BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED REBUTTAL TESTIMONY
OF
DANIEL P. YARDLEY

IN RE:
CHATTANOOGA GAS COMPANY
DOCKET NO. 09-00183

electronically filed 4/5/10 at 4:05pm

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

A. My name is Daniel P. Yardley. I am Principal, Yardley & Associates and my business address is 2409 Providence Hills Drive, Matthews, North Carolina 28105.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Chattanooga Gas Company ("CGC" or the "Company").

Q. Are you the same Daniel P. Yardley who previously provided prepared direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The Consumer Advocate and Protection Division of the Office of Attorney General ("CAPD") sponsored the testimony of several witnesses in this proceeding. Two of these witnesses, Dr. David Dismukes and Mr. Terry Buckner offered testimony on rate design matters addressed in my direct testimony. My rebuttal testimony responds to CAPD's testimony on rate design and related issues. Specifically, I will respond to Dr. Dismukes testimony regarding the Company's Alignment and Usage Adjustment ("AUA") Tariff and to Mr. Buckner's testimony regarding rate design.

Q. Are you sponsoring any exhibits that accompany your prepared rebuttal testimony?

A. Yes. I am sponsoring the following four exhibits, which will be explained later in my testimony:

Exhibit DPY-14:	National Association of Regulatory Utility Commissioners Decoupling for Electric and Gas Utilities: Frequently Asked Questions.
Exhibit DPY-15:	Michigan State University Institute of Public Utilities Revenue Decoupling Bibliography.
Exhibit DPY-16:	United States Department of Energy / United States Environmental Protection Agency National Action Plan for Energy Efficiency Building Code Report Excerpt.
Exhibit DPY-17:	Alternative Straight-Fixed-Variable Rate Designs Provided in Response to Staff Request 2-29.

RATE DESIGN INNOVATION

Q. Please briefly describe the nature of the Company's AUA Tariff proposal.

A. The AUA Tariff is a revenue adjustment mechanism that operates in conjunction with the Company's base rates. Specifically, the AUA Tariff normalizes base revenue recoveries per customer to the level authorized by the Tennessee Regulatory Authority ("TRA") in the most recent base rate case. CGC's existing base rates recover a substantial proportion of revenue requirements through the variable delivery charge. As a result, the actual level of base revenues received by CGC can vary significantly, positively or negatively, from the level approved by the TRA in a base rate case simply due to variations in customer use.

The proposed AUA Tariff is a symmetrical mechanism that applies a credit or charge to customers to offset variances in revenue recoveries that occur following a rate case. When base revenue recoveries per customer are higher than the authorized level, a credit is applied to bills in a future period. Conversely, when base revenues per customer are lower than the authorized level, a charge is applied to bills in a future period. In essence, the AUA Tariff operates in a manner that is similar to the Company's existing weather normalization clause; however, base revenues are normalized for all factors, not simply due to variations in weather. The AUA Tariff eliminates the link between customer throughput and earnings, which has been broadly recognized as an effective rate design and beneficial to promoting energy efficiency and conservation. The operation of the AUA Tariff only takes into consideration revenue recoveries and is not influenced by the cost of providing service.

Q. Why was the AUA Tariff proposed in this proceeding?

A. CGC proposed the AUA Tariff for two reasons. The first is that the Company strongly believes that the AUA Tariff results in an appropriate rate design outcome for the Company and its customers. Rate design is an important component of a rate case proceeding and the rates established at the conclusion of this proceeding should be fair and equitable. In my view, the likelihood that approved rates produce the expected level of revenues significantly influences the degree of fairness and equity associated with a particular rate design. The AUA Tariff addresses a material deficiency underlying the Company's existing usage-based rate design by adjusting future base revenue recoveries for factors that affect customer consumption.

The second reason for the Company's proposal is to comply with Tennessee's recently enacted legislation that requires the TRA to consider whether the financial interests of utilities are properly aligned with those of their customers with respect to energy use. See Tennessee Annotated Code, Title 65, Chapter 4, Part 1 at Section 126 ("Tennessee Code Annotated 65-4-126"). The AUA Tariff directly addresses the primary reason that the financial interests of CGC and its customers are not aligned by removing the direct link between customer use and earnings. Under the AUA Tariff, the Company would no longer benefit by promoting additional consumption by customers and would no longer be harmed by promoting greater energy efficiency by customers. Achieving these objectives is essential to realizing the goals of the State's energy policy reflected in Tennessee Code Annotated 65-4-126.

Q. Is this proceeding an appropriate forum for assessing the appropriateness of the important modifications to CGC's rate design that you are recommending?

A. Yes. Based on my experience, it is easier to address the various design parameters of this type of mechanism within a base rate proceeding. The TRA relies on base rate proceedings to establish target revenue requirements to be recovered from customers. Various aspects of CGC's proposal rely on a common set of underlying data such as billing determinants and allowed revenues per customer. In addition, all potential issues related to rate design that may be raised by interested parties such as the potential impact on business risk are readily addressed within a base rate case.

While it is possible to undertake a redesign of base rate structures outside of a base rate case, it is more difficult. The TRA noted these difficulties in conjunction with its recent deliberations on a proposal by Piedmont Natural Gas ("Piedmont") in Docket No. 09-00104. Consideration of the Company's proposal in a base rate case is also procedurally consistent with the recently enacted legislative mandate for the TRA to consider whether CGC's rates align the interests of the Company with those of its customers.

Q. What are Dr. Dismukes' views regarding the TRA's consideration of CGC's AUA Tariff proposal in this proceeding?

A. Dr. Dismukes goes to great lengths to paint the Company's efforts to address important rate design issues underlying its existing rate structure as "divisive" and completely without merit. In the process of attacking the Company's proposal, he resorts to hyperbole and rhetoric that would lead an uninformed reader to question why the Company made such a proposal in the first place.

Q. In your opinion, is it fair to characterize the Company's proposal as divisive?

A. Absolutely not. The proposed AUA Tariff is an innovative form of rate design that was developed in a manner that genuinely sought to address important challenges facing the industry today. The importance of these challenges is underscored by the recent Tennessee legislation calling on the TRA to investigate the best means of aligning the interests of utilities with their customers. In addition, the same challenges are being addressed in many jurisdictions across the United States. The National Association of Regulatory Utility Commissioners ("NARUC") has recently passed a number of resolutions addressing energy efficiency and rate design. Stakeholders in many jurisdictions are working toward constructively addressing the same issues that face Tennessee through innovative approaches to rate design and other initiatives. Dr. Dismukes' claims that the Company's proposal is divisive is counter-productive and has the potential to detract from the important matters at hand.

As with any policy initiative, CGC believes that there exists more than one means of achieving a particular policy goal or regulatory challenge and not all parties can be expected to agree. The Company is committed to working with the TRA in this proceeding to develop an appropriate understanding of the issues raised by the existing usage-based rate design as well as the Company's recommended AUA Tariff proposal. There are other means of addressing these rate design issues, which CGC is also committed to exploring to the extent necessary to aid the TRA in making a fully-informed and appropriate decision in this proceeding. CGC believes that an investigation of the leading approaches to rate design will lead to a better outcome for the Company's customers.

Q. Dr. Dismukes argues that the Company's AUA Tariff proposal is not mandated by the recently-enacted legislation in Tennessee Code Annotated 65-4-126. Do you agree?

A. I agree that the legislative requirements of Tennessee Code Annotated 65-4-126 do not require adoption of the AUA Tariff proposal. Dr. Dismukes has stated that the Company believes that adoption of the AUA Tariff or a similar mechanism is mandated by this legislation and related Federal legislation. However, the Company made no such claim that would effectively restrict the alternatives available to the TRA.

Nevertheless, CGC demonstrated that its AUA Tariff proposal is fully consistent with Tennessee energy policy with respect to promoting energy efficiency by consumers, which is certainly important. The Company also demonstrated that the AUA Tariff is more appropriate than its existing rate design and will lead to recovery of the authorized level of revenues by the TRA. The importance of the AUA Tariff extends beyond the matters raised by recent Tennessee legislative policies on energy efficiency.

Q. Dr. Dismukes goes on to claim that the CGC's existing rate design already comports with the legislative mandate in Tennessee Code Annotated 65-4-126. Is this true?

A. No. The existing rate design incorporates the recovery of a substantial portion of the Company's revenue requirements through usage-based charges. As explained in my direct testimony, the result of this approach is that the economic interests of the Company are not aligned with those of its customers with respect to achieving greater levels of energy efficiency. The existing rate design simply does not satisfy the requirements of Tennessee Code Annotated 65-4-126 and is outdated. Suggesting that the existing rate design already provides the proper foundation for promoting energy efficiency may be a conveniently simple approach to take now; however, it does not serve the best interests of CGC customers over the long term.

Q. How do you recommend that the TRA proceed?

A. I believe that it is essential that the TRA press ahead with an evaluation of the Company's AUA Tariff proposal through a fair assessment of the relevant facts and application of its policy objectives. The TRA recently rejected a new rate design approach proposed by Piedmont. Even though the specific proposal was rejected, it is clear from those deliberations that the TRA is interested in continuing to investigate these issues in an appropriate forum.

CGC is committed to aiding the TRA to fully understand the implications of various approaches to rate design in this proceeding, including those associated with Tennessee Code Annotated 65-4-126. My rebuttal testimony is presented with this objective in mind. In addition to addressing some of the more direct criticisms of the AUA Tariff, I will also present an alternative rate design approach that resulted from a discovery request in this proceeding.

Q. What criteria should the Commission apply to reach a fair conclusion?

A. I set forth a set of clear rate design goals in my direct testimony that are appropriate for consideration by the TRA. An appropriate rate design seeks to achieve the goals of:

(1) **Energy Efficiency** – Reducing energy consumption through energy efficiency and conservation helps implement important policy objectives that will benefit customers and the environment.

(2) **Revenue Stability** – Revenue stability means that CGC's base rate revenues are more predictable in view of future uncertainties. As customer use patterns have become less predictable, improved revenue stability through rate design takes on greater importance as a way of mitigating the increased risks associated with such unpredictable consumption patterns.

(3) **Fairness** – Fairness is accomplished through pricing services based on the underlying cost. Fairness is important in many respects including between the Company and its customers, across the classes served by CGC, and among customers taking service under a common rate schedule.

(4) **Rate Moderation** – Moderation ensures that customers are not exposed to dramatic price changes that could result in undesirable impacts including cost increases or economic decisions by existing customers to cease taking gas service from CGC.

(5) **Simplicity** – Simplicity means a rate structure that is easy for customers to understand and straightforward to administer.

These goals are consistent with the attributes of a sound rate structure described by noted ratemaking expert James C. Bonbright in *Principles of Public Utility Rates*. Mr. Bonbright identifies the following ten desirable attributes that regulators should seek to achieve:

(1) Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product safety and quality.

(2) Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

(3) Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity.

(4) Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use: (a) in the control of the total amounts of service supplied by the company; (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality service versus lower quality service).

(5) Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

(6) Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e. equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

(7) Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

(8) Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

(9) The related, practical attributes of simplicity, certainty, convenience of payment, economy of collection, understandability, public acceptability, and feasibility of application.

(10) Freedom from controversies as to proper interpretation.

The Company believes that the assessment of the AUA Tariff proposal, or one of the alternatives set forth in my rebuttal testimony, on the basis of a fair set of criteria will demonstrate the appropriateness of the recommended changes to the existing rate design.

Q. How is the remainder of your rebuttal testimony organized?

A. Dr. Dismukes presents considerable testimony on revenue decoupling in general. While I desire to focus my rebuttal on the Company's specific proposal, I will first address many of the false generalities presented by Dr. Dismukes, because he relies on these as a foundation for attacking the Company's proposal. Next, I will address some of the more specific concerns raised by Dr. Dismukes related to the AUA Tariff. I will also describe a straight-fixed variable ("SFV") rate design alternative that has been developed in response to a discovery request in this proceeding. Lastly, I will address traditional rate design topics including the appropriate customer charge and recovery of the allowed revenue requirements from various classes of customers.

CAPD WITNESS DISMUKES' POLICY VIEWS OF REVENUE DECOUPLING

Q. What general areas of concern do you have after reviewing the testimony of Dr. Dismukes in this proceeding?

A. Dr. Dismukes makes a number of sweeping indictments of revenue decoupling that are based upon misleading representations or that are simply untrue. In fact, so much of Dr. Dismukes testimony is devoted to revenue decoupling in general rather than the Company's specific rate design proposal, that I do not believe that it is constructive to address each of the general assertions that he makes. The specific general assertions that I will respond to include: (1) revenue decoupling has been abandoned as an effective ratemaking approach; (2) revenue decoupling has no support or basis in academic or theoretic literature; (3) revenue decoupling removes the incentive for the utility to control costs; (4) revenue decoupling will reduce utility risk management practices and associated benefits for customers; (5) revenue decoupling shifts risks to customers, (6) revenue decoupling creates incentives for inefficiency and poor service; and (7) utilities have no control over customer consumption. I will also discuss the insufficiency of an alternative construct recommended by Dr. Dismukes – lost base revenue mechanisms.

<u>Revenue Decoupling in Practice Elsewhere</u>

Q. Are innovative forms of rate design including revenue decoupling in place in other jurisdictions?

A. Yes. Revenue decoupling has been successfully implemented in a number of jurisdictions for natural gas utilities, electric utilities or both. I provided a list of natural gas utilities with decoupled rate designs as Exhibit DPY-4 to my direct testimony. During the short time period since this list was prepared in last November, regulators have adopted decoupled rate designs for an additional two utilities, bringing the total to forty-one natural gas utilities in twenty-one different jursidictions.

Q. What claims does Dr. Dismukes make regarding the prevalence of revenue decoupling?

A. Dr. Dismukes attempts to disparage the concept of revenue decoupling by stating that revenue decoupling was "abandoned almost as quickly as it was implemented" and "if revenue decoupling were a proven and effective regulatory approach more states would have adopted this mechanism in the past and it would be almost commonplace today". These statements suggest that revenue decoupling is not widespread, which is quite clearly contradicted by the level of activity across the United States. Over the last decade, nineteen jurisdictions have adopted decoupled rate designs, which equates to a pace of approximately two new states each year. While revenue decoupling has not been implemented in Tennessee, Dr. Dismukes paints a biased and unreasonably diminutive picture of the revenue decoupling activity in other jurisdictions. He also implies that the overall trend is to move away from decoupled rate designs, which is the opposite of actual experience.

Q. Has NARUC recognized the increased interest in evaluating revenue decoupling approaches?

A. Yes. Over two years ago, NARUC issued a paper designed to provide members and stakeholders with important background information concerning revenue decoupling approaches. The introduction to NARUC's paper stated the following:

> State Public Utility Commissions around the country are expressing increasing interest in energy efficiency as an energy resource. However, traditional regulation may lead to unintended disincentives for the utility promotion of end-use efficiency because revenues are directly tied to the throughput of electricity and gas sold. To counter this "throughput disincentive," a number of States are considering alternative approaches intended to align their utilities' financial interests with the delivery of cost-effective energy efficiency programs. "Decoupling" is a term more are hearing as a mechanism that may remove throughput disincentives for utilities to promote energy efficiency without adversely affecting their revenues. *Decoupling for Electric and Gas Utilities: Frequently Asked Questions*, National Association of Regulatory Utility Commissioners. September 2007.

A copy of the NARUC paper is provided as Exhibit DPY-14. In addition, a number of decoupling-related panels and presentations have occurred at NARUC-sponsored conferences, further indicating that NARUC recognizes the importance of continuing to investigate this form of innovative rate design.

Q. What about excerpts from orders in various jurisdictions that do not favor revenue decoupling as cited by Dr. Dismukes?

A. My recommendation to the TRA is that an independent evaluation be performed of the Company's rate design proposals. While there are some jurisdictions that have rejected similar mechanisms as the AUA Tariff, there are more that have elected to approve them. A selective review, such as that presented by Dr. Dismukes, fails to provide an accurate assessment of activity in other jurisdictions.

<u>**Research Support for Revenue Decoupling**</u>

Q. Please state your concerns with Dr. Dismukes assertions regarding research on revenue decoupling matters.

A. Once again, Dr. Dismukes makes unsupportable claims in an attempt to belittle the very concept of revenue decoupling. The following question and answer appear on page 38 of his testimony:

> "Q. Is revenue decoupling based upon any sound economic principles or academic thought?
>
> A. No, and unlike the better part of utility regulation, revenue decoupling has virtually no support or basis in the academic and theoretic economic literature."

This testimony is patently false. The economic principles of revenue decoupling have been broadly written about. The Company's direct testimony provides a review of the economic rationale for its own AUA Tariff proposal. The economic principles are simple – that aligning the interests of utilities and their customers will lead to improved outcomes and more efficient use of natural gas by customers.

Dr. Dismukes' claim is even clearly contradicted by the very academic institution he attempted to rely on in his testimony support it. The Michigan State University Institute of Public Utilities issued a bibliography on revenue decoupling, which is provided as Exhibit DPY-15. A number of papers and reports cited in this bibliography address the benefits of decoupled rate designs.

Dr. Dismukes is free to advocate for a different form of rate design; however, it is disingenuous and counter-productive to assert that there is no support or basis for revenue decoupling.

<u>Revenue Decoupling and Cost Control</u>

Q. Dr. Dismukes claims that revenue decoupling eliminates the incentive for utilities to reduce their costs and will ultimately lead to higher costs to customers. Is this claim consistent with the actual operation of revenue decoupling approaches?

A. No. Under traditional regulation employing a usage-based rate design, utilities have two means of improving their earnings in between rate cases. The first of these is to promote increased consumption by existing customers, while the second is to reduce costs. The implementation of revenue decoupling eliminates the ability for a utility to increase earnings through increased use by existing customers; however, the incentive to lower costs is left completely intact. To the extent that a utility improves efficiency and lowers its cost of providing service, it will experience the same benefits with revenue decoupling as without. Conversely, revenue decoupling does not permit a utility to pass on any increased costs of providing service. Thus, one of the benefits of revenue decoupling is that it forces utilities to focus primarily on the cost side of the profitably equation.

Q. Does revenue decoupling typically guarantee a specified level of earnings?

A. No. Revenue decoupling addresses the recovery of authorized revenues. Utilities remain exposed to potential increases in costs and may achieve cost efficiencies that will lead to actual earnings levels that vary from authorized levels. In fact, inefficient or poor management will equally lead to a reduction in earnings for a decoupled or non-decoupled rate utility.

Q. Does the implementation of revenue decoupling eliminate the benefits of regulatory lag?

A. Regulatory lag has been cited as beneficially affecting utility customers because it promotes cost containment and efficient utility management. Since revenue decoupling focuses on revenues only, the stated benefits of regulatory lag remain largely intact.

Revenue Decoupling and Risk Management

Q. On page 42 of his testimony, Dr. Dismukes asserts that utilities will be less likely to engage in price risk management for gas supply procurement. Is this a reasonable claim?

A. No. The form of base rate design, including whether or not revenue decoupling exists, would have absolutely no impact on the effectiveness of the TRA's gas purchase prudence and audit rules. The TRA established rule 1220-4-7-.05 governing the annual prudence review of natural gas purchases, which provides appropriate regulatory oversight to prevent the type of result that Dr. Dismukes claims could occur. In addition, the Company's tariff specifies independent gas supply purchasing indices that are used to benchmark the Company's practices. In any year that the Company's actual purchased gas costs are below the applicable benchmark plus 1%, the annual prudence review is waived.

In addition, the implementation of revenue decoupling does not insulate a utility from the competitive markets it operates in. CGC remains in direct competition for acquiring and retaining customers with electricity and oil. The Company will continue to seek the best cost for its customers in order to maintain its competitive position. There is no reason to believe that the implementation of a decoupled rate design would lead to any change in CGC's risk management practices. Moreover, I am unaware of any concerns in this area related to any of the other natural gas utilities that have implemented decoupled rate designs. Dr. Dismukes suggestion is simply a red herring that is not credible.

Revenue Decoupling and Risk Shifting

Q. Dr. Dismukes states that the implementation of revenue decoupling shifts risks from the utility to customers. Do you agree?

A. No. Dr. Dismukes' claims fail to recognize the existing risks customers are exposed to under traditional rate design, how these risks are juxtaposed with those of the utility, and how revenue decoupling affects the risks of both parties. I will address his testimony from a ratemaking perspective. Dr. Morin will present additional rebuttal testimony on the issue of risk and the impact of decoupled rate designs on the appropriate determination of return on equity in this proceeding.

Q. Please explain how customer and utility risks differ under a traditional usage-based rate design.

A. Traditionally, rates are set in a rate case based upon projected consumption reflecting a variety of underlying assumptions regarding weather, economic activity and demographics. The utility and customers are subject to potential "risks" that the consumption will vary from that used as the basis to set rates because actual experience varies from expectations underlying the forecast.

For instance, if economic conditions are worse than forecast, consumption will likely be reduced and the utility will recover less revenues than authorized because the rate design process established a link between consumption and revenues. However, if economic conditions are better than forecast, consumption will increase and customers will pay higher revenues than authorized in the rate case. Similar comparisons can be drawn for other factors such as variances in weather and the absolute level of commodity natural gas prices.

Dr. Dismukes assertion that shareholders typically bear the risk of revenue and sales differences from the test year is incorrect. Both customers and the utility bear these revenue-related risks and the potential risks are in the opposite direction. This fact is critically important to properly understanding the impact that implementing revenue decoupling will have on customer and utility risks.

