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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DOCKET NO. 05-057-T01

I. INTRODUCTION

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

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

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

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

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

A. Yes. Attachment 1 to my testimony provides my academic vita that includes a full listing 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 review the joint application submitted by Questar Gas Company ("Questar," "QGC," or "the Company), the Division of Public Utilities ("Division"), and Utah Clean Energy ("UCE") requesting approval for the adoption of a Conservation Enabling Tariff ("CET") and other enabling accounting mechanisms and proposals.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Overview of Revenue Decoupling and the CET Proposal
- Section IV: Conceptual Problems with the CET Proposal
- Section V: The DSM Disincentive has not been Proven
- Section VI: The Proposed CET Shifts Revenue Recovery Risk to Ratepayers
- Section VII: The Proposed CET Creates a Number of Equity Issues
- Section VIII: The CET Proposal is not Accompanied by Strong DSM Commitments
- Section IX: Potential Mismatches in the CET Pilot and DSM Implementation

- Section X: The CET Proposal does not Include a Well-Defined Accountability Program
- Section XI: The CET Proposal does not Have Any Performance Standards
- Section XII: The GDS Report Should Not Substitute for a Utility-Specific DSM Filing
- Section XIII: Mechanical Problems Associated with the CET Proposal
- Section XIV: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A. I recommend the Commission reject the Joint Applicants' CET proposal as not being in the public interest. The proposal suffers from a number of conceptual and mechanical problems that make it an unwise initiative. The Commission should not be persuaded by the arguments that because the proposed CET is a pilot program, shortcomings are unimportant and can be worked out at a later date. Even though it is a pilot program, the proposal would represent a significant departure from the way in which distribution non-gas ("DNG") revenues have heretofore been regulated and could have important precedent-setting implications for Utah's electric utilities as well. Most importantly, the need for such a departure from traditional regulatory approaches is not supported by any well-defined commitments by the Company to pursue any level of demand side management ("DSM") programs or savings – which is the ostensible justification for the proposal.

Q. DOES THE COMMITTEE HAVE AN ALTERNATIVE RECOMMENDATION?

A. Yes, if the Commission believes that decoupling is in the public interest, then my alternative recommendation is that the Joint Applicants be directed to prepare a revised filing that meets the following set of important minimum requirements:

(1) Any decoupling or other DSM incentive mechanism should be implemented only after properly designed DSM programs are in place and functioning for sufficient time that impacts upon ratepayers and the utility can be measured in relation to program goals or targets. Appropriate DSM programs are those that are completely defined and include estimated savings, costs and participation levels.

(2) A cost of capital adjustment should be incorporated into the CET program that accounts for its inherent risk shifting.

(3) A complete listing of DSM programs, estimated costs, and estimated savings and participation levels for the CET pilot period should be required. A defined three-year set of DSM programs, which match the CET pilot period, should be provided.

(4) The Company should define clear reporting requirements and evaluation metrics including annual DSM savings goals for the pilot period. This would include:

- The frequency of the audits.
- The number of customers that will be audited.

- The basis for which customers will be selected for an audit.
- The data provided by the Company that will be examined and compared to utility bills/customer information.
- How the confidentiality of customer information will be treated.
- How other parties will have the opportunity to review audit results.

(5) The Company should be required to participate in the CET program and maintain its DSM commitments during the entire pilot period. If the Company wishes withdraw from the program, it must petition the Commission and show that the cost to ratepayers of maintaining the program outweigh its potential benefits.

<u>III. OVERVIEW OF REVENUE DECOUPLING AND THE CET PROPOSAL</u>

Q. CAN YOU PLEASE EXPLAIN THE PROPOSED CET?

A. Yes. The proposed CET has been offered as a way to remove the disincentives that the parties believe discourages Questar from promoting cost-effective DSM programs. The proposal is to implement the CET as a pilot program for three years.

Q. WHY DO THE JOINT APPLICANTS BELIEVE THERE IS A DISINCENTIVE FOR THE COMPANY TO PROMOTE DSM?

A. Energy efficiency advocates, as well as many utilities, often argue that current regulatory pricing practices discourage utility-sponsored DSM programs. These advocates argue that energy efficiency reduces sales, thereby reducing a utility's ability to recover its fixed costs.

Q. HOW DOES REVENUE DECOUPLING ADDRESS THIS PURPORTED DISINCENTIVE?

A. Revenue decoupling removes the relationship between the collection of a utility's revenue requirement and its sales. A reduction in sales volume that might result from implementing a DSM program would no longer reduce the utilities revenues because the utility's revenue requirement would be collected in rates on a per-customer basis rather than a per volume basis. 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 a utility indifferent between collecting DNG revenues through fixed or variable charges. The process is similar in many ways to loading total DNG revenue requirements into a fixed charge since customers are no longer able to avoid any portion of the DNG revenue requirement through reduced usage.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes, Exhibit CCS-2.1 shows how a revenue decoupling plan would work. The first step in the plan is to set a base year (or test year) DNG revenue per customer level. In this example, 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. An example of this allocation is provided in the second box. 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. In this example, the balancing account is “trued-up” at the end of the year, and the resulting amount is applied to the volumetric charge the customer sees on his or her bill. The new volumetric charge resulting from the example is provided in the third box.

Q. IS THE PROPOSED CET A REVENUE DECOUPLING MECHANISM SIMILAR TO THE ONE YOU JUST DESCRIBED?

A. Yes. The CET is a full revenue decoupling mechanism and works in much the same manner as the example provided in Exhibit CCS-2.1. The one difference is that the frequency of the revenue balance true-up proposed by the parties is ambiguous and could occur as frequently as monthly rather than at the end of the year as assumed in the example.

Q. WHY DO THE ACTUAL SALES AND REVENUES IN THIS EXAMPLE DIFFER FROM THE ALLOWED AMOUNTS?

A. There are a variety of reasons why retail gas sales and revenues in any given year can differ from the test year amount. Test year retail sales and revenues are usually based upon a “typical” year and as such, are usually normalized for typical factors influencing sales such as the weather, the economy, and prices, among other things. In any given year, the actual performance of the economy may differ from the test year, weather may be colder or hotter than the long-run normal weather trends included in the test year, and other factors may occur in any given year that impact sales differently than what was anticipated in the test year determination.

Q. WHO TRADITIONALLY BEARS THE RISK OF DEVIATIONS FROM TYPICAL TEST YEARS?

A. The utility usually bears the risk of revenue and sales differences from the test year for a number of different reasons. First, it is the utility's responsibility to propose a typical year for rate making purposes. It would not be in a utility's, nor its shareholders' best interest to propose a test year that was unsupportive of what management believed was required to recover costs and earn its allowed return. Second, a utility's allowed rate of return, like that of any other business, includes some premium for the business risk inherent to the industry in which it operates.

Q. HOW DOES REVENUE DECOUPLING FIT INTO THIS REVENUE RECOVERY DISCUSSION?

A. Many energy efficiency advocates argue that revenue decoupling removes utility disincentives to promote DSM since the utility is made whole for revenue losses associated with conservation. As argued by the Joint Applicants in this proceeding, if the utility is assured it will recover any energy efficiency-created revenue losses, it will actively promote least-cost DSM programs. The problem with revenue decoupling as proposed by the Joint Applicants is that it makes the Company whole for revenue losses that go beyond any revenue losses caused by energy efficiency per se. As a regulatory policy mechanism, revenue decoupling is like using a steam-roller to crack a peanut: it more than overcorrects for the purported DSM-disincentive and includes guaranteed recovery for revenue changes associated with a wide range of normal business risks.

Q. IS IT CLEAR THAT A *BONA FIDE* 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. All of these factors should more than compensate for any sales disincentive associated with energy efficiency. Further, utilities should have a very strong incentive to develop resources that include the aforementioned characteristics 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. DO ALL DSM MEASURES RESULT IN LOST REVENUES?

A. Not necessarily since, as noted earlier, revenue impacts can vary depending upon a number of different factors including those associated with the types of programs being promoted. Generally, DSM measures or programs can be thought of as: (1) those that shift energy usage from peak to off-peak periods (often referred to as load management or "LM" programs); and (2) those that reduce the use of energy (referred to as "conservation" programs). Exhibit CCS-2.2 is intended to be a general illustration of the impact that these two types of DSM programs can have on customer usage as represented by a hypothetical load curve.

Q. PLEASE EXPLAIN THE ILLUSTRATIVE LOAD MANAGEMENT GRAPH ON THE LEFT-HAND-SIDE OF THE EXHIBIT CCS-2.2.

A. Load management programs tend to reduce peak loads and transfer that usage to off-peak periods. The graph to the left-hand side of Exhibit CCS-2.2, for instance, shows a load curve intended to represent usage changes from the implementation of an LM program. The peak of the curve has been "shaved," representing a reduction in peak usage, while the tails of the curve have increased representing movement of the reduced peak usage to an off-peak period. In some instances, depending upon pricing considerations, LM programs of this nature may not reduce overall revenues, since load is being transferred from peak periods to off-peak periods and the net total revenue impact could be minimal. The goals of these types of DSM programs are to reduce usage at peak periods when energy is most expensive.

Q. WILL YOU PLEASE EXPLAIN THE ILLUSTRATIVE CONSERVATION PROGRAM GRAPH ON RIGHT-HAND-SIDE OF EXHIBIT CCS-2.2?

A. Yes, this graph provides an illustrative example of a true conservation-oriented program. Here, total load is being displaced (entire curve is reduced) for both peak and non-peak periods. These types of energy efficiency programs can result in decreases in total revenues since load in both peak and off-peak periods is being reduced.

Q. WHY ARE THE DIFFERENCES BETWEEN LOAD MANAGEMENT AND ENERGY EFFICIENCY IMPORTANT?

A. Because if the Commission is concerned about potential utility revenue losses associated with energy efficiency, it could require the Company to promote only those load management programs that assist customers in reducing their peak usage and overall bills, but have minimal revenue impacts to the Company. After the Company gains some experience with DSM program costs, participation, and revenue impacts, it can move to more aggressive conservation-oriented programs and discuss the revenue loss implications at that stage. Thus, moving to DSM is not an all-or-nothing proposition and revenue decoupling is not the only means by which revenue loss concerns can be addressed.

