Docket No. 05-057-T01
DPU Exh. No. 6.0R (DGH-A)
Daniel G. Hansen
August 8, 2007

-BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH-

In the Matter of the Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders	) Docket No. 05-057-T01

REBUTTAL TESTIMONY OF

DANIEL G. HANSEN

OF

CHIRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

August 8, 2007

I. Introduction

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

A. My name is Daniel G. Hansen. I am a Vice President at Laurits R. Christensen Associates, Inc. My business address is Suite 700, 4610 University Avenue, Madison, Wisconsin, 53705.

Q. Have you testified in this proceeding before?

A. Yes. On June 1, 2007, I filed testimony on behalf of the Utah Division of Public Utilities (DPU) with an accompanying report on natural gas decoupling mechanisms used in the United States. My educational and business background may be found in that testimony.

Q. What is the purpose of your testimony?

A. On behalf of the DPU, I am responding to a number of the arguments put forth by Dr. David Dismukes, witness for Utah Committee of Consumer Services, in his direct testimony filed on June 1, 2007. I will also expand upon my previous recommendations regarding the continuation of the Conservation Enabling Tariff (CET).

Q. How is your testimony organized?

A. The remainder of my testimony is organized as follows:

- Section II: Discussion of risk shifting issues
- Section III: Other decoupling issues raised by Dr. Dismukes
- Section IV: Comments on Dr. Dismukes's recommendations
- Section V: Summary and Recommendations

Q. What are the conclusions of your testimony?

A. I conclude that Dr. Dismukes does not have a strong foundation upon which to base his "fundamental objection" to decoupling mechanisms, which is that they "shift considerable usage-related risks from the Company and its shareholders to ratepayers."[1] Regarding Dr. Dismukes's recommendations, I conclude the following:

- Lost Revenue Adjustments (LRA) do not solve the utility incentive problems with respect to conservation, primarily because LRAs do not alter the utility's incentive to grow load;
- future test years and/or repression adjustments can be effective in resolving concerns about declining use per customer, but do nothing to alter the utility's incentives with respect to conservation and load growth; and
- altering the CET so that deferrals do not change with the number of customers (an alternative recommendation by Dr. Dismukes) fails to recognize that distribution costs change with the size of the customer base and fails to address a potential method for the utility to game the mechanism.

Q. What is your recommendation with respect to the CET?

A. My recommendation is to retain the CET in its current form, but to institute additional monitoring to ensure that the utility does not game the mechanism, which could occur if the utility deliberately acted to add customers with significantly lower-than-average usage levels.

II. Risk Shifting

Q. Please describe the role of risk shifting in Dr. Dismukes's testimony.

[1] Dismukes June 1, 2007 testimony, p. 4.

A. In responding to the question “what are your fundamental objections to the use of revenue decoupling mechanisms like the CET,” Dr. Dismukes responds that “revenue decoupling mechanisms are overly broad and shift considerable usage-related risks from the Company and its shareholders to ratepayers.”[2]

Q. In your June 1, 2007 testimony, did you address the potential for the CET to shift risk from Questar Gas (Questar) to its ratepayers?

A. Yes I did. I found that, while decoupling mechanisms contain the *potential* to shift economic and commodity price risk from the utility to its ratepayers, an examination of Questar data revealed that such a shift was unlikely to occur under the CET.

Q. Could you please provide a summary of the analysis that you performed?

A. Yes, but it might be useful to start at a high level and define the term “risk”. Risk is the amount of uncertainty associated with an outcome of interest and is typically quantified using a measure of the variability of the outcome (such as variance or standard deviation).[3] In this proceeding, the outcome of interest is a customer’s bill for distribution non-gas (DNG) services. The amount of risk that is caused by different sources of uncertainty can be separately measured. For example, because traditional distribution rates contain a volumetric (i.e., dollar per therm) component, a customer’s DNG bill varies as its usage varies. An example of a source of usage fluctuations, and therefore DNG bill risk, is weather conditions. That is,

[2] Dismukes, June 1, 2007 testimony, p. 4.
[3] An example of defining risk in this way can be found on page 50 of *New Regulatory Finance* by Roger A. Morin (2006): “The risk of an investment is therefore related to the potential variability of its return.”

colder-than-expected winters increase customer DNG bills and milder-than-expected winters decrease customer DNG bills.

Q. What conditions are required in order for a decoupling mechanism like the CET to shift risk from the utility to its ratepayers?

A. There are two conditions. First, the risk must be “in the same direction” for the utility and the ratepayers. That is, conditions that cause one party to be worse off must also cause the other party to be worse off. Second, the source of the risk (e.g., changes in economic conditions) must cause changes in *class-level* use (or revenues) per customer.

Q. Please explain your first condition that the risk must be “in the same direction.”

A. If the utility and its ratepayers experience a risk that is “in the same direction,” there is no way to reduce the risk for one party without increasing the risk for the other. This is most easily illustrated by examining the converse: that is, what happens if the utility’s and ratepayers’ risks are in “opposite” directions? In this case, a mechanism can be designed that reduces the risk for both the utility and its ratepayers. A good example of this is the use of weather normalization mechanisms such as Questar’s Weather Normalization Adjustment (WNA) to reduce weather risk. Both Questar and its ratepayers face risk due to the effect of uncertain weather conditions on DNG revenues. When winters are unusually cold, Questar tends to over-recover DNG revenues (i.e. Questar is better off) and the ratepayers’ bills are higher than expected (i.e., ratepayers are worse off). In unusually cold winters, Questar thus benefits at the expense of its customers. In unusually mild winters, customers benefit at the expense of Questar.

The WNA attempts to reduce the variation in DNG revenues and bills across different weather conditions by adjusting customer usage to normal weather conditions. In an unusually cold winter month, the WNA reduces both Questar's DNG revenues and customers' bills. In an unusually mild winter month, the WNA increases Questar's DNG revenues and customer's bills. As a result, the WNA reduces weather-induced variation and risk in both customer bills and Questar's DNG revenues. This demonstrates that a reduction in a utility's risk can be accompanied by a reduction in customers' risks also, and refutes the notion that risk-reduction for one party must necessarily increase risks for another party.

