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Looking Before Leaping: Are Your Utility's Gas Price Forecasts Accurate?

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Executive Summary

Natural gas prices are critical to a range of regulatory decisions covering both electric and gas utilities. Natural gas prices are also often a crucial variable in electric generation capacity planning and in analyzing the benefit-cost relationship for demand-side and energy-efficiency programs. High natural gas prices, for example, can make coal generation the most economical new source, while low prices can make natural gas generation the most economical. For gas utilities, future natural gas prices affect the benefits of energy efficiency, the level and nature of hedging, and the need for new utility infrastructure. Natural gas prices can also affect decisions about how to control carbon dioxide emissions. Finally, in organized wholesale electricity markets, natural gas prices frequently drive market prices and thus the value of all generating facilities (and their cost to ratepayers).

While natural gas prices constitute only one factor affecting the economics of a utility's decision, an erroneous forecast can cause errors costing hundreds of millions of dollars. The pervasive effects of gas prices mean that state commission decisionmakers frequently must assess, and choose among, parties' competing natural gas price forecasts. Forecasts vary in quality and credibility. With billions in ratepayer and shareholder dollars at stake, regulators need to know what forecasts to trust. Even where forecasts are trustworthy, their wide range requires regulators to understand the uncertainties and risks associated with their decisions.

Gas price forecasters face multiple uncertainties, including (1) uncertainties over the time frame of the current economic recovery and long-term economic growth, (2) the effects of recent shale gas discoveries, (3) liquefied natural gas (LNG) market developments, (4) carbon dioxide regulation, (5) demand for new electric generation, and (6) the effectiveness of energy-efficiency initiatives. The totality of these uncertainties speaks to the unreliability of any natural gas price forecast, especially for longer-term periods (e.g., beyond five years).

Two major questions relate to natural gas price forecasts. *First, how can regulators distinguish between reliable and unreliable forecasts?* Reliable forecasts require a sound analytical framework that quantitatively relates price to different predictors. This relationship must take into account historical patterns and economic theory. This paper illustrates the questions and issues associated with forecasting natural gas prices from an econometric model.

Second, how can regulators best use these forecasts when making decisions? Should regulators identify a single "best guess" forecast, and then base their decisions on that information? (The "best guess" forecast is based on a single scenario chosen by the regulator as the most likely.) Or should they determine a range of forecasts, with the midpoint defined as the "best guess" forecast and the boundary prices representing the high and low prices associated with alternative scenarios?

This paper first explains the major elements composing a natural gas price forecast and the critiques and defenses commonly associated with forecasts. Then the paper makes four recommendations:

1. ***Regulators should require a utility to provide full documentation of its natural gas price forecasts, including the analytical framework and data used, the assumptions made, and the explicit or implicit relationship between price and important predictors of price.*** These predictors can include economic growth, quantity of gas-fired generation capacity, the availability and cost of domestic gas supplies, and natural gas supply- and demand-price elasticities. Regulators should also require utilities to compare their forecasts with other forecasts derived by government agencies or private entities. A comparison can help regulators to gauge the reasonableness of a utility's forecast, and where it lies relative to other forecasts. If a utility's forecast departs from others, the utility should then have to explain why.

2. ***Regulators should require utilities to measure and report on the accuracy of their past forecasts. Where a past forecast turned out wrong, the utility should identify and explain the reasons.*** To what extent were errors the result of (1) wrong assumptions for specific predictors of price, (2) model estimation errors, or (3) other factors? The wisdom of applying the same model to predict future events partially depends on the model's historical forecasting performance.

3. ***Regulators should require utilities and other parties to submit a range of forecasts rather than a single "best guess" forecast.*** Basing a large investment decision solely on a single-point, "best guess" forecast adds risk unnecessarily. Doing so is a valid decision only when (1) the regulator places a high degree of confidence in single-point forecasts, and (2) the consequences of an incorrect price forecast are small. This situation is analogous to a person choosing a financial asset with the highest expected return—say, stock in a high-tech company—without considering its risk relative to other assets. Most people would decide not to allocate all of their investments to this high-return, high-risk asset. They would tend to diversify their investment portfolios to balance the tradeoff between return and risk.

4. ***Regulators should require utilities to forecast the risks associated with the price forecasts.*** A range of forecasts or scenarios can help utilities and regulators quantify and then evaluate the risks associated with individual decisions, related to electric generation planning, energy efficiency, or other matters. The regulator can then judge whether these risks are intolerable. Possible risks require us to ask: Are the possible losses from a particular decision large enough to disqualify that decision from further consideration?

The appendix contains a list of questions that regulators can ask their utilities. Regulators can use these questions to make more informed decisions that could involve hundreds of millions of dollars.

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Looking Before Leaping:
Are Your Utility's Gas Price Forecasts Accurate?

Forecasting is like driving a car blindfolded while following directions given by someone who is looking out of the back window.

Anonymous

When making important decisions, state public utility commissions frequently must choose among competing natural gas price forecasts submitted by the parties. Forecasts vary in quality and credibility. With billions in ratepayer dollars at stake, regulators need to know the difference. Regulators also need to know the reasonable range of forecasts and the risks associated with individual decisions. The risks of actions involving large sums of dollars can trigger different regulatory decisions.

Gas price forecasters face multiple uncertainties, including (1) uncertainties over the time frame of the current economic recovery and long-term economic growth, (2) the emerging but still uncertain future supply of shale gas, (3) liquefied natural gas (LNG) market developments, (4) carbon dioxide regulation, (5) demand for new electric generation, and (6) uncertainties over the effectiveness of energy-efficiency initiatives. The totality of these uncertainties speaks to the high unreliability of any natural gas price forecast.

Reliable forecasts require an underlying framework that quantitatively relates price to different predictors. This relationship must coincide with historical patterns and economic theory. Economic theory tells us that prices are inversely related to supply and directly related to demand. If the demand for natural gas by electric generators increases, we should expect prices to increase. An optimistic assessment of future domestic supply should have a downward effect on future natural gas prices. This paper illustrates the questions and issues associated with forecasting natural gas prices from an econometric model.

This paper recommends that state public utility commissions ("PUCs" or "regulators") require utilities and other parties to submit a reasonable range of forecasts to justify their positions. Basing a large investment decision solely on the "best guess" forecast, or the future deemed most likely to occur, can result in substantially higher costs relative to the best action determined *ex post facto* with actual prices. In other words, a risk decision can result from an action based only on the information provided by a "best guess" price forecast without considering other possible futures and their implications for the preferred decision.

A range of forecasts or scenarios can help utilities and regulators quantify and then evaluate the risks associated with individual decisions, related to electric generation planning, energy efficiency, or other matters, then judge whether these risks are intolerable. Uncertainty requires us to ask: Are the possible losses from a particular decision large enough to disqualify that decision from further consideration? A later section of this paper illustrates with a numerical example the risks or losses associated with choosing one forecast when the future turns out differently.

