BEFORE THE PUBLIC SERVICE COMMISSION
OF UTAH

IN THE MATTER OF:

Joint Application of Questar Gas	)	
Company, the Division of Public	)	
Utilities, and Utah Clean Energy	)	**Docket Number 05-057-T01**
For the Approval of the Conservation	)	
Enabling Tariff Adjustment Option	)	
And Accounting Orders	)	

DIRECT TESTIMONY
OF
DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE
UTAH COMMITTEE OF CONSUMER SERVICES

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I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 6455 Overton Street, Baton Rouge, Louisiana.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

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

Q. HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY OUTLINING YOUR QUALIFICATIONS IN ENERGY AND REGULATED INDUSTRIES?

A. Yes. Attachment 1 to my testimony provides my professional resume that includes a complete list of my publications, presentations, and pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by Utah Committee of Consumer Services ("Committee") to provide an expert opinion on whether or not Questar Gas Company's ("Questar" or "the Company") Conservation Enabling Tariff ("CET") should be continued.

Q. HOW IS THE REMAINDER OF YOUR CURRENT TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations;
- Section III: Procedural History;
- Section IV: Overview of Revenue Neutrality Mechanisms;
- Section V: Maintaining the CET Would Not Be in the Public Interest and Should be Discontinued;
- Section VI: Direct Ratepayer Benefits of the CET are Small
- Section VII: Alternative Remedies for Dealing with Energy Efficiency Disincentives;
- Section VIII: Alternative Methods for Dealing with Declining Use Per Customer;
- Section IX: Conclusions and Recommendations.

Q. HAVE YOU PROVIDED ANY ATTACHMENTS TO YOUR TESTIMONY?

A. Yes, I have included two attachments to my testimony which include my professional resume and a summary overview of state decisions where revenue decoupling was rejected or withdrawn. .

Q. HAVE YOU PROVIDED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I have prepared 17 exhibits to accompany my testimony. The exhibits were prepared by me or under my direct supervision.

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT IS YOUR GENERAL RECOMMENDATION IN THIS PROCEEDING?

A. The CET should be discontinued on a forward going basis. In examining the Company's potential revenues at risk, it is clear at this time that the most significant challenge it faces is a potential exposure to future revenue losses resulting from declines in use per customer rather than large revenue losses associated with the promotion of Demand-Side Management ("DSM") programs. Revenue losses resulting from DSM programs are estimated to be less than one-half of one percent; thus, they are simply not that significant and can be easily accommodated within a straightforward lost revenues adjustment mechanism.

Q. HOW CAN A DECLINE IN USE PER CUSTOMER CREATE RISKS FOR A COMPANY THAT IS SEEING STRONG REVENUE GROWTH RIGHT NOW?

A. Revenue changes, as I will discuss later in my testimony, have two related parts that involve both (1) changes in use per customer and (2) changes in the number of customers. Currently, revenues are increasing due to rapid customer growth. The Company's problem appears to stem from the relationship between the marginal increase in revenues associated with new customers and a much higher marginal increase in investment cost per customer.

Q. SHOULDN'T THE COMPANY BE GIVEN AN OPPORTUNITY TO EARN ITS ALLOWED RETURN?

A. Yes, but it is my recommendation that the CET is not the appropriate mechanism to use for maintaining this opportunity. As I discuss in my testimony, there are a wide range of other regulatory mechanisms that can address these ratemaking and cost-recovery problems.

Q. HAS THE COMPANY'S EARNINGS SUFFERED DUE TO THESE CHANGES IN USE PER CUSTOMER?

A. No. The Company's earnings have not suffered primarily because revenues from overall customer growth have been so significant. Over the past five years, the Company's Utah jurisdictional DNG related return on equity (ROE) has been between 9.06 and 11.09 percent. In 2006, the Company's earnings were 10.86 percent compared to its currently allowed return of 11.2 percent. Earnings for 2007 are forecasted to be 10.32 percent.

Q. WHAT ARE YOUR FUNDAMENTAL OBJECTIONS TO THE USE OF REVENUE DECOUPLING MECHANISMS LIKE THE CET?

A. Revenue decoupling mechanisms are overly broad and shift considerable usage-related risks from the Company and its shareholders to ratepayers. Mechanisms like the CET eliminate a customer's ability to fully realize the complete benefits of their actions to reduce consumption in this high energy price environment. This is neither fair nor efficient since over the long run it can dampen customers' incentives to reduce consumption.

Q. DO YOU SEE DECOUPLING AS PART OF A BROADER TREND IN UTILITY REGULATORY PROPOSALS?

A. Yes. As I will discuss later in my testimony, revenue decoupling is part of a broader set of policy initiatives offered by utilities which shift risk from shareholders to ratepayers. Some of these proposals in gas industry regulation include:

(1) The creation of gas cost recovery ("GCR") mechanisms;

(2) The creation of weather normalization clauses;

(3) The recovery of Lost and Unaccounted for Gas ("LAUF") in GCRs;

(4) The creation of pipeline replacement cost recovery riders;

(5) Shorter weather normalization periods.

Some of the recent proposals in electric industry regulation include:

(1) Bonus or incentive ROEs on the construction of baseload power plants;

(2) Cash earnings on Construction Work in Progress ("CWIP") on nuclear power plants and other baseload generation investments;

(3) Cash earnings on CWIP for power transmission investments;

(4) Antecedent prudence reviews on major capital projects;

(5) Shorter weather normalization periods.

Q. DO YOU HAVE ANY CONCERNS ABOUT THESE TYPES OF PROPOSALS?

A. Yes, these types of proposals raise questions about the proper risk sharing relationship between ratepayers and shareholders. In reviewing several of these types of proposals in both the gas and electric industry, my concern is (1) the precedent-setting nature of the decisions, (2) their piecemeal adoption, and (3) the potential movement down a slippery slope of disjointed policy mechanisms that have interactive and unintended rate implications for ratepayers. One particular concern I have is that many of these proposals fail to attempt to make any ratemaking adjustment for this fundamental shift in risk from shareholders to ratepayers..

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS IN THIS PROCEEDING?

A. I have three primary recommendations:

(1) The Commission should discontinue the use of the CET since it shifts considerable sales risk to ratepayers with little to no offsetting benefits for ratepayers assuming those risks. Further, the CET is overly broad in addressing the problems associated with declining use per customer trends and is unnecessary to address incentive issues associated with the promotion of DSM programs.

(2) The Commission should adopt a lost revenue adjustment ("LRA") mechanism to make the Company whole for changes in usage resulting from its DSM programs. Lost revenue recovery should be tied directly to the estimates included in the Company's DSM cost-effectiveness filings, and updated according to the ongoing

monitoring and verification (M&V) process.

(3) The Commission should direct the Company to address any financial challenges created by decreases in use per customer in its next rate case through the use of a forecasted test year or some known and measurable adjustment if a historic test year is utilized for ratemaking purposes.

Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS?

A. Yes, should the Commission reject my primary recommendations and decide to maintain the CET I would recommend:

(1) The Commission require the CET to be modified such that decoupling true-ups are based upon the difference in historic and actual use per customer times test year customers (or base year customers upon which the revenue per customer statistic is derived) rather than actual customers.

(2) The Commission should explicitly recognize the risk shifting nature of the CET and indicate in its Order that this shifting of risk will be considered in setting the Company's ROE in its next rate case.

III. <u>PROCEDURAL HISTORY</u>

Q. WOULD YOU PLEASE DISCUSS YOUR UNDERSTANDING OF THIS PROCEEDING'S ORIGINS?

A. On December 16, 2005, the Company, the Division of Public Utilities ("the Division") and Utah Clean Energy ("UCE") filed a Joint Application requesting approval of a Conservation Enabling Tariff ("CET") and other enabling accounting mechanisms and proposals. The Joint Applicants offered the CET proposal to remedy what they saw as two fundamental problems confronting the Company. The first problem was the purported financial disincentive related to the promotion of DSM programs. The second problem was the claimed financial challenges stemming from a declining use per customer trend.

Q. WERE YOU ASKED BY THE COMMITTEE TO OFFER AN EXPERT OPINION ON THE CET PROPOSAL?

A. Yes. I provided rebuttal testimony to the Joint Applicants on May 15, 2006. It was my expert opinion and recommendation that the Commission reject the CET proposal as not being in the public interest. My testimony stated:

(1) The CET represented a significant change in ratemaking and shifted risk to customers without any corresponding offset or benefit like a reduction on the overall allowed rate of return. It was, and still is my opinion, that the benefits of the CET are clear for Questar, but questionable for ratepayers.

(2) The CET proposal, as a mechanism to support DSM and declining use per customer trend, was based upon a questionable premise of disincentives. For instance:

a. Utilities have an obligation to provide least-cost reliable service, and if DSM is the least cost resource, utilities are obligated to acquire that resource.

b. If utilities experience a decline in earnings from declining use per customer, they have the option of seeking rate relief.

