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Hedging Natural Gas Price Risk by Electric Utilities:

A Comparison of Fuel Switching to Financial Contracts

by

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Abstract

Electric utilities making baseload expansion decisions are trying to measure the implications of uncertainty and variability in future natural gas prices, to evaluate different strategies in mitigating these consequences, and to provide an useful tool to communicate these results to their regulators. This thesis attempts to address these objectives in the context of the New England region of the United States. It is primarily directed at regulators and utility managers. The goals of this thesis are not only to provide some insight into these issues, but also to present an accessible tool that is easily implemented. Specifically, the goal is to answer two questions:

> Should electric utilities adopt measures to mitigate the risk of natural gas price increases?
>
> Assuming that some type of hedging strategy should be adopted, should utilities use fuel switching or financial contracts as a means of protecting themselves from natural gas price increases?

A random walk model is constructed to address these questions. The results of the model suggest that electric utilities are not exposed to large fuel risk on a per kilowatt basis, assuming that past estimates of natural gas price volatility are reasonable estimates of future price movements. Moreover, fuel switching strategies, such as building coal plants to diversify away from natural gas, are an expensive option. Financial options, such as fixed price fuel contract, may provide a less expensive solution.

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Chapter 1

Introduction and Motivation

Overview of Thesis and Chapter One

Electric utilities making baseload expansion decisions are trying to measure the implications of uncertainty and variability in future natural gas prices, to evaluate different strategies in mitigating these consequences, and to provide an useful tool to communicate these results to their regulators. This thesis attempts to address these objectives in the context of the New England region of the United States. It is primarily directed at regulators and utility managers. The goals of this thesis is not only to provide some insight into these issues, but also to provide an accessible tool that is easily implemented. Specifically, the goal is to answer two questions:

> Should electric utilities adopt measures to mitigate the risk of natural gas price increases?
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> Assuming that some type of hedging strategy should be adopted, should utilities use fuel switching or financial contracts as a means of protecting themselves from natural gas price increases?

Chapter one serves as introduction and motivation. Chapter two explains why a Monte Carlo simulation is used and describes it in detail. The third chapter reports the results, and chapter four discusses their implications and limitations by placing the conclusions in a policy framework.

This chapter motivates the thesis and consists of two sections. Section one describes the characteristics of natural gas combined cycle plants that make this technology an attractive baseload fuel. This section also documents the national and regional trend towards natural gas use in power generation and presents some drawbacks. The three major disadvantages are price variability, price uncertainty, and supply reliability. The second section explains why a comparison is made between coal and natural gas baseload plants and how this comparison is modeled.

Section One: Attractiveness and Vulnerabilities of Natural Gas Fired Plants

The attractiveness of natural gas as a fuel for electric power generation is well documented (Jaffe and Kalt, p.5.). It has significant lower capital cost, technological, and environmental advantages over other fuels, such as coal, oil, nuclear, hydroelectric, and renewables. Nuclear power is not a viable option in the near or medium term, particularly in New England. Its environmental problems, large costs, and poor public perception prevent this technology from being a power source within the next twenty years (EPRI, 1990, Vol. 1, p. 107 & p. 2). Oil is not considered an appropriate baseload fuel compared to natural gas because it suffers the same price volatility and supply risk as natural gas at a higher total cost while being less environmentally benign. The Northeast has been heavily dependent on oil and contains half of the oil-only capacity for the entire country (EPRI, 1990, Vol. 1, p. 107). Since the first oil shock, the region has attempted to diversify away from this fuel source.

Hydroelectric power is well developed in this region, and a large scale expansion is not feasible. Moreover, hydroelectric power is starting to be viewed not as a renewable, clean fuel supply, but as a power source with environmental consequences. Renewables are not currently a major baseload option in the region because the technology is not sufficiently developed at low enough costs. Solar energy suffers from excessive costs as well as poor New England weather conditions. Although wind power has potential in the region, particularly Maine, it has not proven technologically capable of being a baseload power supply.

The main competitor to natural gas is coal. Coal fired power plants suffer from large capital costs and environmental concerns when compared to natural gas. These environmental concerns also included potentially regulated emissions, such as carbon dioxide. However, coal plants have the advantage of a more stable and lower fuel price. Section two develops this comparison further.