I. Regulators Rely on Natural Gas Price Forecasts to Make Major Decisions

Natural gas prices are critical to a range of regulatory decisions covering both electric and gas utilities. In organized wholesale electricity markets, natural gas prices frequently drive market prices and thus the value of all generating facilities (and their cost to consumers). Natural gas prices are also often a crucial variable in electric generation capacity planning and in analyzing the benefit-cost relationship for demand-side and energy-efficiency programs. High natural gas prices, for example, can make coal generation the most economical new source, while low prices can make natural gas generation most economical. For gas utilities, future natural gas prices affect the benefits of energy efficiency, the level and nature of hedging, and the need for new utility infrastructure. Natural gas prices can also affect decisions about how to control carbon dioxide emissions.

A list of how natural gas prices affect areas of interest to regulators, utilities, and other stakeholders follows. (The parentheses contain the time horizons of the relevant forecast. The wide range shows the relevance of natural gas price forecasts for both short- and long-term decisions.)

1. **The relative economics of renewable energy, nuclear power, and coal-fired generation (20-30 years):** The economics of new gas-fired generation and economic dispatch, relative to alternative resources, depend on future natural gas prices. The uncertainty of forecasts also affects the benefits placed on fuel and technology diversity. A primary rationale for diversity is that the benefits of having a more diversified portfolio (which could include both self-generation and power purchases) hedge against price, fuel supply, electric reliability, and government risks.

2. **Price forecasts in organized wholesale electric markets (1-30 years):** In some organized markets, such as the New England Power Pool (NEPOOL) and the Electric Reliability Council of Texas (ERCOT), gas-fired plants in most periods set the market price.[1] By affecting wholesale electricity prices, natural gas prices play an important role in the economics of mergers and buyouts that involve electric generating units.[2]

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[1] That is, gas-fired plants are the marginal source of generation whose cost of operation tends to determine the price of wholesale power.

[2] *See*, for example, Jenny Anderson and Julie Creswell, "Power Players, Unplugged," *New York Times*, February 28, 2010, BU 1. A lower expected price for natural gas, for example, would lower the future earnings from coal-fired and nuclear plants. Lower earnings translate into a lower future economic value for these plants.

3. **Cost-benefit of energy-efficiency measures (10-15 years):** The gross benefits of gas utility energy-efficiency initiatives are proportional to natural gas prices, which represent avoided costs to the utility. Marginal energy-efficiency initiatives that avoid high natural gas prices are no longer cost-beneficial at lower prices. The recent development of gas shale and its likely downward effect on future natural gas prices might make some energy-efficiency actions less tenable (e.g., those energy-efficiency initiatives with a benefit-cost ratio of 1.1 at a natural gas price of $7 would have a ratio of less than one when gas prices fall below $6).

4. **Energy burden on low-income households (1-5 years):** Higher prices mean less affordability of natural gas, which in turn translates into a greater need for energy assistance to low-income households. If the expectation is that natural gas prices will increase dramatically over the next few years, regulators and utilities might consider action today to assist low-income households in the future.

5. **The economics of gas-fired generation (20-30 years):** Prices affect operating costs, which are a major part of the total costs for gas-fired plants. Both regulated and unregulated electric generators might consider natural gas as a possible fuel source for new generating capacity. The difficulties in forecasting natural gas prices in addition to their inherent price volatility make gas-fired facilities less economically attractive. Natural gas prices can also affect the cost of controlling carbon dioxide in a regulated environment. This cost, in turn, is an important determinant of the relative economic attractiveness of different generation technologies.

6. **The need for new gas-utility investments (10-30 years):** Storage facilities become more valuable as price volatility and future prices increase, and the need for new distribution pipes depends on future peak demands, which in turn depend upon future gas prices. Gas utilities use storage to buy gas during periods of low prices so that they can avoid buying gas during the winter months when prices can rise dramatically.

7. **Hedging activities (1-5 years):** The level of future price volatility affects the benefits of hedging for a utility and its customers. The magnitude of price volatility also affects how a utility carries out hedging.[3]

8. **Natural gas demand forecasts (1-2 years, 20-30 years):** Future test-year sales, often an issue in rate cases, hinge on natural gas prices; longer-term demand forecasts also depend on natural gas prices. Some gas consumers, especially industrial firms, have some ability to shift away from higher-priced fuels when price expectations suggest that such switching can provide large long-term savings.

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[3] *See*, for example, Michael Gettings, "Prudence Standards for Utility Hedging," presentation at the NARUC Winter Committee Meetings, February 15, 2010, at http://www.naruc.org.

9. **Electricity demand forecasts (20-30 years):** Electricity and gas are substitutes for various end uses. The relative prices of natural gas and electricity are major drivers of changes in energy choices over time, and among and between regions in the U.S.

II. A Prologue to the Following Sections

A. Two definitions of "forecast"

This paper uses the term "forecast" to encompass both (1) the future outcome that is most likely to occur (i.e., the "best guess" or single-point forecast) and (2) a future outcome that is less likely to happen, based on an alternative set of assumptions on predictors of price such as economic conditions, the demand for natural gas and electricity, and the growth of renewable energy. Some analysts refer to "best guess" forecasts as reference forecasts when they reflect the future with the highest probability of occurrence.[4] They might alternatively define the outcomes in (2) as "projections," or outcomes conditioned on assumptions or "what if" scenarios. The "best guess" forecast is based on a set of events that the forecaster expects will occur, or *considers more likely to occur than other events*. If you had to choose a single forecast with a bet of $100 on the line, what would it be? It would presumably be the "best guess" forecast, since it is assumed that the payoff would go to the person whose forecast lies closest to the actual outcome.

B. The nature of natural gas prices in the spot, contract, and futures markets

Both electric and gas utilities buy natural gas in the spot market. Well-developed day-ahead and monthly spot markets for natural gas have thrived since the early 1990s. The U.S. has several spot markets with a large number of sellers and buyers transacting natural gas and other services.[5] A spot market usually has several pipeline interconnections. Many utilities, consultants, and other entities such as the U.S. Energy Information Administration (EIA) attempt to forecast the Henry Hub price.[6] An individual utility who buys natural gas from the local spot

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[4] This paper considers so-called "business-as-usual" projections as forecasts, but not "best guess" forecasts, since they assume a static world that, in most circumstances, is unrepresentative of the most likely future.

[5] Spot markets have low transaction costs. The spot market for natural gas is a highly integrated one, especially between the East Coast and central regions. Co-integration of regional prices confirms what economists call the "law of one price." This law refers to the high correlation of prices across regions. Analysts can apply statistical techniques to test the hypothesis of co-integration. With co-integration, arbitrage is effectively working to narrow regional price differences. Co-integration also means that transportation and transaction costs largely explain regional price differences.