Q. Does the implementation of a decoupled rate design affect utility risks?

Yes. However, the resulting impact does not shift risk from the utility to the customer, but reduces aggregate revenue-related risks borne by the utility and customers together. It is only possible to shift risk from one entity to another when the potential revenue risks associated with a particular variable are in the same direction. In this case, the revenue-related risks are in the opposite direction. The implementation of revenue decoupling reduces the likelihood that the utility will experience revenue reductions from the forecast level and the risk that customers will experience revenue increases from the forecast level. The impact is a net reduction in total short-term revenue-related risks experienced by the utility and customers together. The impact on longer-term revenue-related risks is negligible as the revenue impacts over longer periods are expected to average out.

Q. Is it a reasonable goal of rate design to impose a revenue recovery risk on the utility?

A. No. To suggest that rate design should be approached from the perspective that it is acceptable to assign revenue risk to the utility leads to the conclusion that it is reasonable for customers to underpay for the service that they receive. I disagree with this notion and the premise that the rate design structure should be an accepted source of revenue recovery risk. Instead, rate design should appropriately reflect current public policy goals and objectives as well as present circumstances. It is the changing nature of these factors, which I describe in my direct testimony, that drives the need to implement new rate design approaches such as the proposed AUA Tariff. The growing need to stabilize base revenue recoveries is motivated largely by the overall maturation of the gas distribution industry. Whereas declining revenues could be offset by significant customer growth and cost savings in the past, these opportunities are diminishing greatly.

Q. Has the issue of the potential for risk shifting under revenue decoupling ever been studied in practice?

A. Yes. The Lawrence Berkeley Laboratory, Energy and Environment Division at the University of California Berkeley studied this issue among others based upon the actual decoupling of the rate structure of California electric utilities. This study found that there was virtually no shifting of risk from utilities' shareholders to customers under revenue decoupling. The outcome is not unexpected given the nature of customer and utility revenue risks underlying traditional ratemaking approaches as I have described.

<u>Revenue Decoupling and Customer Service</u>

Q. Is it reasonable to claim that revenue decoupling creates incentives for inefficiency and poor service.

A. The suggestion that revenue decoupling will contribute to a degradation in either efficiency or customer service is insupportable. Revenue decoupling does not insulate the utility from any of the factors that drive it to achieve high levels of customer satisfaction and operational efficiency. As I have noted previously, gas utilities such as

CGC are subject to competitive forces. These competitive forces, as well as regulatory oversight, remain in full force and effect under decoupled rate designs.

Contrary to Dr. Dismukes claims, revenue decoupling has been shown to increase customer satisfaction. I explained in my direct testimony that J.D. Power and Associates has identified a link between utilities with decoupled rates and higher levels of customer satisfaction. There is absolutely no reason to believe that the implementation of revenue decoupling will lead to a decline in the level of service provided to customers.

Q. Does Dr. Dismukes offer examples of how a utility might behave differently if its rates are decoupled?

A. Yes. On page 57 of his direct testimony, Dr. Dismukes makes the following assertions:

> "If utility service is interrupted, revenue decoupling without any corresponding protections, will ensure that a Company has been made whole for those sales losses, minimizing its incentives for speedy service restoration. If customer service is poor, and customers leave for alternative energy sources (like electricity), a decoupled natural gas utility will be made whole for that loss and is held unaccountable for its actions. If a utility's rates are not competitive, and it loses customers to bypass or fuel switching, a decoupled utility will be made whole for the inefficiency. If opportunities to add new loads arises [*sic*] through business relocations or expansions, revenue decoupling discourages active pursuit of those loads since a utility will be made whole with, or without, the new customers."

The implications of Dr. Dismukes testimony represent an affront to utility managements across the United States. To suggest that any utility would be slower to restore utility service when an outage occurs due to the implementation of decoupled rates is ludicrous. In all my years working with natural gas utilities, I have never heard any employee link the manner in which service is restored after an outage to revenue recoveries. These utilities have established careful operating plans to prevent and respond to potential outage situations in an aggressive manner because it is the right thing to do.

The remaining examples cited by Dr. Dismukes completely misrepresent the way revenue decoupling operates. If a natural gas utility loses a customer under a decoupled rate design, it will forego the average revenues per customer. There is no "make whole" component. The same is true for any potential customer loss due to bypass or fuel switching.

Dr. Dismukes' claim that the implementation of revenue decoupling discourages the active pursuit of new business opportunities is equally fallacious. The incentive to add profitable customers remains under a properly designed revenue decoupling mechanism. It is essential to provide a fair representation of the mechanics of these rate designs in order to provide a reliable opinion on their merits.

Q. Does Dr. Dismukes draw any conclusions based on these misrepresentations?

A. Yes. He concludes that "revenue decoupling does nothing to align customer and utility interests, and does everything to move those interests in opposite directions". It is only possible to arrive at such a ridiculous claim through the twisting of facts to suit the desired end.

It is very important for the TRA to reach a determination on the Company's rate design proposal based upon an accurate understanding of the facts regarding the operation of the proposed AUA Tariff. The examples cited by Dr. Dismukes and his resulting conclusions should simply be dismissed.

Relationship Between Utilities and Their Customers

Q. Does Dr. Dismukes believe that utilities have any influence over customer consumption behavior?

A. Contrary to mainstream opinion, I conclude that he does not. On page 48 of his testimony, Dr, Dismukes testifies regarding this matter as follows:

> "How utilities would encourage more throughput between rate cases is absolutely beyond explanation: utilities cannot control customers or customer usage."

Once again, I find this statement perplexing and completely disassociated from reality. Utilities enjoy unprecedented interaction with their customers on a regular basis through various forms of communication. The utility-customer relationship is an important means of influencing customer behavior, including with respect to energy efficiency and conservation. The importance of leveraging this relationship has been broadly recognized and accepted.

Utilities are also able to influence the success of customer energy efficiency initiatives indirectly through various community involvement and advocacy efforts including those related to appliance efficiency standards and building codes. Some examples are provided in the excerpt from a recent resource report prepared by the United States Department of Energy and United States Environmental Protection Agency National Action Plan for Energy Efficiency addressing building codes provided as Exhibit DPY-16.

Insufficiency of Lost Base Revenue Approach

Q. Dr. Dismukes claims that establishing a lost base revenue mechanism for CGC would be superior to the Company's proposal. Do you agree that establishing a

mechanism that compensates CGC for lost base revenues is a reasonable alternative to the Company's proposal?

A. No. Lost base revenue mechanisms are too narrowly focused to address the rate design challenges attendant with a usage-based rate design. Specifically, lost base revenue mechanisms fail to account for energy efficiency initiatives that may be independent of specific programs. In addition, the implementation of a lost base revenue mechanism often leads to additional administrative complexity and often contention over measurement and verification of energy savings that are linked to utility compensation. For these reasons, a number of jurisdictions that formerly relied on lost base revenue mechanisms have shifted to decoupled forms of rate design.

CGC AUA TARIFF PROPOSAL

Q. Does Dr. Dismukes offer any testimony that relates to the Company's AUA Tariff proposal?

A. Beginning at page 68, Dr. Dismukes devotes approximately five pages of text to a review and analysis of CGC's specific tariff proposal in this proceeding. He raises three areas of concern with the Company's proposal and offers recommended changes. These are: (1) to retain a separate weather normalization mechanism, (2) to exclude firm transportation customers, and (3) to eliminate the per-customer aspect of the AUA Tariff calculations.

In addition, Dr. Dismukes asserts that approval of the AUA Tariff should reflect other terms and conditions approved for either New Jersey Natural Gas and South Jersey Gas in New Jersey or Avista Utilities in Washington. Lastly, Dr. Dismukes recommends that any AUA Tariff approval be accompanied by a presumption that the mechanism is repealed after three years.

<u>Retention of Separate Weather Normalization Mechanism</u>

Q. Do you believe that it is appropriate to maintain a separate mechanism to account for weather variances?

A. No. I disagree with Dr. Dismukes' claims that relying on a single mechanism to adjust for the base revenue impact of weather-related and non-weather-related factors is more readily understood by customers. In my view, maintaining separate mechanisms is unnecessary and implies a false precision as it is difficult to exactly separate the weather and non-weather impacts from one another. Many similar base revenue normalization mechanisms adjust for weather and non-weather impacts through a combined mechanism without leading to customer confusion.

Dr. Dismukes also indicates that maintaining a separate weather clause will make it easier to terminate the AUA Tariff at some future point in time. The potential termination of the AUA Tariff is not a reasonable justification for implementing a more cumbersome mechanism that maintains two separate adjustment clauses. The potential reinstatement of weather normalization clauses at the end of a specified term has been readily addressed for other decoupled utilities that implemented a combined mechanism.

<u>Inclusion of Firm Transportation Customers</u>

Q. Why is it necessary to include both firm transportation customers and firm sales customers under the AUA Tariff?

A. The AUA Tariff is a base revenue mechanism that addresses the recovery of costs associated with distribution service, not gas supply service. The distribution service provided to firm transportation and firm sales customers is the same. Therefore, it is appropriate to include both types of customers within a common mechanism. In addition, firm transportation customers are not precluded from participating in the Company's energy efficiency programs. The potential future migration of customers back and forth between firm sales and firm transportation customers would influence the comparison of actual and benchmark revenues per customer in an undesirable manner. This is avoided by including both types of customers in the AUA Tariff calculations.

<u>Per Customer AUA Tariff Calculations</u>

Q. Why are the AUA Tariff calculations performed on a per-customer rather than total revenue basis?

A. As I described in my direct testimony, it is necessary to implement the AUA Tariff on a per customer basis in order to reflect future changes in the number of customers served, which is a significant cost driver on CGC's system. In fact, this approach preserves the status quo with respect to the revenue treatment of positive and negative changes to the number of customers served by CGC. Under the existing rate design structure, CGC retains base revenues from incremental customers to offset the revenue requirements associated with the incremental capital expenditures needed to connect them to CGC's system. Additionally, CGC experiences revenue losses for customers that cease taking service. The per-customer approach to the AUA Tariff calculations leads to the same outcome and is the basis for the majority of similar adjustment mechanisms.

Q. Dr. Dismukes claims that you have offered no evidence explaining why revenues associated with customer growth must be retained by CGC? Is this allegation true?

A. Absolutely not. I addressed this issue in my direct testimony beginning on page 30. Moreover, the basic economics of adding natural gas customers to the distribution system are fundamental in nature.

Q. **Are there any material and adverse outcomes associated with eliminating the ability for the gas utility to retain revenues from customer growth as recommended by Dr. Dismukes?**

A. Yes. Elimination of growth in revenues associated with growth in customers will impose an immediate disincentive to add any new customer to the gas distribution system and would lead to uneconomic behavior on the part of the utility. This results from the fact that the need to invest capital in services, meters and other facilities as each new customer is added to the system without any incremental base revenue recovery would lead to a reduction in CGC's rate of return under Dr. Dismukes' recommendation. Failure to add beneficial customer loads would be detrimental to the environment and existing customers over the long term. In addition, CGC would not experience revenue losses when customers leave the system, which is also an undesirable outcome. These improper outcomes brought about by Dr. Dismukes recommended modification are the very ones he stated should be avoided.

Q. **Is it necessary for CGC to demonstrate that the incremental cost of serving new customers exceeds the embedded or average cost in order to justify the retention of revenues from customer growth?**

A. No. The proper ratemaking question is not whether the incremental costs exceed the average costs, but whether the incremental costs are greater than $0. The revenues from existing customers are needed to offset the revenue requirements associated with providing service to existing customers. If the incremental costs are greater than $0, then it is necessary to allow CGC to retain the incremental revenues from new customers to maintain current operating incentives and the resulting benefits. In the case of CGC, the incremental costs of adding new customers are actually quite similar to the average costs.

Imposition of Additional Terms from New Jersey or Washington

Q. What is the basis for Dr. Dismukes' proposal to add provisions from the revenue decoupling programs approved for Local Distribution Companies ("LDCs") in New Jersey or Washington?

A. Dr. Dismukes claims that the approval of the AUA Tariff requires additional "consumer protections" such as those implemented for these other utilities.

Q. Are the New Jersey and Washington approaches relevant to the consideration of the AUA Tariff proposal?

A. In my view, these programs are largely irrelevant to this proceeding and should be approached with a great deal of caution. The specific terms referenced by Dr. Dismukes come from programs that were each implemented through negotiated settlements and were each adopted independent of a base rate case proceeding. Either of these considerations alone make it difficult to assess the transferability of the provisions to CGC.

In addition, Dr. Dismukes has fundamentally misrepresented the structure of the programs adopted for New Jersey Natural Gas and South Jersey Gas. Specifically, the upstream gas supply savings included in the annual calculations largely resulted from pre-identified release transactions to utility affiliates. Further, the efficiency program funding provided by these two companies was enabled by other offsetting revenue attributes of the negotiated agreements. In my view, the consideration of this type of program for CGC would only be appropriate if the Company's upstream capacity markets and supply-demand balance mirrored that of the New Jersey utilities, which it does not. A complete understanding of the approach adopted in New Jersey reveals how difficult it is to adopt elements of programs from other jurisdictions on a piecemeal basis, particularly when these programs result from negotiated agreements rather than litigated decisions.

Q. What about the recovery limitation associated with the Avista program approved in Washington?

A. Dr. Dismukes proposes to allow 24% of the base revenue variance to flow through the AUA Tariff. The remaining 76% would be excluded. It is readily apparent that limiting the AUA Tariff in this manner preserves the status quo and does not represent an appropriate rate design or satisfy the requirements of Tennessee Code Annotated 65-4-126.

Q. Are additional consumer protections even needed?

A. I strongly disagree with the notion that the type of additional terms proposed by Dr. Dismukes are necessary or appropriate. The AUA Tariff intrinsically represents a strong consumer protection for CGC customers. Implementation of the AUA Tariff will ensure that customers pay on average the exact level of base revenues authorized by the TRA in this proceeding. Therefore, the AUA Tariff offers superior protection to consumers when compared with the Company's existing rate design.

The additional provisions called for by Dr. Dismukes are not consumer protections, but rather are attempts to re-establish the link between base revenues and customer consumption. Under any of these type of changes, CGC's revenue outlook would be improved if customers use more natural gas. This is contrary to the very reason that innovative rate designs are being approached on a broad scale.

Q. Would there be a more appropriate form of safeguard that could be implemented in conjunction with the AUA Tariff?

A. To the extent that the TRA desires to implement a recovery limitation associated with the AUA Tariff, I would recommend an off-ramp that requires the Company to file a base rate case within nine months of experiencing any AUA Tariff annual revenue deferral that equates to ten percent of revenues. The calculation of this requirement should exclude the revenue impact of variations in weather.

This type of off-ramp is manageable and offers an extra protection to the TRA that the operation of the AUA Tariff will not lead to rate instability without requiring a new rate case. Moreover, because the outcome of reaching the trigger point is a base rate filing, the recovery limit operates in a manner that is consistent with the provisions of Tennessee Code Annotated 65-4-126. The mechanism is similar to one noted on page 10 of the NARUC revenue decoupling analysis presented in Exhibit DPY-14.

<u>Presumption of Repeal After Three Years</u>

Q. Do you have any concerns regarding the establishment of a presumption that the AUA Tariff is cancelled after three years?

A. Yes. Most energy efficiency programs require a long-term perspective to recover up-front investment costs that lead to long-term savings. A threat to eliminate the AUA Tariff before the program even begins could undermine its very objectives. It also strikes me as unnecessarily premature to establish a predisposition toward cancelling the program given the fact that the TRA always retains the ability to revisit policies based on changing circumstances or outcomes. I also believe that the TRA should carefully consider the nature of information that it would like to evaluate prior to mandating a review of the operation of the AUA Tariff.

STRAIGHT-FIXED-VARIABLE RATE DESIGN ALTERNATIVE

Q. Please describe the rate design alternatives to the AUA Tariff proposal that were submitted by CGC in response to discovery in this proceeding.

A. Staff discovery requests 2-29 through 2-31 requested the Company's position on SFV rate design and also the development of an SFV rate design alternative. In response to these requests, the Company prepared two SFV rate designs that it believes are appropriate alternatives to the AUA Tariff in that they satisfy the underlying rate design objectives set forth in my direct testimony and reflected in Tennessee Code Annotated 65-4-126.

Q. Please describe the first SFV rate design alternative developed by CGC.

A. The first SFV alternative replaces the existing delivery charge with a demand charge applied to customer-specific billing demand quantities. The billing demand quantity reflects the quantity of natural gas utilized at peak periods and accommodates size differences among customers. Under the first alternative SFV rate design, the demand charge is $11.094 per peak unit per month. The demand charge would be billed on a sculpted basis over the twelve months of the year. The recovery of fixed demand-related costs through a fixed charge allows for a lower fixed customer charge as well. Therefore, this alternative rate design reflects a $1 increase to the proposed residential customer charge to yield $13 per month during the winter and $12 per month during the summer. The Company's response to Staff Request 2-29 containing this rate design is provided as Exhibit DPY-17. The first SFV rate design alternative is provided in Attachment 29-1 to this response.

Q. Why is the demand charge sculpted across the months of the year?

A. The annual demand charge is applied on a sculpted basis to the billing demand quantity as a means of mitigating bill impacts across the months of the year. This approach also matches customer expectations for higher bills during peak periods and lower bills during off-peak periods.

Q. What are the benefits of this rate design alternative?

A. An important benefit of this SFV rate design is that it fully aligns the economic interests of the Company with those of its customers with respect to energy efficiency and conservation. Appropriately-designed SFV rates represent a direct means of achieving this goal without any ongoing revenue adjustment mechanism such as the AUA Tariff. This SFV rate design achieves important rate design goals including supporting energy efficiency, revenue stability and fairness. Further, through the sculpting of the demand charge across months, bill impacts are appropriately managed

Q. Please describe the second alternative rate design.

A. The second alternative rate design retains a small delivery charge to recover a portion of the Company's revenue requirements. Under the second alternative, the demand charge is reduced to $7.75 per month and the monthly customer charges are held at the same levels derived in the first SFV rate design. The resulting rates including the delivery charges are provided in Attachment 29-2 to the Company's response to Staff Request 29 and are also provided in Exhibit DPY-17.

Even though this second alternative rate design retains a delivery charge, the resulting rates achieve a sufficient degree of alignment between the Company's interests and those of its customers to satisfy Tennessee's ratemaking policy favoring the development of energy efficiency. The continuation of a delivery charge under this second SFV alternative necessitates retaining the Company's existing weather normalization clause; however, the annual adjustments will be significantly reduced. The demand charge levels presented in the two SFV rate design alternatives establish a range that CGC believes appropriately satisfies important rate design goals and meets the standards established in Tennessee Code Annotated Section 65-4-126.

Q. Does CGC have any relevant experience with the implementation of this type of SFV rate design?

A. Yes. This form of rate design was implemented by the Company's affiliated LDC in Georgia, Atlanta Gas Light Company ("AGLC") approximately 12 years ago. Based upon this experience, the rate design is understandable to customers and properly mitigates bill impacts for various size and load factor customers.

Q. What are your conclusions regarding these alternative SFV rate designs?

A. CGC would support adoption of either SFV rate design as an alternative to its proposed rate design and AUA Tariff.

REBUTTAL OF WITNESS BUCKNER'S RATE DESIGN TESTIMONY

Q. Please describe CAPD's rate design recommendations.

A. Mr. Buckner presents CAPD's recommended changes to CGC's rate structure. After reviewing the fixed charges of other Tennessee LDCs and noting that customers conserve in part due to the existence of volumetric charges, Mr. Buckner recommends that CGC's overall base revenue increase be applied entirely to delivery charges. As a result, he proposes to retain all of the Company's monthly customer charges at present levels. Further, he recommends applying the increase proportionately to all rate classes.

Q. What specific CAPD rate design recommendations will you respond to?

A. First I will respond to Mr. Buckner's customer charge recommendations. Specifically, I will address his proposal to retain the same level of residential (R-1) and industrial (F-1/T-2) customer charges. I proposed no increase to the remaining customer classes based on the results of the Allocated Cost of Service Study ("ACOSS") presented in my direct testimony. Therefore, I am only responding to Mr. Buckner's proposed R-1 and F-1/T-2 proposed customer charges. Second, I will respond to Mr. Buckner's proposal to allocate the proposed revenue increase equally to all rate classes.

Q. Please describe your concerns with Mr. Buckner's proposal to retain the existing residential and industrial customer charges.

A. The monthly customer charge provides an important price signal to customers associated with the costs incurred by CGC to provide distribution service regardless of the amount of natural gas that is consumed each month. These costs include revenue requirements associated with meters and services as well as monthly meter reading, billing and customer account services. Failure to increase customer charges leads to material concerns associated with important rate design principles including fairness and revenue stability.

In my direct testimony, I performed a comprehensive analysis of monthly customer-related costs of serving customers. For many rate classes, the monthly customer charge was similar to the corresponding customer cost. The two exceptions were the R-1 and F-1/T-2 rate classes. Customer charges for each of these classes are presently less than 60% of customer-related costs as indicated by the comparison presented in Exhibit DPY-8.

From the perspective of fairness, it is important to change base rates in a manner that moves individual rate elements closer to cost-based levels. Failure to increase customer charges to reflect the results of the ACOSS retains existing inequities for larger customers within a rate class, including residential customers that heat with natural gas.