Q. How is your weather normalization mechanism example relevant to decoupling mechanisms?

A. A weather normalization mechanism can reduce risk for both the utility and its ratepayers because they face risks that are in opposite directions (i.e., weather conditions that cause one party to be worse off make the other party better off). This creates the potential to develop a mechanism that reduces risk for both parties.

This is relevant to decoupling because under traditional rate designs the utility over-recovers DNG revenues at the expense of its ratepayers (and utility under-recovery benefits its ratepayers). Therefore, as with weather normalization, decoupling addresses conditions that cause one party to be worse off while making the other party better off. Therefore, to the extent that decoupling reduces the uncertainty in a utility's DNG revenues (e.g., under CET when the number of customers remains constant), it also reduces the uncertainty in the amount of DNG revenues paid by customers. Therefore, the baseline assumption should be that over time (i.e., including decoupling deferrals and DNG revenues in the current year) decoupling can reduce DNG revenue (or bill) risk for *both* the utility and its ratepayers.

I feel that it is important to point out that traditional DNG rates (such as Questar's GS-1 rate) contain risk for consumers. Because opponents of decoupling do not discuss the risk embedded in traditional DNG rates, the implication may be that they are not risky for ratepayers, while alternatives such as decoupling or Straight Fixed Variable (SFV) pricing are.

By allowing customers' payment of allowed DNG costs to vary with usage, traditional DNG rates will lead to customers either over- or under-paying for those allowed costs except in the extraordinary case in which actual usage is exactly as forecast when rates were set. SFV pricing, in which all fixed costs are recovered with fixed charges, is the *least* risky DNG revenue recovery mechanism for the ratepayers because the DNG portion of the bill doesn't vary at all. (However, the customer incentive and equity effects may be comparatively undesirable, as described in more detail below.) When the effects of deferrals are included, decoupling is likely to be less risky for consumers than traditional rates, but more risky than SFV pricing.

Q. But didn't you say that decoupling contains the potential to shift economic and commodity price risk shift from the utility to its ratepayers?

A. Yes, these are exceptions to the rule described above. When these risks exist, the utility and its ratepayers will be worse off at the same time (i.e., the risks are "in the same direction"). For example, in theory a downturn in the economy could adversely affect customers (e.g., through job loss), causing them to reduce usage in an attempt to lower their bills, which in turn reduces the utility's DNG revenues. Because deteriorating economic conditions and increases in commodity prices adversely affect the utility and its ratepayers at the same time, a mechanism cannot be designed that reduces these risks for both parties at the same time. Therefore, the *potential* for a shift of these risks is present.[4]

Q. Please elaborate on the second condition required for decoupling mechanisms like the CET to shift risk from the utility to its ratepayers.

A. Recall that the second condition is that the source of the risk (e.g., changes in economic conditions) must cause changes in *class-level* use (or revenues) per customer. The reason for this is as follows: any *one* customer who reduces usage in response to job loss or high natural gas prices will receive essentially the same bill reduction as it would under the standard tariff. The CET only produces deferrals for Questar if revenues per customer change for the entire class. The following simple example illustrates this point.

Suppose that a customer typically uses 21.81 decatherms (Dth) in January and that the DNG rate is $1.94638 per Dth, so that the customer pays the January allowed DNG per customer amount of $42.45 (= 21.81 x $1.94638). If this customer reduces its usage by 25 percent (5.45 Dth) by, say, lowering its thermostat, their DNG bill in that month will decrease to (21.81 – 5.45) x $1.94638 = $31.84, which is a reduction of $10.61.[5] This bill reduction will go into the CET deferral account. Suppose that class-level usage is roughly 16,600,000 Dth for the month (which comes from

[4] "Commodity price risk" exists when increases in the commodity price cause customers to reduce usage, which reduces the utility's DNG revenues at the same time customers are dealing with high bills through the commodity cost portion of the bill.

[5] Assuming a fixed charge of $5.00 per month, a supplier non-gas cost of $1.23005 per Dth and a commodity cost of $5.37212 per Dth, the customer's *total* bill will decrease from $191.44 to $144.85.

830,000 customers multiplied by 20 Dth / customer). The DNG rate increase in the following January due to this customer's 25 percent usage reduction is equal to $10.61 divided by 830,000 Dth, or $0.00000064 per Dth.[6] When this rate increase is multiplied by the customer's expected usage in the following January, it does not even add up to a penny's worth of bill increase for that individual customer.

Alternatively, if *all* of the customers in the class had reduced usage by 25 percent in January in this example, the DNG rate in the following January would have increased by approximately 25 percent as well.[7] This would still leave customers with the full benefit of the reduction in the supplier non-gas and commodity cost portions of the bill.

This example shows how simple anecdotes about customers reducing usage in response to deteriorating economic conditions and/or increases in commodity costs are not sufficient to demonstrate that economic or commodity price risks are shifted under the CET. After all, if a subset of the customers reduces their usage, but not enough to significantly affect aggregate revenues per customer for the customer class, their bills in the following year are essentially unchanged by the CET.

Q. Does the CET meet the two requirements for risk to be shifted from the utility to its ratepayers?

A. No. As described above, the two sources of risk that meet the first requirement are changes in economic conditions and the commodity price. In order

[6] This simple example ignores interest, the deferrals from all other months, assumes that the deferral will be recovered only in January, and assumes that, on average, the remaining customers in the class produce the allowed revenues per customer.
[7] The 25 percent increase in rates assumes that the deferral is spread over the baseline quantity (i.e., 21.81 Dth) and not the post-reduction quantity (i.e., 16.36 Dth).

to determine whether the second requirement is met for these two sources of risk, I analyzed data from 1980 through 2005 for Questar's GS-1 customers.

Section 5.2 of my report filed on June 1, 2007 contains the results of a statistical analysis of the relationship between annual GS-1 use per customer and weather conditions, the commodity price, economic conditions, and a time trend variable. In order to ensure that the results were not dependent upon a particular specification or variable definition, I presented the results associated with ten different models, which included the use of three alternative measures of economic conditions (the Utah gross domestic product, unemployment rate, and per capita disposable personal income).

