A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation

by

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1. Introduction

Traditional regulated natural gas rates recover a significant share of fixed costs through volumetric prices. This creates a link between the utility's sales and its realized rate of return. When sales are below the level used when setting rates—which may occur because of a mild winter, customer response to increasing commodity prices, utility-sponsored conservation, or a downturn in the regional economy—the utility will under-recover its fixed costs. All else equal, this reduces the utility's realized rate of return.

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

On October 5, 2006, the Utah Public Service Commission approved a three-year pilot program for Questar Gas Company's Conservation Enabling Tariff (CET). This decoupling mechanism was originally submitted in a Joint Application by Questar Gas, the Division of Public Utilities (DPU), and Utah Clean Energy. The settlement stipulation allows for a one-year review of CET, which will include an evaluation of the performance of the mechanism to date as well as additional consideration of alternative methods or mechanisms.

Christensen Associates Energy Consulting, LLC (CA Energy Consulting) has been retained by DPU to assist in the evaluation of the CET and alternative proposals. As part of this assistance, this report reviews alternative decoupling designs currently used by natural gas utilities, providing the advantages and disadvantages associated with the various possible features. In addition, the report provides an overview and evaluation of alternatives to decoupling.

2. Features of Decoupling Mechanisms

A recent article in *Public Utilities Fortnightly* reported that sixteen utilities in nine states had adopted a natural gas decoupling mechanism.[1] While the method used in specific decoupling mechanisms can appear to be quite complex, the basic formula for a decoupling mechanism can be summarized quite simply by Equation 1 below.

Equation 1: Deferral = $REV^B{}_i - REV^A{}_i$

[1] Costello (2007). Listed by state, the utilities are: in California, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Gas, and Southwest Gas; in Indiana, Vectren Energy Delivery; in Maryland, Baltimore Gas & Electric and Washington Gas Light; in New Jersey, New Jersey Natural Gas and South Jersey Gas; in North Carolina, Piedmont Natural Gas; in Ohio, Vectren Energy Delivery; in Oregon, Cascade Natural Gas and Northwest Natural; in Utah, Questar Gas; and in Washington, Avista Utilities and Cascade Natural Gas.

In this equation, $REV^B{}_i$ is the base revenue for rate class *i*, which is typically taken from the most recent rate case and may be adjusted to account for various factors (*e.g.*, deviations from normal weather conditions or a change in the number of customers) and $REV^A{}_i$ is the actual revenue collected by the utility from rate class *i*.

Negative deferrals (*i.e.*, caused by actual revenues exceeding base revenues) lead to customer refunds, which are provided through a rate reduction in a future period (usually in the following year). Positive deferrals lead to customer surcharges, which are collected through a rate increase in a future period.

There are significant differences in the design of the decoupling mechanisms currently in use. The remainder of this section describes the key distinctions between them, while Section 3 contains an evaluation of the various designs. Note that some of the design alternatives can be combined. For example, a mechanism could modify base revenues to account for both the change in the number of customers (called revenue per customer decoupling, described in Section 2.2) and deviations from normal weather (described in Section 2.1.2).

2.1 Full Versus Partial Decoupling

A full decoupling mechanism defers the entire difference between baseline and actual revenues.[2] Equation 1 above summarizes one form of full decoupling. "Partial" decoupling mechanisms use one of two methods to reduce the amount of deferrals, as described below.

2.1.1 Partial decoupling as a percentage of full decoupling

One method to reduce the amount of the decoupling deferral is to simply apply a percentage factor to the monthly deferral amount. This is illustrated in Equation 2 below.

Equation 2: Deferral = $F * (REV^B{}_i - REV^A{}_i)$

In Equation 2, *F* is a percentage factor that can in principle lie between 0 and 100 percent, but in practice ranges from 85 to 90 percent. This method is currently used by Vectren Energy Delivery of Indiana (which uses an 85 percent factor) and Avista Utilities of Washington (which uses a 90 percent factor). Northwest Natural Gas in Oregon had a 90 percent factor in its initial decoupling mechanism that was subsequently removed.[3,4]

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[2] For purposes of this report "revenues" and "margins" are used synonymously in the context of decoupling mechanisms.

[3] The removal of the 90 percent factor (or, more accurately, modification of the percentage factor to 100 percent) was recommended in an independent review of the mechanism in Hansen and Braithwait (2005).

[4] Less explicit limits on the deferrals are sometimes used. For example, several decoupling mechanisms are limited so that the utility cannot earn in excess of a specified (allowed) rate of return due to the effects of the mechanism. They are New Jersey Natural Gas and South Jersey Gas and Avista Utilities in Washington.

2.1.2 Partial decoupling removing effects of weather from full decoupling

"Partial" decoupling may also refer to the removal of the effect of weather on revenues. This method is used for Vectren Energy Delivery of Ohio and Cascade Natural Gas of Washington.[5] Equation 3 below illustrates this method:

Equation 3: Deferral = $REV^{B,WA}_i - REV^{A}_i$

In Equation 3, $REV^{B,WA}_i$ represents weather-adjusted base revenues for rate class i.[6] The method used to perform the weather adjustment varies, but the effect of the adjustment is always to increase base revenues in cold winters (when natural gas usage is expected to be higher than forecast levels) and reduce base revenues in mild winters (when natural gas usage is expected to be lower than forecast levels). These adjustments are intended to offset the expected changes in actual revenues, with the goal of eliminating deferrals due to deviations from normal weather.

Equation 4 provides an example of now the weather adjustment could be implemented. (It also includes revenue per customer decoupling, described in Section 2.2.)

Equation 4: Deferral = $R_i * \{C^A_i * [UPC^B_i + H_i * (HDD^A - HDD^N)] - Q^A_i\}$,

where
i indexes rate classes;
R_i = approved margin per therm;
C^A_i = the actual number of customers;
UPC^B_i = weather normal (baseline) therms per customer;
H_i = heat sensitivity factor, in therms per heating degree day per customer;[7]
HDD^A = actual heating degree days;
HDD^N = normal heating degree days; and
Q^A_i = actual total therm usage (*i.e.*, not per customer) for rate class i.

This weather adjustment method starts with weather normal use per customer (UPC^B_i) and adjusts it to a use per customer value that represents the weather that actually occurred (HDD^A) using a weather sensitivity parameter (H_i) that is typically estimated from historical data. Implicitly, the mechanism assumes that the utility is only entitled to distribution margins for usage associated with normal weather conditions.

2.2 "Standard" Decoupling Versus Revenue Per Customer Decoupling

At the time of a rate case, the allowed distribution margin is established based on the current (or forecast test year) level of fixed costs to serve the current (or forecast) number of customers in each rate class. Over time, the number of customers will change, and most decoupling mechanisms account for this change using a method referred to as

[5] Northwest Natural in Oregon also removes the effect of weather in its decoupling mechanism. However, a separate weather adjustment mechanism (WARM) was established later. The combined effects of the decoupling mechanism and WARM are very similar to full revenue per customer decoupling.
[6] Alternatively, actual revenues can be adjusted to normal weather conditions.
[7] This factor can be derived using methods described in Section 5.2.

revenue per customer decoupling (RPCD). Equation 5 illustrates the basic concept behind RPCD.

Equation 5: Deferral = $R_i * UPC^B_i * C^A_i - REV^A_i$

In this equation, baseline revenues are calculated as the product of the approved margin per therm (R_i), use per customer from the previous rate case (UPC^B_i), and the current (or actual) number of customers (C^A_i). This method provides a change in distribution revenues as customers are added or subtracted that parallels the change that occurs under the standard tariff in the absence of decoupling.

The specific method used for implementing RPCD may vary. For example, Questar Gas's Conservation Enabling Tariff replaces the ($R_i * UPC^B_i$) portion of Equation 5 with pre-specified "allowed DNG Revenue per Customer Month" values that are based on historical usage and distribution non-gas revenues.