Q. CAN USE OF COST-EFFECTIVENESS TESTS IMPACT POTENTIAL REVENUE LOSSES ASSOCIATED WITH DSM PROGRAMS?

A. Yes. State regulatory commissions usually adopt a unique cost-effectiveness standard in approving DSM programs. A program is said to be "cost-effective" under these evaluation standards if its benefits are greater than its costs. Since a wide-range of stakeholders are impacted by DSM programs (customers, utilities, ratepayers in general, and society at large), and each of these stakeholders face a different set of costs and benefits, a number of different cost-effectiveness tests are used to measure the impacts of DSM programs on different stakeholder groups. Two commonly cited cost-effectiveness standards used by state regulators include the Ratepayer Impact Measure ("RIM") and Total Resource Cost ("TRC") test.

Q. HOW DO THESE TWO COST-EFFECTIVENESS TESTS IMPACT THE REVENUE IMPACTS OF DSM PROGRAMS?

A. The RIM test defines a DSM program as being cost-effective when the benefits of the program (savings) outweighs program costs which includes the lost utility revenues created by the DSM program. The TRC program, however, looks at aggregate savings versus aggregate costs and excludes lost utility revenues associated with reduced usage created by the DSM program.[1] The set of DSM programs evaluated under the RIM test tends to be much smaller than those evaluated under the TRC test since lost revenues are considered to be a cost in the former and not the later (i.e., the RIM test is much more conservative).

Q. COULD THE COMMISSION ADDRESS LOST REVENUES THROUGH ITS SELECTION OF A COST-EFFECTIVENESS STANDARD?

A Yes. If the Commission is concerned about lost revenue impacts, one opportunity at its disposal is to define the RIM test as the appropriate cost-

[1] California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects, October 2001, p. 13 and p. 18.

effectiveness standard for gas utility DSM programs until further information can be gathered, and a larger DSM commitment from Questar (potentially resulting in lost revenues) can be secured. Again, the Commission does not necessarily have to adopt revenue decoupling in order to initiate gas utility DSM programs. There are other regulatory tools to address potential lost revenue concerns. The Commission has used the RIM test in the past for Pacificorp where it found that "[p]rograms that have the potential to pass the Ratepayer Impact Test (RIM) and lead to lower rates for all customers should receive particular attention."[2]

Q. HAS THE COMPANY INDICATED WHICH COST-EFFECTIVENESS TEST IT BELIEVES IS APPROPRIATE?

A. No. The Company has not defined its position on which cost-effectiveness standard is appropriate for its DSM program screening. The Company's lack of commitment on the appropriate DSM cost-effectiveness standard raises legitimate and important questions about its commitment to significant DSM development and implementation. When explicitly asked about its preference on DSM cost-effectiveness standards, the Company, after identifying all of the commonly recognized cost-effectiveness tests, failed to answer the question and dodged the issue of whether it explicitly support TRC-based programs.[3]

Q. WHY IS THIS DISCUSSION OF COST-EFFECTIVENESS STANDARDS IMPORTANT?

[2]In the Matter of the Application of PacifiCorp for an Increase in its Rates and Charges, Docket No. 01-035-01, Utah Public Service Commission, September 10, 2001, Issued.

[3]Response to Committee Data Request 4.08.

A. It is important for two reasons. First, the Joint Applicants have not presented any set of specific DSM programs for implementation during the CET pilot period. Without any specific DSM commitment, it is impossible to know the degree and extent of potential lost revenues since the scope of the DSM programs, and the cost-effectiveness standard upon which they are based, is unknown. Second, the Commission has not had the opportunity to rule on the issue of the appropriate cost-effectiveness standard for Utah gas DSM programs. The Joint Applicants' proposal would appear to delegate the determination of the appropriate cost-effectiveness standard to a DSM Task Force.

Q. DOES A PUBLIC UTILITY HAVE A RESPONSIBILITY TO PROMOTE ENERGY EFFICIENCY?

A. Yes. Utah public utilities have a statutory obligation to provide least-cost, reliable, and safe service in return for getting an opportunity to earn a fair return on and of their investments.[4] If a utility has a lower cost resource available to meet customer resource requirements, then it has the obligation to select that resource regardless of whether the resource is capacity-oriented (and rate base-building) or demand-oriented. If there are millions of dollars of available least-cost DSM savings opportunities to meet customer resource requirements, and a Utah public utility is not taking advantage of those opportunities, it raises a bigger regulatory issue than the treatment of lost revenues.

Q. ARE THERE ANY GUIDING PRINCIPLES THAT YOU THINK THE COMMISSION SHOULD CONSIDER IN EVALUATING THE PROPOSED CET AND GAS DSM PROGRAMS GENERALLY?

[4] Utah Code 54-3-1.

A. Yes. The Commission should be supportive of cost-effective energy efficiency but keep in mind a number of guiding principles in its review of not only the CET proposal at hand, but in developing overall policies that encourage utilities to promote least-cost resource options for their customers:

- Alternative regulatory mechanisms should be developed that provide incentives (or remove disincentives) for utilities in taking advantage of positive energy efficiency opportunities within their control, not outside of their control. Creating a "hold-harmless" mechanism like the proposed CET would not be an effective regulatory policy since the utility had nothing to do with this customer-initiated conservation.
- Alternative regulatory mechanisms should not unnecessarily shift risks inherent in traditional regulation without some corresponding offset or credit to the party bearing a greater share of those risks. The Division has acknowledged the risk shifting inherent in the proposed CET, and has acknowledged a potential rate of return adjustment may be appropriate for the proposed CET, but has failed to make any specific recommendation.[5]
- Alternative regulatory mechanisms should require a firm commitment on the behalf of the utility. The proposed CET, which allows the Company to withdraw at any point in the future, would not meet this standard.
- Alternative regulatory mechanisms should clearly:

[5] Direct Testimony of Dr. George R. Compton, 212-214.

- o Define the programs that will be promoted;
- o Set performance goals, standards and metrics for measuring effectiveness; and
- o Include opportunities for rewards for superior performance and penalties for inferior performance.

<u>IV. CONCEPTUAL PROBLEMS WITH THE CET PROPOSAL</u>

Q WOULD YOU PLEASE DISCUSS THE CONCEPTUAL PROBLEMS ASSOCIATED WITH THE COMPANY'S CET PROPOSAL?

A There are a number of conceptual problems associated with the Joint Applicants' CET proposal. These problems include:

- The DSM disincentive upon which the proposal is based is unproven and supported by weak and undocumented information.
- The proposal shifts all business risk associated with retail revenue recovery to customers.
- There are a number of potential equity issues with the proposal.
- The Company has made neither firm commitments to the proposed CET nor any specific set of DSM programs and savings. In fact, the Company suggests that the Pilot Program could be modified or discontinued at any time.[6]
- There is likely to be a timing issue associated with the CET Pilot Program and DSM program implementation. Since no DSM programs

[6]Direct Testimony of Barrie L. McKay, 227-228.

have been proposed concurrently with the CET proposal, there is bound to be some degree of lag or disconnect between the two.

- Program accountability is minimal, is not-well defined, and excludes any set of evaluation metrics.
- The program sets no performance standards, terms, or conditions that financially tie the Company to DSM program success.

<u>V. THE DSM DISINCENTIVE HAS NOT BEEN PROVEN</u>

Q. ARE THE JOINT APPLICANTS' CLAIMS OF UTILITY DISINCENTIVES FOR PROMOTING DSM WELL SUPPORTED?

A. No. Not only is the claim unsupported relative to Questar, but it is also not supported by the general industry-wide information provided in the Joint Applicants' Application, Direct Testimony, and Exhibits. In particular, the Joint Applicants have:

(1) Failed to show any evidence that decreases in average usage have resulted in financial harm to the Company in the past, nor have they been able to specifically show that the promotion of DSM would cause any harm to the Company's financial position in the future.

(2) Failed to put gas utility revenue decoupling into perspective. While many LDCs have a variety of DSM programs, few have initiated revenue decoupling to address incentive concerns.

(3) Generally presented a one-sided view of revenue decoupling and not highlighted, in any conclusive way, the short comings of revenue decoupling identified by other state commissions.

(4) Failed to compare the context and terms in which revenue decoupling has been offered and adopted in other states.

Q. WHAT IS THE BASIS OF QUESTAR'S CLAIM THAT DECLINING AVERAGE USAGE HAS IMPACTED QUESTAR'S HISTORIC FINANCIAL PERFORMANCE?

A. The Company claims that its current rate design does not allow it to collect its fixed costs when there is a decline in average customer usage, and according to the Company, average usage has been declining for several years.[7] The Company maintains that it is only during periods when average usage is stable that revenue per customer is equal to the revenues allowed by the Commission in current rates and results in a steady achieved return on equity ("ROE").[8]

Q. DO YOU AGREE WITH THE COMPANY'S POSITION?

A. No. The Company has provided speculation, but no specific evidence, to support any reason for the declining average usage depicted in Exhibit 1.4. In fact, Exhibit 1.4 suffers from a significant deficiency that renders it unreliable for any consideration in this proceeding.

Q CAN YOU EXPLAIN THE PROBLEMS WITH EXHIBIT 1.4?

A Yes. The Committee requested that the Company provide the workpapers and source documents to this exhibit in Data Request 3.03. In response, the Company provided an electronic spreadsheet which contained the data points on the graph. No calculations supporting the source documents were provided. The

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[7]Direct Testimony of Barrie L. McKay, 139-140.

[8]Direct Testimony of Barrie L. McKay, 151-153.