(3) There are a number of other, less dramatic regulatory mechanisms that can adjust utility rates for changes in usage created by either long run trends in overall efficiency or the Company's DSM programs.

Q. HAS YOUR EXPERT OPINION CHANGED SINCE FILING YOUR TESTIMONY LAST YEAR?

A. No. My expert opinion has not changed. I continue to believe that the CET is not a positive rate design change for ratepayers. I recommend that the Commission discontinue its use on a forward-going basis.

Q. DID YOU OFFER ANY ADJUSTMENTS OR ALTERNATIVES TO THE CET AS A RESULT OF THE JUNE 7, 2006 TECHNICAL CONFERENCE?

A. The Commission's Staff requested that parties provide a number of potential alternatives to the proposed CET during the course of the June 7, 2006 Technical Conference. This request was part of a larger set of questions submitted by Commission Staff to parties for comment relative to the CET. I provided Supplemental Testimony responding to all of these questions, including a number of possible alternatives to the CET. The two alternatives that I provided at that time were: (1) an incentive-based system where a utility's reward increases as it secures greater levels of cost-effective DSM savings; and (2) a "statistical recoupling" mechanism that would attempt to re-couple some of the exogenous factors (changes in gas commodity prices, economy, weather, etc.) impacting revenue back onto the Company and its shareholders.

IV. OVERVIEW OF REVENUE NEUTRALITY MECHANISMS

Q. WOULD YOU PLEASE DEFINE REVENUE NEUTRALITY?

A. Revenue neutrality can be defined as a set of policy mechanisms that make a utility indifferent to its level of sales. Typically, these policy mechanisms establish rate designs that either (a) remove revenue recovery from sales through some kind of fixed charge or (b) true-up revenues to some target amount. The goal of revenue neutrality mechanisms has generally been to remove a utility's purported disincentive to promoting energy efficiency. Over time, revenue neutrality mechanisms began to be promoted as (a) more consistent with "sound economic principles," and (b) giving utilities a better opportunity to earn their authorized rates of return.

Q. IS REVENUE NEUTRALITY A NEW IDEA?

A. No. As a regulatory concept, revenue neutrality has been around for nearly twenty years. In fact, the first Energy Policy Act (of 1992) addressed revenue neutrality and required states to consider this mechanism in conjunction with integrated resource planning ("IRP") standards, which emphasized the use of demand-side resources in a manner comparable to traditional supply-side considerations. The purported goals of revenue neutrality policies then, as well as now, were to develop rate design approaches that supposedly make a utility indifferent between promoting energy efficiency and sales.

Q. WHAT TYPES OF POLICY MECHANISMS ARE USED TO PROMOTE REVENUE NEUTRALITY?

A. Since the early 1990s, a variety of different approaches to revenue neutrality have been adopted. The primary revenue neutrality methods being promoted in the natural gas industry include what are commonly referred to as "revenue decoupling" (and its different forms) and "straight-fixed variable" ("SFV") rate design mechanisms.

Q. HAS REVENUE NEUTRALITY BEEN WIDELY ADOPTED SINCE THE PASSAGE OF EPACT 1992?

A. No. The original impetus for revenue neutrality was in the electric power industry. However, a combination of competition, a decades-long boom in the U.S. economy, and low fossil fuel prices worked to diminish interest in revenue decoupling throughout most of the 1990s. Recent increases in fossil fuel prices, particularly natural gas, have renewed interest in this ratemaking concept, particularly for natural gas LDCs, although several electric utilities are starting to revisit the concept as well.

Q. CAN YOU BRIEFLY DESCRIBE A SFV RATE DESIGN?

A. A SFV rate design represents a dramatic change in the method in which utilities charge their customers for distribution service. Common utility pricing practice is based upon what is referred to as a "two-part tariff." This two-part tariff is comprised of a fixed customer charge and a per unit (volumetric) charge. Natural gas commodity charges are also variable, and applied to customers' bills on a usage basis. A SFV rate design completely changes this pricing practice and recovers all distribution (non-gas) charges on a fixed basis rather than the commonly accepted two-part approach. Under SFV, the only variable charge the customer will see is the commodity gas charges recovered through the gas cost recovery ("GCR") rate.

Q. EARLIER YOU MENTIONED THAT REVENUE DECOUPLING IS A FORM OF REVENUE NEUTRALITY. PLEASE EXPLAIN THE CONCEPT OF REVENUE DECOUPLING IN GREATER DETAIL?

A. Revenue decoupling is a form of revenue neutrality that changes the manner in which revenues are collected from ratepayers. Typically, rates are fixed and based upon an allowed rate of return (among other factors). While the allowed revenues included in this formula are considered fixed, actual revenues vary from year-to-year depending upon a wide range of factors. Revenue decoupling basically changes the nature of this process. Under a revenue decoupling regime, revenues are fixed and virtually guaranteed while rates are allowed to vary from year-to-year to assure a guaranteed level of revenue recovery.

Q. HOW DOES REVENUE DECOUPLING WORK?

A. Revenue decoupling is typically done on a revenue per customer basis where an allowed revenue per customer is established in a rate case, or some other agreed upon level. This allowed revenue per customer is then determined for every month of the year. Over time, the allowed revenue per customer is compared to the actual revenue per customer. If actual revenues are lower than allowed, the revenue shortfall is booked to a true-up account to be factored into rates. These true-ups can occur as frequently as every month, every quarter, or annually. The process is symmetrical – if revenues are greater than allowed, excess revenues are credited to the balancing account for a future rate decrease.

Q. CAN REVENUE DECOUPLING TAKE DIFFERENT FORMS?

A. Yes, there are two general forms of revenue decoupling: full revenue decoupling and partial revenue decoupling. Full decoupling allows the entire under or over-recovery of revenues to fall into a balancing account for later true up. Partial decoupling only allows some part of that overage/underage to enter the balancing account. In some instances, the balances are adjusted for changes in prices, weather, and/or the economy. That is, revenue changes related to gas commodity prices, the economy or weather are not eligible for recovery in the balancing account. This process can also be referred to as "statistical re-coupling" since estimates from statistical load forecasts are used to make the price, weather, and economic-related adjustments. Another form of partial decoupling can occur through a fixed cap percentage on revenue recovery. For instance, North Carolina has caps on total decoupling balance recoveries. The current interim approach in Utah also has a cap on total revenues that can be recovered in the decoupling balancing account.

Q. ARE SFV AND REVENUE DECOUPLING RELATED?

A. Somewhat. Revenue decoupling usually preserves the traditional rate design structure utilized by most state regulatory commissions where distribution service rates are comprised of a fixed customer charge and a volumetric distribution charge. Revenue decoupling sets a revenue per customer level to be recovered under these rates: if actual recovery falls below the target, then rates are increased in a subsequent period to make up for the shortfall and vice versa. Thus, one can think of revenue decoupling as creating a true-up process that sets variable rates at a level that makes customers indifferent between rates being fixed or variable. SFV can be thought of as "perfect revenue decoupling" since rates are not required to be "trued-up" in any given year and are directly (rather than indirectly) charged to customers on a fixed per-customer basis.

Q. HOW ARE THESE TWO REVENUE NEUTRALITY MECHANISMS RELATED TO QUESTAR'S CET?

A. The Company's CET is a form of full revenue decoupling where actual revenues are trued-up to some fixed benchmark. Customers would still be billed on a volumetric basis, but these volumetric rates would be "trued-up" periodically based upon the actual revenues collected per customer. In effect, the revenue decoupling process makes the Company indifferent between collecting DNG revenues through fixed or variable charges. The process is similar in may ways to loading total DNG revenue requirements into a fixed charge since customers are no longer able to avoid any portion of the DNG revenue requirement through reduced usage.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes, CCS Exhibit 1.1 shows how the CET works. The first step, conducted in an earlier phase of this proceeding, was to set a base year (or test year) DNG revenue per customer level. For illustration purposes, the test year total DNG revenue per customer is $250. The second step is to allocate the total charge per customer on a monthly basis over the course of a "typical" year which is provided in the second box of this exhibit. Each month the actual revenues collected per customer (from the per unit, or per Mcf charge) are compared to allowed monthly amounts and are either credited or debited to a balancing account. The balancing account is "trued-up" at every six months, and the resulting amount is applied to the volumetric charge on customers' bills. The new volumetric charge resulting from the example is provided in the third box. This represents the difference for the month of January alone. The same procedure would need to be replicated for the remaining 11 months of the year, and the accrual summed to a total amount.