The alternative to RPCD is to simply base deferrals on a comparison of approved base revenues (unadjusted for changes in the number of customers) to actual revenues. Avista Utilities in Washington provides an example of this method. Specifically, Avista's decoupling mechanism excludes usage associated with "customers added since the corresponding month of the test year."[8]

2.3 Other Design Differences

The design features described above constitute the major differences between decoupling mechanisms. However, close examination of specific mechanisms reveals many more differences, including (but not limited to) the following:

- *Frequency of rate changes*: typically deferrals affect rates once per year, though semi-annual and monthly adjustments are also used.
- *Applicable rate classes*: decoupling typically applies to residential and small commercial customers, though occasionally larger customer classes are included (*e.g.*, South Jersey Gas, which includes General Service Large Volume customers).
- *Program status*: decoupling is often initially approved as a pilot program, and can require a program review after one or more years in order to be renewed.
- *Application of an earnings test*: several decoupling mechanisms do not allow the utility to earn in excess of its allowed rate of return due to the effects of the decoupling mechanism.[9]
- *Application of a DSM test*: the percentage of the net margins that is deferred for Avista Utilities in Washington is based on the performance of its demand-side management (DSM) programs.[10]

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[8] Final Order Approving Decoupling Program, Docket UG-060518 before the Washington State Utilities and Transportation Commission, p. 4.
[9] These include Avista Utilities in Washington, New Jersey Natural Gas, and South Jersey Gas.
[10] For example, if Avista achieves between 70 and 80 percent of its target DSM savings, 60 percent of net margins is deferred.

- *Separate weather normalization mechanism*: five utilities have weather normalization mechanisms in addition to decoupling.[11] The presence of such a mechanism essentially removes concern regarding whether decoupling shifts weather risk from the utility to consumers.
- *Large customer count adjustment*: New Jersey Natural Gas and South Jersey Gas both include a provision in which large customers (*e.g.*, over 2,000 cubic feet per hour for New Jersey Natural Gas) count as more than one additional customer in the RPCD deferral calculation.

3. Evaluation of Design Alternatives

This section evaluates the decoupling features that were described in the previous section. The evaluation of a decoupling mechanism should be based on the extent to which it achieves the goals of its proponents and mitigates the criticisms of its opponents. Because of this, it may be useful to provide an overview of the arguments for and against decoupling.

3.1 Reasons for Supporting Decoupling

Decoupling has found support from a seemingly unlikely pair: utilities and environmental groups. Utilities support decoupling primarily because it provides more certainty in fixed-cost recovery, and therefore in the utility's realized rate of return. In addition, decoupling shields the utility from potential revenue loss associated with reductions in use per customer between rate cases.

Environmental groups (primarily the Natural Resources Defense Council or NRDC) support decoupling because it removes the utility's disincentive to promote conservation without significantly affecting the customer-level incentive to pursue energy efficiency. In the absence of decoupling, a customer's incentive to reduce usage is the sum of the commodity price and the distribution fixed-cost recovery component, or $P^G + P^D$. Under Straight Fixed Variable (SFV) pricing, an alternative to decoupling in which fixed costs are recovered through fixed customer charges and variable costs are recovered through volumetric prices, a customer's incentive to conserve is reduced to P^G. This incentive reduction is the reason that organizations such as NRDC do not support SFV.

Under decoupling, the customer-level incentive is essentially unchanged relative to traditional rates. That is, when the customer reduces usage by one therm, the current bill is reduced by $P^G + P^D$. However, the decoupling mechanism causes P^D to be placed in a deferral account for subsequent recovery by the utility. On the surface, this may appear to be similar to what happens under SFV. However, in the case of decoupling, the customer will only have to pay back a small percentage (equal to the customer's usage divided by the expected customer class usage) of P^D in the following year. This leaves the customer-level incentive to conserve essentially unchanged relative to traditional rates.

[11] They are: Vectren Energy Delivery of Indiana, New Jersey Natural Gas, South Jersey Gas, Northwest Natural, and Questar Gas.

Other arguments used to support decoupling are that it is easier to implement and administer than many (or all) of the alternatives, that it can reduce the frequency of rate cases, and that it reduces contentiousness between the utility and its regulator.[12]

3.2 Reasons for Opposing Decoupling

Critics of decoupling mechanisms cite several potential problems, the most prominent being the potential shifting of risks from the utility to consumers. Under standard ratemaking the utility's fixed-cost recovery varies with several uncertain factors, including weather, economic conditions, and commodity prices. The introduction of decoupling can eliminate variation in fixed-cost recovery due to these and other causes.

However, the extent of the risk shifting may be overstated by the critics. In particular, arguments regarding the shifting of weather risk do not tend to account for the fact that the utility and its customers can both reduce weather risk with a well-designed mechanism. This is described in more detail in Section 3.3.3 below.

Critics of decoupling have a better case regarding the shifting of economic and commodity price risk to customers. In contrast to the case of weather risk, the utility and the customers' economic and commodity price risks cannot offset one another. For example, when the economy suffers, customers conserve in attempt to reduce their bill because they are worse off in general, which causes the utility to under-recover fixed costs. A mechanism that makes the utility better off must necessarily increase customer bills (though possibly in the following year, when economic conditions may have improved).

While the shifting of economic and commodity price risk exists in principle, the *magnitude* of the risk that is shifted in practice is unclear. For example, analyses conducted by the author using data for Northwest Natural indicate that it can be difficult to estimate the effect of changes in economic conditions on natural gas use per customer, with the effects varying dramatically as the economic variable is changed or a time trend variable is included.[13]

Estimating the magnitude of commodity price risk can also be complicated. First, the analysis should avoid using average revenue, which is often easily obtained and calculated, as a proxy for price. Because of the presence of customer charges and blocked rates, using average revenue will tend to produce over-estimates of customer price response. That is, even when customer usage increases due to non-price factors (*e.g.*, because of colder than expected weather), average revenue will be reduced because the customer charge is spread across more units of usage (and/or because more usage is priced at the lower tail block price). Again, analyses conducted by the author using data

[12] This is based on the idea that the utility and regulator will no longer have to agree on a forecast level of usage, which is used to determine rates under traditional regulation. In this situation, utilities have an incentive to under-forecast usage (leading to high rates) and the consumer groups have an incentive to advocate higher levels of forecast usage (which would produce lower rates).

[13] Hansen and Braithwait (2005), p. 29 shows the lack of statistical significance for the unemployment rate in explaining variations in residential use per customer from 1993 to 2004.

for Northwest Natural found difficulties in obtaining a robust estimate of the effect of changes in prices on use per customer.[14] (In contrast, these analyses show an effect of heating degree days on use per customer that is stable across alternative specifications and consistently highly statistically significant.) Section 5.2 contains an analysis of Questar Gas Company data to determine the extent of weather, economic, and price risk shifting that may occur due to the Conservation Enabling Tariff. The findings are consistent with the Northwest Natural Gas findings, in that the effect of weather on use per customer is well estimated, but the link between use per customer and economic conditions or commodity price is not strong.

The primary conclusions regarding the issue of whether decoupling shifts risks from the utility to customers are:

1. With effective program design, weather risk can be reduced for both the utility and its customers.[15]
2. Economic and commodity price risks are shifted from the utility to customers, but utility-specific studies should be conducted to determine whether the magnitude of the risk shift is significant.

Critics of decoupling cite a range of additional concerns about decoupling, including a reduction in the incentives to control costs, provide customer service, and promote economic development. While there does not appear to be any merit in the criticism that decoupling reduces the utility's incentive to control costs,[16] the incentives to provide customer service and promote economic growth are addressed in the evaluations below.

3.3 Decoupling Design Alternative Evaluations

Based on the arguments of the proponents and critics of decoupling, the following criteria are applied in evaluating decoupling mechanism design alternatives:

1. Whether it removes the utility's disincentive to promote conservation.
2. Whether it reduces the variability of utility fixed-cost recovery.
3. Its effect on individual customer incentives to engage in conservation.
4. Whether it shifts weather, economic, or commodity price risk from the utility to customers.
5. Whether it affects the utility's incentive to provide customer service.
6. Whether it affects the utility's incentive to promote economic growth.

3.3.1 Full decoupling

Each of the decoupling design alternatives are now evaluated against the perceived benefits and costs of decoupling, beginning with a "standard" (*i.e.*, not revenue per customer) full decoupling mechanism. Because this is the most basic decoupling design,

[14] Ibid. As shown in Table 4-2, the estimated coefficient on the retail price varies in its level and statistical significance across specifications.

[15] As described in Section 3.3.3, full decoupling in conjunction with a separate weather normalization mechanism that affects current customer bills using customer-specific adjustments is the best means of reducing weather risk for both the utility and its customers.

[16] That is, decoupling affects only revenues. The incentive to reduce costs (to maximize profits) exists both with and without decoupling.

an evaluation across all categories will be completed. For subsequent design alternatives, evaluations will only be discussed where the effect differs from standard full decoupling.