The findings from these models indicated that GS-1 use per customer is strongly related to weather conditions (in the form of heating degree days) and somewhat related to a time trend (indicating a decrease in use per customer over time, all else equal). However, the finding that is relevant to the risk shifting issue is that the models showed that **GS-1 use per customer is not related to economic conditions or the commodity price**. That is, during 1980 through 2005 (a period that includes a variety of economic conditions and significant changes in the commodity price) there was no statistically significant relationship between changes in GS-1 use per customer and changes in economic conditions or the commodity price. Based on this finding, we would expect that (for example) if economic conditions were to worsen in the future, there would be no effect on overall GS-1 use per customer, and therefore the worsening economic conditions would have no effect on CET deferrals. In the absence of an effect on class-level use per customer, the shifting of risk from the utility to its ratepayers does not occur.

Q. Dr. Dismukes asserts that CET "shifts considerable sales risk to ratepayers."[8] Does he provide any evidence that risk is shifted from the Company and its shareholders to ratepayers?

A. The only evidence that Dr. Dismukes provides in his June 1, 2007 testimony to support his claim is the outcome for Central Maine Power's (CMP) decoupling mechanism in the early 1990s.[9] The commonly held view is that an economic downturn in the state of Maine produced a large decoupling deferral ($52 million) owed to CMP. Because the effects of conservation were deemed to be very small in comparison to this value, the decoupling mechanism was ended in 1993.

Q. Is this example relevant to an examination of the CET?

A. Even if one assumes that the CMP deferrals were due to a downturn in the regional economy (I have not personally examined the relevant data to determine whether this conclusion is correct), the fact that CMP is an electric utility limits the relevance of this example for the current proceeding. Under the CET, economic risk is shifted from Questar to its ratepayers only if class-level revenues per customer decline as economic conditions deteriorate. However, customers' changes in *electricity* usage in response to changes in economic conditions may be very different from their changes in *natural gas* usage because the nature of the end uses can be quite different. The primary sources of natural gas usage are space heating, water heating, and cooking. The demand for these services could be more inelastic (i.e.,

[8] Dismukes June 1, 2007 testimony, p. 6.
[9] Id., pp. 23-24.

less responsive to changes in price or income) than the demand for some electricity end uses that may be more "discretionary" in nature (e.g., televisions, computers, video games, etc.). Therefore, one cannot simply assume that the relationship between decoupling deferrals and economic conditions that occurred for CMP would hold true for Questar as well.

As described above, decoupling contains the *potential* for a shift in economic risk from the utility to its ratepayers, but the issue needs to be analyzed on a case-by-case basis to determine whether the risk shift exists in practice. The outcome for CMP is taken from a different industry (electricity versus natural gas), a different region of the country, and a different time period from the CET. As described above, my analysis of Questar's data indicated that GS-1 class-level use per customer is not related to economic conditions or the commodity price, indicating that risk shifting is not likely to be an issue for the CET.

Q. In the 3rd set of data request to CCS-Consultant Dismukes by the Division of Public Utilities, Dr. Dismukes was asked to provide studies, analysis, reports or other evidence to support the assertion that "revenue decoupling mechanisms… shift considerable usage-related risks from the Company and its shareholders to ratepayers." Was the additional evidence any more convincing?

A. No. I'll summarize the items provided below.

- "Revenue Decoupling for Natural Gas Utilities" by Ken Costello of the National Regulatory Research Institute (2006): In a table, this report assesses the arguments made against decoupling, and categorizes as "weak" arguments (as opposed to "strong" arguments) "unequivocally increased customer risk" and "preference for lost revenue adjustment (LRA) mechanism."[10] This report therefore seems to undermine both Dr. Dismukes's chief reason for opposing decoupling mechanisms and his primary recommendation.

- ELCON position paper on revenue decoupling (2007). This report merely states, without evidence, that "it is the expressed intent of RD mechanisms to shift risks from shareholders to consumers."[11] I've never observed such intent expressed in the present proceeding or elsewhere.
- Connecticut Division of Public Utility Investigation into Decoupling Energy Distribution Company Earnings from Sales (2006). The conclusions of this report state that "decoupling mechanisms… would eliminate normal business risks for the gas LDCs"[12], but no claim is made that risks are shifted from the utility to its ratepayers. (Recall that risk reductions for one party do not necessarily imply risk increases for another.)
- Arizona Decision No. 68487 (2006). This Order, which rejects the implementation of a decoupling mechanism, does not present any evidence that risk is shifted from the utility to its ratepayers. In fact, it encourages Southwest Gas to "coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties."[13]

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[10]"Revenue Decoupling for Natural Gas Utilities" by Ken Costello of the National Regulatory Research Institute (2006), p 17. Note that on page 19, the report describes my study of decoupling for NW Natural as "the most comprehensive and analytical *ex post* investigation of a RD mechanism for gas utilities."

[11] Electricity Consumers Resource Council, "Revenue Decoupling: A Policy Brief of the Electricity Consumers Resource Council", January 2007, p. 5.

[12] Connecticut Division of Public Utility Investigation into Decoupling Energy Distribution Company Earnings from Sales (2006), p. 13.

[13] Arizona Decision No. 68487 (2006), pp. 17-18.

- State of Washington Orders 04 and 03 for Dockets UE-050684 and UE-050412, respectively (2006). The Order rejects the use of decoupling for PacifiCorp, in part because PacifiCorp's proposal "fails to… quantify the effect the mechanism may have on risks associated with recovery of fixed costs."[14] In other words, no evidence demonstrating the effect of decoupling on risk was presented. In addition, the Order states that "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."[15]
- Arkansas Order No. 16 from Docket No. 04-121-U (2005). While the text of the Order claims that the proposed decoupling mechanism "would inappropriately shift risk from Arkla's stockholders to Arkla's customers,"[16] this claim is based on the testimony of two individuals. An examination of the underlying testimony (by Staff witness Wright and AGC witness Marcus[17]) reveals that only reductions in *utility* risk are asserted and discussed. No mention is made of a shift of this risk to ratepayers. For example, witness Wright testifies that "While Arkla's risks are reduced, there is no corresponding reduction in risk to customers."[18]
- Florida Order No. PSC-05-0208-PAA-GU from Docket No. 040956-GU (2005). This Order does not appear to be about decoupling mechanisms. Rather, it rejects the full implementation of Straight Fixed Variable pricing.