[6] Henry Hub is a pipeline interchange located in Louisiana that serves as the delivery point of natural gas futures contracts. It is the most active gas hub in North America, with access to major onshore and offshore gas producers.

market then adjusts the Henry Hub forecast for "basis."[7] Utilities look at historical differences to estimate basis, which when added to (or subtracted from) the Henry Hub price forecast, equals the price paid at the local delivery point.

The spot price of gas depends on factors such as production cost, storage levels, economic conditions, weather, total demand, pipeline capacity, and random shocks (e.g., events in the Middle East affecting oil prices). These factors themselves are difficult to predict, aggravating the uncertainty of natural gas prices. Natural gas prices over the next two years, according to most experts, will depend largely on the timing and strength of the country's economic recovery, the effectiveness of energy-efficiency initiatives, the competitiveness of natural gas for electricity generation, and the availability of LNG and shale gas at prevailing market prices. All of these factors are difficult to predict, making any natural-gas price forecasts susceptible to error.

Most industry experts consider natural gas a commodity whose price exhibits high volatility and close correlation with fluctuations in consumption and supply. Even if a utility buys all of its physical gas supply in the volatile spot market, it can still stabilize the price charged to customers by purchasing financial derivatives, such as futures contracts and swaps. A large number of gas utilities, for example, purchase futures contracts to cover future months' requirements and to fix their purchase price. When the month for which the utility requires physical gas approaches, it will sell its futures contract and purchase physical gas. As the two transactions occur almost simultaneously, their prices cancel each other (with an adjustment for what the gas industry calls "basis" to account for the difference in the spot prices at the Henry Hub and the local delivery point). The result is that customers pay the original price of the futures contract for the physical gas they purchase from the utility.

Many analysts consider NYMEX futures prices to be unbiased forecasts of Henry Hub spot prices; they regard prices discovered at futures exchanges as today's best estimate of tomorrow's cash market prices for standardized quantities of commodities such as natural gas. Futures prices are good only as a short-term forecast; the vast majority of NYMEX contracts settle within the following twelve months. The historical pattern of natural gas futures prices exhibits high volatility, even on a month-to-month basis.

Gas utilities and other buyers also purchase natural gas under contracts for different durations. What price they pay for contract gas, and its relationship to the spot price, depends on the relative price-risk aversion of the seller and buyer. If a buyer exhibits more risk aversion than a seller, the buyer would tend to pay more than the spot price to reduce price uncertainty. A buyer who operates in a non-liquid spot market, where extremely high prices can occur, might also pay a premium for contracted gas to protect against the possibility of regional supply shortages and other events.

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[7] Basis is the difference between the quoted futures price for a specific delivery month and the cash or spot price at the local market. For storable commodities such as natural gas, the basis reflects both carrying charges and transportation costs.

C. Many factors affect natural gas prices

More factors come into play when forecasting natural gas prices, especially when looking several years into the future (*see* Table 1). Major natural-gas price uncertainties over the next twenty years include (1) the completion of the Alaskan gas pipeline, (2) gas production in offshore areas historically closed for exploration and drilling, (3) the development of shale gas, and (4) the integration of the U.S. gas market with the world market through LNG imports and exports. Regulators, therefore, face a tough challenge in making decisions based on forecasts, especially long-term forecasts.[8] Investments with long lives, such as new and replacement infrastructure or energy-efficiency hardware, require long-term forecasts. One useful piece of information would be the ranking of the "uncertainty" factors in accordance with their relative effects on future natural gas prices. Sound modeling methods together with good historical data can provide quantitative estimates of these effects. Regulators should require utilities to consider how the major factors affect natural gas prices. Utilities should document the assumptions made for each factor (e.g., electricity consumption will grow 2 percent annually) and the uncertainty underlying each one as well as the assumed combination of factors. This information will help to provide regulators with a reasonable range of natural gas price forecasts.

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[8] In examining its past long-term projections for the *Annual Energy Outlook*, the EIA concluded that:

> The fuel with the largest difference between the projections and actual data has generally been natural gas. As regulatory reforms that increased the role of competitive markets were implemented in the mid-1980s, the behavior of natural gas was especially difficult to predict. The technological improvement expectations embedded in early *AEO*s proved conservative and advances that made petroleum and natural gas less costly to produce were missed. After natural gas curtailments that artificially constrained natural gas use were eased in the mid-1980s, natural gas was an increasingly attractive fuel source, particularly for electricity generation and industrial uses. Historically, natural gas price instability was strongly influenced by natural gas resource estimates, which steadily rose, and by the world oil price. (*See* U.S. Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of Projections in Past Editions (1982-2008)*, September 2008, 2.)

Table 1. Factors Affecting Natural Gas Prices

• Growth of domestic shale gas and other gas production	• Growth of renewable generation
• Supply and demand price elasticities	• Growth in industrial activity
• Level of LNG imports	• Carbon dioxide regulations
• Construction of new pipeline infrastructure accessing areas of new or increased production	• Commercialization of clean coal
• Growth of the U.S. and world economies	• Prices of other energy sources and effect on natural gas consumption
• Availability of adequate storage capacity	• Offshore/onshore gas drilling restrictions
• Growth in electricity consumption	• Level of financial speculation and effect on natural gas price
• Energy-efficiency measures	• Growth of nuclear power

III. How Can Regulators Distinguish between Reliable and Unreliable Forecasts?

A. Illustrating with an econometric model what constitutes a sound analytical framework

Accurate forecasts require an analytical framework with good predictive capability. These models can include time series models that produce price forecasts based on past values of price;[9] econometric models that relate energy prices to variables (i.e., predictors) that explain movements in price over time or differences in prices across geographical areas; or gas sector equilibrium models that predict price at the level where demand equals supply.[10] The last two models have the advantage of quantifying the effects of different assumptions on a forecast. They can help identify the major predictors of price, which might include not-so-obvious factors such as electricity load growth and the development of nuclear power and other non-gas sources of electricity generation.[11]

Models serve two major purposes: (1) forecasting natural gas prices and (2) quantifying the effects of different assumptions on natural gas prices. If one were interested in only a single-point forecast, the second purpose would become less relevant. But, as this paper emphasizes, utilities should develop a range of forecasts, which then gives importance to understanding the

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[9] Statisticians refer to these models as autoregressive models. In an autoregressive process, price in the current period represents a weighted average of past price observations going back several periods, plus a random disturbance in the current period. *See*, for example, Robert S. Pindyck and Daniel L. Rubinfeld, *Econometric Models and Economic Forecasts* (New York: McGraw-Hill Book Company, 1976), 458.