By fixing the level of distribution revenue regardless of the level of customer usage, full decoupling is effective in eliminating the utility's disincentive to promote conservation and energy efficiency. It is important to note that the financial effects of the mechanism do not provide an explicit *incentive* for the utility to promote conservation. However, because the mechanism is typically proposed and approved using conservation-based arguments, the utility has an incentive to see that conservation takes place, provided that there is some risk that decoupling could be taken away if the utility does not alter its behavior with respect to conservation. This "secondary" incentive argues for ongoing monitoring of the utility's performance in promoting or supporting conservation efforts.

Full decoupling essentially eliminates variability in the utility's distribution revenue, which is the key benefit of the mechanism for the utility. In addition, as discussed in Section 3.1, full decoupling retains the vast majority of the customer-level incentive to pursue conservation that is contained in the standard tariff.

Full decoupling does, as its critics charge, change the allocation of weather, economic, and commodity price risks. However, as described in Section 3.3.3, the increase in customers' weather risk from decoupling is expected to be small, and weather risk can be reduced or eliminated for both the utility and its customers if full decoupling is combined with a separate weather normalization mechanism.

Section 3.2 describes how the shifting of economic and commodity risks to customers is a potential problem with full decoupling, but one that should be studied on a utility-specific basis to determine whether the shift in risk is significant in magnitude. An example of a utility-specific study is found in Section 5.2. In addition, if the risk shift is found to be significant, the customers can be compensated for bearing the risk through a reduction in the utility's allowed rate of return. An overview of the methods that can be used to determine the amount of the reduction is found in Appendix A.

Because full decoupling provides the utility with the same amount of distribution revenue regardless of the level of customer usage or number of customers served, incentives to provide customer service and promote economic growth are reduced. Concerns regarding the incentive to provide customer service can be easily mitigated by imposing (or enforcing existing) customer service standards.[17] Section 3.3.4 describes how revenue per customer decoupling can mitigate concerns about the incentive to promote economic growth.

3.3.2 Partial decoupling as a percentage of full decoupling

Partial decoupling as a percentage of full decoupling mitigates both the benefits and costs associated with full decoupling. For example, a program that defers only 80 percent of

[17] No reduction in the quality of customer service was found in the independent evaluation of Northwest Natural's decoupling mechanism (Hansen and Braithwait, 2005), though this decoupling program included both customer service quality standards and revenue per customer decoupling.

the difference between baseline and actual revenues retains a disincentive for the utility to promote conservation. Specifically, the utility will lose 20 percent of the per-therm distribution revenue for every therm reduction in usage that conservation brings about. At the same time, percentage factor also reduces the shifting of risks from the utility to consumers and the change in the incentives to provide customer service and promote economic growth.

This type of decoupling seems to simply be a compromise position with no analytical basis for setting the percentage factor. By failing to eliminate the utility's disincentive to promote conservation, this form of decoupling does not fully accomplish its primary goal. Furthermore, the reduction in the perceived negative effects (*e.g.*, risk shifting and the incentive to promote economic growth) is not sufficient to placate critics of decoupling (who do not support partial decoupling) and does not appear to be based upon a formal evaluation of how the percentage factor mitigates the negative effects associated with full decoupling.

Better methods exist for dealing with adverse effects of full decoupling. For example, if the primary concern about decoupling is due to the shifting of risk, the mechanism can be modified to explicitly remove the particular risk factor from the deferrals (*e.g.*, through statistical recoupling, described in Section 4), or the risk shift can be quantified and customers compensated through an appropriate reduction in the utility's allowed rate of return.

3.3.3 Partial decoupling removing effects of weather from full decoupling

As described in Section 2.1.2, some decoupling mechanisms attempt to remove the effects of weather from the deferrals (and do not have a separate weather normalization mechanism). However, unlike economic or commodity price risk, the utility's weather-induced risk is in the opposite direction of the customers' risk. That is, when sales increase due to a colder than average winter, the utility benefits through over-recovery of fixed costs at the customers' expense (through higher bills). In principle, if the weather risk faced by the utility is reduced, the customers can achieve a parallel risk reduction. Weather adjustment mechanisms, such as Northwest Natural's WARM or Questar Gas's Weather Normalization Adjustment, have been created with the intent of reducing weather risk for both the utility and its customers.

In the case of decoupling alone, the shifting or reducing of weather risk is somewhat ambiguous. While an opportunity exists to reduce risk for both parties, the fact that decoupling deferrals typically affect rates in the following year produces opportunities for customers to be made temporarily worse off. For example, if a mild winter is followed by an especially cold winter, the surcharge that decoupling produces for the mild winter will be added to bills that are already higher than expected during the cold winter in the following year.

Note that this potential problem can be mitigated by simply changing when the weather adjustments affect customers' bills. That is, if the weather-induced deferrals were passed through to customers in the current month, the mechanism would reduce weather risk for both the utility and its customers. However, because this method is not used in decoupling mechanisms, an analysis was conducted using Questar Gas weather data from 1980 through 2005 to provide an example of how decoupling deferrals interact with variations in weather across years to affect customers' bills.

To keep the focus on the effect of weather variation across years (as opposed to variations in the number of customers or the tariff rates), the analysis held the following factors constant across years: the number of customers (assumed to be 825,000); the change in use per customer due to a change in heating degree days (0.0175 Dth/HDD, based on a regression analysis of Questar Gas usage and weather data described in Section 5.2); the distribution non-gas cost recovery per Dth ($1.63718/Dth in summer and $1.94638/Dth in winter[18]); and the total retail price per Dth ($7.58683/Dth in summer and $8.54855/Dth in winter).

Figure 1: Effect of Decoupling Deferrals on Weather-Induced Bill Changes using Questar Gas Weather Data from 1980 through 2005

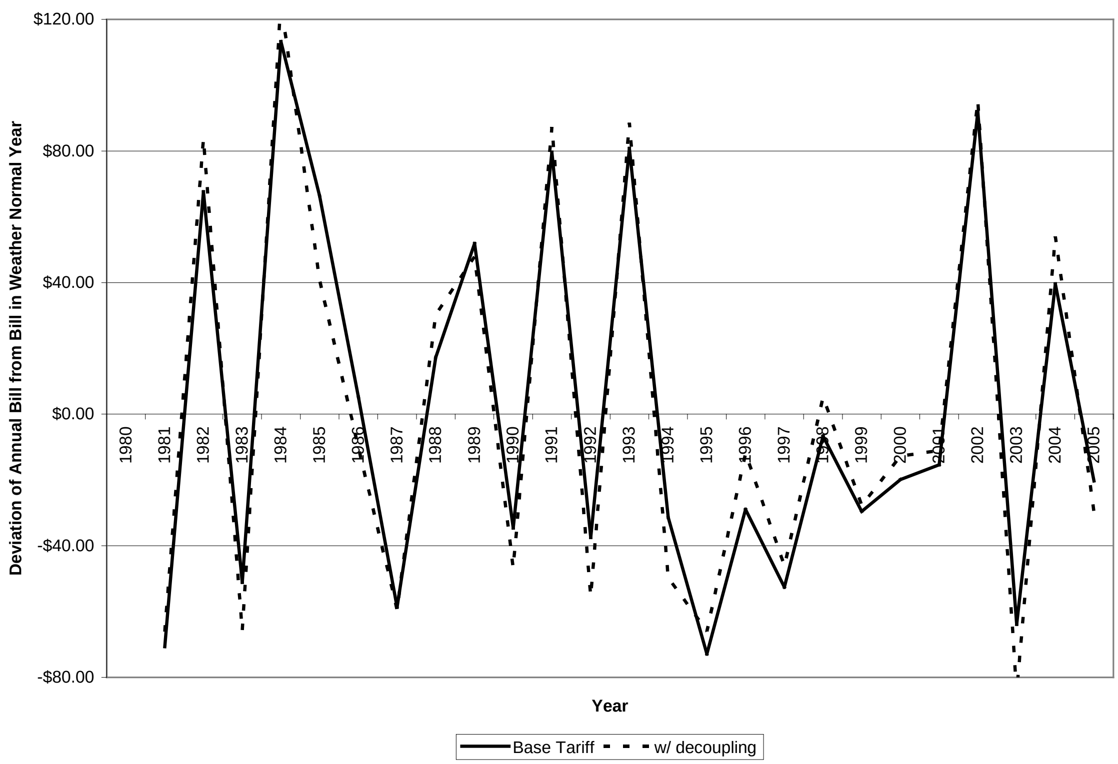

Figure 1 shows the results of the analysis. Seven of the twenty-five years (1982, 1984, 1989, 1991, 1993, 2002, and 2004) had weather-induced bill increases that were significantly above average. Averaging across these seven years, the presence of decoupling, which carries over weather effects from the previous year, increased the average customer's bill by $8.17 per year. The largest single-year addition to the bill was

[18] These rates are taken from the current GS-1 tariff, and are the price for the first 45 Dth of usage per month. Because the second block price is lower, the use of this value overstates the revenue impacts associated with weather fluctuations.