From the perspective of revenue stability, customer charges should be increased in order to recover a greater proportion of fixed costs through fixed charges. Given that virtually all of the Company's revenue requirements are fixed, customer charges should be increased by some measure within a base rate case. Implementation of the AUA Tariff proposal would alleviate some concerns over the level of customer charges; however, CAPD has recommended rejection of the AUA Tariff as well.

Q. Did Mr. Buckner take into consideration the results of ACOSS in developing his recommendation to apply all of the revenue increase to delivery charges?

A. Based on Mr. Buckner's recommendations, it is readily apparent that he did not. Mr. Buckner's only reference to an ACOSS appears on page 26 of his direct testimony where he quotes a Tennessee supreme court decision indicating that cost of service is not an exclusive means that the TRA must rely to set rates, but that rate design is a value judgment undertaken by the TRA through the application of sound judgment and discretion. While I do not disagree with the need for the TRA to exercise appropriate judgment and discretion in the design of rates, the underlying cost of providing service is an important fact to be weighed by the TRA in the exercise of its regulatory responsibility. Mr. Buckner's complete dismissal of the cost of serving violates accepted rate design principles.

Q. Does the TRA require the Company to file an allocated cost of service study in conjunction with a natural gas base rate case?

A. Yes. Minimum filing requirement No. 55 requires the Company to file an allocated cost of service study.

Q. Is it reasonable to limit CGC's residential customer charge because of similar charges for other distribution companies?

A. Mr. Buckner notes that CGC's existing residential customer charges are comparable to those of the Tennessee operating divisions of Piedmont and Atmos Energy ("Atmos"). As shown on page 24 of Mr. Buckner's direct testimony, CGC's residential customer charge is actually $1 per month lower than either Piedmont or Atmos during the winter and the same as these LDCs in the summer. Mr. Buckner goes on to state that there is "abundant equity for the residential and commercial customers of the three major LDCs in Tennessee". While Mr. Buckner has not explain in his testimony what he means by the term "abundant equity", the concept of limiting the charges CGC bills to customers on the basis of charges of other LDCs is inappropriate.

By limiting CGC's residential customer charge because it is similar to the corresponding charge for Piedmont and CGC, Mr. Buckner has imposed an arbitrary and unreasonable limit upon the level of CGC's customer charge. Such an approach is contrary to accepted ratemaking principles whereby the actual cost of providing service is an important basis for setting prices. Interestingly, Mr. Buckner has not also recommended that the higher residential delivery charge for Piedmont also be applied to CGC's customers. Allowing Mr. Buckner's proposal to be approved would lead to an unwieldy regulatory approach as all utilities would have an incentive to take active positions in the rate proceedings of other utilities so as to preserve their interests with respect to the rate design appropriate to their own customers.

Moreover, Mr. Buckner has not applied the principal consistently to CGC. Specifically, if equity exists when Piedmont's and Atmos' customer charges are $1 higher than CGC, it would be appropriate to raise CGC's customer charges to a minimum level that is $1 higher than Piedmont and Atmos. In addition, the currently-effective tariff for Atmos indicates customer charges that are $13.75 during the winter months and $10.75 during the summer. While I don't agree with the ratemaking standard outlined by Mr. Buckner, a consistent application would call for residential customer charges that are as high as $14.75 in the winter and $11.75 in the summer, i.e., $1 per month greater than other major Tennessee LDCs.

Q. What undesirable outcomes would result if Mr. Buckner's customer charge recommendations were adopted?

A. Retaining customer charges that are far below cost-based levels in the absence of implementing any other fixed charges perpetuates intra-class subsidies provided by larger customers to smaller customers. Within the residential class, this results in heating customers shouldering more than their fair share of CGC's residential revenue requirements.

Mr. Buckner's residential and industrial customer charge proposals also unnecessarily increase the weather-sensitivity of CGC's margin revenue recoveries. This is equally undesirable for the Company and its customers. The increased weather-sensitivity would unnecessarily lead to proportionately larger credits and debits flowing through the Company's AUA Tariff or weather normalization clause, and larger amounts to be refunded or collected from customers in subsequent periods.

Q. Turning to the allocation of the revenue increase to various rate classes, please address Mr. Buckner's proposal to apply an equal increase to all rate classes.

A. Mr. Buckner suggests that his proposal to allocate the revenue change to all rate classes equally "would assure that the benefits or burdens created by any rate adjustment in this case are shared proportionately by all customers". While this is the result of Mr. Buckner's proposal, the recommendation is completely arbitrary. There is simply no foundation for Mr. Buckner's proposal. Further, in view of the underlying cost of providing service, applying an equal percentage revenue increase to all rate classes violates a number of important and accepted rate design principles including that of fairness. While it is important for the TRA to apply a reasoned judgment to the rate design process, it is equally important that the cost of service standard be considered.

Q. Why is it important to differentiate the revenue increase applied to CGC's various rate classes?

A. Typically, base rates are only modified in the context of a base rate proceeding. It is important to adjust rates in a manner that moves all rates toward the underlying cost of service in order to promote fairness and equity as well as provide consumers with appropriate price signals. Given the current level of cross-subsidies among CGC's rate classes, it is appropriate to apply varying percentage increases to various classes.

The Company's proposed rate design set forth in my direct testimony properly balances the cost of service standard with the need to moderate rate changes and avoid rate shock. In particular, under the Company's proposal, no rate class receives a rate decrease reducing the rate increase that is passed on to other classes, while moderately reducing the existing rate subsidies demonstrated by the ACOSS results. This approach properly recognizes the cost of service standard, while adhering to other important ratemaking goals. Mr. Buckner's proposals set aside the cost of standard altogether, which leads to inappropriate conclusions and outcomes.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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NARUC

Decoupling For Electric & Gas Utilities: Frequently Asked Questions (FAQ)

Grants & Research Department
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Introduction

State Public Utility Commissions around the country are expressing increasing interest in energy efficiency as an energy resource. However, traditional regulation may lead to unintended disincentives for the utility promotion of end-use efficiency because revenues are directly tied to the throughput of electricity and gas sold. To counter this "throughput disincentive," a number of States are considering alternative approaches intended to align their utilities' financial interests with the delivery of cost-effective energy efficiency programs. "Decoupling" is a term more are hearing as a mechanism that may remove throughput disincentives for utilities to promote energy efficiency without adversely affecting their revenues.

In its July 14, 2004, resolution supporting efficiency for gas and electric utilities, the National Association of Regulatory Utility Commissioners (NARUC) resolved "to address regulatory incentives to address inefficient use of gas and electricity" (NARUC, 2004). In doing so, NARUC found that regulators are confronted with questions about what ratemaking mechanisms would be most effective in achieving commission objectives, satisfying the needs of utilities, and providing the greatest benefit to ratepayers. Decoupling represents a departure from common regulatory practice, and States that are considering decoupling should approach this with appropriate care. **For States considering decoupling, this paper is intended to provide an introduction and answer some of the most frequently asked questions, and to help determine if and how decoupling might be used.**

1. What is decoupling? In the electricity and gas sectors, "decoupling" (or "revenue decoupling") is a generic term for a rate adjustment mechanism that **separates (decouples) an electric or gas utility's fixed cost[1] recovery from the amount of electricity or gas it sells.** Under decoupling, utilities collect revenues based on the regulatory determined revenue requirement, most often on a per customer basis. On a periodic basis revenues are "trued-up" to the predetermined revenue requirement using an automatic rate adjustment.

The result is that **the actual utility revenues should more closely track its projected revenue requirements, and should not increase or decrease with changes in sales.** Since utilities will be protected if their sales decline because of efficiency, proponents of decoupling contend that they are more likely to invest in this resource, or may be less likely to resist deployment of otherwise economically beneficial efficiency.[2] Decoupling is also being explored in the water utility sector, though this paper focuses on the electricity and natural gas sectors.

2. How does decoupling work? Decoupling begins with the same rate case process as current regulatory models use, so it is useful to review traditional ratemaking to understand how decoupling works.

How are rates are set under traditional regulation? With traditional regulation, the rates utilities can charge are determined in a **rate case**, using the **"cost of service" theory of regulation.**[3] Rates are set at a

[1] For our purposes "fixed costs" are those costs incurred to render service, which remain relatively constant between rate cases. These typically include investment costs, including interest on debt and return on equity, and unavoidable maintenance costs for power plants, transmission lines, gas pipelines, and other infrastructure, as well as employee payroll. Variable costs are those which vary with the level of electric or gas output and include fuel expenses, purchased power, and costs that vary broadly from month to month and are not included in decoupling mechanisms. These are often addressed through fuel or other adjustment clauses under existing regulatory practice.

[2] Decoupling advocates note that it removes a financial disincentive to energy efficiency, but may not create an incentive. Some decoupling advocates also argue that decoupling can help remove barriers to the integration of demand response and distributed resources.

[3] Why are utilities prices set by regulation and based on their cost of service? Electricity and natural gas are considered to be essential services, and it is in the interest of society to ensure that the businesses that provide these services can pay for the costs of their operations and capital. Because these services are provided by

level sufficient to allow the utility to recover costs incurred in providing service to its customers based on the operating experience of a typical 12 month period (referred to as a "**test year**"). Test year expenses include the commission-determined or -allowed rate of return on investments. The utility's **revenue requirement** is determined by adding the total of these expenses and the allowed return on investment. The revenue requirement is divided by the amount of sales in the test year to derive throughput based rates. In a rate case, test-year sales and operating costs are typically adjusted to reflect "normal" weather. This can be based on a model of future years, or it can be based on past years: test years based on forecasted experience are known as future test years, while test years based on prior financial performance are referred as historical test years. Regardless of the type of test year used, the resulting prices are what customers pay per unit of electricity or gas that they use until rates are reset with next rate case.

How does traditional rate regulation create a throughput incentive? While prices are based on test year information, after a rate case actual sales will almost always differ because the exact patterns of customer use are complex to predict: weather, changes in the economy, demographic shifts, new end-use technologies, additions or reductions in the number of customers, and many other factors can affect actual sales. As a result, it is highly likely that the utility will sell more or less electricity or gas than had been assumed for the test year during the rate case. However, fixed costs are likely to be predictable. In the energy sector, the cost of service tends to have a large component of fixed costs associated with investments like power plants, gas pipelines, and electric transmission lines. This makes it difficult, but not impossible, for the utility to increase profits by cutting costs[4]. Revenues are much easier to increase, which means that utilities have a strong incentive to increase revenues by increasing sales. For existing customers, sales growth may not require a great deal of new infrastructure and in these cases, the utility's fixed costs would not go up with increased sales[5]. In these cases, increases in sales volumes translate into increased revenues which in turn directly lead into increased profits. **In fact, some observers have noted that because of the link between profits and sales, a 1% increase in sales might lead to a 5% increase in profits (with corresponding decreases in profits when efficiency reduces sales)** (Harrington, 2007, 1994). Because the utility makes more money and profit by selling more electricity or gas, this structure could theoretically create a significant **disincentive for utilities to encourage their customers to lower consumption through energy efficiency.**

3. How is decoupling different?

Decoupling does not change the traditional rate case procedure but, in its simplest form, adds an automatic "true-up" mechanism that adjusts rates between rate cases based upon the over- or under-recovery of target revenues. As in the traditional rate case, a rate is set by determining the revenue requirement and dividing it by expected sales[6]. Then, on a regular basis, prices are re-computed to

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monopoly utilities, customers could be vulnerable to price exploitation. As a result, for over a century, prices have been regulated by State PUCs to recover the utilities' costs, while utilities have assumed an obligation to provide service to the public.

[4] What about variable costs? Even though utilities' fixed costs are high, they also see fluctuations in variable items such as purchased power and the cost of fuels like coal or natural gas. These items are, in part, covered in the rate set in a rate case, but unexpected costs are also covered through surcharges that are temporary in nature and do not involve going through a whole rate case. Fuel Adjustment Clauses are an important variable cost that is passed through directly to customers in most states. Decoupling is not applied to these variable components.

[5] For new customers, infrastructure costs may reflect regional patterns. In some regions of the country, adding new customers may require high additional infrastructure costs: connecting a building full of new gas customers in the urban areas of the Northeast may require a short new addition of pipe in an area with an existing distribution system. In other areas, adding new customers means adding costly new infrastructure, such as building long system additions to provide new gas service to rapidly-growing areas of the Southwest.

[6] In decoupling's simplest form, prices are adjusted to maintain a constant target revenue; however, in most applications of decoupling the target revenue is adjusted for changes in the customer base so that the revenue target varies with the number of customers, but not on the basis of how much electricity or gas the utility sells.

collect a target revenue based on actual sales volumes[7]. Decoupling mechanisms can be designed to be adjusted on a monthly or quarterly basis, or some other regular interval.

The end result is that utilities should no longer have an incentive to maximize their sales because the rate of return does not change within the revenue requirement. Nor is there a disincentive to promote efficiency.

Decoupling should have the effect of stabilizing the revenue stream of a utility because its revenues are no longer dependent on sales. If sales increase, rates drop in the next period; if sales decrease, rates increase to compensate. Under traditional rate regulation, there is little oversight of earnings between rate cases, and it may be years before rates are re-aligned with actual revenue requirements. Since decoupling adjusts actual revenues to align them with revenue requirements, its proponents argue that it **reduces regulatory lag.**

A hypothetical example of how decoupling might work:

During its rate case, Utility A determines it will have a $1 million revenue requirement to provide electricity service 25 million kilowatt hours (kWh) of electricity in a test year. Under the existing system, this means Utility A will charge $.04 per kWh[1].

If a successful energy efficiency program helped customers reduce overall consumption in by 1.5%, the utility would sell 375,000 fewer kWh, and its revenues would decline by $15,000. Under decoupling, prices would be adjusted to $.0406 per kWh to maintain the $1 million dollar allowed revenue recovery.

If a customer's rate goes up, their bill won't necessarily follow, as will be discussed later in the FAQ: the bill-reduction benefits of consuming less significantly outweigh the reduction in those benefits that is caused by rates being adjusted.

4. What is the relationship between decoupling and incentives for energy efficiency?

If utilities are required to promote energy efficiency programs, their revenues may be affected through a variety of mechanisms. Commissions can address these new costs by providing program cost recovery and shareholder incentives, as well as by addressing the throughput issue.

A great deal has been written about incentives for energy efficiency, which is a related but different discussion. **While it can remove disincentives for utilities to promote efficiency, decoupling is not designed to create an incentive for energy efficiency.** Furthermore, as discussed above, there are other methods that remove the throughput disincentive, although revenue decoupling may best balance the removal of utility disincentives to energy efficiency while preserving customer incentives to deploy energy efficiency.

Some decoupling proponents have argued that removing disincentives is not enough. They contend that the cost of efficiency programs should be included as part of the cost of service. Moreover, in order to make efficiency investments profitable when compared to other possible investments that the utility could make, such as power plants or transmission, performance incentives for efficiency would reward utilities that invest in successful programs by allowing them to earn an equivalent rate of return on those investments. **Conversely, some argue that incentives alone, without decoupling, are a better approach to driving energy efficiency.** They note that many utilities are doing little to promote additional sales of electricity and the increases are customer-driven. Furthermore, some who have investigated decoupling note that in many cases utility spending on efficiency is already effective, cost-effective and well-managed. (Connecticut DPUC, 2006, NASUCA 2007 Resolution). In addition, large customers have argued that they may already possess the means and incentives to enact energy efficiency measures, and that decoupling does little to create new opportunities for efficiency in these markets (ELCON 2006).

[7] The target revenue can be the same as that used in the last rate case, or it too can be adjusted over time by increasing or decreasing the average revenue per customer value. More information on alternatives to the Per-Customer method is included later in the FAQ.

Finally, **some argue that utilities are not the best providers of energy efficiency.** In this argument, utilities are organizations designed to deliver kilowatt hours and therms to their customers, and are ill-suited to champion products that "unsell" electricity or gas. Arguments have been made that taking utilities out of the efficiency businesses and having that function played by a State, quasi-State, or private sector entity is a preferable alternative to removing disincentives to their promoting efficiency (ELCON, 2006). In fact, numerous examples exist of successful efficiency programs being delivered by non-utility providers. However, some make the case that if utilities are required to examine efficiency as a resource comparable to supply (generation) and delivery (transmission) resources, this may create a perverse tension between the utility's least-cost resource planning processes and the financial interest of its shareholders (Costello, 2006) **In situations where the utility is recast as a provider of energy *services*, rather than a strict provider of kilowatt hours or therms, decoupling may help remove this tension** (Costello 2006, NAPEE, 2006).

Some proponents of decoupling also note that even if a the utility is taken out of the efficiency business and that function is played by a State, quasi-State, or the private sector, the problem of the effect of decreased sales on utility revenues due to energy efficiency and the consequent decreased likelihood of the utility receiving its authorized revenue requirement does not go away. In this argument, even if other entities are responsible for providing energy efficiency services, the same need for decoupling still exists.

Whether decoupling will in itself result in increased efficiency is still the subject of debate. While no major studies have been undertaken linking decoupling directly to increased efficiency activities at utilities, anecdotally energy efficiency advocates point to strong increases in efficiency spending concurrent with decoupling undertaken by utilities, in particular in the electricity sector, with examples such as Puget Energy and PacifiCorp increasing activity and spending under decoupling and experiencing drop-offs in efficiency spending when decoupling was rescinded (NRDC, 2001). However, a closer look at Consolidated Edison's efficiency spending while using decoupling (1993-1997) tells a different story: in this time period, efficiency spending increased by all the regulated utilities in New York, whether they used decoupling or not.

Decoupling is one of three major approaches for dealing with the throughput issue:

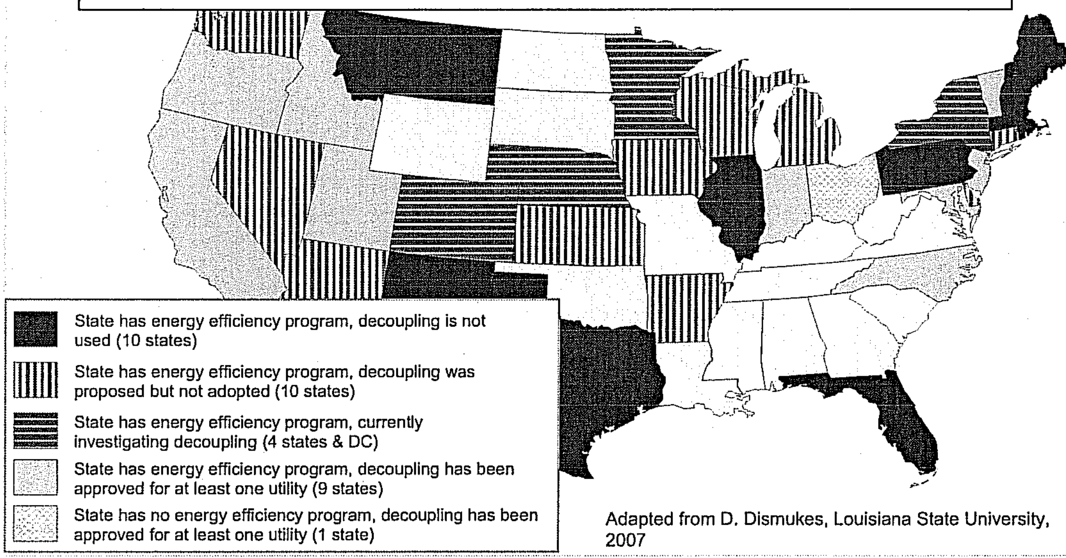
1. Full or Per-Customer Adjustment Revenue Decoupling. This is the mechanism that has been discussed so far. It adjusts utility revenues for any deviation between expected and actual sales regardless of the reason for the deviation. A variation of the full sales adjustment clause is the per-customer method, which sets a per-customer revenue target. In the years following a rate case, allowed revenues are adjusted for increases or decreases in the number of customers. In addition to Sales-Revenue Decoupling, another variation called "Sales-Margin Decoupling" separates margin recovery from sales by setting a margin-per-customer target. Any of these can use a forecast of revenue or use historical years to create a test year from which to derive the revenue target.

2. Net Lost Revenue Recovery, Lost Revenue Adjustments, or Conservation and Load Management Adjustment Clauses. This mechanism adjusts net changes in revenues only for sales deviations that can be proven or demonstrated to have resulted from conservation and load- management programs. Revenues continue to be susceptible to variations in sales from all other causes. While favored by some observers, this mechanism has also been criticized as being less effective than decoupling because it does not remove the sales incentive, can require much more sophisticated monitoring and evaluation, and could allow utilities to recover costs for expenditures on programs that do not result in increased efficiency.

3. Straight-Fixed Variable Rate Design. This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.

5. Is decoupling new? What States have implemented a decoupling mechanism? Although only a few States have adopted it, decoupling itself is not a new idea; in fact, it has been implemented in some parts of the country for decades. California has the most experience with decoupling, having operated such a mechanism in the electricity sector from 1981 through 1996, and just recently restarting the system in the State. Others that have implemented decoupling are detailed on the map below.

Ill. 1: States That Have Considered Electricity or Gas Decoupling



Note that some of these States have recently adopted decoupling (like Idaho), others have been using it for some time (e.g. Maryland), some have considered and rejected it (e.g. Connecticut and Arizona), some have discontinued using it (e.g. Maine) and others have discontinued, and then returned to using decoupling (e.g. California).

6. Will decoupling raise customer bills? Because of the adjustment mechanism, some designs of decoupling could potentially result **in more frequent up-and-down changes in rates** for consumers. However, by increasing the frequency with which rates are brought into alignment with the PUC-approved revenue requirement, the changes should be smaller, and the likelihood of a sharp hike or decline in rates (common in traditional rate cases) may be reduced.