[10] An equilibrium model that encompasses different sectors would forecast natural gas prices based on market clearing conditions for all the sectors. In other words, the model would simulate endogenously the price, demand, and supply for non-gas sectors. An important advantage of an equilibrium model is that it attempts to achieve consistency between the different sectors. One such model is the National Energy Modeling System (NEMS), which the U.S. Energy Information Administration and other groups use to make mid- and long-term projections. As described by the energy agency on its website (http://www.eia.doe.gov):

> The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. energy markets… NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.

[11] Electricity load growth, for example, affects the level of generation from different power plants, including gas-fired plants.

effects of different assumptions on future natural gas prices. Regulators might like to know, for example, the effect on natural gas prices if economic growth is 3 percent instead of 4 percent, or if shale gas development falls below current expectations, or if pipeline projects are completed or not.

1. A simplified model

In econometric or other quantitative models, the analyst must apply reasonable assumptions to the major predictors of price. Economic growth, natural gas demand growth, and the nature and timing of greenhouse gas legislation are three examples of important predictors of price that require much judgment in measuring.

Forecasting means estimating the future, or predicting. Econometric models are widely used in all private-industry and government contexts to predict the quantitative values of certain variables in future periods.

The following expresses a general single-equation econometric model for forecasting natural gas prices:[12]

$$P_{ng} = a_o + b_1X_1 + b_2X_2 + b_3X_3 + \ldots + b_nX_n + u_t,$$

where the price of natural gas (P_{ng}) is a function of different variables (or predictors), X_1 through X_n, and a constant term (a_o); the "*b*" coefficients estimate the per-unit change in a predictor on price, holding the other predictors constant; and u_t is the error term.

The accuracy of forecasts using the above model requires several conditions. One condition is the ability of model to specify all major variables that affect price. By leaving out relevant variables, the model is unable to produce an unbiased forecast of price. The second condition is the estimation of unbiased "*b*" coefficients, which requires certain assumptions. One assumption is that a one-way causal relationship exists between price and the predictors. If Gross Domestic Product (GDP), for example, is a predictor of price, then price cannot be a predictor of GDP. If price affects GDP, then the model would need to include at least one additional equation to account for this simultaneous cause-and-effect relationship. The third condition is accurate historical data for estimating the parameters in the model. The absence of good data precludes any possibility of producing reliable forecasts.

A forecaster often adjusts the output of models to account for factors not subject to quantification. She will review the reasonableness of forecasts from a model. She might decide that the model provides less-than-satisfactory information. She would then consider whether to adjust the forecast and, if so, by how much. Decisionmakers might use modeling results as only one piece of information for forecasting important variables. Models may have a poor track

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[12] For a more detailed description of the econometric method, *see* Evgenia Shumilkina, *Utility Performance: How Can Commissions Evaluate It Using Indexing, Econometrics, and Date Envelopment Analysis?* NRRI 10-05, March 2010, pp. 9-17, at http://nrri.org/pubs/multiutility/NRRI_utility_performance_mar10-05.pdf.

record of forecasting, or factors considered important may not be quantifiable. Decisionmakers commonly make adjustments even to complex and sophisticated models.

Regulators should also require utilities to compare their forecasts with other forecasts derived by government agencies or private entities. A comparison can help regulators gauge the reasonableness of a utility's forecast, and where it lies relative to other forecasts. Since natural gas price forecasts do vary substantially, it is important that utilities do a comparison and present this information to the regulator. If a utility's forecast is an abnormality, the utility should then have the burden to explain why its forecast differs so much from other forecasts.

2. What can cause inaccurate forecasts?

Regulators should consider at least six potentially serious problems that can plague forecasts from econometric models:

1. A model could identify several predictors, but some of them may add little to the model's forecasting capability. Extraneous predictors can actually weaken the statistical properties of a model, thereby reducing confidence in the model output.

2. The predictors may have similar characteristics, which can lead to what econometricians call multicollinearity. This problem can make it difficult to interpret the "*b*" coefficients for the correlated variables, since they assume independency between the variables. This problem can distort estimates of the effect of changes in individual predictors on price, thereby diminishing the capability of the model to conduct sensitivity analysis. The model, for example, might estimate that the short-run price elasticity of demand is -0.3 when the actual number is much different. Such a result can make the model less suitable for sensitivity or scenario analysis.

3. The model may omit important predictors. Some of the predictors may not be quantifiable or the underlying theory of the model may be incorrect. This problem may produce poor statistical properties for the "*b*" estimates. The degree of market speculation, for example, can be a crucial predictor that a model leaves out. The result is less accurate forecasts.

4. The values for the predictors themselves might depend on the forecasted variable (e.g., total natural gas demand, which is a predictor of price, is itself a function of price). This simultaneity relationship may require a multi-equation model to avoid biased forecasts and other problems. The model should specify a two-way relationship between variables when the relationship is statistically significant. Again, when the model lacks this feature it can produce less accurate forecasts.

5. The modeler faces difficulties in determining values for the predictors. These predictors are forecasted values themselves subject to assumptions regarding a number of factors; economic growth, for example, depends on technological improvements, productivity growth, and population growth. With incorrect values for the predictors, the regulator should place less confidence in the price forecast.

6. The estimated relationships between predictors and the forecasted variable using historical data may not hold for future periods. An estimated model may have good statistical properties from applying historical data, but perform poorly in forecasting. One possible explanation is that a structural change in the natural gas market could make the historical relationships between price and predictors irrelevant for predicting the future. One example involves greater future availability of cost-effective energy-efficiency hardware, which should make consumers more responsive to increased prices in the future than historically.

Even with the best effort and resources, forecasts are never going to be 100 percent accurate; they may not even be accurate enough to help in making better decisions. In some instances they might provide decisionmakers with misleading information. Regulators should expect utilities, however, to derive the best possible "best guess" forecast. This forecast can represent the midpoint between what the utility deems to be the reasonable highest and lowest forecasts. These forecasts, in other words, are the extreme ends of forecasts that the utility should consider.

B. Utilities should document their forecasts

In presenting its forecast, a utility should file sufficient documentation to permit a thorough review by the regulator and stakeholders of the forecasting methodology, data sources, assumptions for the predictors, and the past forecasting record of the utility. Only then can the regulator test the validity of the forecast.

In the previous discussion of the econometric method for forecasting, the utility should provide the regulator with different information. First, the utility should explain the theoretical construct of the model: what were the reasons for choosing the predictors specified in the model? Why the utility chose a linear, quadratic or other functional form for the model? Second, the utility should provide the entire data used in estimating the model. Regulatory staff may want to replicate the results—it could only do so by re-estimating the model with the actual data used by the utility. Third, the utility should document the statistical procedures used and their rationales. Fourth, the utility should document the underlying assumptions of the predictors use in the model. What did the utility assume, for example, about economic growth, sources of new gas supplies and new gas-fired generating capacity? Finally, the utility should demonstrate the forecasting ability of its model. How well did the model forecast past prices assuming that the utility knew the values of the predictors? In this example, any forecasting error would result from how the utility specified and estimated the model, rather than from making wrong assumptions about the predictors.

