In addition, if Southwest does not meet its 2012 savings goals, it will not be allowed to recover its estimated lost base revenue for 2013. The Company will only be allowed to recover upcoming estimated lost revenue if it meets or exceeds the prior year's energy savings goals.

Q. How would adjustments be made?

A. Each year, the Commission would undertake a reconciliation process, much like the one proposed under the Company's decoupling mechanisms. However, under Staff's alternative, the Company's actual energy efficiency savings would be compared to the Commission's current efficiency goals. If the Company attains 100 percent of its required energy efficiency goals at the time of the reconciliation, it would be allowed to increase its surcharge amount to a level comparable to the lost base revenues anticipated for the next year's energy efficiency activities. If the Company fails to reach those goals, there would be no surcharge allowed for the upcoming year's lost base revenues.

Q. What would happen if the Company exceeds its energy efficiency goals in any reconciliation period?

A. The Company would only be allowed to recover 100 percent of the upcoming year lost base revenues. However, the Company would be permitted to recover, through the surcharge, in the following year the difference between 100 percent collected from customers and the actual amount of lost base revenues associated with attaining energy saving greater than 100 percent of the year's goal, as limited by yearly targets in the energy efficiency rules.

Q. Would usage changes related to weather be included in Staff's alternative proposal?

A. No, since changes in usage that were created by the weather are not related to the Company's energy efficiency performance.

Q. How would the reconciliation process work?

A. The reconciliation period would begin April 1 of each year with the filing of the Company's DSM report as currently required for the preceding year. In this filing, the

Company would file its energy efficiency savings and lost revenue information along with all supporting calculations and documentation for the calendar year. This filing would also include the surcharge calculation for the upcoming year. For example, the Company's 2012 filing would be based upon calendar year 2011 energy efficiency savings. Staff would review the LFCR filing within 60 days. If Staff finds problems with the filing, those problems would be taken to the Commission for further resolution. If there are no problems with the Company's filing, the surcharge would take effect June 1.

Q. Should an independent audit and evaluation be performed in order to confirm compliance with the Commission's Gas Energy Efficiency rules and/or or adjust the savings reported in the Company's annual DSM progress report, as filed each April 1st?

A. Yes. Staff has proposed an adjustor mechanism to permit recovery of lost revenue to recover possible stranded fixed costs due to the Company's efforts to meet the Commission's gas energy efficiency standards. An independent audit/evaluation would ensure that recovery through this mechanism is based on the most accurate possible determination of the energy savings achieved. Such an audit/evaluation will also be useful for ensuring that the savings achieved by the Energy Efficient and Renewable Energy Resource Technology Portfolio ("EE and RET Portfolio") are commensurate with the level of ratepayer funding.

Q. How should the independent audit and evaluation be performed?

A. The audit/evaluation should be performed by an independent consultant selected by Staff, at a time to be determined by Staff, and may include, but not be limited to, the following elements:

- Verifying the correct installation of a sampling of DSM and RET measures;
- Verifying the therm, or therm equivalent, savings per measure in a sampling of DSM and RET measures;
- Verifying the therm, or therm equivalent, savings in a sampling of DSM or RET programs;
- Reviewing calculations relating to the portfolio or energy efficiency savings for accuracy;
- Determining whether any baselines utilized for determining energy savings should be reset due to changes in appliance or building standards;
- Determining whether participation levels are reported accurately;
- Evaluating any education or assessment programs to determine whether they are leading to energy savings due to an increased awareness about energy use and opportunities for saving energy; and
- Evaluating Southwest's claims of savings related to changes in building and appliance standards to verify savings from those changes, and to verify that Southwest's efforts to support the adoption and implementation of the new standards have been adequately demonstrated and documented.

Q. How should the independent audit and evaluation be funded?

A. Staff would select an independent consultant using the Request for Proposal process and would oversee the audit/evaluation, but Southwest would be responsible for funding the audit/evaluation for up to $50,000.

Q. What does Staff see as the benefit of its proposal relative to the Company's requested decoupling mechanism?

A. Staff believes that its LFCR proposal offers a number of advantages over the Company's full revenue decoupling mechanism. The LFCR will:

- Re-couple performance, cost, and revenue recovery in a fashion consistent with the best practices and traditions of utility regulation.

- Preserve traditional risk relationships in utility regulation with the Company bearing risks associated with both its costs and the overall business environment in which it operates.

- Remove disincentives for energy efficiency by creating positive (not neutral) incentives.

- Remove the increasingly-recognized deficiency created by full revenue decoupling that could allow utilities to collect revenue deficiencies that far exceed their energy efficiency efforts.

H. Ratepayer Protection Mechanisms

Q. Are ratepayer protection mechanisms commonly adopted with revenue decoupling?

A. Yes, and Staff has surveyed some of these provisions for utilities that have approved revenue decoupling plans in Exhibit DED-7. Various states have used one or a combination of the following protections in the development of their respective revenue decoupling mechanisms:

- Recovery Structures: This type of protection mechanism typically limits the range of revenue recovery for a utility under decoupling. One example of this is Colorado's approach that only allows revenue recovery in instances where UPC falls by more than 50 percent of the five year average decrease. Another would be Washington's approach that caps total recoveries to 45 percent of all revenue deferrals and conditions recovery of that 45 percent on the utility's energy efficiency performance.

- Recovery Limitations: This type of protection restricts the amount of revenue that can be collected in any period by some fixed amount. Examples include Oregon's original approach that limits revenue recovery to only 90 percent of the difference between actual and allowed margins, and Indiana's provisions for its gas utilities that restricts revenue recovery to only 85 percent of the difference between allowed and actual margins.

- Caps on Accruals: This approach is common among approved decoupling mechanisms and caps the amount of overall accrual to some pre-defined percent of total revenues or some other measure. An example would be Utah's limitation on recovery balances of one percent of total revenues or Wisconsin's 100 basis point limitation.

- DSM Targets or Goals: Many programs either require DSM targets or goals to be a companion of the adoption of revenue decoupling. Some commissions, like the WUTC, actually tie revenue decoupling recoveries to EE achievement. The purpose of these types of protections is to ensure that the benefits created by utility energy efficiency programs are balanced against the cost of potential revenue decoupling surcharges.

- Annual Filings and Periodic Reviews: Many programs require utilities to file information on balances and true ups periodically and many limit the adoption of revenue decoupling programs to a fixed period for a review on potential unanticipated consequences.

Q. Should the Commission adopt ratepayer protection mechanisms?

A. Yes. The Commission should adopt ratepayer protection mechanisms under either the Company's full decoupling approach or under the Staff's proposed LFCR. Staff will first present the ratepayer protection mechanisms for a full revenue decoupling approach like the one proposed by the Company and then its LFCR.

Q. Should the Commission adopt a rate cap under the Company's decoupling proposal?

A. Yes. If the Commission accepts the Company's proposal, it should cap deferrals to one percent of total revenues. This level is consistent with many other state revenue cap provisions for revenue decoupling.

Q. What about a hard earnings cap?

A. Yes. If the Commission approves the Company's revenue decoupling mechanism, Staff recommends that the Commission require an annual earnings review. The Company should be required to refund all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

Q. Does Staff recommend any other ratepayer protections?

A. Yes. The Company's energy efficiency performance, under full revenue decoupling, should be examined after a three-year period. The regulatory review at the end of the fixed period should be clearly defined and should be based upon a regulatory presumption that the Company's proposed revenue decoupling mechanism will be discontinued unless the Company can clearly demonstrate that its disincentives for the promotion of energy efficiency have been eliminated and the mechanism served its intended purposes.

A three-year review period is similar to the time periods that have been accepted in other states approving revenue decoupling proposals. Three years seems to be a long enough period to evaluate meaningful changes in the Company's promotion of energy efficiency, but not so long as to allow unanticipated consequences of revenue decoupling from becoming unmanageable.

Q. What review criteria should the Commission include in this process?

A. The Commission should consider adopting several criteria in its evaluation process that are similar to those adopted in other states. Review criteria could fit into four general categories that would include: (1) an energy efficiency review; (2) a revenue deferrals and collections review; (3) a customer usage analysis; and (4) other review criteria that are defined by the Commission, the Company and other stakeholders.

Q. What should be included in the energy efficiency part of the review?

A. A review of the Company's energy efficiency activities is important in understanding the role that revenue decoupling mechanisms play in removing the purported disincentive to promoting energy efficiency. Some of the potential areas of review should include, but not be limited to:

- A comparison of pre- and post-review period energy efficiency performance primarily focused on program participation and energy savings. Goals should be set and the Company's ability to attain these goals should be monitored both annually and during the review process through an "Evaluation, Monitoring, and Verification" process ("EM&V").

- An analysis of the scope, magnitude, and innovation with which the Company is promoting energy efficiency.

- An analysis of the incremental energy efficiency program offerings and/or expansions from current practices.

- An analysis of the changes in the avoided costs impacting energy efficiency program participation and savings and the degree to which non-participating customers attained capacity related savings from the Company's energy efficiency programs.

- An analysis of energy efficiency expenditures per program.

- An analysis of the breadth of energy efficiency program offerings across various customer classes.

- A comparison of actual energy efficiency savings to those included in the Company's long run planning process.

Q. Should the Commission review the Company's revenue deferral and collection experience?

A. Yes. If the Commission accepts the Company's revenue decoupling proposal then there needs to be careful scrutiny on the mechanism's deferrals and collections. Some of the areas of analysis in this category of review should include, but should not be limited to:

- An analysis of monthly, seasonal, annual, and cumulative revenue deferrals and balances.
- An analysis of any changes made to the deferral calculations.
- Comparison of estimated deferrals to those suggested in the rate case.
- An analysis of the potential impact of deferrals on earnings and overall returns.
- An analysis of the bill impacts associated with the decoupling mechanism.
- An analysis of the interest or carrying charges associated with the deferrals, if these types of costs are allowed.
- An analysis of the actual direct lost margin associated with the Company's total and incremental DSM efforts.

Q. Are there any additional criteria Staff would recommend including?

A. The Commission could include other important review criteria, particularly if it accepts the Company's revenue decoupling proposal. Two additional analyses that may not fit neatly into the categories defined above, but may be nonetheless equally important, could include:

- The degree to which the Company's corporate culture regarding the promotion of energy efficiency has meaningfully changed as a result of the adoption of revenue decoupling.

- An analysis of financial market perceptions of the Company's revenue decoupling mechanism and its potential impact on earnings.

Q. Should the Company be required to make any annual filings if the Commission adopts revenue decoupling mechanism?

A. Yes. The Company should be required to make annual filings with the Commission, including the Company's proposal to reconcile actual-to-allowed revenue. In addition, the Company should be required to provide an annual earnings surveillance report, as well as a per measure/per customer class reconciliation of its actual and forecasted energy efficiency savings and participation levels.

Q. If the Commission adopts Staff's LCFR, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's LCFR mechanism is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should be conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether it adopts a full decoupling mechanism or the LFCR mechanism recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.
- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.
- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.
- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

I. Recommendations and Conclusions

Q. Would you please summarize your decoupling recommendations and conclusions?

A. Yes. Staff recommends that the Commission reject the Company's proposed revenue decoupling mechanism since:

- The proposed EEP mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the Company and its shareholders and onto ratepayers. Such a shifting of risk, without any corresponding mitigation or ratepayer protection measures, will result in rates that are not fair, just, and reasonable.

- The unnecessary inclusion of a weather component in the proposed EEP provides the Company with virtually free weather-related sales insurance without any corresponding benefit to ratepayers. Even if revenue decoupling is adopted, this aspect of the Company's EEP proposal should be rejected, without some corresponding benefit to ratepayers.

- The EEP mechanism has been offered on a permanent bases and has no review or analysis period to assess its effectiveness or the emergence of any unanticipated consequences.

- The EEP mechanism is not accompanied or tied to any verifiable, performance-based energy efficiency goals and outcomes.

- The EEP mechanism is likely to make the Company whole for changes in sales that have nothing to do with its energy efficiency efforts.

Q. What are Staff's recommendations?

A. Should the Commission accept the need for decoupling, Staff recommends that the Commission approve the LFRC performance-based mechanism that would actively incent the Company to meet the Commission's energy efficiency goals, while holding it harmless for the revenue losses associated with its energy efficiency efforts if it meets the Commission's goals. If the Company is correct that cost-effective energy efficiency programs result in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals. Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

Q. If the Commission adopts the Company's proposed revenue decoupling mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Company's decoupling mechanism is approved:

- Adoption of an annual earnings review and a refund of all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

- Adoption of a three year review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the decoupling mechanism is initiated. This review should include a regulatory presumption that any lost revenue recovery mechanism will be repealed in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.

- A three year review process that includes: (1) an energy efficiency review; (2) a revenue deferrals and collections review if full decoupling is adopted by the Commission; (3) a customer usage analysis; and (4) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both the Company's proposal to reconcile actual-to-allowed revenue and an annual earnings surveillance report, and also identify per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The three year review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $100,000 per review.

Q. If the Commission adopts Staff's alternative mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's alternative mechanism is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether the Commission adopts a full decoupling mechanism or the LFCR recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.

- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.
- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.
- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

CLASS COST OF SERVICE STUDY

A. Introduction

Q. What is the purpose of a class cost of service study?

A. A class cost of service study ("CCOSS") is a method by which utility costs are allocated to different customer classes in order to set rates. The goal of the study is to determine the cost of providing service to each customer class and the revenue contribution each class makes in covering its allocated costs. A CCOSS generates a class-specific revenue requirement that can be used as a starting point in setting rates.

Q. How is a CCOSS performed?

A. Typically the CCOSS is performed in three distinct steps: functionalization, categorization, and allocation. The first step in this process, functionalization, simply identifies costs by their activity type or function. For instance, costs associated with transmitting natural gas are "functionalized" as transmission costs, and costs associated with providing distribution service are identified (functionalized) as distribution-related. This process continues until all costs are allocated to some type of operational function. The next step of the process "categorizes" each of these respective costs into a particular type including demand-related costs, commodity-related costs, or customer-related costs. The last step of the process "allocates" each of these costs to a respective customer class.

Q. Is this a relatively simple process?

A. No, since some costs can be clearly identified and directly assigned to a function or category, while several others are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what is known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize into any one particular function or category. Unique allocation factors, therefore, are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and imbued with various interpretations and emphases.

Q. Earlier, you referenced a categorization process. Can you please define the three major categories of costs included in a CCOSS?

A. Yes. These categories include demand-related costs, customer-related costs, and commodity-related costs. Demand-related costs are associated with meeting maximum gas flow requirements. Transmission and large distribution mains are designed, in part, to meet peak demand day requirements such that natural gas can be delivered to households, businesses, and industries under peak load conditions usually motivated in part by weather-related usage and general economic growth. Gas supply contracts can also have a capacity component that is demand-related.

Q. How are commodity-related costs defined?

A. Commodity-related costs are defined as those that tend to change with the amount of throughput (volume) sold or transported. High pressure mains can also be allocated on some measure of throughput.

Q. What about customer-related costs?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. Have you prepared an exhibit that compares the Company's allocation factors to the Staff recommended allocation factors?

A. Yes. Exhibit DED-8 compares the factors proposed by the Company to Staff recommendations. The first column lists the account name, and the second and third columns compare the Company's proposed allocation methods against Staff's recommendations, respectively.

B. Alternative CCOSS Allocation Factors and Recommendations

Q. Do you disagree with any of the assumptions or allocation factors incorporated in the Company's proposed CCOSS?

A. Yes. I disagree with a number of the allocation factors and assumptions used by the Company in its CCOSS including:

- The assumptions used by the Company to allocate distribution and other plant-related costs and expenses.
- The Company's treatment of CIAC.

- The omission of special gas procurement customers under Schedule G-30, Optional Gas Service, from the CCOSS.
- Some minor mistakes in the Company's CCOSS which it has agreed to in response to discovery have been corrected.

C. Plant Allocation Factors

Q. Can you please explain the Company's methodology for allocating distribution mains?

A. Yes. The Company's distribution mains plant allocation factor is based upon the premise that costs are created by (a) customers interconnected to the system and (b) the demand occurring on the Company's distribution system. The Company proposes a mains allocation factor based upon a 50 percent demand-based component and a 50 percent customer-based component.

Q. How should the non-customer portion of the distribution mains be allocated?

A. Staff recommends that the Commission allocate these costs on a 50-50 demand/commodity basis since these costs are partially peak related, and partially related to serving gas distribution needs throughout the course of the year. For instance, the distribution mains account includes investments that are used to regulate, measure, and treat natural gas not just during the peak, but throughout the entire year. Some throughput share should be included in the allocation factor given the peak and off-peak functions of the investments included in this account. Similarly, distribution mains serve both peak day and non-peak day loads. Allocating the non-customer portion of these investments on strictly a demand-basis does not consider the off-peak functions of these investments. Thus, including some small volumetric component is reasonable.

Q. Do cost of service manuals such as those published by the National Association of Regulatory Utility Commissioners ("NARUC") and the American Gas Association ("AGA"), support the exclusive use of demand-based allocation factors?

A. No. The NARUC Gas Distribution Rate Design Manual ("NARUC Manual") recognizes that a cost of service study often requires making a series of potentially controversial choices in allocating costs.[18] For instance, the NARUC Manual recognizes:

> The multiplicity of available methods (which in fact reflects the insoluble nature of the problems) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses. ...
>
> [t]he most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.[19]

Likewise, the AGA Gas Rate Fundamental's publication addresses a variety of allocation methods including the average and excess, Seaboard, and United methods of allocating costs. All three methods include a commodity component in the demand formula.[20]

Q. Do you have any other differences in the Company's plant allocation assumptions?

A. Yes. The Company allocated Account 385, Measuring and Regulating Equipment – Industrial on a 100 percent commodity basis, to all customers, including residential. These investments, however, should be allocated directly to industrial customers since

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[18] The National Association of Regulatory Utility Commissioners' ("NARUC") Gas Distribution Rate Design Manual, p. 30.
[19] The National Association of Regulatory Utility Commissioners' ("NARUC") Gas Distribution Rate Design Manual, pp. 26-27.
[20] American Gas Association, Gas Rate Fundamentals, pp. 144-145.

they do not serve any other customer classes, particularly residential. These costs should also be categorized as being 50 percent demand and 50 percent commodity related.

Q. Do you have any remaining differences of opinion with the Company's plant allocation assumptions?

A. Yes. Staff disagrees with the Company's using a 100 percent demand-based allocation factor for allocating the cost of distribution plant in Account 374 (Land and Land Rights) and Account 375 (Structures and Improvements). The Company's proposed allocation is inconsistent with the same allocation factors used for plant that leverages these investments; namely, Mains (Account 376) and Measuring and Regulating Equipment (Account 378). Staff recommends that, for consistency purposes, the Commission use a composite factor consisting of Mains and Measuring and Regulating Equipment that has been provided on Exhibit DED-8.

Q. Is there a standard CCOSS model?

A. There is no standard methodology for designing a CCOSS and many different methods have been approved by state commissions. For that reason, the CCOSS should be used as a general guide only and is but one of many considerations in designing rates.

D. Customer Class Exclusions

Q. Did the Company exclude any customer classes from its CCOSS?

A. Yes. The Company excluded special gas procurement agreement customers that sign separate contracts with Southwest under Schedule G-30, Optional Gas Service. The Company simply allocated the Schedule G-30 revenues (based upon net operating margin of each class) as a credit across the remaining customer classes included in the CCOSS. Not explicitly accounting for this customer class in the CCOSS potentially masks its true contribution, and even subsidy. The fact that the Commission, at some point in the past, approved these contracts, and that those past contract terms may have covered their respective cost of service at some point in the past, does not serve as a basis for their continued exclusion from a full CCOSS. The Commission should be apprised of the current and ongoing cost characteristics of these customers, relative to the past terms and conditions under which the original contracts were signed. The inclusion of these customers, as an individual class, will also provide information to the Commission, on a forward-going basis, about the relative cost of service characteristics of this class that may be useful in reviewing future proposed special contracts.

Q. What are your recommendations regarding the omission of Schedule G-30, Optional and Special Gas Service customers from the CCOSS?

A. Staff recommends that the Commission order the Company to provide a CCOSS in its next rate case filing that includes all Schedule G-30 customers as a separate class.

E. CIAC Allocation

Q. Would you describe the deficiencies with the Company's CIAC allocation?

A. Yes. The Company did not adequately distribute CIAC credits to each of its respective rate classes since it claims that it cannot identify the per-customer class amount of CIAC in rate base. The Company explains this omission, in part, in response to Staff Data Request 27-3, on the fact that the FERC Uniform System of Accounts ("USOA") does not contain a specific account to record CIAC. The Company suggested that there might have been such an account, but it was discontinued more than 30 years ago.[21]

[21] Response to Data Request ACC-STF-27-3.

Q. Is the Company's adherence to the FERC chart of accounts adequate?

A. No. CIAC is collected for purposes of installing new extensions to customers. The Company's record keeping should be sufficient enough to identify the customer classes under which CIAC was collected, as well as the account to which it was booked. Under the Company's cost allocation methodology, the CIAC is effectively allocated to the customer classes on the basis of the plant in service to which it was booked. The problem with this assumption is that there is no guarantee that the resulting allocation percentage closely matches the amount of CIAC actually collected from each customer class. It is likely that there could be differences between the assumed amount of CIAC that is allocated to each customer class in the CCOSS and the amount that was actually paid.

Q. What are your CIAC allocation factor recommendations?

A. Staff recommends that the Commission order the Company to maintain its books and records in a manner such that CIAC, accumulated CIAC, and amortization of CIAC can be directly assigned to the class from which the funds are collected. Direct assignments, where available, should be the preferable approach in assigning costs (or credits in this case) to customer classes.

F. Expense Allocation Factors

Q. Would you discuss your disagreements with the Company's expense account allocations?

A. Yes. Staff's disagreements with the Company's expense account allocations are similar to those expressed earlier in Staff's plant allocation recommendations. Expense allocations for plant investments should be allocated in a fashion comparable to the investments those expenses are intended to support. For example, the Company allocates the cost of Account 886 (Maintenance of Structures & Improvements) on a 100 percent demand basis. Staff, instead, recommends a 50 percent customer, 25 percent demand, and 25 percent commodity allocation factor, consistent with my plant account recommendation discussed earlier. Likewise, the Company used an allocation factor consisting of 50 percent customer and 50 percent demand for mains expenses. Staff recommends a mains expense allocation factor based upon a 50 percent customer, 25 percent demand, and 25 percent commodity basis. The Company also allocates Account 889 (Maintenance of Measuring & Regulating Station Equipment) on a 50 percent customer and 50 percent demand basis. However, Staff recommends that these expenses be allocated on the basis of 50 percent commodity and 50 percent demand since the maintenance activities for these assets, like the assets themselves, are more closely related to demand and delivery than the number of customers on the system.

Q. Would you please discuss the mistakes the Company discovered in its CCOSS?

A. Yes. In response to Staff Data Requests 27-7 and 27-9, the Company explained that it had uncovered some errors in its CCOSS. The corrections identified by the Company include:

- In developing the weighted service cost to allocate costs in Account 380, Services, Southwest inadvertently used the residential service cost to weight the small general service category.[22] Staff corrected this in its recommended CCOSS by using the small general service cost to weight the cost of services.

[22] Response to Staff Data Request ACC-STF-27-9.

- Southwest unintentionally transposed the medium and small general service classes' service costs.[23] Staff's recommended CCOSS applied the correct service cost to the correct customer category.

- Southwest used one-half of the residential service cost for the residential Compression Natural Gas ("CNG") class. Staff's recommended CCOSS used the full amount of the residential service cost.[24]

- The Company included $23,682 for the service cost to Essential Agricultural class. Southwest, however, states that this amount is not representative and a cost of $5,660 is more appropriate: this correction has been included in Staff's recommended CCOSS.[25,26]

- The service costs for the medium and large general service were transposed and have been corrected in Staff's recommended CCOSS.[27]

- The Company inadvertently used the incorrect service cost for gas lights; Staff used the correct amount in its recommended CCOSS.[28]

- The Master Metered Mobile Home classes' meter cost should be changed from $251 to $618. Southwest states that it used the cost of a Medium General Service

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[23] Response to Staff Data Request ACC-STF-27-9.
[24] Response to Staff Data Request ACC-STF-27-9.
[25] Response to Staff Data Request ACC-STF-27-9.
[26] The Company's response states that the amount should be $5,274, however, the supporting document showed the amount to be $5,660.
[27] Response to Staff Data Request ACC-STF-27-9
[28] Response to Staff Data Request ACC-STF-27-9

meter when the amount used in the last case is more appropriate.[29] Staff has made this change to its proposed CCOSS.

G. CCOSS Recommendation Summary

Q. Would you please summarize your Class Cost of Service Study recommendations?

A. Yes. Staff recommends that the Commission adopt the following alternative CCOSS allocation factors:

- Distribution mains should be allocated on a 50-50 basis with 50 percent of those investments being allocated to customers and the other 50 percent allocated on non-customer factors. This differs from the Company's proposal to allocate mains investment on a 50 percent demand/50 percent customer allocation basis.

- The non-customer component of the mains investment allocator should be divided on a 50-50 commodity-demand basis.

- Measuring and regulating equipment should be allocated on a 50 percent demand and 50 percent commodity basis, instead of the 50 percent customer and 50 percent demand allocation proposed by the Company.

- Maintenance of mains should be allocated on the basis of 50 percent customers, 25 percent demand, and 25 percent commodity, consistent with the plant account associated with these maintenance activities.

[29] Response to Staff Data Request ACC-STF-27-7.

- Measuring and regulating equipment – industrial should be allocated to industrial customers only, as opposed to the Company's method which allocated these costs to all customers.

- The Commission should order the Company to include the special procurement gas customers served under Schedule G-30 in the CCOSS submitted in its next rate case.

- The Commission should order the Company to develop an accounting process that explicitly identifies customer class-specific CIAC in such a manner that CIAC can be appropriately assigned to the classes that paid the CIAC.

- All CCOSS errors identified by the Company in response to Staff's discovery should be corrected including those associated with the allocation of services, meters, and customer installation expenses.

Q. Do your CCOSS recommendations change the class rates of return?

A. Yes, and those have been identified and compared to the Company's original CCOSS results in Exhibit DED-12. My CCOSS recommendations under the Company's current and proposed rate design are depicted on Exhibit DED-11. I have prepared Exhibit DED-10 to show the Company's CCOSS results.

Q. Have you prepared an analogous exhibit showing the CCOSS results using the Staff's recommended revenue requirement and revenue distribution?

A. Yes. These results are shown on Exhibit DED-13.

RATE DESIGN

A. Rate Design Objectives

Q. What are some of the guiding criteria or principles upon which rate design should be based?

A. There are several generally-accepted rate design principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable.
2) To the extent possible, gradualism should be used to protect customers from rate shock.
3) Rate continuity should be maintained.
4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
5) Rates should be understandable to customers.

Q. How are the above criteria blended to develop rates for a regulated utility?

A. While it is important to consider all of the earlier-mentioned principles, the weight of any one principle can change depending upon the relative importance of certain policy goals. Rate design should strike a balance between policy goals to ensure rates are fair, just, and reasonable. Because there is no pre-set universally-accepted formula for developing rates, judgment is often necessary in formulating a rate design that meets these objectives.

Q. Has the Commission come to similar rate design conclusions?

A. Yes. In Southwest's 2004 rate case, the Commission commented upon the subjective nature of rate design by noting:

> ...designing rates is not an exact science that may be achieved by the application of a formula tied directly to a cost of service study. Rather, the formulation of just and reasonable rates is accomplished only through consideration of multiple factors that balances the desire of the Company to recover as much of its margin as possible with recognition of the legitimate interests of customers in paying rates that are affordable, as well as advancing societal goals. As discussed below, we have attempted to determine just and reasonable rates based on these competing principles and interests.[30]

Q. How does the Company define its overall rate design goals?

A. Southwest identified four rate design objectives including designing rates that: 1) fairly and equitably recover costs; 2) work well with the energy efficiency enabling provision; 3) are understandable and generally acceptable to customers; and 4) are supportive of the Company's energy efficiency efforts.[31]

Q. Can you summarize the Company's rate design proposals?

A. Yes. The Company is not proposing any significant changes to the current structure of its rate design. Existing and proposed rates will continue to be based upon various forms of customer, demand, and volumetric-based charges. The Company intends to keep all of its basic customer charges the same and recover any remaining deficiencies through its various volumetric-based rates.[32] The Company is also not seeking any changes for the Purchased Gas Adjustor Mechanism, the Low Income Ratepayer Assistance Adjustor, the Demand Side Management Adjustor, the Gas Research Fund Adjustor, the Department of Transportation Adjustor, nor the Small Essential Agriculture User Gas Service rate.[33]

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[30] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, February 23, 2006, p. 35.
[31] Direct Testimony of Edward B. Gieseking, p. 8.
[32] Direct Testimony of Edward B. Gieseking, p. 10.
[33] Response to Data Request ACC-STF-4-1, ACC-STF-4-2, and Company's Filing Schedule H-3.

Q. Is the Company proposing any new rates?

A. Yes. The Company proposes to divide its Large General Service Class into two separate rate classes, Large-1 and Large-2. Currently, the Large General Service Class serves customers that use between 7,201 and 180,000 therms annually. Southwest notes that there is a large difference between the cost of providing service to the smaller customers in this class versus the cost to serve the larger customers. The Company's proposal would disaggregate the existing general service class into a "General Gas Service Large-1" class serving customers using between 7,201 and 50,000 therms per year, and "General Gas Service Large-2" that would serve customers using more than 50,000 therms, and up to 180,000 therms per year.[34]

Q. Does the Company propose to close any rate classes?

A. Yes. The Company proposes to close Rate Class G-75, Small Essential Agriculture Gas Service, to new customers. Since Decision No. 58377 in 1993, the Company has been moving customers from Rate Class G-75 to Rate Class G-25 when it benefits the customer.[35] In this case, Southwest has moved 42 customers to the new rate class. There are now 51 remaining customers under the existing rate schedule that, according to the Company, will need to be moved.[36]

[34] Direct Testimony of Edward B. Gieseking, p. 12.
[35] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, (February 23, 2006) at 46.
[36] Direct Testimony of Edward B. Gieseking, p. 13.

B. Revenue Distribution

Q. Would you please describe how the Company distributed its revenue requirement among its various customer classes?

A. Yes. The Company proposes to limit the increase in margin revenue for any given class at 1.25 times the system average increase. The remaining deficiency was spread to classes that had a return less than three times the requested system average Rate of Return ("ROR").[37]

Q. Is Staff's proposed revenue distribution comparable to the Company's?

A. Yes, at least generally. However, Staff's recommended revenue distribution, provided on Exhibit DED-12, is based upon Staff's recommended CCOSS results and includes a comparable gradualism component that limits rate increases to 1.25 times the system average increase of 14.6 percent, and like the Company, distributes any of the remaining revenue deficiency across classes earning less than three times the proposed system average rate of return. All customers would receive a rate increase under my recommended revenue distribution unlike the Company's that proposes a rate decrease for one customer class (i.e., natural gas engines).

Q. Would you please explain your recommended revenue distribution under the Staff's recommended revenue increase?

A. Staff's recommended revenue distribution methodology remains the same as under the Company's proposed rate increase under the Staff's recommended revenue increase.

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[37] Company's Filing Schedule H-2 (Summary of Margin Spread Allocation to Classes).

C. Customer Charges

Q. What is a customer charge?

A. A customer charge is a monthly fixed charge assessed to customers based on the type of installed meter, usually defined by the pressure level of natural gas that can flow through that particular class of meter. Customer charges are typically fixed regardless of the amount of natural gas consumed.

Q. Is the Company proposing to change its customer charges?

A. No. The Company proposes to maintain its customer charges at their current level for two reasons: 1) to encourage customers to be more energy efficient, and 2) to meet the rate design objectives of customer acceptance and understandability.[38] A summary of the Company's current customer charges has been provided in Exhibit DED-17.

Q. How do the Company's residential customer charges compare with the results of its class cost of service study?

A. The customer charge for the Single Family Residential Class is 35 percent of its class cost of service, and the Multi-Family Residential Class is 44 percent of its cost of service. The customer charges for the Single Family Low-Income and the Multi-Family Low-Income Residential Classes are set at 27 percent and 33 percent of the cost of service, respectively.

Q. How do the Company's commercial customer charges compare with the results of its CCOSS?

A. The customer charge for the Transportation eligible rate class has the lowest percentage of its cost of service being recovered through a fixed charge at nine percent. The customer

[38] Direct Testimony of Edward B. Gieseking, p. 10.

charge for the Small General Service class is set at the highest percentage (67 percent) of total cost of service. The remaining classes are proposed to see customer charges that recover between 14 percent to 32 percent of their full cost of service. The Company's proposed customer charge, as a share of each class's cost of service, are provided in Exhibit DED-13.

Q. How do the Company's proposed residential customer charges compare to other natural gas distribution companies?

A. The Company's residential and commercial customer charge proposals are higher than the average residential customer charge of $10.31 and the average commercial customer charge of $18.66 as compared on Exhibit DED-14. This exhibit develops a comparable average from a survey of current residential and commercial customer charges for major local gas distribution companies ("LDCs") operating in the western U.S.[39] that are regulated by public service commissions. There are 40 gas distribution utilities in the survey with residential customer charges greater than $10.70 per month, and 70 companies with a customer charge less than the Company's current (and proposed) $10.70 per month amount. Compared to the LDCs in the West, Southwest's residential customer charge is higher than 85 percent of the sample. When comparing the Company's current (and proposed) commercial customer charge of $27.50 per month to other western LDCs, 17 utilities included in the survey have customer charges that are higher than Southwest, while 91 utilities have customer charges lower than the Company's. Southwest's commercial customer charge is greater than 93 percent of the other Western LDCs.

[39] The West region includes the states of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming as defined by the U.S. Census Bureau.

Q. Do you agree with the Company's proposal to keep its residential and commercial customer charges the same?

A. Yes. The Company's customer charges (both residential and commercial) are relatively high when compared to other gas distribution companies. In addition, the Company's customer charges already account for a relatively large portion of its overall cost of service results (i.e., 35 percent for Single-Family Residential and 67 percent for Small General Gas Service of what the Company defines as "fixed costs"). Given these two factors, there is no need to increase customer charges, and Staff agrees with the Company's proposal to hold the existing customer charges at their current levels.

Q. Can you explain why customer charges should not be decreased at this time?

A. Yes. There is no compelling evidence indicating that customer charges should be decreased at this time. The Commission found the Company's charges to be reasonable in Southwest's last rate case and there have been no dramatic changes since that time requiring a deviation from the Commission's prior policy. Holding customer charges constant helps preserve the affordability and access of gas service for many customers, and will place emphasis volumetric charges that is consistent with the Commission's goal of encouraging energy efficiency.

D. Volumetric Charges

Q. How are utility distribution rates typically structured?

A. Distribution rates are typically based upon a two-part tariff composed of a fixed monthly customer charge and a usage-based volumetric charge. The volumetric rate can be set in a variety of fashions. Historically, many gas utilities set volumetric distribution rates on either a declining block or uniform rate basis. A declining block rate is one that ratchets rates to lower levels as usage increases. Consider as an illustration a rate structure where a typical customer faces a charge of $0.25 per therm for the first 10 therms of consumption (first block); a rate of $0.10/therm for the next 10 therms of usage (second block); and $0.05/therm for all usage above 20 therms. A uniform rate, on the other hand, charges a fixed uniform volumetric fee on all units of consumption. An illustration of different rate designs has been provided on Exhibit DED-15.

Q. What rate structure does the Company currently have?

A. For the most part, the Company has a uniform rate structure. The only exception is the Special Residential Gas Service for Air Conditioning rate which has a declining summer block rate. A summary of the Company's current and proposed volumetric rates has been provided on Exhibit DED-17.

Q. How common are uniform rate structures?

A. Uniform volumetric rates are perhaps one of the more common forms of volumetric pricing mechanisms for U.S. LDCs and have been surveyed in Exhibit DED-16. The survey, based upon 108 gas LDCs, shows 70 utilities currently offering uniform volumetric rates, 25 utilities currently offer declining block rates, and only three have an inclining block rate structure for both their residential and small commercial ratepayers. Some companies have different rate structures for residential and small commercial classes: three utilities have a combination of uniform and declining block rate structures; six have a combination of declining and inclining block rate structures; and one has a combination of uniform and inclining block rate structures.

Q. Would you please explain the Company's volumetric rate proposals?

A. Yes. As mentioned above, most of the Company's classes have a uniform rate structure, and it is proposing no changes to the overall structure of its rates in the current rate proceeding.

Q. What is Staff's volumetric rate recommendations?

A. Staff agrees with the Company that the continuation of the existing uniform rate structure, which has been in existence for many years, satisfies the goal of rate continuity. Staff does have differing recommendations, however, with the degree to which these rates should be increased. This difference between my recommended volumetric rates and the Company's is primarily a function of my alternative CCOSS and Staff's differing revenue requirement recommendation. Staff's proposed rates are provided in Exhibit DED-17.

E. Low-Income Residential Gas Service

Q. Would you please discuss the Company's low-income residential service rate design proposals?

A. Southwest is proposing to keep the customer charge the same and to expand the 20 percent discount provided to its low-income customers to include all usage during the winter months of November through April. The discount currently applies only to the first 150 therms of monthly winter consumption. The Company claims that its low income rate proposal will simplify rates and create additional benefits without significantly impacting other customer classes.[40]

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[40] Direct Testimony of Edward B. Gieseking, p. 11.

Q. Has the Commission addressed a similar proposal before?

A. Yes. The Commission rejected a similar Company proposal in its last rate case that would have applied a 15 percent discount to all low-income usage rather than the current discount of 20 percent on the first 150 therms during the winter months. In that proceeding, the Commission adopted the Staff's recommendation to maintain the existing discount of 20 percent for the first 150 therms of winter usage.[41] Staff's witness recommended maintaining the 20 percent discount on winter usage since that period tends to include the months with both the highest usage and the highest natural gas commodity rates.[42]

Q. Is the Company's low-income residential service rate design proposal in this case consistent with the Commission's energy efficiency goals?

A. No. While the Company's proposal may appear to be generous and facilitate public policy goals of helping less-advantaged customers during a trying economic period, the proposal may run afoul of the Commission's energy efficiency policies since, as the Company notes, "low income customers use nearly the same amount of gas, on average as non-low-income customers."[43] Furthermore, a proposal of this nature, at least in theory, could have the negative and unexpected consequence of reducing the economic attractiveness of

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[41] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, (February 23, 2006) at 40.