Decoupling could create higher bills for customers who do not participate in efficiency programs, although proponents of decoupling argue that these reductions would be diluted across a wide enough customer base to render any increases nearly unnoticeable. This may not occur, however, if decoupling is applied to a small customer class, where the effect of conservation in rates may be more pronounced.

Of special concern is the impact on low-income users, who would be least able to respond to changes in bills. Decoupling proponents note that this heightens the profile of targeted energy efficiency programs that serve these customers, lowering their bills without impacting utility revenues.

Others with concerns about decoupling comment that **unless it is designed to avoid doing so, decoupling could create unfair transfers between customer classes.** For example, if transfers between classes are allowed, commercial and industrial customers who are ineligible to participate in residential efficiency programs might see higher rates resulting from those programs.

Will rates go up for customers who implement energy efficiency? **Because they are consuming less, these customers' bills will go down.** Rates for all customers under a decoupling mechanism may increase in the short run when efficiency reduces sales because the utilities have to cover their costs and necessary returns on investments. In the example above, if the utility is selling fewer kWh of electricity, but its revenue requirement remains the same, each kWh will need to cover a greater share of the cost of service and will need to be priced higher. However, **any rate increases would be small, particularly when compared to the benefits for customers engaging in conservation**, and some analysis suggests the systemwide benefits from increased efficiency may outweigh costs for all customers[8]. Moreover, if efficiency programs cut sales without lessening fixed costs, under traditional regulation rate calculations would reflect that in the next rate case anyway.

Will decoupling result in rampant rate instability? In the experience of some States, such as New York, California, and Oregon, fluctuations in rates under decoupling were less than 1% for ratepayers in most years, and never exceeded 4%. **Customers may already see significantly greater rate variability through surcharges for fuel and purchased power.** Moreover, rate variability under decoupling may depend on a number of factors, including the program design, but also including other factors, like economic and weather variability. These examples and issues are discussed more in the section on "Does Decoupling Transfer Risk to Customers" section, later in the FAQ.

In theory, decoupling adjusts rates to more closely maintain the underlying relationship between prices and revenue requirements over time. **This should lessen the likelihood of large-scale "rate shocks" in the next rate case** (though this may vary based on the frequency of the reconciliation.) There are other mechanisms that can be put into place to reduce the frequency of large rate adjustments, including using a balancing account, applying a "Rate-Adjustment Band," or including a course-correction mechanism. These are also discussed in more detail in the "Off-Ramps & Adjustments" section later in the FAQ.

How is decoupling different from having more frequent rate cases? Decoupling does not change the rate base and rate of return decided in a rate case. It is also worth remembering that **decoupling affects revenue only between rate cases**: at the next rate case, the base rates are reset, using the mechanisms familiar to regulators in traditional cost of service regulation. Some have argued that a utility would not need decoupling if it regularly entered into rate cases. Decoupling proponents have replied that it is a mechanism used to make utilities indifferent to sales as a function of profits, and that regular rate cases remain essential but are not the same thing. Moreover, **rate cases are expensive and time consuming, and most consider it impractical to revise base rates with the frequency proposed for adjustments under decoupling.** In the 1990s, Wisconsin revised its base rates each year but discarded this approach because of the effort involved and the less-predictable incentive structure created for utilities by the short period between rate cases.[9]

7. Does decoupling transfer risk from the utilities to customers?

Efficiency is not the only variable that can affect sales. For example, an unexpectedly hot summer can increase sales, or an economic downturn can drive commercial customers out of business and reduce sales. Under traditional regulation,

[8] Rates may go up to restore the lost distribution revenue, but utility bills could also drop as cost-effective efficiency offsets the need to purchase more expensive kilowatt-hours or therms. In this case, the utility would be able to sell less electricity or gas with no corresponding loss of revenue, while customers would benefit by avoiding the costs of the electricity or gas that is not needed.

[9] Some commenters have raised an objection to decoupling, making the case that **it violates a regulatory principle against single-issue ratemaking.** They note that decoupling focuses on efficiency and ignores other sources of costs increases & decreases that are considered in a traditional rate case that may counterbalance changes in rates from efficiency. Decoupling proponents argue that with normalization mechanisms, these other factors are taken into account and that decoupling simply raises the profile of demand-side management's effect on revenue. On a regulatory theory level, they assert that decoupling meets the requirements for a "tracker", a ratemaking instrument designed to take into account specific issues that have effects on rates.

risk is borne by utilities (and shared with customers via rate pass-throughs) for a number of factors that can affect sales that are beyond the utility's control. In both cases, the utility's fixed costs would remain the same, and changes in revenues would not be related to changes in underlying costs for the utility to provide service. Some argue that because decoupling constrains the utility's revenues to "normal weather" levels and economic trends, theoretically the utility's business and weather risk conveyed in rates for fixed costs is eliminated entirely. They have raised a concern that this represents a shift of risk from the utility to customers.

One of the main reasons some Public Utility Commissions are reluctant to explore decoupling is **the concern that revenues could remain stable for utilities even if weather or business factors cause customer rates to increase** or to incur large balances in deferral accounts, illustrated by Maine's experience in the 1990's (see box, this page.)

Maine's decoupling experience

If the impact of energy efficiency is not adequately anticipated during the rate case, sales will be lower than expected and rates will go up. But rates could also go up if sales are lower because of a mild summer or an economic downturn. This created a crisis in Maine, which had pioneered a decoupled rate design with Central Maine Power in 1991 but faced a recession in the early 1990s. The recession resulted in lower electricity sales, and the decoupling adjustments kicked in to reflect pre-recession target revenues, causing rates to go up when customers were least prepared to pay them. This sudden and sharp downturn in the Maine economy reduced consumption to a much greater degree than the utility's efficiency efforts, and decoupling became increasingly viewed as a mechanism that was shifting the economic impact of the recession from the utility to consumers, rather than providing the intended energy efficiency and conservation incentive impact. By 1993, deferrals accumulated by the adjustment mechanism had reached $52 million, and the PUC and the utility agreed to end the experiment. (Maine PUC, 2004)

It should be noted that while decoupling is often cited as the culprit here, in fact the economic downturn was the problem. Traditional regulation would have eventually yielded rate changes through a traditional rate case and the resulting price increases would have reflected the same economic circumstances.

Proponents assert that decoupling can use normalization mechanisms to eliminate these risks or assign them appropriately, and some State experiences suggest that decoupling may not shift any risk to consumers. California's Electric Rate Adjustment Mechanism (or ERAM, which operated between 1981 and 1996) adjusted the target revenue based on factors affecting the cost of service which were beyond the utility's control, such as inflation or weather. A 1994 analysis of California's program found that "the record in California indicates that the risk-shifting accounted for by ERAM is small or non-existent and, in any case, ERAM has **contributed far less to rate volatility than have other adjustments to rates, such as the fuel-adjustment clause.**" The analysis concluded that California's decoupling created lower risks for consumers (that they could be faced with unexpected bill increases) and profit risk reductions to utilities (who could be assured of fixed cost recovery, even in the face of efficiency improvements) (Eto et al, 1994).

The authors went further, undertaking a statistical analysis to calculate the dollar value of risk from shifts in weather and economic activity under decoupling in a hypothetical case. Based on these estimates, the authors concluded that with the normalization procedures used in this decoupling structure, the quantitative risk burden transferred to consumers would be one-fifth of one percent of electricity revenues from each of those customers – **a $2 risk-shifting burden on a $1200 annual bill.** (Eto et al, 1994)

Consolidated Edison in New York had a similar mechanism in place from 1993 to 1997. The rate variability under this system suggests that rate impacts were minimal here as well. In 1993, a shortfall with just under 3% effect on rates was collected from customers, and rates went up. For the next four years, over-collections occurred, and rates went down just under 1% per year. (NRDC, 2001)

Under some decoupling mechanisms (such as some of those implemented in the Pacific Northwest) **the revenue target can be adjusted to accommodate unexpected weather patterns.** Northwest Natural Gas in Oregon, for example, subtracts an estimated sales impact for weather from its periodic adjustment. A more complex, but comprehensive, approach is called "statistical recoupling," in which weather, fuel costs, economic changes, and the number of customers is modeled, and that model is used to determine the revenue target. (Eric Hirst, 1993)

Some have raised a concern about statistical recoupling and other economic and weather normalization methods, commenting that **adding these systems makes decoupling so complicated that its administrative and accounting burdens can outweigh its benefits, or that it can be manipulated to allow "over-earning" by utilities.** Some proponents of decoupling respond that weather and economic risk is already shared with consumers through rates, and that the traditional rate case structure simply delays accounting for these costs (or revenues) until the next rate case. Moreover, weather normalization computations of some type are universally included in the determination of the revenue requirement in each rate case, with about half of the States allowing normalization adjustments between rate cases.

8. Will decoupling discourage utility companies from cutting their costs? No. Concerns have been raised that to the extent that utilities become isolated from possible changes in revenues, they have little motivation to lower their costs in order to meet their revenue requirement. However, **because decoupling affects only revenues, the utility remains at risk for any changes in costs.** Decoupling proponents argue that the rate case mechanism underlying decoupling continues to ensure that utilities strive to control fixed costs that cannot easily be reduced to the greatest degree possible. They note that performance indicators can also be included to identify when cost reductions have arisen from a decreased level of service rather than from gains in efficiency.

One solution pioneered by New Jersey in its Conservation Incentive Program allows gas utilities to adjust their rates to account for changes in consumption resulting from efficiency efforts, but **the adjustment is capped at the amount of verifiable supply cost reductions achieved by the utility.** (Fox et al, 2007)

9. Can a utility increase its profitability with decoupling? Yes. With a per-customer form of decoupling, utilities receive their revenue from customers that cover the fixed costs of service, and that cost of service includes a rate of return that contributes to profits. In other words, instead of making more money by selling more kilowatt hours or therms, utilities would make more money when they increase their customer base, regardless of whether there is a corresponding increase in sales. Alternatively, **if the utility can find a way to improve its efficiency and thereby lower its cost of service without decreasing its number of customers, it has an opportunity to improve its bottom line.** Under decoupling, the primary driver for profitability growth is the addition of new customers, especially in areas where the addition of new customers does not carry high infrastructure addition costs. In these cases, the customers who would bring the greatest potential profitability to a utility are those who are the most energy efficient, since they can be added with the lowest incremental addition to the utility's cost of service[10].

As noted before, decoupling can reduce risk for the utility by ensuring that its revenues and return on investment remain stable. **A lower risk-profile should make the cost of capital lower for the utility[11].** For investors, this can be realized through an increase in the utility's debt/equity ratio, a decrease in the return on equity, improved debt ratings and credit requirements.

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[10] Again, this may reflect differences between regions and sectors: where unexpectedly adding new customers brings significant new operating costs not anticipated in the rate case, the outcome may be different and, as would occur in traditional ratemaking, could trigger a rate case.

[11] Illustrating this, one utility has proposed a lower target return as part of its decoupling proposals in MD and DC.

10. Is decoupling different for gas than it is for electricity? Decoupling is fundamentally the same for both gas and electric utilities. They both share similar cost structures which are dominated by high fixed costs. However, the two industries are facing different underlying trends in customer revenues. While the gas industry generally faces declining average revenues per customer over time, the electric industry is experiencing increasing average revenues per customer. As a result, gas utilities tend to face revenue and profit erosion between rate cases, while electric utilities garner increasing revenue and profits between rate cases. Decoupling has the effect of eliminating most of these effects. As a result, gas utilities have tended to be more open to implementing decoupling than have electric utilities. However, a small but growing number of electric utilities have either implemented, requested or are investigating decoupling. Some have suggested that this could be partly in response to longer-term expectation about capital expenditures and environmental costs. Energy efficiency may be a cost-effective way to avoid potential future risks such as carbon regulation. In addition, recent policy initiatives at both the federal and State level have embraced energy efficiency as a high priority resource[12]. If energy efficiency is deployed more widely in the future, electric utilities may become more interested in decoupling.

What off-ramps and adjustments are possible?

Decoupling is a substantial departure from traditional rate-making, and may be new to States and utilities. Therefore it makes sense to approach implementation with caution, considering corrective mechanisms to ensure that the change in structure has the intended effects and avoids harmful unintended consequences. Some of the mechanisms that have been considered are:

Balancing Accounts: Depending on the frequency of adjustments, a separate account can be established and used to track and accumulate over- or under-collections, in order to defer the adjustment and "smooth out" unusual spikes in rates. Typically this kind of account is used when adjustments are scheduled to occur less frequently.

Rate banding: As discussed above, this triggers the periodic adjustment to rates when the changes in revenue would result in a change within a certain percentage. If the rate band were set to 10% over or under the target rate, only changes less than 10% would trigger the adjustment. Outside the band, a new rate case would be triggered.

Revenue banding / shared earnings: In order to prevent unintended windfalls or shortfalls by the utility, earnings greater or less than certain limits can be shared with customers. For example, if an earnings band is set to 5% of return on equity compared to the allowed return found in the most recent rate case, earnings or shortfalls greater than 5% would be shared with consumers on a proportional basis though rates. This can also be computed on the basis of revenue changes, which avoids the complication (and potential litigation) of computing returns on equity.

Course corrections for single events, changes in industrial customers or activity: The addition of a new customer among large users, such as an industrial customer, or large change in the activity of a customer--a factory adding a new shift, for example--can have a disproportionate effect on rates for other customers in that class. In these cases, language allowing for adjustments that take special circumstances into account can help avoid unexpected rate shifts.

11. Would decoupling work the same for regulated and deregulated States? Broadly speaking, utilities in deregulated markets appear to be more vulnerable to revenue losses incurred by decreased sales from efficiency than utilities in vertically-integrated markets. In the 2006 report on the National Action Plan For Energy Efficiency, the authors note that "once divested of a generation plant, the

[12] For more on energy efficiency as a high priority resource, see the National Council on Electricity Policy's study for DOE's Section 139 Report To Congress (2006) and the National Action Plan on Energy Efficiency, (2006).

distribution utility is a smaller company (in terms of total rate base and capitalization), and fluctuations in throughput and earnings have a relatively larger impact on return." (NAPEE, 2006)

In States where distribution utilities purchase most or all of their commodities from a wholesale market, decoupling would be integrated into the largely-fixed cost structure of the distribution utilities. In States with vertically integrated utilities, decoupling can also be applied, but care must be taken in the rate case context to accurately separate fixed costs from variable costs, applying the decoupling adjustments only to the fixed costs. In all other respects, decoupling is applied in the same manner in both types of situations.

12. Where can I find out more? This FAQ was authored by Miles Keogh of NARUC's Grants & Research staff with funding from the U.S. Environmental Protection Agency. It was developed through research, interviews, and input from a number of parties, including the staffs of the New Jersey Board of Public Utilities, Massachusetts Department of Public Utilities, Arizona Corporation Commission, US Environmental Protection Agency, North Carolina Attorney General's Office, and Public Service Commission of the District of Columbia. Oversight was provided by Commissioner Rick Morgan of the District of Columbia PSC, and technical assistance came from Wayne Shirley of the Regulatory Assistance Project. More resources on decoupling are included below.

RESOURCES

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3. The National Action Plan on Energy Efficiency, US EPA / US DOE, Chapter 2, July 2006 http://www.epa.gov/cleanrgy/pdf/napee/napee_chap2.pdf
4. U.S. Environmental Protection Agency (US EPA) "Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States", (Section 6.2) June 2006. http://www.epa.gov/cleanenergy/pdf/gta/guide_action_chap6_s2.pdf
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"All forms of regulation provide incentives. Incentives, information asymmetries, and principal-agent problems all affect company performance. Cost-of-service (rate-of-return) regulation provides an opportunity to cover costs. It also provides companies with an incentive to over/under incest in plant, inflate costs, and cross-subsidize. Regulators generally try to remedy these perverse incentives though regulatory lag, sliding scales, and efficiency audits/reviews. Price cap regulation provides companies with incentives to cut costs. It also dampens the effects of cost information asymmetries between companies and regulators. Service quality and infrastructure development may suffer. Yardstick regulation promotes cost-containment, and dampens the effects of cost information asymmetries between companies and regulators. However, developing appropriate yardsticks is resource intensive. Performance-based regulation utilizes targets to incent the utility. Good performance measures should be accurately observed and verifiable, should reflect the utilities' efforts, and should be structured to reduce the impact of random variation. Franchise regulation represents another approach – where the low-price bidder becomes the supplier. Carefully designed incentive plans can result in benefits to both supplier and consumers."

▢ Boonin, David Magnus (2008). *A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements.* National Regulatory Research Institute 08-08 (July). [link]

"The search for low-carbon electricity resources intensifies as more attention is paid to greenhouse gases (GHG). If energy efficiency in the electricity sector is to be a major resource in the battle against greenhouse gases, utility regulators need to create an environment that enables and encourages cost-effective energy efficiency. This paper addresses one overlooked method of decoupling a utility's income from sales and offers a complementary set of price signals to consumers that are designed to enhance energy efficiency. The decoupling strategy is a Straight Fixed Variable (SFV) rate design, and the customer price signal is a Revenue-Neutral Energy Efficiency Feebate (REEF)."

▢ Brennan, Timothy J. (2008). "'Night of the Living Dead' or 'Back to the Future'? Electric Decoupling, Reviving Rate-of-Return Regulation and Energy Efficiency." Washington, DC: Resources for the Future Discussion Paper No. 08-27 (August). [link]

"The distribution grid for delivering electricity to the user has been paid for as part of the charge per kilowatt-hour that covers the cost of the energy itself. Conservation advocates have promoted the adoption of policies that "decouple" electric distribution company revenues or profits from how much electricity goes through the lines. Their motivation is that usage-based pricing leads utilities to encourage use and discourages conservation. Because decoupling divorces profits from conduct, it runs against the dominant finding in regulatory economics

in the last twenty years—that incentive-based regulation outperforms rate-of-return. Even if distribution costs are independent of use, some usage charges can be efficient. Price-cap regulation may distort utility incentives to inform consumers about energy efficiency—getting more performance from less electricity. Utilities will subsidize efficiency investments, but only when prices are too low. Justifying policies to subsidize energy efficiency requires either prices that are too low or consumers who are ignorant."

Carter, Sheryl (2001). "Breaking the Consumption Habit Ratemaking for Efficient Resource Decisions," *The Electricity Journal* 14: 66-74. [link]

"Traditional rate design, which ties utilities' financial health directly to the volume of commodity sales, invites an exclusive focus on more traditional distribution and generation capacity expansions – often in direct conflict with other important societal objectives. This antiquated design must be changed to reward utilities' for making more economically and environmentally efficient resource decisions. Adoption of these ratemaking reforms is critical to the effective integration of promising alternatives such as distributed resources."

Cavanagh, R. C. (1989). "Global Warming and Least-Cost Energy Planning," *Annual Review of Energy* 14: 343-73. [link]

"This article contends that US energy policy has been working to increase, rather than forestall, the danger of global warming. In particular, recent trends toward deregulation of the energy sector are grossly insufficient as solutions to the problem, although not necessarily inconsistent with them. The article outlines a way to organize urgent US and international energy policy reforms, drawing on the experience of certain state utility regulators with an approach called 'least-cost energy planning.' Least-cost planning recognizes improvements in the efficiency of energy use as a major source of additional energy supplies, and seeks fair competition for energy investment dollars between conservation measures and production facilities."

Cavanagh, Ralph (2006). "Rebuttal Testimony of Ralph Cavanagh for Questar Gas," before the Public Service Commission of Utah. Docket No. 05-057-T01 (August). [link]

"My testimony rebuts challenges in this proceeding to the Company's proposal to institute modest annual rate true-ups, or "decoupling," in order to remove a strong disincentive to Company investments and advocacy in support of energy efficiency improvements,"

Center for Energy, Economic and Environmental Policy (2005). "Decoupling White Paper #1," Rutgers University (October). [link]

"There is no single definition of decoupling or method of achieving its goals. In the most narrow sense, decoupling could retain a cost-of-service basis but severe the link the between a utility's revenues and its sales. The utility would recover its prudently incurred costs but the recovery of its fixed costs would be independent of its throughput. In a broader sense, decoupling could include incentives and penalty mechanisms that reward and penalize a utility based on its performance. Not only would the link between throughput and revenues be decoupled, but also the link between costs and revenues would be decoupled."

□ Costello, Kenneth (2006). "The 'Great Debate' Over Revenue Decoupling," at the 2006 Mid-America Regulatory Conference, Columbus, Ohio (June). [link]

"In regulatory proceedings, groups have presented several arguments on both sides of the RD debate. Applying longstanding ratemaking principles and regulatory objectives, RD scores well in some aspects while not so well in others."

□ Costello, Kenneth (2006). "Obstacles to Revenue Decoupling for Gas Utilities," at the Workshop on Aligning Regulatory Incentives with Demand-Side Resources, San Francisco (August). [link]

"Important elements needed to get broad acceptance of RD: (1) commitment by a utility to promoting energy efficiency, (2) demonstration of benefits to consumers, or at least no harm to consumers, and (3) consumer/public education."

□ Costello, Kenneth (2007). "Revenue Decoupling for Natural Gas Utilities," at the Mid-Atlantic Conference of Regulatory Utilities Commissioners, Williamsburg, Virginia (June). [link]

"Cogent arguments, in support of advancing specific regulatory objectives, presented before state commissions on both sides of the RD debate. Some of the arguments, however, are feeble (or even foolish), and state commissions should immediately weed them out."