Committee again requested supporting documentation in its Data Request 4.16. Specifically, the Committee requested:

> For purposes of this request please refer to the Company's response to the Committee's Data Request 3.03. In addition to what may be provided by the Company in response to 7d above, which specifically refers to tariff changes, please provide all workpapers and source documents used to develop the temperature adjusted 12 month moving total per customer provided as an attachment to this response. Workpapers would include but not be limited to: the non temperature adjusted data, the formulas and calculations used to develop the temperature adjusted data, statistical equations used, the number of customers used to develop the usage per customer, and any and all other information required to reproduce Exhibit 1.4 from the original raw data used to develop the temperature adjusted usage per customer. The information provided should allow one to replicate the information depicted on Exhibit 1.4 on a monthly and 12-month rolling average basis. Provide the requested information in its native electronic format.[9]

Q. DID THE COMPANY PROVIDE THE SUPPORTING INFORMATION?

A. No. The Company did not provide any additional documentation, data, source documents, or formulas beyond that which was previously provided in response to Committee Data Request 3.03. The Company's response was as follows:

> Much of the data asked for in this request is not readily available or accessible in the fourteen days allowed to respond. For most of the past 25 years, the temperature adjusting procedure/calculation **used various input files from the Company's now non-existent** Legacy Customer Information System. The intermediate data requested was not stored, only the final product, of customers and temperature adjusted usage.

> In general, the monthly temperature adjusting procedure is a function of actual decatherms, customers, the difference in normal billing cycle degree-days and actual billing cycle degree-days, and a temperature adjusting or usage per degree-day slope. The

[9]Committee of Consumer Services Data Request CCS 4.16.

> concept of this adjustment has remained relatively stable over the years, however, **the specific calculation and formulas have changed and evolved with several improvements during the 25 year period**.
>
> The temperature adjusting slope is calculated each year, or more often, as needed or requested. It is a function of customers, actual usage and degree-days for the prior three years. In the 1980's it was calculated only for the general service rate schedules. In the early 1990's it was calculated in more detail for the residential and commercial customers separately. In the mid 1990's, the slope was calculated for each major climatic area within the Company's Utah service territory, and for the residential, commercial and industrial customer groups. Since July 2004, this slope can be calculated by customer from the Company's new CDX Billing and Customer Information System.[10]

Q SO THE COMPANY CANNOT COMPLETELY DOCUMENT ITS ANALYSIS OF AVERAGE USAGE TRENDS?

A Yes, that appears to be the case, as well as any information on the numerous (and different) slope adjustments that have occurred over the course of the reporting period for the data series. While the Company has a general idea of how the data in Exhibit 1.4 was developed, the process has evolved over time. A number of intermediate calculations and adjustments have been made to this data, but the formulas used to create these adjustments cannot be provided, and only generally explained. Calculations and adjustment factors on usage can be replete with subjective assumptions, which in turn, can impact the resulting series and any conclusions drawn about average usage. Given the unsupported nature of this graph, and a number of unexplained anomalies in the series, the Commission should reject any recommendations associated with the CET offered by the Joint Applicants that are based upon this graph.

[10] Response to Committee of Consumer Services Data Request CCS 3.03, emphasis added.

Q LET'S RETURN TO THE DISCUSSION ON THE JOINT APPLICANT'S CLAIMS REGARDING FINANCIAL DISINCENTIVES AND DSM. HAS THE COMPANY PROVED ANY FINANCIAL HARM POTENTIALLY CREATED BY A DECREASE IN AVERAGE USE?

A Not beyond the general discussions in its testimony. The only quantitative estimate provided by the Company was in Response to CCS-4.01. In this example, the Company estimated that every 1 decatherm reduction in average usage resulted in $1.6 million of financial harm. This calculation is simply the lost DNG revenue associated with a 1 decatherm reduction for the GS-1 class. Mathematically, it is the product of a 1 decatherm reduction and the average DNG revenue and the total number of customers. (i.e., 1 x $1.97 x 803,000).

Q IS THIS AN ACCURATE CALCULATION OF THE FINANCIAL HARM CREATED BY A REDUCTION IN AVERAGE USE?

A No, because the estimate focuses exclusively on revenues, as has the discussion included in the Joint Application and testimony. The Joint Applicants offer some sweeping conclusions regarding financial incentives and DSM based on the purported, and unsupported trends in Questar's reduced average usage, and the impacts those purported trends have on revenues, and then simply conclude that without revenue decoupling, DSM is a "financial bad" for Questar and will not be pursued without a revenue decoupling mechanism.

Q DO YOU THINK THE RELATIONSHIP BETWEEN DSM AND REVENUES IS THE IMPORTANT RELATIONSHIP TO BE CONSIDERING IN THIS PROCEEDING?

A No. It is commonly recognized that firms maximize profits not revenues. Revenues, in fact, are only one portion of the overall equation that determines profits. Equally important to that profit equation is the role that costs play. If revenues are falling, but costs are falling by a larger amount, then overall profitability should increase. Instead of focusing exclusively on revenues and average usage when considering DSM programs, the Commission should focus on profitability.

Q HAS THE TREND IN DECLINING AVERAGE USAGE RESULTED IN SIGNIFICANT DECREASES IN TOTAL REVENUES?

A No. Exhibit CCS-2.3 shows that total company revenues have been increasing steadily every year since 2001. Further, average revenue has also been relatively stable during the same period of time ranging from a level of $289.04 per customer in 2001 to $290.48 in 2005. So, even the Joint Applicant's claims regarding the relationship between average usage and average revenue can be challenged. The Company has been able to steadily increase total revenue and revenue per customer since 2001, despite a decrease in average usage (118.97 Dth per customer in 2001 to 112.88 Dth in 2005).

Q HAS THE COMPANY'S ROE DECREASED CONSIDERABLY DURING THIS PERIOD?

A No, Exhibit CCS-2.4 shows that the Company's achieved ROE has not followed the same pattern as its decline in average usage. While average use has declined by 5 percent since 2001, Questar's achieved ROE in 2005 is slightly higher (10.46 percent to 10.68 percent). In addition, the Company has projected an increase in its ROE to 10.89% for the year ending 2006 despite these decreases in average use.

Q. WHY WOULD THE RETURN ON EQUITY NOT DIRECTLY FOLLOW USAGE PER CUSTOMER?

A. There are several reasons. First, when revenues and net operating income decline due to usage reductions or increases in costs, the Company is free to request rate relief, which the Commission may grant if appropriate. This traditional regulatory regime contributes, in a fundamental way to breaking any direct relationship between declining usage and declining profitability. If DSM did result in a decrease in utility profitability to where the utility's ability to earn a reasonable return on its investment was challenged, the utility is always free to request a rate increase.

Q. ARE THERE ANY OTHER REASONS WHY PROFITABILITY MAY NOT DECREASE?

A. Yes. Customer growth also contributes to the Company's ability to maintain its ROE. While usage per customer might decline, growth in customers can offset the lost revenues created by this decline. In fact, as seen in Exhibit CCS-2.5, Questar's Utah GS customers have been increasing by approximately 3 percent per year over the last four years.

Q. WHAT ARE THE OTHER REASONS PROFITABILITY DOES NOT DIRECTLY FOLLOW USAGE PER CUSTOMER?

A. As noted earlier, costs are the other portion of the profitability equation. If a firm can reduce expenses, or limit the rate at which expenses are rising, it can maintain its profitability. Exhibit CCS-2.6 in fact, shows that Questar's expenses per customer have generally fallen steadily since 2001. This Exhibit also tracks actual revenues per customer during this time period. As shown, steady revenues per customers, coupled with decreases in average costs per customer, have given the Company an opportunity to maintain profitability despite decreases in average use. One would expect to see trends like this under traditional regulation.

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. While utilities have very little control over their revenues, they have considerable control over their costs. Utilities will need to actively pursue cost efficiency opportunities between rate cases to compensate for unknown changes in revenues, thereby increasing overall profitability. Under revenue decoupling, one-half of a utility's profit function (i.e., revenues) is determined with certainty, thereby substantially reducing any incentive to aggressively manage costs.

Q. HAVE YOU PROVIDED AN EXAMPLE THAT SHOWS HOW PROFITABILITY IS IMPACTED BY REVENUE DECOUPLING?

A. Yes, Exhibit CCS-2.7 shows how the Company's achieved ROE could have been impacted by a revenue decoupling mechanism. The example is based upon actual reported jurisdictional financial information for 2001-2005.

Revenues included in the example are based upon a revenue per customer amount for 2001 and were adjusted in 2003 for the Company's last rate case. The chart shows that if the Company had a decoupling mechanism in place during this period, its achieved ROE would have started at 10.46 percent in 2001 and increased to 11.46 percent by 2005 – an amount in excess of its currently authorized ROE of 11.2 percent.

Q DOES THIS EXAMPLE CONTRADICT YOUR EARLIER STATEMENT THAT A UTILITY'S COST EFFICIENCY INCENTIVES COULD BE REDUCED BY REVENUE DECOUPLING?

A No, because the example uses assumed revenues based upon a revenue decoupling formula, and actual costs incurred under a traditional regulatory environment. Thus, the incentives driving costs in this example are based upon traditional regulation. The example does, however, allude to the potential disincentives for utility cost efficiencies under a revenue decoupling mechanism. A growing utility, with an increasing customer base, and fixed revenues per customer, would have some incentive to put the breaks on cost efficiency if it saw its earnings progressing in the manner shown in this exhibit. It is the certainty of revenues created by a revenue decoupling mechanism, taken in conjunction with a utility's ability to control a large portion of its cost structure, that creates the potential for cost inefficiencies.

Q LET'S TURN TO THE SECOND ISSUE YOU RAISED WITH THE JOINT APPLICANTS' ARGUMENTS IN SUPPORT OF DECOUPLING. ARE A

LARGE NUMBER OF STATES ADOPTING REVENUE DECOUPLING FOR GAS UTILITIES?