[42] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Direct Testimony of Robert G. Gray, pp. 37-38.

[43] Direct Testimony of Edward B. Gieseking, p. 11. The Company's data shows that Single Family Residential Low Income customers use only slightly less (38.79 therms) in the winter compared to standard Single Family Residential customers (38.97 therms).

energy efficiency measures for low-income customers including those offered within the Company's proposed energy efficiency program.

Q. What is Staff's low-income residential gas service rate recommendations?

A. Staff recommends that the Commission reject the Company's request and continue with the existing 20 percent discount for the first 150 therms of winter usage. The Company has provided no convincing evidence to support its proposed change especially in light of its contradiction of the Commission's energy efficiency policies.

F. Special Residential Gas Service for Air Conditioning

Q. Would you please discuss the Company's Special Residential Gas Service for Air Conditioning rate design proposal?

A. The Company's rate structure for Special Residential Gas Service for Air Conditioning (Schedule No. G-15) consists of a monthly basic service charge and a per therm delivery charge that is differentiated per summer/winter season. The proposed winter delivery charge (November – April) is a uniform rate of $0.80176 per therm. In the summer months (May through October), the proposed delivery charge is structured as a declining block rate with a head block (0 – 15 therms) of $0.80176 per therm and a tail block (over 15 therms) of $0.12297 per therm. The current delivery charge is also declining, but with a much more moderate decline since the current head block rate is $0.5707 per therm and the current tail block rate is $0.28860 per therm. The Company proposes a 57 percent decrease for the tail block rate even though the overall class will see a 9.26 percent increase in overall rates.[44]

[44] Company's Application, p. 1.

Q. How did the Company develop the tail block rate for the summer differential?

A. Southwest has no cost information upon which to base this rate. Instead, the Company uses the commercial and industrial summer season rate (Rate Schedule G-40) as a proxy for the cost of the upper tail block.[45] The Company states it has little cost data to perform a meaningful cost study because there are only 90 customers taking service under Schedule No. G-15, and residential air conditioning is not separately metered.[46] Southwest claims that in the future, if demand develops, installation numbers increase, and metering options mature, it may have more cost-based information upon which to base its G-15 rates.[47]

Q. What is Staff's recommendation regarding the Company's proposal to tie the summer season differential for Rate Schedule G-15 to Rate Schedule G-40?

A. Staff recommends moving towards a uniform rate structure for this class by increasing the current tail block by 10 percent. The Company has provided no cost support for its volumetric rate proposals. Moving to a uniform rate structure is consistent with the structure of the Company's other rates and is consistent with the basic volumetric rate design of other gas utilities.

G. General Service

Q. Would you please describe the Company's General Service customer classes?

A. Yes. The General Gas Service rate class currently consists of four subclasses: Small General Gas Service; Medium General Gas Service; Large General Gas Service; and Transportation Eligible General Gas Service. Small General Gas Service customers are

[45] Company's Tariff Schedule No. G-40
[46] Response to Data Request ACC-STF-13-6.
[47] Response to Data Request ACC-STF-13-6.

defined as those with average annual usage of less than or equal to 600 therms; Medium General Gas Service customers are defined as those with usage of 601 – 7,200 therms; Large General Gas Service customers include those using 7,201 – 180,000 therms; and Transportation-Eligible Gas Service customers have usage volumes greater than 180,000 therms.[48]

Q. Would you please discuss the Company's General Service rate design proposals?

A. Yes. The Company proposes to separate the Large General Service Class into two subclasses, Large-1 and Large-2. The proposed Large-1 General Service Class would include those with annual usage between 7,201 – 50,000 therms while the Large-2 General Service Class would be defined by those customers using between 50,001 – 180,000 therms annually. The Company claims that its proposed change is cost-based given the large differential that exists between the cost of serving the smaller and larger General Service customers.[49]

Q. How large are the cost differences between the two (Large General Service) customer groups?

A. The Company's CCOSS indicates that meter costs for a typical customer in the proposed Large-1 General Service class is $800 while meter costs for the typical customer in the proposed Large-2 General Service class is more than four times larger at $3,500 per meter.[50] The Company also notes that the annual load factor for the proposed Large-2 General Service class is 12 percent larger than the Large-1 General Service class.[51]

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[48] Company's Tariff Schedule No. G-25.
[49] Direct Testimony of Edward B. Gieseking, p. 12.
[50] Company's 2010 CCOSS and Rate Design Model, Tab G-1 (Meter Cost by Class).
[51] Response to Data Request ACC-STF-3-49.

Further, Large-1 customers' annual usage per customer is 14,609 therms compared to the Large-2 customers' annual UPC of 80,817 therms.

Q. Does Staff support the Company's proposal to separate the Large General Service class into two classes?

A. Yes. There appear to be sufficient differences between the two customer groups to warrant separate rates.

Q. Does Staff agree with the specific rates proposed by the Company for the new Large General Service customer classes?

A. No. The Company's proposal is likely to violate the rate design principles of gradualism and rate continuity since the changes in both level and structure of the new rates are relatively significant. For instance, Southwest proposes to reduce the customer charge for the General Service L-1 customers from $160 per month to $80.00 per month, a reduction of 50 percent. However, at the same time, the Company proposes to increase its volumetric charges from $0.29084 per therm to $0.38756 per therm, an increase of 33 percent. Southwest's proposed customer and delivery charges for the General Service L-2 customers are equally problematic. The Company proposes to increase the customer charge for the General Service L-2 customers from $160 per month to $470 a month, an increase of almost 200 percent. This is counterbalanced against a relatively moderate 9.4 percent decrease to the delivery charge, from $0.29804 per therm to $0.27 per therm.

Q. What is Staff's recommendations for the General Service L-1 customers under the Company's requested revenue requirement?

A. Staff recommends that the Commission reduce the customer charge for the General Service L-1 customers by 25 percent to $120 per month and examine further reductions to the customer charge in the Company's next rate case. This is still a meaningful reduction for the customers taking service under this new rate, but one that is more consistent with gradualism and moving this new class closer to its overall cost of service. A $120 per month customer charge allows for a more moderate volumetric delivery charge increase of 21 percent to $0.3515 per therm.

Q. What is Staff's recommendations regarding the General Service L-2 class?

A. Staff recommends that the customer charge be increased by only 50 percent, from $160 per month to $240 per month. A more moderate increase in the customer charge for this class will leave to a more moderate, 1.6 percent increase in the delivery charge to $0.30282 per them.

H. Small Essential Agriculture User Gas Service

Q. Would you please discuss the Company's Small Essential Agriculture User Gas Service rate design proposals?

A. The Company proposes to close Rate Schedule No. G-75, Small Essential Agriculture User Gas Service, to new customers. Southwest states it has moved customers from Rate Schedule No. G-75 to Schedule No. G-25, General Gas Service, in instances where it benefits the customer. There are currently 51 customers still remaining under Rate Schedule No. G-75.[52]

Q. Has the Company made similar proposals for this class in the past?

A. Yes. The Company originally proposed to close this rate schedule back in its 1992 rate case. The Commission rejected this prior proposal and directed Southwest to gradually

[52] Direct Testimony of Edward B. Gieseking, p. 13.

move the customers on the Small Essential Agriculture Rate Schedule to the general service tariff. The Commission also specifically rejected the Company's request to close the Small Essential Agriculture tariff to new customers at the time because "closure may unfairly treat identical customers."[53]

Q. Does Staff agree with the Company's proposal?

A. Yes. Staff recommends that this rate class be closed to new entrants and that the Company continue the process of migrating customers, where beneficial, to other service schedules.

Q. Does Staff have any other rate design recommendations for the Commission's consideration?

A. Yes. Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural gas consumption decisions. Staff recommends that the Commission order the Company to evaluate other rate designs, inclining an inclining block rate structure, for residential and commercial customers in the next rate case. Each alternative rate design proposal offer by the company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

[53] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, February 23, 2006, pp. 46-48.

I. Potential Bypass and Standby Gas Service

Q. What changes does the Company propose to Rate Schedule No. B-1 – Potential Bypass/Standby Gas Service?

A. The Company proposes to remove all language related to potential bypass gas service. In response to Staff's Data Request, the Company explained that over time, Rate Schedule No. T-1 (Transportation) has evolved into the rate schedule that accommodates potential bypass transportation customers. Therefore, the bypass provision contained in currently effective Schedule No. B-1 is no longer necessary. The Company's modifications to Rate Schedule No. B-1 will apply to only the remaining standby provisions and be renamed to Schedule No. SB-1.[54]

Q. What are Staff's recommendations for Rate Schedule No. B-1?

A. Staff has no objection to the Company's proposed tariff change.

J. Revenue Comparisons and Bill Impacts

Q. Has Staff prepared an exhibit that shows a comparison of revenue under the Company's present rates and Staff's proposed rates?

A. Yes. Staff has prepared Exhibits DED-18 and DED-19, which compare total revenue (including gas costs) generated under the Company's present rates and under Staff's proposed rates for all classes except the transportation eligible, special contract and optional gas service classes. Exhibit DED-18 contains the rates and revenue under both present and proposed rates. Exhibit DED-19, summaries just the revenue impact of the Staff's recommended revenue for each class.

[54] Response to Data Request ACC-STF-24-2.

Q. What is the impact of Staff's proposed rates on Residential Class revenue?

A. Single-Family Residential revenue would increase from $446.5 million to $492.5 million, or a 10.3 percent overall increase in total revenues, including gas costs, or a 17.6 percent increase for base rate revenue alone. Likewise, the Single-Family Low Income Residential total revenue including gas costs would increase from $14.4 million to $16.1 million: an 11.6 percent to overall total revenues and a 24 percent increase in the base rate component of overall revenues. The Special Residential Gas Service Air Conditioning class would see an 12.7 percent increase in total revenue, including gas costs, and 26.4 percent in base revenues.

Q. What would the total revenue change be under Staff's proposed rates for the General Service Classes?

A. The Small General Service revenue would increase from $10.7 million to $11.2 million, or 4.3 percent. The Medium General Service Class revenues would increase from $49.9 million to $51.3 million, or 2.9 percent. The Large-1 General Service Class revenues would increase from $116.1 million to $119.1 million, or 2.5 percent. The Large-2 General Service Class revenues are proposed to increase from $34.7 million to $35.7 million, or 2.8 percent.

Q. What is the total revenue impact for the General Service Air Conditioning customers?

A. Air Conditioning total revenue would increase from $0.337 million to $0.355 million, or 5.2 percent. Base revenue would increase by 21.4 percent.

Q. How do the revenue for the Cogeneration Gas Service Class compare under the Staff's proposal?

A. The Cogeneration Gas Service class total revenue would increase from $3.8million to $4.4 million by 16.7 percent and base revenue by 21.8 percent.

Q. How do revenues change for the Small Essential Agriculture User Class revenue?

A. Small Essential Agriculture User total revenue would increase from $2.6 million to $2.7 million, or 2.0 percent. Base revenues would increase by 7.2 percent.

Q. How would revenues from the Natural Gas Engine Class change under the Staff's recommendation?

A. Total revenues for the Natural Gas Engine Class would increase from $5.4 million to $5.5 million, or by 2.4 percent. Base revenues would increase by 7.5 percent.

Q. Did Staff prepare a summary of bill impacts (or typical bill comparisons) under the Staff's proposed rates?

A. Yes. Staff prepared Exhibit DED-20, comparing the bill impacts of Staff's proposed rates.

Q. What is the typical bill impact of Staff's proposed rates on residential customers?

A. Single-Family Residential winter bills would increase from $64.89 to $71.74, or by 10.6 percent, based on the average annual usage of 39 therms. Single-Family Low Income Residential winter bills would increase from $51.76 to $57.66, or 11.4 percent, based on the average annual usage of 39 therms.

A Special Residential Gas Service for Air Conditioning customer using an average of 67 therms in the summer would see an average bill increase from $89.12 to $102.81, or 15.4 percent

Q. How would the standard bill for general service customers be impacted by the Staff's recommendation?

A. Typical Small General Service bills would increase from $58.07 to $60.65, or 4.4 percent. Typical Medium General Service Class bills would increase from $310.81 to $319.11, or 2.7 percent. Typical Large-1 General Service Class bills would increase from $1,504.80 to $1,538.265, or 2.2 percent. Typical Large-2 General Service bills would increase from $8,055.70 to $8,248.41, or 2.4 percent.

Q. What are the typical bill impacts for the Gas Service for Compression on Customer's Premises Class?

A. A typical Small Gas Service for Compression on Customer's Premises customer would see its bill increase from $558.41 to $561.25, or 0.5 percent, based on an annual usage of 528 therms. Large customers with an average annual usage of 5,186 therms would see bills increase from $5,464.57 to $5,492.42, or 0.5 percent; whereas, Residential customers with an average usage of 36 therms would see bills increase from $46.90 to $47.09, or 0.4 percent.

Q. How is the Cogeneration Class bill affected by the Staff's proposed rates?

A. The Small Cogeneration class would see an increase in bills from $33.22 to $33.40, or 0.5 percent, based on an average annual usage of 6 therms. Medium Cogeneration class customers would see bills increase from $4,886.41 to $5,036.71, or 3.1 percent, based on an average annual usage of 5,076 therms. Large Cogeneration customers' bills would increase from $3,721.58 to $3,792.12, or 1.9 percent, based on an average annual consumption of 3,733 therms.

Q. What is the change in the typical bill for Natural Gas Engine Class customers under the Staff's recommendations?

A. As shown on DED-20, this classes' typical bill would increase from $1,623.92 to $1,655.14, or 1.9 percent, based on an average annual consumption of 1,864 therms.

K. Incremental Cost Model ("ICM")

Q. The Commission previously ordered the Company to submit an ICM for review in its next rate case. Did the Company provide this model in this proceeding?

A. Yes. The Company provided a copy of its ICM and several model examples in response to Data Request ACC-STF-3-19 and ACC-STF-3-20. The Company specifically provided its model inputs and eleven examples where it used the ICM to develop the amount of construction advances and developer-required CIAC. Southwest undertakes service and main extensions on the basis of economic feasibility, which in turn, is determined by the ICM.[55] The Commission's cost recovery policy for new customer additions are contained in Rule 6 tariff provisions.

Q. Can you summarize the Commission's Rule 6 policies for new customer cost recovery?

A. Yes. Rule 6 states that gas service and main line extensions will be made by a utility at its own cost for the "allowable investment" as calculated by an incremental contribution

[55] The policy states, "All service and main extensions are made on the basis of economic feasibility except those for master-metered mobile home parks (MMP), whose extensions shall be made in accordance with the provisions in Section B.3 hereof."

methodology.[56] The "allowable investment", according to the rule is "a determination by the Utility that revenues less the incremental cost to serve the applicant customer provides a Rate of Return on the Utility's investment no less than the overall Rate of Return authorized by the Commission in the Utility's most recent general rate case."

Q. What is the purpose of the ICM?

A. The goal of the ICM analysis is to ensure that incremental cost to serve new customers is supported by the expected incremental margin from these customers and that new customer additions do not place a burden on current customers, or shareholders.[57]

Q. Did the Commission address the ICM in the Company's last rate case?

A. Yes. The Commission ordered the Company to provide "an explanation, with sample calculations and documentation, of how it has been implementing the ICM and Rule 6 tariff provisions."[58] The Commission explained a review was necessary because it had been nearly ten years since the Company's Rule 6 portion of the tariff had been reviewed, despite the Company's indication that it made significant changes to the ICM during that period.[59]

Q. Has Staff reviewed the ICM?

A. Yes. Staff found it to be well prepared and for the most part well documented.

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[56] Company Tariff Rule No. 6B(4).
[57] Direct Testimony of Robert A. Mashas, p. 22.
[58] Decision No. 70665, p. 53. (December 24, 2008)
[59] Decision No. 70665, p. 53. (December 24, 2008)

Q. What are the inputs to the ICM?

A. There are several inputs. The traditional rate case-type inputs include cost of capital, state and federal income tax rates, property tax rates, book depreciation rates and the uncollectible rates that are embedded in the new tariff rates authorized by the Commission. Other inputs include the standard service stub and extension footage per customer and cost per foot and the therm usage for heating, water heating, cooking, clothes drying, and gas logs, which the Company indicated are updated annually."[60]

Q. What are the parameters in the ICM that determine what a customer has to pay in the form of an advance or a contribution?

A. The ICM is designed to determine if a project will earn a rate of return ("ROR") and a return on equity ("ROE") allowed by the Commission in the Company's last rate case. Currently, these rates are 8.06 percent for the ROR and 10 percent for the ROE. For a project to be viable, both the three year average, and the fourth year Commission-allowed ROR and ROE, must be met. The amount of the main extension advances for construction, and the need for further contributions through CIAC, are determined based upon the three-year average achieved returns. If a development's average three-year achieved return is not equal to or greater than the Commission's allowed returns, additional advances are required. If a project that fails, in its fourth year, to achieve the target ROR and ROE, an additional contribution in the form of CIAC from the developer is required.

[60] Direct Testimony of Robert A. Mashas, pp. 23-24.

Q. Were you able to verify the default financial assumptions used in the Model and their consistency with the Commission's most recent rate case order?

A. Yes. Input assumptions were examined based upon the Commission's most recent order and were found to be consistent with the most recent order.

Q. Do you have any concerns about the application of the ICM?

A. Yes. Staff reviewed the eleven examples of the ICM for specific projects. This review raised questions concerning how the Company uses the model and its results. Exhibit DED-21 shows the ICM-estimated three and five year average ROR and ROE for a number of example projects. In almost every instance the ICM estimates RORs and ROEs in excess of the Commission's allowed ROR and ROE. [redacted]. These returns, as well as the returns for two other projects, are significantly in excess of those allowed by the Commission.

Q. Are the RORs and ROEs for the other projects close to the Commission's authorized returns?

A. No. While they are not as extreme as the previous examples, most [redacted].

Q. What are the implications of these higher than authorized rates of return?

A. These higher than authorized RORs suggest that the Company is collecting more advances for construction and/or CIAC than is necessary.

Q. Is there a way to resolve this problem in the model?

A. Yes. There is a "goal-seeking" feature in the ICM that can be used in connection with determining the needed CIAC. This optimization feature can constrain estimated project contributions to level consistent with a five year average allowed return. While the use of this optimization feature could possibly resolve the current over-earning problem, it does not address the issue of over-collecting advances for construction which is based upon the Company's policy of collecting advances for all the first year capital expenditures. It would appear that to achieve more reasonable returns the Company would need to alter its advances for construction policies and the resulting assumptions in the model.

Q. What is Staff's recommendations concerning the ICM?

A. Staff recommends that the Commission order the Company to either discontinue collecting advances and CIAC that result an ROE that is more than 50 basis points above the allowed return. In the alternative, the Company needs to demonstrate that the ICM results provided to Staff are not representative of final advances and CIAC collected from customers.

L. Rate Design Recommendations

Q. Would you please summarize Staff's rate design recommendations?

A. Yes. Staff's rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average and distribute any of the remaining revenue deficiency across classes earning less than three times the proposed system average increase.

- Existing customer charges should be held at their current levels.

- The Company's existing uniform volumetric rate structure should be continued.

- Volumetric rates should be increased according to the results of my alternative class cost of service model and the Staff's recommended revenue requirement.

- Staff recommends the Commission reject the Company's low income class rate design proposal and continue the existing 20 percent discount on the first 150 therms of winter usage.

- For the Company's Special Residential Gas Service for Air Conditioning rate, Staff recommends moving towards a uniform volumetric rate for this class until such time that the Company can support a declining block rate with class-specific cost information.

- Staff agrees with the Company proposal to separate the Large General Service class. However, the Commission should reject the Company's customer and delivery charge proposals for the Large-1 and Large-2 General Service classes. Instead, Staff recommends that the Commission decrease the customer charge of the Large-1 General Service class to $120 per month and examine further decreases in the Company's next rate case. Staff also recommends the Commission increase the customer charge of the Large 2 General Service class to $240 per month.

- Staff recommends that the Commission order the Company close the Small Essential Agriculture tariff to all new customers.

- Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural gas consumption decisions. Staff recommends the Commission order the Company to evaluate alternative rate designs, including an inclining block rate structure for residential and commercial customers, in the next rate case. Each alternative rate design proposal offered by the Company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

- Staff recommends the Commission adopt the Company's proposed change for Rate Schedule No. B-1.

- Staff recommends that the Commission order the Company to either (a) discontinue collecting advances and CIAC that result in a return on equity that is more than 50 basis points above the allowed return, or (b) demonstrate that the ICM filed in this case, and used to estimate these advances, are not representative of the final advances and CIAC collected from customers.

CONCLUSIONS

Q. Would you please summarize Staff's recommendations and conclusions regarding the Company's proposed revenue decoupling mechanism?

A. Yes. Staff recommends that the Commission reject the Company's proposed revenue decoupling mechanism since:

- The proposed EEP mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the Company and its shareholders and onto ratepayers. Such a shifting of risk, without any corresponding mitigation or ratepayer protection measures will result in rates that are not fair, just, and reasonable.

- The unnecessary inclusion of a weather component in the proposed EEP provides the Company with virtually free weather-related sales insurance without any corresponding benefit to ratepayers. Even if revenue decoupling is adopted, this aspect of the Company's EEP proposal should be rejected, without some corresponding benefit to ratepayers.

- The EEP mechanism has been offered on a permanent basis and has no review or analysis period to assess its effectiveness or the emergence of any unanticipated consequences.

- The EEP mechanism is not accompanied or tied to any verifiable, performance-based energy efficiency goals and outcomes.

- The EEP mechanism is highly likely to make the Company whole for changes in sales that have nothing to do with its energy efficiency efforts.

Q. Would you please describe Staff's LCFR mechanism proposals?

A. Yes. Should the Commission accept the need for decoupling, Staff recommends that the Commission approve the LFCR performance-based mechanism that would actively incent the Company to meet the Commission's energy efficiency goals, while holding the

Company harmless for the revenue losses associated with its energy efficiency efforts if it meets the Commission's goals. If the Company is correct that cost-effective energy efficiency programs result in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals. Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

Q. If the Commission adopts the Company's proposed revenue decoupling mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Company's decoupling mechanism is approved.

- Adoption of an annual earnings review and a refund of all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

- Adoption of a three year review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the decoupling mechanism is initiated. This review should include a regulatory presumption that any lost revenue recovery mechanism will be discontinued in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.

- A three year review process that includes: (1) an energy efficiency review; (2) a revenue deferrals and collections review if full decoupling is adopted by the Commission; (3) a customer usage analysis; and (4) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both the Company's proposal to reconcile actual-to-allowed revenue, an annual earnings surveillance report, and a reconciliation of the forecasted to actual per measure/per customer class total energy efficiency savings and participation levels in the prior year.

- The three year review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $100,000 per review.

Q. If the Commission adopts Staff's LCFR mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's alternative mechanism is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether the Commission adopts a full decoupling mechanism or the LFCR recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.
- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.

- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.
- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

Q. Would you please summarize Staff's CCOSS recommendations?

A. Yes. Staff recommends that the Commission adopt the following alternative CCOSS allocation factors:

- Distribution mains should be allocated on a 50-50 basis with 50 percent of those investments being allocated to customers and the other 50 percent allocated on non-customer factors. This differs from the Company's proposal to allocate mains investment on a 50 percent demand/50 percent customer allocation basis.

- The non-customer component of the mains investment allocator should be divided on a 50-50 commodity-demand basis.

- Measuring and regulating equipment should be allocated on a 50 percent demand and 50 percent commodity basis, instead of the 50 percent customer and 50 percent demand allocation proposed by the Company.

- Maintenance of mains should be allocated on the basis of 50 percent customers, 25 percent demand, and 25 percent commodity, consistent with the plant account associated with these maintenance activities.

- Measuring and regulating equipment – industrial should be allocated to industrial customers only, as opposed to the Company's method which allocated these costs to all customers.

- The Commission should order the Company to include the special procurement gas customers served under Schedule G-30 in the CCOSS submitted in its next rate case.

- The Commission should order the Company to develop an accounting process that explicitly identifies customer class-specific CIAC in such a manner that CIAC can be appropriately assigned to the classes that paid the CIAC.

- All CCOSS errors identified by the Company in response to Staff's discovery should be made including those associated with the allocation of services, meters, and customer installation expenses.

Q. Would you please summarize Staff's rate design recommendations?

A. Yes. Staff's rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average and distribute any of the remaining revenue deficiency across classes earning less than three times the proposed system average rate of return.

- Existing customer charges should be held at their current levels.

- The Company's existing uniform volumetric rate structure should be continued.

- Volumetric rates should be increased according to the results of my alternative class cost of service model and the Staff's recommended revenue requirement.

- Staff recommends the Commission reject the Company's low income class rate design proposal and continue the existing 20 percent discount on the first 150 therms of winter usage.

- For the Company's Special Residential Gas Service for Air Conditioning rate, Staff recommends a gradual move towards a uniform volumetric rate for this class until such time that the Company can support a declining block rate with class-specific cost information.

- Staff agrees with the Company proposal to separate the Large General Service class. However, the Commission should reject the Company's customer and delivery charge proposals for the Large-1 and Large-2 General Service classes. Instead, Staff recommends that the Commission decrease the customer charge of the Large-1 General Service class to $120 per month and examine further decreases in the Company's next rate case. Staff also recommends the Commission increase the customer charge of the Large 2 General Service class to $240 per month.

- Staff recommends that the Commission order the Company to close the Small Essential Agriculture tariff to all new customers.

- Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural gas consumption decisions. I recommend the Commission order the Company to evaluate alternative rate designs, including an inclining block rate structure for residential and commercial customers, in the next rate case. Each alternative rate design proposal offered by the Company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

- Staff recommends the Commission adopt the Company's proposed change for Rate Schedule No. B-1.

- Staff recommends that the Commission order the Company to either (a) discontinue collecting advances and CIAC that result in a return on equity that is more than 50 basis points above the allowed return, or (b) demonstrate that the Incremental Cost Model filed in this case, and used to estimate these advances, are not representative of the final advances and CIAC collected from customers.

Q. Does this complete your Direct Testimony?

A. Yes it does.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
1995-2000	Assistant Professor

E.J. Ourso College of Business Administration, Department of Economics

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).

2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market.* (2002). With Fred I. Denny. New York: CRC Press.

2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

1. "The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico." (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis.* 4(2).

2. "Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US." (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

3. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*)

4. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review.* 10 (October): 206-212.

5. "Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures." (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues.* Volume 6, Number 1.

6. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest.* 38: 2.

7. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

8. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

9. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy.* 9 (2): 47-59.

10. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics.* 21:153-166.

11. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

12. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.

13. "A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal.* 63:1108-1112.

14. "The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

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1. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues.* September: 17-21.

2. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management.* March.

3. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" *(2000).* With Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000.* July.

4. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering.* June: 294-298.

5. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development.* October: 499-504.

6. "Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

7. "Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

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29. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

30. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

31. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

32. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

33. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

34. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

35. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

36. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

37. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

38. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

41. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

42. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

43. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

2. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

3. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

4. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

5. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

6. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

7. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

8. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

9. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

2. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

3. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

4. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

5. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

6. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

7. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

8. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

9. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

10. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

11. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

12. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

13. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

14. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

15. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

16. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

17. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

18. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

19. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

20. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

21. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

22. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

23. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

24. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

25. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

26. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

27. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

28. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

29. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

30. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

31. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

32. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

33. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

34. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

35. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

36. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

37. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

38. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

39. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

40. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

41. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

42. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

43. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

44. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

45. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

46. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

47. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

48. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

49. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

50. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

51. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

52. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

53. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

54. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

55. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

56. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

57. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

58. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

59. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

60. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

61. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

62. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

63. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

64. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

65. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

66. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

67. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

68. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

69. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

70. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

71. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

72. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

73. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

74. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

75. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

76. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

77. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

78. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

79. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

80. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

81. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

82. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

83. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

84. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

85. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

86. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

87. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

88. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

89. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

90. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

91. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

92. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

93. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

94. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

95. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

96. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

97. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

98. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

99. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

100. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

101. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

102. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

103. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

104. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

105. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

106. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

107. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

108. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

109. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

110. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

111. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

112. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

113. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

114. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

115. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

116. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

117. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

118. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

119. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

120. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

121. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

122. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

123. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

124. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

125. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

126. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

127. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

128. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

129. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

130. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

131. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

132. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

133. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

134. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

135. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

136. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

137. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

138. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

139. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

140. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

141. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

142. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

143. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company. Issues: revenue decoupling and rate design.

2. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: capital cost rider, revenue decoupling.

3. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: pipeline replacement rider, revenue decoupling.

4. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

5. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

6. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric

Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

7. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

8. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

9. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

10. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

11. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

12. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

13. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service

adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

14. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

15. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

16. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

17. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

18. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

19. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

20. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue

decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

21. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

22. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

23. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

24. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

25. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

26. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

27. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public

Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

28. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

29. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

30. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

31. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

32. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

33. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

34. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

35. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

36. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

37. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

38. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

39. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

40. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

41. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

42. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

43. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

44. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

45. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

46. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

47. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

48. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

49. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

50. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

51. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

52. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

53. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

54. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

55. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al.* (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

56. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

57. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

58. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

59. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

60. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor

Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

61. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

62. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

63. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

64. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

65. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

66. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

67. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

68. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

69. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

70. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

71. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

72. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

73. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

74. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

75. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

76. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

77. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

78. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

79. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 2010-Current, *Economics of Energy & Environmental Policy*
Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists (IAEE), and the National Association for Business Economics (NABE).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as “Top 40 Under 40” (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Principles of Microeconomic Theory
Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

THESIS/DISSERTATIONS COMMITTEES

5 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Co-Director/Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-current).
LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Energy Efficiency Resource Standards

WA: *pursue all* cost effective conservation: ~10% by 2025

OR: 1% annual savings by 2013

CA: save 1,500 MW, 7,000 GWh; reduce peak 1,537 MW: 2010-12

NV: 0.6% annual savings (~5%) to 2015; EE to 25% of RPS

UT: PUC examining 1% annual

CO: 11.5% energy savings by 2020

AZ: at least 22% cumulative savings by 2020; peak credits

NM: 10% retail electric sales savings by 2020 .

OK: EE up to 25% of renewable goal

TX: 25% annual savings in 2012; 30% in 2013 and beyond

HI: 30% electricity reduction by 2030

MN: 1.5% annual savings to 2015

IA: 1.5% annual; 5.4% cumulative savings by 2020

WI: 1.5% electric savings by 2014; 15% peak reductions

MI: 1% annual energy savings

IL: 2% energy reduction, 0.1% peak by 2015

IN: 2% energy savings by 2019

OH: 22% energy savings by 2025 ; 8% peak by 2018

ME: 1.4% annual energy savings by 2013

VT: 2% annual; 11% cumulative energy reductions by 2011

MA: 2.4% annual electricity savings by 2012

NY: reduce electric use 15% by 2015

CT: 1.5% annual utility savings, 10% peak

RI: reduce consumption 10% by 2022

NJ: BPU proceeding to reduce consumption, peak

DE: reduce consumption 15%; peak 10% by 2015

PA: reduce consumption 3%; peak 4.5% by 2013

MD: reduce electricity use and peak 15% by 2015

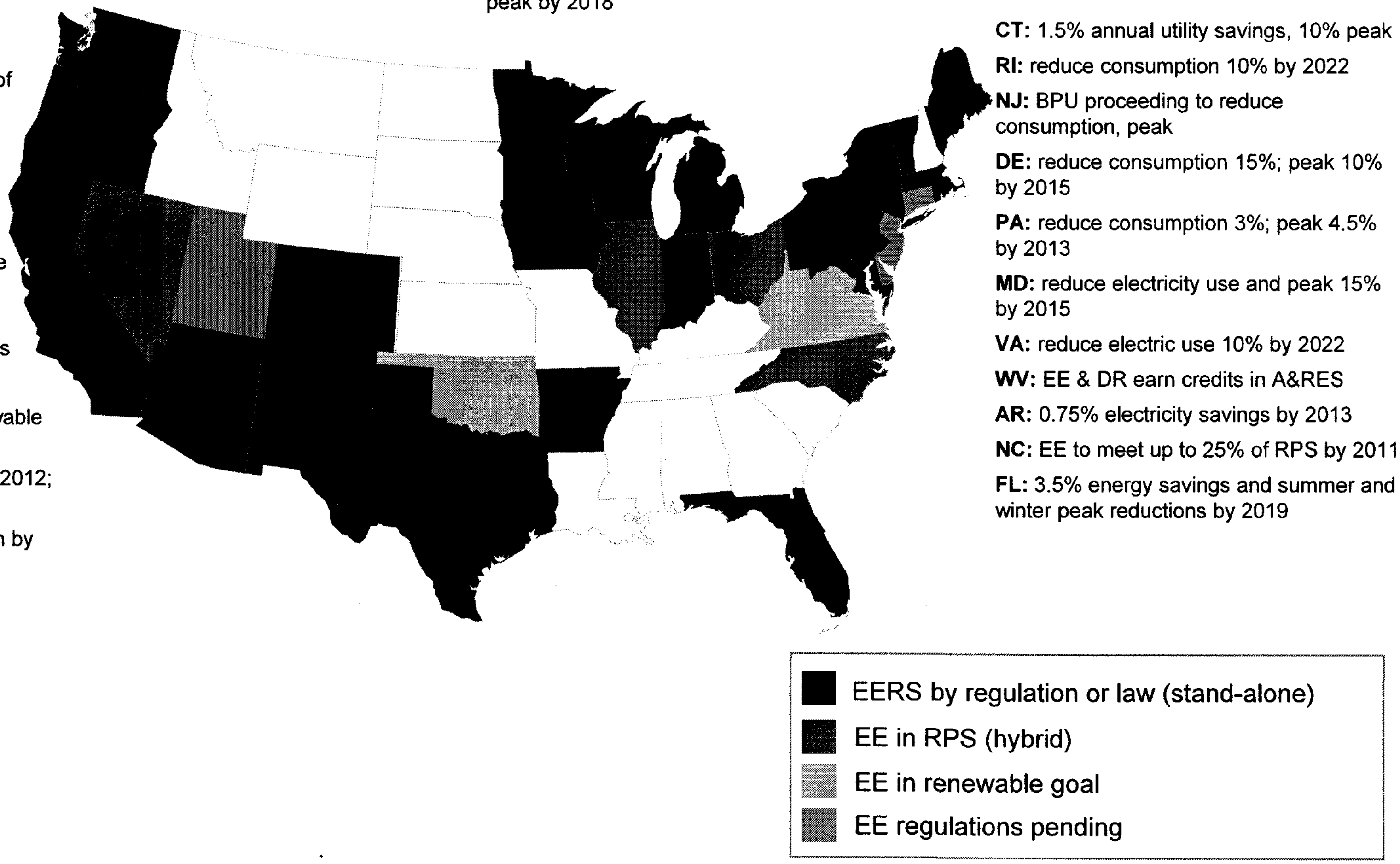
VA: reduce electric use 10% by 2022

WV: EE & DR earn credits in A&RES

AR: 0.75% electricity savings by 2013

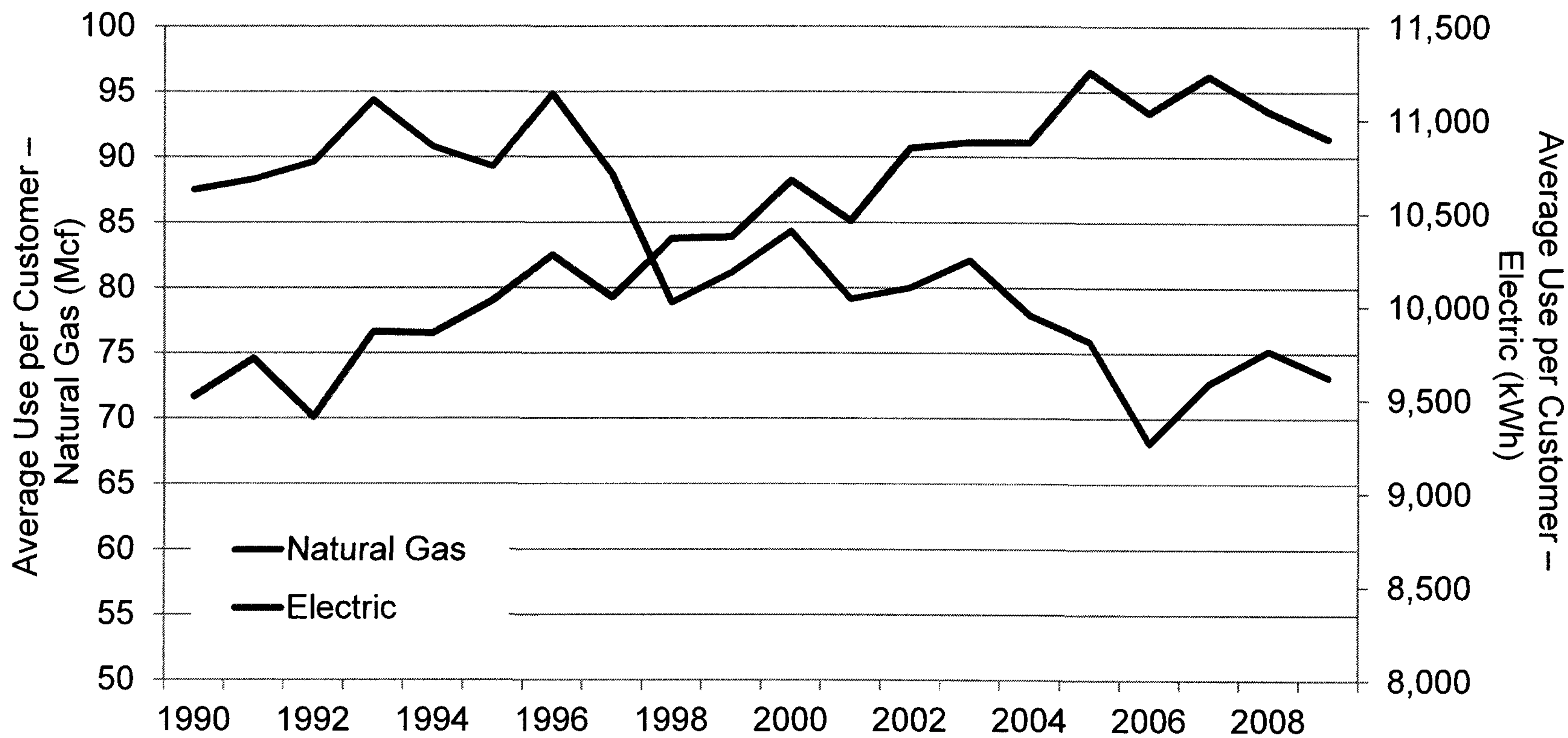
NC: EE to meet up to 25% of RPS by 2011

FL: 3.5% energy savings and summer and winter peak reductions by 2019



Note: As of April 15, 2011.
Source: Federal Energy Regulatory Commission.