Q. IS REVENUE NEUTRALITY PRESENTLY UNDERGOING AN ACTIVE POLICY DEBATE?

A. Yes. Revenue neutrality is being actively debated before various state legislatures and state regulatory commissions. For some groups, revenue neutrality is seen as a must-have for the promotion of energy efficiency. Other groups, particularly consumer groups, are very concerned about the adoption of these types of policy mechanisms and the implications they may have for customer bills. Two prominent consumer groups have recently either opposed or had members expressing serious concerns regarding revenue neutrality mechanisms. These groups include the Electric Consumers Resource Council ("ELCON") and the National Association of State Utility Consumer Advocates ("NASUCA").

Q. WHAT POSITION HAS ELCON TAKEN RECENTLY ON REVENUE DECOUPLING?

A. ELCON, an advocacy group comprised of a large number of major industrial customers of electricity, has recently issued both a position statement and White Paper that is adamantly opposed to revenue decoupling: a position similar to that taken by most industrial customers in the early 1990s when revenue neutrality mechanisms were initially debated. The White Paper issued by ELCON noted many flaws with this policy mechanism including:

(1) Decoupling promotes mediocrity in the management of a utility;

(2) Decoupling shifts significant business risk from shareholders to consumers with only limited opportunities for net increases in consumer benefits;

(3) Decoupling eliminates a utility's financial incentive to support economic development within its franchise area;

(4) Decoupling tends to address "Lost Revenues" and not the real issue which is "lost profits;"

(5) Sending appropriate price signals is the most important step in promoting energy efficiency;

(6) Third party, independent delivery of energy efficiency services is a more effective means of addressing incentives.

Q. WHO DOES NASUCA REPRESENT?

A. NASUCA represents the various state-funded attorneys general, consumer counsels, and consumer advocate agencies charged with representing the interests of small customers in utility proceedings.

Q. HAS NASUCA ISSUED A FORMAL POSITION STATEMENT OR RESOLUTION ON REVENUE DECOUPLING?

A. Decoupling is a topic being closely watched by various NASUCA Committees (consumer protection, gas and electric) and will be actively discussed in Denver this summer. Most of the member states of NASUCA that have been engaged in revenue neutrality proceedings at the state level have opposed most forms of revenue neutrality, including revenue decoupling.

Q. WHAT IS THE CURRENT STATUS OF REVENUE NEUTRALITY PROPOSALS?

A. Various states have taken action on revenue decoupling and SFV rate design proposals for both electric and gas utilities. CCS Exhibit 1.2 and CCS Exhibit 1.3 provide maps showing the states that have considered each of these policy mechanisms. While many states have considered both forms of revenue neutrality, very few have adopted SFV, while only slightly more have embraced revenue decoupling.

Q. HOW MANY STATES HAVE EITHER ADOPTED OR ARE CURRENTLY CONSIDERING THE ADOPTION OF REVENUE DECOUPLING MECHANISMS?

A. CCS Exhibit 1.2 shows the recent activity on revenue decoupling for electric and gas utilities across the U.S. Currently, there are ten states that have adopted revenue decoupling as either a permanent or pilot mechanism for electric and/or gas utilities. These states include North Carolina, Indiana, Ohio, New Jersey, Maryland, Vermont, California, Oregon, Idaho, and Utah. Another three states (Minnesota, Colorado, and Nebraska) are currently considering revenue decoupling.

Q. HAVE ANY STATES REJECTED REVENUE DECOUPLING PROPOSALS?

A. Yes, revenue decoupling proposals for gas or electric utilities have either been rejected by state commissions or withdrawn by utilities in eleven states, including Washington, Arizona, Nevada, Kansas, Arkansas, Wisconsin, New York, Delaware, Michigan, Iowa, and Connecticut. All of these states except for Arkansas have an active DSM program in place for the utility whose revenue decoupling proposal was either rejected or withdrawn. Most state commissions rejected revenue decoupling on a variety of sound public policy reasons that are consistent with the position taken by the Committee in this proceeding. Further, many of these state commissions were not convinced that revenue decoupling was necessary for the adoption of cost-effective DSM programs. Appendix 2 provides a summary of the state decisions rejecting revenue decoupling or states in which revenue decoupling proposals were withdrawn.

Q. IS REVENUE DECOUPLING REQUIRED FOR THE ADOPTION OF ENERGY EFFICIENCY?

A. No. CCS Exhibit 1.2 clearly shows there are a large number of electric and gas utilities operating in ten states that have mature and extensive energy efficiency programs without a revenue decoupling mechanism. Some 21 states, accounting for around 47 percent of all U.S. residential electric and gas customers, have found a way to promote energy efficiency under more traditional ratemaking approaches.

Q. HAVE THE STATES RECENTLY ADOPTING REVENUE DECOUPLING SEEN CONSIDERABLE DSM INITIATIVES BY THEIR REGULATED UTILITIES?

A. Some have, while others have not. In Utah, Questar has clearly made a significant effort in developing DSM programs on an accelerated pace. However, in other states, the results are a little more mixed. For example, revenue decoupling was adopted in Ohio and Indiana in the latter half of 2006, but utilities have been slow to respond with new DSM programs. North Carolina adopted revenue decoupling about 18 months ago and ratepayers are being asked to cover a $50 million revenue decoupling balancing account shortfall with what appears to be limited access to DSM programs.

Q. WHAT HAS BEEN THE PROCEDURAL CONTEXT IN WHICH REVENUE NEUTRALITY PROPOSALS HAVE BEEN CONSIDERED IN OTHER STATES?

A. Over the past three years, revenue neutrality programs have been considered in at least 15 rate case proceedings rather than a stand-alone docket like the one in Utah. This is an important distinction since a rate case gives a regulatory commission, as well as other parties, a wide range of ratemaking tools and policy options to address structural and programmatic changes in demand that may be affecting a utility's earnings.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW A RATE CASE WOULD BE A BETTER VENUE TO CONSIDER MANY OF THE ISSUES RAISED BY THE COMPANY?

A. Yes, if the declining use per customer trend is significant and quantifiable, then there are approaches such as repression adjustments to test year billing determinants that can account for the structural changes in demand. Examining these issues outside of a general rate case confines the potential remedies to an "all-or-nothing" solution: revenue decoupling or nothing. Unfortunately, this is very limiting, and I will discuss some of the other options at the Commission's disposal (most of which would be in the context of a rate case) in Section VII of my testimony.

V. MAINTAINING THE CET WOULD NOT BE IN THE PUBLIC INTEREST AND SHOULD BE DISCONTINUED

Q. IS IT CLEAR THAT A SIGNIFICANT UTILITY DISINCENTIVE TO PROMOTE ENERGY EFFICIENCY REALLY EXISTS?

A. No. It is not clear that a significant utility disincentive exists in promoting least-cost efficiency resources because often the net results of utility-sponsored DSM are varied. For some utilities, promoting energy efficiency can be a means of offering a value-added service that reduces customer bills, increases customer satisfaction, increases planning flexibility, and reduces the overall long run cost of service. Further, utilities should have a very strong incentive to develop least cost resources through traditional regulation and their opportunity to earn a fair rate of return on their investments.

Q. ARE THERE ANY OTHER REASONS WHY DSM CAN IMPACT UTILITY PROFITABILITY DIFFERENTLY?

A. Yes, it is difficult to assign any generalized DSM-specific impact on utility profitability since the net result is influenced by a range of factors that can include the types of programs a utility promotes, the forecasted changes in its customer base and its costs of serving those customers, the certainty with which it has estimated potential customer savings, the costs and scope of the energy efficiency programs it is promoting, and other incentives (both positive and negative) that have been offered by its state utility regulators.

Q. IN LOOKING AT OTHER GAS UTILITIES, IS IT THE CASE THAT REVENUE DECOUPLING IS NEEDED IN ORDER TO BE SUCCESSFUL AT PROMOTING DSM?

A. No, that does not appear to be the case. CCS Exhibit 1.4 is a modified version of an exhibit presented by one of the Joint Applicants in the original filing (Exhibit HG-2) examining DSM programs, costs, and savings for 2004. Of the ten gas utilities listed, only three have revenue decoupling. Interestingly enough, the top two gas utilities on the list in terms of total program spending as a percent of retail revenues (Vermont Gas and Aquila) do not have revenue decoupling. However, these two utilities outspend as a share of revenues, the three utilities that have revenue decoupling. In terms of performance, Vermont Gas and Keyspan were able to attain benefit-cost ratios of 5.6 and 3.0, respectively, without any type of revenue decoupling program.

Q. LOOKING AT THIS ISSUE MORE BROADLY, IS IT THE CASE THAT MOST ELECTRIC AND GAS UTILITIES PROMOTING DSM HAVE REVENUE DECOUPLING MECHANISMS?

A. No. Exhibit CCS Exhibit 1.2, discussed earlier, also shows that there are several states that require the use of energy efficiency programs yet have no revenue decoupling mechanisms. Currently, there are ten states that have energy efficiency programs but do not have revenue decoupling mechanisms.