The advantages of natural gas compared to other alternatives are reflected in the strong trend in the use of natural gas fired generation, both by electric utilities and nonutilitiy generators (NUGs) in the United States. The natural gas growth rate will be substantial, potentially doubling new generation usage over the next 15 years (EPRI 1992 p. S-2). As of 1990, gas-fired combined cycle and combustion-turbine units accounted for 44 percent of planned electric utility capacity additions through 2000. Including NUGs, the total new gas-fired capacity is over 50 percent (EPRI 1992 p. S-2&3). Electric utilities are planning to add over 11,000 megawatts (MW) of combined-cycle capacity between the years 1990 and 2000 (EPRI 1992 p.S-4). These plants will be used both as base-load units at capacity factors of 70-80 percent and intermediate electric load (EPRI 1992 p.S-5). Table 1.1 compares the projected shares of generation by fuel type between 1990 and 2010.

Table 1.1: Projected Shares of Generation by Fuel Type: 1990 and 2010

Fuel	1989	2010
Coal	56%	53%
Oil	6%	4%
Natural Gas	10%	17%
Nuclear	19%	14%
Renewable/Other	10%	12%

Source: Energy Information Administration, Electric Power Annual 1989 (p. 15), and Annual Energy Outlook 1992 for 2010 projection. Totals may not add to 100% due to rounding.

This national trend is reflected in the New England. The Analysis Group for Regional Electricity Alternatives (AGREA) at the M.I.T. Energy Laboratory evaluates potential strategies for the region in collaboration with its advisory group, which consists of regulators, utility executives, and environmental and consumer groups. As a result, AGREA studies reflect the interests and concerns of the regional stakeholders in the electric utility arena. Recent reports by the AGREA project team to its advisory panel document the attractiveness of natural gas and the corresponding concern of being overdependent on this fuel (AGREA).

As a specific example, New England Electric System (NEES) published a report stating that in 2010 its energy mix would include almost 60 percent natural gas as a fraction of kilowatthours (KWh) (NEESPLAN 4, p. 18). The report states unequivocally: "History has dramatically demonstrated the price volatility inherent in overdependence on any fuel source (NEESPLAN 4, p. 18)." The report continues, "If we rely exclusively on natural gas, today's fuel of choice, to fill the future unspecified need, we would not have a diverse energy mix....So, while we plan to increase the percentage of natural gas in our energy mix, we are committed to identifying and expanding the range of cost-effective fuel choices available to us (NEESPLAN 4, p. 18)." NEES's fears are well founded: investors view overdependence on natural gas as a risk due to its price volatility and questionable reliability (Jaffe, p. 19).

The assumption behind the desire for a diverse fuel mix is that to hedge natural gas' price movements other fuels must be used. NEES makes this assumption explicit in NEESPLAN 4 by citing their biomass gasification project, their Green Request for Proposal, and advances in clean coal technologies as alternatives to natural gas (NEESPLAN 4, p. 18). However, financial instruments, such as contracts, options, futures, and other derivatives, provide another category of tools that can mitigate price risk. By quantifying the implications of natural gas price movements on power plant expansion decisions, these financial alternatives can be evaluated.

It is important to state clearly what is meant by natural gas price risk, which has two components. One is variance, or the fluctuation of price around a mean. The other is uncertainty, or what the mean will be. These components together will be referred to as volatility. The other perceived drawback of natural gas - its fuel source reliability - is not addressed explicitly in this thesis. Historically, there have been legitimate concerns over receiving natural gas deliveries. For example, the severe weather during the winter of 1976/1977 caused large supply interruptions (EPRI 1991, p. S-1). However, since then the natural gas industry has been deregulated, which has removed the price controls that impacted both production and demand that led to such curtailments. In the most recent cold weather spell (winter of 1993-1994), there were none of the delivery problems experienced in the past, something that the industry has been waiting to see proven (WSJ, 2/8/94).