U.S. Average Residential Use Per Customer Natural Gas and Electric



Source: Energy Information Administration, U.S. Department of Energy.

Annual Lost Base Revenues

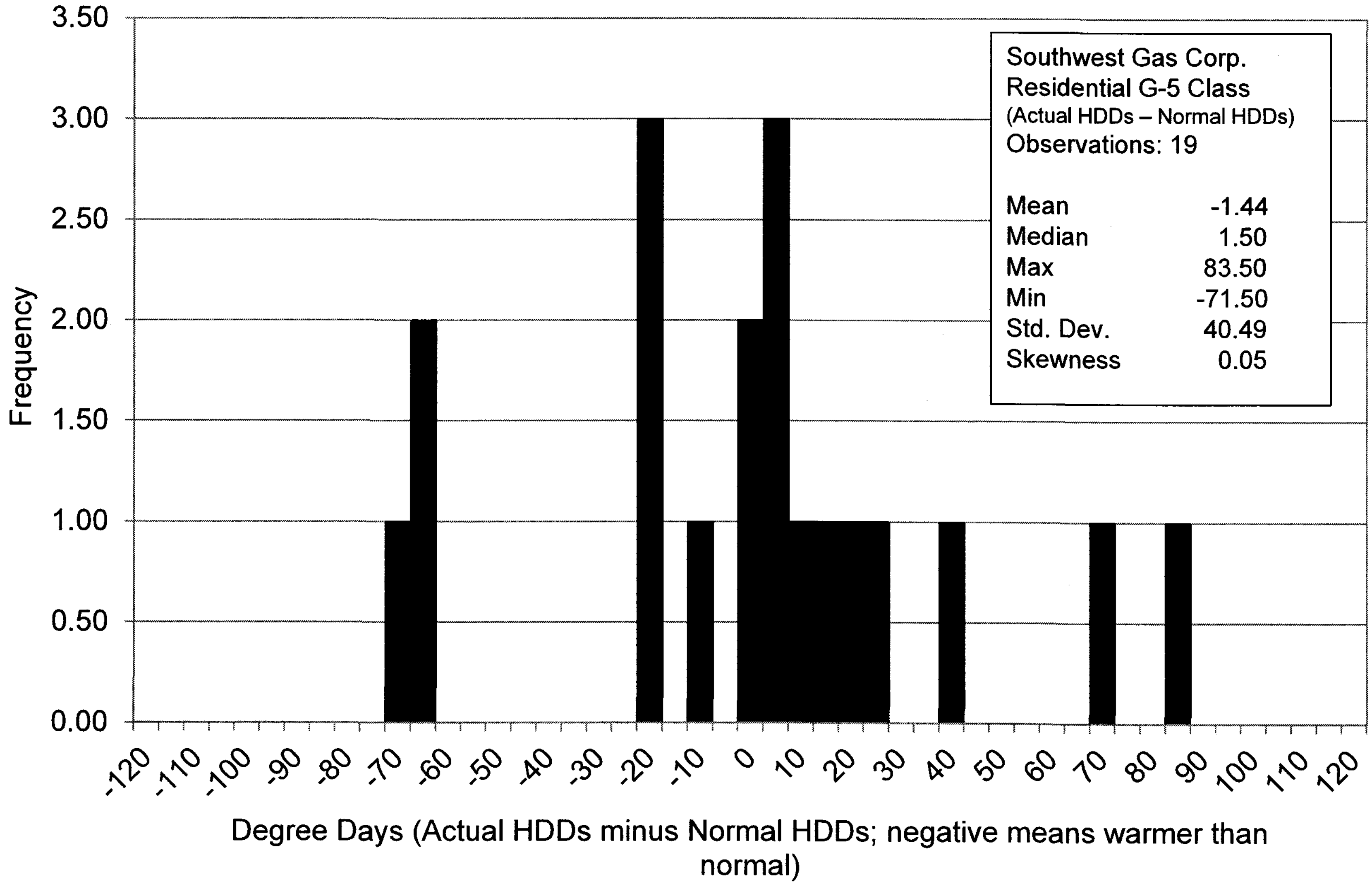
	Energy Efficiency Programs			Total	EE Lost
	Annual Savings (therms)	Program Costs ($)	Lost Margin ($)	Non-Gas Base Revenue ($)	Margin as a Percent of Base Revenue (%)
Current Energy Efficiency Programs					
2007	48,651	$ 861,661	$ 25,630	$ 399,816,248	0.01%
2008	125,825	$ 1,024,247	$ 66,287	$ 401,119,083	0.02%
2009	163,563	$ 1,199,521	$ 93,345	$ 409,715,094	0.02%
2010	348,405	$ 1,396,821	$ 198,835	$ 418,246,266	0.05%
Proposed Energy Efficiency Programs					
2011	2,451,000	$ 16,500,000	$ 2,766,243	$ 419,189,742	0.66%
2012	2,451,000	$ 16,500,000	$ 2,766,243	$ 419,189,742	0.66%
2013	2,451,000	$ 16,500,000	$ 2,766,243	$ 419,189,742	0.66%

Southern Connecticut Gas ROE Comparison (With and Without WNA)

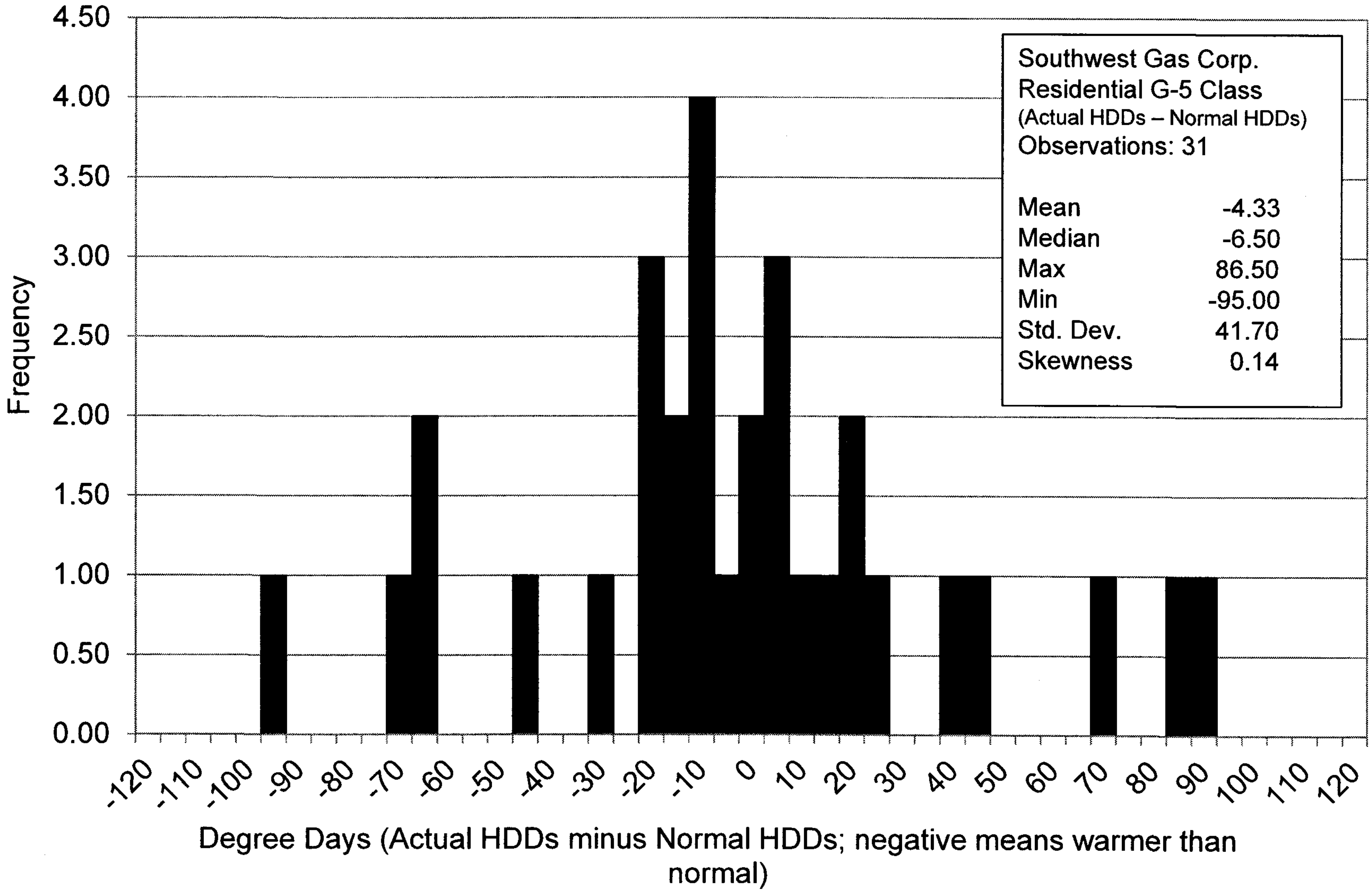
Year	Percent ROE with WNA	Percent ROE without WNA	Difference
1994	11.97%	12.05%	0.08%
1995	11.34%	9.79%	-1.55%
1996	12.38%	13.52%	1.14%
1997	12.35%	11.71%	-0.64%
1998	11.53%	8.19%	-3.34%
1999	12.46%	10.48%	-1.98%
2000	12.74%	12.28%	-0.46%
2001	15.05%	13.80%	-1.25%
2002	8.49%	6.40%	-2.09%
2003	10.44%	11.57%	1.13%
2004	10.84%	10.45%	-0.39%
2005	7.42%	7.05%	-0.37%
2006	7.04%	5.13%	-1.91%
2007	11.93%	10.98%	-0.95%
2008	11.27%	9.84%	-1.43%
Average	11.15%	10.22%	-0.93%

Source: Application of the Southern Connecticut Gas Company for a rate increase. *Connecticut Department of Public Utility Control.* Docket No. 08-12-07. July 17, 2009.

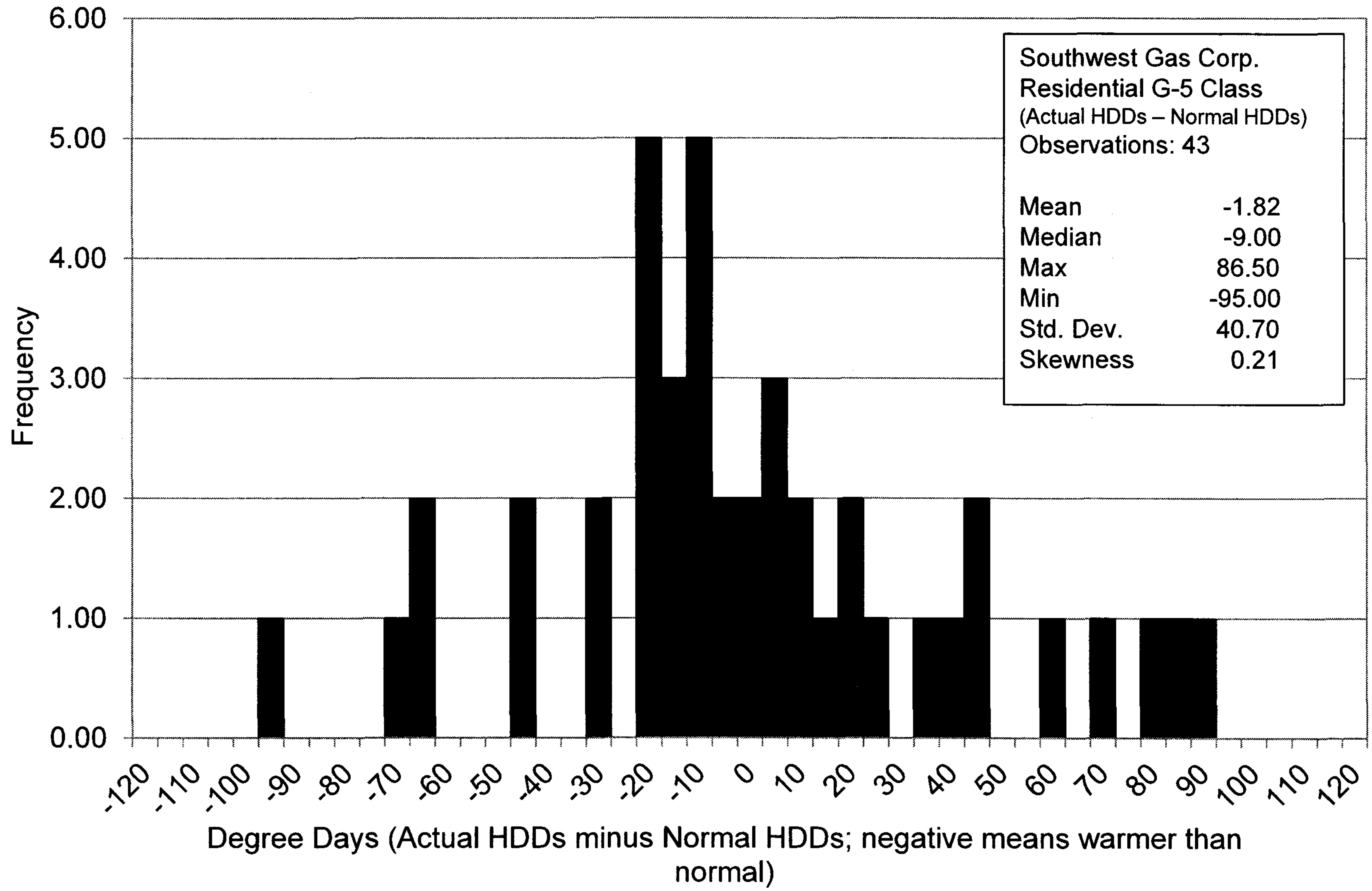
Actual HDDs less Normal HDDs
(3 years ending January 2011, heating season)



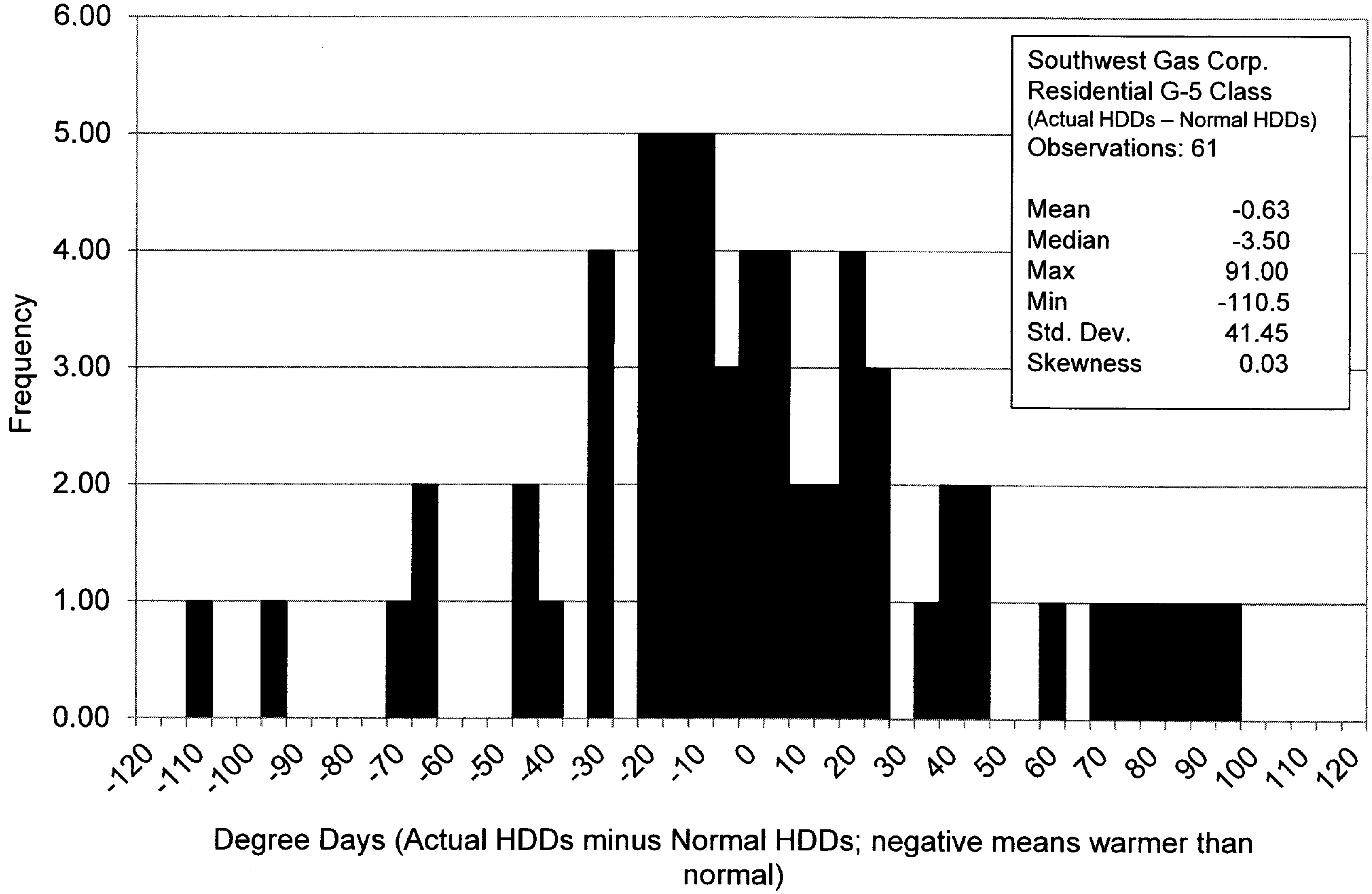
Actual HDDs less Normal HDDs
(5 years ending January 2011, heating season)



Actual HDDs less Normal HDDs
(7 years ending January 2011, heating season)

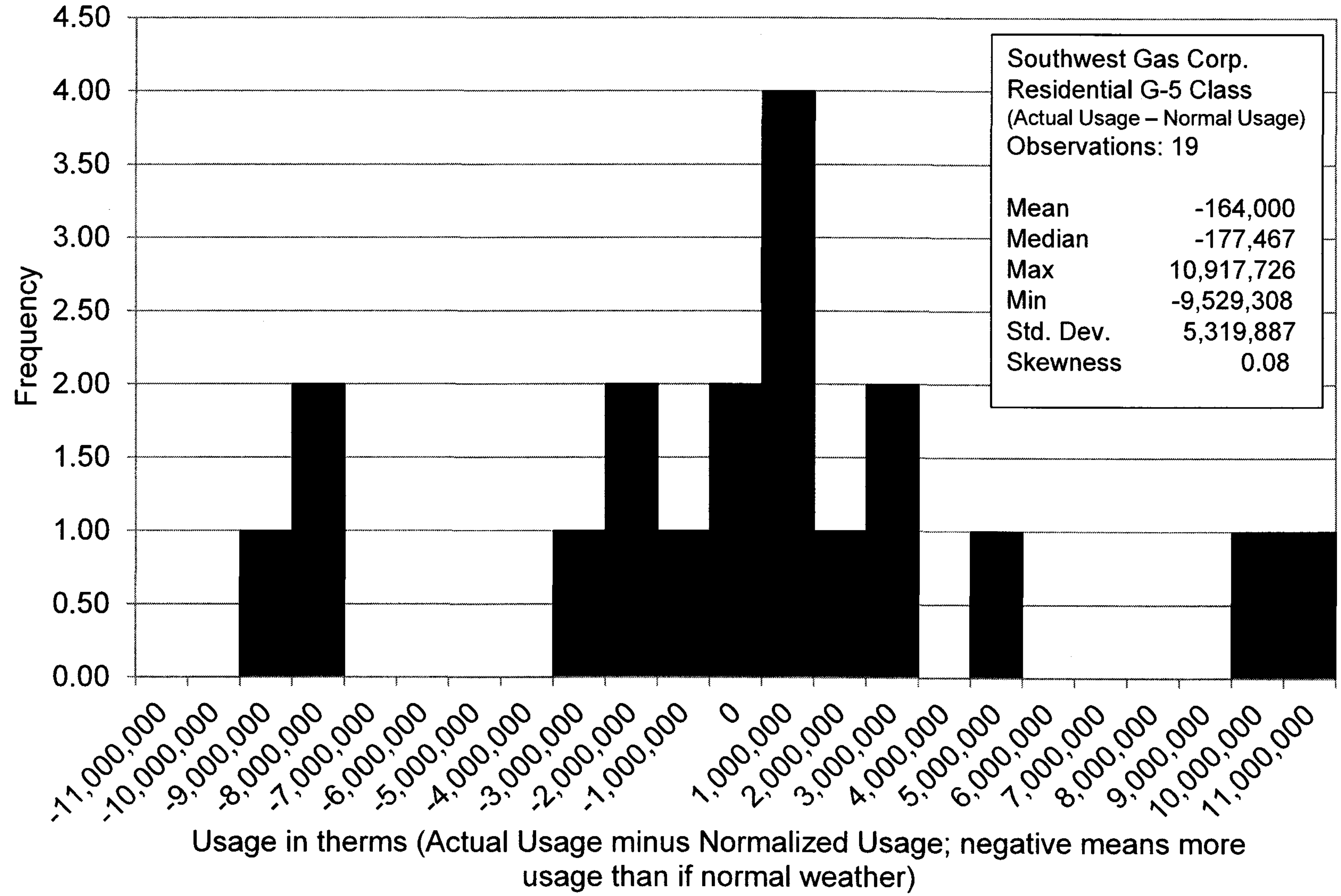


Actual HDDs less Normal HDDs
(10 years ending January 2011, heating season)

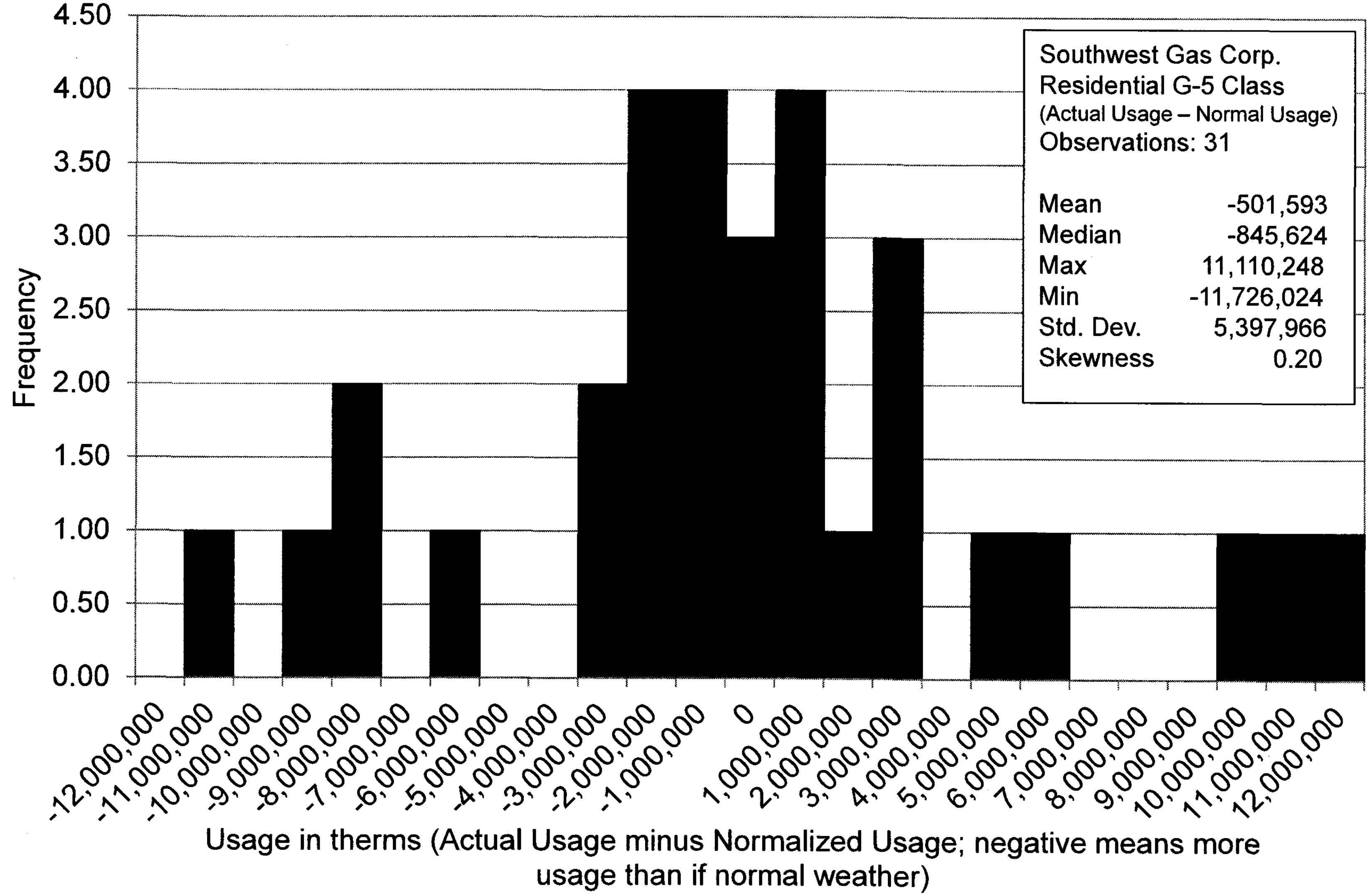


Source: Response to Staff Data Request ACC-STF-3-6.

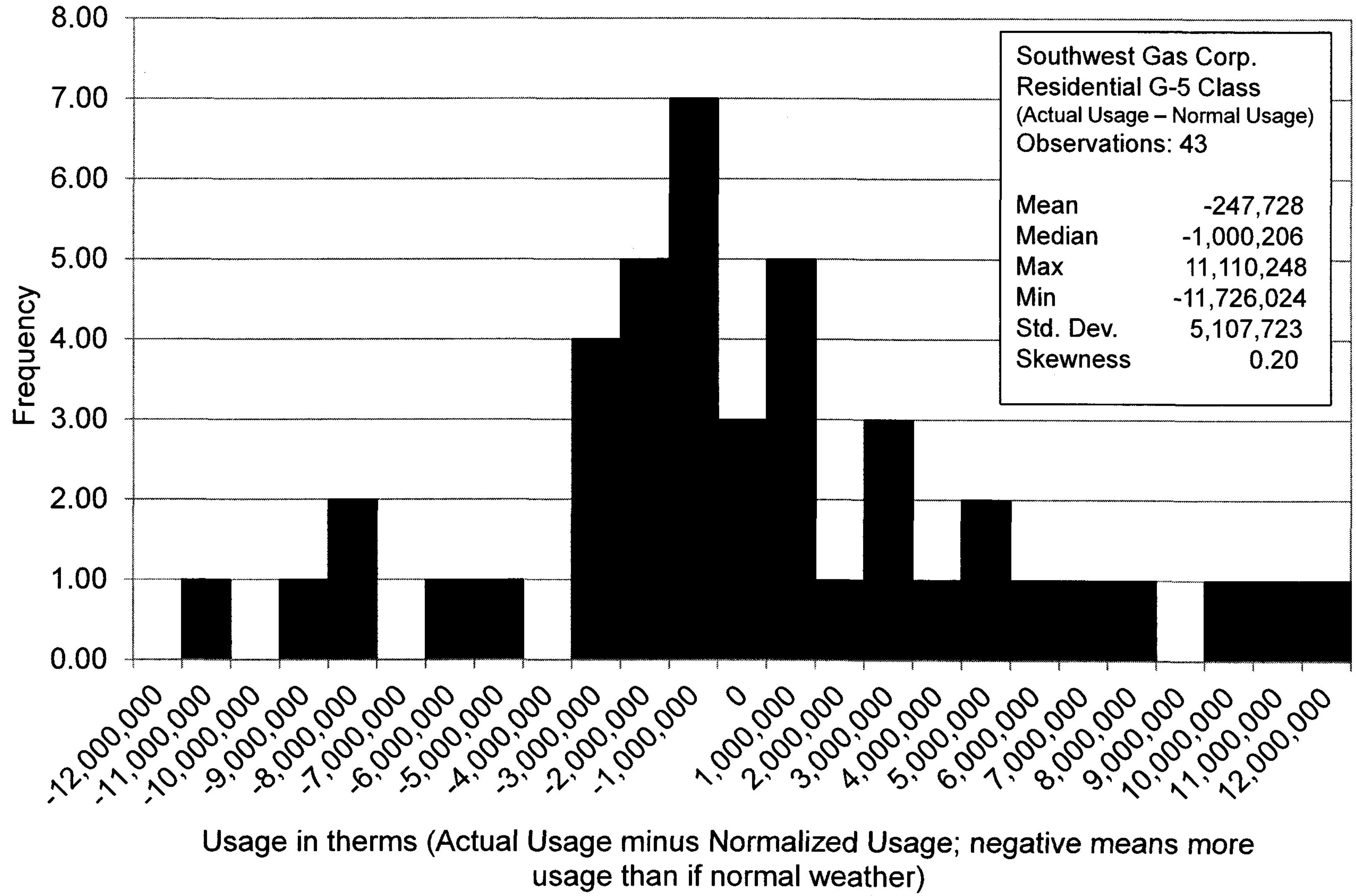
Actual Usage less Normalized Usage
(3 years ending January 2011, heating season)



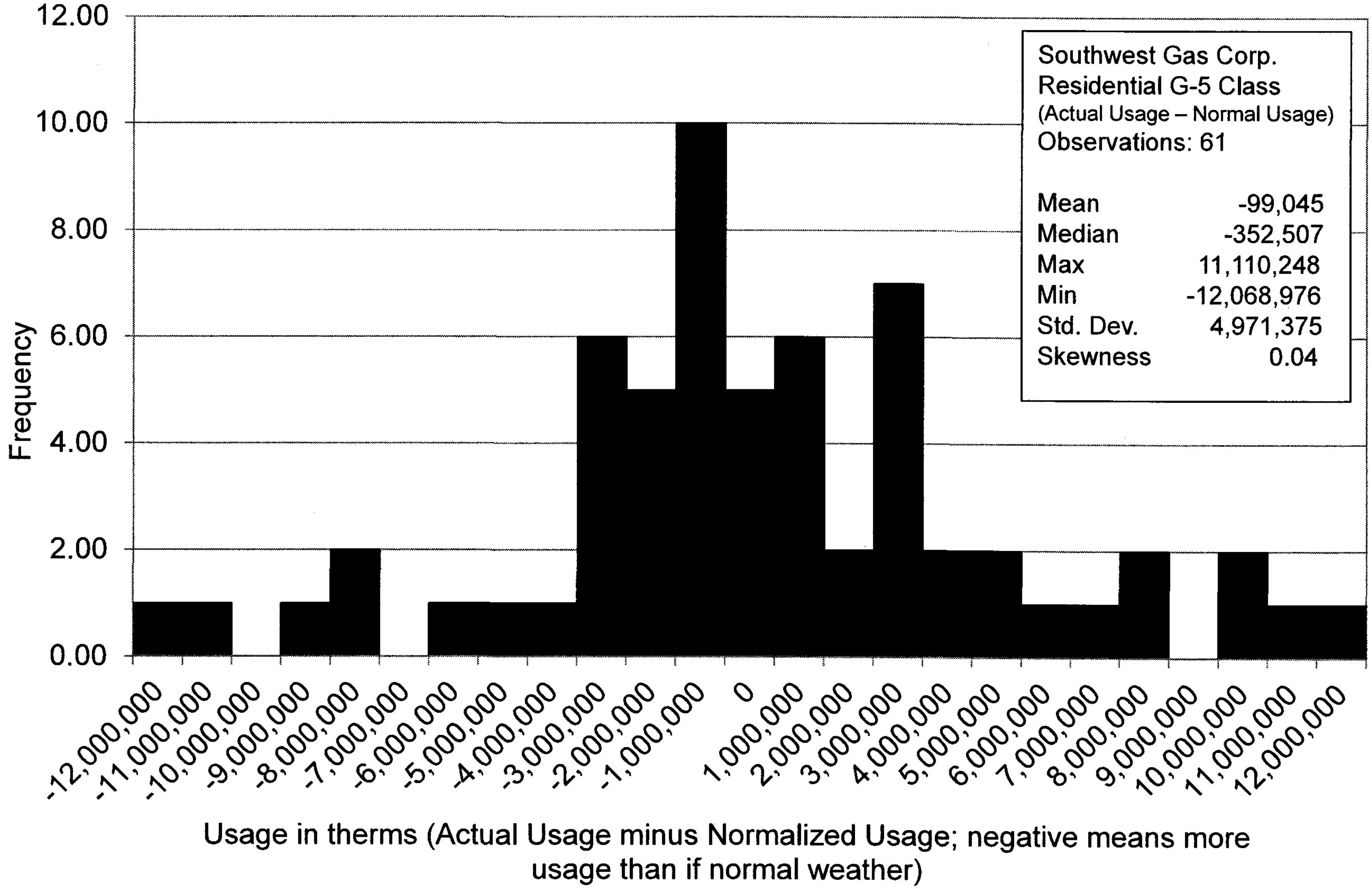
Actual Usage less Normalized Usage
(5 years ending January 2011, heating season)



Actual Usage less Normalized Usage
(7 years ending January 2011, heating season)



Actual Usage less Normalized Usage (10 years ending January 2011, heating season)



Source: Response to Staff Data Request ACC-STF-3-6.

Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decouping - Gas/ Electric	Date of Decision	Decision Type	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Arkansas Oklahoma Gas (AR)	Gas	Gas	11/20/07	Settlement		XXX			
Arkansas Western Gas (AR)	Gas	Gas	06/01/07	Settlement		XXX		XXX	
CenterPoint Energy (AR)	Gas	Gas	10/25/07	Settlement		XXX			
Pacific Gas & Electric (CA)	Electric & Gas	Electric & Gas	05/27/04	Settlement		XXX	XXX		
San Diego Gas & Electric (CA)	Electric & Gas	Electric & Gas	03/17/05	Settlement		XXX	XXX		
Southern California Gas (CA)	Gas	Gas	03/17/05	Settlement		XXX	XXX		
Southern California Edison (CA)	Electric	Electric	04/22/02	Order		XXX	XXX		
Southwest Gas (CA)	Gas	Gas	03/16/04	Order		XXX	XXX		
PSC of Colorado (CO)	Electric & Gas	Gas	06/18/07	Settlement	XXX	XXX	XXX	XXX	
United Illuminating (CT)	Electric	Electric	02/04/09	Order	XXX		XXX		XXX
HECO Companies (HI)*	Electric	Electric	08/31/40	Order		XXX			XXX
Idaho Power (ID)	Electric	Electric	03/12/07	Settlement	XXX		XXX	XXX	
North Shore Gas Company (IL)	Gas	Gas	02/05/08	Settlement	XXX			XXX	XXX
Peoples Gas Light and Coke (IL)	Electric & Gas	Gas	02/05/08	Settlement	XXX			XXX	XXX
Citizens Energy (IN)	Gas	Gas	08/29/07	Settlement			XXX	XXX	
Vectren Southern Indiana Gas (IN)	Gas	Gas	12/01/06	Settlement	XXX	XXX	XXX	XXX	
Vectren Indiana Gas (IN)	Gas	Gas	12/01/06	Settlement	XXX	XXX	XXX	XXX	
Bay State Gas (MA)	Gas	Gas	10/30/09	Order	XXX				
Boston Gas (MA)	Gas	Gas	11/02/10	Order	XXX				
Massachusetts Electric (MA)	Electric	Electric	11/30/09	Order	XXX				
New England Gas (MA)	Gas	Gas	03/31/11	Order	XXX				
Western Massachusetts Electric (MA)	Electric	Electric	01/11/11	Order	XXX				
Baltimore Gas & Electric (MD)	Electric & Gas	Gas	02/27/98	Settlement					
Delmarva Power & Light (MD)	Electric	Electric	07/19/07	Settlement					
PEPCO (MD)	Electric	Electric	07/19/07	Settlement					
Washington Gas (MD)	Gas	Gas	08/11/05	Settlement					
Consumers Energy (MI)	Electric & Gas	Electric	11/02/09	Order			XXX	XXX	XXX
Detroit Edison (MI)	Electric	Electric	01/11/10	Order			XXX	XXX	XXX
Michigan Gas Utilities (MI)	Gas	Gas	07/01/10	Order			XXX	XXX	XXX
Michigan Consolidated Gas (MI)	Gas	Gas	06/03/10	Order			XXX	XXX	XXX
CenterPoint Energy (MN)	Gas	Gas	01/11/10	Settlement	XXX		XXX	XXX	XXX
NorthWestern Energy (MT)	Electric & Gas	Electric	01/07/10	Order				XXX	XXX
Southwest Gas (NV)	Gas	Gas	11/03/09	Order			XXX		
New Jersey Natural (NJ)	Gas	Gas	10/12/06 & 1/21/10	Settlement	XXX	XXX	XXX	XXX	
South Jersey Gas (NJ)	Gas	Gas	10/12/06 & 1/21/10	Settlement	XXX	XXX	XXX	XXX	

Note: *HECO Companies include Hawaiian Electric, Hawaii Electric Light, and Maui Electric Company.

Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decouping - Gas/ Electric	Date of Decision	Decision Type	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Consolidated Edison (NY)	Electric & Gas	Electric & Gas	9/25/07 & 3/25/08	Settlement			XXX	XXX	
National Gas Distribution (NY)	Gas	Gas	09/20/07	Order			XXX		
Orange and Rockland (NY)	Electric & Gas	Electric	07/23/08	Settlement					
Central Hudson Gas & Elec. (NY)	Electric & Gas	Electric & Gas	06/22/09	Settlement	XXX				
Niagara Mohawk (NY)	Electric & Gas	Gas	05/15/09	Settlement					
Piedmont Natural Gas (NC)	Gas	Gas	11/3/05 & 10/23/08	Settlement			XXX	XXX	
PSC of North Carolina (NC)	Gas	Gas	10/24/08	Settlement			XXX		
Vectren (OH)	Gas	Gas	09/13/06	Settlement			XXX	XXX	XXX
Cascade Natural Gas (OR)	Gas	Gas	04/19/06	Settlement		XXX	XXX	XXX	XXX
Northwest Natural (OR)	Gas	Gas	09/12/02	Settlement	XXX		XXX	XXX	
Portland General Electric (OR)	Electric	Electric	01/22/09	Order	XXX		XXX	XXX	XXX
Chattanooga Natural Gas (TN)	Gas	Gas	11/08/10	Order	XXX			XXX	XXX
Questar Gas (UT)	Gas	Gas	10/5/06 & 11/5/07	Order			XXX	XXX	XXX
Virginia Natural (VA)	Gas	Gas	12/23/08	Settlement			XXX	XXX	XXX
Columbia Gas of Virginia (VA)	Gas	Gas	12/04/09	Settlement			XXX	XXX	XXX
Green Mountain Power (VT)	Electric	Electric	12/22/06	Settlement	XXX	XXX	XXX	XXX	
Avista (WA)	Gas	Gas	2/1/07 & 12/22/09	Settlement	XXX	XXX	XXX	XXX	XXX
Cascade Natural Gas (WA)	Gas	Gas	01/12/07	Settlement		XXX	XXX	XXX	XXX
Wisconsin Public Service (WI)	Electric & Gas	Electric & Gas	12/30/08	Settlement	XXX		XXX	XXX	XXX
Questar Gas (WY)	Gas	Gas	06/17/09	Order			XXX	XXX	XXX

Comparison of Class Cost of Service Allocation Factors

FERC Account	Description	Staff Recommended Factor	SWG Factor
OPERATION AND MAINTENANCE EXPENSES			
Distribution Operations & Maintenance Expenses			
813	Other Gas Supply	100% Commodity	100% Commodity
870	Operation Supervision & Engineering	Accounts 871-879	Accounts 871-879
871	Distribution Load Dispatching	100% Commodity	100% Commodity
874	Mains & Services	Accounts 376 & 380 Mains and Services	Accounts 376 & 380 Mains and Services
875	Measuring & Regulating Exps. - General	Account 376	Account 376
878	Meters & House Regulators	Weighted Customers by Meter Cost	Weighted Customers by Meter Cost
879	Customer Installations Expenses	100% Customers	Weighted Customers by Meter Cost
880	Other	Accounts 871-879	Accounts 871-879
881	Rents	Accounts 871-879	Accounts 871-879
885	Maintenance Supervision & Engineering	Accounts 887-893	Accounts 887-893
886	Maintenance of Structures & Improvement	50% Customers / 25% Demand / 25% Commodity	100% Demand
887	Maintenance of Mains	50% Customers / 25% Demand / 25% Commodity	50% Customers / 50% Demand
889	Maint of Meas. & Reg. Station Equipment	50% Commodity / 50% Demand	50% Customers / 50% Demand
892	Maintenance of Services	Account 380	Account 380
893	Maintenance of Meters & House Regulators	Weighted Customers by Meter Cost	Weighted Customers by Meter Cost
894	Maintenance of Other Equipment	Accounts 887-893	Accounts 887-893
Customer Accounts Expense			
901	Supervision	Accounts 902-904	Accounts 902-904
902	Meter Reading Expense	Bills with Meters(# of customers excluding streetlighting)	Bills with Meters(# of customers excluding streetlighting)
903	Customer Accounting	100% Customers	100% Customers
904	Uncollectible Accounts	100% Customers	100% Customers
905	Miscellaneous Expense	Accounts 902-904	Accounts 902-904

Comparison of Class Cost of Service Allocation Factors

FERC Account	Description	Staff Recommended Factor	SWG Factor
Customer Service & Information Expense			
908	Customer Assistance Expense	100% Customers	100% Customers
909	Info. & Instructional Advertising Exps.	100% Customers	100% Customers
910	Msc Customer Service and Info Expense	100% Customers	100% Customers
911-13	Sales Expense	100% Customers	100% Customers
Administrative & General Expense Acts (920-935)		Total O&M Expenses other than A&G	Total O&M Expenses other than A&G
Depreciation Expense		Related Plant	Related Plant
Amortization Expense			
	Amortization Gas Plant Acquisition	Related Plant	Net Distribution Plant
	Regulatory Amortizations	Weighted Customers by Service Cost	Weighted Customers by Service Cost
Interest on Customer Deposits		Applicable Customers	Applicable Customers
Tax Adjustments			
Interest Expense		Net Distribution Plant	Net Distribution Plant
Investment Tax Credit (I.T.C.)		Net Distribution Plant	Net Distribution Plant
South Georgia - Federal		Net Distribution Plant	Net Distribution Plant
Tax Expenses			
Taxes Other Than Income Taxes		Net Distribution Plant	Net Distribution Plant
	State Income Taxes	Calculated	Calculated
	Federal Income Taxes	Calculated	Calculated

Comparison of Class Cost of Service Allocation Factors

FERC Account	Description	Staff Recommended Factor	SWG Factor
RATE BASE ACCOUNTS			
Utility Plant			
Intangible Plant			
301	Organization	Net Distribution Plant	Net Distribution Plant
302	Franchise & Consents	Net Distribution Plant	Net Distribution Plant
303	Miscellaneous Intangible Plant	Net Distribution Plant	Net Distribution Plant
Distribution Plant			
374	Land & Land Rights	Accounts 376 & 378	100% Demand
375	Structures & Improvements	Accounts 376 & 378	100% Demand
376	Mains	50% Customer / 25% Demand / 25% Commodity	50% Customers / 50% Demand
378	Measuring & Regulation Station Equip	50% Commodity / 50% Demand	50% Customers / 50% Demand
380	Services	Weighted Customers by Service Cost	Weighted Customers by Service Cost
381-82	Meters & Meter Installation	Weighted Customers by Meter Cost	Weighted Customers by Meter Cost
385	Measuring & Reg Equipment Industrial	50% Demand / 50% Commodity to Transportation, A/C, and Electric Generation Customers Only	100% Commodity to All Customers
387	Miscellaneous Equipment	100% Customers	100% Demand
389-398	**General Plant**	Net Distribution Plant	*Net Distribution Plant*
OTHER RATE BASE ACCOUNTS			
	Cash Working Capital	Total O&M Expenses	Total O&M Expenses
	Materials & Operating Supplies	Net Distribution Plant	Net Distribution Plant
	Prepayments	Total O&M Expenses	Net Distribution Plant
	Customer Deposits	Applicable customers	Applicable customers
	Customer Advances	Applicable customers	Applicable customers
	Deferred Income Taxes	Net Distribution Plant	Net Distribution Plant

Source: Company Class Cost of Service Study.

Class Cost of Service Study – Present Rates
Under Company's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$1,809,908,655	$1,397,040,982	$ 39,117,897	$2,531,118	$25,709,734	$ 91,238,638	$115,249,313	$ 68,164,677	$49,836,748	$ 225,727	$370,549	$ 2,818,607	$11,841,511	$ 2,652,976	$ 3,110,178
Total Common Systems Allocable Net Plant	38,161,320	29,456,143	824,788	53,368	542,081	1,923,736	2,429,993	1,437,229	1,050,791	4,759	7,813	59,429	249,674	55,937	65,577
Cash Working Capital	(4,472,151)	(3,627,828)	(124,396)	(3,978)	(67,658)	(172,061)	(221,316)	(140,027)	(73,294)	(438)	(626)	(4,630)	(19,703)	(4,606)	(11,591)
Materials & Supplies	9,920,409	7,657,413	214,412	13,873	140,919	500,094	631,701	373,622	273,163	1,237	2,031	15,449	64,905	14,541	17,047
Prepayments	4,744,133	3,661,924	102,536	6,635	67,390	239,155	302,092	178,673	130,632	592	971	7,388	31,039	6,954	8,152
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(224,800,994)	(6,294,548)	(407,288)	(4,137,011)	(14,681,414)	(18,545,025)	(10,968,531)	(8,019,343)	(36,322)	(59,626)	(453,548)	(1,905,444)	(426,896)	(500,466)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$1,456,517,467**	**$1,106,520,949**	**$ 29,890,364**	**$2,176,524**	**$20,303,447**	**$ 77,325,935**	**$ 99,846,757**	**$ 59,045,644**	**$43,198,698**	**$ 195,555**	**$321,112**	**$ 2,442,696**	**$10,261,982**	**$ 2,298,906**	**$ 2,688,898**
Margin															
Net Operating Margin	$ 392,027,615	$ 269,876,468	$ 7,590,591	$ 863,947	$ 7,908,814	$ 22,579,171	$ 43,845,416	$ 21,689,599	$11,254,459	$ 82,169	$ 53,386	$ 859,687	$ 2,982,640	$ 727,284	$ 1,713,984
Special Contract Margin	6,788,127	4,673,028	131,434	14,960	136,945	390,968	759,202	375,565	194,876	1,423	924	14,886	51,646	12,593	29,678
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,108	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	**$ 410,912,098**	**$ 284,999,042**	**$ 8,591,439**	**$ 881,284**	**$ 8,190,937**	**$ 23,218,247**	**$ 44,879,936**	**$ 22,114,557**	**$11,476,217**	**$ 84,064**	**$ 57,847**	**$ 875,850**	**$ 3,039,078**	**$ 746,054**	**$ 1,757,546**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (110,976,336)	$ (3,805,296)	$ (121,689)	$ (2,069,671)	$ (5,263,397)	$ (6,770,127)	$ (4,283,465)	$ (2,242,076)	$ (13,391)	$ (19,145)	$ (141,637)	$ (602,718)	$ (140,894)	$ (354,577)
Administrative & General Expenses	(65,125,498)	(52,830,085)	(1,811,505)	(57,930)	(985,263)	(2,505,631)	(3,222,907)	(2,039,136)	(1,067,336)	(6,375)	(9,114)	(67,426)	(286,923)	(67,072)	(168,796)
Depreciation Expenses	(99,586,591)	(76,869,376)	(2,152,384)	(139,270)	(1,414,627)	(5,020,223)	(6,341,362)	(3,750,625)	(2,742,167)	(12,420)	(20,389)	(155,088)	(651,555)	(145,975)	(171,131)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,203,877)	(20,998,259)	(587,963)	(38,044)	(386,431)	(1,371,365)	(1,732,258)	(1,024,551)	(749,072)	(3,393)	(5,570)	(42,365)	(177,984)	(39,876)	(46,748)
Total Operating Deductions	**$ (331,628,903)**	**$ (264,381,447)**	**$ (8,461,117)**	**$ (357,385)**	**$ (4,907,367)**	**$(14,205,942)**	**$ (18,066,653)**	**$ (11,097,777)**	**$ (6,800,652)**	**$ (35,578)**	**$ (54,217)**	**$ (406,517)**	**$ (1,719,181)**	**$ (393,817)**	**$ (741,252)**
Taxable Income															
Taxable Income before Interest Expense	$ 79,283,195	$ 20,617,595	$ 130,321	$ 523,898	$ 3,283,570	$ 9,012,305	$ 26,813,283	$ 11,016,780	$ 4,675,565	$ 48,485	$ 3,630	$ 469,333	$ 1,319,897	$ 352,237	$ 1,016,295
Interest Expenses	(42,713,744)	(32,970,090)	(923,180)	(59,734)	(606,748)	(2,153,227)	(2,719,877)	(1,608,683)	(1,176,144)	(5,327)	(8,745)	(66,519)	(279,459)	(62,610)	(73,400)
Total Taxable Income	**$ 36,569,451**	**$ (12,352,495)**	**$ (792,859)**	**$ 464,164**	**$ 2,676,821**	**$ 6,859,078**	**$ 24,093,405**	**$ 9,408,097**	**$ 3,499,421**	**$ 43,158**	**$ (5,115)**	**$ 402,814**	**$ 1,040,438**	**$ 289,627**	**$ 942,895**
State Income Tax															
State Income Tax	$ 2,548,159	$ (860,722)	$ (55,246)	$ 32,343	$ 186,521	$ 477,941	$ 1,678,828	$ 655,556	$ 243,840	$ 3,007	$ (356)	$ 28,068	$ 72,498	$ 20,181	$ 65,701
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	**$ 2,548,159**	**$ (860,722)**	**$ (55,246)**	**$ 32,343**	**$ 186,521**	**$ 477,941**	**$ 1,678,828**	**$ 655,556**	**$ 243,840**	**$ 3,007**	**$ (356)**	**$ 28,068**	**$ 72,498**	**$ 20,181**	**$ 65,701**
Federal Income Tax															
Federal Income Tax	$ 11,907,452	$ (4,022,121)	$ (258,164)	$ 151,137	$ 871,605	$ 2,233,398	$ 7,845,102	$ 3,063,389	$ 1,139,453	$ 14,053	$ (1,666)	$ 131,161	$ 338,779	$ 94,306	$ 307,018
Investment Tax Credit (I.T.C.)	(528,360)	(407,833)	(11,420)	(739)	(7,505)	(26,635)	(33,644)	(19,899)	(14,549)	(66)	(108)	(823)	(3,457)	(774)	(908)
South Georgia Federal	290,114	223,935	6,270	406	4,121	14,625	18,474	10,926	7,988	36	59	452	1,898	425	499
Total Federal Income Tax	**$ 11,669,206**	**$ (4,206,019)**	**$ (263,314)**	**$ 150,804**	**$ 868,221**	**$ 2,221,388**	**$ 7,829,931**	**$ 3,054,417**	**$ 1,132,893**	**$ 14,023**	**$ (1,714)**	**$ 130,790**	**$ 337,220**	**$ 93,957**	**$ 306,608**
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	**$ 65,065,829**	**$ 25,684,336**	**$ 448,881**	**$ 340,751**	**$ 2,228,828**	**$ 6,312,976**	**$ 17,304,523**	**$ 7,306,807**	**$ 3,298,832**	**$ 31,455**	**$ 5,700**	**$ 310,475**	**$ 910,179**	**$ 238,099**	**$ 643,985**
Rate of Return on Rate Base	**4.47%**	**2.32%**	**1.50%**	**15.66%**	**10.98%**	**8.16%**	**17.33%**	**12.37%**	**7.64%**	**16.08%**	**1.78%**	**12.71%**	**8.87%**	**10.36%**	**23.95%**

Class Cost of Service Study – Proposed Rates
Under Company's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,908,655	$ 1,397,040,982	$ 39,117,897	$ 2,531,118	$ 25,709,734	$ 91,238,638	$ 115,249,313	$ 68,164,677	$ 49,836,748	$ 225,727	$ 370,549	$ 2,818,607	$ 11,841,511	$ 2,652,976	$ 3,110,178
Total Common Systems Allocable Net Plant	38,161,320	29,456,143	824,788	53,368	542,081	1,923,736	2,429,993	1,437,229	1,050,791	4,759	7,813	59,429	249,674	55,937	65,577
Cash Working Capital	(4,472,151)	(3,627,828)	(124,396)	(3,978)	(67,658)	(172,061)	(221,316)	(140,027)	(73,294)	(438)	(626)	(4,630)	(19,703)	(4,606)	(11,591)
Materials & Supplies	9,920,409	7,657,413	214,412	13,873	140,919	500,094	631,701	373,622	273,163	1,237	2,031	15,449	64,905	14,541	17,047
Prepayments	4,744,133	3,661,924	102,536	6,635	67,390	239,155	302,092	178,673	130,632	592	971	7,388	31,039	6,954	8,152
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(224,800,994)	(6,294,548)	(407,288)	(4,137,011)	(14,681,414)	(18,545,025)	(10,968,531)	(8,019,343)	(36,322)	(59,626)	(453,548)	(1,905,444)	(426,896)	(500,466)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$ 1,456,517,467**	**$ 1,106,520,949**	**$ 29,890,364**	**$ 2,176,524**	**$ 20,303,447**	**$ 77,325,935**	**$ 99,846,757**	**$ 59,045,644**	**$ 43,198,698**	**$ 195,555**	**$ 321,112**	**$ 2,442,696**	**$ 10,261,982**	**$ 2,298,906**	**$ 2,688,898**
Margin															
Net Operating Margin	$ 465,217,053	$ 332,857,067	$ 9,361,994	$ 928,479	$ 8,499,555	$ 24,265,700	$ 47,120,407	$ 23,309,683	$ 12,095,100	$ 88,307	$ 65,845	$ 923,900	$ 3,205,425	$ 781,608	$ 1,713,984
Special Contract Margin	6,788,127	4,856,821	136,604	13,548	124,020	354,068	687,549	340,119	176,483	1,289	961	13,481	46,771	11,405	25,009
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,108	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	**$ 484,101,536**	**$ 348,163,435**	**$ 10,368,011**	**$ 944,404**	**$ 8,768,753**	**$ 24,867,877**	**$ 48,083,273**	**$ 23,699,194**	**$ 12,298,465**	**$ 90,067**	**$ 70,341**	**$ 938,659**	**$ 3,256,989**	**$ 799,189**	**$ 1,752,877**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (110,976,336)	$ (3,805,296)	$ (121,689)	$ (2,069,671)	$ (5,263,397)	$ (6,770,127)	$ (4,283,465)	$ (2,242,076)	$ (13,391)	$ (19,145)	$ (141,637)	$ (602,718)	$ (140,894)	$ (354,577)
Incremental Uncollectible Expenses	(186,105)	(146,035)	(4,444)	(226)	(2,701)	(8,602)	(11,017)	(6,674)	(4,376)	(22)	(34)	(256)	(1,079)	(245)	(395)
Administrative & General Expenses	(65,125,498)	(52,830,085)	(1,811,505)	(57,930)	(985,263)	(2,505,631)	(3,222,907)	(2,039,136)	(1,067,336)	(6,375)	(9,114)	(67,426)	(286,923)	(67,072)	(168,796)
Depreciation Expenses	(99,586,591)	(76,869,376)	(2,152,384)	(139,270)	(1,414,627)	(5,020,223)	(6,341,362)	(3,750,625)	(2,742,167)	(12,420)	(20,389)	(155,088)	(651,555)	(145,975)	(171,131)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,203,877)	(20,998,259)	(587,963)	(38,044)	(386,431)	(1,371,365)	(1,732,258)	(1,024,551)	(749,072)	(3,393)	(5,570)	(42,365)	(177,984)	(39,876)	(46,748)
Total Operating Deductions	**$ (331,815,008)**	**$ (264,527,482)**	**$ (8,465,561)**	**$ (357,611)**	**$ (4,910,068)**	**$ (14,214,545)**	**$ (18,077,670)**	**$ (11,104,451)**	**$ (6,805,028)**	**$ (35,600)**	**$ (54,251)**	**$ (406,773)**	**$ (1,720,260)**	**$ (394,062)**	**$ (741,646)**
State Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 83,635,953	$ 1,902,450	$ 586,792	$ 3,858,685	$ 10,653,332	$ 30,005,603	$ 12,594,744	$ 5,493,438	$ 54,467	$ 16,091	$ 531,886	$ 1,536,729	$ 405,127	$ 1,011,231
Interest Expenses	(42,713,744)	(32,970,090)	(923,180)	(59,734)	(606,748)	(2,153,227)	(2,719,877)	(1,608,683)	(1,176,144)	(5,327)	(8,745)	(66,519)	(279,459)	(62,610)	(73,400)
State Taxable Income	$ 109,572,784	$ 50,665,863	$ 979,270	$ 527,058	$ 3,251,937	$ 8,500,106	$ 27,285,726	$ 10,986,061	$ 4,317,293	$ 49,140	$ 7,346	$ 465,367	$ 1,257,270	$ 342,517	$ 937,831
State Income Tax	$ 7,635,032	$ 3,530,397	$ 68,236	$ 36,725	$ 226,595	$ 592,287	$ 1,901,269	$ 765,509	$ 300,829	$ 3,424	$ 512	$ 32,427	$ 87,607	$ 23,867	$ 65,348
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	$ 7,635,032	$ 3,530,397	$ 68,236	$ 36,725	$ 226,595	$ 592,287	$ 1,901,269	$ 765,509	$ 300,829	$ 3,424	$ 512	$ 32,427	$ 87,607	$ 23,867	$ 65,348
Federal Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 83,635,953	$ 1,902,450	$ 586,792	$ 3,858,685	$ 10,653,332	$ 30,005,603	$ 12,594,744	$ 5,493,438	$ 54,467	$ 16,091	$ 531,886	$ 1,536,729	$ 405,127	$ 1,011,231
Interest Expenses	(42,713,744)	(32,970,090)	(923,180)	(59,734)	(606,748)	(2,153,227)	(2,719,877)	(1,608,683)	(1,176,144)	(5,327)	(8,745)	(66,519)	(279,459)	(62,610)	(73,400)
Federal Taxable Income	$ 109,572,784	$ 50,665,863	$ 979,270	$ 527,058	$ 3,251,937	$ 8,500,106	$ 27,285,726	$ 10,986,061	$ 4,317,293	$ 49,140	$ 7,346	$ 465,367	$ 1,257,270	$ 342,517	$ 937,831
Federal Income Tax	$ 35,678,214	$ 16,497,413	$ 318,862	$ 171,616	$ 1,058,870	$ 2,767,736	$ 8,884,560	$ 3,577,193	$ 1,405,762	$ 16,000	$ 2,392	$ 151,529	$ 409,382	$ 111,528	$ 305,369
Investment Tax Credit (I.T.C.)	(528,360)	(407,833)	(11,420)	(739)	(7,505)	(26,635)	(33,644)	(19,899)	(14,549)	(66)	(108)	(823)	(3,457)	(774)	(908)
South Georgia Federal	290,114	223,935	6,270	406	4,121	14,625	18,474	10,926	7,988	36	59	452	1,898	425	499
Total Federal Income Tax	$ 35,439,968	$ 16,313,515	$ 313,713	$ 171,283	$ 1,055,485	$ 2,755,726	$ 8,869,389	$ 3,568,221	$ 1,399,202	$ 15,971	$ 2,343	$ 151,158	$ 407,823	$ 111,179	$ 304,960
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	$ 109,211,529	$ 63,792,041	$ 1,520,502	$ 378,784	$ 2,576,605	$ 7,305,319	$ 19,234,945	$ 8,261,014	$ 3,793,406	$ 35,072	$ 13,236	$ 348,301	$ 1,041,299	$ 270,082	$ 640,923
Rate of Return on Rate Base	**7.50%**	**5.77%**	**5.09%**	**17.40%**	**12.69%**	**9.45%**	**19.26%**	**13.99%**	**8.78%**	**17.93%**	**4.12%**	**14.26%**	**10.15%**	**11.75%**	**23.84%**

Source: AZ 2010 CCOSS and rate design.

Class Cost of Service Study – Present Rates
Under Staff's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$1,809,908,655	$ 1,346,606,658	$ 38,369,221	$2,407,161	$27,536,194	$ 97,399,492	$120,612,420	$ 93,599,302	$52,526,767	$ 463,520	$411,011	$ 3,549,482	$17,688,579	$ 2,730,037	$ 6,008,811
Total Common Systems Allocable Net Plant	38,161,320	28,392,752	809,002	50,754	580,591	2,053,636	2,543,073	1,973,510	1,107,509	9,773	8,666	74,840	372,958	57,562	126,694
Cash Working Capital	(4,472,151)	(3,469,691)	(114,853)	(4,972)	(70,371)	(182,692)	(275,944)	(194,199)	(94,294)	(941)	(760)	(7,566)	(35,209)	(6,048)	(14,609)
Materials & Supplies	9,920,409	7,380,974	210,308	13,194	150,930	533,863	661,097	513,033	287,908	2,541	2,253	19,455	96,954	14,964	32,935
Prepayments	4,744,133	3,680,707	121,838	5,274	74,651	193,803	292,726	206,010	100,029	998	807	8,027	37,351	6,416	15,498
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(216,685,494)	(6,174,077)	(387,342)	(4,430,911)	(15,672,770)	(19,408,015)	(15,061,273)	(8,452,200)	(74,586)	(66,137)	(571,155)	(2,846,309)	(439,296)	(966,891)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$1,456,517,467**	**$1,063,039,215**	**$ 29,271,115**	**$2,066,866**	**$21,889,076**	**$ 82,603,117**	**$104,425,357**	**$ 81,036,382**	**$45,475,719**	**$ 401,305**	**$355,839**	**$ 3,073,082**	**$15,314,323**	**$ 2,363,634**	**$ 5,202,437**
Margin															
Net Operating Margin	$ 392,027,615	$ 269,876,468	$ 7,590,591	$ 863,947	$ 7,908,814	$ 22,579,171	$ 43,845,416	$ 21,689,599	$11,254,459	$ 82,169	$ 53,386	$ 859,687	$ 2,982,640	$ 727,284	$ 1,713,984
Special Contract Margin	6,788,127	4,673,028	131,434	14,960	136,945	390,968	759,202	375,565	194,876	1,423	924	14,886	51,646	12,593	29,678
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,108	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	**$ 410,912,098**	**$ 284,999,042**	**$ 8,591,439**	**$ 881,284**	**$ 8,190,937**	**$ 23,218,247**	**$ 44,879,936**	**$ 22,114,557**	**$11,476,217**	**$ 84,064**	**$ 57,847**	**$ 875,850**	**$ 3,039,078**	**$ 746,054**	**$ 1,757,546**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (106,138,894)	$ (3,513,395)	$ (152,082)	$ (2,152,664)	$ (5,588,601)	$ (8,441,211)	$ (5,940,617)	$ (2,884,487)	$ (28,774)	$ (23,263)	$ (231,457)	$ (1,077,064)	$ (185,015)	$ (446,895)
Incremental Uncollectible Expenses	$ (65,125,498)	$ (50,527,229)	$ (1,672,545)	$ (72,399)	$ (1,024,772)	$ (2,660,444)	$ (4,018,423)	$ (2,828,020)	$ (1,373,155)	$ (13,698)	$ (11,074)	$ (110,185)	$ (512,735)	$ (88,076)	$ (212,743)
Administrative & General Expenses	(99,586,591)	(74,094,328)	(2,111,189)	(132,449)	(1,515,124)	(5,359,212)	(6,636,456)	(5,150,114)	(2,890,180)	(25,504)	(22,615)	(195,303)	(973,279)	(150,215)	(330,623)
Depreciation Expenses	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Interest on Customer Deposits	(27,203,877)	(20,240,205)	(576,710)	(36,181)	(413,883)	(1,463,965)	(1,812,868)	(1,406,847)	(789,505)	(6,967)	(6,178)	(53,351)	(265,869)	(41,034)	(90,316)
Taxes other than Income	(331,628,903)	(253,708,047)	(7,977,809)	(393,564)	(5,157,819)	(15,117,550)	(20,908,958)	(15,325,598)	(7,937,327)	(74,943)	(63,130)	(590,296)	(2,828,946)	(464,340)	(1,080,577)
Total Operating Deductions	**$ (331,628,903)**														
Taxable Income		31290995.67	613629.477	487720.13	3033117.82	8100697.87	23970978	6788959	3538889.81	9120.221045	-5283.83	285554.7741	210131.989	281713.92	676969.856
Taxable Income before Interest Expense	$ 79,283,195	$ (31,779,842)	$ (905,511)	$ (56,809)	$ (649,853)	$ (2,298,623)	$ (2,846,446)	$ (2,208,938)	$ (1,239,629)	$ (10,939)	$ (9,700)	$ (83,768)	$ (417,449)	$ (64,429)	$ (141,808)
Interest Expenses	(42,713,744)	(488,847)	(291,882)	430,911	2,383,265	5,802,075	21,124,532	4,580,021	2,299,261	(1,819)	(14,984)	201,787	(207,317)	217,285	535,162
Total Taxable Income	**$ 36,569,451**														
State Income Tax		-34062.84226	-20338.3388	30025.896	166065.916	404288.604	1471957.36	319135.8407	160212.508	-126.7356772	-1044.06	14060.53172	-14445.882	15140.4327	37290.1058
State Income Tax	$ 2,548,159	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
South Georgia State	-	(34,063)	(20,338)	30,026	166,066	404,289	1,471,957	319,136	160,213	(127)	(1,044)	14,061	(14,446)	15,140	37,290
Total State Income Tax	**$ 2,548,159**														
Federal Income Tax		-159174.3713	-95040.2869	140309.88	776019.735	1889225.33	6878400.973	1491309.692	748666.98	-592.2310177	-4878.86	65704.332	-67505.061	70750.6682	174255.252
Federal Income Tax	$ 11,907,452	$ (393,110)	$ (11,201)	$ (703)	$ (8,039)	$ (28,433)	$ (35,210)	$ (27,324)	$ (15,334)	$ (135)	$ (120)	$ (1,036)	$ (5,164)	$ (797)	$ (1,754)
Investment Tax Credit (I.T.C.)	(528,360)	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
South Georgia Federal	290,114	(336,434)	(100,091)	139,993	772,395	1,876,404	6,862,524	1,478,989	741,753	(653)	(4,933)	65,237	(69,833)	70,391	173,464
Total Federal Income Tax	**$ 11,669,206**														
		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Amortization	$ -														
		31661492.46	734058.807	317701.22	2094656.87	5820005.04	15636496.39	4990834.342	2636924.64	9900.202851	693.198	206257.1438	294411.356	196182.185	466215.464
Net Income	**$ 65,065,829**														
		0.029783936	0.02507792	0.1537116	0.09569417	0.07045745	0.149738501	0.061587576	0.05798533	0.024670026	0.00195	0.067117357	0.01922458	0.08300023	0.08961482
Rate of Return on Rate Base	**4.47%**	**3.11%**	**2.58%**	**15.38%**	**12.28%**	**7.07%**	**13.96%**	**5.96%**	**4.91%**	**2.70%**	**1.51%**	**6.44%**	**2.09%**	**6.60%**	**6.97%**

Class Cost of Service Study – Proposed Rates
Under Staff's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,908,655	$ 1,346,606,658	$ 38,369,221	$ 2,407,161	$ 27,536,194	$ 97,399,492	$ 120,612,420	$ 93,599,302	$ 52,526,767	$ 463,520	$ 411,011	$ 3,549,482	$ 17,688,579	$ 2,730,037	$ 6,008,811
Total Common Systems Allocable Net Plant	38,161,320	28,392,752	809,002	50,754	580,591	2,053,636	2,543,073	1,973,510	1,107,509	9,773	8,666	74,840	372,958	57,562	126,694
Cash Working Capital	(4,472,151)	(3,469,691)	(114,853)	(4,972)	(70,371)	(182,692)	(275,944)	(194,199)	(94,294)	(941)	(760)	(7,566)	(35,209)	(6,048)	(14,609)
Materials & Supplies	9,920,409	7,380,974	210,308	13,194	150,930	533,863	661,097	513,033	287,908	2,541	2,253	19,455	96,954	14,964	32,935
Prepayments	4,744,133	3,680,707	121,838	5,274	74,651	193,803	292,726	206,010	100,029	998	807	8,027	37,351	6,416	15,498
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(216,685,494)	(6,174,077)	(387,342)	(4,430,911)	(15,672,770)	(19,408,015)	(15,061,273)	(8,452,200)	(74,586)	(66,137)	(571,155)	(2,846,309)	(439,296)	(966,891)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$ 1,456,617,467**	**$ 1,063,039,215**	**$ 29,271,116**	**$ 2,066,866**	**$ 21,889,076**	**$ 82,603,117**	**$ 104,425,357**	**$ 81,036,382**	**$ 45,475,719**	**$ 401,306**	**$ 355,839**	**$ 3,073,082**	**$ 15,314,323**	**$ 2,363,634**	**$ 5,202,437**
Margin															
Net Operating Margin	$ 465,217,053	$ 332,857,067	$ 9,361,994	$ 924,698	$ 8,464,941	$ 23,255,120	$ 46,928,513	$ 23,519,082	$ 12,545,302	$ 101,345	$ 65,845	$ 901,522	$ 3,678,693	$ 778,425	$ 1,834,507
Special Contract Margin	6,788,127	4,856,821	136,604	13,493	123,515	339,323	684,749	343,174	183,052	1,479	961	13,154	53,677	11,358	26,768
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,108	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	**$ 484,101,536**	**$ 348,163,435**	**$ 10,368,011**	**$ 940,567**	**$ 8,733,634**	**$ 23,842,551**	**$ 47,888,579**	**$ 23,911,650**	**$ 12,755,237**	**$ 103,296**	**$ 70,341**	**$ 915,954**	**$ 3,737,163**	**$ 796,960**	**$ 1,875,159**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (106,138,894)	$ (3,513,395)	$ (152,082)	$ (2,152,664)	$ (5,588,601)	$ (8,441,211)	$ (5,940,617)	$ (2,884,487)	$ (28,774)	$ (23,263)	$ (231,457)	$ (1,077,064)	$ (185,015)	$ (446,895)
Incremental Uncollectible Expenses	(186,105)	(140,160)	(4,233)	(235)	(2,862)	(9,167)	(12,296)	(9,196)	(4,905)	(45)	(39)	(352)	(1,712)	(275)	(628)
Administrative & General Expenses	(65,125,498)	(50,527,229)	(1,672,545)	(72,399)	(1,024,772)	(2,660,444)	(4,018,423)	(2,828,020)	(1,373,155)	(13,698)	(11,074)	(110,185)	(512,735)	(88,076)	(212,743)
Depreciation Expenses	(99,586,591)	(74,094,328)	(2,111,189)	(132,449)	(1,515,124)	(5,359,212)	(6,636,456)	(5,150,114)	(2,890,180)	(25,504)	(22,615)	(195,303)	(973,279)	(150,215)	(330,623)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,203,877)	(20,240,205)	(576,710)	(36,181)	(413,883)	(1,463,965)	(1,812,868)	(1,406,847)	(789,505)	(6,967)	(6,178)	(53,351)	(265,869)	(41,034)	(90,316)
Total Operating Deductions	$ (331,815,008)	$ (253,848,207)	$ (7,982,042)	$ (393,799)	$ (5,160,681)	$ (15,126,717)	$ (20,921,254)	$ (15,334,793)	$ (7,942,232)	$ (74,989)	$ (63,169)	$ (590,648)	$ (2,830,658)	$ (464,615)	$ (1,081,204)
State Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 94,315,228	$ 2,385,969	$ 546,768	$ 3,572,954	$ 8,715,834	$ 26,967,326	$ 8,576,856	$ 4,813,004	$ 28,307	$ 7,172	$ 325,306	$ 906,505	$ 331,345	$ 793,955
Interest Expenses	(42,713,744)	(31,779,842)	(905,511)	(56,809)	(649,853)	(2,298,623)	(2,846,446)	(2,208,938)	(1,239,629)	(10,939)	(9,700)	(83,768)	(417,449)	(64,429)	(141,808)
State Taxable Income	$ 109,572,784	$ 62,535,386	$ 1,480,457	$ 489,959	$ 2,923,101	$ 6,417,211	$ 24,120,879	$ 6,367,918	$ 3,573,375	$ 17,368	$ (2,527)	$ 241,538	$ 489,055	$ 266,916	$ 652,147
State Income Tax	$ 7,635,032	$ 4,357,466	$ 103,158	$ 34,140	$ 203,682	$ 447,151	$ 1,680,743	$ 443,717	$ 248,993	$ 1,210	$ (176)	$ 16,830	$ 34,077	$ 18,599	$ 45,442
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	$ 7,635,032	$ 4,357,466	$ 103,158	$ 34,140	$ 203,682	$ 447,151	$ 1,680,743	$ 443,717	$ 248,993	$ 1,210	$ (176)	$ 16,830	$ 34,077	$ 18,599	$ 45,442
Federal Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 94,315,228	$ 2,385,969	$ 546,768	$ 3,572,954	$ 8,715,834	$ 26,967,326	$ 8,576,856	$ 4,813,004	$ 28,307	$ 7,172	$ 325,306	$ 906,505	$ 331,345	$ 793,955
Interest Expenses	(42,713,744)	(31,779,842)	(905,511)	(56,809)	(649,853)	(2,298,623)	(2,846,446)	(2,208,938)	(1,239,629)	(10,939)	(9,700)	(83,768)	(417,449)	(64,429)	(141,808)
Federal Taxable Income	$ 109,572,784	$ 62,535,386	$ 1,480,457	$ 489,959	$ 2,923,101	$ 6,417,211	$ 24,120,879	$ 6,367,918	$ 3,573,375	$ 17,368	$ (2,527)	$ 241,538	$ 489,055	$ 266,916	$ 652,147
Federal Income Tax	$ 35,678,214	$ 20,362,272	$ 482,055	$ 159,537	$ 951,797	$ 2,089,521	$ 7,854,048	$ 2,073,471	$ 1,163,534	$ 5,655	$ (823)	$ 78,648	$ 159,242	$ 86,911	$ 212,347
Investment Tax Credit (I.T.C.)	(528,360)	(393,110)	(11,201)	(703)	(8,039)	(28,433)	(35,210)	(27,324)	(15,334)	(135)	(120)	(1,036)	(5,164)	(797)	(1,754)
South Georgia Federal	290,114	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
Total Federal Income Tax	$ 35,439,968	$ 20,185,012	$ 477,004	$ 159,220	$ 948,172	$ 2,076,700	$ 7,838,171	$ 2,061,150	$ 1,156,620	$ 5,594	$ (877)	$ 78,181	$ 156,914	$ 86,552	$ 211,556
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Net Income	$ 109,211,529	$ 69,772,750	$ 1,805,807	$ 353,408	$ 2,421,100	$ 6,191,983	$ 17,448,412	$ 6,071,990	$ 3,407,392	$ 21,502	$ 8,226	$ 230,295	$ 715,514	$ 226,194	$ 536,957
Rate of Return on Rate Base	**7.50%**	**6.56%**	**6.17%**	**17.10%**	**11.06%**	**7.50%**	**16.71%**	**7.49%**	**7.49%**	**5.36%**	**2.31%**	**7.49%**	**4.67%**	**9.57%**	**10.32%**

Source: AZ 2010 CCOSS and rate design.

Comparison of Class Rate of Returns Under Company's and Staff's CCOSS

	Company's Original CCOSS	Company's Proposed CCOSS	Staff's Recommended CCOSS
Single-Family Residential Gas Service	2.32%	5.77%	5.94%
Multi-Family Residential Gas Service	1.50%	5.09%	5.48%
Master Metered Mobile Home Park Gas Service	15.66%	17.40%	17.03%
Small General Gas Service	10.98%	12.69%	11.08%
Medium General Gas Service	8.16%	9.45%	8.09%
Large-1 General Gas Service	17.33%	19.26%	16.65%
Large-2 General Gas Service	7.64%	8.78%	7.02%
Transportation Eligible	12.37%	13.99%	7.02%
Air Conditioning Gas Service	16.08%	17.93%	4.95%
Street Lighting	1.78%	4.12%	1.94%
Gas Service for Compression on Customer's Premises	12.71%	14.26%	7.02%
Electric Cogeneration	8.87%	10.15%	4.30%
Small Essential Agriculture User Gas Service	10.36%	11.75%	9.59%
Natural Gas Engines	23.95%	23.84%	10.35%
Overall	4.47%	7.50%	7.02%

Source: Company's Class Cost of Service Study.