□ Dismukes, David E. (2007). "Regulatory Issues for Consumer Advocates in Rate Design, Incentives and Energy Efficiency," for the National Association of State Utility Consumer Advocates (June). [link]

"The commodity share of overall natural gas rate has increased over recent years. Yet despite high prices, and decreases in use per customer, overall DNG revenues per customer are at close to historic highs."

□ Electricity Consumers Resource Counsel (2007). *Revenue Decoupling.* Washington DC: ECRC (January). [link]

"ELCON members are strong supporters of energy efficiency and are world-class practitioners of innovative technologies that reduce their energy costs to improve their competitiveness. But ELCON strongly opposes decoupling because it disrupts and distorts the utility core business functions and is not a particularly effective way of promoting energy efficiency or anything of benefit to customers. Time and time again decoupling has been tried in several states, only to be suspended because it unduly interferes with the overall regulatory process."

□ Eto, Joseph, et. al. (1994). *The Theory and Practice of Decoupling.* Berkley, CA: Lawrence Berkley Lab, LBL-34555 (January). [link]

"Decoupling revenues from sales is an important regulatory option under consideration by regulators seeking to transform utilities from sellers of a least-cost energy commodity to providers of least-cost energy services. This report examines decoupling from three perspectives. First, we consider threshold issues for decoupling, including characterization of the ratemaking practices addressed by decoupling which make incremental sales profitable to utilities, the role of rate case frequency in limiting the consequences of this incentive, and finally the existence of other incentives to sell electricity, which are not addressed by decoupling. Second, we examine the operation and performance of decoupling, including the mechanics of decoupling as a between-rate-case

modification to the traditional ratemaking process, the ability of revenue-per-customer decoupling versus traditional ratemaking to recover nonfuel costs accurately, and a comparison of the profit implications of various decoupling approaches. Third, we review the rate impacts of decoupling for California's electric utilities, which have had the longest experience with decoupling."

- Florida Public Service Commission (2008). "Report to the Legislature on Utility Revenue Decoupling" (December). [link]

"Altogether, stronger mandates for conservation, the administrative complexity of decoupling mechanisms currently implemented in other states, and the FPC revenue decoupling experiment support the position that Florida is already paving a path toward the objectives of decoupling without incurring the cost and difficulties associated with design, implementation and maintenance of a specific decoupling mechanism. This consideration must be weighed with the fact that a significant portion of revenues (including an increasing level of capital costs) are currently being recovered through clauses, achieving a similar effect as would be achieved with a decoupling mechanism. The greater the emphasis placed on achieving mandatory energy efficiency goals, the lesser the impact that would be gained by implementing a decoupling mechanism."

- Graniere, Robert and Andrew Cooley (1994). *Decoupling and Public Utility Regulation.* Columbus, Ohio: The National Regulatory Research Institute 94-14 (August). [link]

"The purpose of the report is to study the relationship between decoupling and public utilities regulation. Decoupling is a regulatory mechanism whose design promotes demand-side management (DSM) by breaking the linkage that ties the utility's financial position (that is, revenues or profits) in any year to its actual sales in that year. However, a decoupling mechanism has a particularly unique way of breaking these ties. Any mechanism of this type makes the utility whole regardless of the source of the revenue or profit losses. Consequently, the utility is insulated from the financial effects of weather fluctuations, competition, misforecasts of ratepayer growth, unanticipated movements in the business cycle, and DSM."

- Hansen, Daniel G. (2007). *A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation.* Madison, WI: Christensen Associates Energy Consulting, LLC (May). [link]

"A potentially important outcome of traditional ratemaking is that the utility has a disincentive to promote conservation and energy efficiency. Several methods have been proposed to reduce, eliminate, or reverse this incentive problem. Decoupling mechanisms attempt to solve the incentive problem by adjusting rates to allow the utility to recover deviations between actual and allowed revenues, where various adjustments may be made to allow revenues depending upon the specific mechanism. Because the utility recovers its fixed costs regardless of the level of actual sales, the disincentive to promote conservation and energy efficiency is removed."

- Hill, Lawrence (1995). *A Primer on Incentive Regulation for Electric Utilities.* Oak Ridge, TN: Oak Ridge National Laboratory ORNL/CON-422 (October). [link]

"In contemplating a regulatory approach, the challenge for regulators is to develop a model that provides incentives for utilities to engage in socially desirable behavior. In this primer, we provide guidance on this process by discussing (1) various models of economic regulation, (2) problems implementing these models, and (3) the types of incentives that various models of regulation provide electric utilities. We address five regulatory models in depth. They include cost-of-service regulation in which prudently incurred costs are reflected dollar-for-dollar in rates and four performance-based models: (1) price-cap regulation, in which ceilings are placed on the average price that a utility can charge its customers; (2) revenue-cap regulation, in which a ceiling is placed on revenues; (3) rate-of-return bandwidth regulation, in which a utility's rates are adjusted if earnings fall outside a 'band' around equity returns; and (4) targeted incentives, in which a utility is given incentives to improve specific components of its operations. The primary difference between cost-of-service and performance-based approaches is the latter sever the tie between costs and prices. A sixth, 'mixed approach' combines two or more of the five basic ones. In the recent past, a common mixed approach has been to combine targeted incentives with cost-of-service regulation. A common example is utilities that are subject to cost-of-service regulation are given added incentives to increase the efficiency of troubled electric-generating units."

- Hirst, Eric. (1993). *Statistical Recoupling: A New Way to Break the Link Between Electric-Utility Sales and Revenues.* Oak Ridge, TN: Oak Ridge National Laboratory ORNL/CON-372 (September). [link]

"Statistical recoupling uses statistical models that explain retail electricity sales as functions of the number of utility customers, winter and summer weather, the condition of the local economy, electricity price, and perhaps a few other key variables. These models, along with the actual values of the explanatory variables, are used to estimate 'allowed' electricity sales and revenues in future years. For example, a utility might use quarterly data from 1980 through 1992 to estimate the SR models. The models would then be used to determine allowed revenues for 1993, 1994, and 1995"

- Hirst, Eric, et al. (1994). "Three Ways to Decouple Electric-Utility Revenues from Sales," *Electricity Journal* 7, 38-47. [link]

"Decoupling first breaks the link between utility revenues and kWh sales. It then recouples revenues to something else, such as growth in the number of customers, the determinants of changes in fixed costs, or the determinants of changes in electricity use. This paper explains and compares three forms of decoupling: revenue-per-customer (RPC) decoupling, RPC decoupling with a factor that allows for changes in elasticity use per customer, and statistical recoupling. We use data from five utilities to see how the three methods perform in terms of electricity-price volatility and ease of implementation. We discuss the strengths and limitations of each approach, emphasizing the tradeoff between simplicity and price stability."

- Kihm, Steve (2008). *A Financial Framework for Analyzing Incentives and Disincentives for Wisconsin Utilities to Promote Energy Efficiency.* Madison, WI: The Energy Center of Wisconsin (September).

"This paper provides a framework for analysis of the incentive and disincentives for utilities to promote energy efficiency. While we draw conclusions where they are analytically obvious, we make no policy recommendations. As such, the paper provides a structure that may help policy makers in assessing the reasonableness of policy options related to the impact of energy efficiency efforts on utilities. While our framework is broad-based in nature, we focus the analysis on issues specific to Wisconsin. The thrust is to present a basic structure for analysis that can accommodate the Wisconsin experience."

- Kihm, Steven. "When Revenue Decoupling Will Work . . . And When It Won't," *The Electricity Journal* 22(8), 19-28.

"As long as the Averch–Johnson effect continues to hold –which it likely will for many utilities – it may be difficult to persuade such utilities to abandon large-scale supply-side construction plans in favor of aggressive promotion of energy efficiency, even if a decoupling mechanism is in place."

Kushler, Mark, et al. (2006). *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives.* Washington, DC: American Counsel for Energy-Efficient Economy U061 (October). [link]

"This report examines recent experience with two key regulatory approaches to overcome these structural disincentives: (1) 'decoupling' of utility revenues and profits though periodic 'tune-up' of actual to projected sales; and (2) providing shareholder 'performance incentives' for achieving energy efficiency program objectives. These basic concepts are not new. In the 1980s and 1990s during the era of integrated resource planning' a number of states enacted such policies. However, the advent of the utility restructuring movement greatly diminished interest in such policies and regulations; most of them were dropped in the mid- to late 1990s. The growing need for energy efficiency as a resource to help meet utility system needs has renewed interest in these regulatory approaches. Our review of these recent experiences includes case studies of states or individual utilities where either decoupling or shareholder performance incentives have been enacted."

Lazar, Jim (2008). *Decoupling Impacts on the Cost of Capital.* Regulatory Assistance Project for the Minnesota Public Utilities Commission (April). [link]

"The investor receives the same return, more stable earnings, and a lower business risk profile. The consumer receives a lower revenue requirement. If weather decoupling is done in real-time (every billing cycle), the consumer also receives a lower bill in cold years, when bills are most difficult to pay."

Lesh, Pamela, G. (2009). *Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling.* Graceful Systems LLC (June). [link]

"This report compiles the rate impact experience during this decade with decoupling of retail gas and electric utility revenues from sales volumes and provides, along with this, information on relevant order numbers, statutes, mechanism descriptions, and implementing tariffs. Sources included utility and state regulatory commission websites, the American Gas Association and the Edison Electric Institute, and, in a few cases, helpful utilities. Immediately below is a brief explanation of 'decoupling' as used in this report, followed by a summary of the findings and a short description of methodology. The report concludes with observations about utility ratemaking."

Maine Public Utilities Commission (2004). "Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability," Report to the State Utilities and Energy Committee (February). [link]

"In broad outline, the Commission has concluded that the incentives utilities currently have under rate cap regulation to increase sales, although magnified to some degree, are similar in kind to the incentives they had under more traditional regulation. Moreover, it does not appear that utilities currently acting on these incentives have a significant opportunity to blunt the effectiveness of current efficiency and conservation programs in Maine, especially now that those programs have been removed from utility control. Finally, while there are a number of tools available to the Legislature and the Commission that could to some degree lessen the remaining utility incentives to frustrate conservation efforts, these tools are likely to have ancillary consequences that could, in the Commission's view, create substantial adverse effects."

🗋 McCarthy, Kevin E. (2009). "Electric Rate Decoupling in Other States," Connecticut General Assembly Office of Legislative Research Report (January). [link]

"Under current rate-making practices in most states, the vast majority of a utility company's revenues are tied to its sales. Advocates of decoupling argue that this creates a financial disincentive for companies to promote conservation programs and may increase rates by increasing uncertainty that the company will recover its allowed costs. On the other hand, people who are skeptical of decoupling believe that (1) the companies have been effective in promoting conservation without using this approach, (2) decreases in sales can be the result of factors unrelated to conservation, and (3) decoupling is inconsistent with established utility rate-making principles."

🗋 Meehan, Eugene T. and Wayne P. Olson (2006). *Distributed Resources: Incentives.* NERA Economic Consulting (April). [link]

"The primary focus of this white paper is to set forth for consideration several workable models for financial incentives that would encourage utilities to play an appropriate role in efficient DR deployment and operation. These proposals are necessarily tentative in nature. The very nature of DR makes it very difficult to craft robust DR incentive schemes that can work well in a variety of circumstances. The great variety of historical and regulatory environments may result in irreducible differences between utilities and across jurisdictions by dramatically changing the cost/benefit analysis for each type of DR program. Care must be taken in ensuring that the unique circumstances in a particular jurisdiction are recognized. This paper specifically addresses DR in a restructured environment, since implementing DR in the new electricity markets poses a novel and important challenge."

🗋 Moskovitz, David, et. al. (1992). *Decoupling vs. Lost Revenues: Regulatory Considerations.* Gardiner, ME: Regulatory Assistance Project (May). [link]

"Much of the effort to align utility shareholders' financial interests with the goals of least cost planning has focused on the removal of the potent disincentives to energy efficiency created by the current rate setting process. Decoupling and lost revenue recovery are the two general approaches used to eliminate the disincentives. This paper discusses the important characteristics and distinctions between the two options."

🗋 National Association of Regulatory Utility Commissioners (2007). *Decoupling for Electric and Gas Utilities: FAQ.* Washington, DC: NARUC Grants and Research Department (September). [link]

"State Public Utility Commissions around the country are expressing increasing interest in energy efficiency as an energy resource. However, traditional regulation may lead to unintended disincentives for the utility promotion of end-use efficiency because revenues are directly tied to the throughput of electricity and gas sold. To counter this "throughput disincentive," a number of States are considering alternative approaches intended to align their utilities' financial interests with the delivery of cost-effective energy efficiency programs. "Decoupling" is a term more are hearing as a mechanism that may remove throughput disincentives for utilities to promote energy efficiency without adversely affecting their revenues."

🗋 Perkins, John R. (2007). "Policy Options for Energy Efficiency Programs: Decoupling, Incentives and Third-Party Administrators," at NARUC Summer Meeting, New York (July). [link]

"Tension between energy efficiency and natural gas utilities' opportunity to earn authorized rate of return 'does not appear to be a substantial problem in Iowa.' The data does not show a direct correlation between IOU net operating income and declining customer usage as a result of energy efficiency programs"

🗋 Reddy, Amulya K.N. (1991). "Barriers to Improvements in Energy Technology," *Energy Policy* 19, 953-961. [link]

"[T]he paper discusses the typology of barriers, explores their origin and suggests measures that, by themselves or in combination with other measures, will overcome these barriers. Since most of the barriers dealt with can be found in the 'barriers' literature, any originality in the paper lies in the systematic organization, synoptic view and holistic treatment. Of course, the scheme can be expanded and improved. In that sense, this paper is intended to initiate a comprehensive treatment of barriers, their origins and the measures that contribute to overcoming them. Hopefully, such a treatment will facilitate the implementation of energy-efficiency improvements involving a wide diversity of ever-changing energy end-uses and consumer preferences."

🗋 Sedano, Richard (2009). "Decoupling Utility Sales from Revenues," for the Kentucky Public Service Commission (April). [link]

"Ratemaking policy should align utilities' profit motives with public policy goals: acquiring all cost-effective resources, whether supply or demand."

🗋 Solar Electric Power Association (2009). *Decoupling Utility Profits from Sales.* Washington, DC: SEPA Report No. 03-09 (February). [link]

"This decoupling white paper stays neutral on the topic, instead providing an overview of the problem with revenue loss and a background on net metering and its specific impact on the problem. The paper then goes on to more specifically define and discuss decoupling and alternatives to decoupling. This is followed by a decoupling case study of a hypothetical utility, which shows the relative magnitude of decoupling overall and estimations of the impact of photovoltaics from a renewable portfolio standard that includes a solar specific requirement."

🗋 Sotkiewicz, Paul, M. (2007). "Advantages and Drawbacks of Revenue Decoupling: Rate Design and Regulatory Implementation Does Matter," Florida Public Service Commission's Workshop on Energy Efficiency Initiatives (November). [link]

"Balance the risk and reward between utilities and customers...this will depend upon perceptions of risk and reward in the two implementations. Stable customer rates and bills...two-part tariff (SFV) accomplishes this. Stable utility revenues...in theory either implementation can accomplish this, but hearings under volumetric rate implementation introduces risk... bills...two-part tariff (SFV) would do better. Administrative simplicity and managing regulatory costs...two-part (SFV) would do better by eliminating the need for true-up hearings."

Sotkiewicz, Paul M. (2007). "Determining Winners and Losers from Revenue Decoupling: Rate Design and Regulatory Implementation Does Matter," Florida Energy Commission's Advisory Group on Energy Efficiency and Conservation, Orlando (July). [link]

"Consumers and utilities can both win under a two-part tariff implementation with the right regulatory mechanisms and implementation. But this takes more thought, time, effort, and thinking outside the 'traditional regulatory box.'"

Additional Decoupling Reference Links

- Center for Energy, Economic and Environmental Policy. "Decoupling Resources." [link]
- Massachusetts Technology Collaborative. "Decoupling of Utility Rates." [link]
- The Rhode Island Public Utility Commission. "DOCKET NO. 3943." [link]

Appendix C: Examples of Program Administrator Activities to Advance Codes

National Code Development

Energy Efficient Codes Coalition: The Energy Efficient Codes Coalition is a collaborative group formed to advocate for a 30 percent improvement in the 2009 IECC's residential energy code provisions compared with the 2006 version of the standard. Key program administrators in the coalition include electric utilities—represented through the Edison Electric Institute—the American Public Power Association, and regional energy efficiency organizations (e.g., Northeast Energy Efficiency Partnerships [NEEP] and Northwest Energy Efficiency Alliance [NEEA]). The coalition was successful in seeing the ICC's voting members adopt 55 of the coalition's 80 recommendations and 13 of the 21 elements of the coalition's comprehensive proposal ("The 30% Solution"), resulting in energy efficiency gains of approximately 12 percent nationwide compared with the 2006 IECC. This group now operates as the Building Energy Efficient Codes Network, and it is continuing to work toward improvements during the next code cycle.

Pacific Gas & Electric (PG&E), Southern California Edison, and Sempra Utilities (San Diego Gas & Electric and Southern California Gas): California's investor-owned utilities (IOUs) have been involved in advancing the state's Title 24 building codes since the mid 1990s. These administrators have since become active participants in national code development, engaging with ASHRAE and the ICC. For example, program engineers from California IOUs have served on ASHRAE technical committees and assisted in the development of test procedures and design requirements for Standard 90.1. A key reason for the California administrators' involvement is the potential to expand the market share for technologies required under Title 24 and thus drive down the costs faced by local builders and residents. The national code developers also benefit from the experience and knowledge that California utilities bring to the process. In addition to assisting ASHRAE and the ICC, California IOUs interact at the national level with DOE, major national building organizations, and national building product manufacturers and suppliers to advance specific code upgrades.

Northwest Energy Codes Group (NWECG): NEEA is a regional organization that both advocates for and delivers energy efficiency programs to businesses and residences. It has played a role in national model code development for more than 25 years, and it has successfully leveraged the expertise of utility members and contractors to develop code upgrade proposals and advance them through the national upgrade process. To assist in this process and to represent the region at the national level, NEEA and its members formally established NWECG in 2004. Since then, NWECG has demonstrated how administrators with significant voluntary program experience at the state and regional levels can influence a national model code. For example, in 2006, NWECG proposed 14 code changes to the IECC, 10 of which were fully incorporated into the code.

Regional, State, and Local Code Development and Adoption Efforts

NEEP: NEEP is a regional efficiency organization with significant experience providing technical assistance to states on building codes. For example, in 2008, NEEP worked with the Maine Public Utilities Commission to adopt and implement the state's first energy code. NEEP and its program administrator members helped Massachusetts upgrade its code to the most recent versions of the IECC (2009) and ASHRAE Standard 90.1 (2007), and then in the spring of 2009 they helped the state adopt a first-in-the-nation "informative appendix" to the building energy code, or "stretch code," which provides municipalities with a state-approved option for an above-code building standard, should they desire it. In all cases, NEEP played a key role in bringing a wide range of partners, including program administrator members, to the table to educate and inform decision-makers about the benefits of codes and related issues. Appendix D provides a list of NEEP's administrator members.

NEEA: As the regional efficiency organization for the Northwest, NEEA draws heavily on the expertise of its 139 program administrator members, including public and private utilities, in offering technical assistance to states on code adoption and upgrades. For example, NEEA recently assisted Idaho and Montana in the adoption of their first statewide energy codes, and it played a role in upgrading codes in both Oregon and Washington. In Oregon, NEEA successfully integrated its Northwest Energy Homes specification, on a provision-by-provision basis, into the state's 2008 residential code. For 2009, NEEA is working to assemble and fund a team to assist the Oregon Department of Energy with the implementation of a 20–30 percent upgrade in its nonresidential code. Appendix D provides a list of NEEA's administrator members.

Southwest Energy Efficiency Project (SWEEP): SWEEP, the regional efficiency organization for the Southwest, includes several program administrator members that it calls on to advance codes. These administrators have played roles providing data on cost-effectiveness, assisting in the adoption of statewide energy codes (often by providing testimony on specific code elements), and helping local stakeholders understand key provisions in the national model codes. For example, in 2009 SWEEP is working to help communities in Arizona better understand the costs and benefits of adopting the most recent residential IECC. At the national level, SWEEP partnered with the NWECG and the Energy Efficient Codes Coalition in 2008 to achieve a significant upgrade to the IECC's residential code. Appendix D provides a list of SWEEP's administrator members.

Local Implementation and Compliance

Efficiency Vermont (EVT): EVT is the sole administrator of electric efficiency programs and services in Vermont. With aggressive statewide goals for efficiency savings and a limited codes infrastructure, EVT and the Department of Public Service identified code compliance as a key opportunity. Unlike municipalities in most states, Vermont municipalities are not required to conduct health and safety inspections of new homes, nor do they issue occupancy permits. In the absence of on-the-ground inspection and enforcement of energy codes, builders are responsible for self-certifying compliance. Recognizing this gap, EVT instituted a training and technical assistance package designed to increase understanding and compliance. One component of their approach is a telephone hotline, operated by EVT experts, which builders and tradespeople can call with codes-related questions. In addition, EVT works to educate and train selected participants in their voluntary programs on code provisions. With a relatively small building market, EVT has been successful in reaching the majority of large builders.