$16.05 per year, while the largest single-year subtraction from the bill was $4.02 per year. Conversely, the sample includes years like 2003, in which customer bill *reductions* from a mild winter were enhanced by the decoupling deferral from the previous year.

The conclusion that one can draw from Figure 1 is that decoupling may slightly increase the variability in customer's weather-induced bill changes, but the effect appears to be small. In this analysis, only seven out of twenty-five years had unusually cold winters, and the average effect of the previous years' decoupling deferrals on bills in those seven years was less than one dollar per customer month.

In addition, the use of a separate weather adjustment mechanism in combination with full decoupling can all but eliminate the small increase in risk observed in Figure 1. In fact, if the therm/HDD adjustment factor used by the weather adjustment mechanism is exactly right, the weather-induced bill changes will be zero in all years. (The graph would simply be a line on the horizontal axis instead of the peaks and valleys shown in Figure 1.) That is, the weather normalization mechanism can affect *current* customer bills (*e.g.*, Northwest Natural's WARM), removing weather variability from the decoupling deferrals.

In summary, there does not appear to be a compelling case for the use of partial decoupling mechanisms that remove the effects of weather. A well-designed program that combines full decoupling with a weather normalization mechanism can reduce weather risk for both the utility and its customers.[19]

3.3.4 Revenue per customer decoupling (RPCD)

RPCD differs from standard decoupling in that the utility's distribution revenue changes with the number of customers served. This has the potential to introduce both positive and negative incentive effects.

RPCD can improve the performance of the decoupling mechanism by reducing the shift in economic risk somewhat, provided that there is a correlation between economic conditions and the number of customers served. For example, an economic downturn might lead to businesses closing (reducing the number of commercial customers) and residential customers relocating to seek employment elsewhere. Under RPCD, the utility would experience a decrease in revenues in this example. Despite this potential effect, some economic risk remains under RPCD if use per customer is related to changes in economic conditions. A relationship between economic conditions and the number of customers served also implies that RPCD increases the utility's incentive to promote economic growth relative to standard decoupling.

[19] A separate analysis of weather normalization mechanisms is warranted. For example, Northwest Natural's WARM program could be improved by using customer-specific weather adjustment factors (*i.e.*, the change in therms per change in HDD). Another example, the Weather Normalization Adjustment used by Questar Gas, uses customer-specific adjustments, but does so in a way that links the customer's marginal price to the weather conditions. Specifically, the change in the customer's distribution non-gas bill as usage changes is equal to $(HDD^N / HDD^A) * P^{DNG}$, where HDD^N = normal HDDs, HDD^A = actual HDDs and P^{DNG} = the distribution non-gas cost. This can lead to a significant change in the overall retail price when there is a large deviation from normal weather conditions.

In addition, to the extent that improved customer service attracts new customers and prevents the departure of current customers, RPCD improves the utility's incentive to provide good customer service.

An additional effect that RPCD may produce relative to standard decoupling is that it may lengthen the time between rate cases. This may be regarded as either a positive attribute because fewer costs will be incurred in carrying out rate cases, or as a negative attribute because it may be more difficult to initiate a rate case to "fine tune" the decoupling mechanism and/or address other regulatory issues.

RPCD may introduce two incentive problems relative to standard decoupling. First, it provides the utility with an incentive to overstate the number of customers on the rate, because each additional customer adds to distribution revenue through the RPCD formula. (For example, this could be done by adding meters to existing premises.) This concern can be mitigated by tracking customer count changes over time and analyzing the data for statistical anomalies (*i.e.*, a rapid increase in customer count following the introduction of decoupling). The statistical anomaly would then trigger a more in-depth analysis, or some compensating action such as a reversion to standard decoupling. Alternatively, standard decoupling (*i.e.*, not RPCD), which does not contain this incentive problem, could be adopted.

The second area of potential concern with RPCD is that the method may not adequately account for differences in use per customer between new and existing customers. That is, RPCD typically applies the use (or revenue) per customer from existing customers to all new customers. However, use per customer for new customers may differ from that of existing customers because of improvements in appliance energy efficiency or changes in average home size over time. Equation 6 (which is equivalent to Equation 5, but modified for use in this example) can be used to evaluate the effect of differences between use per customer for new and existing customers.

Equation 6: RPCD Deferral = $R_i * (UPC^B{}_i * C^A{}_i - Q^A{}_i)$

If a new customer is added that has usage below $UPC^B{}_i$, RPCD will produce a surcharge (in the amount of $R_i * [UPC^B{}_i - Q^A{}_c]$) that will be paid by the entire customer class in the following year (where $Q^A{}_c$ is the usage for the new customer). Relative to the standard tariff alone, RPCD creates an incentive for the utility to enroll smaller than average customers and to avoid larger than average customers.[20] However, each customer adds to distribution revenues (in an amount equal to that of the average existing customer), so the utility will benefit by connecting *any* customer for which the increase in distribution revenues exceeds the incremental cost to serve.

[20] Note that the surcharge that RPCD produces when the utility adds a smaller than average customer provides the utility with an incentive to promote energy efficiency among new customers (as opposed to simply removing a disincentive to promote conservation, as decoupling does more generally).

To the extent that concerns exist regarding the utility's incentives to pursue (or not pursue) customers based on expected usage levels, there are two methods that can mitigate the problem (in addition to reverting to standard decoupling). First, as described in Section 3.3.5, New Jersey Natural Gas and South Jersey Gas have implemented a method that partially mitigates the utility disincentive to enroll large customers, in which large customers count as more than one additional customer for purposes of RPCD calculations. Second, different values of use per customer can be applied to new and existing customers. For example, standard decoupling could apply to existing customers, while RPCD could be used for added customers, where the value of $UPC^{B}{}_{i}$ is set to reflect the characteristics of the average new customer. This combined method would be most appropriate for use where consistent customer growth is expected. However, this method would make implementing and administering the mechanism more difficult.

Overall, whether RPCD is an improvement relative to standard decoupling depends upon how one weighs RPCD's improvements in incentives to promote economic growth and improve (or maintain) customer service levels against the introduction of incentives to artificially inflate the customer count and enroll smaller than average customers.

3.3.5 Other design differences

Three of the design differences described in Section 2.3 can assist in reducing the adverse effects associated with decoupling mechanisms. A DSM test of some kind can provide the utility with an *incentive* to promote conservation (as opposed to merely removing a disincentive). The decoupling mechanism implemented for Avista Utilities in Washington is an example of how this can work. In this mechanism, the deferral calculation includes a percentage factor (as in Equation 2) that is based on the share of target DSM savings the utility achieves. However, DSM tests have their own disadvantages, which parallel those of lost revenue adjustments described in Section 4.1. Specifically, DSM tests lead to disputes over how to measure program results, provide the utility with an incentive to promote programs that are likely to produce over-estimates of usage reductions, and lead to the introduction of only programs that can be easily measured (*e.g.*, rebates on high efficiency furnaces as opposed to educating customers on the methods for and benefits of improving insulation).

The second design alternative is to include a separate weather normalization mechanism. If properly designed, this can reduce weather risk for both the utility and its customers. Ideally, such a mechanism would use customer-specific weather sensitivity parameters (which are estimates of the change in usage per change in heating degree day), affect current customer bills, and not depend on current customer usage.[21] A combination of weather normalization and decoupling mechanisms can improve the functioning of both. As discussed earlier in this report, the presence of the weather normalization adjustment improves the decoupling mechanisms by reducing customers' weather risk.

[21] That is, the weather adjustment should be based on normal weather, actual weather, and a weather sensitivity parameter that is calculated from historical data. Designing the weather adjustment in this way ensures that the customer's incentive to change usage is same as it is under the base tariff, with the weather adjustment simply reducing the variation in bills across months and years.