C. Measuring past forecasting errors and identifying their causes

Regulators should require utilities to measure the accuracy of their past forecasts. If a utility applied a model to derive these forecasts, it should pinpoint the causes of forecast errors. To what extent were errors the result of (1) wrong assumptions for specific predictors of price or (2) model estimation errors? The validity of applying the same model to predict future events partially depends on the model's historical forecasting performance.

One simple measure of forecasting accuracy *ex post facto* is to compare the actual prices with the forecasted price. This is expressed mathematically as:

$$E_t = P_t^a - P_t^e$$

where E is the forecast error for period t, P^a is the actual price for period t, and P^e is the price forecast for period t. Variants of this measure express the error in percentage terms or as a root mean square error over several periods. Forecast errors measured with historical data provide an indicator of a model's past performance. They can offer a guide to the model's future forecasting performance; but often they will understate the error because of market and other dynamics that could jeopardize the forecasting accuracy of the model for future periods.

When outcomes vary from forecasts, regulators must be able to distinguish between two causes: faulty forecasts, and unexpected events that a prudent forecast could not have accounted for. The objective should be to minimize forecast error by producing the best possible forecast—for example, producing unbiased forecasts from an econometric model. Regulators should require utilities to produce forecasts with sound methods and verifiable data given the knowledge they have, and are expected to have, about the future. This standard, for example, requires that utilities use generally acceptable statistical and modeling techniques. If utilities do not meet this standard, regulators should question their prudence.

Forecasting errors can result from mistaken assumptions and the wrong theory. The wrong theory might result in model misspecification with important predictors left out and minor predictors included. The underlying theory might predict that natural gas prices depend solely on physical demand and supply factors. If, in fact, financial speculation plays an important role in affecting prices, application of this theory could produce biased forecasts that would systematically over- or under-forecast natural gas prices for specific future periods.[13]

D. A word about outside forecasts

Utilities should subscribe to outside forecasting services if they lack the expertise and resources to generate internal forecasts. Some utilities use forecasts from a number of sources to better evaluate the range of likely future natural gas prices. Internal forecasting can absorb substantial resources; besides, a utility might feel that its regulator and other parties would perceive any internal forecast as biased in favor of its own interests.

[13] Studies present contrasting views and evidence of the relationship between financial speculation and commodity prices. Some analysts contend that financial speculation has at most a transitory and weak effect on prices; other analysts believe that the effect is longer-term and robust. *See*, for example, Ken Costello, *Speculation in the Natural Gas Market: What It Is and What It Isn't; When It's Good and When It's Bad*, NRRI Paper 08-10, November 2008.

Regulators need to subject outside forecasts produced by reputable firms to the same scrutiny they would apply to a utility-produced forecast. Regulators cannot take for granted that a forecast produced by an outside firm is sound and objective. The firm might have a reputation for producing results that favor a utility or other clients' positions in regulatory and other venues.

IV. Regulators Have Different Options

A. Rely only on the "best guess" forecast

The regulator has options in using the information on future natural gas prices provided by the utility. First, it could approve the utility action based on the single-point price forecast—for example, the "best guess" price of natural gas is $7, so the decision is contingent only on this price. This is a valid decision, however, only when (1) the regulator places a high degree of confidence in single-point forecasts, and (2) the consequences of incorrectly forecasting price within a large range are minimal (e.g., the preferred decision does not depend upon whether natural gas prices are $4 or $9).

This situation is analogous to a person choosing a financial asset with the highest expected return—say, stock in a high-tech company—without considering its risk relative to other assets. Most people would decide not to allocate all of their investments to this high-return, high-risk asset. They would tend to diversify their investment portfolios to balance the tradeoff between return and risk. For financial assets, diversification implies an objective other than merely maximizing expected return or minimizing risk. Diversification usually means managing risk at a cost acceptable to the decisionmaker given the degree and nature of her risk adversity. Modern portfolio theory takes into account the risk inherent in various types of financial and physical assets and develops methods for combining investments to maximize the tradeoff between risk and return.[14] As an example, selecting a specific generation technology, or group of technologies, may stem from its lower risks relative to other technologies, even if these other technologies have lower expected levelized costs.

Sometimes a utility will contend that its recommended decision is based on what it calls conservative forecasts. It might argue, for example, that its "best guess" forecast of natural gas prices is $7, which supports spending money on energy efficiency. It might go on to say: "If you don't believe that prices will be $7, we can show that energy efficiency is still cost-effective with prices as low as $6." The purpose of this exercise by the utility is to defuse any notion that the underlying support for its recommendation stems from biased forecasts. The utility is bolstering its case by arguing that, even if its "best guess" forecast is questionable, its proposal is still the right choice—up to a point. In this example, the utility ignores the possibility that natural gas prices can be $5 or even $4. Prices this low can change the economics of energy efficiency. A regulator should inquire whether energy efficiency is no longer cost-effective at these prices and, if possible, about the likelihood that prices could go this low.

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[14] The seminal paper on modern portfolio theory is Harry Markowitz, "Portfolio Theory," *The Journal of Finance* 7 (March 1952): 77-91.

B. Apply a range of forecasts and conduct sensitivity analysis

As a second choice, the regulator could approve the utility action based on a range of price forecasts. It could, for example, review several forecasts from credible sources to select high, medium, and low price forecasts that represent reasonable pricing possibilities. The evidence might show, for example, that price forecasts within the range of $6 to $9 result in the same preferred decision (e.g., spend $50 million on energy efficiency). This sensitivity analysis makes the decisionmaker more confident that the action taken will carry little risk, unless it assigns a non-trivial probability to prices beyond this range. (The risk would be the opportunity cost of making a particular decision when another decision would have produced a better outcome after the fact.) Analysts consider such actions to be robust or preferred under a wide range of conditions. Robustness means that regulators could demand less precision from a "best guess" forecast.

C. Use only the statistically expected forecast

A third choice for the regulator is to approve the utility action based only on the statistically expected price forecast. Such a forecast is equivalent to the probability-weighted sum of possible prices. The expected value in the statistical sense differs from the "best guess" or most probable value. It reflects an average price calculated over different possible future states. The probability of natural gas prices being $6, $7, and $8, for example, is 0.3, 0.5 and 0.2, respectively; thus, the expected price is $6.90. Unlike the "best guess" price, the expected price as calculated here takes into account the possibility that price can take on different values. It also assigns greater importance to those forecasts with the highest probabilities of occurrence.[15]

The problem with these forecasts lies with trying to estimate the probabilities of specific outcomes. The probability of the natural gas price being $8 depends upon several factors such as natural gas demand and supply, governmental policies, and economic growth. These conditions, in addition, have to be consistent with each other—for example, a high natural-gas demand future would likely require a high degree of economic growth or legislation favoring the use of natural gas, or both. This correlation between the different factors complicates any reasonably accurate calculation of a probability for a particular price future.