Further, all of the 11 states which recently rejected or withdrew revenue decoupling have programs to support energy efficiency. In total, there are some 21 states which support energy efficiency without revenue decoupling.

Q. DOES REVENUE DECOUPLING HAVE ANY NEGATIVE IMPLICATIONS FOR RATEPAYERS?

A. Yes, revenue neutrality proposals can have a number of negative implications for ratepayers including shifting a wide range of traditional business risks away from shareholders and towards ratepayers. This includes risks associated with changes in the economy, changes in commodity prices, and in some instances, changes in weather. Those proposals that fail to account for this risk shifting, through some type of adjustment mechanism, can impose a cost onto ratepayers without any corresponding benefit.

Q. HOW DO TYPICAL REVENUE NEUTRALITY PROPOSALS SHIFT RISK AWAY FROM UTILITIES AND TOWARDS CUSTOMERS?

A. Risk is shifted to customers through the revenue per customer true-up mechanism. This mechanism provides utilities with a **guaranteed** revenue per customer amount. Current regulatory approaches only give utilities an **opportunity** to earn typical revenues, but do not guarantee that recovery. Under the current rate design, customers have the opportunity to avoid a portion of their distribution non-gas charges if they conserve energy (lower consumption), install energy efficient appliances, or take other energy efficiency steps. This will not be the case under the CET which essentially requires customers to reimburse the utility for any savings that result from customers' conservation efforts. .

Q. WHAT TYPES OF FACTORS IMPACT REVENUE RECOVERY UNDER TRADITIONAL REGULATORY APPROACHES?

A. A number of factors can influence sales including economic conditions, gas commodity prices, weather, and other unanticipated events that impact usage. Under traditional regulation, these risks are usually borne by the utility, not by ratepayers. Under the Company's proposals, these risks are entirely shifted to ratepayers since there is no means for customers to reduce distribution charges by reducing usage in the face of economic recessions, higher prices, warmer weather, and other factors.

Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?

A. If revenues decline due to a contraction in the economy, customers will be required to make the utility whole for those revenue shortfalls. Decreases in sales associated with economic downturns have nothing to do with energy efficiency or a DSM program promoted by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times. Under the CET, customers will be required to make a utility whole for possible losses during economic downturns, whereas under traditional regulation, this would not have been the case.

Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE NEUTRALITY PROGRAMS CREATED SERIOUS PROBLEMS DURING AN ECONOMIC CONTRACTION?

A. Yes, one of the more widely-recognized failures of revenue decoupling occurred in Maine during the early 1990s. The program, known as "ERAM"

("Electric Revenue Adjustment Mechanism"), was put into place for a three-year trial period to encourage Central Maine Power ("CMP") to promote DSM. The ERAM had no adjustments for changes in regional activity. The adoption of the ERAM coincided with a recession that resulted in lower sales levels and substantial revenue deferrals. CMP was entitled to recover these deferrals under the provisions of the ERAM mechanism, which by the end of 1992 reached $52 million. Only a very small portion of this amount was attributed to CMP's conservation efforts as most of the deferral resulted from the economic recession. The ERAM was viewed by many as a mechanism that shielded CMP from the economic impact of the recession rather than furthering the intended conservation incentives. CMP's ERAM was terminated on November 30, 1993.[1]

Q. HOW IS COMMODITY PRICE RISK SHIFTED TO CUSTOMERS?

A. When gas commodity prices increase, customers tend to reduce consumption. In fact, it is likely that some portion of the decreases in use per customer highlighted throughout the Company's original application are the result of price-induced reductions in consumption created by recent increases in natural gas prices. Since the Company did not have DSM programs in place prior to January 2007, these historic use per customer reductions are clearly based upon actions taken by customers, not Questar. While the Company has been active in developing and rolling out its DSM programs over the past year, it will take some time before participation goals (savings) are realized. Thus, any balances

[1] *Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability*, Maine Public Utilities Commission, Presented to the Utilities and Energy Committee, February 1, 2004, Internet Website: http://www.maine.gov/mpuc/staying_informed/legislative/2004legislation/Eff-Rel%20Report-final.htm

(positive or negative) associated with the current CET are clearly not associated with DSM programs at this time.

Q. DO YOU AGREE WITH THE STATEMENT THAT REJECTING REVENUE NEUTRALITY IS COMPARABLE TO DENYING A UTILITY THE OPPORTUNITY TO EARN ITS ALLOWED REVENUES?

A. No. The fact that the utility exactly recovers its allowed revenues until its next rate case is not the problem. The issue is that a very large portion of the risk associated with recovering those revenues has been shifted entirely onto ratepayers without any corresponding benefit. If this proposal is, in fact, a good thing for the Company, then some type of benefit should be passed long to its customers for absorbing this risk. Further, the benefit needs to be more than just the DSM program offerings being provided by the Company. These programs and their potential benefits, while important, are limited. Even under the Company's best estimates, their DSM programs will only provide direct benefits to a small share of their residential and small commercial customer base while the CET impacts all GS-1 and GSS customers.

Q. HAVE ADJUSTMENTS TO A UTILITY'S ALLOWED RATE OF RETURN FROM REVENUE NEUTRALITY PROPOSALS BEEN RECOGNIZED IN OTHER UTILITY PROCEEDINGS?

A. Yes. CCS Exhibit 1.5 shows information from various past regulatory proceedings that have recognized cost of capital adjustments due to revenue neutrality programs that change the risk profiles of regulated utilities. Many of these adjustments have actually been proposed, or developed, by utilities.

These adjustments range from 25 to 100 basis points on a utility's allowed ROE. To date, most of these adjustments have been offered in proposal form and, with the limited exception of the FERC proceedings, have not been used to offset the risk-shifting nature of the various revenue neutrality mechanisms. In fact, revenue neutrality was rejected in most of the states where these risk-adjustment proposals were offered. Recently, the Citizens Utilities Regulatory Board in Kansas requested a 110 basis point reduction on the allowed ROE. This proceeding recently settled and the revenue neutrality proposals were withdrawn for later consideration in a generic docket. In Vermont, Green Mountain Power agreed to a 50 basis point reduction and noted that its Alternative Regulation Plan "has the effect of shifting risk associated with varying power costs to ratepayers; in recognition of this risk shift, the Plan provides a lower return on equity."[2]

Q. DO YOU THINK THAT MAKING THESE ADJUSTMENTS WOULD BE APPROPRIATE AT THIS TIME?

A. No, for at least two reasons. First, any adjustments to the Company's ROE should be done within the context of a rate case. In fact, over the past several years, most revenue neutrality proposals (decoupling and SFV) have been proposed within the context of a rate case allowing regulators to fully evaluate all adjustment mechanisms that may, or may not, be needed to facilitate energy efficiency. These potential adjustment mechanisms are not limited to

[2] Petition of Green Mountain Power Corporation for approval of an alternative-regulation plan, Docket No. 7175; Docket No. 7176, Vermont Public Service Board, December 22, 2006, Order Entered.

revenue decoupling or SFV alone, and can range from combinations of revenue neutrality and a utility's allowed ROE, to partial revenue decoupling, to simply changing test year billing determinants, to rate design changes, to no changes at all. As noted earlier, the current CET proceeding does not lend itself well to many of these types of adjustments since this is not a rate case where a broad range of other options would be candidates for consideration. Second, the adjustments provided in CCS Exhibit 1.5 are specific to the companies in those proceedings, and while these are important in providing insight into the range of potential ROE adjustments associated with revenue neutrality, any adjustment for Questar needs to be evaluated relative to its specific financial circumstances.

Q. IF NO ADJUSTMENTS ARE MADE TO OFFSET THE RISK-SHIFTING NATURE OF THE CET, CAN MAINTAINING THIS MECHANISM RESULT IN FAIR, JUST, AND REASONABLE RATES?

A. No. The Company's CET shifts a significant amount of risk to ratepayers. These risks include potential changes in price, the economy, and other factors like greater economy-wide energy efficiency. However, there is no corresponding offset in rates to compensate ratepayers for this shift. Granted, the current monthly balances associated with the CET have been mostly offsetting. But relatively low net-adjustments are more a function of current circumstances in the market as opposed to a removal of these risks. It could very well be the case that circumstances could shift (unfavorably) and change the overall nature of the balances accruing in the CET balancing account. Ratepayers would be on-call to cover those shortfalls should this negative market realization materialize. Thus, maintaining the CET, while failing to recognize the risk-shifting inherent in this mechanism, results in rates that by definition are not fair, just, and reasonable and allows the utility to claw into the very monopoly profits that regulation is intended to control.