Class Cost of Service Study – Present Rates
Staff Recommended Revenue Requirement

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,572,803	$ 1,346,357,520	$ 38,362,434	$ 2,406,675	$ 27,531,432	$ 97,381,463	$ 120,588,399	$ 93,582,850	$ 52,516,333	$ 463,431	$ 410,926	$ 3,548,748	$ 17,685,225	$ 2,729,530	$ 6,007,837
Total Common Systems Allocable Net Plant	36,846,288	27,414,358	781,131	49,004	560,591	1,982,869	2,455,405	1,905,522	1,069,331	9,436	8,367	72,259	360,104	55,578	122,331
Cash Working Capital	(4,940,151)	(3,830,442)	(126,154)	(5,493)	(77,773)	(204,324)	(305,199)	(213,667)	(105,379)	(1,037)	(854)	(8,339)	(38,748)	(6,664)	(16,080)
Materials & Supplies	9,920,409	7,380,978	210,310	13,194	150,932	533,863	661,088	513,038	287,904	2,541	2,253	19,455	96,954	14,964	32,936
Prepayments	4,559,036	3,534,937	116,422	5,069	71,773	188,561	281,654	197,183	97,250	957	788	7,696	35,758	6,150	14,839
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(292,517,552)	(217,638,773)	(6,201,290)	(389,039)	(4,450,458)	(15,741,719)	(19,493,122)	(15,127,673)	(8,489,268)	(74,914)	(66,426)	(573,655)	(2,858,818)	(441,229)	(971,167)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$ 1,452,932,392**	**$ 1,060,351,888**	**$ 29,192,529**	**$ 2,062,206**	**$ 21,834,489**	**$ 82,418,499**	**$ 104,188,225**	**$ 80,857,253**	**$ 45,376,170**	**$ 400,415**	**$ 355,054**	**$ 3,066,163**	**$ 15,280,476**	**$ 2,358,330**	**$ 5,190,697**
Margin															
Net Operating Margin	$ 389,982,496	$ 267,949,922	$ 7,472,018	$ 863,947	$ 7,908,814	$ 22,579,171	$ 43,845,416	$ 21,689,599	$ 11,254,459	$ 82,169	$ 53,386	$ 859,687	$ 2,982,640	$ 727,284	$ 1,713,984
Special Contract Margin	6,788,127	4,664,000	130,060	15,038	137,663	393,018	763,184	377,534	195,898	1,430	929	14,964	51,917	12,659	29,834
Other Revenue	12,096,356	10,448,939	869,321	2,383	145,227	248,246	275,586	49,525	26,951	472	3,536	1,283	4,810	6,181	13,895
Total Revenue	**$ 408,866,979**	**$ 283,062,861**	**$ 8,471,399**	**$ 881,368**	**$ 8,191,703**	**$ 23,220,436**	**$ 44,884,185**	**$ 22,116,659**	**$ 11,477,308**	**$ 84,072**	**$ 57,852**	**$ 875,934**	**$ 3,039,367**	**$ 746,125**	**$ 1,757,713**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,838,555)	$ (106,100,435)	$ (3,494,376)	$ (152,146)	$ (2,154,245)	$ (5,659,619)	$ (8,453,780)	$ (5,918,414)	$ (2,918,927)	$ (28,719)	$ (23,646)	$ (230,988)	$ (1,073,281)	$ (184,588)	$ (445,391)
Administrative & General Expenses	(59,195,567)	(45,898,434)	(1,511,647)	(65,817)	(931,914)	(2,448,319)	(3,657,056)	(2,560,272)	(1,262,711)	(12,424)	(10,229)	(99,924)	(464,295)	(79,852)	(192,673)
Depreciation Expenses	(99,569,492)	(74,081,647)	(2,110,845)	(132,424)	(1,514,883)	(5,358,294)	(6,635,227)	(5,149,280)	(2,889,646)	(25,500)	(22,611)	(195,265)	(973,107)	(150,189)	(330,574)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,065,517)	(20,137,274)	(573,781)	(35,996)	(411,784)	(1,456,520)	(1,803,623)	(1,399,705)	(785,479)	(6,931)	(6,146)	(53,078)	(264,515)	(40,825)	(89,858)
Total Operating Deductions	**$ (325,577,647)**	**$ (248,925,180)**	**$ (7,794,619)**	**$ (386,837)**	**$ (5,064,201)**	**$ (14,968,080)**	**$ (20,549,686)**	**$ (15,027,671)**	**$ (7,856,763)**	**$ (73,574)**	**$ (62,632)**	**$ (579,255)**	**$ (2,775,199)**	**$ (455,454)**	**$(1,058,496)**
Taxable Income															
Taxable Income before Interest Expense	$ 83,289,332	$ 34,137,681	$ 676,779	$ 494,531	$ 3,127,503	$ 8,252,356	$ 24,334,499	$ 7,088,988	$ 3,620,545	$ 10,497	$ (4,780)	$ 296,678	$ 264,168	$ 290,671	$ 699,217
Interest Expenses	(42,571,123)	(31,673,747)	(902,496)	(56,618)	(647,691)	(2,290,949)	(2,836,904)	(2,201,584)	(1,235,474)	(10,902)	(9,667)	(83,486)	(416,054)	(64,214)	(141,337)
Total Taxable Income	**$ 40,718,209**	**$ 2,463,934**	**$ (225,717)**	**$ 437,913**	**$ 2,479,812**	**$ 5,961,407**	**$ 21,497,596**	**$ 4,887,403**	**$ 2,385,071**	**$ (405)**	**$ (14,448)**	**$ 213,192**	**$ (151,886)**	**$ 226,457**	**$ 557,879**
State Income Tax															
State Income Tax	$ 2,830,038	$ 171,251	$ (15,688)	$ 30,436	$ 172,354	$ 414,336	$ 1,494,147	$ 339,689	$ 165,770	$ (28)	$ (1,004)	$ 14,817	$ (10,557)	$ 15,739	$ 38,774
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	**$ 2,830,038**	**$ 171,251**	**$ (15,688)**	**$ 30,436**	**$ 172,354**	**$ 414,336**	**$ 1,494,147**	**$ 339,689**	**$ 165,770**	**$ (28)**	**$ (1,004)**	**$ 14,817**	**$ (10,557)**	**$ 15,739**	**$ 38,774**
Federal Income Tax															
Federal Income Tax	$ 13,224,623	$ 800,246	$ (73,309)	$ 142,227	$ 805,403	$ 1,936,170	$ 6,982,075	$ 1,587,350	$ 774,633	$ (132)	$ (4,692)	$ 69,241	$ (49,330)	$ 73,550	$ 181,190
Investment Tax Credit (I.T.C.)	(528,360)	(393,110)	(11,201)	(703)	(8,039)	(28,433)	(35,209)	(27,324)	(15,334)	(135)	(120)	(1,036)	(5,164)	(797)	(1,754)
South Georgia Federal	290,114	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
Total Federal Income Tax	**$ 12,986,377**	**$ 622,987**	**$ (78,360)**	**$ 141,910**	**$ 801,778**	**$ 1,923,349**	**$ 6,966,199**	**$ 1,575,029**	**$ 767,719**	**$ (193)**	**$ (4,746)**	**$ 68,774**	**$ (51,659)**	**$ 73,190**	**$ 180,399**
Regulatory Amortization	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Net Income	**$ 67,472,917**	**$ 33,343,444**	**$ 770,827**	**$ 322,184**	**$ 2,153,370**	**$ 5,914,672**	**$ 15,874,153**	**$ 5,174,269**	**$ 2,687,056**	**$ 10,718**	**$ 970**	**$ 213,087**	**$ 326,383**	**$ 201,741**	**$ 480,043**
Rate of Return on Rate Base	**4.64%**	**3.14%**	**2.64%**	**15.62%**	**9.86%**	**7.18%**	**15.24%**	**6.40%**	**5.92%**	**2.68%**	**0.27%**	**6.95%**	**2.14%**	**8.55%**	**9.25%**

Class Cost of Service Study – Proposed Rates
Staff Recommended Revenue Requirement

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,572,803	$ 1,346,357,520	$ 38,362,434	$ 2,406,675	$ 27,531,432	$ 97,381,463	$ 120,588,399	$ 93,582,850	$ 52,516,333	$ 463,431	$ 410,926	$ 3,548,748	$ 17,685,225	$ 2,729,530	$ 6,007,837
Total Common Systems Allocable Net Plant	36,846,288	27,414,358	781,131	49,004	560,591	1,982,869	2,455,405	1,905,522	1,069,331	9,436	8,367	72,259	360,104	55,578	122,331
Cash Working Capital	(4,940,151)	(3,830,442)	(126,154)	(5,493)	(77,773)	(204,324)	(305,199)	(213,667)	(105,379)	(1,037)	(854)	(8,339)	(38,748)	(6,664)	(16,080)
Materials & Supplies	9,920,409	7,380,978	210,310	13,194	150,932	533,863	661,088	513,038	287,904	2,541	2,253	19,455	96,954	14,964	32,936
Prepayments	4,559,036	3,534,937	116,422	5,069	71,773	188,561	281,654	197,183	97,250	957	788	7,696	35,758	6,150	14,839
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(292,517,552)	(217,638,773)	(6,201,290)	(389,039)	(4,450,458)	(15,741,719)	(19,493,122)	(15,127,673)	(8,489,268)	(74,914)	(66,426)	(573,655)	(2,858,818)	(441,229)	(971,167)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$ 1,452,932,392**	**$ 1,060,351,888**	**$ 29,192,529**	**$ 2,062,206**	**$ 21,834,489**	**$ 82,418,499**	**$ 104,188,225**	**$ 80,857,253**	**$ 45,376,170**	**$ 400,416**	**$ 355,054**	**$ 3,066,163**	**$ 15,280,476**	**$ 2,358,330**	**$ 5,190,697**
Margin															
Net Operating Margin	$ 446,859,736	$ 316,799,076	$ 8,834,219	$ 912,916	$ 8,357,088	$ 23,858,966	$ 46,330,589	$ 22,548,996	$ 12,086,635	$ 97,149	$ 63,119	$ 864,948	$ 3,526,396	$ 768,507	$ 1,811,133
Special Contract Margin	6,788,127	4,812,410	134,198	13,868	126,950	362,435	703,796	342,536	183,605	1,476	959	13,139	53,569	11,674	27,512
Other Revenue	12,096,356	10,448,939	869,321	2,383	145,227	248,246	275,586	49,525	26,951	472	3,536	1,283	4,810	6,181	13,895
Total Revenue	**$ 465,744,219**	**$ 332,060,426**	**$ 9,837,739**	**$ 929,166**	**$ 8,629,265**	**$ 24,469,647**	**$ 47,309,970**	**$ 22,941,057**	**$ 12,297,191**	**$ 99,097**	**$ 67,614**	**$ 879,370**	**$ 3,584,775**	**$ 786,362**	**$ 1,852,540**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,838,555)	$ (106,100,435)	$ (3,494,376)	$ (152,146)	$ (2,154,245)	$ (5,659,619)	$ (8,453,780)	$ (5,918,414)	$ (2,918,927)	$ (28,719)	$ (23,646)	$ (230,988)	$ (1,073,281)	$ (184,588)	$ (445,391)
Incremental Uncollectible Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Administrative & General Expenses	(59,195,567)	(45,898,434)	(1,511,647)	(65,817)	(931,914)	(2,448,319)	(3,657,056)	(2,560,272)	(1,262,711)	(12,424)	(10,229)	(99,924)	(464,295)	(79,852)	(192,673)
Depreciation Expenses	(99,569,492)	(74,081,647)	(2,110,845)	(132,424)	(1,514,883)	(5,358,294)	(6,635,227)	(5,149,280)	(2,889,646)	(25,500)	(22,611)	(195,265)	(973,107)	(150,189)	(330,574)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,065,517)	(20,137,274)	(573,781)	(35,996)	(411,784)	(1,456,520)	(1,803,623)	(1,399,705)	(785,479)	(6,931)	(6,146)	(53,078)	(264,515)	(40,825)	(89,858)
Total Operating Deductions	**$ (325,577,647)**	**$ (248,925,180)**	**$ (7,794,619)**	**$ (386,837)**	**$ (5,064,201)**	**$ (14,968,080)**	**$ (20,549,686)**	**$ (15,027,671)**	**$ (7,856,763)**	**$ (73,574)**	**$ (62,632)**	**$ (579,256)**	**$ (2,775,199)**	**$ (455,454)**	**$ (1,058,496)**
State Income Tax															
Taxable Income before Interest Expense	$ 140,166,572	$ 83,135,246	$ 2,043,119	$ 542,329	$ 3,565,065	$ 9,501,568	$ 26,760,284	$ 7,913,386	$ 4,440,428	$ 25,523	$ 4,982	$ 300,114	$ 809,576	$ 330,908	$ 794,044
Interest Expenses	(42,571,123)	(31,673,747)	(902,496)	(56,618)	(647,691)	(2,290,949)	(2,836,904)	(2,201,584)	(1,235,474)	(10,902)	(9,667)	(83,486)	(416,054)	(64,214)	(141,337)
State Taxable Income	$ 97,595,449	$ 51,461,499	$ 1,140,623	$ 485,711	$ 2,917,374	$ 7,210,619	$ 23,923,380	$ 5,711,802	$ 3,204,954	$ 14,620	$ (4,685)	$ 216,628	$ 393,522	$ 266,695	$ 652,707
State Income Tax	$ 6,783,176	$ 3,576,729	$ 79,277	$ 33,758	$ 202,766	$ 501,160	$ 1,662,747	$ 396,987	$ 222,754	$ 1,016	$ (326)	$ 15,056	$ 27,351	$ 18,536	$ 45,365
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	**$ 6,783,176**	**$ 3,576,729**	**$ 79,277**	**$ 33,758**	**$ 202,766**	**$ 501,160**	**$ 1,662,747**	**$ 396,987**	**$ 222,754**	**$ 1,016**	**$ (326)**	**$ 15,056**	**$ 27,351**	**$ 18,536**	**$ 45,365**
Federal Income Tax															
Taxable Income before Interest Expense	$ 140,166,572	$ 83,135,246	$ 2,043,119	$ 542,329	$ 3,565,065	$ 9,501,568	$ 26,760,284	$ 7,913,386	$ 4,440,428	$ 25,523	$ 4,982	$ 300,114	$ 809,576	$ 330,908	$ 794,044
Interest Expenses	(42,571,123)	(31,673,747)	(902,496)	(56,618)	(647,691)	(2,290,949)	(2,836,904)	(2,201,584)	(1,235,474)	(10,902)	(9,667)	(83,486)	(416,054)	(64,214)	(141,337)
Federal Taxable Income	**$ 97,595,449**	**$ 51,461,499**	**$ 1,140,623**	**$ 485,711**	**$ 2,917,374**	**$ 7,210,619**	**$ 23,923,380**	**$ 5,711,802**	**$ 3,204,954**	**$ 14,620**	**$ (4,685)**	**$ 216,628**	**$ 393,522**	**$ 266,695**	**$ 652,707**
Federal Income Tax	$ 31,697,440	$ 16,713,871	$ 370,456	$ 157,751	$ 947,516	$ 2,341,894	$ 7,769,931	$ 1,855,102	$ 1,040,918	$ 4,748	$ (1,522)	$ 70,357	$ 127,810	$ 86,618	$ 211,989
Investment Tax Credit (I.T.C.)	(528,360)	(393,110)	(11,201)	(703)	(8,039)	(28,433)	(35,209)	(27,324)	(15,334)	(135)	(120)	(1,036)	(5,164)	(797)	(1,754)
South Georgia Federal	290,114	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
Total Federal Income Tax	**$ 31,459,194**	**$ 16,536,612**	**$ 365,405**	**$ 157,434**	**$ 943,892**	**$ 2,329,073**	**$ 7,754,055**	**$ 1,842,781**	**$ 1,034,004**	**$ 4,687**	**$ (1,576)**	**$ 69,890**	**$ 125,481**	**$ 86,259**	**$ 211,198**
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	**$ 101,924,201**	**$ 63,021,906**	**$ 1,698,437**	**$ 351,137**	**$ 2,418,407**	**$ 6,671,335**	**$ 17,343,483**	**$ 5,673,618**	**$ 3,183,670**	**$ 19,819**	**$ 6,883**	**$ 215,168**	**$ 666,744**	**$ 226,113**	**$ 537,481**
Rate of Return on Rate Base	**7.02%**	**5.94%**	**5.48%**	**17.03%**	**11.08%**	**8.09%**	**16.65%**	**7.02%**	**7.02%**	**4.95%**	**1.94%**	**7.02%**	**4.30%**	**9.59%**	**10.35%**

Source: AZ 2010 CCOSS and rate design.

Relationship of Customer Charges to Cost of Service

	Company's		Staff's	
	Proposed Customer Charge ($)	Cost of Service (%)	Proposed Customer Charge ($)	Cost of Service (%)
Single-Family Residential Gas Service	$10.70	35%	$10.70	36%
Multi-Family Residential Gas Service	$9.70	44%	$9.70	46%
Single-Family Low Income Residential Gas Service	$7.50	27%	$7.50	36%
Multi-Family Low Income Residential Gas Service	$7.50	33%	$7.50	42%
Special Residential Gas Service for Air Conditioning	$10.70	14%	$10.70	13%
Master Metered Mobile Home Park Gas Service	$66.00	13%	$66.00	13%
Small General Gas Service	$27.50	67%	$27.50	68%
Medium General Gas Service	$43.50	33%	$43.50	33%
Large-1 General Gas Service	$80.00	14%	$120.00	22%
Large-2 General Gas Service	$470.00	20%	$160.00	7%
Transportation Eligible	$950.00	9%	$950.00	10%
Air Conditioning Gas Service	$27.50 - $120	14%	$27.50 - $120	13%
Gas Service for Compression on Customer's Premises	$10.70 - $250	8%	$10.70 - $250	10%
Electric Cogeneration	$27.50 - $950	1%	$27.50 - $950	11%
Small Essential Agriculture User Gas Service	$120.00	9%	$120.00	9%
Natural Gas Engines	$125.00	14%	$125.00	14%

Source: Company's Class Cost of Service Study.

Survey of Customer Charges

State	Company	Customer Charge Residential ($/month)	Customer Charge Commercial ($/month)	State	Company	Customer Charge Residential ($/month)	Customer Charge Commercial ($/month)
AK	ENSTAR Natural Gas Company	$ 13.50	$ 29.00	HI	The Gas Company (Molokai)	$ 8.50	
AK	Fairbanks Natural Gas	$ 9.20	$ 17.25	HI	The Gas Company (Lanai)	$ 8.50	
AR	Centerpoint Energy	$ 9.75	$ 13.00	IA	Atmos Energy Corporation	$ 7.95	$ 13.00
AZ	Southwest Gas Corporation	$ 10.70	$ 27.50	ID	Avista Corporation	$ 4.00	$ 4.00
AZ	UniSource Energy Services	$ 10.00	$ 15.50	ID	Intermountain Gas Company	$ 6.50	$ 9.50
CA	Southern California Gas Company[1]	$ 5.00	$ 15.00	ID	Questar Gas Company	$ 5.00	$ 21.00
CA	Pacific Gas and Electric Company [1,2]	$ 3.00	$ 8.23	IL	Nicor Gas	$ 13.55	$ 20.80
CA	San Diego Gas and Electric Company	$ -	$ 10.00	IL	Atmos Energy Corporation	$ 9.90	$ 25.00
CA	Southwest Gas Corporation (Southern)	$ 5.00	$ 11.00	IL	Peoples Gas Light and Coke Company[3]	$ 19.50	$ 24.80
CA	Southwest Gas Corporation (Northern)	$ 5.00	$ 11.00	IN	Northern Indiana Public Service Co	$ 11.00	$ 30.00
CO	Atmos Energy Corporation	$ 10.00	$ 24.00	KS	Atmos Energy Corporation	$ 15.50	$ 37.00
CO	Black Hills Energy	$ 10.00	$ 15.00	KS	Kansas Gas Service Company	$ 12.25	$ 23.35
CO	Eastern Colorado Utility Company	$ 8.50	$ 10.00	KY	Atmos Energy Corporation	$ 12.50	$ 30.00
CO	Colorado Natural Gas	$ 10.00	$ 20.00	LA	Atmos Energy Corporation	$ 13.20	$ 21.98
CO	Public Service Co of Colorado	$ 10.00	$ 20.00	MA	Boston Gas (National Grid)	$ 10.00	$ 21.00
CO	SourceGas Distribution (Area 2)	$ 10.00	$ 20.00	MA	Essex (National Grid)	$ 10.00	$ 21.00
CO	SourceGas Distribution (Area 1)	$ 11.00	$ 22.00	MA	NSTAR Gas Company	$ 6.50	$ 15.00
CO	Westpac Utilities	$ 6.50	$ 16.00	MA	Colonial Gas Co (National Grid)	$ 8.00	$ 11.00
CT	Southern Connecticut Gas Co	$ 13.00	$ 30.00	MA	Berkshire Gas Company	$ 11.39	$ 12.48
CT	Yankee Gas Service Co	$ 13.50	$ 42.00	MA	Northern Utilities	$ 8.50	$ 24.00
CT	Connecticut Natural Gas Co	$ 13.00	$ 38.00	ME	Maine Natural Gas	$ 22.13	$ 31.61
GA	Atmos Energy Corporation	$ 12.30	$ 19.25	ME	Bangor Gas Company	$ 13.10	$ 14.65
GA	Atlanta Gas Light	$ 11.00	$ 20.00	ME	Northern Utilities	$ 4.96	$ 10.47
HI	The Gas Company (Oahu)	$ 8.50	$ 12.50	MI	Consumers Energy Company	$ 10.50	$ 11.65
HI	The Gas Company (South Hilo)	$ 8.50	$ 12.50	MI	Michigan Consolidated Gas (DTE Energy)	$ 10.50	$ 25.00
HI	The Gas Company (North Kona)	$ 8.50	$ 12.50	MO	Atmos Energy Corporation (Northeast)	$ 22.68	$ 22.68
HI	The Gas Company (Maui)	$ 8.50	$ 12.50	MO	Atmos Energy Corporation (Southeast)	$ 13.75	$ 13.75
HI	The Gas Company (Kauai)	$ 8.50	$ 12.50	MO	Atmos Energy Corporation (West)	$ 20.17	$ 20.17

Note: If a company has customer charges that differ by season, the higher charge was chosen for this table.
1 These companies have daily customer charges. The daily charge was multiplied by 365/12 to calculate the monthly customer charge.
2 Pacific Gas and Electric's commercial customer charge varies with usage.
3 The Peoples Gas Light and Coke Company customer charge is based on meter class. The customer charge for the first meter class is shown.
4 The customer charge for New York gas utilities is volumetric after a certain usage amount (usually 3-4 Ccf).
5 The Inside City Limits rate is shown.

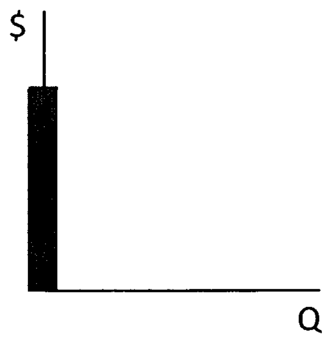
Survey of Customer Charges

State	Company	Customer Charge Residential ($/month)	Customer Charge Commercial ($/month)
MS	Atmos Energy Corporation	$ 6.95	$ 11.27
MT	Energy West Montana	$ 6.75	$ 17.00
MT	Montana-Dakota Utilities Co	$ 6.35	$ 10.40
MT	NorthWestern Energy	$ 6.90	$ 17.10
NC	Piedmont Natural Gas	$ 10.00	$ 22.00
NH	Northern Utilities	$ 9.50	$ 18.70
NH	EnergyNorth Natural Gas (National Grid)	$ 17.16	$ 40.37
NJ	Public Service Electric and Gas Co	$ 5.46	$ 9.80
NJ	New Jersey Natural Gas	$ 8.25	$ 25.00
NJ	South Jersey Gas Company	$ 8.92	$ 23.81
NM	New Mexico Gas Company	$ 9.59	$ 16.50
NM	Zia Natural Gas Company	$ 10.96	$ 15.15
NV	Southwest Gas Corporation (Southern)	$ 9.00	$ 21.50
NV	Southwest Gas Corporation (Northern)	$ 9.00	$ 24.00
NY	Consolidated Edison New York Inc[4]	$ 16.80	$ 23.10
NY	Niagara Mohawk[4]	$ 17.85	$ 23.65
NY	National Fuel Gas Distribution[4]	$ 15.54	$ 17.86
NY	Rochester Gas and Electric[4]	$ 16.30	$ 16.30
NY	Orange & Rockland[4]	$ 16.94	$ 27.31
NY	Central Hudson Gas & Electric[4]	$ 19.00	$ 35.00
OH	Columbia Gas of Ohio (NiSource)	$ 17.81	$ 17.81
OH	East Ohio Gas Company (Dominion)	$ 17.58	$ 20.00
OK	Oklahoma Natural Gas Co (Rate Choice A)	$ 11.20	$ 18.75
OK	Oklahoma Natural Gas Co (Rate Choice B)	$ 26.75	$ 33.95
OR	Avista Corporation	$ 7.00	$ 9.00
OR	Cascade Natural Gas Corporation	$ 3.00	$ 3.00
OR	Northwest Natural Gas Company	$ 6.00	$ 8.00
SC	Piedmont Natural Gas	$ 10.00	$ 22.00
TN	Atmos Energy Corporation	$ 13.75	$ 31.15
TN	Piedmont Natural Gas	$ 13.00	$ 29.00
TX	Atmos Energy Corporation (West TX - Inside City Limits)	$ 7.50	$ 14.50
TX	Atmos Energy Corporation (West TX - Outside City Limits)	$ 8.50	$ 14.50
TX	Atmos Energy Corporation (Amarillo - Inside City Limits)	$ 8.21	$ 15.52
TX	Atmos Energy Corporation (Amarillo - Outside City Limits)	$ 9.50	$ 15.00
TX	Atmos Energy Corporation (Lubbock - Inside City Limits)	$ 7.65	$ 14.90
TX	Atmos Energy Corporation (Lubbock - Outside City Limits)	$ 8.74	$ 12.26
TX	Atmos Energy Corporation (Fritch-Sanford)	$ 3.20	$ 3.20
TX	Atmos Energy Corporation (Dalhart-Channing)	$ 4.30	$ 4.30
TX	Atmos Energy Corporation (Mid TX) - Dallas & Unincorporated	$ 16.00	$ 30.00
TX	Atmos Energy Corporation (Mid TX) - All Other Cities	$ 7.00	$ 13.50
UT	Questar Gas Company	$ 5.00	$ 21.00
VA	Atmos Energy Corporation	$ 9.00	$ 20.00
VT	Vermont Gas Systems[1]	$ 18.67	$ 30.95
WA	Avista Corporation	$ 6.00	$ 6.00
WA	Cascade Natural Gas Corporation	$ 4.00	$ 10.00
WA	Northwest Natural Gas Company	$ 3.47	$ 3.47
WA	Puget Sound Energy	$ 10.00	$ 32.32
WI	Wisconsin Gas Company[1]	$ 9.43	$ 9.43
WY	Cheyenne Light Fuel and Power Company	$ 15.00	$ 20.00
WY	Energy West Wyoming	$ 11.00	$ 11.00
WY	Wyoming Gas Company	$ 15.00	$ 20.00
WY	MGTC Inc	$ 5.00	$ 5.00
WY	Montana-Dakota Utilities Co[1]	$ 12.17	$ 27.38
WY	Questar Gas Company	$ 10.00	$ 44.00
WY	Wyoming Industrial Gas Company	$ 5.00	$ 5.00

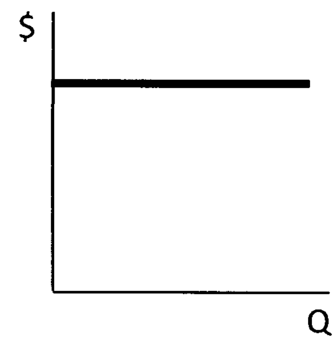
Source: Tariffs.
Note: If a company has customer charges that differ by season, the higher charge was chosen for this table.
1 These companies have daily customer charges. The daily charge was multiplied by 365/12 to calculate the monthly customer charge.
2 Pacific Gas and Electric's commercial customer charge varies with usage.
3 The Peoples Gas Light and Coke Company customer charge is based on meter class. The customer charge for the first meter class is shown.
4 The customer charge for New York gas utilities is volumetric after a certain usage amount (usually 3-4 Ccf).
5 The Inside City Limits rate is shown.

Rate Design Structures

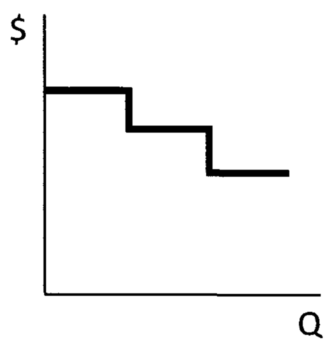
flat rate per period, no usage charge



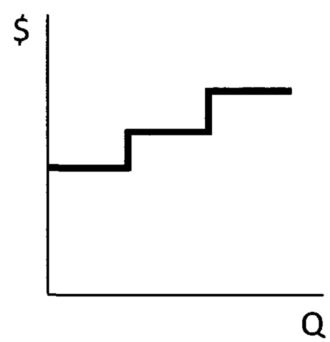
uniform: flat rate per unit



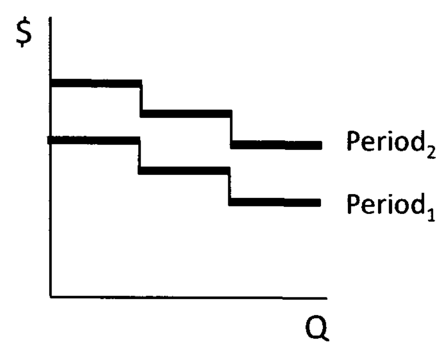
declining block



inverted block



seasonal or time-of-use



Source: Costello, Ken. *Revenue Decoupling: Supplemental* Information. The National Regulatory Research Institute. Prepared for The Basics: Practical Skills for the Changing Electric, Natural Gas and Water Industries, sponsored by the Center for Public Utilities, New Mexico State University, October 18, 2007.

Survey of Volumetric Charges

State	Company	Units	Residential First Tier	Commercial First Tier
Uniform Rate Structure				
AK	ENSTAR Natural Gas Company	Ccf	$ 0.09780	$ 0.09660
AK	Fairbanks Natural Gas	Ccf	$ 2.33500	$ 2.29100
AZ	Southwest Gas Corp	Therm	$ 0.57070	$ 0.57059
AZ	UniSource Energy Services	Therm	$ 0.32700	$ 0.28060
CO	Atmos Energy Corp	Ccf	$ 0.14385	$ 0.11242
CO	Black Hills Energy	Therm	$ 0.14109	$ 0.14109
CO	Eastern Colorado Utility Company	Ccf	$ 0.15800	$ 0.15800
CO	Colorado Natural Gas	Therm	$ 0.59500	$ 0.59500
CO	Public Service Co of Colorado	Therm	$ 0.09418	$ 0.13111
CO	Source Gas Distribution (Area 2)	Therm	$ 0.20700	$ 0.14240
CO	Source Gas Distribution (Area 1)	Therm	$ 0.22820	$ 0.18690
CO	Westpac Utilities	Therm	$ 0.21523	$ 0.16746
GA	Atmos Energy Corp	Ccf	$ 0.25920	$ 0.15950
HI	The Gas Company (Oahu)	Therm	$ 2.20530	$ 2.79562
HI	The Gas Company (South Hilo)	Therm	$ 2.60420	$ 2.53431
HI	The Gas Company (North Kona)	Therm	$ 2.60420	$ 2.45880
HI	The Gas Company (Maui)	Therm	$ 1.82550	$ 1.58550
HI	The Gas Company (Kauai)	Therm	$ 2.23100	$ 1.58550
HI	The Gas Company (Molokai)	Therm	$ 2.23630	
HI	The Gas Company (Lanai)	Therm	$ 2.76650	
ID	Avista Corporation	Therm	$ 0.37515	$ 0.37515
IL	Atmos Energy Corp	Ccf	$ 0.20150	$ 0.16080
IN	Northern Indiana Public Service Co	Therm	$ 0.11282	$ 0.10006
KS	Atmos Energy Corp	Ccf	$ 0.12953	$ 0.12953
KS	Kansas Gas Service Co	Mcf	$ 2.12300	$ 1.97460
LA	Atmos Energy Corp	Ccf	$ 0.25300	$ 0.40319
MA	Northern Utilities	Therm	$ 0.47700	$ 0.37940
ME	Bangor Gas Co	Therm	$ 0.36100	$ 0.27900
MI	Consumers Energy Co	Mcf	$ 2.42890	$ 2.14540
MI	Michigan Cons. Gas (DTE Energy)	Ccf	$ 0.23184	$ 0.24102
MO	Atmos Energy Corporation (Northeast)	Ccf	$ 0.11546	$ 0.05778
MO	Atmos Energy Corporation (Southeast)	Ccf	$ 0.08735	$ 0.04536
MO	Atmos Energy Corporation (West)	Ccf	$ 0.10682	$ 0.05944
MS	Atmos Energy Corp	Mcf	$ 1.32050	$ 1.72290
MT	Montana-Dakota Utilities Co	Dth	$ 1.12600	$ 1.35300

State	Company	Units	Residential First Tier	Commercial First Tier
Uniform Rate Structure				
MT	NorthWestern Energy	Dth	$ 1.85727	$ 1.83622
NC	Piedmont Natural Gas	Therm	$ 0.97929	$ 0.87830
NJ	New Jersey Natural Gas	Therm	$ 0.50110	$ 0.46230
NJ	Public Service Electric and Gas Co	Therm	$ 0.29053	$ 0.25205
NJ	South Jersey Gas Co	Therm	$ 0.55460	$ 0.46660
NM	New Mexico Gas Company	Therm	$ 0.16460	$ 0.06480
NM	Zia Natural Gas Company	Ccf	$ 0.24360	$ 0.24360
NV	Southwest Gas Corp (Southern)	Therm	$ 0.30968	$ 0.34714
NV	Southwest Gas Corp (Northern)	Therm	$ 0.34917	$ 0.42050
OK	Oklahoma Nat. Gas Co (Rate Choice A)	Dth	$ 3.73230	$ 4.55990
OR	Avista Corporation	Therm	$ 0.40865	$ 0.32551
OR	Cascade Natural Gas Corporation	Therm	$ 0.34691	$ 0.24035
OR	Northwest Natural Gas Company	Therm	$ 0.41346	$ 0.33497
SC	Piedmont Natural Gas	Therm	$ 1.08094	$ 0.98045
TN	Atmos Energy Corp	Ccf	$ 0.13470	$ 0.20730
TN	Piedmont Natural Gas	Therm	$ 0.85919	$ 0.89397
TX	Atmos Energy Corp (West TX - Inside City Limits)	Ccf	$ 0.27514	$ 0.18484
TX	Atmos Energy Corp (Mid TX) - Dallas	Mcf	$ 0.43150	$ 0.57480
TX	Atmos Energy Corp (Mid TX) - All Other Cities	Mcf	$ 2.27070	$ 0.98770
TX	Atmos Energy Corporation (West TX - Outside City Limits)	Ccf	$ 0.11035	$ 0.18484
TX	Atmos Energy Corporation (Amarillo - Inside City Limits)	Ccf	$ 0.12862	$ 0.12617
TX	Atmos Energy Corporation (Amarillo - Outside City Limits)	Ccf	$ 0.07425	$ 0.09100
TX	Atmos Energy Corporation (Lubbock - Inside City Limits)	Ccf	$ 0.17429	$ 0.13159
TX	Atmos Energy Corporation (Lubbock - Outside City Limits)	Ccf	$ 0.09668	$ 0.09500
VA	Atmos Energy Corp	Ccf	$ 0.18850	$ 0.14370
VT	Vermont Gas Systems	Ccf	$ 0.48050	$ 0.33110
WA	Avista Corporation	Therm	$ 0.89276	$ 0.89276
WA	Cascade Natural Gas Corporation	Therm	$ 0.26248	$ 0.23179
WA	Northwest Natural Gas Company	Therm	$ 0.68290	$ 0.68279
WA	Puget Sound Energy	Therm	$ 0.37372	$ 0.31527
WI	Wisconsin Gas Co	Therm	$ 0.20910	$ 0.20910
WY	Cheyenne Light Fuel and Power Company	Dth	$ 1.85190	$ 1.72270
WY	MGTC Inc	Mcf	$ 1.94350	$ 1.94350
WY	Montana-Dakota Utilities Co	Dth	$ 0.63300	$ 0.58300
WY	*Wyoming Gas Company*	Ccf	$ 0.23404	$ 0.24457

Survey of Volumetric Charges

State	Company	Units	Residential First Tier	Residential Second Tier	Commercial First Tier	Commercial Second Tier
Declining Block Rate						
AR	Centerpoint Energy	Ccf	$0.34655	$0.16664	$0.15177	$0.11479
CT	Southern Connecticut Gas Co	Ccf	$0.94890	$0.34740	$0.73730	$0.19100
CT	Yankee Gas Service Co	Ccf	$0.75230	$0.49740	$0.48960	$0.27700
CT	Connecticut Natural Gas Co	Ccf	$0.88960	$0.30690	$0.67200	$0.24220
IA	Atmos Energy Corp	Therm	$0.29110	$0.17170	$0.25400	$0.13200
ID	Questar Gas Co	Dth	$2.22938	$0.92557	$2.22938	$0.92557
IL	Peoples Gas Light and Coke Co	Therm	$0.33372	$0.12360	$0.30615	$0.13084
KY	Atmos Energy Corp	Mcf	$1.10000	$0.77000	$1.10000	$0.77000
MA	Berkshire Gas Co	Therm	$0.61540	$0.32570	$0.64100	$0.37540
ME	Maine Natural Gas	Therm	$0.35600	$0.31700	$0.35600	$0.31700
ME	Northern Utilities	Ccf	$0.40260	$0.22780	$0.33850	$0.22550
MT	Energy West Montana	Ccf	$0.13500	$0.01782	$0.19850	$0.06840
NH	Northern Utilities	Therm	$0.41020	$0.29900	$0.30180	$0.19690
NH	EnergyNorth Nat. Gas (National Grid)	Therm	$0.27140	$0.22430	$0.32220	$0.20950
NY	Central Hudson Gas & Electric	Ccf	$0.84390	$0.39440	$0.55720	$0.27040
NY	National Fuel Gas Distribution	Mcf	$3.72554	$1.00813	$2.51345	$1.94282
NY	Niagara Mohawk	Therm	$0.41890	$0.06385	$0.31452	$0.18296
NY	Rochester Gas and Electric	Therm	$0.16675	$0.15549	$0.16675	$0.15549
NY	Orange & Rockland	Ccf	$0.43029	$0.41413	$0.34432	$0.33059
TX	Atmos Energy Corporation (Fritch-Sanford)	Ccf	$0.11069	$0.10354	$0.11069	$0.10354
TX	Atmos Energy Corporation (Dalhart-Channing)	Ccf	$0.11866	$0.09354	$0.11866	$0.09354
UT	Questar Gas Co	Dth	$2.22938	$0.92557	$2.22938	$0.92557
WY	Questar Gas Co	Dth	$2.00841	$1.26955	$2.00841	$1.26955
WY	Wyoming Industrial Gas Company	Therm	$0.30583	$0.24536	$0.30583	$0.24536
WY	Energy West Wyoming	Mcf	$2.20000	$2.16000	$2.20000	$2.16000

State	Company	Units	Residential First Tier	Residential Second Tier	Commercial First Tier	Commercial Second Tier
Inclining Block Rate						
MA	Boston Gas (National Grid)	Therm	$0.40870	$0.49270	$0.40650	$0.50050
MA	Essex (National Grid)	Therm	$0.40870	$0.49270	$0.24420	$0.30040
MA	Colonial Gas (National Grid)	Therm	$0.34980	$0.41670	$0.29890	$0.36370
Combination of Declining Block Rate / Inclining Block Rate						
CA	Pacific Gas and Electric Co	Therm	$0.44369	$0.70990	$0.35980	$0.11058
CA	San Diego Gas and Electric Company	Therm	$0.63422	$0.78984	$0.31346	$0.17462
CA	Southern California Gas Co	Therm	$0.33482	$0.58482	$0.52624	$0.26583
CA	Southwest Gas Corp (Northern)	Therm	$0.56131	$0.67202	$0.44975	$0.35375
CA	Southwest Gas Corp (Southern)	Therm	$0.53672	$0.69836	$0.47043	$0.36693
OH	East Ohio Gas Co (Dominion)[1]	Mcf	$1.42210	$1.42210	$1.80010	$2.62010
Combination of Uniform Rate / Declining Block Rate						
IL	Nicor Gas	Therm	$0.04850		$0.12010	$0.05490
MA	NSTAR Gas Co	Therm	$0.68710	$0.42580	$0.25290	
NY	Consolidated Edison New York Inc	Therm	$0.78590		$0.64340	$0.45200
Combination of Uniform Rate / Inclining Block Rate						
ID	Intermountain Gas Company	Therm	$0.41494		$0.36221	$0.39133

Source: Tariffs.
Note:
1 This is actually a declining rate. Tier 3 is $1.3505/Mcf, and Tier 4 is $1.3039/Mcf.

