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A Prescription for Regulatory Agreements Regarding Energy Commodity Price Risk Mitigation

July 18, 2008

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Preface

The genesis of this paper was a discussion between Pace and NRRI personnel early in 2008 on the status of hedging by gas and electric utilities. Both parties agree that opportunities exist for improvements in both utility and commission practices and policies, as they relate to hedging. Pace offered to draft a paper that outlines its views on hedging. These views derive from the extensive experiences of Pace assisting different utility clients in undertaking hedging programs. NRRI reviewed early drafts of the paper and offered a number of comments and suggestions. Later revisions reflect many of these comments, but not all of them. NRRI, for this reason as well as others, does not endorse all the arguments and other content in the paper. Notwithstanding this caveat, NRRI strongly encourages state commissions and other interested parties to read this paper and contemplate the ideas contained in it. The paper touches on a topic of considerable importance to state commissions. It also presents ideas, some of which are innovative, that deserve the attention of state commissions for their potential to serve customers and the public interest. The hope of NRRI is that the paper will advance the dialogue on a topic that will continue to challenge state commissions in the years ahead.

Gas and electric utilities increasingly have hedged the input cost of fuels and purchased power as prices have exhibited higher volatility over the last ten years. Hedging includes the utility purchasing financial instruments, such as futures contracts, options and swaps.

State public utility commissions have assumed different roles in overseeing a utility's hedging activities. Some commissions review proposed hedging plans and offer suggestions for changes, while others only review retrospectively the costs and actions associated with a hedging plan. The appropriate role of a commission is open to debate: a commission could engage in discussions regarding appropriate objectives and program framework, thereby providing guidance, or a commission could get involved only after the fact, avoiding any potential for undue influence on utility decisions that arguably lie solely within the purview of utility management. Most commissions allow utilities to hedge but most frequently they provide little guidance that articulates, for example, standards for hedging plans.

This paper by Mike Gettings, Executive Vice President of Pace, addresses some of the most complex issues that have emerged from the several years of experience with financial hedging by gas and electric utilities. These issues include a discussion of regulatory influence in hedging activities, a perspective on the value of price stability to customers, and a discussion of the possible merits of regulatory incentives related to utility hedging.

The paper first lays out a rationale for why a utility should hedge from the perspective of its customers. Unlike hedging by most firms, a utility manages price risk mainly to increase the welfare of risk-averse customers.

The paper also warns of the incompatibility between a utility designing and executing a robust and large-scale hedging strategy and prevailing regulatory incentives. It, for example, identifies the uncertainty of cost recovery as discouraging a utility from engaging in hedging on a scale and level of sophistication that could best serve the interests of customers. The paper proposes one possible regulatory structure and incentive mechanism that would help to overcome this problem.

A major part of the paper proposes what the author calls a "robust risk mitigation" approach that manages both the upside and downside risks of hedging. Hedging, for example, can lock a utility into a price that lies above the prevailing market price and the author contends that such risk can and should be managed. The approach requires "clarity of decision rules, ongoing quantitative assessments, and clear governance and controls." The author outlines a view of the appropriate role of a commission in overseeing such a program in addition to identifying criteria for the recovery of hedging costs.

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Introduction

Energy commodity prices for power, gas, oil, and coal have been on a wild ride for at least a decade and utility customers, regulators, and utility management teams are all frustrated by the impact of ever-increasing volatility. To be clear, volatility has *not* been evidenced as transient up-and-down movements, always returning to some academic concept of long-term equilibrium value. Instead volatility has played out as a sequence of dramatic price upswings, with some smaller-magnitude downswings. And for the year or two prior to each spike in prices, industry pundits deemed the prospect of those price levels as improbable future outliers – until they were real.

As an industry, utilities, regulators and advocates must find effective ways to deal with mitigating energy price volatility. So this document will deal with the following topics:

1. "Why hedge at all?" is an important foundational question.
2. An overview of the characteristics of a robust risk-mitigation program.
3. A discussion of how a new regulatory approach, including advocacy for much greater clarity in regulatory agreements, can stimulate more robust risk mitigation.
4. A template for how to create clarity in regulatory expectations so that utility performance consistent with those expectations will result in appropriate cost recovery.