Besides deregulation, there are other reasons why natural gas reliability does not need to be examined explicitly. The amount of natural gas storage has increased by 1.6 trillion cubic feet (TCF) since 1976, which allows for a buffer supply to ride out cold weather. This increase was a key factor in improving the reliability of the natural gas industry during December 1989's ***double freeze*** (EPRI 1991, p. 3-5). (***Double freeze*** refers to a situation when cold weather increases natural gas demand and hampers production efforts.) There also has been significant construction of natural gas pipelines in the Northeast. TransCanada PipeLines is spending more than $2.3 billion on pipelines with 73% going to the Northeast. An additional $500 million is being spent by the Iroquois Pipeline, again with most of this investment directed at the Northeast's gas markets. This $3 billion plus investment, not including other smaller regional pipeline expansions, is equivalent to more than 2 years of total U.S. pipeline expenditures at recent rates (EPRI 1990, Vol 1, p. 108).

A portion of natural gas delivery risk can be addressed by diversification. Natural gas has two types of delivery risk: random events that do not depend on the weather, and weather related risk. The use of different suppliers and transporters can reduce some of this non-weather risk. Moreover, coal itself has some delivery risk, for instance strikes that interrupt coal delivery, whether they are by coal miners or railroads workers or even cold weather. Of course, the difficulty of storing natural gas on power plant sites compared to that of coal, makes natural gas disruptions a more severe problem. The use of certain types of oil such as distillate as a fuel substitute in the event of natural gas supply disruptions can be viewed as an alternative but expensive way to store natural gas. Natural gas delivery fears can also be addressed by the buyer paying a price premium, whether this premium is for a backup oil reserve or to ensure delivery priority ahead of others (EPRI, 1990, Vol 1, p. 30).

Section Two: Why a Baseload Comparison is Made Between Coal and Natural Gas

Natural gas technologies are compared to coal for several reasons. Since coal is the closest competitor to natural gas as a baseload fuel, particularly in cost and reliability, an analysis of these two fuels provides a measure of natural gas vulnerability to fuel price changes. Second, even if another technology is superior to natural gas, across what ever dimension, this comparison will still be useful because it is what electric utilities in the region are currently evaluating. New England Power Pool (NEPOOL) and New England Power Planning (NEPLAN) in their 1991 ***Summary of the Generation Task Force Long-Range Study Assumptions*** only consider wood and wind as possible renewables and only to a limited degree (NEPLAN 1991).

Finally, coal price volatility is very low compared to natural gas volatility. This means that coal provides a natural comparison to gas because coal does not have the price volatility that natural gas has. Moreover, even if coal had a larger price volatility, its impact on the total cost of producing electricity is small because of the low fuel cost of coal relative to natural gas, and the large capital cost of a coal plant. In the case of renewable energy sources, if they do become more economical compared to coal, then the approach used by this analysis is still valid. Renewables are similar to coal fired technologies: their fuel prices are relatively small compared to their capital costs and their fuel price volatility is tiny compared to natural gas. The only exception to this general characterization is wood fuel power plants.

A baseload comparison between natural gas and coal is modeled for several reasons. As an intermediate (load following) fuel or as a peaking energy supply, natural gas dominates coal. Natural gas generation technologies have the ability to start-up quickly and respond to demand fluctuations, whereas coal technologies do not. The intrinsic disadvantage of natural gas - its fuel price volatility - is less important in a peaking facility, which provides capacity (MW), not energy benefits (KWh) to electric utilities. Moreover, the large difference in capital costs between natural gas fired units and coal more than compensates for the higher fuel costs for intermediate and peaking plants that operate less than baseload units. To analyze natural gas price movements, these price changes are modeled stochasticly. A Monte Carlo simulation is conducted, using past price movement as an indication of future movements.

The selection of specific natural gas and coal technologies to be compared is based on several factors. First, the technologies must meet the Clean Air Act (CAA) requirements for the year 2000. A pulverized coal-fired unit with gas flue desulfurization system is the technology modeled. An advanced coal technologies was not selected because there is little United States experience with these technologies; in fact, the region's planning group, NEPLAN, calls these coal technologies "advanced/unproven" (NEPLAN 1991). An existing natural gas combined cycle is used for the natural gas plant. In any event, if this modeling approach is used by electric utilities, they will incorporate their own assumptions about what power plant fuels and technologies will be competing with natural gas as base load fuel.