Decoupling mechanisms improve the functioning of weather normalization mechanisms by "cleaning up" any errors in the definition of normal weather.[22] That is, the key point of debate when establishing a weather normalization mechanism is the setting of normal heating degree days, or HDD^N, which is typically based on an average over prior years. However, the level of HDD^N tends to change as one varies the time period over which the average is taken (*e.g.*, 10 years versus 30 years), leading to potential disputes regarding the appropriate value because errors in the level of HDD^N will skew the effect of the program in favor of the utility or the customers. For example, if HDD^N is set too high, the weather adjustment will consistently behave as though the winter is milder than average, leading to customer surcharges on average. However, if decoupling is also present, this surcharge will be offset by a refund from the decoupling mechanism.[23]

Section 3.3.4 described how differences in use per customer between new and existing customers can be problematic for RPCD mechanisms. The "Incremental Large Customer Count Adjustment" used by New Jersey Natural Gas and South Jersey Gas can be used to reduce this problem for commercial customers. This adjustment increases the number of current customers used in the decoupling calculation above its true value when very large customers are added to the system. While this addresses the issue for the addition of large commercial customers, the more general problem of differences between new and existing use per customer remains.

4. Alternatives to decoupling

4.1 Lost Revenue Adjustments and Performance Incentives

Lost revenue adjustments (LRA) have long been used to compensate the utility for revenue reductions due to demand-side management (DSM) programs. At best, an LRA makes the utility indifferent to the performance of its conservation programs. However, utilities argue that they are made worse off by LRAs, as they earn a rate of return on infrastructure used to serve customers, while they earn no return on a DSM program (which can be viewed as a substitute for added infrastructure). For this reason, performance incentives have sometimes been added to LRAs. According to Kushler et al (2006), the performance incentives can take several forms, including:

- Allowing utilities to earn a rate of return on energy efficiency investments;
- Providing the utility with an increased overall rate of return;
- Providing the utility with an increased rate of return on energy efficiency investment;
- Providing a pre-specified financial reward for meeting energy efficiency targets; or
- Providing an incentive equal to a proportion of the program's net benefits.

[22] Winter weather conditions are typically quantified using heating degree days, where HDD = MAX[0, Threshold Temp. – Avg. Daily Temp.]. In this equation, the threshold temperature is often set at 65 degrees Fahrenheit.

[23] The customer class as a whole is therefore indifferent to the definition of normal heating degree days. However, some (likely small) within-class cross-subsidies will occur because the weather normalization affects current bills while decoupling deferrals affect future bills.

The following is a list of the pros and cons associated with LRAs.

Pros:

- Targets losses due to sponsored DSM programs with no "side effects" (*i.e.*, revenue adjustments due to other factors such as weather, economic conditions, or commodity prices).
- Maintains the current distribution of risks between the utility and consumers.
- When augmented by performance incentives, LRAs can provide an incentive for the utility to promote conservation (and not just remove the disincentive).

Cons:

- LRAs are limited to programs that can be measured.[24]
- Provides the utility with an incentive to implement programs that produce high *estimates* of usage reductions, but deliver relatively small *actual* usage reductions.
- Can be difficult and contentious to administer, specifically in coming to agreement on the measurement of program effects.
- LRAs retain the utility's incentive to grow load.

Based on the evaluation presented here, LRAs are inferior to decoupling in a number of ways. With respect to conservation, LRAs have the fatal flaw of preserving the utility's strong incentive to grow load outside of the DSM programs. When the additional problems of administrative complexity and the utility's incentive to game the mechanism are also taken into account, decoupling appears to be a superior method for addressing utility conservation incentives.

4.2 Straight Fixed Variable Rates

Straight fixed variable (SFV) rates apply the principle that fixed costs should be recovered through fixed charges and variable costs should be recovered through volumetric rates.[25] SFV solves the utility incentive problem, as changes in usage do not alter the utility's level of fixed-cost recovery. However, SFV is not supported by conservation groups because the reduction in the volumetric rate (relative to standard rates) reduces the *customers'* incentive to engage in conservation.

SFV has the benefit of providing the framework for the most economically efficient rates. Specifically, if the volumetric rate included all of the "externalities" associated with incremental energy use (*i.e.*, effects of a customer's energy use on all other parties, such as the effects of pollution), customers would be provided with the *correct* incentive to increase or decrease usage (which may or may not be higher than the current volumetric rate, which includes fixed-cost recovery but not externalities). Alternatively, if fixed

[24] Examples of programs whose effects cannot easily be measured are advertising campaigns to encourage lowering thermostats in winter, or general education programs focused on improving home insulation.
[25] Some utilities (*e.g.*, Southwest Gas) have proposed a combination of higher fixed charges and the introduction of a decoupling mechanism. If the increase in the fixed charge is sufficient to approximate SFV (*i.e.*, if the fixed charge recovers all fixed costs), the addition of decoupling is redundant.

costs are included in a volumetric rate that includes a price increase for all externalities, customers are overpaid for usage reductions. (That is, customers would have too large of an incentive to conserve.)

While the foregoing discussion on the efficiency of SFV is theoretically correct, it is very difficult to estimate the dollar value of the externalities associated with natural gas use. In addition, some method must be developed to deal with the externality charge. Proposed carbon taxes may provide a method of accounting for externalities without producing utility over-recovery, but there is no guarantee that these taxes will be set at the correct level (if they are introduced at all).

In addition, critics of SFV charge that the increase in the fixed charge will harm low-income customers. (More broadly, SFV will tend to increase bills for low *use* customers.) Partial rebates on the fixed charge based on income qualifications could be used to mitigate this problem, but would complicate the administration of the rate.

A summary of the pros and cons of SFV follows.

Pros:

- Capable of providing the most economically efficient price signals to customers, which would allow for the “best” use of the economy’s resources.
- Easy for customers to understand.

Cons:

- High fixed charge harms low-income customers.
- Lower volumetric rate reduces customers’ incentive to pursue energy efficiency (which is corrected if externalities are included in the rate).
- Can be difficult to include externalities in the rate and compensate customers for adverse distributional effects.

In theory, SFV is capable of providing the best solution to the problems presented by traditional ratemaking. However, the practical problems associated with correctly pricing the rate (to account for the external effects of energy usage) and the potential need to address equity concerns (because of adverse effects on low-income customers) may be difficult to surmount.

4.3 Statistical Recoupling

Statistical recoupling (SR), as described in Hirst (1993), attempts to remove the effects of decoupling on the allocation of weather, economic and commodity price risks while retaining the elimination of the utility’s disincentive to promote conservation.

SR uses a statistical model to calculate baseline quantities, as described in Equations 7a and 7b.

Equation 7a: Deferral = $R_i * (Q^{B,E}{}_i - Q^A{}_i)$

Equation 7b: $Q^{B,E}{}_i = F$(weather, economic conditions, retail price, number of customers)

Equation 7a shows that the SR deferral is based on the per-therm margin (R_i) multiplied by the difference between estimated class usage ($Q^{B,E}{}_i$) and actual class usage ($Q^A{}_i$). Equation 7b shows that estimated class usage is a function of weather conditions, economic conditions, the retail price per therm, and the number of customers in the rate class.

The parameters of the function in Equation 7b (*e.g.*, the effect of changes in heating degree days on class usage) are estimated using historical utility data. In a particular time period (a month, quarter, or year), the actual values for weather, economic conditions, the retail price, and the number of customers are entered into the function to produce the predicted level of class usage, controlling for these factors. The difference between predicted and actual usage, which could be due to DSM conservation, customer-initiated conservation, or modeling error, serves as the basis for SR deferrals.

By adjusting baseline usage for weather, economic conditions, and the commodity price, SR does not alter the allocation of risks between the utility and its customers (though it will be successful only to the extent that the parameter estimates are correct). This is the advantage of SR relative to decoupling.[26] A secondary advantage of SR cited by its advocates is an increase in the utility's incentive to promote economic growth.[27] That is, to the extent that the utility can take action to improve the economic variable that is included in the statistical model (*e.g.*, employment, or state-level gross domestic product) it will receive an increase in baseline usage and its associated revenues through the SR equation. However, it seems reasonable to question whether the utility has enough influence on economy-wide statistics for SR to provide a strong incentive in this regard.

A disadvantage of SR is that there could be significant disagreements regarding the specification of the statistical model. This could include a wide variety of issues, such as:

1. The time period to include in the statistical model (*e.g.*, 10 years versus 20 years);
2. The economic variable(s) to include (*e.g.*, employment, state-level gross domestic product);
3. The temperature thresholds for use in cooling and heating degree day calculations;
4. Whether additional weather variables, such as relative humidity, are included;
5. The granularity of the data (monthly, quarterly or annual);
6. Method of accounting for autocorrelation (*e.g.*, in a monthly model, 1- and/or 12-period lags may be examined);
7. Whether to include a time trend variable to account for changes in appliance energy efficiency and other trends over time, and, if included, how (or whether) to apply it in creating estimated baseline quantities;
8. Whether to model usage in log or level terms; and

[26] However, recall that decoupling does not shift weather risk from the utility to consumers.
[27] Hirst (1993), p. 37.