Background

Consider the typical gas distribution company having a policy of always being 25% hedged; that is, it fixes 25% of its commodity costs sometime in advance of its actual need, but leaves 75% of its costs exposed to whatever commodity prices might emerge in the spot market.[1] They passed along double-digit bill increases through their gas cost recovery charges following the hurricanes of 2005. That same firm, having remained 25% hedged during the gas price troughs of 2006 and 2007, now finds itself (or more

[1] Later in the paper the term Hedge Ratio will be used to describe the percentage of commodity needs that have been fixed in price.

precisely its customers) facing double-digit price increases again in 2008. Or consider the more dramatic case of another firm that follows a more reactive strategy. As prices rose in 2005 this firm did nothing to fix prices; why lock in $7.00 gas when it was $6.00 just last month? Then as prices went to $12.00 and became intolerable, that firm could no longer tolerate the price increases so they locked in prices, only to find themselves paying $12 in a much lower-priced market the following year.

These natural gas illustrations could be recast in electricity terms, as reflected in elements of the California energy crisis, and the same effects apply to oil, coal, and other commodity costs in the energy complex.

These examples have some characteristics in common, and unfortunately those characteristics are common in much of the domestic utility industry. What are they?

1. Often utilities and regulators focus on perfunctory decision rules for hedging rather than core objectives. I define perfunctory decision rules as simple strategies that are not responsive to market conditions, like hedging a predetermined – usually small – percent of requirements by a certain time. In contrast, more responsive strategies focus on core objectives, like defense of the intolerable; they respond to market conditions. The first anecdote described above could be characterized as a 25% perfunctory strategy. There was no risk-mitigation response as high prices emerged; most utility risk programs prescribe no response to rising volatility to prevent intolerable high-cost outcomes.

   Sometimes, in extreme markets, such perfunctory strategies become painful and then companies decide, in a crisis mode, that they must do something. The second anecdote describes the kind of hedging that sometimes follows a nonresponsive strategy that has gone badly. The impulse to hedge at market peaks can be avoided if an orderly response to volatility increases is planned.

2. Typically utility risk-mitigation programs do not mitigate the potential for unfavorable hedge outcomes (except by not hedging). This deficiency is troublesome on its face, but also on a second level. With no plan to mitigate poor hedge results, hedging to mitigate high costs becomes a riskier endeavor and good decisions are suppressed out of fear.

3. Usually utilities and regulators (or customers) have no mutual clarity as to what is tolerable, either in terms of upside price tolerances or the potential for unfavorable hedge outcomes. When mutual clarity is lacking, the mode of operation is often a nonresponsive, perfunctory hedge strategy with the shortcomings described.

It must be recognized that robust risk mitigation deploys specialized skills, and ironically, without an understandable framework for deployment, it feels “risky” to policy makers. For investor-owned utilities (“IOUs”), who often possess those specialized skills, there is a perception that, in the absence of a regulatory agreement, stepping out with a more robust program on behalf of customers puts shareholders at risk. And for regulators, there is a perception that stepping out with mandates for more robust programs is overly prescriptive, particularly where the issues are complex and results are uncertain.

Yet an effective framework is possible. The author has worked extensively with large public power entities where regulation is typically structured differently, as a governing council or board of trustees. These public power entities, more often than IOUs, conduct robust risk mitigation on behalf of their customers. They somehow reach an agreement with their trustees acting as proxy for the customers' interest

Why Hedge at All?

When the question "Why Hedge at All?" arises, one will often hear discussions of whether or not one can "beat the market." Those discussions miss the point, so they will not be debated here. Let us accept that anyone who has confidence in beating the market would not be writing papers about it.