D. Measure the losses from wrong forecasts

Finally, the regulator could approve the utility action after considering the cost of making the wrong decision based on erroneous price forecasts (i.e., the loss function). The building of a gas-fired plant based on a gas price of $6, for example, could cost the utility an additional $50 million a year compared with building a coal plant when the actual price of gas turns out to be $9. The regulator might want the utility to "hedge" its plan to moderate the cost (i.e., loss) from

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[15] In this example, the "best guess" price would be $7, which lies close to the $6.90. The decisionmaker ostensibly would make the same choice using either the "best guess" price forecast or the expected price forecast. In other instances, the two forecasts may deviate enough to result in a different decision.

mis-forecasting price and other variables instrumental to an action; the regulator, for example, might want the utility to take a wait-and-see posture as it accumulates more information to improve its forecasting accuracy before spending substantial sums on a particular action. To the extent that waiting reduces price uncertainty, the utility may reap an "option value" from an investment delay stemming from this uncertainty.[16] By waiting two years to make a major decision that depends on future natural gas prices, for example, the utility could know more about the status of shale gas and carbon dioxide regulations.[17]

In sum, regulators must make decisions in an environment where future natural gas prices are uncertain and the preferred utility action depends upon non-quantifiable information. Notwithstanding these obstacles, regulators can demand that utilities submit a range of forecasts along with information on the risks associated with individual decisions that rely on those forecasts.

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[16] For a discussion of option theory and its application, see Lenos Trigeorgis, *Real Options: Managerial Flexibility and Strategy in Resource Allocation* (Cambridge, MA: The MIT Press, 1996); and *The Quarterly Review of Economics and Finance*, 38, Special Issue, 1998.

[17] Other factors, however, could arise in the meantime that would make uncertainty even greater than before.

V. The Rationales for a Reasonable Range of Forecasts and Possible Losses from Individual Decisions

A. Future natural gas prices have high uncertainty

Natural gas prices have exhibited wide fluctuations since the beginning of this century, with particularly pronounced price variability during certain sub-periods such as the middle of 2008 to the present. Partially because of the weak short-run response of gas supply and demand to price changes, even moderate changes in market conditions can produce large fluctuations in price. This tendency was evident during 2008, when prices rose sharply early in the year and then fell almost as sharply starting around early summer. A number of industry observers blame speculation in financial derivatives by noncommercial market participants (e.g., hedge funds, pension funds, and other institutional investors) for the volatility and rise in natural gas prices. The evidence seems to favor the belief that financial speculation has aggravated price volatility, with no agreement as to the magnitude.

The uncertainty of natural gas prices gives support to regulators looking at a range of possible future prices, rather than focusing only on the most probable future price. In other words, regulators should not put all of their faith in one forecast even if that forecast is superior to all other single-point forecasts.

B. Three dimensions to price uncertainty and utility decisionmaking

Uncertainty in the context of applying natural gas price forecasts to utility decisions has three dimensions. The first is not knowing the future price. Almost without exception, analysts cannot even assign an accurate probability to different price futures. They might be able to say that one price future or a range of price futures is more likely than others, but trying to quantify the probabilities with tolerable accuracy is beyond the realm of reason.

The second dimension of uncertainty is not knowing all the factors that affect prices and to what degree they affect price. How much do physical demand and supply conditions affect price, for example, relative to financial speculation? If long-term economic growth is 3 percent per annum instead of 4 percent, how would that affect natural gas prices? How would slower growth in electricity consumption directly affect the demand for gas-fired generation and, indirectly, the price of natural gas?

The third dimension of uncertainty relates to not knowing the consequences of an action when the natural gas price can take on a range of values. If, for example, a gas utility decides to spend $50 million on energy efficiency based on a future price of $7, what would be the opportunity cost if the actual price is $6? The opportunity cost here refers to the greater benefits that would result from spending the $50 million or a portion of it on something else. All of these uncertainties are quantifiable at varying levels of accuracy. They are all estimates, however, that hinge on assumptions and statistical methods that are subject to inevitable error.

C. The risk of a preferred utility action

In their review of a range of forecasts, regulators are able to examine whether the preferred utility action is compatible with natural gas prices within the specified range; does the preferred action hold, for example, when natural gas prices are between $6 and $8, or between $5 and $8? The robustness of an action refers to its preferentiality to alternative actions over a wide range of forecasted natural gas prices. A robust action implies little risk in undertaking the action in view of future uncertainties. A utility and its regulator would find it useful to know whether the action taken is most desirable over a range of natural gas prices.[18] The challenge is to derive an appropriate range of prices, which requires quantifying the effects of the major price predictors (e.g., how do different industrial growth rates affect natural gas prices?) and the correlations between the different predictors.

The primary rationale for use of a range of price forecasts is that the future is highly uncertain; thus, any decision carries risk. Most utility and regulatory actions have more than one objective. The intent of a decision is, therefore, not to optimize a single objective (e.g., minimized levelized costs) but rather to strike an appropriate balance between achieving two or more often conflicting objectives (e.g., risk minimization, cost minimization, penetration of new technologies, a clean environment). A major objective presumably is to control risk to a tolerable level.

As an illustration, decisionmakers have to consider the societal consequences of advancing lower-cost electricity by compromising clean air and power system reliability. Decisionmakers face the challenge of specifying objectives for generation capacity expansion and their separate contribution to overall social welfare in the presence of less-than-perfect information. In addition, decisionmakers have to assign values to the advancement of certain objectives relative to others. When they invest in different financial instruments, most people do not choose the instrument with the highest expected return. They look at the returns of different instruments relative to their risks. Their decision ultimately depends also on their risk tolerance. As an analogy, two utilities with the same information on expected returns and risks might not choose the same portfolio of generating units because of dissimilar risk tolerances.

Objectives affect the information that decisionmakers should draw from forecasts. The goal of risk moderation, for example, requires regulators to know the possible range of forecasts and their consequences when making different decisions.

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[18] One utility commented in its plan that:

> To determine how changes in our assumptions impact the costs or characteristics of different resource plans, we examine our plans under a number of scenarios. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we may propose an expansion plan that is less sensitive to assumption changes, but slightly more costly in the baseline scenario. (*See* Xcel Energy, *2007 Resource Plan*, submitted to the Minnesota Public Utilities Commission, December 14, 2007, 4-7.)