9. Whether to model total usage (and include the number of customers) or usage per customer.

Though Hirst (1993) did not examine all of the variations described above, it conducted a study which concluded that the outcome of statistical recoupling is not overly sensitive to modifications in the model specification. However, the analysis contained in Section 5.2 illustrates some the difficulties in arriving at a model specification. For example, the effects associated with economic variables are not well estimated and change dramatically when a time trend variable is added to the model.

SR provides a plausible alternative to decoupling if the shifting of economic and commodity price risks from the utility to consumers is determined to be a significant problem. SR could be made more appealing if it is used to control economic and commodity price risks, but allows weather risk to be affected by the mechanism (by using normal weather in the calculation of $Q^{B,E}{}_{i}$). However, SR is more complex to implement than decoupling mechanisms and the author of this report does not share the view reflected in Hirst (1993)[28] that the estimated usage function (Equation 7b) will be robust to alternative specifications and therefore not a significant source of dispute and/or manipulation.

5. Evaluation of Questar Gas Company's Conservation Enabling Tariff

This section focuses on the specific decoupling mechanism that is the subject of the regulatory proceeding that includes this report: the Conservation Enabling Tariff (CET) implemented for Questar Gas Company. Section 5.1 provides a review and critique of CET's design elements and Section 5.2 contains an analysis of the potential for the shifting of economic and commodity price risks following the implementation of CET.

5.1 Conservation Enabling Tariff Design

The CET is a fairly standard revenue per customer decoupling mechanism that applies to Questar Gas's GS-1 and GSS tariffs. Equation 8 shows the method used to calculate monthly accruals.

Equation 8: CET Accrual in month $m = C_m * RPC_m^{Allowed} – Rev_m^{Actual}$

That is, the accrual is equal to the difference between allowed and actual distribution revenue, where allowed distribution revenue is equal to actual number of GS-1 and GSS customers in month m (C_m) multiplied by the allowed revenue per customer in month m ($RPC_m^{Allowed}$). The latter values are specified in the CET and are based on historical monthly average values of distribution revenue per customer. Accruals affect rates no less than semi-annually, with block tariff rates increased or decreased by a uniform percentage to recover or refund the amortized accruals. An initial limit (through August 2007) is placed on the amount of revenue that can be accrued and amortized, though this limit appears to be high relative to the expected level of accruals. A separate weather

[28] Ibid, pages 38-40, and 53.

adjustment mechanism is in place (the Weather Normalization Adjustment, or WNA) that affects customer bills in the current month.

The CET contains the fundamental design elements that are preferred based on the evaluation of decoupling design alternatives contained in Section 3. Specifically, it combines RPCD (which reduces concerns regarding incentives to promote economic growth and provide quality customer service) and a separate weather adjustment mechanism (which reduces weather risk for both the utility and its customers). The analysis contained in Section 5.2 shows that the shifting of economic and commodity price risks is not expected to be a problem in this situation.

There are a couple of ways in which the design of CET could be improved. The first is to improve the method for deriving the "allowed DNG revenue per customer per month" values ($RPC_m^{Allowed}$). The current method calculates $RPC_m^{Allowed}$ using data from a single historical year, unadjusted for weather conditions. The resulting pattern of values across months is likely to produce more monthly accrual activity than necessary, as the weather patterns in the current year are unlikely to match those of the historical year. (However, this is not a significant problem because improving the calculation of the values will not alter the amount of *annual* accruals.)

Questar staff has stated that they intend to change the calculation of $RPC_m^{Allowed}$ so that it is based on a three-year average of customer usage patterns (but will not alter the total allowed DNG revenue per year of $255.53). This method is sufficient to reduce the amount of monthly accrual activity.

Second, because the GS-1 class can include a wide range of customer average usage levels, the inclusion of a "large customer count adjustment" resembling the one used in New Jersey may be appropriate. That is, under the standard tariff the addition of a large commercial customer adds a significant amount to distribution revenue. However, because CET counts the customer as being only average in size, CET reduces distribution revenue relative to the standard tariff (in this example). This reduces Questar's incentive to connect large customers (though CET gives Questar an incentive to enroll any customer whose incremental cost to serve is less than $255.53 per year). By counting a new large customer as multiple customers for purposes of CET calculations, this adjustment would largely (if not entirely) restore the utility's incentive to connect large customers.

In addition to the design changes described above, the Utah Division of Public Utilities may consider ongoing monitoring of Questar's performance regarding the promotion of conservation and energy efficiency. While the use of a concrete quantitative measure of performance is not advised (because it brings all of the problems associated with Lost Revenue Adjustments along with it), the regulator should retain the ability to cancel CET if Questar does not act in good faith in its promotion of conservation. Given that DSM programs are now in place (and can therefore be evaluated based on funding levels and standard methods of evaluating cost effectiveness), the additional monitoring may consist only of a review of Questar's marketing efforts. While the promotion of natural gas use in space heating, water heating, and cooking applications should be allowed,[29] other load growth initiatives should be questioned.

5.2 Analysis of Risk Shifting under Questar Gas's CET Mechanism

As described in Section 3.2, a key issue of concern regarding decoupling mechanisms is the possibility that they shift weather, economic, and commodity price risks from the utility to the consumers. This report has described how an effective program design can reduce weather risk for both the utility and its customers. However, a statistical analysis must be conducted in order to determine whether the shifting of economic and commodity price risks is an important issue for a particular utility. This section presents an analysis of Questar Gas using annual data from 1980 through 2005.

The analysis of whether the reallocation of a particular risk is important depends on two factors: whether an estimate of the effect of a particular risk factor on use per customer is statistically significantly different from zero, and whether multiplying the variation in the underlying variable (*e.g.*, the standard deviation of HDDs) by the estimated coefficient results in "large" variations in use per customer. That is, one must determine that the risk shift exists, and that the magnitude of the risk shift is large enough to be of concern. Clearly disagreements can exist regarding what constitutes a "large" risk shift. However, the current debate seems to consist only of declarations that risks are shifted, without any reference to the expected effect of the shifts on the utility and its customers. The debate regarding the reallocation of risks can only be improved by attempting to measure and compare the various potential risk shifts.

The statistical models presented in this section relate annual use per customer (decatherm usage divided by the number of customers for the GS-1 class) to various potential explanatory variables, including:

1. Weather conditions, measured as heating degree days;
2. The natural gas commodity price;
3. Economic conditions, measured using the Utah unemployment rate, Utah gross domestic product, and Utah per capital disposable personal income; and
4. A time trend.

The data sources for the study are as follows: the GS-1 customer count, decatherm natural gas usage, and heating-degree day data are taken from Exhibit 1.7 of the August 15, 2006 surrebuttal testimony of Barrie McKay; Utah gross domestic product and per capita disposable personal income data are taken from the Bureau of Economic Analysis (BEA) web site; the Utah unemployment rate and consumer price index (used in converting nominal to real values) data are taken from the Bureau of Labor Statistics (BLS) web site; and the Utah residential natural gas price (in dollars per thousand cubic feet) is taken from the Energy Information Administration (EIA) web site.[30]

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[29] The use of electricity appliances for these end uses (in place of natural gas appliances) can result in a less efficient use of natural gas, as natural gas is increasingly used to generate electricity.

[30] Marlin Barrow of the Utah Division of Public Utilities provided Questar Gas price data for October 2001 through November 2006. However, EIA data were required in order to include usage and weather data extending back to 1980. During the overlapping timeframe, the correlation between the Questar Gas price

Equation 9 shows the form of the specification that is estimated.

Equation 9: $UPC_t = \alpha + \beta_{HDD}*HDD_t + \beta_{Price}*Price_t + \beta_{Econ}*Econ_t + \beta_{Trend}*Trend_t + \varepsilon_t$

where,
UPC_t = decatherms per customer for the GS-1 class in year t;
α = the estimated constant term;
β_{HDD} = the estimated effect of heating degree days (HDDs) on use per customer;
HDD_t = heating degree days in year t;
β_{Price} = the estimated effect of the commodity price on use per customer;
$Price_t$ = the commodity price in year t;
β_{Econ} = the estimated effect of economic conditions on use per customer;
$Econ_t$ = economic conditions in year t, represented by the Utah unemployment rate, Utah gross domestic product, or Utah per capita disposable personal income;
β_{Trend} = the estimated annual average change in use per customer;
$Trend_t$ = an annual time trend variable; and
ε_t = the estimated residual at time t.