Energy commodity price movements are typically skewed; that is, relative to expectations, potential upside price movements are generally much greater than downside movements. This effect can be shown mathematically[2] by any quantitative analyst in the energy commodity business, and it can be seen intuitively in Exhibit 1. That exhibit shows NYMEX settlements for natural gas, but the concept of skewed price risk is also applicable to power and virtually any commodity.

<u>Exhibit 1.</u>

Source: NYMEX

By way of a colloquial illustration, in 2002 when natural gas price expectations, as reflected in the NYMEX futures market, were $3.00 per MMBtu, the uncertain range of future prices might have been estimated as $2.00 to $5.00. In other words, the uncertain range at the time could have encompassed 2 dollars up, but only 1 dollar

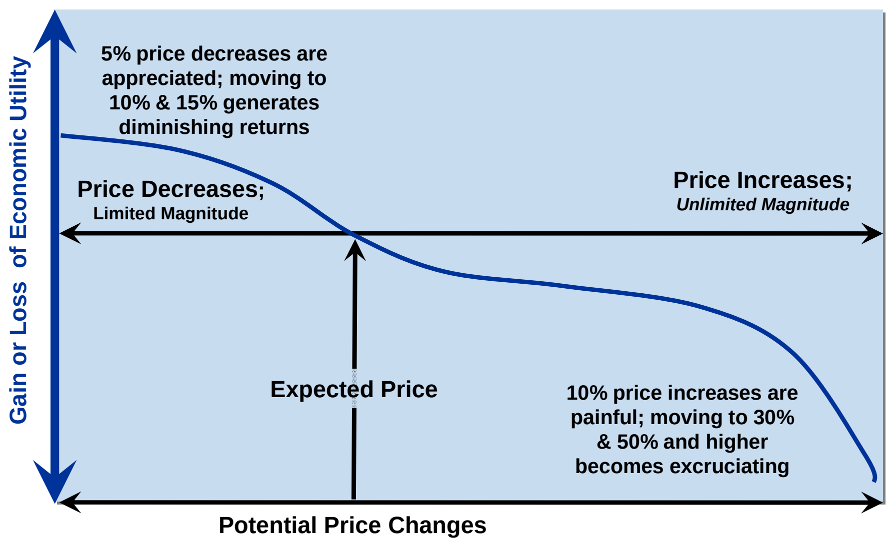
[2] There are generally accepted ways to estimate future price risk. Natural gas price risk is typically assessed using a lognormal distribution which captures this skew to some extent, but the author will (mercifully) avoid burdensome mathematics.

down. Different observers might have been more aggressive in estimating that range; some even may have estimated the high side more accurately at the $14 level realized in 2005, but if they did, they never would have estimated an equally dramatic downside range of *minus* $8.00. While an $11 increase did occur, an $11 price drop would have been viewed correctly by 2002 observers as impossible.

The reality of skewed price risk conspires with a perceptual issue: customers, regulators, and utilities perceive more pain when faced with extreme upside prices than they benefit when prices are low. I do not assert this with documentary support, but am confident that the perception will be widely shared by the bulk of readers who field customer complaints, plan utility strategy, and make regulatory policy.

That perceptual consideration amplifies the issue of skewed-price risk. They combine to produce a risk-averse profile. Exhibit 2 illustrates the point in a subjective fashion. Potential price increases can dwarf potential decreases as reflected on the horizontal scale, and the loss of perceived value can be dramatic as shown on the bottom-right quadrant of the graphic.

Exhibit 2.



Source: Subjective Illustration

So why hedge? The answer is to mitigate the disproportionate pain associated with dramatic price increases, not to "beat the market." To do this, a utility's risk mitigation program must be responsive to different market environments. A 25% hedge ratio might be appropriate in relatively stable markets, but as volatility and price levels rise, the program should respond.

Regulatory Implications

If one accepts the above reasoning, then extension of that reasoning would indicate that measured investments in risk mitigation should yield a net improvement in the welfare of consumers.