Summary of Present and Proposed Rates

Company's Present Rates

Description	Sch.	Rate
Single-Family Residential Gas Service	G-5	
Basic Service Charge per Month		$ 10.70
Delivery Charge per Therm		
All Usage		$ 0.57070
Multi-Family Residential Gas Service	G-6	
Basic Service Charge per Month		$ 9.70
Delivery Charge per Therm		
All Usage		$ 0.55343
Single-Family Low Income Residential Gas Service	G-10	
Basic Service Charge per Month		$ 7.50
Delivery Charge per Therm		
Summer (May - October)		
All Usage		$ 0.55343
Winter (November - April)		
First 150 Therms		$ 0.31624
Over 150 Therms		$ 0.55343
Multi-Family Low Income Residential Gas Service	G-11	
Basic Service Charge per Month		$ 7.50
Delivery Charge per Therm		
Summer (May - October)		
All Usage		$ 0.55343
Winter (November - April)		
First 150 Therms		$ 0.31624
Over 150 Therms		$ 0.55343

Company's Proposed Rates

Description	Sch.	Rate	Difference from Present Rates
Single-Family Residential Gas Service	G-5		
Basic Service Charge per Month		$ 10.70	0%
Delivery Charge per Therm			
All Usage		$ 0.80176	40%
Multi-Family Residential Gas Service	G-6		
Basic Service Charge per Month		$ 9.70	0%
Delivery Charge per Therm			
All Usage		$ 0.80176	45%
Single-Family Low Income Residential Gas Service	G-10		
Basic Service Charge per Month		$ 7.50	0%
Delivery Charge per Therm			
Summer (May - October)			
All Usage		$ 0.80176	45%
Winter (November - April)			
All Usage		$ 0.51491	63%
Multi-Family Low Income Residential Gas Service	G-11		
Basic Service Charge per Month		$ 7.50	0%
Delivery Charge per Therm			
Summer (May - October)			
All Usage		$ 0.80176	45%
Winter (November - April)			
All Usage		$ 0.51491	63%

Staff's Recommended Rates

Description	Sch.	Rate	Difference from Present Rates
Single-Family Residential Gas Service	G-5		
Basic Service Charge per Month		$ 10.70	0.0%
Delivery Charge per Therm			
All Usage		$ 0.74651	30.8%
Multi-Family Residential Gas Service	G-6		
Basic Service Charge per Month		$ 9.70	0.0%
Delivery Charge per Therm			
All Usage		$ 0.74651	34.9%
Single-Family Low Income Residential Gas Service	G-10		
Basic Service Charge per Month		$ 7.50	0.0%
Delivery Charge per Therm			
Summer (May - October)			
All Usage		$ 0.74241	34.1%
Winter (November - April)			
First 150 Therms		$ 0.46743	47.8%
Over 150 Therms		$ 0.74241	34.1%
Multi-Family Low Income Residential Gas Service	G-11		
Basic Service Charge per Month		$ 7.50	0.0%
Delivery Charge per Therm			
Summer (May - October)			
All Usage		$ 0.74241	34.1%
Winter (November - April)			
First 150 Therms		$ 0.46743	47.8%
Over 150 Therms		$ 0.74241	34.1%

Summary of Present and Proposed Rates

Company's Present Rates			Company's Proposed Rates			Difference from Present Rates	Staff's Recommended Rates			Difference from Present Rates
Description	Sch.	Rate	Description	Sch.	Rate	Rates	Description	Sch.	Rate	Rates
Special Residential Gas Service for Air Conditioning	G-15		**Special Residential Gas Service for Air Conditioning**	G-15			**Special Residential Gas Service for Air Conditioning**	G-15		
Basic Service Charge per Month		$ 10.70	Basic Service Charge per Month		$ 10.70	0%	Basic Service Charge per Month		$ 10.70	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
Summer (May - October)			Summer (May - October)				Summer (May - October)			
First 15 Therms		$ 0.57070	First 15 Therms		$ 0.80176	40%	First 15 Therms		$ 0.74651	30.8%
Over 15 Therms		$ 0.28860	Over 15 Therms		$ 0.12297	-57%	Over 15 Therms		$ 0.45241	56.8%
Winter (November - April)			Winter (November - April)				Winter (November - April)			
All Usage		$ 0.57070	All Usage		$ 0.80176	40%	All Usage		$ 0.74651	30.8%
Master Metered Mobile Home Park Gas Service	G-20		**Master Metered Mobile Home Park Gas Service**	G-20			**Master Metered Mobile Home Park Gas Service**	G-20		
Basic Service Charge per Month		$ 66.00	Basic Service Charge per Month		$ 66.00	0%	Basic Service Charge per Month		$ 66.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.40830	All Usage		$ 0.44370	9%	All Usage		$ 0.43926	7.6%
General Gas Service	G-25		**General Gas Service**	G-25			**General Gas Service**	G-25		
Basic Service Charge per Month			Basic Service Charge per Month				Basic Service Charge per Month			
Small		$ 27.50	Small		$ 27.50	0%	Small		$ 27.50	0.0%
Medium		$ 43.50	Medium		$ 43.50	0%	Medium		$ 43.50	0.0%
Large		$ 160.00	Large-1		$ 80.00	-50%	Large-1		$ 120.00	-25.0%
			Large-2		$ 470.00	194%	Large-2		$ 240.00	50.0%
Transportation Eligible		$ 950.00	Transportation Eligible		$ 950.00	0%	Transportation Eligible		$ 950.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
Small, All Usage		$ 0.57059	Small, All Usage		$ 0.72007	26%	Small, All Usage		$ 0.68813	20.6%
Medium, All Usage		$ 0.37996	Medium, All Usage		$ 0.42359	11%	Medium, All Usage		$ 0.41717	9.8%
Large, All Usage		$ 0.29084	Large-1, All Usage		$ 0.38756	33%	Large-1, All Usage		$ 0.35145	20.8%
			Large-2, All Usage		$ 0.26989	-7%	Large-2, All Usage		$ 0.30668	5.4%
Transportation Eligible		$ 0.10776	Transportation Eligible		$ 0.10350	-4%	Transportation Eligible		$ 0.10422	-3.3%
Demand Charge			Demand Charge				Demand Charge			
Transportation Eligible		$ 0.06234	Transportation Eligible		$ 0.07729	24%	Transportation Eligible		$ 0.07424	19.1%

Summary of Present and Proposed Rates

Company's Present Rates			Company's Proposed Rates			Difference from Present Rates	Staff's Recommended Rates			Difference from Present Rates
Description	Sch.	Rate	Description	Sch.	Rate		Description	Sch.	Rate	
Optional Gas Service	G-30		**Optional Gas Service**	G-30			**Optional Gas Service**	G-30		
Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 27.		Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 27.			Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 27.		
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage	As Specified on A.C.C. Sheet No. 28.		All Usage	As Specified on A.C.C. Sheet No. 28.			All Usage	As Specified on A.C.C. Sheet No. 28.		
Air Conditioning Gas Service	G-40		**Air Conditioning Gas Service**	G-40			**Air Conditioning Gas Service**	G-40		
Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 32.		Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 32.			Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 32.		
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.11010	All Usage		$ 0.12297	12%	All Usage		$ 0.13965	26.8%
Street Lighting Gas Service	G-45		**Street Lighting Gas Service**	G-45			**Street Lighting Gas Service**	G-45		
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
of Rated Capacity			of Rated Capacity				of Rated Capacity			
All Usage		$ 0.61050	All Usage		$ 0.75297	23%	All Usage		$ 0.72590	18.9%
Gas Service for Compression on Customer's Premises	G-55		**Gas Service for Compression on Customer's Premises**	G-55			**Gas Service for Compression on Customer's Premises**	G-55		
Basic Service Charge per Month			Basic Service Charge per Month				Basic Service Charge per Month			
Small		$ 27.50	Small		$ 27.50	0%	Small		$ 27.50	0.0%
Large		$ 250.00	Large		$ 250.00	0%	Large		$ 250.00	0.0%
Residential		$ 10.70	Residential		$ 10.70	0%	Residential		$ 10.70	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.18678	All Usage		$ 0.20232	8%	All Usage		$ 0.19215	2.9%
Electric Generation Gas Service	G-60		**Electric Generation Gas Service**	G-60			**Electric Generation Gas Service**	G-60		
Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 40.		Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 40.			Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 40.		
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.13535	All Usage		$ 0.14591	8%	All Usage		$ 0.16496	21.9%

Summary of Present and Proposed Rates

Company's Present Rates			Company's Proposed Rates			Difference from Present Rates	Staff's Recommended Rates			Difference from Present Rates
Description	Sch.	Rate	Description	Sch.	Rate		Description	Sch.	Rate	
Small Essential Agriculture User Gas Service	G-75		**Small Essential Agriculture User Gas Service**	G-75			**Small Essential Agriculture User Gas Service**	G-75		
Basic Service Charge per Month		$ 120.00	Basic Service Charge per Month		$ 120.00	0%	Basic Service Charge per Month		$ 120.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.24396	All Usage		$ 0.26423	8%	All Usage		$ 0.26344	8.0%
Natural Gas Engine Gas Service	G-80		**Natural Gas Engine Gas Service**	G-80			**Natural Gas Engine Gas Service**	G-80		
Basic Service Charge per Month			Basic Service Charge per Month				Basic Service Charge per Month			
Off-Peak Season (October - March)		$ -	Off-Peak Season (October - March)		$ -		Off-Peak Season (October - March)		$ -	
Peak Season (April - September)		$ 125.00	Peak Season (April - September)		$ 125.00	0%	Peak Season (April - September)		$ 125.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.19069	All Usage		$ 0.19069	0%	All Usage		$ 0.20744	8.8%

Source: Company's Filing Schedule H-3.

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-5, Single-Family Residential Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	10,418,131		$ 10.70	$ 111,474,002
Commodity Charge				
Sales Therms		261,822,441	$ 0.57070	$ 149,422,067
Total - Excluding Cost of Gas				$ 260,896,069
Base Cost of Gas (per therm)		261,822,441	$ 0.70873	$ 185,561,419
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 446,457,488

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	10,418,131		$ 10.70	$ 111,474,002	0.0%
Commodity Charge					
Sales Therms		261,822,441	$ 0.74651	$ 195,453,070	
Total - Excluding Cost of Gas				$ 306,927,072	17.6%
Base Cost of Gas (per therm)		261,822,441	$ 0.70873	$ 185,561,419	
Total Revenue				$ 492,488,491	10.3%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-6, Multi-Family Residential Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	378,334		$ 9.70	$ 3,669,840
Commodity Charge				
Sales Therms		5,862,713	$0.55343	$ 3,244,601
Total - Excluding Cost of Gas				$ 6,914,441
Base Cost of Gas (per therm)		5,862,713	$0.70873	$ 4,155,081
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 11,069,522

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	378,334		$ 9.70	$ 3,669,840	0.0%
Commodity Charge					
Sales Therms		5,862,713	$0.74651	$ 4,376,574	
Total - Excluding Cost of Gas				$ 8,046,414	16.4%
Base Cost of Gas (per therm)		5,862,713	$0.70873	$ 4,155,081	
Total Revenue				$ 12,201,495	10.2%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-10, Single-Family Low Income Residential Gas Service

Current Rates			Bills	Therms	Current Rate	Revenue
Basic Service Charge			415,096		$ 7.50	$ 3,113,220
Commodity Charge						
Summer				2,301,968	$0.55343	$ 1,273,978
Winter	First	150 therms		8,137,766	$0.31624	2,573,487
Winter	Over	150 therms		55,464	$0.55343	30,695
Total - Excluding Cost of Gas						$ 6,991,380
Base Cost of Gas (per therm)				10,495,198	$0.70873	$ 7,438,262
(applies proposed base cost of gas for comparability)						
Total Revenue						$ 14,429,642

Proposed Rates			Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge			415,096		$ 7.50	$ 3,113,220	0.0%
Commodity Charge							
Summer				2,301,968	$0.74241	$ 1,709,004	
Winter	First	150 therms		8,137,766	$0.46743	3,803,836	
Winter	Over	150 therms		55,464	$0.74241	41,177	
Total - Excluding Cost of Gas						$ 8,667,237	24.0%
Base Cost of Gas (per therm)				10,495,198	$0.70873	$ 7,438,262	
Total Revenue						$ 16,105,499	11.6%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-11, Multi-Family Low Income Residential Gas Service

Current Rates			Bills	Therms	Current Rate	Revenue
Basic Service Charge			37,729		$ 7.50	$ 282,968
Commodity Charge						
Summer				210,209	$0.55343	$ 116,336
Winter	First	150 therms		499,906	$0.31624	158,090
Winter	Over	150 therms		330	$0.55343	183
Total - Excluding Cost of Gas						$ 557,577
Base Cost of Gas (per therm)				710,445	$0.70873	$ 503,514
(applies proposed base cost of gas for comparability)						
Total Revenue						$ 1,061,091

Proposed Rates			Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge			37,729		$ 7.50	$ 282,968	0.0%
Commodity Charge							
Summer				210,209	$0.74241	$ 156,061	
Winter	First	150 therms		499,906	$0.46743	233,671	
Winter	Over	150 therms		330	$0.74241	245	
Total - Excluding Cost of Gas						$ 672,945	20.7%
Base Cost of Gas (per therm)				710,445	$0.70873	$ 503,514	
Total Revenue						$ 1,176,459	10.9%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-15, Special Residential Gas Service for Air Conditioning

Current Rates			Bills	Therms	Current Rate	Revenue
Basic Service Charge			1,080		$ 10.70	$ 11,556
Commodity Charge						
Summer	First	15 therms		23,038	$0.57070	$ 13,148
Summer	Over	15 therms		12,945	$0.28860	3,736
Winter				53,236	$0.57070	30,382
Total - Excluding Cost of Gas						$ 58,822
Base Cost of Gas (per therm)				89,219	$0.70873	$ 63,232
(applies proposed base cost of gas for comparability)						
Total Revenue						$ 122,054

Proposed Rates			Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge			1,080		$ 10.70	$ 11,556	0.0%
Commodity Charge							
Summer	First	15 therms		23,038	$0.74651	$ 17,198	
Summer	Over	15 therms		12,945	$0.45241	5,856	
Winter				53,236	$0.74651	39,741	
Total - Excluding Cost of Gas						$ 74,351	26.4%
Base Cost of Gas (per therm)				89,219	$0.70873	$ 63,232	
Total Revenue						$ 137,583	12.7%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-20, Master Metered Mobile Home Park (MMMHP) Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	1,812		$ 66.00	$ 119,592
Commodity Charge				
Sales Therms		1,823,059	$ 0.40830	$ 744,355
Total - Excluding Cost of Gas				$ 863,947
Base Cost of Gas (per therm)		1,823,059	$ 0.70873	$ 1,292,057
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 2,156,004

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	1,812		$ 66.00	$ 119,592	0.0%
Commodity Charge					
Sales Therms		1,823,059	$ 0.43926	$ 800,797	
Total - Excluding Cost of Gas				$ 920,389	6.5%
Base Cost of Gas (per therm)		1,823,059	$ 0.70873	$ 1,292,057	
Total Revenue				$ 2,212,446	2.6%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Small

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	205,593		$ 27.50	$ 5,653,808
Commodity Charge				
Sales Therms		3,951,454	$ 0.57059	$ 2,254,660
Transport Therms		607	$ 0.57059	346
Total - Excluding Cost of Gas				$ 7,908,814
Base Cost of Gas (per therm)		3,951,454	$ 0.70873	$ 2,800,514
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 10,709,328

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	205,593		$ 27.50	$ 5,653,808	0.0%
Commodity Charge					
Sales Therms		3,951,454	$ 0.68813	$ 2,719,114	
Transport Therms		607	$ 0.68813	418	
Total - Excluding Cost of Gas				$ 8,373,340	5.9%
Base Cost of Gas (per therm)		3,951,454	$ 0.70873	$ 2,800,514	
Total Revenue				$ 11,173,854	4.3%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Medium

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	181,390		$ 43.50	$ 7,890,465
Commodity Charge				
Sales Therms		38,541,245	$0.37996	$ 14,644,131
Transport Therms		117,316	$0.37996	44,575
Total - Excluding Cost of Gas				$ 22,579,171
Base Cost of Gas (per therm)		38,541,245	$0.70873	$ 27,315,337
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 49,894,508

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	181,390		$ 43.50	$ 7,890,465	0.0%
Commodity Charge					
Sales Therms		38,541,245	$0.41717	$ 16,078,251	
Transport Therms		117,316	$0.41717	48,941	
Total - Excluding Cost of Gas				$ 24,017,657	6.4%
Base Cost of Gas (per therm)		38,541,245	$0.70873	$ 27,315,337	
Total Revenue				$ 51,332,994	2.9%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Large-1

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	84,872		$ 160.00	$ 13,579,520
Commodity Charge				
Sales Therms		102,012,194	$ 0.29084	$ 29,669,227
Transport Therms		2,051,536	$ 0.29084	596,669
Total - Excluding Cost of Gas				$ 43,845,416
Base Cost of Gas (per therm)		102,012,194	$ 0.70873	$ 72,299,102
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 116,144,518

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	84,872		$ 120.00	$ 10,184,640	-25.0%
Commodity Charge					
Sales Therms		102,012,194	$ 0.35145	$ 35,852,186	
Transport Therms		2,051,536	$ 0.35145	721,012	
Total - Excluding Cost of Gas				$ 46,757,838	6.6%
Base Cost of Gas (per therm)		102,012,194	$ 0.70873	$ 72,299,102	
Total Revenue				$ 119,056,940	2.5%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Large-2

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	5,136		$ 160.00	$ 821,760
Commodity Charge				
Sales Therms		33,135,165	$ 0.29084	$ 9,637,031
Transport Therms		2,735,757	$ 0.29084	795,668
Total - Excluding Cost of Gas				$ 11,254,459
Base Cost of Gas (per therm)		33,135,165	$ 0.70873	$ 23,483,885
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 34,738,344

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	5,136		$ 240.00	$ 1,232,640	50.0%
Commodity Charge					
Sales Therms		33,135,165	$ 0.30668	$ 10,161,892	
Transport Therms		2,735,757	$ 0.30668	839,002	
Total - Excluding Cost of Gas				$ 12,233,534	8.7%
Base Cost of Gas (per therm)		33,135,165	$ 0.70873	$ 23,483,885	
Total Revenue				$ 35,717,419	2.8%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-40, Air Conditioning Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge				
General Service - Small	184		$ 27.50	$ 5,060
General Service - Medium	0		$ 43.50	$ -
General Service - Large	24		$ 160.00	$ 3,840
Essential Agricultural	36		$ 120.00	$ 4,320
Total Basic Service Charges				$ 13,220
Commodity Charge				
Sales Therms		359,940	$0.11010	$ 39,629
Transport Therms		266,305	$0.11010	29,320
Total - Excluding Cost of Gas				$ 82,169
Base Cost of Gas (per therm)		359,940	$0.70873	$ 255,100
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 337,269

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	184		$ 27.50	$ 5,060	
General Service - Medium	0		$ 43.50	$ -	
General Service - Large 1	24		$ 120.00	$ 2,880	
Essential Agricultural	36		$ 120.00	$ 4,320	
Total Basic Service Charges				$ 12,260	-7.3%
Commodity Charge					
Sales Therms		359,940	$0.13965	$ 50,266	
Transport Therms		266,305	$0.13965	37,189	
Total - Excluding Cost of Gas				$ 99,715	21.4%
Base Cost of Gas (per therm)		359,940	$0.70873	$ 255,100	
Total Revenue				$ 354,815	5.2%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-45, Street Lighting Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	180		$ -	$ -
Commodity Charge				
Sales Therms		87,447	$0.61050	$ 53,386
Total - Excluding Cost of Gas				$ 53,386
Base Cost of Gas (per therm)		87,447	$0.70873	$ 61,976
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 115,362

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	180		$ -	$ -	
Commodity Charge					
Sales Therms		87,447	$0.72590	$ 63,478	
Total - Excluding Cost of Gas				$ 63,478	18.9%
Base Cost of Gas (per therm)		87,447	$0.70873	$ 61,976	
Total Revenue				$ 125,454	8.7%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-55, Gas Service for Compression on Customer's Premises

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge				
General Service - Small	192		$ 27.50	$ 5,280
General Service - Large	240		$ 250.00	$ 60,000
General Service - Residential	984		$ 10.70	$ 10,529
Total Basic Service Charges				$ 75,809
Commodity Charge				
Sales Therms - Small		101,442	$0.18678	$ 18,947
Sales Therms - Large		1,244,594	$0.18678	232,465
Sales Therms - Residential		35,148	$0.18678	6,565
Total - Excluding Cost of Gas				$ 333,786
Base Cost of Gas (per therm)		101,442	$0.70873	$ 71,895
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 405,681

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	192		$ 27.50	$ 5,280	
General Service - Large	240		$ 250.00	$ 60,000	
General Service - Residential	984		$ 10.70	$ 10,529	
Total Basic Service Charges				$ 75,809	0.0%
Commodity Charge					
Sales Therms - Small		101,442	$0.19215	$ 19,492	
Sales Therms - Large		1,244,594	$0.19215	239,149	
Sales Therms - Residential		35,148	$0.19215	6,754	
Total - Excluding Cost of Gas				$ 341,204	2.2%
Base Cost of Gas (per therm)		101,442	$0.70873	$ 71,895	
(applies proposed base cost of gas for comparability)					
Total Revenue				$ 413,099	1.8%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-60, Cogeneration Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge				
General Service - Small	36		$ 27.50	$ 990
General Service - Medium	24		$ 43.50	$ 1,044
General Service - Large	36		$ 160.00	$ 5,760
Essential Agricultural	12		$ 120.00	$ 1,440
Total Basic Service Charges				$ 9,234
Commodity Charge				
Sales Therms		1,235,925	$0.13535	$ 167,282
Transport Therms		20,137,894	$0.13535	2,725,664
Total - Excluding Cost of Gas				$ 2,902,180
Base Cost of Gas (per therm)		1,235,925	$0.70873	$ 875,937
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 3,778,117

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	36		$ 27.50	$ 990	
General Service - Medium	24		$ 43.50	$ 1,044	
General Service - Large 1	36		$ 120.00	$ 4,320	
Essential Agricultural	12		$ 120.00	$ 1,440	
Total Basic Service Charges				$ 7,794	-15.6%
Commodity Charge					
Sales Therms		1,235,925	$0.16496	$ 203,878	
Transport Therms		20,137,894	$0.16496	3,321,947	
Total - Excluding Cost of Gas				$ 3,533,619	21.8%
Base Cost of Gas (per therm)		1,235,925	$0.70873	$ 875,937	
Total Revenue				$ 4,409,556	16.7%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-75, Small Essential Agriculture User Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	611		$ 120.00	$ 73,320
Commodity Charge				
Sales Therms		2,647,768	$0.24396	$ 645,949
Transport Therms		32,852	$0.24396	8,015
Total - Excluding Cost of Gas				$ 727,284
Base Cost of Gas (per therm)		2,647,768	$0.70873	$ 1,876,553
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 2,603,837

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	611		$ 120.00	$ 73,320	0.0%
Commodity Charge					
Sales Therms		2,647,768	$0.26344	$ 697,528	
Transport Therms		32,852	$0.26344	8,655	
Total - Excluding Cost of Gas				$ 779,503	7.2%
Base Cost of Gas (per therm)		2,647,768	$0.70873	$ 1,876,553	
Total Revenue				$ 2,656,056	2.0%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-80, Natural Gas Engine Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	1,999		$ 125.00	$ 249,875
Commodity Charge				
Sales Therms		7,272,353	$ 0.19069	$ 1,386,765
Transport Therms		405,928	$ 0.19069	77,406
Total - Excluding Cost of Gas				$ 1,714,046
Base Cost of Gas (per therm)		7,272,353	$ 0.50345	$ 3,661,266
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 5,375,312

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	1,999		$ 125.00	$ 249,875	0.0%
Commodity Charge					
Sales Therms		7,272,353	$ 0.20744	$ 1,508,577	
Transport Therms		405,928	$ 0.20744	84,206	
Total - Excluding Cost of Gas				$ 1,842,658	7.5%
Base Cost of Gas (per therm)		7,272,353	$ 0.50345	$ 3,661,266	
Total Revenue				$ 5,503,924	2.4%

Source: Company's Class Cost of Service Study.

Summary of Comparison of Company's Present and Staff's Proposed Revenues

	Base Revenue		Percent	Total Revenue		Percent
	Current	Proposed	Change	Current	Proposed	Change
Rate Schedule G-5, Single-Family Residential Gas Service	$ 260,896,069	$ 306,927,072	17.6%	$ 446,457,488	$ 492,488,491	10.3%
Rate Schedule G-6, Multi-Family Residential Gas Service	$ 6,914,441	$ 8,046,414	16.4%	$ 11,069,522	$ 12,201,495	10.2%
Rate Schedule G-10, Single-Family Low Income Residential Gas Service	$ 6,991,380	$ 8,667,237	24.0%	$ 14,429,642	$ 16,105,499	11.6%
Rate Schedule G-11, Multi-Family Low Income Residential Gas Service	$ 557,577	$ 672,945	20.7%	$ 1,061,091	$ 1,176,459	10.9%
Rate Schedule G-15, Special Residential Gas Service for Air Conditioning	$ 58,822	$ 74,351	26.4%	$ 122,054	$ 137,583	12.7%
Rate Schedule G-20, Master Metered Mobile Home Park (MMMHP) Gase Service	$ 863,947	$ 920,389	6.5%	$ 2,156,004	$ 2,212,446	2.6%
Rate Schedule G-25, General Gas Service, Small	$ 7,908,814	$ 8,373,340	5.9%	$ 10,709,328	$ 11,173,854	4.3%
Rate Schedule G-25, General Gas Service, Medium	$ 22,579,171	$ 24,017,657	6.4%	$ 49,894,508	$ 51,332,994	2.9%
Rate Schedule G-25, General Gas Service, Large-1	$ 43,845,416	$ 46,757,838	6.6%	$ 116,144,518	$ 119,056,940	2.5%
Rate Schedule G-25, General Gas Service, Large-2	$ 11,254,459	$ 12,233,534	8.7%	$ 34,738,344	$ 35,717,419	2.8%
Rate Schedule G-40, Air Conditioning Gas Service	$ 82,169	$ 99,715	21.4%	$ 337,269	$ 354,815	5.2%
Rate Schedule G-45, Street Lighting Gas Service	$ 53,386	$ 63,478	18.9%	$ 115,362	$ 125,454	8.7%
Rate Schedule G-55, Gas Service for Compression on Customer's Premises	$ 333,786	$ 341,204	2.2%	$ 405,681	$ 413,099	1.8%
Rate Schedule G-60, Cogeneration Gas Service	$ 2,902,180	$ 3,533,619	21.8%	$ 3,778,117	$ 4,409,556	16.7%
Rate Schedule G-75, Small Essential Agriculture User Gas Service	$ 727,284	$ 779,503	7.2%	$ 2,603,837	$ 2,656,056	2.0%
Rate Schedule G-80, Natural Gas Engine Gas Service	$ 1,714,046	$ 1,842,658	7.5%	$ 5,375,312	$ 5,503,924	2.4%

Summary of Bill Impacts

Rate Schedule G-5, Single-Family Residential Gas Service
Customer Bill Impact

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 10.70	$ 3.54	$ 3.73	$ 0.55	$ 18.52	$ 17.65	4.9%
10	$ 10.70	$ 7.09	$ 7.47	$ 1.10	$ 26.36	$ 24.59	7.2%
11 Summer Avg.	$ 10.70	$ 7.80	$ 8.21	$ 1.21	$ 27.92	$ 25.98	7.5%
15	$ 10.70	$ 10.63	$ 11.20	$ 1.65	$ 34.18	$ 31.54	8.4%
20	$ 10.70	$ 14.17	$ 14.93	$ 2.20	$ 42.00	$ 38.49	9.1%
21	$ 10.70	$ 14.88	$ 15.68	$ 2.31	$ 43.57	$ 39.88	9.3%
25 Annual Avg.	$ 10.70	$ 17.72	$ 18.66	$ 2.75	$ 49.83	$ 45.44	9.7%
30	$ 10.70	$ 21.26	$ 22.40	$ 3.30	$ 57.66	$ 52.38	10.1%
39 Winter Avg.	$ 10.70	$ 27.64	$ 29.11	$ 4.29	$ 71.74	$ 64.89	10.6%
40	$ 10.70	$ 28.35	$ 29.86	$ 4.40	$ 73.31	$ 66.28	10.6%
50	$ 10.70	$ 35.44	$ 37.33	$ 5.50	$ 88.97	$ 80.17	11.0%
60	$ 10.70	$ 42.52	$ 44.79	$ 6.60	$ 104.61	$ 94.07	11.2%
75	$ 10.70	$ 53.15	$ 55.99	$ 8.25	$ 128.09	$ 114.91	11.5%
100	$ 10.70	$ 70.87	$ 74.65	$ 11.00	$ 167.22	$ 149.64	11.7%
125	$ 10.70	$ 88.59	$ 93.31	$ 13.75	$ 206.35	$ 184.38	11.9%
150	$ 10.70	$ 106.31	$ 111.98	$ 16.50	$ 245.49	$ 219.11	12.0%
200	$ 10.70	$ 141.75	$ 149.30	$ 22.00	$ 323.75	$ 288.59	12.2%
250	$ 10.70	$ 177.18	$ 186.63	$ 27.50	$ 402.01	$ 358.06	12.3%
300	$ 10.70	$ 212.62	$ 223.95	$ 33.00	$ 480.27	$ 427.53	12.3%
400	$ 10.70	$ 283.49	$ 298.60	$ 44.00	$ 636.79	$ 566.47	12.4%
500	$ 10.70	$ 354.37	$ 373.26	$ 55.00	$ 793.33	$ 705.42	12.5%

Summary of Bill Impacts

Rate Schedule G-6, Multi-Family Residential Gas Service
Customer Bill Impact

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Staff Proposed Rates: Base Cost of Gas	Staff Proposed Rates: Margin Rate	Staff Proposed Rates: Monthly PGA Rate	Staff Proposed Rates: Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 9.70	$ 3.54	$ 3.73	$ 0.55	$ 17.52	$ 16.56	5.8%
10 Summer Avg.	$ 9.70	$ 7.09	$ 7.47	$ 1.10	$ 25.36	$ 23.42	8.3%
15	$ 9.70	$ 10.63	$ 11.20	$ 1.65	$ 33.18	$ 30.28	9.6%
16 Annual Avg.	$ 9.70	$ 11.34	$ 11.94	$ 1.76	$ 34.74	$ 31.65	9.8%
20	$ 9.70	$ 14.17	$ 14.93	$ 2.20	$ 41.00	$ 37.14	10.4%
21 Winter Avg.	$ 9.70	$ 14.88	$ 15.68	$ 2.31	$ 42.57	$ 38.52	10.5%
25	$ 9.70	$ 17.72	$ 18.66	$ 2.75	$ 48.83	$ 44.00	11.0%
30	$ 9.70	$ 21.26	$ 22.40	$ 3.30	$ 56.66	$ 50.86	11.4%
40	$ 9.70	$ 28.35	$ 29.86	$ 4.40	$ 72.31	$ 64.59	12.0%
50	$ 9.70	$ 35.44	$ 37.33	$ 5.50	$ 87.97	$ 78.31	12.3%
60	$ 9.70	$ 42.52	$ 44.79	$ 6.60	$ 103.61	$ 92.03	12.6%
75	$ 9.70	$ 53.15	$ 55.99	$ 8.25	$ 127.09	$ 112.61	12.9%
100	$ 9.70	$ 70.87	$ 74.65	$ 11.00	$ 166.22	$ 146.92	13.1%
125	$ 9.70	$ 88.59	$ 93.31	$ 13.75	$ 205.35	$ 181.22	13.3%
150	$ 9.70	$ 106.31	$ 111.98	$ 16.50	$ 244.49	$ 215.52	13.4%
200	$ 9.70	$ 141.75	$ 149.30	$ 22.00	$ 322.75	$ 284.13	13.6%
250	$ 9.70	$ 177.18	$ 186.63	$ 27.50	$ 401.01	$ 352.74	13.7%
300	$ 9.70	$ 212.62	$ 223.95	$ 33.00	$ 479.27	$ 421.35	13.7%
400	$ 9.70	$ 283.49	$ 298.60	$ 44.00	$ 635.79	$ 558.56	13.8%
500	$ 9.70	$ 354.37	$ 373.26	$ 55.00	$ 792.33	$ 695.78	13.9%

Summary of Bill Impacts

Rate Schedule G-10, Single-Family Low Income Residential Gas Service
Customer Bill Impact - Summer Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.74	$ 0.11	$ 9.06	$ 8.87	2.1%
2	$ 7.50	$ 1.42	$ 1.48	$ 0.22	$ 10.62	$ 10.24	3.7%
3	$ 7.50	$ 2.13	$ 2.23	$ 0.33	$ 12.19	$ 11.62	4.9%
4	$ 7.50	$ 2.83	$ 2.97	$ 0.44	$ 13.74	$ 12.99	5.8%
5	$ 7.50	$ 3.54	$ 3.71	$ 0.55	$ 15.30	$ 14.36	6.5%
6	$ 7.50	$ 4.25	$ 4.45	$ 0.66	$ 16.86	$ 15.73	7.2%
7	$ 7.50	$ 4.96	$ 5.20	$ 0.77	$ 18.43	$ 17.11	7.7%
8	$ 7.50	$ 5.67	$ 5.94	$ 0.88	$ 19.99	$ 18.48	8.2%
9	$ 7.50	$ 6.38	$ 6.68	$ 0.99	$ 21.55	$ 19.85	8.6%
10	$ 7.50	$ 7.09	$ 7.42	$ 1.10	$ 23.11	$ 21.22	8.9%
11 Summer Avg.	$ 7.50	$ 7.80	$ 8.17	$ 1.21	$ 24.68	$ 22.59	9.3%
15	$ 7.50	$ 10.63	$ 11.14	$ 1.65	$ 30.92	$ 28.08	10.1%
20	$ 7.50	$ 14.17	$ 14.85	$ 2.20	$ 38.72	$ 34.94	10.8%
25 Annual Avg.	$ 7.50	$ 17.72	$ 18.56	$ 2.75	$ 46.53	$ 41.80	11.3%
30	$ 7.50	$ 21.26	$ 22.27	$ 3.30	$ 54.33	$ 48.66	11.7%
39	$ 7.50	$ 27.64	$ 28.95	$ 4.29	$ 68.38	$ 61.01	12.1%
40	$ 7.50	$ 28.35	$ 29.70	$ 4.40	$ 69.95	$ 62.39	12.1%
50	$ 7.50	$ 35.44	$ 37.12	$ 5.50	$ 85.56	$ 76.11	12.4%
60	$ 7.50	$ 42.52	$ 44.54	$ 6.60	$ 101.16	$ 89.83	12.6%
72	$ 7.50	$ 51.03	$ 53.45	$ 7.92	$ 119.90	$ 106.30	12.8%
75	$ 7.50	$ 53.15	$ 55.68	$ 8.25	$ 124.58	$ 110.41	12.8%
100	$ 7.50	$ 70.87	$ 74.24	$ 11.00	$ 163.61	$ 144.72	13.1%
125	$ 7.50	$ 88.59	$ 92.80	$ 13.75	$ 202.64	$ 179.02	13.2%
150	$ 7.50	$ 106.31	$ 111.36	$ 16.50	$ 241.67	$ 213.32	13.3%
200	$ 7.50	$ 141.75	$ 148.48	$ 22.00	$ 319.73	$ 281.93	13.4%
250	$ 7.50	$ 177.18	$ 185.60	$ 27.50	$ 397.78	$ 350.54	13.5%
300	$ 7.50	$ 212.62	$ 222.72	$ 33.00	$ 475.84	$ 419.15	13.5%
400	$ 7.50	$ 283.49	$ 296.96	$ 44.00	$ 631.95	$ 556.36	13.6%
500	$ 7.50	$ 354.37	$ 371.21	$ 55.00	$ 788.08	$ 693.58	13.6%