A No. While a number of states are addressing issues associated with gas conservation programs and energy efficiency, the adoption by other states of revenue decoupling as a means of promoting DSM is limited. Exhibit CCS-2.8 shows that currently only four states have adopted revenue decoupling for gas utilities while another five are considering decoupling proposals. Some 80 percent of U.S. residential gas customers are in non-decoupled states, representing some 85 percent of total residential gas sales. Thus, revenue decoupling for gas utilities is not wide-spread, nor is the mechanism gaining significant amounts of traction in other states at this time. Regulatory commissions seem to be turning to mechanisms other than decoupling for promoting DSM.

Q HOW HAVE OTHER STATES ADDRESSED THE INCENTIVE ISSUE?

A Exhibit CCS-2.9 highlights regulatory approaches in addressing gas utility DSM issues. This table is a replica of Table 10-1 of the GDS Report. The table shows that while some states do not have incentive programs in place, others are addressing incentive issues through a range of different options that include incentive returns or direct lost revenues.

Q. LET'S TURN TO THE THIRD ISSUE YOU RAISED WITH THE JOINT APPLICANTS' ARGUMENTS IN SUPPORT OF DECOUPLING. HAVE OTHER STATES HAD PROBLEMS WITH REVENUE DECOUPLING?

A. Yes. There are a number of state regulatory commissions that have reviewed and rejected revenue decoupling as a policy mechanism for promoting DSM. Connecticut, Arizona, and Washington are among those states that have expressed concerns or serious reservations about the use of revenue decoupling as a regulatory policy tool.

Q. WOULD YOU PLEASE DISCUSS THE CONNECTICUT FINDINGS REGARDING REVENUE DECOUPLING?

A. The Connecticut Department of Public Utility Control ("DPUC") recently ruled against revenue decoupling for its electric and gas utilities. The DPUC ruled that the state's utilities are "performing well and that incentives available to the companies and their customers provide good incentives to promote conservation and load management."[11] Thus, as noted earlier, the DPUC seems to believe that the traditional regulatory framework provides appropriate incentives for utilities to provide least-cost service, regardless of whether the resources acquired are supply- or demand-oriented.

Q. CAN CONNECTICUT UTILITIES GET LOST REVENUES ASSOCIATED WITH DSM?

A. Only in limited situations where the utility shows that lost revenues due to conservation resulted in achieved earnings below their allowed rate of return. In addition, the DPUC took issue with: (1) the position that decoupling creates incentives for DSM; and (2) the degree to which decoupling shifts business risk from a utility to consumers. The DPUC found that:

[11] DPUC Investigation into Decoupling Energy Distribution Company Earnings from Sales, Decision, Connecticut Department of Public Utilities, Docket No. 05-05-09, January 18, 2006.

> …decoupling by itself does not provide an incentive to energy DCs to promote conservation. Rather, in helping to ensure fixed cost recovery, it removes a disincentive for companies to promote conservation. However, it may also shift to ratepayers such normal business risks as lower sales due to economic downturns, weather, new energy efficiency technology, and demand response to price increases. This report discusses mechanisms for various degrees of decoupling ranging from partial to full decoupling. **In general, the more complete the decoupling, the more business risks are shifted from the energy DCs to the ratepayers**.[12]

Q WHAT ABOUT THE ARIZONA FINDINGS REGARDING REVENUE DECOUPLING?

A The Arizona Corporation Commission ("ACC") addressed a number of issues comparable to those raised in this case. Of particular relevance to the CET proposal at hand, were the claims made in that proceeding about revenue decoupling and recent declines in average use per customer. The ACC found, similar to the guiding principles I discussed earlier, that:

> …there is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future, and whether conservation efforts are the direct cause of Southwest Gas' inability to earn its authorized return from such customers."[13]

The Commission added:

> "[t]he Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor public policy requires such a result."[14]

[12]Ibid, *emphasis added*.

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

[14]Ibid.

Q. ARE YOU AWARE OF ANY RECENT DECOUPLING REJECTIONS THAT WERE COMPARABLE TO THE CURRENT CET PROPOSAL?

A. Yes. The Washington Utilities and Transportation Commission ("WUTC") recently rejected a joint decoupling proposal offered by PacifiCorp and the Natural Resources Defense Council ("NRDC"), an environmental advocacy group. The WUTC found several problems with PacifiCorp's proposal, many of which are similar to the problems associated with the Joint Applicant's proposals in this proceeding. Namely, that the proposal was not well-founded, documented, and did not have firm commitments for explicit DSM programs. The WUTC ruled:

> We favor utility efforts that accomplish cost-effective conservation through reducing utility costs and allowing consumers to manage their bills.[15] A well-designed decoupling mechanism may support the Company's increased investment in energy conservation and promote our state's goal of furthering energy conservation. We must reject the specific joint proposal offered by the Company and NRDC, however, for the following reasons: 1) We cannot calculate the mechanism's fixed cost revenue requirement without first having adopted an allocation methodology sufficient to make rates;[16] 2) The proposal lacks important analysis of implementation costs and its impact on the Company's overall revenues and cost of equity, and; 3) The Company has failed to identify and commit to incremental conservation measures as a counterbalance to its potential reduction in risk. We expect the Company to provide such evidence to allow us to fully consider a decoupling proposal.[17]

[15]*Natural Gas Decoupling Rulemaking*, Docket UG-050369, Summary, Analysis of Comments and Decision to Close Docket without Action at 10 (Oct. 17, 2005).

[16]See our discussion concerning the Revised Protocol, *infra*.

[17]Washington Utilities and Transportation Commission, Docket UE-050684, Order 04, Order Rejecting Tariffs, As Filed; Rejecting Stipulation On Net Power Costs; Rejecting, In Part, And Accepting, In Part, Stipulation On Temperature Normalization Adjustment; Determining Cost Of Capital, Docket Ue-050412, Order 03, April 17, 2006.

Q. LET'S TURN TO THE LAST ISSUE YOU RAISED WITH THE JOINT APPLICANTS' ARGUMENTS IN SUPPORT OF DECOUPLING. WHAT WERE THE TERMS AND CONDITIONS UNDER WHICH MOST STATE COMMISSIONS AND UTILITIES ADOPTED OR CONSIDERED REVENUE DECOUPLING?

A. Most all of the utilities that were granted revenue decoupling, or whose regulators are in the process of evaluating revenue decoupling proposals (hereafter, collectively referred to as "decoupled gas utilities"), (1) had prior DSM experience and/or (2) were making some additional level of commitment to expand their DSM initiatives.

Q HOW MANY OF THESE DECOUPLED UTILITIES HAD PRIOR EXPERIENCE WITH DSM?

A Several decoupled utilities had prior DSM experience. For instance, NW Natural has had DSM programs in place for a decade and, over the past 8 years, has defined their DSM strategies as part of their IRP. In California, natural gas utility energy efficiency programs are required by statute.[18] In addition, Southwest Gas Company ("SWG") had experience with DSM in both Arizona and Nevada. And, while Baltimore Gas & Electric ("BG&E") and Washington Gas Light ("WGL") may not have had DSM plans in place for natural gas, BGE had extensive experience in DSM on the electric side of their operations.

Q. HOW DOES THIS RELATE TO THE CURRENT CET PROPOSAL?

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[18]"Order Instituting Rulemaking to Examine the Commission's Future Energy Efficiency Policies, Administration and Programs," Decision 03-12-060; Rulemaking 01-08-028, California Public Utilities Commission, August 23, 2001, Filed; December 18, 2003, Dated.

A. The Joint Applicant's request to have the Commission adopt revenue decoupling, even in a pilot fashion, seems premature and is inconsistent with practices in most other states. Those states generally adopted revenue decoupling when its gas utilities had experience with DSM and were asking to expand their initiatives beyond current levels. Questar does not have a long track record with DSM programs, has no active programs at this time, and has not provided any programs (or commitments) as part of the CET proposal. The Company has noted, in fact, that "the Company has not aggressively pursued DSM programs in the past."[19] Thus, the current CET proposal is comparable in name only (i.e., it is a revenue decoupling proposal) with the activities, terms, and conditions in other revenue decoupled states.

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. Exhibit CCS-2.10 is a modified version of an exhibit presented by one of the Joint Applicants (Exhibit HG-2) examining DSM programs, costs, and savings for 2004. Of the 10 listed, only three have revenue decoupling. Interestingly enough, the top 2 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 and yet outspend, as a share of revenues, the three utilities that have revenue decoupling. In terms of

[19]Response to Committee of Consumer Services Data Request CCS 4.04.

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 DID STATE REGULATORS OFFER ANY OF THESE GAS UTILITIES INCENTIVE PROGRAMS FOR DSM PERFORMANCE?

A Yes, five of them had some variation of a performance incentive plan for DSM. I will discuss the merits of this approach later in my testimony. It is important to note, however, that of the utilities presented in the table, both Puget Sound Energy ("PSE") and Vermont Gas have no performance incentive or revenue decoupling mechanisms.

Q. ARE THERE ANY INTERESTING OBSERVATIONS ABOUT VERMONT GAS AND ITS PROMOTION OF DSM?

A. Yes. Vermont does not have a purchased gas acquisition clause ("PGA") that allows them to pass along gas commodity and transportation costs to their retail customers. As a result, Vermont Gas faces considerable commodity supply risk and faces a serious set of incentives in using all resources at its disposal to reduce costs. Coincidentally, Vermont Gas also has the largest level of DSM expenditures as share of revenues, and the highest level of DSM performance (as measured by its benefit-cost ratio), of any gas utility listed in Exhibit CCS-2.10. One inference that could be drawn from this example is that the use of PGAs may send negative incentives to utilities to promote DSM.

VI. THE PROPOSED CET SHIFTS REVENUE RECOVERY RISK TO RATEPAYERS

Q. HOW DOES DECOUPLING 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 Applicants' revenue decoupling proposal, if revenues per customer fall short of the target amount, customers are expected to make up the difference. The opposite would occur if sales were larger than the target amount.

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

A. A number of factors can influence sales including weather, economic conditions, gas commodity prices, and other unanticipated events that impact usage. Under traditional regulation, these potential risks are borne by utility, not by ratepayers. Under revenue decoupling these risks are all shifted to ratepayers.