Yet, IOUs and regulators have not found a good framework to capture these benefits. Any major utility that participates in energy marketing, trading, or asset management through an unregulated affiliate is deploying experts to manage the market risk. Yet market risk also translates to customer-bill risk, and few deploy comparable expertise to manage the customer-bill risk, which in aggregate applies to millions of customers and billions of dollars; instead perfunctory hedge programs remain prevalent. Why?

Hedge outcomes are uncertain; they are not predictable. In the face of that uncertainty, amorphous regulatory understandings for cost recovery of hedge gains or losses chill hedging judgments. The typical understandings achieved to date between utilities and regulators does not reward judgment informed by risk expertise, and by not rewarding that expert judgment, it tends to suppress it.

Where there is no explicit agreement on the treatment of uncertain outcomes, the natural response of utilities often will be, and has been to minimize the activities that give rise to that uncertainty. Those foregone activities are the risk-mitigation programs customers require for their own certainty of outcomes.

Regulators cannot change the underlying market uncertainty, but they can address, with the utilities' cooperation, amorphous standards for cost recovery. To be clear, the envisioned standards are not preemptive of prudence findings, but a benchmark for evaluation and assessment of effectiveness.

What Constitutes Robust Risk Mitigation

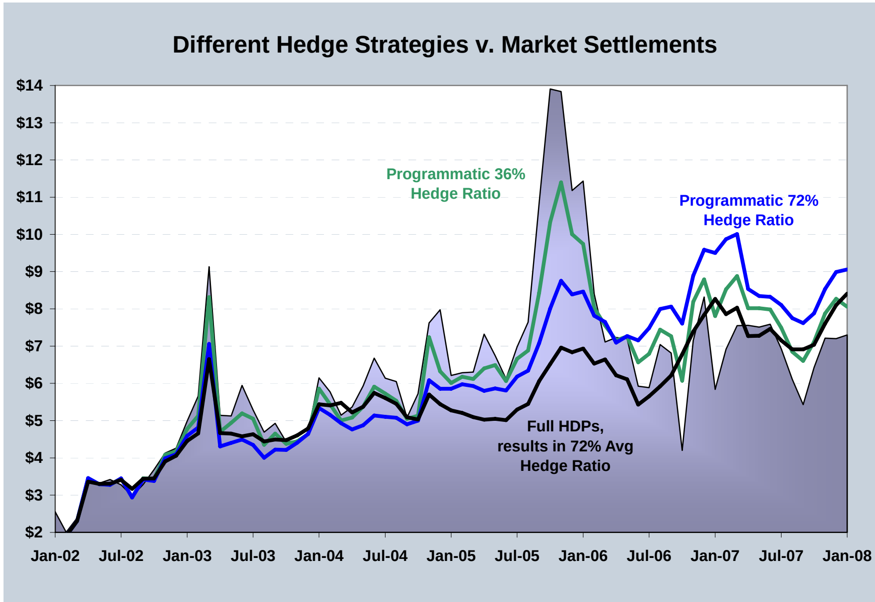
Market risk is Bipolar. There is the risk of market prices running up when requirements are un-hedged, and there is the risk of market prices running down against already executed hedges. A robust risk-mitigation program manages both, and to do so requires more expertise, more governance, and some investment. Yet it can be done very well if hedging decisions are planned in a rigorous manner.

The next graphic, Exhibit 3, shows cost results from three approaches to hedging as they would have played out in the gas markets of the last half-dozen years:

1. (Green) Simple, steady, perfunctory accumulation of hedges up to a 36% hedge ratio
2. (Blue) The same simple accumulation up to a 72% hedge ratio, and
3. (Black) A sophisticated set of Hedging Decision Protocols ("HDPs") that also happen to achieve a 72% average hedge ratio. These HDPs will be described in the next section.

Note that the 36%-perfunctory strategy provided only modest protection against the 2005-2006 spike in gas prices, but reasonably tracked with the subsequent downturn in prices. The 72%-perfunctory strategy provided more upside protection, but diverged substantially from market prices in the subsequent downturn. Finally the set of robust HDPs provided both, robust upside price mitigation and good participation in the market downturn that followed.