D. Specific information that utilities should submit to regulators

What information should accompany natural gas price forecasts and how the utility should use this information depend on the degree of uncertainty and the objective of the utility's action. If the objective is to minimize expected revenue requirements, then to identify the preferred action based only on the "best guess" forecast would suffice. If instead the objective is to minimize the likelihood that revenue requirements will exceed a certain level, the utility should then develop a range of forecasts—for example, plausible scenarios with the midpoint measured as the "best guess" forecast. Scenarios could either span the range of reasonably low and high prices (e.g., prices that assume a high and low demand price elasticity, respectively) or address low-probability outcomes that would result in a much different decision or outcome. The range can indicate to the utility that, for example, if it wants to avoid a high-cost scenario it should not build a gas-fired plant. Such a scenario could occur if natural gas prices are in the range of $8 and higher, which the utility assesses could happen under plausible future events.

Good scenarios require the analyst deliberately to consider the major factors that drive future outcomes. How these factors affect future natural gas prices, for example, demands a quantitative framework such as an econometric model.

Scenario analysis is a tool that planners commonly use to structure the uncertainty (i.e., identify the probability of midpoint and upper and lower "boundary" values or a range of values or input predictive variables), and then examine the robustness of potential outcomes to changes in the underlying assumptions. Would more LNG imports or growth of domestic gas production cause enough changes in natural gas prices to affect the preferred decision? Would the recovery of more shale gas at low cost lead to lower domestic natural gas prices that could make natural gas vehicles and additional new gas-fired generating units economical?

1. Price scenarios

Utilities should present their regulators with a range of plausible prices. As an example, they can point out that "it is highly likely with a 5 percent level of statistical error that actual gas prices will be in the range of $6 and $8 over the period 2020-2025." The first observation is that the actual price will likely lie within the specified range. The decisionmaker, whether the utility or the regulator, can with a high degree of confidence conclude that prices will fall between $6 and $8. The narrower the range of high probability, the more precise the forecast and the more useful the information. If instead the price range is wide, say between $4 and $9, the decisionmaker becomes less certain of what it should do. A price of $4 might mean that energy efficiency is uneconomical, but if the actual price is $9 or even $7, the utility could justify spending $50 million on energy efficiency.

In this example, the utility has three choices: (1) spend nothing on energy efficiency today, (2) spend $50 million today, or (3) spend a portion of the $50 million today. The first decision reflects a highly risk-averse utility who wants to avoid spending money on energy efficiency when it is not cost-effective or a utility that is highly optimistic about the future gas-supply situation. This utility, for example, places great confidence in prices being $4 or at values that could not justify spending money on energy efficiency. Another utility with the same information might decide to spend all of the $50 million today on energy efficiency. The utility might also be risk-averse in the sense that it prefers to spend money on energy efficiency even when it may not be cost-effective. The utility also might believe that actual prices will be on the high side of the range, justifying the spending of the $50 million on energy efficiency. Another utility might "hedge" by spending some of the $50 million today on energy efficiency but want to wait for new information on natural gas prices before committing to spending more.

Rational risk-averse decisionmakers, implicitly if not explicitly, apply what is called a "loss function." This function calculates the cost of a decision conditioned on a single forecast or range of forecasts that turn out to be wrong. Assume that the decision to build a new gas-fired generating plant is contingent on natural gas prices being in the range of $6 to $8. If actual prices were $9, the utility's revenue requirements would be $300 million lower if it chose to build a coal plant instead. The $300 million represents a loss from relying on the wrong forecasts, which is inevitable when dealing with something as dynamic and unpredictable as natural gas prices.

The above example has a parallel to the current global warming debate. Studies have shown that catastrophic consequences can follow if we do not take actions today to reduce greenhouse gases; but this consequence is highly uncertain, so much so that scientists cannot assign probabilities to their likelihood. We may, therefore, spend money today to avoid an outcome that may never occur. The question is: What should we do today? The same question applies when an event is highly unlikely to occur, but will cause a catastrophic outcome if it does. A society, group, or individual that is risk-averse would tend to spend something today, for example buying life insurance, to mitigate possible serious financial consequences in the future.[19]

2. Numerical example of decision options for energy efficiency[20]

Assume that a utility is contemplating an energy-efficiency initiative in which it wants to know what strategy to pursue. The utility is looking at three alternative actions, "low," "moderate," and aggressive," that represent increasing levels of spending on energy efficiency. The utility has also forecasted three future prices for natural gas: $5, $7, and $9. (These prices represent average prices over the next several years corresponding to the lives of the energy-efficiency initiatives.) It assumes different future gas and demand conditions in addition to assuming different values for other price predictors (e.g., economic growth, greenhouse gas

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[19] In the example of gas hedging, a *bona fide* hedger is concerned only with price volatility; she is not concerned with price expectations (akin to auto drivers who purchase auto insurance irrespective of the likelihood of an accident).

[20] Much of this section relied on the conceptual discussion in William Mendenhall and James E. Reinmuth, *Statistics for Management and Economics*, Third Edition (Belmont, CA: Duxbury Press, 1978), 323-333.

legislation). The forecasted prices, when multiplied by the estimated net savings, measure the gross benefits from the energy-efficiency initiatives. Assume that the utility considers the middle price, $7, more likely to occur than the other two prices. It has not explicitly estimated the probability of occurrence for each price.

Table 2 shows the net benefits for each energy-efficiency action for three price forecasts. These benefits derive from a cost-effectiveness test that measures the benefits and costs of the energy-efficiency initiatives. Under the Total Resource Cost (TRC) test, the utility compares the cost savings from producing, transporting, and distributing less electricity or natural gas with both the utility and customer costs for energy efficiency. The difference constitutes net benefits. The reader should note a few things from the table. First, at a price of $5, when the utility moderately or aggressively spends on energy efficiency, some individual initiatives have negative net benefits. In fact, at $5 the net benefits are greatest under a "low" strategy. When the utility spends more at this price, additional initiatives fail to pass the TRC test and thereby produce gross benefits lower than the incremental costs. At a price of $7, the optimal strategy is the "moderate" action. At this price, for example, the utility is forgoing cost-beneficial initiatives by pursuing the "low" action. The "aggressive" action is also suboptimal because the utility is spending additional money on initiatives that do not pass the TRC test. At $9, the "aggressive" action is optimal, as the utility would be forgoing cost-beneficial initiatives under the other two actions.

Table 3 shows the losses from forecasting error. These losses are the difference between the maximum net benefits under each price scenario and the net benefits obtained by selecting a particular action. Under the $5 scenario, Table 2 shows that the preferred action is "low" because it has the highest net benefits. The "3" and "5" in the $5 column in Table 3 represent the losses (i.e., forgone net benefits, sometimes called the "regret") from pursuing the "moderate" and "aggressive" actions, respectively, when the price is $5. The same process applies to calculating the losses for the other price scenarios. Under the $9 scenario, for example, losses occur for both the "low" and "moderate" actions. The utility forgoes $18 million of net benefits when it pursues the "low" action and the price turns out $9.