[14]State of Washington Orders 04 and 03 for Dockets UE-050684 and UE-050412, respectively (2006), p. 25.
[15]Id., p. 15.
[16] Arkansas Order No. 16 from Docket No. 04-121-U (2005), p. 32.
[17] The Order actually references testimony by AGC witness Johns, which does not appear to exist. However, the Marcus testimony is on the relevant topic and is from the same organization, so I assume that this testimony was the intended reference.
[18] Testimony of Alice D. Wright, Docket No. 04-121-U, May 24, 2005, page 10.

- Nevada Order for Docket No. 04-3011 (2004). This Order, which rejects the implementation of a decoupling mechanism, makes no reference to risk shifting.
- State of Washington Settlement Agreement for Docket No. UG-060256 (2006). This agreement approves a decoupling mechanism pilot program and makes no mention of risk shifting. In fact, the agreement lists four elements that must be considered in any evaluation of the pilot program.[19] None of them involve an examination of the whether risk is shifted from the utility to its ratepayers.
- A NARUC presentation on decoupling and other issues (2007). This presentation asserts, without providing evidence, that decoupling shifts risks from the utility to its ratepayers.

In summary, my review of the documents provided by Dr. Dismukes reveals no evidence supporting his assertion that decoupling mechanisms shift risk from the utility to its ratepayers.

Q. If CET doesn't shift economic or commodity price risk from Questar to its ratepayers, does it reduce risk for the utility?

A. It probably will, though this outcome is not guaranteed. Under the GS-1 rate schedule, DNG revenues change with sales levels. Under the CET, DNG revenues (including deferrals) change with the number of customers. Therefore, from Questar's perspective, the variability (or risk) in DNG revenues will be reduced by CET in the likely event that the annual variation in sales is higher than the annual variation in the number of customers.

[19] State of Washington Settlement Agreement for Docket UG-060256, p. 11.

Q. Dr. Dismukes cites examples in which financial analysts have indicated the risk-reducing benefits of decoupling for utilities.[20] Is this proof that decoupling shifts risks from the utility to its ratepayers?

A. No. As described above, risk may be reduced for one party without increasing risk for another party. The fact that in some instances financial ratings agencies have found that decoupling reduces the utility's risk does not say anything about the level of risk that its ratepayers bear.

Q. How would you summarize the issue of decoupling shifting risk from the utility to its ratepayers?

A. Dr. Dismukes has stated that the shifting of risk from the utility to ratepayers is his "fundamental objection" regarding the CET.[21] However, he has failed to demonstrate that any shift in risk can be expected to occur under the CET. In contrast, Section 5.2 of my previously filed report explicitly analyzes the issue of whether the CET can be expected to shift risks from Questar to its ratepayers, reaching the conclusion that such a shift does not appear to be likely in this case.

III. Dr. Dismukes's Other Criticisms of Decoupling

Q. In addition to his allegation that decoupling shifts risks from the utility to its ratepayers, do you disagree with any of Dr. Dismukes's other statements regarding decoupling?

A. Yes, there are four that I would like to discuss here:

[20] Dismukes June 1, 2007 testimony, pp. 28-29.
[21] Id., p. 4.

1. His claim that decoupling mechanisms make "customers indifferent between rates being fixed or variable";[22]
2. His assertion that decoupling reduces the utility's incentive to control costs;[23]
3. His claim that decoupling is unnecessary because DSM savings are relatively small;[24] and
4. His assertion that CET deferral calculations should be based on the test year number of customers.[25]

Q. Please elaborate on Dr. Dismukes's claim that decoupling mechanisms make "customers indifferent between rates being fixed or variable."

A. My example above, which shows the financial effects of the CET when a single customer reduces its usage by 25 percent, demonstrates that this statement is incorrect. In the quote above, Dr. Dismukes was referring to a comparison of decoupling to SFV pricing, in which all fixed costs are recovered through fixed charges and all variable costs are recovered through variable rates.

Insofar as the purpose of decoupling is to remove utility disincentives for conservation, SFV pricing eliminates the need for decoupling because fixed cost recovery does not change with the level of usage. However, relative to traditional rates, implementing SFV pricing will tend to lower volumetric rates and increase fixed rates. This raises two concerns that are distinct from the utility incentive issue. First, conservation-oriented groups such as the Natural Resources Defense Council (NRDC) dislike SFV pricing because it reduces the customer-level incentive to

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[22] Id., pp. 13-14.
[23] Id., pp. 29-30.
[24] Id., pp. 31-34.
[25] Id., p. 40.

conserve (by lowering the volumetric rate). Second, low-income consumer advocates may be concerned that SFV pricing has a particularly adverse impact on low-income customers because they tend to be low-*use* customers who would be disproportionately harmed by increases in fixed rates.

In the example above, if SFV pricing were in place, the individual customer who reduces usage by 25 percent will not reduce the DNG portion of their bill at all in the current month. This is in contrast to the outcome under the CET, in which the customer's DNG bill is reduced by $10.61, with no measurable effect on their bill in the following year through the deferral mechanism. There is therefore a clear difference between SFV and decoupling from the customer's perspective, and the difference in customer-level incentives is the reason that organizations such as the NRDC promote decoupling but not SFV.

Dr. Dismukes's assertion is further refuted by an ELCON white paper that he cites in his June 1, 2007 testimony.[26] Though Dr. Dismukes is correct that ELCON strongly opposes the use of decoupling mechanisms, he fails to point out that ELCON advocates what appears to be the electricity equivalent of SFV pricing:

> Thus the first and most important step regulators can take to ensure that ratepayers themselves are induced to make energy efficient investments and behavioral changes is to implement retail rates that send the proper price signals to each customer class. *This includes the allocation of fixed costs to customer (or 'demand') charges and time-variant energy charges*.[27] (Emphasis added.)

[26] Id., pp. 15-16.
[27] Electricity Consumers Resource Council, "Revenue Decoupling: A Policy Brief of the Electricity Consumers Resource Council", January 2007, p. 7.