Q. DO YOU THINK THE FINANCIAL COMMUNITY RECOGNIZES THE RISK SHIFTING NATURE OF REVENUE NEUTRALITY MECHANISMS?

A. Yes, as well as a number of other favored, risk-shifting programs that can, depending upon the state, include the adoption of gas recovery clauses, weather normalization clauses, shorter weather normalization periods, and pass-through recovery of LAUF and uncollectibles expense. Revenue neutrality, in the form of revenue decoupling or SFV rate designs, however, appears to be the most popular regulatory mechanism with many of these financial analysts (with the exception of the few utilities that do not have GCRs). These analysts see revenue neutrality mechanisms as being beneficial to shareholders by reducing overall risk. Many financial analysts are starting to preference the ratings and categorizations of those companies that have such policies in place.

Q. DO YOU HAVE ANY EXAMPLES?

A. Yes, Moody's Investor Service ("Moody's"), in a June 2005 Special Comment on natural gas utilities, noted:

> "Moody's believes that having utility rate designs that compensate the gas LDC for variations in conservation as with variations in weather would serve to stabilize the utility's credit metrics and credit ratings."[3]

[3] *Special Comment: Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector,* Moody's Investors Services, June, 2005: 8.

Further, Moody's indicated that revenue decoupling can impact the business risk categorization under which utilities are judged by Standard and Poor's. This categorization, based upon business risk profiles, includes a measure for utilities that face supply and volumetric risk. Those with high risk are in the higher categories (highest risk category is 10), while those utilities that face lower risks by having adjustment clauses, are moved to lower levels. NW Natural, a gas distribution utility in Oregon that has both a GCR and decoupling mechanism, was able to lower its rank to 1, the lowest level category. Moody's recently reiterated the strong benefits revenue decoupling would provide in maintaining shareholder value. Such a mechanism will maintain strong credit metrics and improve credit ratings relative to utilities that do not have such mechanisms since revenue decoupling eliminates shareholder exposure to risk and volatility from price and climate changes.[4]

Q. CAN REVENUE DECOUPLING LEAD TO POTENTIAL COST INEFFICIENCIES?

A. Yes. Utilities, while regulated, are similar to other competitive firms in their goals of maximizing profits. These profits are a function of revenues and costs, both of which can reflect a certain degree of uncertainty. However, of the two, revenues can be more uncertain since, as noted earlier, they can be impacted by a wide range of factors beyond a utility's control like changes in commodity prices, changes in the economy, and changes in the weather, to name a few. Costs normally have more certainty and are typically within a utility's control.

[4] *Special Comment: Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings,* Moody's Investor Services, June 2006.

Q. HOW DOES THE TRADITIONAL RATEMAKING PROCESS GIVE UTILITIES INCENTIVES TO REDUCE COSTS?

A. The regulatory lag inherent in the traditional ratemaking process gives utilities strong incentives to reduce costs, and potentially increase earnings, during periods between rate cases. In many instances, this will require effective efforts at reducing costs since, as noted earlier, revenues are much more uncertain. Active cost reducing efforts have the ability to compensate for unexpected changes (decreases) in revenues, thereby increasing profitability. However, under most revenue neutrality mechanisms, one-half of this equation, revenues is now known. Revenue decoupling eliminates revenue uncertainty (assuming a constant level of customers), which in turn can dampen efficiency incentives.

Q. GIVEN THE COMPANY'S RECENT FINANCIAL PERFORMANCE, IS THE CET NECESSARY?

A. No. From a financial perspective, maintaining the CET is unnecessary for at least 4 reasons:

(1) The Company has been able to maintain relatively strong earnings despite decreases in use per customer.

(2) The CET appears to have less to do with addressing revenue losses from energy efficiency than assuring revenue certainty. The order of magnitude of the potential losses resulting from DSM programs are small relative to the potential changes resulting from use per customer decreases.

(3) Revenue growth associated with adding new customers more than offsets revenue losses from both DSM and use per customer changes.

(4) As noted earlier in the Elcon White Paper opposing revenue decoupling, the real issue is profitability, not revenues. The real potential drag in overall Company profitability appears to have less to do with revenue losses and more to do with increases in incremental investment (rate base) per customer.

VI. <u>DIRECT RATEPAYER BENEFITS OF THE CET ARE SMALL</u>

Q. HOW SIGNIFICANT ARE THE COMPANY'S ANTICIPATED DSM SAVINGS?

A. CCS Exhibit 1.6 provides an overview of the anticipated level of natural gas savings (in Dth) from the Company's DSM programs over the three year pilot period. Total savings for each year increases from a level of 163,501 decatherms ("Dth") in the first year of the program to a high of 189,731 Dth by the third and last year of the pilot program. Two of these DSM programs account for 72 percent to 84 percent of the total anticipated DSM savings.

Q. HOW DO THESE COMPARE TO OVERALL SALES LEVELS?

A. The right hand side of the chart shows that these savings levels are very small shares of the Company's overall total sales. Using the Company's historic rate of sales growth (2.0 percent), shows that DSM savings over the next three years will only comprise between 0.184 percent to 0.205 percent of overall sales.

Q. HOW DO THESE SAVINGS PERCENTS COMPARE TO THE PROGRAMS LISTED BY OTHER LEADING GAS UTILITIES?

A. These levels of savings are low relative to most gas utilities that are often referred to as leaders in gas-use energy efficiency. CCS Exhibit 1.4, discussed earlier, shows that most of the leading gas utilities are achieving a level of savings that range from a low of 0.1 to a high of 1.0 percent. The average for the ten utility sample is a savings level of 0.5 percent.

Q. ARE YOU SUGGESTING THE COMPANY ISN'T DOING A GOOD JOB PROMOTING ITS DSM PROGRAMS?

A. Not at all. In fact, the Company has done a good job in developing and promoting its DSM plan to date. However, it appears from the savings estimates generated by Questar and its consultants that the cost-effective savings potential is less in Questar's service territory compared to other parts of the country for a variety of different reasons, many of which may have nothing to do with the Company's current efforts.

Q. WHAT ABOUT THE ANTICIPATED PARTICIPATION LEVELS?

A. CCS Exhibit 1.7 provides the anticipated participation for each of the Company's current DSM programs. As seen from the exhibit, most programs have participation rates that are far less than the majority of the customers in the GS-1 class. However, all residential and small commercial customers will be required to participate in the CET, to the benefit of the few that are participating in the Company's DSM programs. Again, this is not to suggest that the Company is not doing a commendable job in promoting its DSM programs. It does suggest however, that the CET is too broadly applied.

Q. HOW LARGE ARE THE ANTICIPATED LOST REVENUES?

A. CCS Exhibit 1.8 provides the annual anticipated lost DNG revenues associated with the Company's DSM programs. These lost revenues, over a three-year period, range from a low of $288,537 to a high of $334,826. In each year, the amount of revenue lost from the promotion of cost-effective DSM is less than one-half of one percent of the Company's total GS-1 revenues.

Q. HAVE YOU ATTEMPTED TO ESTIMATE THE IMPACT THAT THE COMPANY'S DSM PROGRAMS WILL HAVE ON ITS FINANCIAL RESULTS?

A. Yes, CCS Exhibit 1.9 provides an analysis of the potential impact that the Company's current DSM programs may have on its financial results over the next three years. Overall, the Company could see a cumulative total revenue loss of some $1.8 million associated with its DSM programs over the next three years. In addition, if recent trends continue, the Company could see a cumulative revenue loss of $9.3 million decrease associated with a decrease in use per customer – an amount far in excess of the sales decreases resulting from its DSM programs. Over the same period, however, the Company could see a $19.6 million cumulative increase in revenues due to customer growth. The net impact of these usages changes is $5.2 million, resulting in a positive 1.61 percent impact on ROE. Thus, the Company may continue to see a net positive increase in its financial performance despite its promotion of DSM.

Q. WHAT IF THE COMPANY'S DSM PROGRAMS PERFORM BETTER THAN EXPECTED?

A. The Company would have to attain DSM participation levels (or savings per participant levels) well in excess of its current expectations in order for its promotion of DSM to have a meaningful impact on its financial performance. Currently, the Company expects to lose an estimated $1.76 in lost revenues for every one Dth in anticipated energy efficiency savings. The analysis in CCS Exhibit 1.9 shows that at current expectations, the Company has $5.2 million in a positive earnings "buffer" that would have to erode before it became financially challenged from promoting DSM. Given the lost revenue/DSM savings relationship above, it would take an additional 3.0 million Dth in savings to bring the Company to a point where DSM promotion stalls the growth in its achieved ROE. This is a savings level that is some 160 percent higher than current cost-effective savings expectations.

Q. DO YOU THINK THIS LEVEL OF LOST REVENUES JUSTIFIES MAINTAINING THE CET?

A. No, the financial implications of promoting DSM appear to be small and it would appear that a more important benefit the Company and its shareholders get from the CET is associated with revenue insurance on potential changes in use per customer and not the promotion of DSM. As I will discuss later in my testimony, if the change in use per customer is the real concern, there are other, more specific ratemaking tools to address this problem that are preferable to the use of an overly-broad CET.