Note that use per customer (and not total usage) is on the left-hand side of Equation 9. CET will produce revenues that differ from the standard tariff, and therefore a potential reallocation in risk, for two reasons: changes in use per customer for existing customers, or differences in average use per customer for new customers relative to existing customers. The former risk is the subject of analysis in this section.[31] That is, the statistical models will estimate the extent to which changes in use per customer are due to changes in weather, economic conditions, and the commodity price. A strong link between average use per customer and economic conditions or commodity prices indicates that CET shifts risks to existing customers. For example, if an economic downturn led to a reduction in use per customer, CET would compensate the utility for reductions in fixed-cost recovery that would have occurred under the standard tariff.

The parameters of Equation 9 were estimated using a Prais-Winsten estimator, which accounts for the fact that residuals tend to be correlated across observations in time series

data and the EIA price data is 0.855, which provides some confidence that the EIA data reflect prices paid by Questar customers.

[31] The latter risk, that use per customer will differ between new and existing customers, is not explicitly studied here. While the analysis in this section provides evidence that use per customer has declined over time, the available data are not sufficient to determine whether the reduction is due to existing customers becoming more energy efficient or new customers having lower average use per customer (or some combination of the two). Current market trends combine potentially offsetting effects: while appliance efficiency is improving, average home size is also increasing. In addition, both natural gas and electricity prices have increased in recent years, making it difficult to predict the extent (or direction) of changes in fuel (*i.e.*, electricity or natural gas) adoption rates in the near future. Therefore, it is unclear what the relationship between new and existing average customer usage will be in the coming years.

data. Tables 1A and 1B present the estimated coefficients.[32] Ten versions of Equation 9 were estimated to account for variations in the included variables.

Table 1A:
Estimates of the Effects of Weather, Economic Conditions, and the Commodity Price on Annual Use per Customer, 1980 through 2005
Excluding Time Trend Effects

Model:	**No Time Trend**				
	(1)	**(2)**	**(3)**	**(4)**	**(5)**
Heating degree days	0.018** (0.002)	0.018** (0.002)	0.018** (0.002)	0.017** (0.002)	0.019** (0.002)
Real commodity price	n/a	0.099 (2.146)	0.499 (2.298)	0.844 (1.693)	1.591 (1.814)
Utah unemployment rate	n/a	n/a	0.915 (1.454)	n/a	n/a
Real Utah gross domestic product	n/a	n/a	n/a	-0.010** (0.001)	n/a
Real Utah per capita disposable personal income	n/a	n/a	n/a	n/a	-0.016** (0.002)
Constant	44.42** (15.97)	44.00** (18.65)	37.25* (21.49)	118.13** (13.61)	200.19** (24.97)
R-squared	0.882	0.882	0.885	0.964	0.958
Durbin-Watson statistic	1.58	1.57	1.58	1.74	1.56

[32] A parallel set of equations were estimated using the log of use per customer as the dependent variable and taking log of the commodity price, gross domestic product, and per capita disposable personal income where the variables are included. The results are qualitatively similar to those contained in Tables 1A and 1B, with the same pattern of variable sign and statistical significance.

Table 1B:
Including Time Trend Effects

Model:	Including Time Trend				
	(6)	(7)	(8)	(9)	(10)
Heating degree days	0.017** (0.002)	0.017** (0.002)	0.017** (0.002)	0.017** (0.002)	0.018** (0.002)
Annual time trend	-2.306** (0.253)	-2.313** (0.266)	-2.309** (0.301)	-0.869 (1.562)	-1.517* (0.774)
Real commodity price	n/a	0.208 (1.706)	0.221 (1.761)	0.644 (1.757)	0.911 (1.746)
Utah Unemployment rate	n/a	n/a	0.036 (1.117)	n/a	n/a
Real Utah gross domestic product	n/a	n/a	n/a	-0.006 (0.007)	n/a
Real Utah per capita disposable personal income	n/a	n/a	n/a	n/a	-0.006 (0.005)
Constant	4,639** (504)	4,652** (529)	4,644** (601)	1,821 (3,062)	3,125** (1,493)
R-squared	0.964	0.963	0.963	0.965	0.965
Durbin-Watson statistic	1.74	1.74	1.74	1.76	1.70

* denotes statistical significance at the 90 percent level.
** denotes statistical significance at the 95 percent level.
Standard errors are in parentheses.
"n/a" indicates that the variable was not included in the estimated model.

A number of observations can be made regarding Tables 1A and 1B:

- The estimated effect of weather (HDDs) on use per customer is very robust with respect to specification. That is, the estimated coefficient is highly statistically significant and similar in magnitude as different explanatory variables are added to the estimated equation. This indicates that weather risk exists, but as described earlier in this report, methods exist that can mitigate this risk for both the utility and its customers.
- Estimates of the time trend coefficient indicate that use per customer has declined during the 1980 to 2005 timeframe. The coefficient is statistically significant in four of the five models in which it is included. In the fifth, the lack of statistical significance is due to the presence of the Utah GDP variable, which has a 0.994 correlation with the time trend variable. However, note that the inclusion of only the Utah GDP variable leads to a counter-intuitive sign (see column 4 of Table 1A), indicating that an improvement in economic conditions *reduces* use per customer. In contrast, the corresponding model that replaces Utah GDP with a time trend (in column 7 of Table 1B) produces a time trend coefficient estimate that matches intuition (that use per customer has declined due partly to improvements in appliance energy efficiency over time). Therefore, models that include the time trend variable (in Table 1B) are preferred to models that do not (in Table 1A).
- The estimate of the effect of the commodity price on use per customer varies substantially across models and is not statistically significant in any of the

models. Based on these findings, it does not appear that commodity price risk exists for Questar Gas.
- The models do not provide any evidence that changes in economic conditions affect use per customer. The only statistically significant economic variables (in columns 4 and 5 of Table 1A) have the wrong sign, indicating that deteriorating economic conditions *increase* use per customer. (Again, because of the high correlation of these variables with the time trend variable, we do not believe that these estimates reflect actual customer behavior.)[33]

In summary, the findings indicate that weather risk exists, but economic and commodity price risks do not appear to exist based on the analysis of the available data. Therefore, in this case there is no need to consider Statistical Recoupling (to remove the risk shift) or a reduction in Questar's allowed rate of return (to compensate customers for the risk shift).

As a matter of general methodology, it may be interesting to list the steps that would have occurred had the economic or commodity price risks been found to exist. The first step would have been to determine the variation in the underlying variable (*e.g.*, the standard deviation of Utah GDP) and multiply it by the corresponding estimated coefficient. This yields a plausible effect of changes in the variable on use per customer that can be compared across sources of risk. That is, one could perform the calculation for the HDD, GDP, and commodity price variables and compare the change in use per customer that is expected when the conditions change by one standard deviation (one standard deviation above and below the mean encompasses about two-thirds of the possible outcomes). A higher value is associated with a larger potential risk shift (or mutual risk reduction, in the case of weather risk).

If the magnitude of the economic or commodity price risk is sufficiently high, mitigation measures would then be considered. In this case, one possibility for determining whether the risk is "sufficiently high" is if it is similar in magnitude to the weather risk (which is generally believed to be significant in scale for natural gas utilities with significant space heating usage) using the same method.

The mitigation measures to consider are:
- *Statistical Recoupling*: this is described in Section 4.3. Models resembling those shown in Tables 1A and 1B could serve as the basis for an SR mechanism.
- *A reduction in the utility's allowed rate of return*: methods for determining the size of the reduction are outlined in Appendix A.

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[33] Note that if the negative coefficient estimates on the GDP and per capital disposable income *were* correct, CET would reduce economic risk for customers, and not shift the risk to them. For example, if use per customer increased due to a recession the standard tariff would increase customer bills at a time when they are generally worse off. CET deferrals would reduce the effect of the bill increases through a refund in the following period.

6. Summary and Conclusions

This report reviewed the natural gas decoupling mechanisms currently in use in the United States. While significant variations were found across the sixteen programs, the major variations can be summarized according to a few distinctions:

1. Full versus partial decoupling (as a percentage of full decoupling);
2. Inclusion versus removal of weather effects from decoupling; and
3. "Standard" versus revenue per customer decoupling (RPCD).