The italicized portion of the excerpt reflects a desire on ELCON's part to recover fixed costs through fixed or quasi-fixed charges[28]; and variable costs through energy charges (that vary by time in order to reflect persistent variations in electricity costs by season and time of day). ELCON, NRDC, and I therefore seem to agree that there is both a difference and a distinction between decoupling and SFV.

Q. Please elaborate on Dr. Dismukes's claim that decoupling affects the utility's incentive to control costs.

A. His argument is that utility profits are equal to the difference between revenues and costs, and that under traditional regulation he expects that revenues would be substantially more variable than costs. Specifically, he writes that "Costs normally have more certainty and are typically within a utility's control."[29] He goes on to argue that "Active cost reducing efforts have the ability to compensate for unexpected changes (decreases) in revenues… Revenue decoupling eliminates revenue uncertainty (assuming a constant level of customers), which in turn can dampen efficiency incentives."[30]

Q. Do you find this to be a compelling argument?

A. No, the variability in revenues is not related to the utility's incentive to control costs. To illustrate this, consider Exhibits 6.1R 1a and 6.1R 1b, which show a very simple example in which the utility's revenues under traditional rates can either be $100 or $80, with equal probability. Implementing decoupling eliminates the uncertainty in revenues, guaranteeing them to be $90 (the average of $100 and $80).

[28] Revenues from demand charges tend to be significantly less variable than revenues from energy charges.
[29] Dismukes June 1, 2007 testimony, p. 29.
[30] Id., p. 30.

Assume that the starting level of costs is $70 (which doesn't vary as revenues vary, consistent with Dr. Dismukes's assumption that revenues are more variable than costs). Exhibit 6.1R 1a shows that profits would then be $30 if revenues were high, $10 if revenues were low, and $20 if decoupling is implemented (and guarantees revenues). Exhibit 6.1R 1b shows how profits change if costs are reduced from $70 to $60. Notice that regardless of whether revenues are high, low, or guaranteed by decoupling, profits are $10 higher than they otherwise would have been when costs are reduced by $10. This shows that the incentive for the utility to reduce costs is the same regardless of whether revenues vary or are fixed by decoupling.

Q. Please elaborate on Dr. Dismukes's claim that decoupling is unnecessary because DSM savings are relatively small.

A. Dr. Dismukes estimates that "the amount of revenue lost from the promotion of cost-effective DSM is less than one-half of one percent of the Company's total GS-1 revenues."[31] He continues, writing "the financial implications of promoting DSM appear to be small and it would appear that a more important benefit the Company and its shareholders get from the CET is associated with revenue insurance on potential changes in use per customer and not the promotion of DSM."[32]

Q. Do you agree with this argument?

A. I agree that lost revenues associated with DSM are likely to be a relatively small percentage of total sales and that Questar may be concerned about declining use per customer. However, I do not agree with the conclusion that the CET is therefore unnecessary. There are three additional factors to consider. First, in addition to lost

[31] Id., p. 33.
[32] Id., p. 34.

revenues due to DSM programs, Questar is likely to lose revenues from providing additional information on conservation methods. For example, Questar's ThermWise web site contains a page devoted to energy saving tips.[33] Conservation that is initiated through educational programs such as this will not be counted in a DSM program. In the absence of decoupling, the utility has no incentive to initiate, continue, or improve programs such as this (i.e., programs that lead to conservation, but whose benefits are not easily tracked). Second, decoupling does more than remove a disincentive to promote DSM programs (which could be achieved by other means, for example, if Lost Revenue Adjustments – or LRA – could be properly implemented). Revenue per customer decoupling (RPCD) mechanisms (such as the CET) also create a disincentive for the utility to *grow* the loads of its existing customers. That is, as usage increases for current customers, the CET produces a deferral that transfers dollars from the utility to its ratepayers, whereas under traditional rates the usage increase raises DNG revenues through the volumetric rate. In the absence of decoupling, the utility has the incentive to promote inefficient load growth through other sales programs, perhaps even as they promote cost-effective DSM programs (with the lost revenues presumably being returned to the utility through something like an LRA).

Third, even though lost revenues are small relative to GS-1 revenues, they are a larger share of net income. Net income is a more relevant denominator, as it represents the outcome of interest for the utility. Questar Gas is a subsidiary of Questar Corporation. Questar Corporation's 2006 Annual Report claims that Questar Gas's 2006 net income was approximately $37 million. Therefore, the DSM lost

[33] http://www.thermwise.com/tips.html

revenues shown on Dr. Dismukes's CCS Exhibit 1.8 (which range from $288,537 to $334,826) account for nearly one percent net income (0.78 to 0.90 percent). While this is still not an overly large percentage, it does indicate that the effect, when more properly scaled, is six times larger than Dr. Dismukes claimed (e.g., 0.78 percent divided by 0.13 percent = 6.0).

Q. Please elaborate on Dr. Dismukes's assertion that CET deferral calculations should be based on the test year number of customers.

A. Dr. Dismukes asserts that "In order to make an LDC whole relative to the test year upon which its rates are based, a decoupling mechanism should be examining the difference between actual and test year revenues per customer relative to the test year customer level upon which costs and revenues are based."[34]

Q. Do you agree that the CET (and other revenue per customer decoupling mechanisms) should use the test year number of customers in calculating deferrals as opposed to using the current number of customers?

A. No. Dr. Dismukes fails to acknowledge that traditional rates allow for DNG revenues to increase as customers are added to the system. That is, new customers contribute to DNG revenues through the volumetric DNG rate, potentially allowing the utility to recover more than the amount of DNG revenue approved for the test year. By altering the CET to calculate deferrals using only the test year number of customers, Dr. Dismukes's proposed method would severely penalize Questar relative to the outcome under traditional rates, and fail to acknowledge that DNG costs increase as the size of the customer base increases. In a report on decoupling produced for the Idaho Power Company (which therefore describes sales in terms of

[34] Dismukes June 1, 2007 testimony, p. 40.

kilowatt hours instead of therms), Mr. Eric Hirst (an energy industry consultant) wrote: [35]

> Decoupling involves two major steps. The first is the policy decision to break the link between sales and revenues. The second, analytically more difficult, step is to recouple utility revenues (more precisely, revenues to cover fixed costs) to something other than actual kWh sales.