Q. ISN'T WEATHER RISK ALREADY COVERED BY QUESTAR'S WEATHER NORMALIZATION ADJUSTMENT (WNA)?

A. Yes, those risks are assumed by customers that elect to participate in the WNA. An important issue, however, is customers can choose to opt-out of the WNA whereas the current revenue decoupling proposal is mandatory.

Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?

A. If revenues fall 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 revenue decoupling, customers would be required to make a utility whole for revenue losses during these economic downturns, whereas under traditional regulation, utilities bear the risks of these economic contractions. This is clearly inappropriate since (1) making utilities whole for these revenue losses has absolutely nothing to do with the promotion of DSM and (2) penalizes customers at a time in which this risk can be least afforded.

Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE DECOUPLING CREATES 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, much like the proposed CET, to encourage Central Maine Power (“CMP”) to promote DSM. The ERAM, like the proposed CET, 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 energy efficiency and conservation incentives. CMP's ERAM was terminated on November 30, 1993.[20]

Q. COULD THE CET PROPOSED BY THE APPLICANTS CREATE THE SAME KINDS OF PROBLEMS AS THOSE EXPERIENCED IN MAINE?

A. Yes. The proposed CET makes no allowances or adjustments for changes in economic activity, positively or negatively. If the economy underperforms during the CET pilot period, ratepayers will be required to make the Company whole, even though revenue losses associated with this downturn had nothing to do with the implementation of DSM programs.

Q. DOESN'T THIS WORK IN THE OPPOSITE DIRECTION IF REGIONAL ECONOMIC ACTIVITY EXCEEDS THE TRENDS INHERENT IN RATES?

A. Yes it does. If the economy exceeds expectations, then ratepayers will get revenue credits equal to the excess revenue recovered during the CET pilot period. This may seem like an offsetting advantage for ratepayers, and in the short run, it may be an advantage, but over the long run, removing a utility's financial tie to the state's economy is not advisable.

[20]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 [http://www.maine.gov/mpuc/staying_informed/legislative/2004legislation/Eff-Rel%20Report-final.htm]

Q. HOW COULD REVENUE DECOUPLING REMOVE A UTILITY'S FINANCIAL INCENTIVE TO THE REGIONAL ECONOMY AND ECONOMIC DEVELOPMENT?

A. Revenue decoupling guarantees a fixed revenue amount per customer. The utility will get the same amount of DNG revenues regardless of whether the economy expands or contracts. Under traditional regulatory practices, utilities could increase revenues beyond the test year levels, and potentially increase earnings (within regulatory allowances), if regional economic performance expanded. With revenue decoupling, a utility is financially indifferent between an expanding or contracting regional economy. Creating a situation where a utility's financial incentives are potentially pulled out of the same "economic boat" as the rest of the state would not be advisable.

Q. ARE YOU SAYING A UTILITY WOULD STOP ALL OF ITS ECONOMIC DEVELOPMENT INITIATIVES IF IT HAD REVENUE DECOUPLING?

A. No, a utility may very well continue to support, or even expand, its economic development initiatives for reasons that could include a commitment to community engagement and genuine concern about the state's welfare. However, the financial incentives associated with this economic development commitment are reduced, and the incentives for ongoing economic development are likely to be more charitable in nature than financial. Since revenue decoupling gives a utility a guaranteed revenue per customer, it has no real financial incentive to encourage greater sales or customers since its revenues are fixed and guaranteed over time regardless of where the state's economy stands.

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 a significant portion of the decreases in average use presented in Exhibit 1.4 of the Company's direct testimony are the result of price-induced reductions in consumption created by recent run ups in natural gas prices over the past 6 years. These reductions had nothing to do with any DSM activities undertaken by the Company, rather they reflect customer-initiated actions to either reduce usage or increase their efficiency.

Q. DOESN'T THIS SUPPORT THE JOINT APPLICANTS' CLAIM THAT DECREASING AVERAGE USE IS A PROBLEM?

A. No and there are at least three reasons why revenue decoupling should not be implemented to address this purported problem. First, as noted earlier, the real issue is whether, or the extent to which, declining average usage has impacted profitability. As already discussed there is no evidence that decreased average usage is responsible for a deteriorating profitability situation for the Company, nor is there any evidence that the promotion of future DSM will impact the Company's profitability. Second, as noted earlier, there are a variety of less-intrusive methods for addressing potential lost revenues resulting from DSM that are specific to DSM programs and not industry wide trends. Third, stripping the Company of its risk exposure without a corresponding adjustment to its allowed rate of return, would be unfair to ratepayers.

Q. CAN REVENUE DECOUPLING INCREASE RATE VOLATILITY TO CUSTOMERS?

A. Currently, bills and average rates will change as commodity prices change. If gas commodity costs change, then approximately 55 percent of a customer's typical residential rate will change.[21] Under revenue decoupling, 100 percent of the bill would change at each true-up.

VII. THE PROPOSED CET CREATES A NUMBER OF EQUITY ISSUES

Q. ARE THERE ANY EQUITY ISSUES THAT ARISE WITH THE PROPOSED CET?

A. There are a number of policy and equity issues that the Commission should consider in its review of the proposed CET. These include:

(1) The potential of customers participating in DSM programs to subsidize non-participating customers.

(2) Penalties to customers that have already made investments in energy efficiency.

(3) Potential conflicts between the proposed CET and the Commission's rate design policies attempting to balance fixed and variable charges in the recovery of DNG revenues.

Q. WOULD YOU PLEASE DISCUSS YOUR FIRST CONCERN IN GREATER DETAIL?

A. Yes. The proposed CET will apply to all GS-1 customers. Any revenue shortfalls (or overages) will be collected from the entire class regardless of whether or not any individual customer participates in a DSM program. This

[21] Response to CCS Data Request 4.08(b).

could result a significant inequity if DSM programs are not broadly defined and give **<u>all</u>** customers opportunities for savings during the **<u>entire</u>** CET pilot period. Revenue decoupling, combined with narrowly defined DSM programs, will result in a wealth transfer from one group of customers (DSM participants) within the GS-1 class to another (DSM non-participants).

Q. WHAT ABOUT YOUR SECOND EQUITY CONCERN?

A. Many customers are capable of creating their own energy efficiency opportunities whether it includes installing a timer or wrap on their hot water heater, buying a more efficient furnace, or applying various types of weatherization to their home. Decreases in average usage to date would suggest that the market for non-utility-provided energy efficiency does work. Under a revenue decoupling plan, customers that have made “self directed” efficiency investments could be penalized since they will be required to support the Company’s revenue losses without having the ability to take advantage of any the potential direct benefits of incentive payments associated with these programs. Further, these customers will be required to subsidize the costs of DSM programs provided to other customers (comparable to their own investments) without being able to participate in the program themselves.

Q. COULD REVENUE DECOUPLING CREATE ANY OTHER UNINTENDED IMPACTS ON CUSTOMERS THAT SELF-PROVIDED THEIR OWN ENERGY EFFICIENCY INVESTMENTS?

A. Yes, lost revenue recovery mechanisms could impose a type of “stranded cost” on customers. This occurs through a “shift” in the regulatory rules associated with energy efficiency investments. If the Commission adopts the proposed CET, the costs of these new programs, in addition to lost revenues, could result in a change to the anticipated "pay-back" to customers that have made their own comparable energy efficiency investments. In making the initial investment, the customer anticipates having a savings on his or her **total bill**, not just the commodity portion alone. The CET would change the rules of the game for these customers by imposing a cost (i.e., lost revenues) they did not anticipate at the time they made their own comparable energy efficiency investment. At the margin, it is possible that this shift in regulatory policy could result in a change to the household investment payback for some of these energy efficiency investments.

Q. CAN YOU PLEASE DISCUSS YOUR LAST EQUITY CONCERN?

A. Yes. The proposed CET is in direct conflict with the Commission's policy of recovering all DNG revenues through a combination of fixed and variable charges rather than completely recovering all DNG costs through a fixed charge.

Q. BUT DIDN'T THE JOINT APPLICANTS PROPOSE TO RECOVER THE CET ADJUSTMENTS THROUGH A VOLUMETRIC CHARGE?

A. Yes, but revenue decoupling sets these rates at levels that make a utility indifferent between fixed or variable charge revenue recovery. The variable charges, under a CET proposal, are adjusted in such a fashion to mirror fixed charge recovery. Put another way, the volumetric charges under the CET proposal make a utility completely whole, and indifferent to a fixed or variable rate recovery mechanism. Thus, the proposed CET is nothing more than a fixed rate recovery mechanism in disguise, and the fact that these charges are applied volumetrically is a difference without a distinction.

VIII. THE CET PROPOSAL IS NOT ACCOMPANIED BY STRONG COMMITMENTS

Q. ONE OF THE GUIDING PRINCIPLES INDICATED IN THE COMMITTEE'S ALTERNATIVE RECOMMENDATION YOU OUTLINED EARLIER WAS A FIRM, DSM COMMITMENT BY THE UTILITY. CAN YOU EXPLAIN WHY FIRM COMMITMENTS ARE IMPORTANT?

A. As noted earlier, revenue decoupling has been recognized as a significant departure from traditional regulatory approaches. A change of this nature should be assessed within the context of the risks and rewards (costs and benefits) associated with its implementation. For revenue decoupling, this would entail comparing this significant departure from traditional regulation to an equally significant commitment to a wide range of energy efficiency programs and well defined customer savings levels. If no clearly-defined energy efficiency commitments are made, it is impossible to compare the potential risks of revenue decoupling to its offsetting rewards. The proposed CET does not include a defined DSM program commitment. That alone should cause this Commission to conclude the program is not in the public interest.