The model compares the cost of a natural gas fired plant with a coal plant; the capacity (MW) of the plants are selected in order to provide identical energy benefits (KWh) using each technology's availability factor. The difference in cost after including capital and operating and maintenance (O&M) expenses, depends on the random movement of natural gas prices. The model generates a pre-tax net present cost (NPC) distribution, which can be used to evaluate the price risk associated with natural gas fired plants. This approach is commonly known as risk analysis or risk simulation (Park and Sharp-Bette, Chapter 12). The resulting distribution provides an ***ex ante*** evaluation that building a coal plant will protect a utility from natural gas price risk. Unfortunately, an ***ex post*** evaluation may give a different conclusion. After the coal plant's capital cost, which are both fixed and sunk, are paid for, a utility would rather operate a coal unit than a natural gas fired one due to the difference in variable costs.

This tension between an ***ex post*** and ***ex ante*** evaluation results in a conflict between economic dispatch and long-term gas contracting, which EPRI has identified as the "most important single problem facing the region" in terms of the use of natural gas to fuel power plants (EPRI, 1990, Vol 1, p. 108). Since Northeastern power plants are dispatched regionally, out-year price guarantees cannot be given to power producers by power purchasers. However, these guarantees are instrumental in securing bank financing for pipeline expansions and NUG capacity additions. The implications of the different conclusions that an ***ex post*** and an ***ex ante*** evaluation may give are discussed in chapter four. However, an ***ex ante*** evaluation is an appropriate starting point for examining a capacity expansion decision.

A NPC technique is used instead of a revenue requirement method, which is the industry's traditional approach, for three reasons. First, given the trend towards market deregulation particularly in power generation, NPV analysis is the correct method of evaluating investment alternatives (Brealey & Myers, Chapter 5). The existence of NUGs, which do not operate under cost of service regulations, are a specific example this phenomenon. Secondly, under consistent assumptions, after tax cash flow NPC analysis is equivalent to popular variants of revenue requirement methods (Park & Sharp-Bette, p. 649). Finally, this same Monte Carlo approach can be used with revenue requirement methods. The next chapter justifies using a Monte Carlo model and presents its details.

Chapter 2

Model Justification and Description

Chapter Overview

This chapter justifies and describes in detail the model and assumptions used to analyze natural gas price volatility. It is divided into three sections. Section one articulates the reasons behind selecting a Monte Carlo simulation. It presents evidence that past predictions of natural gas prices have been poor and may be susceptible to bias. Moreover, it describes the limitations of analysis that depends only on deterministic forecasts. The benefits of using a Monte Carlo simulation to model natural gas prices as a random walk are discussed. The second section presents the statistical analysis supporting the use of a random walk. Section three provides a detail listing of the assumptions used in the model, and section four describes how the model is constructed.

Section One: Model Justification

Past Forecasting Errors of Natural Gas Prices

Long range (two years or greater) forecasts are notoriously poor. Mintzberg (1994, p. 229-30) cites a review (Hogarth and Makridakis) of forecasts in the fields of population, economics, energy, transportation, and technology. These fields are "characterized by much experience and expertise in making forecasts as well as readily available data (Hogarth and Makridakis, p. 122)." The reviewers conclude that errors varied between a few to several hundred percentage points and contained systematic biases. Moreover, it could not be determined beforehand which forecasting technique or forecaster would have been right or wrong: choosing a forecast is as difficult as making one.

In particular, past estimates of medium to long term fossil fuel prices have been inaccurate. Comparing predictions of oil prices made during the energy crisis of the early 1970s to actual prices in 1994 suggest that forecasters are prone to error. These large errors have caused one commentator to write, "But the lack of attention to the oil forecasts themselves has led many to overlook the historical record of these expectations, which has been so bad that long-term oil market forecasting has often been described as virtually impossible (Lynch 1992, p. 1)." In the case of natural gas, predicted versus actual discrepancies are large. Table 2.1 presents three forecasts made in 1985 for gas prices in 1990.