Q. WHAT IS THE RELATIONSHIP BETWEEN TOTAL USAGE, USE PER CUSTOMER, AND NET EARNINGS?

A. In the earlier phase of this proceeding, I provided an exhibit in my supplemental rebuttal testimony outlining the relationship between earnings and changes in sales and revenue. The relationship has been replicated in CCS Exhibit 1.10. This exhibit shows that changes in total usage are a function of: (1) the change in usage per customer associated with existing customers and (2) the new usage associated with customer growth. If usage increases resulting from customer growth outpace the usage decrease associated with reduced usage per customer (from existing customers), then total usage will increase. The inverse would occur if usage from customer growth was less than the total decreases created by reduced use per customer. If prices and costs are held constant, then earnings will continue to increase if new customer-related usage growth outpaces the decrease in use per customer for existing customers. The inverse would occur if new customer-created usage was less than the decreases in use per customer for existing customers; again, holding other factors constant. Thus, the impact that decreases in use per customer have on earnings growth can be offset for a utility serving a growing service territory. Utilities that serve very slow growing service territories could see earnings attrition if usage per customer falls. All of these relationships are based upon the premise that other factors are held constant.

Q. HAVE YOU UPDATED YOUR ESTIMATE OF THE CHANGES IN NET REVENUES FROM CHANGES IN USE PER CUSTOMER BASED ON THE COMPANY'S ACTUAL DATA?

A. Yes. I have presented a series of different exhibits that highlight some of these relationships from information included in the Company's Results of Operations. CCS Exhibit 1.11 shows the offsetting impacts on total usage created by (1) changes in use per customer and (2) changes associated with customer growth. Between 2001 and 2002, the Company saw a net GS1 sales decrease by 37,156 Dth. GS-1 customers during that period grew by 2.6 percent, or by some 17,976 customers. Usage decreases associated with decreases in use per customer were of a comparable percent (2.6 percent), or from 118.97 Dth/customer to 115.84 Dth/customer. As seen from the last three columns, the impact on total consumption was close to offsetting between the two impacts. Total usage reductions resulting from decreased use per customer were estimated to be around 2,119,521 Dth, while increased usage from new customers is estimated to be 2,082,365 Dth. The net change (subtracting the two) was a decrease of 37,156 Dth.

Q. HOW HAVE USAGE TRENDS CHANGED IN LATER YEARS?

A. There have been several years of both increases and decreases in total usage. Between 2002-2003, both use per customer and usage associated with new customers increased. Increases in annual use per customer is estimated to have contributed 2,126,113 Dth to overall sales. The increase in use from new customer growth was 3,401,338 Dth. The total annual change in sales that year is the sum of these two impacts or 5,527,451 Dth. Other years have seen comparable movements; in the most recent full year, use per customer reductions contributed to a decrease of 1,148,163 Dth, while increased usage associated with customer growth was 2,094,399 Dth, resulting in a net positive change of 946,235 Dth. Over the past five years, there have been two years of net decreases in usage amounting to 878,484 Dth. There have also been three years of substantial net increases in usage accounting for 9,096,013 Dth. The net period change has been an increase in usage (net of decreases created by use per customer declines) of 8,217,528 Dth. In other words, the Company has seen total usage increase of over 8 million Dth despite the decrease in average use per customer.

Q. HAVE YOU UPDATED YOUR ANALYSIS TO EXAMINE THE CHANGES IN REVENUE ASSOCIATED WITH THESE USAGE CHANGES?

A. Yes, CCS Exhibit 1.12 presents a comparable analysis on a revenue basis. Two different columns have been provided that show the estimated changes in revenues associated with a decrease in use per customer versus the increase in revenues associated with changes in customer growth. Between 2001 and 2002, I have estimated that revenues decreased by $2.8 million dollars due to decreased usage per customer. There was, however an estimated revenue increase due to customer growth for that period of $4.9 million, resulting in a net revenue increase of $2.1 million. In the subsequent year, it is estimated that revenues increased for both impacts since average usage per customer and customer growth were both positive and significant (net positive change of $17.8 million).

Q. HAVE YOU ATTEMPTED TO ESTIMATE THE FINANCIAL IMPACT OF THE RECENT CHANGES IN USAGE?

A. Yes. CCS Exhibit 1.13 provides that information. The exhibit consists of three pages: (1) a summary page; (2) detailed calculations on the estimated financial impact of changes in use per customer; and (3) detailed calculations on the estimated financial impact of changes from customer growth. The first summary page of the exhibit shows that for the better part of the five year period, the positive financial contributions of customer growth exceeded the negative implications of decreases in use per customer. The only exception was in 2003 when positive use per customer is estimated to have actually contributed more to the overall financial results than the increase in customer growth. The information at the bottom of the summary table provides comparable information for the return on equity ("ROE").

Q. IF USAGE PER CUSTOMER DOES NOT APPEAR TO BE DRAGGING DOWN THE COMPANY'S FINANCIAL PERFORMANCE, WHERE IS THE PROBLEM?

A. The problem appears to be associated with the cost of providing service to new customers. Page 1 of CCS Exhibit 1.13 shows that changes in rate base have the largest negative impact on the Company's achieved ROR – not changes in usage. CCS Exhibit 1.14 shows the Company's recent investment trends on an average and incremental basis. The bottom two rows are the more informative. Average net utility plant in service per customer ranges between $835 to $934 per customer. However, the incremental net utility plant cost per change in customer is significantly higher at an average of around $1,430 for the past several years.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS ANALYSIS?

A. It appears that the real challenge the Company faces is associated with its average incremental investment costs relative to the revenues gained from new customers. This has nothing to do with DSM, and appears to have less to do with decreasing use per customer (for existing customers), or usage in general. The problem appears to be one that is more cost-related and associated with making new capital investments. These are issues that are more appropriately addressed in the traditional ratemaking areas of cost recovery and rate design, rather than through a revenue decoupling mechanism like the CET. Trying to use decoupling as a means of correcting this problem is akin to creating an attrition adjustment. This would be inconsistent with the purpose of decoupling as it has been adopted in other states.

Q. DOES THIS DECOMPOSITION OF USAGE AND CUSTOMER GROWTH IMPACTS HAVE ANY BEARING ON THE CONSTRUCTION OF THE CET?

A. Yes. The common complaint that many LDCs express is that use per customer has been falling over recent years and that rates, set in the past, fail to catch up with the differences between test (or base) year use per customer and actual use per customer. In order to remedy this problem, decoupling has been proposed to "true-up" revenues to the test year in order to give LDCs the opportunity to earn their authorized rate of return. In order to make an LDC whole relative to the test year upon which its rates are based, a decoupling mechanism should be examining the difference between actual and test year revenues per customer relative to the test year customer level upon which costs and revenues are based. However, the current formulation of the CET, like many LDC decoupling proposals, adjust current period revenues for more than just changes in use per customer from the test year, and also allows for revenue recovery associated with customer growth.

Q. CAN YOU PLEASE EXPLAIN THIS CONCERN IN GREATER DETAIL?

A. Yes. The left hand side of CCS Exhibit 1.15 shows an example of the Company's current CET methodology that is comprised of three important steps:

(1) determining the test year use per customer;

(2) estimating the difference between test (or base) year revenue per customer and actual revenue per customer;

(3) Multiplying the difference by the actual (new) level of customers.

The third step in this calculation is the one to note since it allows for the collection of revenues based upon customer growth.

Q. HOW COULD THIS BE CHANGED TO BE MORE CONSISTENT WITH THE TEST YEAR UPON WHICH RATES ARE SET?

A. Instead of multiplying differences in actual from historic revenue per customer by a new level of customers (step 3 discussed earlier), this difference should instead be multiplied by the customers included in the base year. An example of this calculation has been provided on the right hand side of CCS

Exhibit 1.15 and shows that the CET accrual account using this methodology would be approximately $228,100 less than the current method of calculation for that given monthly example.

~~VI.~~VII. ALTERNATIVE REMEDIES FOR DEALING WITH ENERGY EFFICIENCY DISINCENTIVES

Q. ARE THERE ANY OTHER POTENTIAL REGULATORY MECHANISMS FOR ADDRESSING DSM SALES LOSSES?

A. Yes. One of the more common regulatory mechanisms for dealing with sales losses associated with DSM implementation has been what is referred to as a lost revenue adjustment (“LRA”) mechanism. Under this approach, a utility’s ability to recovery lost revenues is based upon actual savings which result from its DSM programs. For instance, if a gas utility were promoting a Energy Star Clothes Washer program that achieved 8,700 Dth in savings, and had an average DNG rate of $1.75, then the lost revenues associated with the program would be $15,225. Thus, revenue recovery is restricted to specific DSM-created changes in sales and not some broader measure of sales loss (like decoupling) that could result from a variety of factors, many of which are beyond the utility’s control.