Q. HAVE ANY SUBSTANTIAL OR SPECIFIC DSM COMMITMENTS BEEN MADE BY THE PARTIES IN THE JOINT APPLICATION?

A. No. The Joint Applicants have proposed no specific DSM programs, levels of savings, or timetables under which those savings will occur. The

Company has noted that the CET puts it in "the position to encourage customers to conserve," and to "actively support demand side management programs because the financial detriment of lower usage will be eliminated."[22] However, to date not one decatherm of energy savings, based upon any Company-specific programs, has been explicitly included in the CET proposal; only the suggestion that such programs will be forthcoming at some time in the future.

Q. DOESN'T THE GDS REPORT OFFER A CONSIDERABLE LEVEL OF ENERGY EFFICIENCY OPPORTUNITIES?

A. The Joint Applicants note that the GDS Report suggests considerable savings can result from the development of energy efficiency programs in Utah. The GDS Report identifies over a ten-year period, about $1.5 billion in potential savings stemming from the adoption of Questar-specific energy efficiency programs.[23] Despite these reported opportunities, the Company has not proposed any set or sub-set of programs included in the GDS Report for immediate adoption during the proposed three-year CET pilot period. In fact, the Company dedicates a total of 18 lines (less than one page) in its entire 24 page testimony to its discussion of "proposed demand-side-management initiatives."[24]

Q. ARE THERE ANY OTHER COMMITMENT ISSUES THAT SHOULD RAISE CONCERNS FOR THE COMMISSION?

[22]Direct Testimony of Barrie L. McKay, 187-191.

[23]Direct Testimony of Barrie L. McKay, 110-111.

[24]Direct Testimony of Barrie L. McKay, 342-360.

A. Yes. The Company has noted in its Direct Testimony that it (and any other party) can recommend that the pilot program be discontinued at any time.[25] This raises a serious question about the Company's commitment to this process. Rather than working out difficult issues, the Company can withdraw from the process leaving the costs associated with developing the current proposal, and its implementation, potentially on the table for ratepayers to recover.

IX. POTENTIAL MISMATCHES IN THE CET PILOT AND DSM IMPLEMENTATION

Q. HOW HAVE THE JOINT APPLICANTS PROPOSED TO CREATE DSM PROGRAMS?

A. The Joint Applicants have proposed that a new "DSM Task Force," consisting of the same parties that participated in the Allocation, Rate Design and Demand Side Management Task Force ("Rate Design Task Force") created in the aftermath of the Company's 2002 rate case, be established to evaluate and propose specific cost-effective natural gas DSM programs using the "GDS Report as a guide."[26] In addition to the findings included in the GDS Report, the Joint Applicants are offering to consider two other opportunities: (1) educational and set of low-income programs; and (2) an effort to expand the capabilities of the Low Income Weatherization Assistance Program ("LIWAP").

Q. DO YOU HAVE ANY PROBLEMS WITH THE APPLICATION'S FAILURE TO PROVIDE ANY SPECIFIC DSM PROGRAMS?

[25]Direct Testimony of Barrie L. McKay, 227-228.

[26]Direct Testimony of Barrie L. McKay, 347-349.

A. Yes. If the Company is not adopting any DSM at this time, then it doesn't need a CET at this time. If the Commission finds that revenue decoupling is in the public interest, it should nevertheless, only approve a CET if and when Questar has developed and presented to the Commission a concrete set of DSM programs and savings as the *quid pro quo* for the CET proposal. This would ensure that there is some consistency of timing between the DSM program implementation and the CET pilot period (i.e., programs should be in place at the time the CET begins).

Q. WHY SHOULD DSM PROGRAMS BE OFFERED SIMULTANEOUSLY WITH THE CET PROPOSAL?

A. If the GDS Report is accurate, and if the energy savings included in the Report are based upon genuine Company costs and reasonably forecasted benefits, and more importantly, if the purpose of the proposed CET is to remove utility disincentives to actively promote DSM, then the process should be to identify those programs that that (1) can be developed in a time period comparable to the CET pilot period and (2) are based upon a rank ordering of programs from those with the highest benefit-cost ratio to the those with the lowest.

Q. WHAT DO YOU THINK ABOUT THE COLLABORATIVE NATURE OF THE PROPOSED DSM WORKING GROUP?

A. The collaborative process, while well-intentioned, is likely to create time delays, and could result in a less than optimal set of DSM programs being in place during the course of the CET pilot program period. Further, there is no reason to believe that the DSM Task Force will address DSM issues any quicker than the Rate Design Task Force did. The current CET proposal which is the ultimate result of this task force's work was filed in early 2006, about three years after the task force was created. In fact, the Division's own representative to the process noted that he "lost interest in continued participation because…group progress seemed to be painfully slow."[27] Lastly, it should be the utility's responsibility to define programs, quantify potential savings, and potential costs. While stakeholder input is important, it is the utility that is responsible for these programs and the one that should take the leadership role – not a passive role in facilitating discussion and input.

Q. DOES THE LACK OF A SPECIFIC SET OF DSM PROGRAMS DAMPEN THE URGENCY FOR PROMOTING THIS PROPOSAL?

A. Yes. Even if the Commission disagrees with the Committee's recommendation that revenue decoupling is not in the public interest, it should defer any decision on the CET proposal until a complete list of cost effective DSM programs can be proposed for the pilot period. Adopting the CET proposal at this point, without any corresponding DSM programs, converts the CET proposal from one that ostensibly removes utility disincentives for conservation, to one that provides the utility with a hold-harmless mechanism for potential revenue shortfalls.

X. THE CET PROPOSAL DOES NOT INCLUDE A WELL-DEFINED ACCOUNTABILITY PROGRAM

[27] Direct Testimony of Dr. George R. Compton, 37-39.

Q. ARE THE ACCOUNTABILITY PROVISIONS OF THE CET PROPOSAL WELL DEFINED?

A. No. As proposed by the Joint Applicants, the program has some general and rather cryptic references regarding the CET review process. For instance, the Company, in defining program accountability, notes that it will be the Division's responsibility to:

(1) Review the results of the CET.

(2) Review the cost-benefits of DSM at the end of each quarter for the first year of the program

(3) After the first year, review the cost-benefits associated with DSM programs annually (or more frequently as needed)

(4) Submit reports to the Commission that include an analysis of each years' results.[28]

Q. HOW DOES THE DIVISION CHARACTERIZE ITS REVIEW RESPONSIBILITIES?

A. The Division indicates that "to a great extent, the DSM Advisory Group will monitor and report on Questar's DSM performance."[29] The Division also notes that it will provide the Commission with reports, it can audit customers' bills, and can audit the CET accounts to "ensure that the tariff mechanism is working in a manner consistent with the intent outlined in the Joint Application."[30] **Q. DO**

[28] Direct Testimony of Barrie L. McKay, 222-225.

[29] Direct Testimony of Dr. William A. Powell, 281-284.

[30] Direct Testimony of Dr. William A. Powell, 287, 291-293.

YOU THINK THIS IS AN EFFECTIVE REVIEW REQUIREMENT GIVEN THE NATURE OF THE PROPOSAL?

A. No. The review process is filled with considerable ambiguities and unanswered questions. For instance, while the Joint Applicants note an "audit process," they do not clarify what exactly will be audited, nor do they specify the purpose of the audit. Other important oversight considerations that are not clearly discussed include:

- The frequency of the audits;
- The number of customers that will be audited;
- The basis for which customers will be selected for an audit;
- The data provided by the Company that will be examined and compared to utility bills/customer information;
- How the confidentiality of customer information will be treated; and
- How other parties will have the opportunity to review audit results.

Q. ULTIMATELY, DO YOU THINK THAT THE ACCOUNTABILITY OF THE PROGRAM SHOULD REST WITH THE DIVISION?

A. No, the Company should be held accountable for its own DSM programs much like it would any other program being recovered in rates. Further, the Company should be required to have a standard set of filing requirements with the Commission during the course of the CET pilot period, and those filings, and the information supporting the filings, should be made available to all parties to this proceeding. Lastly, some CET post-pilot period proceeding needs to be defined so that parties can address the success of the process, and any problems or shortcomings that may have arisen.

Q. HAVE ANY OF THE JOINT APPLICANTS DEFINED THE METRICS OR PROCESS BY WHICH THE PROGRAM WILL BE EVALUATED?

A. No. While the Joint Applicants discuss the need to evaluate the program, no defined metrics have been proposed. Defining these metrics up front is important so that program goals are clearly articulated, and the process by which the program is evaluated is known to all parties. This will assist in understanding the success of the program, will provide a meaningful and known means of evaluating success as the program proceeds, and will minimize potential "revisionist" goals and success measures at some future point in time.

XI. THE CET PROPOSAL DOES NOT HAVE ANY PERFORMANCE STANDARDS

Q. ARE THERE ANY PERFORMANCE STANDARDS ASSOCIATED WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal excludes important details associated with the types of DSM programs they are willing to pursue, and the savings goals they anticipate achieving. Without programs and goals, there is no meaningful performance standard the Commission can use to determine whether the CET has been successful or not.

Q. WHY ARE PERFORMANCE STANDARDS IMPORTANT?

A. Performance standards are an important part of any program, especially one associated with energy efficiency. Defining goals, and metrics that measure the successes or shortcomings of reaching those goals, helps explain program success, and can provide important diagnostic information in correcting problems, that may arise during program implementation. The lack of well-defined programs and savings goals is, therefore, a serious shortcoming associated with the Joint Applicants' proposal.

Q. DO YOU THINK PERFORMANCE STANDARDS ARE A BETTER MEANS OF ALIGNING INCENTIVES FOR THE PROMOTION OF DSM?

A. They can be if appropriately defined. As noted earlier by a Connecticut DPUC ruling, at best, a revenue decoupling proposal make utilities indifferent to the promotion of energy efficiency. Tying some kind of explicit incentive to the promotion of energy efficiency gives the utilities a financial stake in maximizing efficiency opportunities for its customers. Under such a mechanism, the higher the savings, the higher the potential rewards to the utilities. Likewise, the lower the savings, the greater the penalties to utilities from poor performance.