Exhibit 3.



Source: Pace Global Energy Risk Management simulation

There are two key elements in the third approach that are absent from the perfunctory approaches.

A. The HDPs include a process of monitoring prices and volatility and comparing the *potential* for price increases to an explicit upside tolerance. Hedges are then accumulated in proportion to the emerging need to mitigate exposures. Think of this as an early warning mechanism that triggers additional hedging as upside risk increases.

B. Also the HDPs include an early warning mechanism for mark-to-market risk,[3] and a plan to switch to an option[4] strategy when that risk exceeds tolerances. Options can be used to secure downside participation in market movements while constraining upside exposure; they require the outlay of a premium which appropriately is included in the cost metrics of Exhibit 3.

Deployment of these two elements demands clarity of decision rules, ongoing quantitative assessments, and clear governance and controls. Those same characteristics provide the basis for a regulatory agreement and unambiguous standards for the assessment of the program. We discuss each of these concepts next.

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[3] Mark-to-market risk is the potential for existing hedges to diverge unfavorably from prevailing market prices.

[4] By way of illustration, an option strategy could include "call" options which provide a cap on upside price exposures and allow full participation in downside market movements. A "call" secures the right, but no obligation to buy at a specified price.

Hedging Decision Protocols

Hedging decisions can be segmented into four categories. Each category serves a purpose, and a well balanced program considers the effects of each category's design in relation to the others.

The categories are:

Category	Purpose
Programmatic	Accumulate protection on a dollar cost averaging basis to preemptively reduce exposure to volatility
Discretionary	Accumulate protection in response to specific value-oriented objectives.
Defensive	Accumulate protection when increases in price and/or volatility threaten tolerances.
Contingent	Utilize an options strategy when volatility threatens to yield an unfavorable mark to market compared to mark-to-market tolerances.[5]

The nuances of designing HDPs are beyond the scope of this paper, but the design process yields an interesting side benefit that has regulatory implications. By simulating numerous HDPs against historical and hypothetical market prices one can establish market-compatible sets of tolerances and options budgets.[6] Different firms may choose the most appropriate set of tolerances based on their own circumstances, customer demographics, risk tolerances, etc. The next few paragraphs will explain in words and pictures.

Two such market-compatible sets are illustrated in the spider diagram of Exhibit 4.

The red triangle shows a tolerance for a 10% customer-bill increase paired with a 3% mark-to-market tolerance and a modest options budget. In other words, by following the appropriate set of hedging decision protocols, the utility could constrain bill increases to 10% and be highly confident that unfavorable hedge settlements would not grow to 3% of the cost of service; the strategy would require an options budget of $3 million.

In contrast, the blue triangle shows how budgeting more in the way of options expenditures allows both tolerances to be constrained to more risk-averse levels (customer-bill-increase tolerance at 8% v. 10%; mark-to-market tolerance at 2% v. 3%; options budget at $8 million v. $3 million)

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[5] Options strategies are well suited to regulated companies because FAS accounting standards allow deferral of gains or losses to the flow month when governed by appropriate regulatory treatment.

[6] The design process produces results with a specified confidence. Typically Pace Global Energy Risk Management has done its simulations at 97.7% confidence, representing a single 2-sigma tail.