The calculations in Table 3 show that the largest risk might lie with pursuing the "low" action. This strategy produces the largest sum of losses ($27 million). But in assessing the risk associated with each action, an analyst could assign probabilities to each of the price scenarios, if she can make reasonable estimates.[21] Assume that the probabilities for the three prices are 0.3, 0.4, and 0.3, respectively. These probabilities allow for the calculation of the expected losses for each action. The expected losses for the "low," "moderate," and "aggressive" actions are: $9 million, $3 million, and $3.5 million.[22] Expected losses are the lowest under the "moderate"

[21] But, as argued earlier in the paper, estimated probabilities for different price futures require several assumptions, which themselves contain significant uncertainties. The analyst cannot, therefore, expect to estimate these probabilities with a reasonable degree of accuracy.

[22] Losses from: the "low" action equal $0(0.3) + $9(0.4) + $18 (0.3) = $9 million; the "moderate" action's losses equal $3(0.3) + 0(0.3) + $7(0.3) = $3 million; and the "aggressive" action's losses equal $5(0.3) + $5(0.4) + $0(0.3) = $3.5 million.

strategy. It is also true that the expected net benefits are the highest under this same strategy. It is likewise true that the "moderate" action is preferred under the "best guess" forecast."[23] Overall, it appears that the utility should pursue the "moderate" action, given that it has both the lowest risk and the highest expected "payoff." But, the preferred "moderate" action is not robust in the sense that at $5 and $9 it represents the best choice. If we know today that price will be $5, the "low" strategy is the preferred option;[24] at $9, the preferred option is the "aggressive" strategy.[25]

In other situations with different net benefit calculations, the utility might face a conflict between minimizing risk and maximizing the expected "payoff." The utility, along with its regulator, will then have to balance this tradeoff to achieve a preferred outcome.

Whether the utility would take the "moderate" route depends on its risk adversity and the regulatory policy on cost recovery. The utility, for example, might fear that a pro-energy-efficiency commission might penalize it for not taking the most aggressive action if the actual price turns out to be $9 or above. Another utility operating in a state whose commission is skeptical toward energy efficiency might want to pursue the "low" strategy even if, from a social perspective, it seems inferior to the other strategies.

E. The relevance of regulatory incentives and option value

How a utility would respond to the information provided in the previous subsection depends in part on the regulatory incentives. If a regulator would be more inclined to penalize a utility for not implementing cost-effective energy efficiency after the fact, the utility may decide to spend aggressively today even if the evidence does not support this decision. A regulator might, on the other hand, tend to penalize a utility for energy efficiency that has a negative net benefit after the fact. This act could motivate the utility not to spend on energy efficiency when the evidence is inconclusive.

A utility that has $50 million today to spend on a particular action, for example, may assign an "option value" to a wait-and-see posture as new developments unfold before deciding whether to spend the $50 million. Option value also comes into play when deciding whether or not to sign a long-term gas contract. A buyer, for example, might hesitate to sign a multi-year contract at a price that can turn out to be much higher than the market or spot price. The buyer might choose not to commit now to a contract but, instead, buy short-term until it is more certain of the future market price.

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[23] The $7 price has a probability of 0.4, which is higher than the probability for any of the other prices.

[24] As Table 3 shows, at a price of $5 the "low" strategy has $3 million higher net benefits than the "moderate" strategy.

[25] As Table 3 shows, at a price of $9 the "aggressive" strategy has $7 million higher net benefits than the "moderate" strategy.

The option value results from the ability to make a better decision when conditions vary from the expectations in earlier periods. The option value increases with the degree of prevailing uncertainty and the length of the time horizon for new investments and other actions. It relates to the opportunity for a utility to reduce the cost of over-commitment to an investment that turns out less well than expected. If a utility is uncertain about future natural gas prices, it might hesitate to commit to investing large amounts of money in new storage capacity. It might instead want to wait for new information that could reduce the uncertainty of future prices. This decrease in the level of uncertainty would in turn reduce the utility's risk in adding to its storage capacity.

Retrospective reviews and regulatory cost-recovery rules affect the risks faced by a utility, thereby directly influencing its actions to best accommodate those risks. Retrospective reviews, for example, may stimulate additional hedging by a utility to avoid future cost disallowances from purchasing natural gas in the spot market and paying an extremely high price of which a regulator would likely disapprove. The outcome of this response by a utility would be higher expected gas costs in the long run (from the additional hedging costs) but lower cost variance. Even if a utility is risk-neutral, it would likely not want to simply minimize expected gas-purchase costs in light of the threat of potential retrospective reviews.

Table 2. Net Benefits from Energy Efficiency for Three Gas Price Forecasts (in 10^6 Dollars)

Natural Gas Price Forecast

Energy-Efficiency Action	**\$5**	**\$7**	**\$9**
Low cost/low effort	15	21	27
Moderate cost/moderate effort	12	30	38
High cost/aggressive effort	10	25	45

Table 3. Losses from Forecast Error (in 10^6 Dollars)

Natural Gas Price Forecast

Energy-Efficiency Action	$5	$7	$9
Low cost/low effort	0	9	18
Moderate cost/moderate effort	3	0	7
High cost/aggressive effort	5	5	0

Appendix: Questions Regulators Should Ask

This paper discusses the major issues regulators face in evaluating forecasts of natural gas prices. Regulators should ask a number of questions. This paper provides answers to some of these questions. The following is a list of the most pertinent questions:

Forecasting techniques and sound forecasts

1. What do we mean by a "sound and objective forecast"?
2. How can regulators know that a utility has submitted a sound and objective forecast?
3. To what extent should forecasts derive strictly from models and statistical techniques?
4. To what extent should decisionmakers make adjustments to forecasts derived from models?
5. What are examples in which poor forecasts have caused bad decisions?
6. To what extent could those decisions have been avoided with better single-point forecasts or ranges of forecasts?
7. What techniques are available for testing the accuracy of past forecasts?

Single-point forecasts

1. What is the definition of a single-point forecast? Can there be more than one definition?
2. What are the risks associated with making a decision based on a single-point forecast?
3. Under what conditions can they be used? When shouldn't they be used?
4. What information is lacking in a single-point forecast?
5. How can this deficient information lead to a bad or excessively risky decision?

Forecasting uncertainty and risk

1. What makes natural-gas price forecasts so uncertain? What can be done to make them more reliable?
2. What are the major risks associated with making decisions with incorrect forecasts?
3. What information is most useful for quantifying the uncertainty of a forecast?

4. What are statistical techniques for quantifying uncertainty?

5. If something is highly unpredictable and crucial for decisionmaking, what action, if any, should a utility take? When should it take that action?

Range of forecasts

1. What is the justification for developing a range of forecasts for decisionmaking?

2. What information should derive from a range of forecasts?

Regulatory objectives and uses of forecasts

1. How do regulatory objectives affect the use of forecasts?

2. What are the objectives of a decision that uses price forecast as an input?