Summary of Bill Impacts

Rate Schedule G-10, Single-Family Low Income Residential Gas Service
Customer Bill Impact - Winter Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.47	$ 0.11	$ 8.79	$ 8.63	1.9%
2	$ 7.50	$ 1.42	$ 0.93	$ 0.22	$ 10.07	$ 9.77	3.1%
3	$ 7.50	$ 2.13	$ 1.40	$ 0.33	$ 11.36	$ 10.90	4.2%
4	$ 7.50	$ 2.83	$ 1.87	$ 0.44	$ 12.64	$ 12.04	5.0%
5	$ 7.50	$ 3.54	$ 2.34	$ 0.55	$ 13.93	$ 13.17	5.8%
6	$ 7.50	$ 4.25	$ 2.80	$ 0.66	$ 15.21	$ 14.31	6.3%
7	$ 7.50	$ 4.96	$ 3.27	$ 0.77	$ 16.50	$ 15.44	6.9%
8	$ 7.50	$ 5.67	$ 3.74	$ 0.88	$ 17.79	$ 16.58	7.3%
9	$ 7.50	$ 6.38	$ 4.21	$ 0.99	$ 19.08	$ 17.71	7.7%
10	$ 7.50	$ 7.09	$ 4.67	$ 1.10	$ 20.36	$ 18.85	8.0%
11	$ 7.50	$ 7.80	$ 5.14	$ 1.21	$ 21.65	$ 19.98	8.4%
15	$ 7.50	$ 10.63	$ 7.01	$ 1.65	$ 26.79	$ 24.52	9.3%
20	$ 7.50	$ 14.17	$ 9.35	$ 2.20	$ 33.22	$ 30.20	10.0%
25 Annual Avg.	$ 7.50	$ 17.72	$ 11.69	$ 2.75	$ 39.66	$ 35.87	10.6%
30	$ 7.50	$ 21.26	$ 14.02	$ 3.30	$ 46.08	$ 41.55	10.9%
39 Winter Avg.	$ 7.50	$ 27.64	$ 18.23	$ 4.29	$ 57.66	$ 51.76	11.4%
40	$ 7.50	$ 28.35	$ 18.70	$ 4.40	$ 58.95	$ 52.90	11.4%
50	$ 7.50	$ 35.44	$ 23.37	$ 5.50	$ 71.81	$ 64.25	11.8%
60	$ 7.50	$ 42.52	$ 28.05	$ 6.60	$ 84.67	$ 75.60	12.0%
72	$ 7.50	$ 51.03	$ 33.65	$ 7.92	$ 100.10	$ 89.22	12.2%
75	$ 7.50	$ 53.15	$ 35.06	$ 8.25	$ 103.96	$ 92.62	12.2%
100	$ 7.50	$ 70.87	$ 46.74	$ 11.00	$ 136.11	$ 121.00	12.5%
125	$ 7.50	$ 88.59	$ 58.43	$ 13.75	$ 168.27	$ 149.37	12.7%
150	$ 7.50	$ 106.31	$ 70.11	$ 16.50	$ 200.42	$ 177.75	12.8%
200	$ 7.50	$ 141.75	$ 107.24	$ 22.00	$ 278.49	$ 246.35	13.0%
250	$ 7.50	$ 177.18	$ 144.36	$ 27.50	$ 356.54	$ 314.96	13.2%
300	$ 7.50	$ 212.62	$ 181.48	$ 33.00	$ 434.60	$ 383.57	13.3%
400	$ 7.50	$ 283.49	$ 255.72	$ 44.00	$ 590.71	$ 520.79	13.4%
500	$ 7.50	$ 354.37	$ 329.96	$ 55.00	$ 746.83	$ 658.00	13.5%

Summary of Bill Impacts

Rate Schedule G-11, Multi-Family Low Income Residential Gas Service
Customer Bill Impact - Summer Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.74	$ 0.11	$ 9.06	$ 8.87	2.1%
2	$ 7.50	$ 1.42	$ 1.48	$ 0.22	$ 10.62	$ 10.24	3.7%
3	$ 7.50	$ 2.13	$ 2.23	$ 0.33	$ 12.19	$ 11.62	4.9%
4	$ 7.50	$ 2.83	$ 2.97	$ 0.44	$ 13.74	$ 12.99	5.8%
5	$ 7.50	$ 3.54	$ 3.71	$ 0.55	$ 15.30	$ 14.36	6.5%
6	$ 7.50	$ 4.25	$ 4.45	$ 0.66	$ 16.86	$ 15.73	7.2%
7	$ 7.50	$ 4.96	$ 5.20	$ 0.77	$ 18.43	$ 17.11	7.7%
8	$ 7.50	$ 5.67	$ 5.94	$ 0.88	$ 19.99	$ 18.48	8.2%
9	$ 7.50	$ 6.38	$ 6.68	$ 0.99	$ 21.55	$ 19.85	8.6%
10	$ 7.50	$ 7.09	$ 7.42	$ 1.10	$ 23.11	$ 21.22	8.9%
11 Summer Avg.	$ 7.50	$ 7.80	$ 8.17	$ 1.21	$ 24.68	$ 22.59	9.3%
15	$ 7.50	$ 10.63	$ 11.14	$ 1.65	$ 30.92	$ 28.08	10.1%
19 Annual Avg.	$ 7.50	$ 13.47	$ 14.11	$ 2.09	$ 37.17	$ 33.57	10.7%
20	$ 7.50	$ 14.17	$ 14.85	$ 2.20	$ 38.72	$ 34.94	10.8%
25	$ 7.50	$ 17.72	$ 18.56	$ 2.75	$ 46.53	$ 41.80	11.3%
30	$ 7.50	$ 21.26	$ 22.27	$ 3.30	$ 54.33	$ 48.66	11.7%
40	$ 7.50	$ 28.35	$ 29.70	$ 4.40	$ 69.95	$ 62.39	12.1%
50	$ 7.50	$ 35.44	$ 37.12	$ 5.50	$ 85.56	$ 76.11	12.4%
60	$ 7.50	$ 42.52	$ 44.54	$ 6.60	$ 101.16	$ 89.83	12.6%
72	$ 7.50	$ 51.03	$ 53.45	$ 7.92	$ 119.90	$ 106.30	12.8%
75	$ 7.50	$ 53.15	$ 55.68	$ 8.25	$ 124.58	$ 110.41	12.8%
100	$ 7.50	$ 70.87	$ 74.24	$ 11.00	$ 163.61	$ 144.72	13.1%
125	$ 7.50	$ 88.59	$ 92.80	$ 13.75	$ 202.64	$ 179.02	13.2%
150	$ 7.50	$ 106.31	$ 111.36	$ 16.50	$ 241.67	$ 213.32	13.3%
200	$ 7.50	$ 141.75	$ 148.48	$ 22.00	$ 319.73	$ 281.93	13.4%
250	$ 7.50	$ 177.18	$ 185.60	$ 27.50	$ 397.78	$ 350.54	13.5%
300	$ 7.50	$ 212.62	$ 222.72	$ 33.00	$ 475.84	$ 419.15	13.5%
400	$ 7.50	$ 283.49	$ 296.96	$ 44.00	$ 631.95	$ 556.36	13.6%
500	$ 7.50	$ 354.37	$ 371.21	$ 55.00	$ 788.08	$ 693.58	13.6%

Summary of Bill Impacts

Rate Schedule G-11, Multi-Family Low Income Residential Gas Service
Customer Bill Impact - Winter Rates

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.47	$ 0.11	$ 8.79	$ 8.63	1.9%
2	$ 7.50	$ 1.42	$ 0.93	$ 0.22	$ 10.07	$ 9.77	3.1%
3	$ 7.50	$ 2.13	$ 1.40	$ 0.33	$ 11.36	$ 10.90	4.2%
4	$ 7.50	$ 2.83	$ 1.87	$ 0.44	$ 12.64	$ 12.04	5.0%
5	$ 7.50	$ 3.54	$ 2.34	$ 0.55	$ 13.93	$ 13.17	5.8%
6	$ 7.50	$ 4.25	$ 2.80	$ 0.66	$ 15.21	$ 14.31	6.3%
7	$ 7.50	$ 4.96	$ 3.27	$ 0.77	$ 16.50	$ 15.44	6.9%
8	$ 7.50	$ 5.67	$ 3.74	$ 0.88	$ 17.79	$ 16.58	7.3%
9	$ 7.50	$ 6.38	$ 4.21	$ 0.99	$ 19.08	$ 17.71	7.7%
10	$ 7.50	$ 7.09	$ 4.67	$ 1.10	$ 20.36	$ 18.85	8.0%
11	$ 7.50	$ 7.80	$ 5.14	$ 1.21	$ 21.65	$ 19.98	8.4%
15	$ 7.50	$ 10.63	$ 7.01	$ 1.65	$ 26.79	$ 24.52	9.3%
19 Annual Avg.	$ 7.50	$ 13.47	$ 8.88	$ 2.09	$ 31.94	$ 29.06	9.9%
20	$ 7.50	$ 14.17	$ 9.35	$ 2.20	$ 33.22	$ 30.20	10.0%
25	$ 7.50	$ 17.72	$ 11.69	$ 2.75	$ 39.66	$ 35.87	10.6%
26 Winter Avg.	$ 7.50	$ 18.43	$ 12.15	$ 2.86	$ 40.94	$ 37.01	10.6%
30	$ 7.50	$ 21.26	$ 14.02	$ 3.30	$ 46.08	$ 41.55	10.9%
40	$ 7.50	$ 28.35	$ 18.70	$ 4.40	$ 58.95	$ 52.90	11.4%
50	$ 7.50	$ 35.44	$ 23.37	$ 5.50	$ 71.81	$ 64.25	11.8%
60	$ 7.50	$ 42.52	$ 28.05	$ 6.60	$ 84.67	$ 75.60	12.0%
72	$ 7.50	$ 51.03	$ 33.65	$ 7.92	$ 100.10	$ 89.22	12.2%
75	$ 7.50	$ 53.15	$ 35.06	$ 8.25	$ 103.96	$ 92.62	12.2%
100	$ 7.50	$ 70.87	$ 46.74	$ 11.00	$ 136.11	$ 121.00	12.5%
125	$ 7.50	$ 88.59	$ 58.43	$ 13.75	$ 168.27	$ 149.37	12.7%
150	$ 7.50	$ 106.31	$ 70.11	$ 16.50	$ 200.42	$ 177.75	12.8%
200	$ 7.50	$ 141.75	$ 107.24	$ 22.00	$ 278.49	$ 246.35	13.0%
250	$ 7.50	$ 177.18	$ 144.36	$ 27.50	$ 356.54	$ 314.96	13.2%
300	$ 7.50	$ 212.62	$ 181.48	$ 33.00	$ 434.60	$ 383.57	13.3%
400	$ 7.50	$ 283.49	$ 255.72	$ 44.00	$ 590.71	$ 520.79	13.4%
500	$ 7.50	$ 354.37	$ 329.96	$ 55.00	$ 746.83	$ 658.00	13.5%

Summary of Bill Impacts

Rate Schedule G-15, Special Residential Gas Service for Air Conditioning
Customer Bill Impact - Summer Rates

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
10	$ 10.70	$ 7.09	$ 7.47	$ 1.10	$ 26.36	$ 26.36	0.0%
20	$ 10.70	$ 13.46	$ 14.93	$ 2.20	$ 41.29	$ 37.08	11.4%
30	$ 10.70	$ 17.98	$ 22.40	$ 3.30	$ 54.38	$ 48.15	12.9%
40	$ 10.70	$ 22.51	$ 29.86	$ 4.40	$ 67.47	$ 59.22	13.9%
50	$ 10.70	$ 27.03	$ 37.33	$ 5.50	$ 80.56	$ 70.30	14.6%
60	$ 10.70	$ 31.56	$ 44.79	$ 6.60	$ 93.65	$ 81.37	15.1%
67 Summer Avg.	$ 10.70	$ 34.72	$ 50.02	$ 7.37	$ 102.81	$ 89.12	15.4%
70	$ 10.70	$ 36.08	$ 52.26	$ 7.70	$ 106.74	$ 92.44	15.5%
80	$ 10.70	$ 40.60	$ 59.72	$ 8.80	$ 119.82	$ 103.52	15.7%
83 Annual Avg.	$ 10.70	$ 41.96	$ 61.96	$ 9.13	$ 123.75	$ 106.84	15.8%
90	$ 10.70	$ 45.13	$ 67.19	$ 9.90	$ 132.92	$ 114.59	16.0%
99	$ 10.70	$ 49.20	$ 73.90	$ 10.89	$ 144.69	$ 124.56	16.2%
100	$ 10.70	$ 49.65	$ 74.65	$ 11.00	$ 146.00	$ 125.66	16.2%
119	$ 10.70	$ 58.25	$ 88.83	$ 13.09	$ 170.87	$ 146.70	16.5%
125	$ 10.70	$ 60.96	$ 93.31	$ 13.75	$ 178.72	$ 153.35	16.5%
150	$ 10.70	$ 72.27	$ 111.98	$ 16.50	$ 211.45	$ 181.03	16.8%
152	$ 10.70	$ 73.18	$ 113.47	$ 16.72	$ 214.07	$ 183.25	16.8%
175	$ 10.70	$ 83.58	$ 130.64	$ 19.25	$ 244.17	$ 208.71	17.0%
200	$ 10.70	$ 94.89	$ 149.30	$ 22.00	$ 276.89	$ 236.40	17.1%
250	$ 10.70	$ 117.51	$ 186.63	$ 27.50	$ 342.34	$ 291.76	17.3%
300	$ 10.70	$ 140.13	$ 223.95	$ 33.00	$ 407.78	$ 347.13	17.5%
350	$ 10.70	$ 162.75	$ 261.28	$ 38.50	$ 473.23	$ 402.50	17.6%
400	$ 10.70	$ 185.37	$ 298.60	$ 44.00	$ 538.67	$ 457.86	17.6%
450	$ 10.70	$ 207.99	$ 335.93	$ 49.50	$ 604.12	$ 513.23	17.7%
500	$ 10.70	$ 230.62	$ 373.26	$ 55.00	$ 669.58	$ 568.60	17.8%

Summary of Bill Impacts

Rate Schedule G-15, Special Residential Gas Service for Air Conditioning
Customer Bill Impact - Winter Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
10	$ 10.70	$ 7.09	$ 7.47	$ 1.10	$ 26.36	$ 24.59	7.2%
20	$ 10.70	$ 14.17	$ 14.93	$ 2.20	$ 42.00	$ 38.49	9.1%
30	$ 10.70	$ 21.26	$ 22.40	$ 3.30	$ 57.66	$ 52.38	10.1%
40	$ 10.70	$ 28.35	$ 29.86	$ 4.40	$ 73.31	$ 66.28	10.6%
50	$ 10.70	$ 35.44	$ 37.33	$ 5.50	$ 88.97	$ 80.17	11.0%
60	$ 10.70	$ 42.52	$ 44.79	$ 6.60	$ 104.61	$ 94.07	11.2%
67	$ 10.70	$ 47.48	$ 50.02	$ 7.37	$ 115.57	$ 103.79	11.3%
70	$ 10.70	$ 49.61	$ 52.26	$ 7.70	$ 120.27	$ 107.96	11.4%
80	$ 10.70	$ 56.70	$ 59.72	$ 8.80	$ 135.92	$ 121.85	11.5%
83 Annual Avg.	$ 10.70	$ 58.82	$ 61.96	$ 9.13	$ 140.61	$ 126.02	11.6%
90	$ 10.70	$ 63.79	$ 67.19	$ 9.90	$ 151.58	$ 135.75	11.7%
99 Winter Avg.	$ 10.70	$ 70.16	$ 73.90	$ 10.89	$ 165.65	$ 148.25	11.7%
100	$ 10.70	$ 70.87	$ 74.65	$ 11.00	$ 167.22	$ 149.64	11.7%
119	$ 10.70	$ 84.34	$ 88.84	$ 13.09	$ 196.97	$ 176.04	11.9%
125	$ 10.70	$ 88.59	$ 93.31	$ 13.75	$ 206.35	$ 184.38	11.9%
150	$ 10.70	$ 106.31	$ 111.98	$ 16.50	$ 245.49	$ 219.11	12.0%
152	$ 10.70	$ 107.73	$ 113.47	$ 16.72	$ 248.62	$ 221.89	12.0%
175	$ 10.70	$ 124.03	$ 130.64	$ 19.25	$ 284.62	$ 253.85	12.1%
200	$ 10.70	$ 141.75	$ 149.30	$ 22.00	$ 323.75	$ 288.59	12.2%
250	$ 10.70	$ 177.18	$ 186.63	$ 27.50	$ 402.01	$ 358.06	12.3%
300	$ 10.70	$ 212.62	$ 223.95	$ 33.00	$ 480.27	$ 427.53	12.3%
350	$ 10.70	$ 248.06	$ 261.28	$ 38.50	$ 558.54	$ 497.00	12.4%
400	$ 10.70	$ 283.49	$ 298.61	$ 44.00	$ 636.80	$ 566.47	12.4%
450	$ 10.70	$ 318.93	$ 335.93	$ 49.50	$ 715.06	$ 635.94	12.4%
500	$ 10.70	$ 354.37	$ 373.26	$ 55.00	$ 793.33	$ 705.42	12.5%

Summary of Bill Impacts

Rate Schedule G-20, Master Metered Mobile Home Park (MMMHP) Gas Service
Customer Bill Impact

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
100		$ 66.00	$ 70.87	$ 43.93	$ 11.00	$ 191.80	$ 188.70	1.6%
200		$ 66.00	$ 141.75	$ 87.85	$ 22.00	$ 317.60	$ 311.41	2.0%
300		$ 66.00	$ 212.62	$ 131.78	$ 33.00	$ 443.40	$ 434.11	2.1%
400		$ 66.00	$ 283.49	$ 175.70	$ 44.00	$ 569.19	$ 556.81	2.2%
425	Summer Avg.	$ 66.00	$ 301.21	$ 186.69	$ 46.75	$ 600.65	$ 587.49	2.2%
500		$ 66.00	$ 354.37	$ 219.63	$ 55.00	$ 695.00	$ 679.52	2.3%
600		$ 66.00	$ 425.24	$ 263.56	$ 66.00	$ 820.80	$ 802.22	2.3%
700		$ 66.00	$ 496.11	$ 307.48	$ 77.00	$ 946.59	$ 924.92	2.3%
800		$ 66.00	$ 566.98	$ 351.41	$ 88.00	$ 1,072.39	$ 1,047.62	2.4%
900		$ 66.00	$ 637.86	$ 395.33	$ 99.00	$ 1,198.19	$ 1,170.33	2.4%
1,000		$ 66.00	$ 708.73	$ 439.26	$ 110.00	$ 1,323.99	$ 1,293.03	2.4%
1,006	Annual Avg.	$ 66.00	$ 712.98	$ 441.90	$ 110.66	$ 1,331.54	$ 1,300.39	2.4%
1,250		$ 66.00	$ 885.91	$ 549.08	$ 137.50	$ 1,638.49	$ 1,599.79	2.4%
1,500		$ 66.00	$ 1,063.10	$ 658.89	$ 165.00	$ 1,952.99	$ 1,906.55	2.4%
1,587	Winter Avg.	$ 66.00	$ 1,124.75	$ 697.11	$ 174.57	$ 2,062.43	$ 2,013.30	2.4%
2,000		$ 66.00	$ 1,417.46	$ 878.52	$ 220.00	$ 2,581.98	$ 2,520.06	2.5%
3,000		$ 66.00	$ 2,126.19	$ 1,317.78	$ 330.00	$ 3,839.97	$ 3,747.09	2.5%
4,000		$ 66.00	$ 2,834.92	$ 1,757.04	$ 440.00	$ 5,097.96	$ 4,974.12	2.5%
5,000		$ 66.00	$ 3,543.65	$ 2,196.30	$ 550.00	$ 6,355.95	$ 6,201.15	2.5%
7,500		$ 66.00	$ 5,315.48	$ 3,294.45	$ 825.00	$ 9,500.93	$ 9,268.73	2.5%
10,000		$ 66.00	$ 7,087.30	$ 4,392.60	$ 1,100.00	$ 12,645.90	$ 12,336.30	2.5%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Small
Customer Bill Impact

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 27.50	$ 3.54	$ 3.44	$ 0.55	$ 35.03	$ 34.45	1.7%
9 Summer Avg.	$ 27.50	$ 6.38	$ 6.19	$ 0.99	$ 41.06	$ 40.00	2.7%
10	$ 27.50	$ 7.09	$ 6.88	$ 1.10	$ 42.57	$ 41.39	2.9%
15	$ 27.50	$ 10.63	$ 10.32	$ 1.65	$ 50.10	$ 48.34	3.6%
20	$ 27.50	$ 14.17	$ 13.76	$ 2.20	$ 57.63	$ 55.29	4.2%
22 Annual Avg.	$ 27.50	$ 15.59	$ 15.14	$ 2.42	$ 60.65	$ 58.07	4.4%
25	$ 27.50	$ 17.72	$ 17.20	$ 2.75	$ 65.17	$ 62.23	4.7%
30	$ 27.50	$ 21.26	$ 20.64	$ 3.30	$ 72.70	$ 69.18	5.1%
34 Winter Avg.	$ 27.50	$ 24.10	$ 23.40	$ 3.74	$ 78.74	$ 74.74	5.4%
40	$ 27.50	$ 28.35	$ 27.53	$ 4.40	$ 87.78	$ 83.07	5.7%
50	$ 27.50	$ 35.44	$ 34.41	$ 5.50	$ 102.85	$ 96.97	6.1%
60	$ 27.50	$ 42.52	$ 41.29	$ 6.60	$ 117.91	$ 110.86	6.4%
75	$ 27.50	$ 53.15	$ 51.61	$ 8.25	$ 140.51	$ 131.70	6.7%
100	$ 27.50	$ 70.87	$ 68.81	$ 11.00	$ 178.18	$ 166.43	7.1%
125	$ 27.50	$ 88.59	$ 86.02	$ 13.75	$ 215.86	$ 201.17	7.3%
150	$ 27.50	$ 106.31	$ 103.22	$ 16.50	$ 253.53	$ 235.90	7.5%
200	$ 27.50	$ 141.75	$ 137.63	$ 22.00	$ 328.88	$ 305.36	7.7%
250	$ 27.50	$ 177.18	$ 172.03	$ 27.50	$ 404.21	$ 374.83	7.8%
300	$ 27.50	$ 212.62	$ 206.44	$ 33.00	$ 479.56	$ 444.30	7.9%
400	$ 27.50	$ 283.49	$ 275.25	$ 44.00	$ 630.24	$ 583.23	8.1%
500	$ 27.50	$ 354.37	$ 344.07	$ 55.00	$ 780.94	$ 722.16	8.1%
600	$ 27.50	$ 425.24	$ 412.88	$ 66.00	$ 931.62	$ 861.09	8.2%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Medium
Customer Bill Impact

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ 43.50	$ 17.72	$ 10.43	$ 2.75	$ 74.40	$ 73.47	1.3%
50		$ 43.50	$ 35.44	$ 20.86	$ 5.50	$ 105.30	$ 103.43	1.8%
75		$ 43.50	$ 53.15	$ 31.29	$ 8.25	$ 136.19	$ 133.40	2.1%
100		$ 43.50	$ 70.87	$ 41.72	$ 11.00	$ 167.09	$ 163.37	2.3%
125		$ 43.50	$ 88.59	$ 52.15	$ 13.75	$ 197.99	$ 193.34	2.4%
150		$ 43.50	$ 106.31	$ 62.58	$ 16.50	$ 228.89	$ 223.30	2.5%
152	Summer Avg.	$ 43.50	$ 107.73	$ 63.41	$ 16.72	$ 231.36	$ 225.70	2.5%
175		$ 43.50	$ 124.03	$ 73.00	$ 19.25	$ 259.78	$ 253.27	2.6%
200		$ 43.50	$ 141.75	$ 83.43	$ 22.00	$ 290.68	$ 283.24	2.6%
220		$ 43.50	$ 155.92	$ 91.78	$ 24.20	$ 315.40	$ 307.21	2.7%
223	Annual Avg.	$ 43.50	$ 158.05	$ 93.03	$ 24.53	$ 319.11	$ 310.81	2.7%
250		$ 43.50	$ 177.18	$ 104.29	$ 27.50	$ 352.47	$ 343.17	2.7%
275		$ 43.50	$ 194.90	$ 114.72	$ 30.25	$ 383.37	$ 373.14	2.7%
290		$ 43.50	$ 205.53	$ 120.98	$ 31.90	$ 401.91	$ 391.12	2.8%
295	Winter Avg.	$ 43.50	$ 209.08	$ 123.07	$ 32.45	$ 408.10	$ 397.11	2.8%
300		$ 43.50	$ 212.62	$ 125.15	$ 33.00	$ 414.27	$ 403.11	2.8%
400		$ 43.50	$ 283.49	$ 166.87	$ 44.00	$ 537.86	$ 522.98	2.8%
500		$ 43.50	$ 354.37	$ 208.59	$ 55.00	$ 661.46	$ 642.85	2.9%
600		$ 43.50	$ 425.24	$ 250.30	$ 66.00	$ 785.04	$ 762.71	2.9%
750		$ 43.50	$ 531.55	$ 312.88	$ 82.50	$ 970.43	$ 942.52	3.0%
1,000		$ 43.50	$ 708.73	$ 417.17	$ 110.00	$ 1,279.40	$ 1,242.19	3.0%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Large-1
Customer Bill Impact

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
200		$ 120.00	$ 141.75	$ 70.29	$ 22.00	$ 354.04	$ 381.91	-7.3%
400		$ 120.00	$ 283.49	$ 140.58	$ 44.00	$ 588.07	$ 603.83	-2.6%
600		$ 120.00	$ 425.24	$ 210.87	$ 66.00	$ 822.11	$ 825.74	-0.4%
800		$ 120.00	$ 566.98	$ 281.16	$ 88.00	$ 1,056.14	$ 1,047.66	0.8%
890	Summer Avg.	$ 120.00	$ 630.77	$ 312.79	$ 97.90	$ 1,161.46	$ 1,147.52	1.2%
1,000		$ 120.00	$ 708.73	$ 351.45	$ 110.00	$ 1,290.18	$ 1,269.57	1.6%
1,212	Annual Avg.	$ 120.00	$ 858.98	$ 425.96	$ 133.32	$ 1,538.26	$ 1,504.80	2.2%
1,250		$ 120.00	$ 885.91	$ 439.31	$ 137.50	$ 1,582.72	$ 1,546.96	2.3%
1,500		$ 120.00	$ 1,063.10	$ 527.18	$ 165.00	$ 1,875.28	$ 1,824.36	2.8%
1,532	Winter Avg.	$ 120.00	$ 1,085.77	$ 538.42	$ 168.52	$ 1,912.71	$ 1,859.86	2.8%
2,000		$ 120.00	$ 1,417.46	$ 702.90	$ 220.00	$ 2,460.36	$ 2,379.14	3.4%
2,500		$ 120.00	$ 1,771.83	$ 878.63	$ 275.00	$ 3,045.46	$ 2,933.93	3.8%
3,000		$ 120.00	$ 2,126.19	$ 1,054.35	$ 330.00	$ 3,630.54	$ 3,488.71	4.1%
4,000		$ 120.00	$ 2,834.92	$ 1,405.80	$ 440.00	$ 4,800.72	$ 4,598.28	4.4%
5,000		$ 120.00	$ 3,543.65	$ 1,757.25	$ 550.00	$ 5,970.90	$ 5,707.85	4.6%
7,500		$ 120.00	$ 5,315.48	$ 2,635.88	$ 825.00	$ 8,896.36	$ 8,481.78	4.9%
10,000		$ 120.00	$ 7,087.30	$ 3,514.50	$ 1,100.00	$ 11,821.80	$ 11,255.70	5.0%
15,000		$ 120.00	$ 10,630.95	$ 5,271.75	$ 1,650.00	$ 17,672.70	$ 16,803.55	5.2%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Large-2
Customer Bill Impact

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
2,000		$ 240.00	$ 1,417.46	$ 613.36	$ 220.00	$ 2,490.82	$ 2,379.14	4.7%
5,000		$ 240.00	$ 3,543.65	$ 1,533.40	$ 550.00	$ 5,867.05	$ 5,707.85	2.8%
5,241	Summer Avg.	$ 240.00	$ 3,714.45	$ 1,607.31	$ 576.51	$ 6,138.27	$ 5,975.26	2.7%
7,000		$ 240.00	$ 4,961.11	$ 2,146.76	$ 770.00	$ 8,117.87	$ 7,926.99	2.4%
7,116	Annual Avg.	$ 240.00	$ 5,043.32	$ 2,182.33	$ 782.76	$ 8,248.41	$ 8,055.70	2.4%
8,000		$ 240.00	$ 5,669.84	$ 2,453.44	$ 880.00	$ 9,243.28	$ 9,036.56	2.3%
8,991	Winter Avg.	$ 240.00	$ 6,372.19	$ 2,757.36	$ 989.01	$ 10,358.56	$ 10,136.14	2.2%
10,000		$ 240.00	$ 7,087.30	$ 3,066.80	$ 1,100.00	$ 11,494.10	$ 11,255.70	2.1%
15,000		$ 240.00	$ 10,630.95	$ 4,600.20	$ 1,650.00	$ 17,121.15	$ 16,803.55	1.9%
20,000		$ 240.00	$ 14,174.60	$ 6,133.60	$ 2,200.00	$ 22,748.20	$ 22,351.40	1.8%
25,000		$ 240.00	$ 17,718.25	$ 7,667.00	$ 2,750.00	$ 28,375.25	$ 27,899.25	1.7%
30,000		$ 240.00	$ 21,261.90	$ 9,200.40	$ 3,300.00	$ 34,002.30	$ 33,447.10	1.7%
35,000		$ 240.00	$ 24,805.55	$ 10,733.80	$ 3,850.00	$ 39,629.35	$ 38,994.95	1.6%
40,000		$ 240.00	$ 28,349.20	$ 12,267.20	$ 4,400.00	$ 45,256.40	$ 44,542.80	1.6%
45,000		$ 240.00	$ 31,892.85	$ 13,800.60	$ 4,950.00	$ 50,883.45	$ 50,090.65	1.6%
50,000		$ 240.00	$ 35,436.50	$ 15,334.00	$ 5,500.00	$ 56,510.50	$ 55,638.50	1.6%
60,000		$ 240.00	$ 42,523.80	$ 18,400.80	$ 6,600.00	$ 67,764.60	$ 66,734.20	1.5%
75,000		$ 240.00	$ 53,154.75	$ 23,001.00	$ 8,250.00	$ 84,645.75	$ 83,377.75	1.5%
100,000		$ 240.00	$ 70,873.00	$ 30,668.00	$ 11,000.00	$ 112,781.00	$ 111,117.00	1.5%
150,000		$ 240.00	$ 106,309.50	$ 46,002.00	$ 16,500.00	$ 169,051.50	$ 166,595.50	1.5%
200,000		$ 240.00	$ 141,746.00	$ 61,336.00	$ 22,000.00	$ 225,322.00	$ 222,074.00	1.5%

Summary of Bill Impacts

Rate Schedule G-40, Air Conditioning Gas Service
Customer Bill Impact - Small General Service

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50		$ 27.50	$ 35.44	$ 6.98	$ 5.50	$ 75.42	$ 73.94	2.0%
100		$ 27.50	$ 70.87	$ 13.97	$ 11.00	$ 123.34	$ 120.38	2.5%
234	Winter Avg.	$ 27.50	$ 165.84	$ 32.68	$ 25.74	$ 251.76	$ 244.85	2.8%
250		$ 27.50	$ 177.18	$ 34.91	$ 27.50	$ 267.09	$ 259.71	2.8%
388	Annual Avg.	$ 27.50	$ 274.99	$ 54.18	$ 42.68	$ 399.35	$ 387.89	3.0%
500		$ 27.50	$ 354.37	$ 69.83	$ 55.00	$ 506.70	$ 491.92	3.0%
536	Summer Avg.	$ 27.50	$ 379.88	$ 74.85	$ 58.96	$ 541.19	$ 525.35	3.0%
750		$ 27.50	$ 531.55	$ 104.74	$ 82.50	$ 746.29	$ 724.12	3.1%
1,000		$ 27.50	$ 708.73	$ 139.65	$ 110.00	$ 985.88	$ 956.33	3.1%
2,000		$ 27.50	$ 1,417.46	$ 279.30	$ 220.00	$ 1,944.26	$ 1,885.16	3.1%
3,000		$ 27.50	$ 2,126.19	$ 418.95	$ 330.00	$ 2,902.64	$ 2,813.99	3.2%
5,000		$ 27.50	$ 3,543.65	$ 698.25	$ 550.00	$ 4,819.40	$ 4,671.65	3.2%
7,500		$ 27.50	$ 5,315.48	$ 1,047.38	$ 825.00	$ 7,215.36	$ 6,993.73	3.2%
10,000		$ 27.50	$ 7,087.30	$ 1,396.50	$ 1,100.00	$ 9,611.30	$ 9,315.80	3.2%
15,000		$ 27.50	$ 10,630.95	$ 2,094.75	$ 1,650.00	$ 14,403.20	$ 13,959.95	3.2%
20,000		$ 27.50	$ 14,174.60	$ 2,793.00	$ 2,200.00	$ 19,195.10	$ 18,604.10	3.2%
30,000		$ 27.50	$ 21,261.90	$ 4,189.50	$ 3,300.00	$ 28,778.90	$ 27,892.40	3.2%
40,000		$ 27.50	$ 28,349.20	$ 5,586.00	$ 4,400.00	$ 38,362.70	$ 37,180.70	3.2%
50,000		$ 27.50	$ 35,436.50	$ 6,982.50	$ 5,500.00	$ 47,946.50	$ 46,469.00	3.2%

Summary of Bill Impacts

Rate Schedule G-40, Air Conditioning Gas Service
Customer Bill Impact - Large General Service

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50		$ 120.00	$ 35.44	$ 6.98	$ 5.50	$ 167.92	$ 206.44	-18.7%
100		$ 120.00	$ 70.87	$ 13.97	$ 11.00	$ 215.84	$ 252.88	-14.6%
234	Winter Avg.	$ 120.00	$ 165.84	$ 32.68	$ 25.74	$ 344.26	$ 377.35	-8.8%
250		$ 120.00	$ 177.18	$ 34.91	$ 27.50	$ 359.59	$ 392.21	-8.3%
388	Annual Avg.	$ 120.00	$ 274.99	$ 54.18	$ 42.68	$ 491.85	$ 520.39	-5.5%
500		$ 120.00	$ 354.37	$ 69.83	$ 55.00	$ 599.20	$ 624.42	-4.0%
536	Summer Avg.	$ 120.00	$ 379.88	$ 74.85	$ 58.96	$ 633.69	$ 657.85	-3.7%
750		$ 120.00	$ 531.55	$ 104.74	$ 82.50	$ 838.79	$ 856.62	-2.1%
1,000		$ 120.00	$ 708.73	$ 139.65	$ 110.00	$ 1,078.38	$ 1,088.83	-1.0%
2,000		$ 120.00	$ 1,417.46	$ 279.30	$ 220.00	$ 2,036.76	$ 2,017.66	0.9%
3,000		$ 120.00	$ 2,126.19	$ 418.95	$ 330.00	$ 2,995.14	$ 2,946.49	1.7%
5,000		$ 120.00	$ 3,543.65	$ 698.25	$ 550.00	$ 4,911.90	$ 4,804.15	2.2%
7,500		$ 120.00	$ 5,315.48	$ 1,047.38	$ 825.00	$ 7,307.86	$ 7,126.23	2.5%
10,000		$ 120.00	$ 7,087.30	$ 1,396.50	$ 1,100.00	$ 9,703.80	$ 9,448.30	2.7%
15,000		$ 120.00	$ 10,630.95	$ 2,094.75	$ 1,650.00	$ 14,495.70	$ 14,092.45	2.9%
20,000		$ 120.00	$ 14,174.60	$ 2,793.00	$ 2,200.00	$ 19,287.60	$ 18,736.60	2.9%
30,000		$ 120.00	$ 21,261.90	$ 4,189.50	$ 3,300.00	$ 28,871.40	$ 28,024.90	3.0%
40,000		$ 120.00	$ 28,349.20	$ 5,586.00	$ 4,400.00	$ 38,455.20	$ 37,313.20	3.1%
50,000		$ 120.00	$ 35,436.50	$ 6,982.50	$ 5,500.00	$ 48,039.00	$ 46,601.50	3.1%