Recoupling revenues to the number of customers (as the CET currently does) is a commonly used (though not the only available) method of recoupling utility revenues. Dr. Dismukes's suggestion to simply modify the CET to incorporate a fixed number of customers fails to recognize the need to recouple utility revenues to some factor other than sales.

Q. Are there any other problems with Dr. Dismukes's proposal to keep the number of customers at the test year level?

A. Yes, it largely fails as a means to protect ratepayers from the potential for the utility to "game" the decoupling mechanism. Recent events at Piedmont Natural Gas in North Carolina indicate the potential for a utility to take advantage of a revenue per customer decoupling (RPCD) mechanism. Specifically, the Customer Utilization Tracker (CUT) is an RPCD mechanism that was approved for use by Piedmont Natural Gas beginning in December 2005. Upon hearing reports of suspiciously high deferral amounts accruing in the utility's favor, I investigated the data associated with one of the sub-classes that is affected by CUT, the Residential Value Rate Schedule

[35] "Decoupling for Idaho Power Company", March 30, 2004, p. 3. The report is available at: http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE0415/company/20040628DECOUPLING%20REPORT.PDF.

No. 101.[36] For this class, the annual allowed therms per customer (as approved for a future test year in the rate case) is 852.7. However, during 2006, the observed therm per customer value was only 702.6. Adjusting this value to normal weather conditions (the winter was mild) only increases it to 754.9 therms per customer, still considerably below the allowed value. This reduction in use per customer and the somewhat rapid increase in the number of customers[37] produced a 2006 deferral of $13,282,270 in the utility's favor. This represents a 16.2 percent increase in the DNG revenues that customers would have paid under standard rates.

Q. Why do you think that the large deferral indicates that a potential problem exists?

A. The large reduction in use per customer could arise from two sources: reductions in usage for "existing" customers (i.e., customers who were on the system at the time of the rate case), or the addition of customers with lower-than-average usage levels. Reductions in use per customer arising from the former source are not subject to gaming on the part of the utility (provided that the utility is not willing to engage in outright fraud with respect to the use of metered data – in which case revenues from *any* rate or mechanism are suspect). However, it is possible that the utility could influence the average usage of new customers, by, for example engaging in marketing programs that encourage the enrollment of customers with only a gas fireplace. Doing so would reduce the overall use per customer and create deferrals in the utility's favor. I would describe such behavior as "gaming" on the part of the

[36] The reporting documents can be found at http://ncuc.commerce.state.nc.us/docksrch.html under Docket G-9 Sub 499.
[37] 2006 had an average of 272,388 customers per month, compared to 238,561 customers in the test year, which represents the projected level of customers in June 2005.

utility, as it results in a financial benefit for the utility due to an intentional manipulation of the mechanism's parameters in a manner that is not consistent with the intent of the mechanism (which is primarily to encourage conservation).[38]

Q. Is the source of the reduction in use per customer at Piedmont Natural Gas known?

A. No, to my knowledge no detailed study of the source of the reductions in use per customer for this customer class has been conducted. Given the available data, I am unable to determine whether the reduction is due to existing customers reducing usage or new customers having lower-than-average usage levels (or some combination of the two).

Q. How does the Piedmont Natural Gas situation relate to Dr. Dismukes's recommendations?

A. Dr. Dismukes recommends basing the deferral calculations on the test year number of customers instead of the current number of customers. If this method had been used for the Piedmont customer class described above, the approximately $13.3 million deferral in 2006 would have been reduced to only $11.75 million. That is, the vast majority of the deferral was caused by reductions in use per customer and not by the increase in the number of customers. Dr. Dismukes does not propose changing the calculation of use per customer. His recommendation is therefore ill-advised for two reasons: it fails to recognize the even traditional DNG rates allow the utility to recover additional DNG revenue as customers are added to the system (i.e., it does

[38] Note that, to some extent, this "gaming" incentive encourages the promotion of energy efficiency. That is, the utility has the incentive to ensure that new customers have the most energy efficient appliances possible, which reduces the class-level use per customer and provides the utility with a benefit through the decoupling mechanism. This is different from ensuring that new customers have as few natural gas end uses as possible, which I would consider gaming behavior.

not "recouple" distribution revenues to a factor other than sales); and it fails to protect customers from the potential for the utility to game the mechanism.

Q. Is there any way to prevent the utility from gaming a decoupling mechanism?

A. Yes. At least two methods are available. The first is to require the utility to report to the DPU usage, DNG revenues, and the number of customers (and therefore both use and revenue per customer) separately for existing premises and newly enrolled premises.[39] This allows the DPU to monitor the extent to which changes in use per customer can be attributed to changes in the behavior of existing customers versus the enrollment of customers with usage levels that deviate from the allowed per customer levels. Should large deferrals occur due to the latter cause (i.e., a change in the composition of the customer class, as opposed to a change in the behavior of the customer class) the burden of proof would be on the utility to show that it is not manipulating customer enrollments to its advantage. The Commission should retain the ability to cancel or suspend the effects of the decoupling mechanism based on its suspicions regarding such gaming behavior.

The second solution to the gaming incentive is to abandon the use of RPCD decoupling and instead base decoupling deferrals on a predetermined allowed DNG revenue level. While this level will likely change over time in a manner pre-specified in a rate case, it would not change because of changes in customer usage levels or the number of customers. For example, the allowed DNG revenue requirement could be

[39] I recommend the use of a "premise" versus a customer because gaming is more likely to occur for new service hookups than for transfers of the ownership of a given premise. For the utility to game an account transfer, they'd need to do something along the lines of convincing a customer who purchases a home with a natural gas furnace to replace it with an electric furnace. The customer would, however, need to retain some other form of gas service (e.g., cooking or a gas fireplace) in order to be counted in the RPCD mechanism.

based on a forecast of costs over the following four years, adjusted for inflation and productivity. At the end of the four-year period, the utility would file another rate case seeking to establish allowed DNG revenues for the following four years. By removing the link between allowed DNG revenues and use (or revenues) per customer, the incentive to enroll customers who use less than typical customers is removed.