Utility Code Group (UCG): In 1991, Washington State began a 3-year process to revise its nonresidential energy code. The goal of the region's utilities and the Northwest Power Planning Council (NWPPC) was to increase the energy efficiency of new commercial buildings to levels proposed by the NWPPC. To achieve this objective and coordinate the program administrator roles, the UCG was established later that year as a nonprofit entity overseen by a board of utility representatives. Key activities funded and conducted by the UCG included:

- Developing and implementing a training program.
- Marketing energy code information and training to industry audiences.
- Cooperating with code officials and funding the development of the Special Plans Examiner and Inspector Program.
- Managing a quality assurance and evaluation program to track progress.
- Coordinating with all stakeholders to assure the successful implementation of the code.

The UCG was in operation for three and a half years, culminating in the successful adoption and implementation of the NWPPC code recommendations in 1994. (Note that the NWPPC became the Northwest Power and Conservation Council [NWPCC] in 2003.)

Nevada Power and Sierra Pacific: In 2005, the State of Nevada adopted the 2003 IECC as its residential code. To prepare and educate the market for this change, Nevada Power and Sierra Pacific worked ahead of the code adoption schedule to provide funding for the training and education of builders and local code officials. DOE contributed additional resources, and the Nevada Energy Office coordinated the overall adoption process.

PG&E: PG&E developed and delivers a training course on California's Title 24 energy code at its Energy Training Center in Stockton. PG&E designed the course to focus on high-impact changes, including duct installation standards and leakage testing requirements in commercial and residential buildings, and explicitly links the utility's energy efficiency incentive programs to the code training curriculum. For example, PG&E develops analytical tools and test methods derived from program experience to estimate energy savings and verify performance of code measures. This supports California's 2008 energy efficiency strategic plan (CPUC, 2008), which emphasizes the need for improved energy code compliance and enforcement. The plan states that: "This strategy will require a strong, coordinated effort among Federal, State and local entities, the utilities, California building officials (and their association, CALBO) and other code compliance organizations, trade and professional licensing/registration agencies, and building/developer/ contractor/manufacturers associations."

State of Maine: In 2004, the Maine Public Utilities Commission was legislatively directed to study the implementation of building energy codes and report its findings and recommendations to the Joint Standing Committee on Utilities and Energy. With the Public Utilities Commission's subsequent recommendation, Maine adopted the latest commercial and residential codes, including a requirement to provide code training to builders and local officials. To assist in carrying out this requirement, Maine's nonprofit program administrator, Efficiency Maine, developed a suite of training resources that address basic and advanced topics related to legal and technical code considerations. Efficiency Maine also delivers the training program and directly assists builders in securing their certification of occupancy.

State of Iowa: In 2008, the Iowa legislature passed a ruling that requires the state's IOUs, as well as cooperative and municipal utilities, to set energy savings goals, create plans for achieving these goals, and report their progress to the Iowa Utilities Board. Although many utilities viewed the new state codes as a strategy for achieving these goals, they had questions about low compliance levels and the resulting impact on energy savings. To address these concerns, the utilities made a commitment, in conjunction with the Iowa Office of Consumer Advocate, to analyze compliance levels, determine the reasons for low compliance, and identify options and best practices for improvement. A study was initiated in late 2007, for which data were gathered via onsite home inspections, leakage tests, and software analyses. Once the results are available, the utilities intend to develop a strategy for improving compliance and enforcement as needed.

New York State Energy Research and Development Authority (NYSERDA): Under New York's 2008 energy portfolio standard proceeding, NYSERDA, the state's largest program administrator, was tasked with expanding its role to advance the commercial and residential building codes. As a first step, NYSERDA will conduct analysis and gather data to assist stakeholders in understanding market conditions and key issues involved in improving code compliance. Other activities include conducting a baseline study to document current building practices in different regions of the state and initiating basic research aimed at identifying areas of low compliance. Once these efforts are complete, NYSERDA will use the results to inform its curriculum for training code officials.

Other Activities

Codes Evaluation—California IOUs: In the late 1990s, California IOUs began actively collaborating with the California Public Utilities Commission (CPUC) to identify, research, and promote codes as a programmatic strategy for achieving efficiency savings at low cost relative to existing resource acquisition programs. Unlike traditional efforts, however, energy savings from utility codes activities are implemented by multiple parties over a long period of time, and are therefore comparatively difficult to evaluate. Nevertheless, the CPUC determined that codes held the potential for large and cost-effective savings, and authorized incentive payments for utilities that demonstrated successful efforts. In a sophisticated evaluation protocol, the CPUC subsequently specified the metrics for measuring savings. The protocol estimates net ex post energy savings achieved from program administrator-induced code changes above and beyond what would naturally occur in the market. Initial evaluations of the utility codes activities in the 2006–2008 program cycle indicate that savings equivalent to 10–12 percent of the total IOU goals were achieved. Based on program expenditure data from the utilities, codes-related savings cost about $0.01 per first-year kilowatt-hour (kWh) (Lee et al., 2008).

DISCOVERY REQUEST NO. 29:

Please explain CGC's position regarding a straight-fixed variable rate design

Response:

The State of Tennessee amended its energy policy as it relates to energy efficiency through an Act of the State Legislature approved in June 2009. Specifically, the Tennessee General Assembly required that the TRA seek to implement a general policy that:

> "ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provides for timely cost recovery and a timely earnings opportunity for cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently".

As explained in its direct testimony, CGC believes that the most significant impediment to achieving this energy policy is the existing throughput incentive associated with the Company's traditional usage-based rate design. Further, the Company proposed a new ratemaking mechanism, the Alignment and Usage Adjustment "AUA" tariff, to address the rate design impediment to the State's policy goals in an equitable manner.

Nevertheless, the Company's proposal is not the only means of achieving a ratemaking policy that aligns CGC's interests with those of its customers with respect to energy efficiency and conservation. Another means of achieving this end is through the implementation of a straight-fixed-variable ("SFV") rate design. A properly-designed SFV rate design offers many advantages to the TRA and to customers. SFV rate design is the most direct means of aligning utility and customer interests and achieves important rate design goals including supporting energy efficiency, revenue stability and fairness. While important implementation considerations including potential bill impacts exist, CGC believes that these considerations can be readily addressed.

There are two basic frameworks for designing an SFV rate design that recovers fixed costs through fixed charges. The first of these is to replace existing delivery charges with a demand-type of charge. The Company's affiliate LDC, Atlanta Gas Light Company ("AGL"), has implemented this type of SFV rate design in an effective manner. The second SFV rate design framework entails increasing the monthly customer charge to recover all revenue requirements allocated to a particular rate class. This approach has been implemented by other LDCs in various jurisdictions.

Applicable Customer Classes

The Company believes that SFV rates are appropriate for all firm classes, which include residential general service (R-1), residential multi-family housing service (R-4), small C&I general service (C-1), medium C&I general service (C-2), and low volume transportation service (T-3). With the exception of Rate Schedule R-4, these are the classes included within the Company's AUA tariff proposal. CGC does not believe that it is appropriate to apply SFV rate design to interruptible customers or customers with less than 100% firm service given the lower level of service afforded to under CGC's non-firm tariffs.

Demand Charge-Based SFV Rate Design

CGC believes that the AGL SFV rate design approach offers an excellent alternative that could be implemented for CGC customers. The AGL rate design relies upon a customer-specific billing demand quantity to recover fixed demand-related costs of providing service. A demand charge rate design is already in place for Rate Schedule C-2 and T-3 customers. The billing demand quantity reflects the quantity of natural gas utilized at peak periods and accommodates size differences among customers. The annual demand charge is applied on a sculpted basis to the billing demand quantity as a means of mitigating bill impacts across the months of the year and to better match customer expectations for higher bills during peak periods.

Attachment Staff 29-1 provides a demand charge-based rate design alternative to the Company's initial proposed rate design. The proposed sculpting of the demand charge for each class is also presented in this Attachment, which is aligned with the existing monthly base revenue collection. For this rate design, the residential customer charge is reduced somewhat to reflect the ability to recover a portion of fixed costs through the demand charge as the Company believes that fairness can be promoted through a smaller increase to the customer charge than is necessary under a rate design without a demand charge. Under the rate design presented in Attachment Staff 29-1, the Company's weather normalization clause would be eliminated.

It is possible to develop an SFV rate design that maintains a small delivery charge component, if desired. Attachment Staff 29-2 provides a second demand charge-based rate design alternative that maintains a limited delivery charge component. In the

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Company's opinion, this second SFV rate design also maintains sufficient alignment between the Company's interests and those of its customers to satisfy Tennessee's ratemaking policy favoring the development of energy efficiency. The continuation of the delivery charge under this alternative necessitates retaining the Company's existing weather normalization clause. The demand charge levels presented in these two demand charge-based SFV rate design alternatives establish the range that the Company believes appropriately achieves the State's policy.

From a customer acceptance viewpoint, these demand charge-based rate designs with the proposed sculpting are understandable and properly mitigates bill impacts for various size and load factor customers. Therefore, the Company would support adoption of either of these rate designs by the TRA in lieu of its proposed rate design and AUA tariff.

Flat-Charge Based Rate Design

The implementation of a flat charge-based SFV rate design results in equal charges to all customers within a particular rate class. Flat charge-based SFV rate designs work best for reasonably homogenous customer classes. For CGC, the only customer class that could accommodate such a rate design is the Residential R-1 rate class as a flat charge rate design without regard to customer size would lead to unreasonable bill impacts for some customers given the broad range of C&I customers served under a common rate schedule.

In order to recover the annual revenue requirements allocated to the residential customer class, the monthly flat charge would need to be increased to approximately $24 per month. In order to mitigate the potential summer bill impacts, a seasonally-differentiated flat charge would be appropriate. A flat residential charge of $29 in the winter months and $18.38 in the summer months would allow CGC to recover the revenue requirements allocated to the R-1 rate schedule.

CGC believes that the flat charge approach is less advantageous than the demand charge-based SFV rate designs. The primary concern is the potential bill impacts for smaller residential customers associated with implementation of the change. These concerns are not present under the demand charge-based rate designs given the continuation of a size-based charge even as the delivery-charge is eliminated. In addition, the flat charge rate design cannot be accommodated within the non-residential classes.

Attachment Staff 29-3 provides a summary of the potential SFV rate designs and compares the rates and associated revenue recoveries to the Company's proposed rate design.

Challanooga Gas Company
Demand Charge-Based SFV Rate Design

Firm Customer Classes

	Post Test Year Billing Units Winter Nov-April	Post Test Year Billing Units Summer May-Oct	Post Test Year Billing Units Total	Present Winter Rates Nov - April Rate	Present Winter Rates Nov - April Revenue	Present Summer Rates May - Oct Rate	Present Summer Rates May - Oct Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Proposed Winter Rates Nov - April Revenue	Proposed Summer Rates May - Oct Rate	Proposed Summer Rates May - Oct Revenue	Proposed Total Revenue
Residential (R-1)													
Number of Bills	321,672	313,605	635,278	$12.00	$3,860,060	$10.00	$3,136,047	$6,996,107	$13.00	$4,181,731	$11 00	$3,449,652	$7,631,383
Demand Charge	340,539	331,999	672,538						$11.094	$3,777,940	$11.094	$3,683,197	$7,461,137
Distribution Charges													
0 - 25 therms	7,467,700	3,497,280	10,964,980	$0.25444	$1,900,082	$0.18425	$644,374	$2,544,455	$0 00000	$0	$0.00000	$0	$0
26-50 therms	6,164,870	691,320	6,856,190	$0 17547	$1,081,750	$0 13160	$90,978	$1,172,727	$0.00000	$0	$0.00000	$0	$0
Over 50 Therms	16,542,330	508,710	17,051,040	$0.15354	$2,539,909	$0.03948	$20,084	$2,559,993	$0.00000	$0	$0 00000	$0	$0
Revenue Adjustment													
Total Residential Margin	30,174,900	4,697,310	34,872,210		$9,381,800		$3,891,483	$13,273,283		$7,959,671		$7,132,849	$15,092,520
PGA					$26,918,600		$3,891,300	$30,809,900		$26,918,600		$3,891,300	$30,809,900
Total Revenues					$36,300,400		$7,782,783	$44,083,183		$34,878,271		$11,024,149	$45,902,420
												Increase	$1,819,237
												Percent	4.1%
Residential (R-4)													
Number of Bills	1,110	1,110	2,220	$6.00	$6,660	$6 00	$6,660	$13,320	$6.00	$6,660	$6.00	$6,660	$13,320
Demand Charge	2,352	2,352	4,704						$4.286	$10,081	$4.286	$10,081	$20,161
Distribution Charges	62,756	19,448	82,204	$0.21768	$13,660	$0.19350	$3,760	$17,420	$0.00000	$0	$0 00000	$0	$0
Revenue Adjustment													
Total Residential (R-4) Margin	62,756	19,448	82,204		$20,320		$10,420	$30,740		$16,741		$16,741	$33,481
PGA					$55,944		$16,147	$72,091		$55,944		$16,147	$72,091
Total Revenues					$76,264		$26,567	$102,831		$72,684		$32,888	$105,572
												Increase	$2,741
												Percent	2.7%

Chattanooga Gas Company
Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units			Present Winter Rates Nov - April		Present Summer Rates May - Oct		Present Total	Proposed Winter Rates Nov - April		Proposed Summer Rates May - Oct		Proposed Total
	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Commercial (C-1)													
Number of Bills	39,563	38,077	77,640	$29 00	$1,147,330	$25.00	$951,910	$2,099,240	$29.00	$1,147,330	$25.00	$951,914	$2,099,244
Demand Charge	183,602	176,703	360,305						$5.281	$969,602	$5.281	$933,169	$1,902,771
Distribution Charges	6,441,514	1,532,171	7,973,685	$0 18581	$1,196,900	$0.14589	$223,530	$1,420,430	$0 00000	$0	$0 00000	$0	$0
Revenue Adjustment													
Total Commercial (C-1) Margin	6,441,514	1,532,171	7,973,685		$2,344,230		$1,175,440	$3,519,670		$2,116,932		$1,885,083	$4,002,015
PGA					$5,758,500		$1,268,300	$7,026,800		$5,758,500		$1,268,300	$7,026,800
Total Revenues					$8,102,730		$2,443,740	$10,546,470		$7,875,432		$3,153,383	$11,028,815
												Increase	$482,345
												Percent	4.6%

	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Commercial (C-2)													
Number of Bills	9,444	9,444	18,888	$75.00	$708,300	$75.00	$708,300	$1,416,600	$75.00	$708,300	$75.00	$708,300	$1,416,600
Demand Charge (Firm) Demand (C-2) in Dths	166,968	166,968	317,076	$5.50	$871,960	$5.50	$871,960	$1,743,920	$16.94	$2,828,438	$16.94	$2,828,438	$5,656,876
Distribution Charges													
0 - 3000 therms	11,318,000	4,227,952	15,545,852	$0.18744	$2,121,450	$0.14717	$622,230	$2,743,680	$0.00000	$0	$0 00000	$0	$0
3,001 - 5,000 therms	1,643,869	415,782	2,059,651	$0.17109	$281,250	$0.11683	$48,580	$329,830	$0 00000	$0	$0.00000	$0	$0
5,001 - 15,000 therms	2,230,552	602,545	2,833,098	$0.16668	$371,740	$0.10892	$65,630	$437,370	$0 00000	$0	$0.00000	$0	$0
over 16,000 therms	981,284	110,850	1,092,114	$0.08623	$84,610	$0.08623	$9,560	$94,170	$0,00000	$0	$0.00000	$0	$0
Revenue Adjustment													$0
Total Commercial (C-2) Margin	16,173,686	5,357,129	21,530,815		$4,439,310		$2,326,260	$8,765,570		$3,536,738		$3,536,738	$7,073,476
PGA					$14,100,020		$5,153,908	$19,253,928		$14,100,020		$5,153,908	$19,253,928
Total Revenues					$18,539,330		$7,480,168	$26,019,498		$17,636,758		$8,690,646	$26,327,404
												Increase	$307,906
												Percent	1.2%

Chattanooga Gas Company
Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units			Present Winter Rates Nov - April		Present Summer Rates May - Oct		Present Total Revenue	Proposed Winter Rates Nov - April		Proposed Summer Rates May - Oct		Proposed Total Revenue
	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue		Rate	Revenue	Rate	Revenue	
Commercial Transportation (T-3)													
Number of Bills	180	180	360	$75 00	$13,500	$75.00	$13,500	$27,000	$75.00	$13,500	$75.00	$13,500	$27,000
Demand Charge (Firm) Demand (T-3) I	16,124	16,124	32,248	$5.50	$88,680	$5 50	$88,680	$177,360	$16.94	$273,137	$16.94	$273,137	$546,274
Distribution Charges													
0 - 3000 therms	519,600	461,500	981,100	$0.18744	$97,390	$0.14717	$87,920	$165,310	$0.00000	$0	$0 00000	$0	$0
3,001 - 5,000 therms	294,700	220,200	514,900	$0.17109	$50,420	$0.11683	$25,730	$76,150	$0 00000	$0	$0.00000	$0	$0
5,001 - 15,000 therms	872,400	516,800	1,389,200	$0.16666	$145,390	$0.10892	$56,290	$201,680	$0 00000	$0	$0.00000	$0	$0
over 15,000 therms	561,000	160,500	721,500	$0 08623	$48,380	$0.08623	$13,840	$62,220	$0 00000	$0	$0.00000	$0	$0
Revenue Adjustment													$0
Total Commercial Transportation (T-3) M	2,247,700	1,359,000	3,606,700		$443,760		$265,960	$709,720		$286,637		$286,637	$573,274
												Increase	-$136,446
												Percent	-19.2%

	Present Total Revenue	Proposed Total Revenue
MARGIN C-2 & T-3 CLASS		
TOTAL C-2	$6,765,570	$7,073,476
TOTAL T-3	$709,720	$673,274
TOTAL MEDIUM C&I GENERAL	$7,475,290	$7,646,750

Chattanooga Gas Company
Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units Winter Nov-April	Post Test Year Billing Units Summer May-Oct	Post Test Year Billing Units Total	Present Winter Rates Nov - April Rate	Present Winter Rates Nov - April Revenue	Present Summer Rates May - Oct Rate	Present Summer Rates May - Oct Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Proposed Winter Rates Nov - April Revenue	Proposed Summer Rates May - Oct Rate	Proposed Summer Rates May - Oct Revenue	Proposed Total Revenue
Interruptible Sales (I-1)													
Number of Bills	6	6	12	$300.00	$1,800	$300 00	$1,800	$3,600	$375.00	$2,250	$375.00	$2,250	$4,500
Distribution Charges													
0 - 15,000 therms	90,000	90,000	180,000	$0.08064	$7,260	$0.08064	$7,260	$14,520	$0 07290	$6,561	$0.07290	$6,561	$13,122
15,001 - 40,000 therms	109,600	145,200	254,800	$0.06891	$7,550	$0 06891	$10,010	$17,560	$0 06117	$6,704	$0.06117	$8,882	$15,586
40,001 - 150,000 therms	15,100	44,200	59,300	$0 03908	$590	$0.03908	$1,730	$2,320	$0 03134	$473	$0 03134	$1,385	$1,858
over 150,000 therms	0	0	0	$0.02402	$0	$0.02402	$0	$0	$0.01628	$0	$0.01628	$0	$0
Revenue Adjustment													$0
Total Interruptible Sales (I-1) Margin	214,700	279,400	494,100		$17,200		$20,800	$38,000		$15,988		$19,078	$35,067
PGA					$182,058		$213,655	$395,713		$182,058		$213,655	$395,713
Total Revenues to Customer					$199,258		$234,455	$433,713		$198,047		$232,733	$430,780
												Increase	-$2,933
												Percent	-0.7%
Industrial Transport with Full Standby (F-1/T-2)													
Number of Bills	162	162	276	$300 00	$48,600	$300.00	$48,600	$97,200	$375 00	$60,750	$375 00	$60,750	$121,500
Demand Charge (Firm) Demand (T-2) i	57,248	57,248	8,788	$5.50	$314,860	$5.50	$314,860	$629,720	$7.50	$429,359	$7.50	$429,359	$858,717
Distribution Charges													
0 - 15,000 therms	2,308,300	2,044,500	4,352,800	$0.08064	$186,140	$0.08064	$164,870	$351,010	$0 07290	$168,275	$0.07290	$149,044	$317,319
15,001 - 40,000 therms	2,492,600	2,032,800	4,525,400	$0.06891	$171,770	$0.06891	$140,080	$311,850	$0 06117	$152,472	$0.06117	$124,346	$276,819
40,001 - 150,000 therms	2,370,600	1,790,600	4,161,200	$0.03908	$92,640	$0.03908	$69,980	$162,620	$0.03134	$74,295	$0.03134	$56,117	$130,412
over 150,000 therms	3,156,100	3,080,700	6,236,800	$0.02402	$75,810	$0.02402	$74,000	$149,810	$0.01628	$51,381	$0.01628	$50,154	$101,535
Revenue Adjustment													$0
Total Industrial Transport with Full Stand	10,327,600	8,948,600	19,276,200		$889,820		$812,390	$1,702,210		$936,532		$869,770	$1,806,302
PGA					$420,187		$420,187	$840,375		$420,187		$420,187	$840,375
Total Revenues					$1,310,007		$1,232,577	$2,542,585		$1,356,719		$1,289,958	$2,646,677
												Increase	$104,092
												Percent	4.1%