The report then evaluated the decoupling design alternatives according to the outcomes desired by the proponents of decoupling and the effects to which opponents of decoupling object. A summary of this evaluation is that the most effective decoupling mechanism would incorporate full decoupling, include weather effects (with a separate weather adjustment mechanism in place), and adjust for the current number of customers (*i.e.*, RPCD).[34]

The primary concern regarding decoupling is that it shifts risk from the utility to its customers. However, the recommended decoupling mechanism actually reduces customers' (and the utility's) weather risk. In addition, while decoupling does shift risks due to economic conditions and commodity prices to consumers in theory, the magnitude of the risk shift in practice is unclear. Utility-specific estimates of this risk should be conducted to assess whether it is worthwhile to mitigate this risk (or compensate customers through a reduction in the utility's allowed rate of return). An analysis of this kind conducted for Questar Gas did not discover the potential for a shifting of economic or commodity price risks due to the Conservation Enabling Tariff.

Three alternatives to decoupling were described and evaluated:

1. Lost revenue adjustments (LRAs), with and without performance incentives;
2. Straight Fixed Variable (SFV) rates; and
3. Statistical recoupling (SR).

LRAs are not able to adequately alter the utility's incentive problems with respect to load growth and are difficult to administer. SFV is intuitively appealing, but could be difficult to implement effectively in the absence of properly set carbon taxes. Based on utility costs alone, SFV leads to a reduction in the volumetric price, and therefore significantly reduces customers' incentives to independently pursue conservation.

SR uses a statistical model in an attempt to eliminate the effects of weather, economic conditions, and commodity prices on decoupling deferrals. This is an appropriate alternative if economic and commodity price risks are found to be significant (and customer compensation through a reduction in the utility's allowed rate of return is not available and/or desired as a solution). However, SR will likely lead to significant disputes over the specification of the statistical model.

[34] Standard decoupling in place of RPCD is acceptable if concerns exist regarding the ability to monitor whether the customer count is accurate.

A recent article in *Public Utilities Fortnightly* concludes that the benefits of decoupling for utilities are clear, but questions whether decoupling provides benefits to consumers. [35] The author of this report believes that customers may benefit significantly from the change in the utility's incentive to promote conservation. These benefits can be both direct, by lowering bills through usage reductions, and indirect, if economy-wide conservation efforts produce a decline in the commodity price. The primary perceived cost to customers associated with decoupling—that it shifts risk to them—can be offset through a reduction in rates (assuming that the risk shift is significant) or the adoption of SR.

[35] Costello (2007), p. 48.

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Appendix A: Methods for Estimating Reductions in the Allowed Rate of Return due to the Introduction of Decoupling

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Introduction and Context

At a general level, the cost of capital to the firm is a function of the demand and supply of capital, expected inflation, and perceptions of risk incurred by investors from holding the securities of the firm. An increase in the demand for capital, which may be due to a general increase in business investment, will cause the cost of capital to rise. Investors discount expected market returns to capital with inflation-adjusted discount rates. This means that, other factors held constant, a rise in the expected level of future inflation will cause a general decline in the market value of outstanding debt securities, the result of which is a rise in effective interest rates. A rise in expected inflation also increases the cost of equity capital in similar fashion, though it will not necessarily translate into a decline in equity securities.

The holders of capital are risk averse and risk is thus costly. An increase (decrease) in perceptions of risks results in a corresponding rise (decline) in the cost of capital for financial assets, including both debt and equity. Variability in the internal cash returns to capital invested in the firm is a relevant measure of risk. Reductions in the variability of internal returns reduce capital risks, all other factors held constant.

As recognized by regulators and other parties, decoupling mechanisms decrease the variability and risks associated with operating income. Operating income constitutes by far the largest component of the internal return to total capital for most utilities. Because decoupling reduces the variability of internal returns, the perceived risks associated with internal cash returns are mitigated. This means that the degree of variability of the coverage of interest on debt and net income available to common shareholders both decline. As a result, decoupling seemingly causes the cost of capital to the firm to decline, though the effects are likely to be relatively small.

Statement of the Issue, Evidence

The main issue in determining whether decoupling mechanisms significantly affect the cost of capital is whether the risks associated with internal accounting returns to capital are related to the cost of capital. Cost of capital is implicit within the prices of financial assets established by efficient capital markets. At a market level, expected market returns approximate the cost of capital for all financial assets. The relevant measures of market risks include Capital Asset Pricing Model (CAPM) betas and the variability of market returns. The question, then, is the extent to which the variability of internal cash returns is positively related to market risks and thus the cost of capital. Certainly, it seems intuitively plausible that a positive relationship exists. Holders of the financial assets would seem to be concerned about high risk in internal accounting returns, and therefore discount the price of securities for firms with comparatively high internal risks, other factors held constant.

Indeed, empirical evidence suggests that risk metrics related to accounting returns are related to market returns and thus the cost of capital. Several studies can be cited. Specifically, Basu (1977) finds that differential P/E multiples appear to influence realized market returns, thus challenging the efficient market hypothesis. "In Debt/Equity Ratio and Expected Common Stock Returns: Empirical Evidence," Bhandari finds that the debt/equity ratio, which explicitly affects the variability of internal returns to common equity, explains market returns after accounting for market risk proxies. Similarly, in "Risk in the Equity Market: An Empirical Appraisal of Market Efficiency," Douglas reports that "…earnings volatility plays a statistically significant but minor role in the determination of its principal component price volatility." In "Regulation, Profit Variability, and Beta," Binder and Norton demonstrate that regulation plays a significant role in the determination of market returns, CAPM betas, and risks. Essentially, regulation serves to buffer or shield various dimensions of risks, though other factors are also important.

Consistent with intuition, the empirical evidence appears to suggest that a well-designed decoupling mechanism would tend to parallel the effects of a binding regulatory constraint, where non-volumetric accounting costs are fully recovered. In essence, this would reduce the cost of capital of the financial assets of the regulated firm. This result comes about because decoupling will tend to smooth the variability of the internal returns to capital. Because risks associated with internal returns are positively related to market risks and thus the cost of capital, the rate of return requirement of the regulated firm declines. Since the rate of return on rate base is a major component of the total cost of service, decoupling can result in a positive dividend for retail consumers.

Analysis Approach

The magnitude of reduction in the cost of capital that can be justified by the introduction of decoupling is an empirical question, the answer to which depends upon several factors. While the cost of capital is likely to decline, the effects are expected to be modest in scale, perhaps on the order of 25 basis points. The appropriate approach to empirically estimate the reduction is as follows:

Step 1: Develop a Sample of Firms with outstanding equity and debt securities that are actively traded in U.S. capital markets. The data can be organized into a panel, with a time series of data available for each of the identified firms. The sample of firms should include both utilities and non-utility companies.

Step 2: Develop Historical Financial Data Covering the Internal Financial Performance for the sample of firms. The data should cover a number of years, focus on the internal returns to total capital and be sufficient to develop a set of alternative measures of the risks associated with the internal returns over a number of years. For example, risk metrics can include statistical variation in internal cash returns, operating income, net income available to common stockholders; interest coverage and variability of coverage, and debt ratings. These financial data are reported to the Securities and Exchange Commission in 10-Q and 10-K filings. These data are also compiled and reported by Compustat, Value Line, and other financial data services, and can be easily gathered and organized.

Step 3: Develop Capital Market Data for the sample of firms, for the historical years covered by the study, including the market prices of the outstanding securities of the sampled firms. Capital market data should include the historical ratings on debt securities, as published by security rating agencies, and also include yields to maturity. For equity securities, the capital market data should include dividends paid, and provide a basis to determine the total market returns, by month and year. The data should provide a basis to determine the statistical variation in realized market returns (market risks) of the sampled firms, and to gauge market risk with respect to the equity market indexes such as the S&P 500 index. Security analysts' assessments of prospective earnings and dividend performance of firms may also useful to the study.

Step 4: Conduct an Analysis focused on the relationship between the internal risk metrics and market risk, including estimates of the cost of capital using CAPM, Discounted Cash Flow (DCF), and possibly variants of Arbitrage Pricing Theory (APT). The analyses would utilize regression analysis to determine the statistical relationship between internal financial risk metrics and estimates of financial market risks and cost of capital, where the latter includes variation in market returns, CAPM betas, and DCF-based estimates of the cost of capital. A comparative analysis of financial risk metrics and corresponding market metrics for firms grouped according to financial metrics would also likely reveal that higher internal risk metrics are associated with higher market risks and estimates of cost of capital.

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