Q. Which of the two solutions do you recommend be adopted for the CET?

A. I recommend that the enhanced monitoring requirements be implemented for the CET. Based on Questar's CET accounting entries for July 2006 through April 2007 (found in QGC Exhibit 1-YR 1.2), there is no evidence that Questar is currently gaming the CET. Exhibit 6.2R shows that Questar's actual DNG revenue per customer during this time period was $228.83, while the allowed DNG revenue per customer was $233.03. (This exhibit is simply QGC Exhibit 1-YR 1.2 with the required calculations added to rows labeled 17 and 18.) This small difference in revenue per customer occurred despite an increase in the number of customers from 809,315 to 835,906 (or 3.3 percent). Because of the absence of evidence of manipulation of RPCD mechanisms (by Questar and elsewhere) and the fact that enhanced monitoring can produce information that can help detect the gaming behavior, I do not believe that the CET requires major changes at this time.

However, should concerns arise regarding the ability of the enhanced monitoring to prevent gaming behavior on the part of the utility, the CET can be modified to use a pre-specified allowed DNG revenue level (that will likely change over time in a manner specified in a rate case). The deferral calculation for a decoupling mechanism of this kind is described in Equation 1 of my report filed on June 1, 2007, replicated below (with the addition of the subscript t to reflect the potential for allowed revenues to change over time):

Equation 1: Deferral = $REV^{B}_{i,t} - REV^{A}_{i,t}$

In this equation, $REV^{B}_{i,t}$ is the "baseline", or allowed DNG revenue level for rate class i in year t, which can vary across years in a pre-determined manner; and $REV^{A}_{i,t}$ is the actual (i.e., metered and billed) DNG revenue from rate class i in year t. The deferral amount is simply equal to the difference between the two revenue values, without reference to number of customers or use per customer. As described in my previous report, the disadvantages associated with using a mechanism of this kind are that it does not provide the utility with an incentive to promote economic growth or high quality customer service (both of which are provided through the number of customers element in an RPCD mechanism).

IV. Comments on Dr. Dismukes's Recommendations

Q. What does Dr. Dismukes recommend in his June 1, 2007 testimony?

A. He has three primary recommendations: to "discontinue the use of the CET," "adopt a lost revenue adjustment (LRA) mechanism to make the Company whole for changes in usage resulting from its DSM programs;" and to use a forecasted test year to address concerns regarding reductions in use per customer.[40] If the Commission disregards his primary recommendations, he provides "alternative recommendations" as follows: to base the CET on the test year number of customers rather than the

[40] Dismukes June 1, 2007 testimony, pp. 6-7.

current number of customers; and for the Commission to consider "the shifting of risk… in setting the Company's ROE in its next rate case."[41]

Q. Do you agree with Dr. Dismukes's alternative recommendations?

A. No. I have already discussed the reasons that I disagree with Dr. Dismukes's recommendation regarding fixing the number of customers in the CET deferral calculations. In addition, given that my research finds no evidence that risk will be shifted from Questar to its ratepayers, I do not believe that the ROE should be adjusted for this reason.

Q. Do you agree with Dr. Dismukes's primary recommendations?

A. No. Dr. Dismukes cites three reasons for recommending that the CET be discontinued: "it shifts considerable sales risk to ratepayers with little to no offsetting benefits;" "the CET is overly broad in addressing the problems associated with declining use per customer trends" and the CET "is unnecessary to address incentive issues associated with the promotion of DSM programs."[42] I've already addressed the fact that the CET does not appear to shift risk from Questar to its ratepayers. Dr. Dismukes's second two reasons are closely tied to his second primary recommendation, which is to implement a Lost Revenue Adjustment (LRA) mechanism. I do not agree that an LRA is an adequate substitute for the CET.

Q. What do you believe are the shortcomings of LRAs?

A. There are several, but the most significant shortcoming in my opinion is that LRAs do nothing to address the utility's incentive to grow load under traditional rates and do not provide the utility with the incentive to promote or improve programs

[41] Id., p. 7.
[42] Dismukes June 1, 2007 testimony, p. 6.

whose effects cannot be easily measured. Note that Dr. Dismukes describes two reasons that energy efficiency advocates tend to oppose LRAs, the second being that "LRA mechanisms do not completely remove the disincentive to promote DSM because the mechanisms are too narrowly focused."[43] Dr. Dismukes does not present any evidence or arguments to refute this criticism of LRAs.

Q. Please explain how LRAs fail to address the utility's incentive to increase usage?

A. Under traditional rates (e.g., GS-1 without the CET), it is clear that increases in customer usage levels increase DNG revenues. However, LRAs only address the fact that *reductions* in sales reduce DNG revenues (and only consider sales reductions that can be attributed to DSM programs). The utility's incentive to promote load growth is unaffected by an LRA. Alternatively, if a decoupling mechanism such as the CET is in place, the utility has no incentive (and actually has a *dis*incentive) to increase usage levels for its current customers. The CET does, however, provide an incentive to add *customers*, which will increase class-level usage levels.

Q. Please explain why LRAs are "too narrow" with respect to DSM programs?

A. LRAs require load reductions to be quantified with some precision. This implies that LRAs are restricted to DSM programs that *can* be measured. One example of an energy efficiency program that is *not* easily measured may be found on Questar's ThermWise web site, specifically the page containing energy saving tips.[44] The utility will not know which of its customers are altering their behavior based on these tips, making it very difficult to measure program-level effects and therefore rendering such a program a bad candidate for an LRA mechanism. Alternatively,

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[43] Id., p. 42.
[44] http://www.thermwise.com/tips.html

under decoupling, the utility could be assured that any DNG revenue reductions brought about by the promotion or improvement of the web site will be recovered through the CET.