Chattanooga Gas Company
Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units			Present Winter Rates Nov - April		Present Summer Rates May - Oct		Present	Proposed Winter Rates Nov - April		Proposed Summer Rates May - Oct		Proposed
	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Total Revenue	Rate	Revenue	Rate	Revenue	Total Revenue
Industrial Transport with Partial Standby (F-1/T-2+T-1)													
Number of Bills	72	72	144	$300.00	$21,600	$300.00	$21,600	$43,200	$375.00	$27,000	$375.00	$27,000	$54,000
Demand in Dths													
Demand Charge (Firm) Demand (T-2)	15,996	15,996	31,992	$5.50	$87,980	$5.50	$87,980	$175,960	$7.50	$119,970	$7.50	$119,970	$239,940
Capacity (Non-Firm) Demand (T-1)	26,938	26,938	53,876	$1.35	$36,370	$1.35	$36,370	$72,740	$2.35	$63,305	$2.35	$63,305	$126,610
Total Demand	42,934	42,934	85,868		$124,350		$124,350	$248,700		$183,275		$183,275	$366,550
Distribution Charges													
0 - 15,000 therms	1,053,300	1,037,900	2,091,200	$0.08064	$84,940	$0.08064	$83,700	$168,640	$0.07290	$76,786	$0.07290	$75,663	$152,448
15,001 - 40,000 therms	1,586,400	1,548,700	3,135,100	$0.06891	$109,320	$0.06891	$106,720	$216,040	$0.06117	$97,040	$0.06117	$94,734	$191,774
40,001 - 150,000 therms	3,495,600	2,813,200	6,308,800	$0.03908	$136,610	$0.03908	$109,940	$246,550	$0.03134	$109,552	$0.03134	$88,166	$197,718
over 150,000 therms	1,109,900	771,600	1,881,500	$0.02402	$26,660	$0.02402	$18,530	$45,190	$0.01628	$18,069	$0.01628	$12,562	$30,631
Revenue Adjustment													
sub-Total Industrial Transport with Partia	7,245,200	6,171,400	13,416,600		$503,480	$318,880	$464,840	$968,320		$511,722		$481,399	$993,121
Special Contracts	3,784,900	4,286,800	8,071,700		$67,788		$69,756	$137,544		$67,788		$69,756	$137,544
Total Industrial Transport with Partial S	11,030,100	10,458,200	21,488,300		$571,268		$534,596	$1,105,864		$579,510		$551,155	$1,130,665
PGA					$117,848		$117,848	$235,696		$117,848		$117,848	$235,696
Total Revenues					$689,116		$652,444	$1,341,560		$697,358		$669,003	$1,366,360
												Increase	$24,801
												Percent	1.8%
Interruptible Industrial Transportation (T-1)													
Number of Bills	156	156	312	$300.00	$46,800	$300.00	$46,800	$93,600	$375.00	$58,500	$375.00	$58,500	$117,000
Capacity (Non-Firm) Demand (T-1)	98,275	98,275	196,549	$1.35	$132,670	$1.35	$132,670	$265,340	$2.35	$230,945	$2.35	$230,945	$461,891
Distribution Charges													
0 - 15,000 therms	2,106,000	2,145,300	4,251,300	$0.08064	$169,830	$0.08064	$173,000	$342,830	$0.07290	$153,527	$0.07290	$156,392	$309,920
15,001 - 40,000 therms	2,648,800	2,793,700	5,442,500	$0.06891	$182,530	$0.06891	$192,510	$375,040	$0.06117	$162,027	$0.06117	$170,891	$332,918
40,001 - 150,000 therms	5,254,200	5,266,700	10,520,900	$0.03908	$205,330	$0.03908	$205,820	$411,150	$0.03134	$164,667	$0.03134	$165,058	$329,725
over 150,000 therms	5,481,000	6,261,900	11,742,900	$0.02402	$131,650	$0.02402	$150,410	$282,060	$0.01628	$89,231	$0.01628	$101,944	$191,174
Revenue Adjustment													
sub-Total Interruptible Industrial Transpo	15,490,000	16,467,600	31,957,600		$868,810		$901,210	$1,770,020		$858,897		$883,730	$1,742,628
												Increase	-$27,392
												Percent	-1.5%

Chattanooga Gas Company
Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
Special Service (SS-1)													
Number of Bills	0	0	0	$300.00	$0	$300 00	$0	$0	$375 00	$0	$375.00	$0	$0
Capacity (Non-Firm) Demand (T-1)	0	0	0	$1.35	$0	$1.35	$0	$0	$2.35	$0	$2.35	$0	$0
T-1 Distribution Charges													
0 - 15,000 therms	0	0	0	$0 08064	$0	$0.08064	$0	$0	$0.07290	$0	$0.07290	$0	$0
15,001 - 40,000 therms	0	0	0	$0.06891	$0	$0 06891	$0	$0	$0.06117	$0	$0 06117	$0	$0
40,001 - 150,000 therms	0	0	0	$0 03908	$0	$0 03908	$0	$0	$0.03134	$0	$0 03134	$0	$0
over 150,000 therms	0	0	0	$0.02402	$0	$0.02402	$0	$0	$0.01628	$0	$0.01628	$0	$0
Revenue Adjustment													
sub-Total Special Service (SS-1) Margin	0	0	0		$0		$0	$0		$0		$0	$0
Special Service (SS-1)					$0		$0	$0		$0		$0	$0
Margin Sharing from IMCR (90% of Difference between Special Service and T-1 Tariff)					$0		$0	$0		$0		$0	$0
Company Retained Base Rate Revenue					$0		$0	$0		$0		$0	$0
Total Firm Base Rate Revenues to Customers					$17,628,820		$8,591,533	$28,220,353		$15,000,221		$13,874,788	$28,875,008
Firm SPECIAL CONTRACTS					$67,788		$69,756	$137,544		$67,788		$69,756	$137,544
MISCELLANEOUS REVENUES					$432,098		$271,429	$703,527		$432,098		$271,429	$703,527
TOTAL FIRM Base Rate REVENUES w/ Special Contracts					$18,128,708		$8,932,718	$27,061,424		$15,500,107		$14,215,972	$29,716,079
TOTAL NON-FIRM Base Rate Revenues to Customers					$1,279,910		$1,277,270	$2,557,180		$1,239,637		$1,237,238	$2,476,875
Non-Firm SPECIAL CONTRACTS					$0		$0	$0		$0		$0	$0
TOTAL NON-FIRM base Rate REVENUES w/ Special Contracts					$1,279,910		$1,277,270	$2,557,180		$1,239,637		$1,237,238	$2,476,875
TOTAL FIRM AND INTERRUPTIBLE Base Rate REVENUES					$19,408,818		$10,209,988	$29,618,804		$18,739,744		$15,453,210	$32,192,954
% Increase												Total Increase	$2,574,350

Chattanooga Gas Company
Demand Charge-Based SFV Rate Design

	Residential R-1			Residential Multi-Family R-4			Small General Service (C-1)			Medium General Service (C-2/T-3)		
	Demand Charge Rate	Sculpting Percentage	Sculpted Rate	Demand Charge Rate	Sculpting Percentage	Sculpted Rate	Demand Charge Rate	Sculpting Percentage	Sculpted Rate	Demand Charge Rate	Sculpting Percentage	Sculpted Rate
HEAT ONLY CUSTOMERS												
Month												
January	$11.094	23.0%	$ 30.63				$5.281	22.9%	$ 14.53	$16.940	22.9%	$ 46.53
February	$11.094	21.6%	$ 26.75				$5.281	21.4%	$ 13.57	$16.940	21.5%	$ 43.77
March	$11.094	16.0%	$ 21.25				$5.281	15.8%	$ 10.04	$16.940	16.0%	$ 32.43
April	$11.094	8.9%	$ 11.88				$5.281	8.9%	$ 5.64	$16.940	8.9%	$ 18.16
May	$11.094	3.1%	$ 4.06		*Not Applicable*		$5.281	3.3%	$ 2.10	$16.940	3.2%	$ 6.43
June	$11.094	0.5%	$ 0.63				$5.281	0.5%	$ 0.29	$16.940	0.5%	$ 0.97
July	$11.094	0.0%	$ -				$5.281	0.0%	$ -	$16.940	0.0%	$ -
August	$11.094	0.0%	$ -				$5.281	0.0%	$ -	$16.940	0.0%	$ -
September	$11.094	0.0%	$ -				$5.281	0.0%	$ -	$16.940	0.0%	$ -
October	$11.094	2.1%	$ 2.81				$5.281	2.0%	$ 1.24	$16.940	2.0%	$ 4.08
November	$11.094	8.2%	$ 10.94				$5.281	8.4%	$ 5.35	$16.940	8.3%	$ 16.89
December	$11.094	16.7%	$ 22.19				$5.281	16.7%	$ 10.61	$16.940	16.7%	$ 34.01
Total	$133.128	100.0%	$133.128				$63.372	100.0%	$63.372	$203.280	100.0%	$203.280
ALL OTHER CUSTOMERS												
Month												
January	$11.094	20.7%	$ 27.59	$4.286	14.5%	$ 7.48	$5.281	19.1%	$ 12.10	$16.940	16.7%	$ 34.04
February	$11.094	19.5%	$ 25.92	$4.286	19.8%	$ 10.18	$5.281	19.3%	$ 12.24	$16.940	16.6%	$ 33.84
March	$11.094	14.5%	$ 19.26	$4.286	11.7%	$ 6.03	$5.281	14.7%	$ 9.29	$16.940	13.6%	$ 27.68
April	$11.094	8.5%	$ 11.26	$4.286	7.8%	$ 4.01	$5.281	8.7%	$ 5.51	$16.940	9.8%	$ 19.92
May	$11.094	3.8%	$ 5.05	$4.286	4.0%	$ 2.04	$5.281	4.5%	$ 2.67	$16.940	6.6%	$ 13.50
June	$11.094	2.0%	$ 2.65	$4.286	3.4%	$ 1.75	$5.281	3.8%	$ 2.41	$16.940	4.8%	$ 9.84
July	$11.094	1.7%	$ 2.22	$4.286	3.7%	$ 1.90	$5.281	3.1%	$ 1.96	$16.940	3.6%	$ 7.26
August	$11.094	1.7%	$ 2.30	$4.286	4.3%	$ 2.23	$5.281	2.8%	$ 1.78	$16.940	3.3%	$ 6.63
September	$11.094	1.7%	$ 2.21	$4.286	4.0%	$ 2.07	$5.281	2.7%	$ 1.73	$16.940	3.1%	$ 6.33
October	$11.094	2.9%	$ 3.89	$4.286	4.2%	$ 2.17	$5.281	2.9%	$ 1.81	$16.940	3.5%	$ 7.02
November	$11.094	7.9%	$ 10.53	$4.286	8.7%	$ 4.48	$5.281	5.8%	$ 3.66	$16.940	6.4%	$ 12.91
December	$11.094	15.2%	$ 20.25	$4.286	13.8%	$ 7.09	$5.281	12.6%	$ 7.99	$16.940	12.0%	$ 24.31
Total	$133.128	100.0%	$133.128	$51.432	100.0%	$51.432	$63.372	100.0%	$63.372	$203.280	100.0%	$203.280

Chattanooga Gas Company
Modified Demand Charge-Based SFV Rate Design

Firm Customer Classes

	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
Residential (R-1)													
Number of Bills	321,872	313,605	635,276	$12.00	$3,860,080	$10.00	$3,136,047	$6,996,107	$13.00	$4,181,731	$11.00	$3,449,652	$7,631,383
Demand Charge	340,539	331,999	672,538						$7.750	$2,639,177	$7.750	$2,572,992	$5,212,170
Distribution Charges													
0 - 25 therms	7,467,700	3,497,280	10,964,980	$0.25444	$1,900,082	$0.18425	$644,374	$2,544,455	$0.15624	$1,166,753	$0.03948	$138,073	$1,304,828
26-50 therms	6,164,870	691,320	6,856,190	$0.17547	$1,081,750	$0.13160	$90,978	$1,172,727	$0.03948	$243,389	$0.03948	$27,293	$270,682
Over 50 Therms	16,542,330	508,710	17,051,040	$0.15354	$2,539,909	$0.03948	$20,084	$2,559,993	$0.03948	$653,091	$0.03948	$20,084	$673,175
Revenue Adjustment													
Total Residential Margin	30,174,900	4,697,310	34,872,210		$9,381,800		$3,891,483	$13,273,283		$8,884,142		$6,208,094	$15,092,236
PGA					$26,918,600		$3,891,300	$30,809,900		$26,918,600		$3,891,300	$30,809,900
Total Revenues					$36,300,400		$7,782,783	$44,083,183		$35,802,742		$10,099,394	$45,902,136
												Increase	$1,818,953
												Percent	4.1%
Residential (R-4)													
Number of Bills	1,110	1,110	2,220	$6.00	$6,660	$6.00	$6,660	$13,320	$6.00	$6,660	$6.00	$6,660	$13,320
Demand Charge	2,352	2,352	4,704						$3.000	$7,056	$3.000	$7,056	$14,112
Distribution Charges	62,756	19,448	82,204	$0.21768	$13,660	$0.19350	$3,760	$17,420	$0.07929	$4,976	$0.05511	$1,072	$6,048
Revenue Adjustment													
Total Residential (R-4) Margin	62,756	19,448	82,204		$20,320		$10,420	$30,740		$18,692		$14,788	$33,480
PGA					$55,944		$16,147	$72,091		$55,944		$16,147	$72,091
Total Revenues					$76,264		$26,567	$102,831		$74,636		$30,935	$105,571
												Increase	$2,740
												Percent	2.7%

Chattanooga Gas Company
Modified Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units			Present Winter Rates Nov - April		Present Summer Rates May - Oct		Present Total	Proposed Winter Rates Nov - April		Proposed Summer Rates May - Oct		Proposed Total
	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Commercial (C-1)													
Number of Bills	39,563	38,077	77,640	$29.00	$1,147,330	$25 00	$951,910	$2,099,240	$29 00	$1,147,330	$25.00	$951,914	$2,099,244
Demand Charge	183,602	176,703	360,305						$4.000	$734,408	$4.000	$706,812	$1,441,220
Distribution Charges	6,441,514	1,532,171	7,973,685	$0.18581	$1,196,900	$0 14589	$223,530	$1,420,430	$0 06555	$422,241	$0.02563	$39,270	$461,511
Revenue Adjustment													
Total Commercial (C-1) Margin	6,441,514	1,532,171	7,973,685		$2,344,230		$1,175,440	$3,519,670		$2,303,979		$1,697,896	$4,001,875
PGA					$5,758,500		$1,268,300	$7,026,800		$5,758,500		$1,268,300	$7,026,800
Total Revenues					$8,102,730		$2,443,740	$10,546,470		$8,062,479		$2,966,296	$11,028,775
												Increase	$482,305
												Percent	4.6%

	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Commercial (C-2)													
Number of Bills	9,444	9,444	18,888	$75.00	$708,300	$75.00	$708,300	$1,416,600	$75 00	$708,300	$75 00	$708,300	$1,416,600
Demand Charge (Firm) Demand (C-2) in Dths	166,968	166,968	317,076	$5.50	$871,860	$5.50	$871,860	$1,743,920	$11.00	$1,836,648	$11.00	$1,836,648	$3,673,296
Distribution Charges													
0 - 3000 therms	11,318,000	4,227,952	15,545,952	$0.18744	$2,121,450	$0.14717	$622,230	$2,743,680	$0.10811	$1,223,589	$0.06652	$281,243	$1,504,832
3,001 - 5,000 therms	1,643,869	415,782	2,059,651	$0.17109	$281,250	$0.11683	$48,580	$329,830	$0.10811	$177,719	$0.06652	$27,658	$205,376
5,001 - 15,000 therms	2,230,552	602,545	2,833,098	$0.16668	$371,740	$0.10892	$65,630	$437,370	$0.08963	$199,924	$0.03189	$19,215	$219,140
over 15,000 therms	981,264	110,850	1,092,114	$0.08623	$84,610	$0.08623	$9,560	$94,170	$0.00920	$9,028	$0.00920	$1,020	$10,047
Revenue Adjustment													$0
Total Commercial (C-2) Margin	16,173,686	5,357,129	21,530,815		$4,439,310		$2,326,260	$6,765,570		$4,155,208		$2,874,084	$7,029,292
PGA					$14,100,020		$5,153,908	$19,253,928		$14,100,020		$5,153,908	$19,253,928
Total Revenues					$18,539,330		$7,480,168	$26,019,498		$18,255,228		$8,027,992	$26,283,220
												Increase	$263,722
												Percent	1.0%

Chattanooga Gas Company
Modified Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units			Present Winter Rates Nov - April		Present Summer Rates May - Oct		Present Total	Proposed Winter Rates Nov - April		Proposed Summer Rates May - Oct		Proposed Total
	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Commercial Transportation (T-3)													
Number of Bills	180	180	360	$75.00	$13,500	$75.00	$13,500	$27,000	$75 00	$13,500	$75.00	$13,500	$27,000
Demand Charge (Firm) Demand (T-3) I.	16,124	16,124	32,248	$5.50	$88,680	$5.50	$88,680	$177,360	$11.00	$177,362	$11 00	$177,362	$354,724
Distribution Charges													
0 - 3000 therms	519,600	461,500	981,100	$0.18744	$97,390	$0 14717	$67,920	$165,310	$0 10811	$56,174	$0.06652	$30,699	$86,873
3,001 - 5,000 therms	294,700	220,200	514,900	$0.17109	$50,420	$0.11683	$25,730	$76,150	$0.10811	$31,860	$0.06652	$14,648	$46,508
5,001 - 15,000 therms	872,400	516,800	1,389,200	$0.16666	$145,390	$0 10892	$56,290	$201,680	$0.08963	$78,193	$0.03189	$16,481	$94,674
over 15,000 therms	561,000	160,500	721,500	$0.08623	$48,380	$0.08623	$13,840	$62,220	$0.00920	$5,161	$0 00920	$1,477	$6,638
Revenue Adjustment													$0
Total Commercial Transportation (T-3) M	2,247,700	1,359,000	3,606,700		$443,760		$265,960	$709,720		$362,250		$254,166	$616,416
												Increase	-$93,304
												Percent	-13.1%

	Present Total Revenue	Proposed Total Revenue
MARGIN C-2 & T-3 CLASS		
TOTAL C-2	$6,765,570	$7,029,292
TOTAL T-3	$709,720	$616,416
TOTAL MEDIUM C&I GENERAL	$7,475,290	$7,645,708

Chattanooga Gas Company
Modified Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units			Present Winter Rates Nov - April		Present Summer Rates May - Oct		Present	Proposed Winter Rates Nov - April		Proposed Summer Rates May - Oct		Proposed
	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Total Revenue	Rate	Revenue	Rate	Revenue	Total Revenue
Interruptible Sales (I-1)													
Number of Bills	6	6	12	$300 00	$1,800	$300.00	$1,800	$3,600	$375.00	$2,250	$375 00	$2,250	$4,500
Distribution Charges													
0 - 15,000 therms	90,000	90,000	180,000	$0.08084	$7,280	$0.08084	$7,280	$14,520	$0.07290	$6,561	$0.07290	$6,561	$13,122
15,001 - 40,000 therms	109,600	145,200	254,800	$0 06891	$7,550	$0.06891	$10,010	$17,560	$0 06117	$6,704	$0.06117	$8,882	$15,586
40,001 - 150,000 therms	15,100	44,200	59,300	$0 03908	$590	$0.03908	$1,730	$2,320	$0.03134	$473	$0.03134	$1,385	$1,858
over 150,000 therms	0	0	0	$0.02402	$0	$0.02402	$0	$0	$0.01628	$0	$0.01628	$0	$0
Revenue Adjustment													$0
Total Interruptible Sales (I-1) Margin	214,700	279,400	494,100		$17,200		$20,800	$38,000		$15,988		$19,078	$35,067
PGA					$182,058		$213,655	$395,713		$182,058		$213,655	$395,713
Total Revenues to Customer					$199,258		$234,455	$433,713		$198,047		$232,733	$430,780
												Increase	-$2,933
												Percent	-0.7%
Industrial Transport with Full Standby (F-1/T-2)													
Number of Bills	162	162	276	$300.00	$48,600	$300.00	$48,600	$97,200	$375 00	$60,750	$375.00	$60,750	$121,500
Demand Charge (Firm) Demand (T-2) i	57,248	57,248	8,788	$5.50	$314,880	$5.50	$314,880	$829,720	$7.50	$429,359	$7.50	$429,359	$858,717
Distribution Charges													
0 - 15,000 therms	2,308,300	2,044,500	4,352,800	$0.08084	$186,140	$0.08084	$164,870	$351,010	$0.07290	$168,275	$0.07290	$149,044	$317,319
15,001 - 40,000 therms	2,492,600	2,032,800	4,525,400	$0.06891	$171,770	$0.06891	$140,080	$311,850	$0 06117	$152,472	$0.06117	$124,348	$276,819
40,001 - 150,000 therms	2,370,600	1,790,600	4,161,200	$0 03908	$92,640	$0.03908	$69,980	$162,620	$0.03134	$74,295	$0.03134	$56,117	$130,412
over 150,000 therms	3,156,100	3,080,700	6,236,800	$0.02402	$75,810	$0.02402	$74,000	$149,810	$0.01628	$51,381	$0.01628	$50,154	$101,535
Revenue Adjustment													$0
Total Industrial Transport with Full Stand	10,327,600	8,948,600	19,276,200		$889,820		$812,390	$1,702,210		$936,532		$869,770	$1,806,302
PGA					$420,187		$420,187	$840,375		$420,187		$420,187	$840,375
Total Revenues					$1,310,007		$1,232,577	$2,542,585		$1,356,719		$1,289,958	$2,646,677
												Increase	$104,092
												Percent	4.1%