Exhibit 4

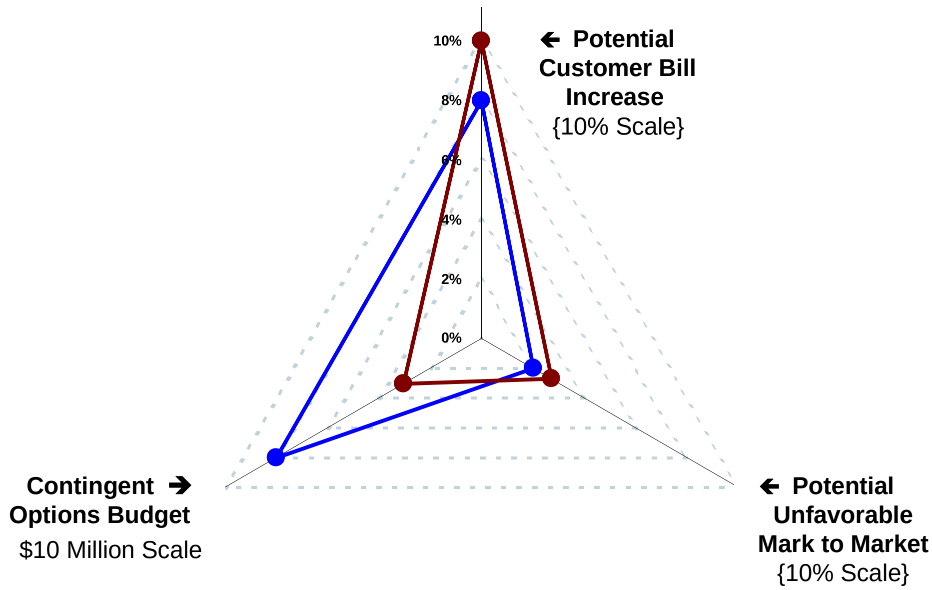
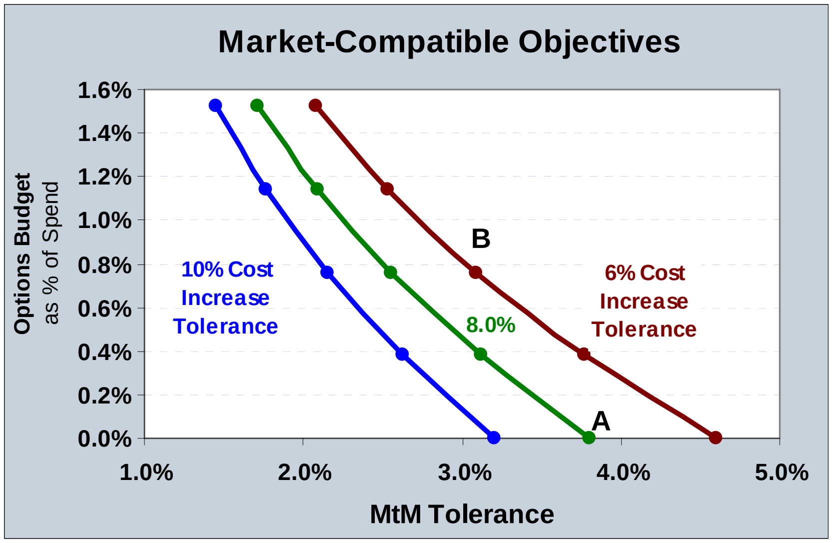


Exhibit 4 shows only two examples, but the upside tolerance, mark-to-market tolerance, and options budget can be linked in many different sets, each of which represents an equally valid set of objectives. To facilitate this discussion, we will refer to these tolerance sets as Market Compatible Objectives. Different firms may choose the most appropriate objective function based on their own circumstances.

An illustration of numerous Market Compatible Objectives is shown below. Each curved line represents an upside price tolerance and any point on the line can be seen to correspond with a mark-to-market ("MtM") tolerance (bottom scale) and an options budget expressed as a percentage of commodity expenditures (left scale).

Exhibit 5.



From a regulatory perspective, any Market Compatible Objectives could define reasonable outcomes. So a regulatory agreement could be built around the definition of reasonable expectations. The points labeled "A" and "B" on Exhibit 5 will be used to illustrate the intent.

Referring to Point A, it lies on the green line which represents a cost-increase tolerance of 8%; that is an 8% increase in customer bills. So Point A indicates it would be reasonable to defend an upside cost tolerance of 8% and a mark-to-market tolerance a bit less than 4% with no need to invest in options. Alternatively looking at Point B, it may be equally valid to defend a 6% upside tolerance (the red line) and approximately a 3% mark-to-market tolerance, but only with an options budget equal to about .8% of the portfolio value. Again, different firms may choose the most appropriate set of tolerances based on their own circumstances.