Summary of Bill Impacts

Rate Schedule G-45, Street Lighting Gas Service
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ -	$ 17.72	$ 18.15	$ 2.75	$ 38.62	$ 35.73	8.1%
50		$ -	$ 35.44	$ 36.30	$ 5.50	$ 77.24	$ 71.46	8.1%
75		$ -	$ 53.15	$ 54.44	$ 8.25	$ 115.84	$ 107.19	8.1%
100		$ -	$ 70.87	$ 72.59	$ 11.00	$ 154.46	$ 142.92	8.1%
125		$ -	$ 88.59	$ 90.74	$ 13.75	$ 193.08	$ 178.65	8.1%
150		$ -	$ 106.31	$ 108.89	$ 16.50	$ 231.70	$ 214.38	8.1%
175		$ -	$ 124.03	$ 127.03	$ 19.25	$ 270.31	$ 250.12	8.1%
200		$ -	$ 141.75	$ 145.18	$ 22.00	$ 308.93	$ 285.85	8.1%
250		$ -	$ 177.18	$ 181.48	$ 27.50	$ 386.16	$ 357.31	8.1%
300		$ -	$ 212.62	$ 217.77	$ 33.00	$ 463.39	$ 428.77	8.1%
350		$ -	$ 248.06	$ 254.07	$ 38.50	$ 540.63	$ 500.23	8.1%
400		$ -	$ 283.49	$ 290.36	$ 44.00	$ 617.85	$ 571.69	8.1%
407	Winter Avg.	$ -	$ 288.45	$ 295.44	$ 44.77	$ 628.66	$ 581.70	8.1%
486	Annual Avg.	$ -	$ 344.44	$ 352.79	$ 53.46	$ 750.69	$ 694.61	8.1%
500		$ -	$ 354.37	$ 362.95	$ 55.00	$ 772.32	$ 714.62	8.1%
564	Summer Avg.	$ -	$ 399.72	$ 409.41	$ 62.04	$ 871.17	$ 806.09	8.1%
750		$ -	$ 531.55	$ 544.43	$ 82.50	$ 1,158.48	$ 1,071.92	8.1%
1,000		$ -	$ 708.73	$ 725.90	$ 110.00	$ 1,544.63	$ 1,429.23	8.1%
1,500		$ -	$ 1,063.10	$ 1,088.85	$ 165.00	$ 2,316.95	$ 2,143.85	8.1%

Summary of Bill Impacts

Rate Schedule G-55, Gas Service for Compression on Customer's Premises
Customer Bill Impact - Small

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ 27.50	$ 17.72	$ 4.80	$ 2.75	$ 52.77	$ 52.64	0.2%
50		$ 27.50	$ 35.44	$ 9.61	$ 5.50	$ 78.05	$ 77.78	0.3%
75		$ 27.50	$ 53.15	$ 14.41	$ 8.25	$ 103.31	$ 102.91	0.4%
100		$ 27.50	$ 70.87	$ 19.22	$ 11.00	$ 128.59	$ 128.05	0.4%
125		$ 27.50	$ 88.59	$ 24.02	$ 13.75	$ 153.86	$ 153.19	0.4%
150		$ 27.50	$ 106.31	$ 28.82	$ 16.50	$ 179.13	$ 178.33	0.4%
175		$ 27.50	$ 124.03	$ 33.63	$ 19.25	$ 204.41	$ 203.46	0.5%
200		$ 27.50	$ 141.75	$ 38.43	$ 22.00	$ 229.68	$ 228.60	0.5%
250		$ 27.50	$ 177.18	$ 48.04	$ 27.50	$ 280.22	$ 278.88	0.5%
300		$ 27.50	$ 212.62	$ 57.65	$ 33.00	$ 330.77	$ 329.15	0.5%
350		$ 27.50	$ 248.06	$ 67.25	$ 38.50	$ 381.31	$ 379.43	0.5%
400		$ 27.50	$ 283.49	$ 76.86	$ 44.00	$ 431.85	$ 429.70	0.5%
450		$ 27.50	$ 318.93	$ 86.47	$ 49.50	$ 482.40	$ 479.98	0.5%
473	Winter Avg.	$ 27.50	$ 335.23	$ 90.89	$ 52.03	$ 505.65	$ 503.11	0.5%
500		$ 27.50	$ 354.37	$ 96.08	$ 55.00	$ 532.95	$ 530.26	0.5%
528	Annual Avg.	$ 27.50	$ 374.21	$ 101.46	$ 58.08	$ 561.25	$ 558.41	0.5%
584	Summer Avg.	$ 27.50	$ 413.90	$ 112.22	$ 64.24	$ 617.86	$ 614.72	0.5%
750		$ 27.50	$ 531.55	$ 144.11	$ 82.50	$ 785.66	$ 781.63	0.5%
1,000		$ 27.50	$ 708.73	$ 192.15	$ 110.00	$ 1,038.38	$ 1,033.01	0.5%
1,250		$ 27.50	$ 885.91	$ 240.19	$ 137.50	$ 1,291.10	$ 1,284.39	0.5%

Summary of Bill Impacts

Rate Schedule G-55, Gas Service for Compression on Customer's Premises
Customer Bill Impact - Large

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1,000		$ 250.00	$ 708.73	$ 192.15	$ 110.00	$ 1,260.88	$ 1,255.51	0.4%
2,000		$ 250.00	$ 1,417.46	$ 384.30	$ 220.00	$ 2,271.76	$ 2,261.02	0.5%
3,000		$ 250.00	$ 2,126.19	$ 576.45	$ 330.00	$ 3,282.64	$ 3,266.53	0.5%
4,000		$ 250.00	$ 2,834.92	$ 768.60	$ 440.00	$ 4,293.52	$ 4,272.04	0.5%
4,922	Summer Avg.	$ 250.00	$ 3,488.37	$ 945.76	$ 541.42	$ 5,225.55	$ 5,199.12	0.5%
5,000		$ 250.00	$ 3,543.65	$ 960.75	$ 550.00	$ 5,304.40	$ 5,277.55	0.5%
5,186	Annual Avg.	$ 250.00	$ 3,675.47	$ 996.49	$ 570.46	$ 5,492.42	$ 5,464.57	0.5%
5,450	Winter Avg.	$ 250.00	$ 3,862.58	$ 1,047.22	$ 599.50	$ 5,759.30	$ 5,730.03	0.5%
6,000		$ 250.00	$ 4,252.38	$ 1,152.90	$ 660.00	$ 6,315.28	$ 6,283.06	0.5%
7,000		$ 250.00	$ 4,961.11	$ 1,345.05	$ 770.00	$ 7,326.16	$ 7,288.57	0.5%
8,000		$ 250.00	$ 5,669.84	$ 1,537.20	$ 880.00	$ 8,337.04	$ 8,294.08	0.5%
9,000		$ 250.00	$ 6,378.57	$ 1,729.35	$ 990.00	$ 9,347.92	$ 9,299.59	0.5%
10,000		$ 250.00	$ 7,087.30	$ 1,921.50	$ 1,100.00	$ 10,358.80	$ 10,305.10	0.5%
12,500		$ 250.00	$ 8,859.13	$ 2,401.88	$ 1,375.00	$ 12,886.01	$ 12,818.88	0.5%
15,000		$ 250.00	$ 10,630.95	$ 2,882.25	$ 1,650.00	$ 15,413.20	$ 15,332.65	0.5%
17,500		$ 250.00	$ 12,402.78	$ 3,362.63	$ 1,925.00	$ 17,940.41	$ 17,846.43	0.5%
20,000		$ 250.00	$ 14,174.60	$ 3,843.00	$ 2,200.00	$ 20,467.60	$ 20,360.20	0.5%
25,000		$ 250.00	$ 17,718.25	$ 4,803.75	$ 2,750.00	$ 25,522.00	$ 25,387.75	0.5%
35,000		$ 250.00	$ 24,805.55	$ 6,725.25	$ 3,850.00	$ 35,630.80	$ 35,442.85	0.5%
50,000		$ 250.00	$ 35,436.50	$ 9,607.50	$ 5,500.00	$ 50,794.00	$ 50,525.50	0.5%

Summary of Bill Impacts

Rate Schedule G-55, Gas Service for Compression on Customer's Premises
Customer Bill Impact - Residential

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 10.70	$ 3.54	$ 0.96	$ 0.55	$ 15.75	$ 15.73	0.1%
10	$ 10.70	$ 7.09	$ 1.92	$ 1.10	$ 20.81	$ 20.76	0.2%
15	$ 10.70	$ 10.63	$ 2.88	$ 1.65	$ 25.86	$ 25.78	0.3%
20	$ 10.70	$ 14.17	$ 3.84	$ 2.20	$ 30.91	$ 30.81	0.3%
25	$ 10.70	$ 17.72	$ 4.80	$ 2.75	$ 35.97	$ 35.84	0.4%
30	$ 10.70	$ 21.26	$ 5.76	$ 3.30	$ 41.02	$ 40.87	0.4%
34 Winter Avg.	$ 10.70	$ 24.10	$ 6.53	$ 3.74	$ 45.07	$ 44.89	0.4%
36 Annual Avg.	$ 10.70	$ 25.51	$ 6.92	$ 3.96	$ 47.09	$ 46.90	0.4%
37 Summer Avg.	$ 10.70	$ 26.22	$ 7.11	$ 4.07	$ 48.10	$ 47.90	0.4%
40	$ 10.70	$ 28.35	$ 7.69	$ 4.40	$ 51.14	$ 50.92	0.4%
50	$ 10.70	$ 35.44	$ 9.61	$ 5.50	$ 61.25	$ 60.98	0.4%
60	$ 10.70	$ 42.52	$ 11.53	$ 6.60	$ 71.35	$ 71.03	0.5%
75	$ 10.70	$ 53.15	$ 14.41	$ 8.25	$ 86.51	$ 86.11	0.5%
100	$ 10.70	$ 70.87	$ 19.22	$ 11.00	$ 111.79	$ 111.25	0.5%
125	$ 10.70	$ 88.59	$ 24.02	$ 13.75	$ 137.06	$ 136.39	0.5%
150	$ 10.70	$ 106.31	$ 28.82	$ 16.50	$ 162.33	$ 161.53	0.5%
200	$ 10.70	$ 141.75	$ 38.43	$ 22.00	$ 212.88	$ 211.80	0.5%
250	$ 10.70	$ 177.18	$ 48.04	$ 27.50	$ 263.42	$ 262.08	0.5%
300	$ 10.70	$ 212.62	$ 57.65	$ 33.00	$ 313.97	$ 312.35	0.5%
400	$ 10.70	$ 283.49	$ 76.86	$ 44.00	$ 415.05	$ 412.90	0.5%
500	$ 10.70	$ 354.37	$ 96.08	$ 55.00	$ 516.15	$ 513.46	0.5%

Summary of Bill Impacts

Rate Schedule G-60, Cogeneration Gas Service
Customer Bill Impact - Small

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
0 Summer Avg.	$ 27.50	$ -	$ -	$ -	$ 27.50	$ 27.50	0.0%
5	$ 27.50	$ 3.54	$ 0.82	$ 0.55	$ 32.41	$ 32.27	0.4%
6 Annual Avg.	$ 27.50	$ 4.25	$ 0.99	$ 0.66	$ 33.40	$ 33.22	0.5%
10	$ 27.50	$ 7.09	$ 1.65	$ 1.10	$ 37.34	$ 37.04	0.8%
11 Winter Avg.	$ 27.50	$ 7.80	$ 1.81	$ 1.21	$ 38.32	$ 37.99	0.9%
15	$ 27.50	$ 10.63	$ 2.47	$ 1.65	$ 42.25	$ 41.81	1.1%
25	$ 27.50	$ 17.72	$ 4.12	$ 2.75	$ 52.09	$ 51.35	1.4%
50	$ 27.50	$ 35.44	$ 8.25	$ 5.50	$ 76.69	$ 75.20	2.0%
75	$ 27.50	$ 53.15	$ 12.37	$ 8.25	$ 101.27	$ 99.06	2.2%
100	$ 27.50	$ 70.87	$ 16.50	$ 11.00	$ 125.87	$ 122.91	2.4%
125	$ 27.50	$ 88.59	$ 20.62	$ 13.75	$ 150.46	$ 146.76	2.5%
150	$ 27.50	$ 106.31	$ 24.74	$ 16.50	$ 175.05	$ 170.61	2.6%
175	$ 27.50	$ 124.03	$ 28.87	$ 19.25	$ 199.65	$ 194.46	2.7%
200	$ 27.50	$ 141.75	$ 32.99	$ 22.00	$ 224.24	$ 218.32	2.7%
250	$ 27.50	$ 177.18	$ 41.24	$ 27.50	$ 273.42	$ 266.02	2.8%
300	$ 27.50	$ 212.62	$ 49.49	$ 33.00	$ 322.61	$ 313.72	2.8%
350	$ 27.50	$ 248.06	$ 57.74	$ 38.50	$ 371.80	$ 361.43	2.9%
400	$ 27.50	$ 283.49	$ 65.98	$ 44.00	$ 420.97	$ 409.13	2.9%
450	$ 27.50	$ 318.93	$ 74.23	$ 49.50	$ 470.16	$ 456.84	2.9%
500	$ 27.50	$ 354.37	$ 82.48	$ 55.00	$ 519.35	$ 504.54	2.9%
750	$ 27.50	$ 531.55	$ 123.72	$ 82.50	$ 765.27	$ 743.06	3.0%
1000	$ 27.50	$ 708.73	$ 164.96	$ 110.00	$ 1,011.19	$ 981.58	3.0%
1250	$ 27.50	$ 885.91	$ 206.20	$ 137.50	$ 1,257.11	$ 1,220.10	3.0%

Summary of Bill Impacts

Rate Schedule G-60, Cogeneration Gas Service
Customer Bill Impact - Medium

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
500		$ 43.50	$ 354.37	$ 82.48	$ 55.00	$ 535.35	$ 520.54	2.8%
600		$ 43.50	$ 425.24	$ 98.98	$ 66.00	$ 633.72	$ 615.95	2.9%
700		$ 43.50	$ 496.11	$ 115.47	$ 77.00	$ 732.08	$ 711.36	2.9%
800		$ 43.50	$ 566.98	$ 131.97	$ 88.00	$ 830.45	$ 806.76	2.9%
900		$ 43.50	$ 637.86	$ 148.46	$ 99.00	$ 928.82	$ 902.17	3.0%
1,000		$ 43.50	$ 708.73	$ 164.96	$ 110.00	$ 1,027.19	$ 997.58	3.0%
1,250		$ 43.50	$ 885.91	$ 206.20	$ 137.50	$ 1,273.11	$ 1,236.10	3.0%
1,500		$ 43.50	$ 1,063.10	$ 247.44	$ 165.00	$ 1,519.04	$ 1,474.62	3.0%
2,000		$ 43.50	$ 1,417.46	$ 329.92	$ 220.00	$ 2,010.88	$ 1,951.66	3.0%
3,000		$ 43.50	$ 2,126.19	$ 494.88	$ 330.00	$ 2,994.57	$ 2,905.74	3.1%
3,772	Summer Avg.	$ 43.50	$ 2,673.33	$ 622.23	$ 414.92	$ 3,753.98	$ 3,642.29	3.1%
4,000		$ 43.50	$ 2,834.92	$ 659.84	$ 440.00	$ 3,978.26	$ 3,859.82	3.1%
5,000		$ 43.50	$ 3,543.65	$ 824.80	$ 550.00	$ 4,961.95	$ 4,813.90	3.1%
5,076	Annual Avg.	$ 43.50	$ 3,597.51	$ 837.34	$ 558.36	$ 5,036.71	$ 4,886.41	3.1%
6,380	Winter Avg.	$ 43.50	$ 4,521.70	$ 1,052.44	$ 701.80	$ 6,319.44	$ 6,130.53	3.1%
7,500		$ 43.50	$ 5,315.48	$ 1,237.20	$ 825.00	$ 7,421.18	$ 7,199.10	3.1%
10,000		$ 43.50	$ 7,087.30	$ 1,649.60	$ 1,100.00	$ 9,880.40	$ 9,584.30	3.1%
12,500		$ 43.50	$ 8,859.13	$ 2,062.00	$ 1,375.00	$ 12,339.63	$ 11,969.50	3.1%
15,000		$ 43.50	$ 10,630.95	$ 2,474.40	$ 1,650.00	$ 14,798.85	$ 14,354.70	3.1%
20,000		$ 43.50	$ 14,174.60	$ 3,299.20	$ 2,200.00	$ 19,717.30	$ 19,125.10	3.1%

Summary of Bill Impacts

Rate Schedule G-60, Cogeneration Gas Service
Customer Bill Impact - Large

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
2,206	Summer Avg.	$ 120.00	$ 1,563.46	$ 363.90	$ 242.66	$ 2,290.02	$ 2,264.70	1.1%
3,000		$ 120.00	$ 2,126.19	$ 494.88	$ 330.00	$ 3,071.07	$ 3,022.24	1.6%
3,733	Annual Avg.	$ 120.00	$ 2,645.69	$ 615.80	$ 410.63	$ 3,792.12	$ 3,721.58	1.9%
5,000		$ 120.00	$ 3,543.65	$ 824.80	$ 550.00	$ 5,038.45	$ 4,930.40	2.2%
5,260	Winter Avg.	$ 120.00	$ 3,727.92	$ 867.69	$ 578.60	$ 5,294.21	$ 5,178.46	2.2%
10,000		$ 120.00	$ 7,087.30	$ 1,649.60	$ 1,100.00	$ 9,956.90	$ 9,700.80	2.6%
12,500		$ 120.00	$ 8,859.13	$ 2,062.00	$ 1,375.00	$ 12,416.13	$ 12,086.00	2.7%
15,000		$ 120.00	$ 10,630.95	$ 2,474.40	$ 1,650.00	$ 14,875.35	$ 14,471.20	2.8%
17,500		$ 120.00	$ 12,402.78	$ 2,886.80	$ 1,925.00	$ 17,334.58	$ 16,856.40	2.8%
20,000		$ 120.00	$ 14,174.60	$ 3,299.20	$ 2,200.00	$ 19,793.80	$ 19,241.60	2.9%
25,000		$ 120.00	$ 17,718.25	$ 4,124.00	$ 2,750.00	$ 24,712.25	$ 24,012.00	2.9%
30,000		$ 120.00	$ 21,261.90	$ 4,948.80	$ 3,300.00	$ 29,630.70	$ 28,782.40	2.9%
35,000		$ 120.00	$ 24,805.55	$ 5,773.60	$ 3,850.00	$ 34,549.15	$ 33,552.80	3.0%
40,000		$ 120.00	$ 28,349.20	$ 6,598.40	$ 4,400.00	$ 39,467.60	$ 38,323.20	3.0%
45,000		$ 120.00	$ 31,892.85	$ 7,423.20	$ 4,950.00	$ 44,386.05	$ 43,093.60	3.0%
50,000		$ 120.00	$ 35,436.50	$ 8,248.00	$ 5,500.00	$ 49,304.50	$ 47,864.00	3.0%
75,000		$ 120.00	$ 53,154.75	$ 12,372.00	$ 8,250.00	$ 73,896.75	$ 71,716.00	3.0%
100,000		$ 120.00	$ 70,873.00	$ 16,496.00	$ 11,000.00	$ 98,489.00	$ 95,568.00	3.1%
150,000		$ 120.00	$ 106,309.50	$ 24,744.00	$ 16,500.00	$ 147,673.50	$ 143,272.00	3.1%
200,000		$ 120.00	$ 141,746.00	$ 32,992.00	$ 22,000.00	$ 196,858.00	$ 190,976.00	3.1%
300,000		$ 120.00	$ 212,619.00	$ 49,488.00	$ 33,000.00	$ 295,227.00	$ 286,384.00	3.1%
500,000		$ 120.00	$ 354,365.00	$ 82,480.00	$ 55,000.00	$ 491,965.00	$ 477,200.00	3.1%

Summary of Bill Impacts

Rate Schedule G-75, Small Essential Agriculture User Gas Service
Customer Bill Impact

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ 120.00	$ 17.72	$ 6.59	$ 2.75	$ 147.06	$ 146.57	0.3%
50		$ 120.00	$ 35.44	$ 13.17	$ 5.50	$ 174.11	$ 173.13	0.6%
100		$ 120.00	$ 70.87	$ 26.34	$ 11.00	$ 228.21	$ 226.27	0.9%
250		$ 120.00	$ 177.18	$ 65.86	$ 27.50	$ 390.54	$ 385.67	1.3%
500		$ 120.00	$ 354.37	$ 131.72	$ 55.00	$ 661.09	$ 651.35	1.5%
1,000		$ 120.00	$ 708.73	$ 263.44	$ 110.00	$ 1,202.17	$ 1,182.69	1.6%
2,500		$ 120.00	$ 1,771.83	$ 658.60	$ 275.00	$ 2,825.43	$ 2,776.73	1.8%
4,296	Summer Avg.	$ 120.00	$ 3,044.70	$ 1,131.74	$ 472.56	$ 4,769.00	$ 4,685.32	1.8%
4,485	Annual Avg.	$ 120.00	$ 3,178.65	$ 1,181.53	$ 493.35	$ 4,973.53	$ 4,886.16	1.8%
4,641	Winter Avg.	$ 120.00	$ 3,289.22	$ 1,222.63	$ 510.51	$ 5,142.36	$ 5,051.94	1.8%
5,000		$ 120.00	$ 3,543.65	$ 1,317.20	$ 550.00	$ 5,530.85	$ 5,433.45	1.8%
7,500		$ 120.00	$ 5,315.48	$ 1,975.80	$ 825.00	$ 8,236.28	$ 8,090.18	1.8%
10,000		$ 120.00	$ 7,087.30	$ 2,634.40	$ 1,100.00	$ 10,941.70	$ 10,746.90	1.8%
15,000		$ 120.00	$ 10,630.95	$ 3,951.60	$ 1,650.00	$ 16,352.55	$ 16,060.35	1.8%
25,000		$ 120.00	$ 17,718.25	$ 6,586.00	$ 2,750.00	$ 27,174.25	$ 26,687.25	1.8%
50,000		$ 120.00	$ 35,436.50	$ 13,172.00	$ 5,500.00	$ 54,228.50	$ 53,254.50	1.8%
75,000		$ 120.00	$ 53,154.75	$ 19,758.00	$ 8,250.00	$ 81,282.75	$ 79,821.75	1.8%
100,000		$ 120.00	$ 70,873.00	$ 26,344.00	$ 11,000.00	$ 108,337.00	$ 106,389.00	1.8%

Summary of Bill Impacts

Rate Schedule G-80, Natural Gas Engine Gas Service
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50		$ 125.00	$ 25.17	$ 10.37	$ 5.50	$ 166.04	$ 165.21	0.5%
100		$ 125.00	$ 50.35	$ 20.74	$ 11.00	$ 207.09	$ 205.41	0.8%
200		$ 125.00	$ 100.69	$ 41.49	$ 22.00	$ 289.18	$ 285.83	1.2%
500		$ 125.00	$ 251.73	$ 103.72	$ 55.00	$ 535.45	$ 527.07	1.6%
974	Off-Peak Avg.	$ 125.00	$ 490.36	$ 202.05	$ 107.14	$ 924.55	$ 908.23	1.8%
1,000		$ 125.00	$ 503.45	$ 207.44	$ 110.00	$ 945.89	$ 929.14	1.8%
1,500		$ 125.00	$ 755.18	$ 311.16	$ 165.00	$ 1,356.34	$ 1,331.21	1.9%
1,864	Annual Avg.	$ 125.00	$ 938.43	$ 386.67	$ 205.04	$ 1,655.14	$ 1,623.92	1.9%
2,000		$ 125.00	$ 1,006.90	$ 414.88	$ 220.00	$ 1,766.78	$ 1,733.28	1.9%
2,746	Peak Avg.	$ 125.00	$ 1,382.47	$ 569.63	$ 302.06	$ 2,379.16	$ 2,333.17	2.0%
3,000		$ 125.00	$ 1,510.35	$ 622.32	$ 330.00	$ 2,587.67	$ 2,537.42	2.0%
5,000		$ 125.00	$ 2,517.25	$ 1,037.20	$ 550.00	$ 4,229.45	$ 4,145.70	2.0%
10,000		$ 125.00	$ 5,034.50	$ 2,074.40	$ 1,100.00	$ 8,333.90	$ 8,166.40	2.1%
25,000		$ 125.00	$ 12,586.25	$ 5,186.00	$ 2,750.00	$ 20,647.25	$ 20,228.50	2.1%
50,000		$ 125.00	$ 25,172.50	$ 10,372.00	$ 5,500.00	$ 41,169.50	$ 40,332.00	2.1%
75,000		$ 125.00	$ 37,758.75	$ 15,558.00	$ 8,250.00	$ 61,691.75	$ 60,435.50	2.1%
100,000		$ 125.00	$ 50,345.00	$ 20,744.00	$ 11,000.00	$ 82,214.00	$ 80,539.00	2.1%
125,000		$ 125.00	$ 62,931.25	$ 25,930.00	$ 13,750.00	$ 102,736.25	$ 100,642.50	2.1%
150,000		$ 125.00	$ 75,517.50	$ 31,116.00	$ 16,500.00	$ 123,258.50	$ 120,746.00	2.1%

Source: Company's Class Cost of Service Study.

Responses to Staff Data Requests

Responses to Staff Data Requests Referenced in Testimony

Data Request ACC-STF-3-32
Data Request RUCO-2-10
Data Request ACC-STF-27-3
Data Request ACC-STF-27-7
Data Request ACC-STF-27-9
Data Request ACC-STF-4-1
Data Request ACC-STF-4-2
Data Request ACC-STF-13-6
Data Request ACC-STF-3-49
Data Request ACC-STF-24-2
Data Request ACC-STF-3-19
Data Request ACC-STF-3-20

493-032

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)

511-010

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

PUBLIC UTILITIES COMMISSION OF NEVADA
DATA REQUEST NO. RUCO-2
(RUCO-2-1 to RUCO-2-32)
* * *

DOCKET NO.:	G-01551A-10-0458
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	APRIL 18, 2011

Request No. RUCO-2-10:

What are the benefits to the ratepayer's of the Company's decoupling proposal?

Respondent: Pricing

Response:

There are several benefits to customers resulting from the proposed Energy Efficiency Enabling Provision. First, the most significant monetary benefit will come from customers experiencing lower bills due to enhanced conservation and energy efficiency efforts. Second, Southwest Gas will never retain more revenue per customer than what the Commission authorizes in a rate case proceeding. Third, customers will receive credits to bills following extreme weather events. Fourth, implementation of full revenue decoupling will likely increase the time in-between rate case filings for utility's, thus stabilizing customer's bills. The Company's proposal also results in a rate setting model whereby the only way it can become more profitable in-between rate case filings is by reducing expenses, thus incentivizing the Company to continue its strong focus on cost saving measures - which are ultimately passed through to customers as part of the rate case process.

To fully appreciate the potential monetary benefit from lower customer bills it requires taking a broad view of the Commission's energy efficiency goals which, as stated in response to RUCO-2-8, cannot be achieved without removing the financial disincentive. In the Commission's decoupling workshops, the Lawrence Berkley National Laboratories (LBNL) identified $5.2 billion in savings for Arizona Public Service (APS) and Tucson Electric Power (TEP) customers if those companies achieve their respective efficiency goals. Most of Southwest Gas' customers are also customers of either APS or TEP and will participate in these savings. Although LBNL did not quantify the lifetime savings for the natural gas energy efficiency goals, substantial savings are expected to occur if those goals are met. However, simply meeting the Company's annual energy savings targets of approximately 3 million therms will save customers $2.2 million in gas costs (at today's gas cost rates).

As noted above, implementation of the proposed EEP will also protect customers from Southwest Gas ever retaining more revenue than what the Commission authorizes in a rate case proceeding. For instance, the monthly weather adjustment component of Southwest Gas' proposed mechanism provides customers with relief from high bills resulting from colder than normal weather. Had the EEP been effective last winter, the Company's analysis shows residential customer bills would have been reduced approximately seven percent on average during the coldest month. Similarly, as noted in response to RUCO 2-2 the recent results of the Nevada decoupling mechanism resulted in a net refund to customers.

526-003

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-27
(ACC-STF-27-1 to ACC-STF-27-9)
* * *

DOCKET NO.:	G-01551A-10-0458
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 10, 2011

Request No. ACC-STF-27-3:

State the amount of CIAC, by category, actually collected from each class of customer. If the Company does not have the requested information, please explain why it does not maintain records that would allow it to associate contributions collected from customers into their associated customer class. Provide the requested information for the calendar years 1999 through 2009 and monthly for 2010 to date. Please provide the requested information and the supporting workpapers and source documents in electronic spreadsheet format 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:

The FERC Uniform System of Accounts (US of A) does not provide a specific account to accumulate Contribution In Aid of Construction (CIAC). It is possible the US of A for natural gas companies once had an account for accrued CIAC; however, any such account was discontinued more than 30 years ago. The Company's accounting for CIAC is as follows: A work authorization (WA) created to accumulate the cost of providing service to either a new customer or groups of customers (for instance apartments, sub-developments) or in the case of existing customers who are requesting to relocate existing facilities and municipalities undergoing major road or other work involving natural gas facilities. The cost of the facilities are accumulated in these WA's. To the extent that a CIAC is associated with the particular WA, the CIAC funds received are credited to that WA. Upon completion of the work associated with the WA all charges net of CIAC are transferred to Account 101, Gas Plant In-Service. There is no operational need or requirement to account for Gas Plant In-Service by customer class, as such the Company does not maintain records of CIAC by customer class, customer requested relocations or government related franchise relocations. Since a CIAC reduces the balances in Account 101, rate base, depreciation and property tax are also reduced.

The Company can identify the amounts in CIAC dollars that have been credited to Account 101 both on a monthly and annual basis. Attached is a schedule that provides the monthly information for the calendar years 1999 through 2010.

526-007

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-27
(ACC-STF-27-1 to ACC-STF-27-9)
* * *

DOCKET NO.:	G-01551A-10-0458
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 10, 2011

Request No. ACC-STF-27-7:

Please provide all workpapers used to develop the meter cost by class included in the sheet meter cost by class in the spreadsheet AZ 2010 ccoss and rate design spreadsheet. Explain how the Company developed the amounts provided in response to this data request and provide the supporting workpapers and source documents in electronic spreadsheet format 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: Pricing

Response:

The average meter and service cost by class used in the CCOSS is developed by the Company's Arizona engineering staff and provided to the Pricing and Tariffs Department via memorandum. Please refer to the response to ACC-STF-13-1 for a copy of the memorandum showing meter costs. The meter cost by class reflected on the referenced spreadsheet, and used in the CCOSS are taken directly from the memorandum except as noted below.

Master Meter Mobile Home - No meter cost was provided. In its application, the Company used the Medium General Service meter cost as a proxy. However, the Company recommends using the meter cost provided for this schedule in its last Arizona general rate case.

Medium General Service - The Company used the average of the costs reflected in the memorandum.

Large 1 General Service - The Company used the cost of the AL 1000 meter provided in the memorandum of $796.94.

Air Conditioning - The Company used the average of the costs reflected in the memorandum.

A revised "meter cost by class" sheet is attached. Please see response to ACC-STF-27-9 for a further discussion of these changes.

526-009

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-27
(ACC-STF-27-1 to ACC-STF-27-9)
* * *

DOCKET NO.:	G-01551A-10-0458
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 10, 2011

Request No. ACC-STF-27-9:

Please provide all workpapers used to develop the service cost by customer class included in the sheet WP-G-1 (MSA&SRVCS Alloc Fact) in the spreadsheet AZ 2010 ccoss and rate design spreadsheet. Explain how the Company developed the amounts provided in response to this data request and provide all supporting workpapers and source documents in electronic spreadsheet format 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: Pricing

Response:

As noted in response to ACC-STF-27-7, the average service cost by class used in the CCOSS is developed by the Company's Arizona engineering staff and provided to the Pricing and Tariff Department via memorandum. A copy of the memorandum was provided in response to ACC-STF-13-1. The average service costs by class are taken directly from the memorandum except as noted below.

Master Meter Mobile Home - No service costs were provided. Therefore the Company used the service costs provided for this schedule in its last Arizona general rate case.

Small General Service - In its application, the Company applied the average residential service costs to small general service. The amounts provided in the memorandum for small general service should be used.

Medium and Large General Service - In its application, the average service costs for these schedules were transposed. The amounts provided in the memorandum for these schedules should be used.

Gas Lights - No service costs were provided. In its application, Southwest Gas inadvertantly used $711 for service costs. However, the Company recommends using the service costs provided for this schedule in its last Arizona general rate case.

Residential CNG - In its application, Southwest Gas used one-half of the residential service cost for this class of customers. The amounts provided in the memorandum should be used.

Essential Agricultural - The Company used the amount of $23,682 provided in the memorandum for Central Arizona in its application. However, this is not representative of the Company's meter cost to serve this size of customer. Therefore, the Company recommends using the Central Arizona division amount of $5,274 provided for this rate schedule in its last Arizona general rate case.

A revised sheet "WP-G-1 (MSA&SRVCS Alloc Fact)" showing these changes is attached.

Making the changes to average service costs, average meter costs and the allocation of costs included in Accts 385, etc discussed in responses to ACC-STF-27-1, ACC-STF-27-7 and ACC-STF-27-9 changes the results of the CCOSS slightly. However, these changes do not impact the results of the CCOSS sufficiently to change Southwest's proposed allocation of revenue to customer classes or resulting rate design.

496-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-4
(ACC-STF-4-1 to ACC-STF-4-40)
***

DOCKET NO.:	G-01551A-10-0458
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	FEBRUARY 25, 2011

Request No. ACC-STF-4-1:

Is Southwest proposing any changes to the purchased gas adjustor mechanism? If so, please describe.

Respondent: Pricing & Tariffs

Response:

No.

496-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-4
(ACC-STF-4-1 to ACC-STF-4-40)
***

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 25, 2011

Request No. ACC-STF-4-2:

Is Southwest proposing any changes to the:

A. Low Income Ratepayer Assistance Adjustor? If so, please describe.

B. Demand Side Management Adjustor? If so, please describe.

C. Gas Research Fund Adjustor? If so, please describe.

D. Department of Transportation Adjustor? If so, please describe.

Respondent: Pricing & Tariffs

Response:

No.

506-006

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 to ACC-STF-13-14)
***

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 12, 2011

Request No. ACC-STF-13-6:

Please refer to page 11, lines 24-27, and page 12, lines 1-3 of Mr. Gieseking's testimony where he states Gas is tying the summer season residential air-conditioning rate under Schedule No. G-I 5 to the air-conditioning rate provided under Schedule No. G-40. Since Southwest Gas has a very small number of customers currently taking this service, it has little cost data to perform a meaningful cost study. 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. Please explain why the Company has very little cost data and supply the cost data the company has. Please provide any associated documentation for the information provided in response to this request. Please provide documents and workpapers in electronic form, with all spreadsheet 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: Pricing & Tariffs

Response:

There were only 90 residential customers served under the Residential Air Conditioning Rate, Schedule No. G-15, in the test period. In addition to natural gas air conditioners, these customers have other end uses behind their meter. Since their air conditioning use is not currently separately metered, the Company is proposing that the rate developed for Rate Schedule No. G-40, a gas air conditioning only schedule, be used as a proxy cost-based rate for residential air conditioning service. In the future, if demand develops for residential natural gas air conditioners and installation numbers increase, and as metering options for individual gas appliances mature, the Company may have more information with which to perform a cost analysis and price residential gas air conditioning.

493-049

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-3-49:

For purposes of this request, please refer to the Direct Testimony of Mr. Edward B. Gieseking, page 12, lines 7-19, where he states: In order to better align the recovery of margin with the costs of providing service, Southwest Gas seeks to refine its Large General Service schedule, Schedule No. G-25. Currently, this schedule applies to customers that use between 7,201 and 180,000 therms per year. Southwest Gas' analysis of the cost of providing service shows a large difference between the cost to serve the smaller customers in this class versus the cost to serve the larger customers. Therefore, Southwest Gas is proposing to further define its general service customers by breaking the currently existing large class into two separate classes. The new class General Gas Service Large-1 is comprised of customers that use more 7,200 and up to 50,000 therms per year. The new class General Gas Service Large-2 is comprised of customers that use more than 50,000 and up to 180,000 therms per year. Further defining this class allows a better allocation of cost and a fairer rate design.

(a) Please provide all analyses performed by the Company which show the large difference between the cost of providing service show to the smaller customers in this class versus the cost to serve the larger customers in this class.

(b) Please provide all workpapers and source documents supporting the Company's response to (a). Provide the requested documents and workpapers in electronic form with all spreadsheet 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.

(c) Please provide all analyses performed by the Company which show how the Company arrived at the usage levels for the Large-1 customer class versus the Large-2 customer class.

(d) Please provide all workpapers and source documents supporting the Company's response to (c). Provide the requested documents and workpapers in electronic form with all spreadsheet 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.

(e) Please provide all analyses performed by the Company which demonstrate that the new definition allows a better allocation of cost and a fairer rate design than the old rate design.

(f) Please provide all workpapers and source documents supporting the Company's response to (c). Provide the requested documents and workpapers in electronic form with all spreadsheet 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: Pricing & Tariffs

Response:

(a) and (b) The differences in the average cost of providing service are reflected in the electronic ccoss schedules provided in response to ACC-STF-1-1 under the sheet named "WP G-1 (Meter Cost by Class). This sheet reflects an average meter cost to service customers on the proposed G-25 L2 schedule that is approximately 4.4 times higher than the average meter cost to serve customers on the proposed G-25 L1 schedule. This information is also provided in the filed Workpapers, Schedule G-1, Sheet 1. Additionally, proposed schedule G-25 L2 customers' annual load factor is roughly 12% greater than that for proposed schedule G-25 L1 customers. This can be determined from information provided in the electronic ccoss under sheet named "G-1 (Peak Demand Alloc Factor).

(c) and (d) Data provided in support of the 50,000 therm usage level separating the proposed G-25 L1 and L2 schedules is provided in the Company's filed Workpapers, Schedule H-1, Sheets 64-64. This information is also provided electronically in response to ACC-STF-1-1 in the file named "G25 greater than 50,000".

(e) and (f) Please refer to the attached Excel worksheet which shows bill calculation comparisions for the proposed G-25 L1 and G-25 L2 rates and the otherwise combined G-25 rate.

523-002

**SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458**

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**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-24
(ACC-STF-24-1 to ACC-STF-24-2)**

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DOCKET NO.:	G-01551A-10-0458
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 5, 2011

Request No. ACC-STF-24-2:

For purposes of this request, please refer to Rate Schedule No. SB-1 of the Company's proposed tariffs.

a. Please explain why the language regarding the bypass customers from Rate Schedule No. B-1 was removed.

b. Please provide a revised Rate Schedule No. SB-1 with language for bypass customers.

c. Please provide the source data and documents relied upon in developing your response.

Respondent: Pricing

Response:

a. Over time, Schedule No. T-1 has evolved into the rate schedule that accommodates potential bypass transportation customers and the bypass provision contained in currently effective Schedule No. B-1 is no longer necessary. Therefore, Southwest is proposing the elimination of the bypass provisions in Schedule No. B-1, modifying the schedule to accommodate only the remaining standby provisions, and renaming to Schedule No. SB-1.

b. Proposed Schedule No. SB-1 is not intended to accommodate bypass potential customers.

c. n/a.