Q. HAVE MANY STATE COMMISSIONS UTILIZED AN LRA APPROACH?

A. Yes, several regulatory commissions have utilized an LRA approach to remove the purported disincentive associated with promoting DSM. LRAs were particularly common for electric DSM programs prior to the advent of retail competition and industry restructuring. While some states still technically allow

LRA recovery, there are few active proceedings where utilities continued to seek recovery of these lost revenues.

Q. IS AN LRA MECHANISM A POPULAR REGULATORY TOOL AMONG ENERGY EFFICIENCY ADVOCATES?

A. No. LRAs are typically opposed by energy efficiency advocates for at least two reasons. First, most energy efficiency advocates believe that LRA mechanisms are exceptionally difficult to implement in practice because sophisticated measurement and estimation is required in order to determine actual DSM savings, and a as result, DSM-related lost revenues. Second, most energy efficiency advocates believe LRA mechanisms do not completely remove the disincentive to promote DSM because the mechanisms are too narrowly focused.

Q. WHY WOULD AN LRA MECHANISM BE A MORE EFFECTIVE TOOL FOR DEALING WITH DSM-CREATED REVENUE LOSSES THAN THE CET?

A. There are various reasons that support the use of an LRA:

(1) Regulatory policy and industry trends are insisting upon greater accountability in measuring energy efficiency savings and the adoption of an LRA would be consistent with these movements;

(2) Revenue decoupling and the CET creates a disincentive for accountability and energy efficiency measurement;

(3) An LRA would increase regulatory confidence in the use of DSM;

(4) The greater accountability created through an LRA could have important planning implications which, in turn, could reduce overall ratepayer costs.

Q. HISTORICALLY, WHAT APPEARS TO BE THE BIGGEST REPORTED DIFFICULTY ASSOCIATED WITH LRA MECHANISMS?

A. Lost revenues are simply the product of average utility base rates and the actual savings attained by the DSM program. Since the average utility base rate is regulated and known, the fundamental challenge in estimating lost revenues is measuring and verifying the actual amount of savings.

Q. HOW ARE LOST REVENUES RELATED TO COST-EFFECTIVENESS?

A. Lost revenues are fundamentally related to overall DSM program cost-effectiveness in two ways. First, since lost revenues are a function of program savings, and overall program savings determine whether a program is cost-effective, lost revenues are clearly linked to cost effectiveness. Second, one of the cost-effectiveness tests (Rate Impact Measure or RIM test) is based on lost revenues. The RIM test, which measures the cost-effectiveness of a DSM program from ratepayers or non-participants perspective, is calculated as the difference between total program savings less total program costs including lost revenues. Thus, lost revenues are integral components of any DSM cost-effectiveness filing.

Q. DOES THE RELATIONSHIP BETWEEN LOST REVENUES AND COST EFFECTIVENESS HAVE ANY BEARING ON THE MEASUREMENT CRITICISMS ASSOCIATED WITH LRA MECHANISMS?

A. Yes. The argument that lost revenues are difficult to measure is somewhat incompatible with cost-effectiveness findings upon which DSM program approvals are usually based. The implication is that regulatory approval of proposed DSM programs cannot really be based upon any accurate level of savings leaving a potentially large amount of unsupportable costs to be recovered in rates. Allowing a large share of unsupported DSM costs into rates would be no different than allowing a similar share of unsupported costs into rates for any other type of resource like a transmission line, power plant, or O&M expense. Allowing unsupportable costs into rates cannot result in rates being fair, just and reasonable.

Q. WHY DO YOU THINK MANY OF THESE LRA MEASUREMENTS ISSUES ARE LESS RELEVANT TODAY THAN IN THE PAST?

A. They are less relevant for a variety of reasons:

(1) Measurability challenges were promoted well over a decade ago and the nature of the energy services business has changed significantly to include a higher level of monitoring and verification (“M&V”) of DSM savings.

(2) The regulatory standards and requirements associated with M&V are becoming more stringent for accountability reasons.

(3) Broader industry and public policy issues are driving M&V to higher standards and this will continue to be the case as DSM is being considered as a resource to meet utility planning requirements and

air emissions standards that are likely to be adopted in response to global climate change issues.

Q. REGARDING YOUR FIRST POINT, WHAT CHANGES IN THE ENERGY SERVICES INDUSTRY HAVE ANY BEARING ON THE LOST REVENUE MEASUREMENT ISSUE?

A. There have been a number of changes in the energy services business that have had a positive impact on measurement issues including:

(1) Greater reliance on performance-based terms and conditions in energy service contracts;

(2) Greater degrees of competition requiring service differentiation via performance and deliverability;

(3) Better measurement equipment and software;

(4) Greater experience with measurement techniques;

(5) Specialization with some energy service companies focusing on independent M&V services; and

(6) Expanding industry estimated to have over $2 billion in project investment.

Q. HAVE REGULATORY STANDARDS CHANGED TO ADDRESS THESE MEASUREMENT ISSUES?

A. Yes, regulatory standards have changed in at least two ways. First, there has been greater understanding and appreciation for M&V for those utilities requesting cost recovery. Second, as will be discussed later in my testimony, many states have moved to third party administrators which in many instances require M&V to assess the effectiveness of publicly-supported programs.

Q. ARE THERE CHANGES IN INDUSTRY AND PUBLIC POLICY THAT TEND TO INCREASE M&V REQUIREMENTS?

A. There are at least two important changes in industry and public policy that are quickly increasing M&V requirements and standards. Currently, most of these changes are associated with electric DSM, but will likely have important implications for gas DSM as well. The first change has to do with the use of DSM as a resource for planning purposes and the second change is the use of DSM as a resource in clean air market models being driven by rapidly escalating climate change concerns among policy makers.

Q. HOW DO UTILITY PLANNING ISSUES AFFECT M&V?

A. Many electric utilities, and even regional transmission organizations ("RTOs") have historically had a difficult time accepting DSM resources for system planning purposes. At best these resources were heavily discounted. However, the challenges of building or acquiring new baseload resources have become more substantial due to climate change concerns, fuel price volatility and concerns relating to storing spent nuclear fuel. This leaves very little in the way of additional resource options with the exception of renewables and DSM. If DSM is to be used, continued efforts in M&V are going to have to occur in order to bridge the gap of confidence between regulators pushing DSM as a resource, and utility planners reluctant to use DSM for planning purposes.

Q. HOW ARE CLIMATE CHANGES AND CLEAN AIR MARKETS DRIVING M&V FOR DSM?

A. Since the passage of the Clean Air Act Amendments of 1990, clean air markets, implemented through what is referred to as "cap and trade" programs have been the policy of choice for reducing air emissions. This has clearly been the case for SO2 and NOx, and will likely occur for future carbon regulation. Many states are already in the process of attempting to use DSM as a potential offset for carbon emissions. Moreover, several states and regions are considering mandatory DSM portfolio requirements much like renewable energy portfolio standards ("RPS"). DSM savings under such a program would likely have environmental attributes with tradable credits. Air market regulators, however, are very strict in ensuring that any resource upon which a tradable environmental attribute is based must be measurable and verifiable. This will put increasing pressure on M&V for utility DSM. If air market regulators can rely upon these DSM savings estimates for their environmental attributes, then it would seem reasonable that utility regulators could use them as a basis for lost revenue recovery as well.

Q. ARE THERE ANY CAVEATS IN YOUR DISCUSSION ABOUT LOST REVENUE MEASUREMENT ISSUES?

A. Yes, this discussion assumes a certain degree of regulatory oversight and accountability. Thus, the issue is not the degree to which DSM savings can be measured as much as it to what extent the regulatory oversight process requires that they be measured, and the methods by which M&V is governed. This is one the primary reasons why my prior testimony in this proceeding emphasized the role of M&V and stressed clearly defining this M&V process prior to the adoption of the CET.

Q. DO YOU THINK REVENUE DECOUPLING LIKE THE CET CREATES NEGATIVE INCENTIVES FOR M&V?

A. Yes. If revenue decoupling removes a utility's incentive to make sales, it is more than likely to also remove a utility's incentive to closely monitor sales losses. Under the CET, sales losses, for whatever reason, are now of no consequence to a utility.

Q. HOW DOES THE ACCOUNTABILITY ASSOCIATED WITH LOST REVENUES ENHANCE COMMISSION CONFIDENCE IN DSM?

A. An LRA directly ties a utility's incentive to DSM by tying lost revenue recovery to actual performance. As such, an LRA can be thought of as a type of performance-based regulation since it is the utility's performance that defines its ability to recover revenues associated with DSM-created sales losses. Tying a utility's incentive to accurate measurement gives the Commission, and other stakeholders, increased confidence that (1) the revenues being recovered by utilities are based upon verifiable achieved savings and (2) the costs incurred for DSM program development and implementation are tied to verifiable savings, thereby justifying ratepayers' investment in these programs.