Note that while these are reasonable examples, the true relationships will depend on prevailing volatility, the composition of the energy commodity portfolio, and how commodity expenditures relate to the utility's cost of service. The design process produces results with a specified confidence.[7]

Template for a Regulatory Agreement Regarding Risk Mitigation

Building on these insights, we can discuss an improved regulatory framework to deal with risk mitigation programs. Detail will of course be specific to each regulatory culture, but an outline for one such regulatory agreement is envisioned as follows:

1. Utility's would file a Risk Mitigation Plan ("RMP") annually, including
    a. Specified tolerances for upside commodity cost and the related customer bill impact

[7] Typically we have done our simulations at 97.5% confidence, representing a single 2-sigma tail.

b. Specified unfavorable mark-to-market tolerance and options budget

c. The Hedging Decision Protocols to be deployed, including hedge-transaction criteria for programmatic, discretionary, defensive, and contingent hedges.

d. Oversight procedures and where flexibility is envisioned for adjusting or waiving the HDPs, the associated approvals and notices that will be required. Should the HDPs be waived or adjusted, regulatory notice would be required under item 3 below.

   It should be noted that the HDP design process contemplates wide variability in prices and other circumstances, so their waiver or adjustment should be associated with extraordinary market conditions or a change in the company's tolerance profile.

2. The regulatory staff would compare the filed plan to the range of Market Compatible Objectives and recommend approval, or return it with comments.
3. Reports would be filed quarterly by the utilities documenting hedge transactions, their purpose under the HDPs, critical risk metrics, and any actions related to 1(d) above.
4. With respect to cost recovery, compliance with the filed RMP would constitute strong evidence of prudent behavior.
   a. The Market Compatible Objectives would constitute reasoned expectations as to the range of normal results, including the potential for unfavorable mark-to-market outcomes.
   b. The contingent strategy, when followed, would provide evidence that the utility was actively managing the potential for unfavorable settlements.
   c. If the RMP was complied with, any results outside of the Market Compatible Objectives should coincide with outlier market conditions, and the utility would be required to demonstrate that such conditions were evident.
5. Incentives could be crafted to promote investment and management focus. These will be discussed next.

The Case for Risk-Mitigation Incentives

If a regulator believes that price volatility damages customers and therefore desires to stimulate more robust risk mitigation, what choices exist to stimulate that change? There is the carrot-and-stick approach, but in this case a skew toward the carrot may be far more effective for numerous reasons.

To illustrate, consider a symmetrical incentive program that rewards hedge gains with 10% participation accruing to the utility, and penalizes the company with 10% of hedge losses. The likely response of the company would be to minimize its own risk profile by diluting its risk mitigation activities.[8] In the financial markets, utilities are low-risk investments; shareholders are risk averse. A more sophisticated risk mitigation program requires investment, and no one, most of all utilities, would be inclined to invest tangible dollars in a zero-expectation payoff, especially one with volatile earnings impacts. So the best strategy for a utility under these circumstances would be to minimize investment and hedging activity to minimize risk. That is exactly the opposite of the desired effect.

A more effective incentive program would be intentionally designed to produce a favorable bias, i.e., *incentives*. One such design is represented below:

A. Specify a dead-band value for unfavorable hedge settlements that will elicit no penalty. This may be specified, for example, as 5% of the commodity expenditures. This provision recognizes that any hedging program will carry some risk of unfavorable hedge settlements; it is the cost of doing business, and must be viewed as occasional "noise" in the context of meeting broader objectives. Referring to the Exhibit 4, the choice of any market-compatible objective set will dictate a mark-to-market risk tolerance by its design.