Q. HAVE OTHER STATES INCLUDED PERFORMANCE MECHANISMS FOR DSM PROGRAMS?

A. Yes. Other states have adopted performance mechanisms and standards for DSM programs. For example, the California Public Utilities Commission ("CPUC") implemented a shared-savings incentive mechanism in the 1990s. The CPUC authorized a 70 percent/30 percent ratepayer/shareholder split of the net benefits arising from implementation of energy efficiency measures during 1994-

1997. This mechanism first awarded shareholder earnings bonuses based on measured program performance. Between 1998 and 2002, the performance incentive was changed to reward "market transformation" efforts by the utilities. The incentives were phased out after 2002, because of the state's overhaul of its energy efficiency policies, but recent activity in an energy efficiency rulemaking process may revisit shareholder incentive structures.

Q. HAS THE NEW YORK COMMISSION APPROVED INCENTIVES FOR DSM?

A. In 2005, the New York Public Service Commission approved a joint proposal, with modification, in a Consolidated Edison ("Con Ed") rate case that included increases in spending on DSM, a lost revenue adjustment mechanism, recovery of reasonable DSM costs through a Systems Benefit Charge, and shareholder performance incentives. The incentive mechanism affords Con Ed an opportunity to earn $22,500 per MW of DSM achieved up to a three-year maximum of $15.188 million. The Commission did not establish a decoupling mechanism, but left open the possibility to do so in another proceeding.[31]

Q. HAVE INCENTIVE PLANS BEEN DEVELOPED AND IMPLEMENTED IN OTHER STATES?

A. Yes. Both New Hampshire and Rhode Island have DSM incentive mechanisms with performance standards. In New Hampshire, the Commission approved a shareholder incentive mechanism. The incentive is based on the performance of the programs measured in terms of their actual cost-

[31] New York Public Service Commission, CASE 04-E-0572, March 24, 2005.

effectiveness and energy savings relative to the projected cost-effectiveness and energy savings, respectively. There are separate target incentives for the residential and commercial/industrial sectors set at 8 percent of the total program and evaluation budgets for each sector. Superior performance could be rewarded by up to 12 percent of the planned sector budgets. The issue of lost revenues was to be dealt with on a utility-specific basis.[32]

Q. WOULD YOU BRIEFLY DESCRIBE THE PLAN IN RHODE ISLAND?

A. Yes. In Rhode Island, in connection with Narragansett Electric Company, the Commission approved, through a collaborative process, a shareholder incentive if certain goals were met. The shareholder incentive mechanism includes two components: (1) four performance-based metrics and (2) kWh savings targets by sector. Each of the four performance-based metrics will provide the utility with the opportunity to earn up to $20,000. There is one metric in the residential sector, two in the Large Business Services/C&I sector and one in the Small Business Services/C&I sector.

XII. THE GDS REPORT SHOULD NOT BE SUBSTITUTED FOR A UTILITY-SPECIFIC DSM FILING

Q. THE JOINT APPLICANTS HAVE REFERENCED THE GDS STUDY AS HIGHLIGHTING THE OPPORTUNITIES FOR DSM SAVINGS IN UTAH. COULDN'T THE COMMISSION USE THIS AS ITS BENCHMARK IN TERMS OF DSM PROGRAMS AND SAVINGS?

[32] Electric Utility Restructuring Energy Efficiency Programs Order Establishing Guidelines for Post-Competition Energy Efficiency Programs DR 96-150; Order No. 23,574 New Hampshire Public Utilities Commission 2000 N.H. PUC LEXIS 157 November 1, 2000.

A. It could, but I believe that would be premature. The GDS Report appears to be a general guide for energy efficiency in Utah. It does not appear to have been prepared for ratemaking purposes. As such, the GDS Report has not been vetted during the course of a normal litigated proceeding and the unique degree of scrutiny typically afforded to such studies in regulatory venues. For instance, parties to this proceeding have not had the ability to conduct discovery and explore the underlying calculations and assumptions of the Report or the validity of its findings. The Commission, therefore, should only rely on this report in general terms.

Q. ARE YOU AWARE OF ANY INSTANCES WHERE THE UTAH COMMISSION HAS REJECTED A REPORT OF SIMILAR NATURE ON POTENTIAL DSM OPPORTUNITIES?

A. Yes. In a similar situation involving PacifiCorp, the Commission found that a report prepared by Tellus in connection with electric DSM potential should not be used for purposes of approving DSM programs. In examining that Report as the basis for DSM programs, the Commission found that it:

> ….will not order the Company to propose new DSM programs at this time. The record is insufficient for us to make a definitive finding that the programs outlined in the Tellus report are the most cost-effective resources available to the Company. However, the Commission notes the findings of the report indicate that ratepayers could benefit from increased investment in DSM. The Company should evaluate each program and incorporate cost-effective demand-side resources in the next interim update of the IRP.[33]

[33]Docket No. 01-035-01, Utah Public Service Commission, 2001 Utah PUC Lexis 390; 13 P.U.R.4th 225, September 10, 2001, Issued. Order on Reconsideration, Docket No. 01-035-01, Utah Public Service Commission, 2001 Utah PUC Lexis 467, October 29, 2001, Issued.

On reconsideration the Commission affirmed its decision, but clarified that PacifiCorp was to consider the DSM programs identified in the Tellus report. However, it did not order any new DSM programs based upon the report.[34]

<u>XIII. MECHANICAL PROBLEMS ASSOCIATED WITH THE CET PROPOSAL</u>

Q. PLEASE DESCRIBE THE REVENUE ACCRUAL ACCOUNT PORTION OF THE PROPOSED CET?

A. The CET balancing account is supposed to record monthly over- or under-recoveries of the authorized GS-1 DNG revenue. The allowed GS-1 DNG revenue for a particular month is equal to the allowed GS-1 DNG revenue per customer for that month times the actual number of GS-1 customers billed in the same month. The amount of the accrual is determined by taking the difference between the actual billed GS-1 DNG revenue and the allowed DNG revenue.

Q. PLEASE DESCRIBE THE MECHANICS OF HOW THE COMPANY PROPOSES TO DETERMINE THE AMOUNT OF THE REVENUE ACCRUAL?

A. As shown in McKay's Exhibit 1.7, the Company essentially began with 2005 current DNG revenue of $224,465,426, and reduced this amount by the proposed $10,218,684 rate reduction. It then determined the portion of this revenue applicable to GS-1 DNG, including the GSS customers that would be moved to the GS-1 rate schedule. This produced a GS-1 DNG 2005 revenue figure of $203,196,646. It divided this amount by year-end customers of 799,271 to develop the proposed annual allowed revenue per customer of $254.23. This formed the basis of the revenue accrual. The $254.23 revenue per customer

[34] Order on Reconsideration, Docket No. 01-035-01, Utah Public Service Commission, 2001 Utah PUC Lexis 467, October 29, 2001, Issued.

figure was then spread to months based on the pattern of GS-1 revenues per customer in 2005, adjusted for the DNG rate changes that occurred during the year.[35] This is the monthly allowed DNG revenue per Utah GS-1 customer to be used to determine the amount of the monthly over or under revenue accrual.

Q. ONCE THE ALLOWED REVENUE PER CUSTOMER IS DEVELOPED, WHAT HAPPENS NEXT?

A. The monthly allowed GS-1 DNG revenue per customer is then multiplied by the actual number of customers in the months that CET is active. The product is compared to the actual revenue collected to determine the amount, either positive or negative, that would be booked to a deferred balancing account. According to the Company, on a schedule of not less than twice a year, it will file for a percentage adjustment to GS-1 DNG rates to amortize the balance in the deferred balancing account over the projected sales for the next 12 months.[36] Currently, the Company plans to file for these rate changes in conjunction with its normal gas, pass -through filings.

Q. DO YOU HAVE ANY PROBLEMS WITH THE COMPANY'S PROPOSED TRUE-UP SCHEDULE?

A. Yes. The periodic revenue adjustment proposed by the Company is not well-defined. It states that these adjustments will not be less than twice a year. However, the Company does not say that the adjustments would not be more

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[35]During 2005 the gathering customers were moved from the GSS rate schedule to the SNG rate schedule and Odgen Valley EAC was removed.

[36] Direct Testimony of Barrie L McKay, 238.

frequent. This of course leaves the door open to have these adjustments quarterly, or even monthly.

Q HOW ARE CUSTOMERS GOING TO BE EDUCATED ON THIS ISSUE?

A The Company has provided no information on how customers are going to be educated about this proposal nor how the adjustments will appear on customers' bills. It is also not clear if the Company will incur any costs in educating customers (assuming it will do so), and whether or not those costs would also be eligible for recovery under its deferred DSM cost account.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE PROPOSED REVENUE ADJUSTMENTS?

A. Yes. Questar proposes that revenue adjustments associated with the proposed CET be developed based upon projected sales over the next 12 months. Sales forecasts can be complicated, involve numerous assumptions, and can be controversial. There is nothing in the Company's filing which indicates how this forecast will be developed for revenue adjustment purposes, or if it will be evaluated by interested stakeholders as would typically be the case in a regulated proceeding.

Q. DOES THE COMPANY HAVE ANY PROPOSALS ON HOW OUTSTANDING BALANCES ASSOCIATED WITH THE REVENUE ACCOUNT WILL BE TREATED?

A. No, the Company has offered no explanation or recommendation on how final balances in this account will be treated at the end of the three-year pilot program. A number of questions arise from this filing deficiency including:

- If there is a negative balance will these amounts be collected from customers and if so, how and over what period of time?
- If there is a positive balance will these amounts be refunded to customers and if so how and over what period of time?
- Should the balances be capped at any particular amount to prevent any unanticipated rate shock and if so, how will that be developed?
- What happens to outstanding balances if the Company decides to withdraw from the pilot program?

Q IS THE COMPANY REQUESTING RECOVERY OF COSTS FOR FUTURE DSM PROGRAMS THAT TO DATE ARE UNDEFINED?