Q. CAN THIS GREATER ACCOUNTABILITY HAVE IMPORTANT IMPLICATIONS FOR RESOURCE PLANNING AND FUTURE RATEPAYER COSTS?

A. Yes since greater accountability reduces the discount to DSM as a planning resource. Greater accountability can have direct implications for ratepayer costs if it defers investment made from discounted DSM benefits. Consider as an example, a planning process that discounts DSM savings over some fixed period of time by 50 percent. Now take that same DSM program and apply a much higher degree of M&V upon its achieved savings, that reduces the overall benefit discount to 25 percent of total annual program savings. This 25 percent differential represents a real capital investment that would otherwise have to be developed to meet ratepayer demand requirements that has now been either eliminated or deferred.

Q. IS AN LRA THE ONLY MECHANISM BY WHICH NEGATIVE DSM INCENTIVES CAN BE REMOVED FROM A UTILITY?

A. No. One alternative method being utilized by several states has been the use of a third-party administrator for the promotion and development of energy efficiency programs. These third-party administrators are independent bodies, usually housed within a state agency, and not directly associated with any specific utility company, although utilities may provide input, or serve on boards advising these administrators. While the responsibilities of these administrators can vary by state, they are usually in charge of developing, monitoring and verifying the success of DSM programs, market transformation initiatives, and in many instances, clean energy programs.

Q. WHAT ARE THE PERCEIVED BENEFITS OF THESE THIRD PARTY ADMINISTRATORS?

A. One of the primary benefits is having a dedicated administrator with no potential conflicts or disincentives to promote energy efficiency and clean energy technologies. There can also be the additional benefit of pooling resources, which could potentially reduce the overall cost of delivering DSM and clean energy. Having these types of activities centralized into one public agency can also reduce coordinating costs and potential redundancies across different types of electric and gas utility programs.

Q. HOW MANY STATES CURRENTLY HAVE SUCH THIRD PARTY ADMINISTRATORS?

A. CCS Exhibit 1.16 provides an overview of the states which currently utilize a third-party administrator for the development and promotion of DSM programs. Most of these administrators oversee both electric and natural gas efficiency programs. Several, like New Jersey, also oversee clean energy rebate programs for things like the development of solar energy as required under the state's Renewable Portfolio Standard ('RPS"). Most of these programs are funded by some type of state-wide surcharge.

~~VII.~~VIII. ALTERNATIVE METHODS FOR DEALING WITH DECLINING USE PER CUSTOMER

Q. ARE THERE ANY METHODS THAT COULD BE UTILIZED TO CORRECT OR ADJUST FOR USE PER CUSTOMER-RELATED CHANGES IN SALES?

A. Yes. There are a number of examples where the traditional regulatory ratemaking framework has reflected changes in usage resulting from exogenous factors like rate changes and even DSM program savings. The typical mechanisms for making these adjustments have been within the context of modifications to the test year usage levels upon which a specific rate case is based. There are several examples of test-year modifications on both a historic and forecasted basis.

Q. CAN YOU PLEASE EXPLAIN THE PURPOSE OF A TEST YEAR IN THE RATEMAKING PROCESS?

A. A test year defines a set period of time, reflecting typical utility operations, upon which regulated utility rates are based. A test year can be based upon a historic period of time using historic information, adjusted for what are commonly referred to as "known and measurable changes" to revenues, expenses, and rate base. Alternatively, a test year can be based upon some future period of time provided revenues, expenses, and rate base projections are developed and adjusted in a fashion that reasonably reflects expected future utility operations.

Q. HOW WOULD A HISTORIC TEST YEAR REFLECT CHANGES IN NATURAL GAS USAGE?

A. A strict definition of a historic test year would only reflect changes in natural gas usage at that point in time. However, a test year which is allowed to reflect known and measurable changes could clearly accommodate reduced sales from DSM and could also reflect structural changes in gas use resulting from shifts in use per customer trends. For instance, it has not been uncommon in past ratemaking proceedings to estimate the potential repression or stimulation that could result from a particular rate design change. Given recent changes in residential natural gas use, a repression estimate could be used to adjust test year billing determinants to reflect overall changes in use per customer.

Q. PRACTICALLY, HOW WOULD THIS REPRESSION ADJUSTMENT WORK?

A. The most straightforward way to make a use per customer repression adjustment would be to average the overall changes in use per customer over some fixed period of time to develop an overall adjustment factor to apply to the estimated usage levels relied on to develop rates. The challenge in developing this factor would be in determining the overall period upon which the factor would be based and any adjustments that might be needed to correct for any near-term usage trends. For instance, as I noted in my supplemental rebuttal testimony earlier in this docket, the decrease in use per customer appears to have slowed in recent years relative to historical trends. Basing an adjustment factor over a longer run use per customer trend could, therefore, overshoot the near term changes anticipated in the market.

Q. PLEASE PROVIDE AN EXAMPLE?

A. CCS Exhibit 1.17 provides an example of how a use per customer repression adjustment could be made as a known and measurable change within the context of a historic test year. Two panels are provided to the right and left of this exhibit reflecting repression adjustments based upon a three-year average and five-year average change in use per customers, respectively. While the exhibit uses Questar-specific data, both examples are presented as illustrative in nature. Row 1 in both examples lists the absolute decrease in use per customer in the two different periods examined. The repression adjustment to test year revenues is provided on row 11 and reflects the additional amount that would need to be collected in rates if changing trends in use per customer were included in a historic test year.

Q. HOW WOULD THIS ADJUSTMENT CHANGE FOR A FORECASTED TEST YEAR?

A. Correcting for changes in use per customer on a forecasted test year basis is relatively straightforward. By definition, a forecasted test year is based upon estimated revenues and costs for some future period. Revenues and ultimately sales are typically based upon projections developed in a load forecast which should be similar, if not the same, as the one included in the Company's Integrated Resource Plan ("IRP"). Over the past several years, for instance, Questar's IRP has reflected longer-term trends in changes in use per customer upon which their planning process is based.

Q. COULD USAGE-RELATED CHANGES RESULTING FROM DSM ALSO BE INCLUDED IN THE FORECASTED TEST YEAR?

A. Yes, provided (1) there is no separate lost revenue recovery mechanism and the forecast is the only place where DSM-created usage changes are accounted for or (2) that any periodic lost revenue process is treated as a true up to what is included in the test year billing determinants. A DSM adjustment would be relatively straightforward calculation. First, total usage would be forecasted for several years including the test year being used to set rates. As noted earlier, this forecast, if conducted appropriately, would account for changes in use per customer. Second, forecasted usage levels would be reduced for the anticipated savings associated with DSM programs for the years those savings are anticipated to be available.

Q. WHAT ARE SOME OF THE BENEFITS OF USING A FORECASTED TEST YEAR TO MAKE THESE TYPES OF CORRECTIONS?

A. There are at least three potential benefits. First, the use of a forecasted test year to make usage-related adjustments to rates would be based upon forward looking information that would better track anticipated trends in the near term. Second, a forecasted test year could, and probably should, be based upon the same forecasted usage information that the Company is using for its own system planning purposes. Third, and most importantly, the current risk associated with changes in sales would remain with the Company and its shareholders, and not shifted to ratepayers. Using a forecasted test year to adjust for changes in usage, particularly changes in use per customer, would be a far preferable alternative than continued use of the CET.

~~VIII.~~IX. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS IN THIS PROCEEDING?

A. I have three primary recommendations:

(1) The Commission should discontinue the use of the CET since it shifts considerable sales risk to ratepayers with little to no offsetting benefits for ratepayers assuming those risks. Further, the CET is overly broad in addressing the problems associated with declining

use per customer trends and is unnecessary to address incentive issues associated with the promotion of DSM programs.

(2) The Commission should adopt a lost revenue adjustment ("LRA") mechanism to make the Company whole for changes in usage resulting from its DSM programs. Lost revenue recovery should be tied directly to the estimates included in the Company's DSM cost-effectiveness filings, and updated according to the ongoing monitoring and verification (M&V) process.

(3) The Commission should direct the Company to address any financial challenges created by decreases in use per customer in its next rate case through the use of a forecasted test year or some known and measurable adjustment if a historic test year is utilized for ratemaking purposes.

Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS?

A. Yes, should the Commission reject my primary recommendations and decide to maintain the CET I would recommend:

(1) The Commission require the CET to be modified such that decoupling true-ups are based upon the difference in historic and actual use per customer times test year customers (or base year customers upon which the revenue per customer statistic is derived) rather than actual customers.

(2) The Commission should explicitly recognize the risk shifting nature of the CET and indicate in its Order that this shifting of risk will be considered in setting the Company's ROE in its next rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY FILED ON JUNE 1, 2007?

A Yes.