B. Specify a participation rate (10% for example) to be applied to favorable outcomes and unfavorable hedge results that fall outside of the dead band, subject to the following conditions:

    a. Participation in gains will only accrue if the utility complied with its filed RMP. This condition will ensure that no speculative activity is rewarded and that hedge decisions are well planned.

    b. Penalties related to results outside the dead band will be levied if the utility is not compliant with its filed RMP. If compliant, the utility will be afforded the opportunity to present evidence that market conditions were more extreme than the design criteria, and that evidence may be considered by the regulator in attenuating penalty assessments.

C. Given the volatility of commodity prices and the implications of incentives to financial results, implement two additional smoothing constraints:

    a. Amortize incentives over a three-year period. Each year's accrued incentive or penalty would be accumulated in a deferred account and booked to income as one-third of the balance annually.

    b. Limit annual income effects to some a portion of return on equity, 100 basis points for example.

While this program exhibits a favorable bias, it is far more appropriate to the regulatory objectives. Improved risk mitigation demands investment as well as commitment to make decisions that put shareholders at some risk. The only means of stimulating such investment, other than direct compensation, is to provide a modest positive return for the incremental expenditures and commitment.

[8] This is consistent with the earlier observation that where there is no explicit agreement on the treatment of uncertain outcomes, the natural response of utilities is to minimize the activities that give rise to that uncertainty.

Administrative Requirements

There would be two segments of effort for a regulatory staff (“Staff”): review of the utility RMPs, and the compliance monitoring associated with the review of quarterly reports. Each should be manageable without a major budget impact.

An outline of the Staff requirements is envisioned as follows:

Utility Risk Mitigation Plans – RMPs

As discussed earlier the annually filed Risk Mitigation Plans would specify:

1. Tolerances for upside commodity cost and the related customer bill impact
2. Mark-to-market tolerance and options budget
3. The Hedging Decision Protocols to be deployed, including hedge-transaction criteria for programmatic, discretionary, defensive, and contingent hedges.
4. A schedule of supporting risk metrics (decision metrics) that will be tracked routinely; these metrics will be necessary to ascertain compliance with HDPs.
5. Oversight procedures and where flexibility is envisioned for adjusting or waiving the HDPs, the associated approvals and notices that will be required.

The Staff skills necessary to review these plans would include familiarity with the HDP concepts and the company’s risk policies. Staff must also understand how to interpret the market compatible objectives in the context of market volatility when reviewing RMPs. These skill requirements might imply some training needs, but issues of volatility and hedging are fundamental to regulatory policies anyway.

Compliance Monitoring & Quarterly Reports

Staff would also need to review compliance with the RMPs periodically. Reviews could be done quarterly or annually depending on budget and resource implications; also the depth of review could be minimal when results fall within expected ranges, and only intensified as hedge results approach the tolerances specified in RMPs. The reviews could be conducted as follows:

- Programmatic hedge compliance would be determined by reviewing if the hedge ratio is at Programmatic hedge levels specified in the RMP.
- Discretionary, Defensive and Contingent protocol compliance would be validated by comparing each company’s documentation of respective decision metrics to the hedge transactions executed. This process would not only inspect the decision metrics supporting hedge transactions, but also the validity of decisions to forego incremental hedging based on those metrics.

Staff’s review would be facilitated by quarterly reports filed by the utilities.

Conclusion

In these volatile energy markets, regulators and utilities have the opportunity, and perhaps the obligation to pursue robust risk mitigation. The benefits would be substantial at times of spiking prices while simultaneously constraining unfavorable outcomes (See Exhibit 3). Given the skew in energy price volatility (upward movements being greater than downward) and the skew in consumers' marginal utility related to price changes, the consumer welfare benefits could be significant. A new regulatory approach has been recommended to stimulate more robust risk mitigation; such an approach has been outlined above.

One important element of that approach would relate to the structuring of incentives. If incentives are designed with a symmetrical zero-expectation payoff, they are likely to produce behavior that is opposite of that intended. There will be investment required by the utilities and a neutral construct will cause that investment to be perceived as simply increasing shareholder risk. An alternative structure has been recommended.