Q. What other potential problems do LRAs present?

A. LRAs provide the utility with an incentive to promote programs that produce high *estimates* of usage reductions and low *actual* usage reductions. Such a program would lead to DNG revenues flowing to the utility through both the LRA and the DNG volumetric rate. Dr. Dismukes makes the argument that "the argument that lost revenues are difficult to measure is somewhat incompatible with cost-effectiveness findings upon which program approvals are usually based."[45] This statement misses an important aspect of how the program measurement is applied when determining LRA payments versus obtaining program approval. In order for a program to be approved, all that is required is that its estimated benefits exceed its costs. The estimates of benefit-cost ratios shown on Dr. Dismukes CCS Exhibit 1.4 span a range from 1.56 to 5.60. In none of these cases would the decision to approve or renew the program be a particularly close call. From an approval perspective, there is no difference between a program that has a benefit-cost ratio of 1.56 and one with a ratio of 5.60 (i.e., both are approved). In contrast, LRAs depend upon the *exact* level of this ratio to determine the amount of money that flows to the utility through the mechanism. Therefore, in the case of LRAs there is a very large difference between a benefit-cost ratio of 1.56 and 5.60. This difference increases both the financial consequences associated with measurement error and the utility's incentive to overstate program benefits. When only DSM program approval is in question, the

[45] Dismukes June 1, 2007 testimony, p. 44.

utility's incentive to overstate program benefits does not exist if the "true" estimate of the benefit-cost ratio is above 1.0.

Q. Do you agree with Dr. Dismukes's proposal to use a forecast test year?

A. If the concern is only with reductions in use per customer, the use of a forecast test year that incorporates appropriate adjustments is an adequate substitute for a decoupling mechanism (though it is reasonable to expect significant disputes regarding what constitutes an "appropriate" adjustment). However, a forecast test year does nothing to alter the utility's incentives to promote conservation or load growth. That is, traditional rates are set so that allowed DNG revenues are recovered through a volumetric rate. The *level* of the allowed DNG revenues (which is the issue addressed by the forecast test year) is irrelevant to the utility when it evaluates its incentives to promote conservation and load growth. For this reason, the use of a forecast test year does not reduce the need for a decoupling mechanism (even when the forecast test year is combined with an LRA).

V. Summary and Recommendations

Q. What are your recommendations regarding the CET?

A. I believe that some form of decoupling is in the best interest of Questar and its ratepayers, and therefore I recommend that the CET be retained. In the absence of the CET, the GS-1 Distribution Non-Gas (DNG) rate creates an incentive problem – Questar has a disincentive to promote conservation and an incentive to increase usage (regardless of the efficiency properties of the increased load). In addition, though customers may be accustomed to the risk, the GS-1 DNG rate, absent the CET pilot program, contains risk for ratepayers: increases in customer usage (relative to rate case levels) lead to the overpayment of DNG revenues. For these reasons, returning to the use of only the GS-1 DNG rate seems inadvisable. In examining the alternatives, I believe that decoupling emerges as the best available solution.

Q. What are the shortcomings associated with the alternatives to decoupling?

A. They are as follows:

- **Lost revenue adjustments** do not address the utility's incentive to grow load (regardless of the efficiency properties of the added usage), cover an incomplete range of DSM programs, require precise measurement of program effects, and create an incentive for the utility to overstate program benefits.
- **Straight fixed variable pricing** reduces the customer-level incentive to conserve relative to the current GS-1 DNG rate (by reducing the volumetric rate) and can lead to adverse bill impacts for low-income customers (by increasing the fixed charge).
- **Forecast test years** can address declining use per customer over time (if properly implemented), but do not affect the utility's incentive with respect to conservation or load growth.

Q. What are the positive attributes of decoupling mechanisms?

A. In contrast to the alternatives described above, **decoupling mechanisms** have the following positive attributes:

1. Removes the utility's disincentive to promote conservation programs;
2. Removes the utility's incentive to grow load by increasing customer-level usage;

3. Retains essentially the entire the customer-level incentive to conserve embedded in the GS-1 DNG rate;
4. Does not alter the fixed charge paid by customers (and therefore does not introduce any concerns about the effect on low-income customers);
5. Does not require the precise measurement of DSM program performance;
6. Eliminates the utility's incentive to overstate DSM program benefits (where the benefit-cost ratio estimate is above 1.0); and
7. Adjusts DNG revenues for decreases in use per customer in between rate cases.

Q. How do you respond to Dr. Dismukes's "fundamental objections" to the use of decoupling mechanisms?

A. Dr. Dismukes's "fundamental objections" to decoupling mechanisms are that they are "overly broad and shift considerable usage-related risks from the Company and its shareholders to ratepayers."[46] However, the "breadth" of decoupling mechanisms relative to LRAs is required in order to obtain many of its benefits. That is, I know of no other means to simultaneously obtain the seven benefits listed above. The potential consequences associated with this "breadth" are twofold. First, there is the potential that economic and commodity price risk will be shifted from the utility to its ratepayers. However, my analysis of Questar data indicates that this is unlikely to occur under the CET. Second, other variations in usage that would have produced variations in DNG revenues under the GS-1 DNG rate will no longer do so (when the effect of deferrals is added to current revenues). In the absence of a shift in risk, this simply means that the utility will be more certain of recovering its allowed DNG

[46] Id., p. 4.

revenues, and its ratepayers will experience less variability in their DNG bills (again, when the effect of deferrals is added to current the bill).

The largest problem that could occur following the implementation of decoupling is that it could allow for the utility to "game" the mechanism to its advantage. Earlier in my testimony, I suggested two means of overcoming this incentive issue.

Q. Do you recommend that any changes be made to the CET?

A. Yes, in response to the potential for the utility to game the mechanism, I recommend requiring the utility to report usage, DNG revenues, and the number of customers (and therefore both use and revenue per customer) separately for existing premises and newly enrolled premises. This will allow the Commission to monitor the extent to which changes in use per customer can be attributed to changes in the behavior of existing customers versus the enrollment of customers with usage levels that deviate from the allowed per customer levels. Should large deferrals occur due to the latter cause (i.e., a change in the composition of the customer class, as opposed to a change in the behavior of the customer class) the burden of proof would be on the utility to show that it is not manipulating customer enrollments to its advantage. The Commission should retain the ability to cancel or suspend the effects of the decoupling mechanism based on its suspicions regarding such gaming behavior.

Q. Does this conclude your testimony?

A. Yes.