Chattanooga Gas Company
Modified Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
Industrial Transport with Partial Standby (F-1/T-2+T-1)													
Number of Bills	72	72	144	$300.00	$21,600	$300.00	$21,600	$43,200	$375.00	$27,000	$375 00	$27,000	$54,000
Demand in Dths													
Demand Charge (Firm) Demand (T-2)	15,996	15,996	31,992	$5 50	$87,980	$5 50	$87,980	$175,960	$7.50	$119,970	$7.50	$119,970	$239,940
Capacity (Non-Firm) Demand (T-1)	26,938	26,938	53,876	$1.35	$36,370	$1.35	$36,370	$72,740	$2.35	$63,305	$2.35	$63,305	$126,610
Total Demand	42,934	42,934	85,868		$124,350		$124,350	$248,700		$183,275		$183,275	$366,550
Distribution Charges													
0 - 15,000 therms	1,053,300	1,037,900	2,091,200	$0.08064	$84,940	$0.08064	$83,700	$168,640	$0 07290	$76,786	$0.07290	$75,663	$152,448
15,001 - 40,000 therms	1,586,400	1,548,700	3,135,100	$0.06891	$109,320	$0.06891	$106,720	$218,040	$0.06117	$97,040	$0.06117	$94,734	$191,774
40,001 - 150,000 therms	3,495,600	2,813,200	6,308,800	$0.03908	$136,610	$0.03908	$109,940	$246,550	$0.03134	$109,552	$0.03134	$88,166	$197,718
over 150,000 therms	1,109,900	771,600	1,881,500	$0.02402	$26,660	$0.02402	$18,530	$45,190	$0.01628	$18,069	$0.01628	$12,562	$30,631
Revenue Adjustment													
sub-Total Industrial Transport with Partia	7,245,200	6,171,400	13,416,600		$503,480	$318,890	$464,840	$868,320		$511,722		$481,399	$993,121
Special Contracts	3,784,900	4,286,800	8,071,700		$67,788		$69,756	$137,544		$67,788		$69,756	$137,544
Total Industrial Transport with Partial S	11,030,100	10,458,200	21,488,300		$571,268		$534,596	$1,105,864		$579,510		$551,155	$1,130,665
PGA					$117,848		$117,848	$235,696		$117,848		$117,848	$235,696
Total Revenues					$689,116		$652,444	$1,341,560		$697,358		$669,003	$1,366,360
												Increase	$24,801
												Percent	1.8%

	Winter Nov-April	Summer May-Oct	Total	Present Winter Rate	Revenue	Present Summer Rate	Revenue	Present Total Revenue	Proposed Winter Rate	Revenue	Proposed Summer Rate	Revenue	Proposed Total Revenue
Interruptible Industrial Transportation (T-1)													
Number of Bills	156	156	312	$300.00	$46,800	$300.00	$46,800	$93,600	$375.00	$58,500	$375.00	$58,500	$117,000
Capacity (Non-Firm) Demand (T-1)	98,275	98,275	196,549	$1.35	$132,670	$1.35	$132,670	$265,340	$2.35	$230,945	$2.35	$230,945	$461,891
Distribution Charges													
0 - 15,000 therms	2,106,000	2,145,300	4,251,300	$0.08064	$169,830	$0.08064	$173,000	$342,830	$0.07290	$153,527	$0.07290	$156,392	$309,920
15,001 - 40,000 therms	2,648,800	2,793,700	5,442,500	$0.06891	$182,530	$0.06891	$192,510	$375,040	$0.06117	$162,027	$0.06117	$170,891	$332,918
40,001 - 150,000 therms	5,254,200	5,266,700	10,520,900	$0.03908	$205,330	$0 03908	$205,820	$411,150	$0.03134	$164,667	$0.03134	$165,058	$329,725
over 150,000 therms	5,481,000	6,261,900	11,742,900	$0.02402	$131,650	$0.02402	$150,410	$282,060	$0.01628	$89,231	$0.01628	$101,944	$191,174
Revenue Adjustment													
sub-Total Interruptible Industrial Transpo	15,490,000	16,467,600	31,957,600		$868,810		$901,210	$1,770,020		$858,897		$883,730	$1,742,628
												Increase	-$27,392
												Percent	-1.5%

Chattanooga Gas Company
Modified Demand Charge-Based SFV Rate Design

	Post Test Year Billing Units Winter Nov-April	Post Test Year Billing Units Summer May-Oct	Post Test Year Billing Units Total	Present Winter Rates Nov - April Rate	Present Winter Rates Nov - April Revenue	Present Summer Rates May - Oct Rate	Present Summer Rates May - Oct Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Proposed Winter Rates Nov - April Revenue	Proposed Summer Rates May - Oct Rate	Proposed Summer Rates May - Oct Revenue	Proposed Total Revenue
Special Service (SS-1)													
Number of Bills	0	0	0	$300 00	$0	$300.00	$0	$0	$375.00	$0	$375.00	$0	$0
Capacity (Non-Firm) Demand (T-1)	0	0	0	$1.35	$0	$1.35	$0	$0	$2.35	$0	$2.35	$0	$0
T-1 Distribution Charges													
0 - 15,000 therms	0	0	0	$0.08064	$0	$0.08064	$0	$0	$0.07290	$0	$0 07290	$0	$0
15,001 - 40,000 therms	0	0	0	$0 06891	$0	$0.06891	$0	$0	$0.06117	$0	$0 06117	$0	$0
40,001 - 150,000 therms	0	0	0	$0 03908	$0	$0.03908	$0	$0	$0 03134	$0	$0 03134	$0	$0
over 150,000 therms	0	0	0	$0 02402	$0	$0.02402	$0	$0	$0.01628	$0	$0 01628	$0	$0
Revenue Adjustment													
sub-Total Special Service (SS-1) Margin	0	0	0		$0		$0	$0		$0		$0	$0
Special Service (SS-1)					$0		$0	$0		$0		$0	$0
Margin Sharing from IMCR (90% of Difference between Special Service and T-1 Tariff)					$0		$0	$0		$0		$0	$0
Company Retained Base Rate Revenue					$0		$0	$0		$0		$0	$0
Total Firm Base Rate Revenues to Customers					$17,628,820		$8,591,533	$26,220,353		$16,807,773		$12,065,868	$28,873,641
Firm SPECIAL CONTRACTS					$67,788		$69,756	$137,544		$67,788		$69,756	$137,544
MISCELLANEOUS REVENUES					$432,098		$271,429	$703,527		$432,098		$271,429	$703,527
TOTAL FIRM Base Rate REVENUES w/ Special Contracts					$18,128,706		$8,932,718	$27,061,424		$17,307,659		$12,407,053	$29,714,712
TOTAL NON-FIRM Base Rate Revenues to Customers					$1,279,910		$1,277,270	$2,557,180		$1,239,637		$1,237,238	$2,476,875
Non-Firm SPECIAL CONTRACTS					$0		$0	$0		$0		$0	$0
TOTAL NON-FIRM base Rate REVENUES w/ Special Contracts					$1,279,910		$1,277,270	$2,557,180		$1,239,637		$1,237,238	$2,476,875
TOTAL FIRM AND INTERRUPTIBLE Base Rate REVENUES					$19,408,616		$10,209,988	$29,618,604		$18,547,296		$13,644,290	$32,191,588
% Increase												Total Increase	$2,572,983

Chattanooga Gas Company
Modified Demand Charge-Based SFV Rate Design

	Residential R-1			Residential Multi-Family R-4			Small General Service (C-1)			Medium General Service (C-2/T-3)		
	Demand Charge Rate	Sculpting Percentage	Sculpted Rate	Demand Charge Rate	Sculpting Percentage	Sculpted Rate	Demand Charge Rate	Sculpting Percentage	Sculpted Rate	Demand Charge Rate	Sculpting Percentage	Sculpted Rate
HEAT ONLY CUSTOMERS												
Month												
January	$7,760	23.0%	$ 21.39				$4 000	22.9%	$ 11.00	$11 000	22.9%	$ 30.22
February	$7 750	21.6%	$ 20.08				$4 000	21.4%	$ 10.28	$11,000	21.5%	$ 28.42
March	$7.750	16.0%	$ 14.85				$4 000	16.6%	$ 7 80	$11 000	16 0%	$ 21.06
April	$7 760	8.9%	$ 8.30				$4 000	8 9%	$ 4.27	$11 000	8 9%	$ 11.79
May	$7,760	3.1%	$ 2.84		Not Applicable		$4:000	3.3%	$ 1.59	$11 000	3.2%	$ 4 18
June	$7 760	0.6%	$ 0 44				$4 000	0 5%	$ 0 22	$11 000	0.5%	$ 0 63
July	$7.750	0.0%	$ -				$4.000	0.0%	$ -	$11,000	0 0%	$ -
August	$7 750	0.0%	$ -				$4.000	0.0%	$ -	$11.000	0 0%	$ -
September	$7.750	0 0%	$ -				$4,000	0.0%	$ -	$11,000	0.0%	$ -
October	$7 750	2 1%	$ 1.96				$4.000	2 0%	$ 0.94	$11 000	2 0%	$ 2 65
November	$7,750	8.2%	$ 7.64				$4 000	8.4%	$ 4.05	$11.000	8.3%	$ 10 97
December	$7 750	16.7%	$ 15.50				$4 000	16.7%	$ 8.04	$11.000	16.7%	$ 22.09
Total	$93,000	100.0%	$93,000				$48,000	100.0%	$48,000	$132.000	100.0%	$132,000
ALL OTHER CUSTOMERS												
Month												
January	$7,760	20.7%	$ 19.27	$3,000	14.5%	$ 5.24	$4.000	19.1%	$ 9.17	$11.000	16.7%	$ 22.10
February	$7.760	19.5%	$ 18.11	$3,000	19 8%	$ 7 12	$4,000	19.3%	$ 9.27	$11 000	16.6%	$ 21.97
March	$7.750	14.5%	$ 13 48	$3 000	11.7%	$ 4.22	$4.000	14.7%	$ 7.03	$11,000	13.6%	$ 17 98
April	$7.760	8.6%	$ 7.86	$3.000	7.8%	$ 2.80	$4,000	8.7%	$ 4.18	$11,000	9.8%	$ 12.94
May	$7.760	3.8%	$ 3.63	$3.000	4 0%	$ 1.43	$4.000	4.5%	$ 2.18	$11,000	6 6%	$ 8 76
June	$7.760	2.0%	$ 1.85	$3 000	3.4%	$ 1.23	$4.000	3.8%	$ 1 82	$11,000	4.8%	$ 6.39
July	$7.760	1.7%	$ 1.55	$3,000	3.7%	$ 1 33	$4.000	3.1%	$ 1.48	$11,000	3.6%	$ 4.72
August	$7.750	1.7%	$ 1.60	$3 000	4 3%	$ 1 56	$4.000	2.8%	$ 1.34	$11 000	3.3%	$ 4 30
September	$7.750	1.7%	$ 1.64	$3 000	4.0%	$ 1.45	$4,000	2.7%	$ 1.31	$11 000	3.1%	$ 4.11
October	$7.750	2.9%	$ 2 72	$3.000	4 2%	$ 1 52	$4.000	2 9%	$ 1.37	$11 000	3.5%	$ 4 58
November	$7,750	7.9%	$ 7 38	$3 000	8.7%	$ 3.14	$4.000	5 8%	$ 2.79	$11,000	6.4%	$ 8.38
December	$7 750	15.2%	$ 14.15	$3 000	13.8%	$ 4.96	$4.000	12.6%	$ 6.05	$11 000	12.0%	$ 15.78
Total	$93.000	100.0%	$93,000	$36.000	100.0%	$36,000	$48.000	100.0%	$48,000	$132,000	100.0%	$132.000

Chattanooga Gas Company
Comparison of SFV Rate Design Alternatives

RESIDENTIAL	Units	Existing Rate Design			Proposed Rate Design			Demand Charge - SFV Rate Design			Modified Demand Charge - SFV Rate Design			Fixed Charge - SFV Rate Design		
		Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%
Customer Charge																
Winter	321,872	$12.00	$ 3,860,060		$16.00	$ 5,146,746		$13.00	$ 4,181,731		$13.00	$ 4,181,731		$29.00	$ 9,328,477	
Summer	313,605	$10.00	3,136,047		$11.00	3,449,652		$11.00	3,449,652		$11.00	3,449,652		$18.38	5,764,055	
Total			$ 6,996,107	52.7%		$ 8,596,398	57.0%		$ 7,631,383	50.6%		$ 7,631,383	50.6%		$ 15,092,532	100.0%
Demand Charge																
Winter	340,539		$ -			$ -		$11.094	$ 3,777,940		$7.750	$ 2,639,177		$0.000	$ -	
Summer	331,999		-			-		$11.094	3,683,197		$7.750	2,572,992		$0.000	-	
Total			$ -	0.0%		$ -	0.0%		$ 7,461,137	49.4%		$ 5,212,170	34.5%		$ -	0.0%
Delivery Charge																
Winter																
0-25 Therms	7,467,700	$0.25444	$ 1,900,082		$0.26071	$ 1,946,904		$0.00000	$ -		$0.15824	$ 1,166,753		$0.00000	$ -	
25-50 Therms	6,164,870	$0.17547	1,081,750		$0.18174	1,120,403		$0.00000	-		$0.03948	243,389		$0.00000	-	
Over 50 Therms	16,542,330	$0.15354	2,539,909		$0.15981	2,643,630		$0.00000	-		$0.03948	653,091		$0.00000	-	
Subtotal	30,174,900		$ 5,521,741			$ 5,710,937			$ -			$ 2,063,234			$ -	
Summer																
0-25 Therms	3,497,280	$0.18425	$ 644,374		$0.19052	$ 666,302		$0.00000	$ -		$0.03948	$ 138,073		$0.00000	$ -	
25-50 Therms	691,320	$0.13160	90,978		$0.13787	95,312		$0.00000	-		$0.03948	27,293		$0.00000	-	
Over 50 Therms	508,710	$0.03948	20,084		$0.04575	23,273		$0.00000	-		$0.03948	20,084		$0.00000	-	
Subtotal	4,697,310		$ 755,435			$ 784,888			$ -			$ 185,450			$ -	
Total	34,872,210		$ 6,277,176	47.3%		$ 6,495,825	43.0%		$ -	0.0%		$ 2,248,684	14.9%		$ -	0.0%
TOTAL ALL REVENUES			$ 13,273,283	100.0%		$ 15,092,223	100.0%		$ 15,092,520	100.0%		$ 15,092,236	100.0%		$ 15,092,532	100.0%
					Note:	AUA Rider addresses delivery charge revenue variance		Note:	Demand Charge charge s to recover greater proportion in winter		Note:	Demand Charge charge sculpted to recover greater proportion in winter				

Chattanooga Gas Company
Comparison of SFV Rate Design Alternatives

R-4

		Existing Rate Design			Proposed Rate Design			Demand Charge - SFV Rate Design			Modified Demand Charge - SFV Rate Des			Fixed Charge - SFV Rate Design		
	Units	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%
Customer Charge																
Winter	1,110	$6.00	$ 6,660		$6 00	$ 6,660		$6.00	$ 6,660		$6 00	$ 6,660				
Summer	1,110	$6 00	6,660		$6.00	6,660		$6.00	6,660		$6.00	6,660				
Total			$ 13,320	43.3%		$ 13,320	39.8%		$ 13,320	39.8%		$ 13,320	39.8%			
Demand Charge																
Winter	2,352	-	$ -		-	$ -		$4.286	$ 10,081		$3.000	$ 7,056				
Summer	2,352	-	-		-	-		$4.286	10,081		$3.000	7,056			Not Applicable	
Total			$ -	0.0%		$ -	0.0%		$ 20,161	60.2%		$ 14,112	42.2%			
Delivery Charge																
Winter	82,758	$0.21766	$ 13,661		$0.25096	$ 15,749		$0 00000	$ -		$0.07929	$ 4,976				
Summer	19,448	$0.19350	3,763		$0.22678	4,410		$0.00000	-		$0.05511	1,072				
Total			$ 17,424	56.7%		$ 20,160	60.2%		$ -	0.0%		$ 6,048	18.1%			
TOTAL ALL REVENUES			$ 30,744	100.0%		$ 33,480	100.0%		$ 33,481	100.0%		$ 33,480	100.0%			
					Note:	AUA Rider addresses delivery charge revenue variance		Note:	Demand Charge charge s to recover greater proportion in winter		Note:	Demand Charge charge sculpted to recover greater proportion in winter				

Chattanooga Gas Company
Comparison of SFV Rate Design Alternatives

C-1

	Units	Existing Rate Design			Proposed Rate Design			Demand Charge - SFV Rate Design			Modified Demand Charge - SFV Rate Des			Fixed Charge - SFV Rate Design		
		Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%
Customer Charge																
Winter	39,583	$29.00	$ 1,147,330		$29.00	$ 1,147,330		$29.00	$ 1,147,330		$29.00	$ 1,147,330				
Summer	38,077	$25.00	951,914		$25.00	951,914		$25.00	951,914		$25.00	951,914				
Total			$ 2,099,244	59.6%		$ 2,099,244	52.5%		$ 2,099,244	52.5%		$ 2,099,244	52.5%			
Demand Charge																
Winter	183,802	-	$ -		-	$ -		$5.281	$ 969,602		$4.000	$ 734,408			Not Applicable	
Summer	176,703	-	-		-	-		$5.281	933,169		$4 000	706,812				
Total			$ -	0.0%		$ -	0.0%		$ 1,902,771	47.5%		$ 1,441,220	36.0%			
Delivery Charge																
Winter	6,441,514	$0 18581	$ 1,196,898		$0 24630	$ 1,586,545		$0.00000	$ -		$0.06555	$ 422,241				
Summer	1,532,171	$0.14589	223,528		$0.20638	316,209		$0.00000	-		$0 02563	39,270				
Total			$ 1,420,426	40.4%		$ 1,902,754	47.5%		$ -	0.0%		$ 461,511	11.5%			
TOTAL ALL REVENUES			$ 3,519,670	100.0%		$ 4,001,999	100.0%		$ 4,002,015	100.0%		$ 4,001,975	100.0%			
					Note:	AUA Rider addresses delivery charge revenue variance		Note:	Demand Charge charge s to recover greater proportion in winter		Note:	Demand Charge charge sculpted to recover greater proportion in winter				

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Chattanooga Gas Company
Comparison of SFV Rate Design Alternatives

C-2/T-3

		Existing Rate Design			Proposed Rate Design			Demand Charge - SFV Rate Design			Modified Demand Charge - SFV Rate Des			Fixed Charge - SFV Rate Design		
	Units	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%	Rate	Revenues	%
Customer Charge																
Winter	9,624	$75.00	$ 721,800		$75.00	$ 721,800		$75.00	$ 721,800		$75.00	$ 721,800				
Summer	9,624	$75.00	721,800		$75 00	721,800		$75.00	721,800		$75.00	721,800				
Total			$ 1,443,600	19.3%		$ 1,443,600	18.9%		$ 1,443,600	19.6%		$ 1,443,600	19.4%			
Demand Charge																
Winter	174,662	$ 5.500	$ 960,640		$7.500	$ 1,309,964		$16.940	$ 2,958,771		$11 000	$ 1,921,280				
Summer	174,662	$ 5.500	960,640		$7.500	1,309,964		$16.940	2,958,771		$11.000	1,921,280			Not Applicable	
Total			$ 1,921,280	25.7%		$ 2,619,927	34.3%		$ 5,917,542	80.4%		$ 3,842,560	51.5%			
Delivery Charge																
Winter																
0-3,000 Therms	11,637,600	$0 18744	$ 2,218,640		$0.16412	$ 1,942,787		$0.00000	$ -		$0.10811	$ 1,279,763				
3,001-5,000 Therms	1,938,569	$0.17109	331,670		$0.16412	318,158		$0.00000	-		$0.10811	209,579				
5,001-15,000 Therms	3,102,952	$0.16666	517,138		$0 14564	451,914		$0.00000	-		$0.08963	278,118				
Over 15,000 Therms	1,542,264	$0.08623	132,989		$0 06521	100,571		$0.00000	-		$0.00920	14,189				
Subtotal	18,421,386		$ 3,200,637			$ 2,813,430			$ -			$ 1,781,648				
Summer																
0-3,000 Therms	4,689,452	$0.14717	$ 690,147		$0 12253	$ 574,599		$0.00000	$ -		$0 06652	$ 311,942				
3,001-5,000 Therms	635,982	$0.11683	74,302		$0.12253	77,927		$0.00000	-		$0.06652	42,306				
5,001-15,000 Therms	1,119,345	$0.10892	121,919		$0.08790	98,390		$0.00000	-		$0.03189	35,696				
Over 15,000 Therms	271,350	$0.08623	23,398		$0.06521	17,695		$0.00000	-		$0.00920	2,496				
Subtotal	6,716,129		$ 909,766			$ 768,611			$ -			$ 392,440				
Total	25,137,515		$ 4,110,403	55.0%		$ 3,582,041	46.9%		$ -	0.0%		$ 2,174,088	29.1%			
TOTAL ALL REVENUES			$ 7,475,283	100.0%		$ 7,645,568	100.0%		$ 7,361,142	100.0%		$ 7,460,248	100.0%			
					Note:	AUA Rider addresses delivery charge revenue variance		Note:	Demand Charge charge s- to recover greater proportion in winter		Note:	Demand Charge charge sculpted to recover greater proportion in winter				