A. Yes. The Company proposes to establish a DSM deferred account to record future, yet to be determined DSM expenditures. According to Questar, the balance in this account will be amortized periodically consistent with the CET revenue balancing account. The Company proposes to begin this deferred DSM expenditures account with a credit balance of $1.3 million. The $1.3 million is money collected from past customers but not spent by the Company. This money had been previously authorized by the Commission for Research and Development ("R&D").

Q. DO YOU THINK THIS DEFERRED DSM COST ACCOUNT SENDS GOOD EFFICIENCY SIGNALS TO THE COMPANY?

A. No. Since costs are proposed to be passed through directly to customers, shortly after they are incurred, there will be little or no incentive for the Company to manage these costs. Like its decoupling proposal, the cost recovery proposal shifts the normal business risk of managing costs away from the Company and onto ratepayers. While the Company has recently indicated (in responses to Committee data requests) that there will be some type of regulatory approval of these costs, it is unclear how (or if) that will occur.[37]

Q. IS THE DEFERRED DSM COST ACCOUNT WELL-DEFINED?

A. No, like its deferred revenue account, the Company's recommendation for a deferred DSM cost account is also very poorly defined. Like the deferred revenue account proposal, there is no certainty as to how frequently the DSM costs will be passed on to customers. The methodology for passing the costs along to customers is also not addressed. If the methodology is the same as the deferred revenue account, it may also be based, in part, on forecasted sales, and probably (although not clear) based upon forecasted costs. The method by which forecasted costs will be developed has not been provided.

Q HOW WILL UNRECOVERED COSTS BE TREATED AT THE END OF THE PILOT?

A That too, has not been clearly defined. There is no specific plan as to how the balance at the end of the pilot program will be treated or what happens to the costs collected from customers if the Company withdraws from the pilot program.

Q. DO YOU HAVE ANY PROBLEMS WITH THE TRANSFER OF ALLOWED R&D EXPENDITURES TO THE DEFERRED DSM COST ACCOUNT?

[37]Response to Committee Data Request 4.14(a-c).

A. Yes. The Company proposes to begin the deferred cost account with a negative balance from unspent R&D money. Questar has not explained how this proposal will work. For example, will the unspent funds in the account accrue interest or will the Company essentially be permitted to earn interest on the funds, but not credit a deferred account? The Company has not explained what programs are being deferred or eliminated as a result of this proposal. At a minimum, the Company should have provided a cost-benefit analysis demonstrating that its proposal is more beneficial to customers than transferring these funds (and eliminating programs) to the deferred DSM cost account.

Q. IS THERE A CAP ON THE PROPOSED DSM EXPENDITURES THAT WOULD BE INCLUDED IN THE DEFERRED COST ACCOUNT?

A. No, like potentially large outstanding revenue balances, the Company has provided no information regarding the treatment of excess balances in the deferred DSM cost account. These costs could become significant, particularly if the number of DSM programs implemented by the Company becomes large and the outstanding balances in the revenue account created by the substantial savings becomes equally large. Failure to define caps, coupled with the ambiguity in how frequently these balances will be recovered, creates the opportunity for increased customer bill volatility and, at minimum, increased billing confusion.

Q. WILL THE COMMISSION HAVE OVERSIGHT OF THIS FUNDING PROPOSAL?

A. This is also not clear. The Company's proposal does not explicitly define the Commission approval process for DSM programs and costs. What is clear is that a DSM Task Force will be created to evaluate and propose cost-effective DSM programs that will be implemented. The DSM Task Force, which includes a utility representative, should not be allowed to supplant the Commission's authority and oversight.

Q COULDN'T THE COMMISSION JUST REVIEW THESE DSM COSTS IN THE NEXT SCHEDULED RATE CASE?

A Possibly, but if the CET proposal entails direct recovery of DSM costs at the time of program initiation, then Commission review in future rate cases becomes more difficult since these program costs have already been collected from customers. Under such an ambiguous CET proposal, which implies a delegation of Commission ratemaking authority to the DSM Task Force, the Commission could easily be faced with a retroactive ratemaking challenge if it were to rule against the wishes of the DSM Task Force and issue a disallowance. The Commission should require an *ex ante* review and approval of all proposed DSM programs and costs prior to implementation and recovery in the deferred account.

Q. HOW HAS THE COMMISSION GONE ABOUT APPROVING COST RECOVERY FOR DSM COSTS FOR PACIFICORP?

A. The Commission approves DSM programs <u>**prior to**</u> allowing the related costs to be passed through to customers. In a decision approving a stipulation concerning the cost recovery for PacifiCorp DSM programs the Commission approved a DSM tariff rider which provided for a DSM surcharge to collect costs of PacifiCorp's DSM programs **approved by the Commission**.[38]

Q ARE THERE ANY OTHER COMMISSION RULINGS YOU THINK ARE IMPORTANT ON THE MATTER OF DSM COST RECOVERY?

A. Yes, in a prior docket (Docket No. 01-035-21) the Commission approved PacifiCorp's request to defer Demand-Side Resource ("DSR") program costs. In approving the deferral of certain DSM costs (Docket No. 01-035-21), the Commission did not adopt the Committee's recommendation to establish a complete record on alternative accounting and cost recovery methods. The Commission did, however, adopt the Committee's recommended conditions for the approved of deferral and future recovery of these DSM costs. Many of those conditions are equally relevant to the CET proposal at hand. The Committee's conditions were:

> a) PacifiCorp be required to maintain detailed records of all costs associated with DSR programs and that the records should be available for audit before costs are included in rates;
>
> b) PacifiCorp be required to show that DSR expenditures have produced a net benefit to ratepayers;
>
> c) Only costs of Commission-approved DSR programs be deferred;
>
> d) The deferred account not include the $ 2.5 million already in PacifiCorp's rates;
>
> e) Deferring DSR costs create no presumption of recovery in rates; and,
>
> f) The carrying charge on deferred DSR costs be limited to the current Allowance for Funds Used During Construction (AFUDC) rate.[39]

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[38]In the Matter of Demand Side Management Cost Recovery by PacifiCorp dba Utah Power & Light Company Docket No. 02-035-T12, Utah Public Service Commission, 2003 Utah PUC Lexis 188, October 3, 2003, Issued, emphasis added.

Q. YOU INDICATED THAT ONE OF THE PROBLEMS WITH THE COST RECOVERY PROPOSAL OF QUESTAR IS THAT IT DOES NOT CONTAIN A CAP. DID THE PACIFICORP'S DSM COST RECOVERY MECHANISM CONTAIN A CAP ON SPENDING?

A. No, the Commission did not require a cap on DSM spending for Pacificorp but acknowledged that its regulatory authority is a form of an "indirect cap" that keeps DSM costs from getting unreasonably large. The Commission noted:

> In response to questioning by the Commission, parties stated that there is no explicit cap on the level of dollars that could be collected through Schedule 191, but noted that there are effectively indirect limits, in that only costs of Commission-approved DSM programs can be collected through the Schedule, and there is a practical limit to the amount of cost-effective DSM that could be implemented in the state, given the varying technical and economic potential of DSM measures. (Ibid.)

Q WHAT RELEVANCE DOES THIS HAVE WITH THE CET PROPOSAL?

A The indirect cap referred by the Commission may not exist since the DSM Task Force, and not the Commission, will be in charge of determining DSM programs, costs and cost recovery amounts. This is inconsistent with the Commission's finding in the Pacificorp case and Questar should be required, if the CET is approved, to follow rules similar to those proceedings.

<u>SECTION XIV: CONCLUSIONS AND RECOMMENDATIONS</u>

Q. WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A. I recommend the Commission reject the Joint Applicants' CET proposal as not being in the public interest. The proposal suffers from a number of

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[39] In the Matter of the Application of PacifiCorp for an Accounting Order Authorizing Treatment of Demand Side Resource Costs, Docket No. 01-035-21, Utah Public Service Commission, 2001 Utah PUC LEXIS 392, September 28, 2001, Issued.

conceptual and mechanical problems that make it an unwise initiative. The Commission should not be persuaded by the arguments that because the proposed CET is a pilot program, shortcomings are unimportant and can be worked out at a later date. Even though it is a pilot program, the proposal would represent a significant departure from the way in which distribution non-gas ("DNG") revenues have heretofore been regulated and could have important precedent-setting implications for Utah's electric utilities as well. Most importantly, the need for such a departure from traditional regulatory approaches is not supported by any well-defined commitments by the Company to pursue any level of demand side management ("DSM") programs or savings – which is the ostensible justification for the proposal.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A. Yes, if the Commission believes that decoupling is in the public interest, then my alternative recommendation is that the Joint Applicants be directed to prepare a revised filing that meets the following set of important minimum requirements:

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prepare a revised filing that meets the following set of important minimum requirements:

(1) Any decoupling or other DSM incentive mechanism should be implemented only after properly designed DSM programs are in place and functioning for sufficient time that impacts upon ratepayers and the utility can be measured in relation to program goals or targets. Appropriate DSM programs are those that are completely defined and include estimated savings, costs and participation levels.

(2) A cost of capital adjustment should be incorporated into the CET program that accounts for its inherent risk shifting.

(3) A complete listing of DSM programs, estimated costs, and estimated savings and participation levels for the CET pilot period should be required. A defined three-year set of DSM programs, which match the CET pilot period, should be provided.

(4) The Company should define clear reporting requirements and evaluation metrics including annual DSM savings goals for the pilot period. This would include:

- The frequency of the audits.
- The number of customers that will be audited.
- The basis for which customers will be selected for an audit.
- The data provided by the Company that will be examined and compared to utility bills/customer information.
- How the confidentiality of customer information will be treated.

- How other parties will have the opportunity to review audit results.

(5) The Company should be required to participate in the CET program and maintain its DSM commitments during the entire pilot period. If the Company wishes withdraw from the program, it must petition the Commission and show that the cost to ratepayers of maintaining the program outweigh its potential benefits.

Q DOES THIS CONCLUDE YOUR TESTIMONY FILED ON MAY 15, 2006?

A Yes.