Table 2.1 Forecast Error for 1985/90 Period

	Forecast 1990 ($/MMBtu)	Actual 1990 ($/MMBtu)	Error (abs.)
DOE/EIA	3.22	1.70	1.52
GRI	3.60		1.90
DOE/NEPP	3.51		1.81

Source: Lynch & Swanson 1993, Volume 2, Table III-3.

From these price forecasts errors, Lynch and Swanson conclude:

> The consistency in price forecasts is particularly interesting, though, suggesting that, as with oil forecasting, a desire to be within the consensus is an exogenous influence on forecasters. The fact that only minor price changes were foreseen (all increases), whereas the price actually plummeted indicates that the forecasts are constrained by beliefs that prices can only increase (Lynch and Swanson, 1993, p. III-3).

These errors in forecasting should come as no surprise. The paradox is as the world becomes more unpredictable, the more forecasts and predictions are relied upon to determine what should be done (Gimpl and Dakin, p. 125, quoted in Mintzberg, p. 235). Not only do forecasting errors result, but so do the negative consequences of actions taken based on those forecasts.

Lynch and Swanson state (p. III-8) that there are three major problems with long-term natural gas price forecasting. First, there is an inherent belief in higher prices and resource constraints. "Oil and natural gas, like all depleting resources, have always been subject to the concern that the industry will ultimately exhaust supply or that exploration and development costs will become unacceptably high (EPRI, 1990, Vol. 1, p. 29)." However, in a study comparing volatilities of ten commodities - oil, copper, lead, zinc, tin, aluminum, nickel, gold, silver, and wheat - from 1985 to 1991, the authors conclude: "All of them exhibit periods of price increases and periods of price decreases, with no strong time trends evident (Plourde and Watkins, 1993, p. 2)." The second source of errors noted is that long term gas forecasting is influenced heavily by the near-term market. Finally, natural gas forecasting suffers from the errors in oil price forecasting. (See Lynch, 1992, for an analysis of the bias in oil price forecasting.)

Another possible source of errors is failure to consider technological improvements. Calantone (1992) argues that, "incorporation of technological change in the wide sense can dramatically alter our view of the long-run cost of (natural gas) supply. Even at very low forecast levels of technological change, the expectations for supply costs are strikingly different from the standard fixed technology approaches (p. 10)." One specific example of technology increasing natural gas reserves is the recovery of tight gas sand and coal seam gas, which has increased estimates of United States reserves by 450 trillion cubic feet (TCF) (Enron, 1992, p. 9; EPRI 1990, Vol. I, pp. 29-30, & p. 37). These improvements include advances in selecting drilling sites and resource recovery methods.

The point of the above discussion is not to paint a bearish price outlook for natural gas but to emphasize that experts do not know future natural gas price levels within a degree of accuracy necessary for power generators to make large capital commitments with certainty. Furthermore, the discussion suggests that their may be some forecast bias. The fact that bias may enter into price predictions is important, because if this is the case, it is influencing the amount of natural gas in utilities' fuel mixes.

Aside from potential bias in price estimates, there are several major relationships that must be predicted correctly in order to make intelligent estimates of future natural gas prices. "They are: (1) world oil prices; (2) the flexibility of the dual-fired market to switch to alternate fuels as a means of moderating gas price increases; and, (3) the nature of the gas resource base (EPRI, 1990, Vol. I, p. 5)." Each of these items are difficult to predict. The lack of success of anticipating world oil prices has already been discussed. It is further complicated by OPEC's attempts to maintain cartel discipline when there is an oversupply of oil on world markets (EPRI 1990, Vol. I, p. 5).

The ability of dual fired boilers to switch between fuels may be restricted by regulatory policy. "A major uncertainty surrounding interfile competition is how much emerging air quality legislation will restrict the ability of dual fuel users to switch to alternate fuels when gas prices get out of line (EPRI 1990, Vol. I, p. 6)." Finally, experts disagree on the amount of coupling between higher wellhead prices and gas drilling. Higher natural gas prices will increase drilling; the question is what price levels will cause drilling that will result in additional proven reserves? Supply elasticities have been estimated between 0.05 and 3.29 (EPRI 1990, Vol. II, p. 46). Given the uncertainties that exist in predicting relationships that influence future natural gas prices, it is not surprising that price forecasts have a far greater variation than other types of forecasts, such as consumption volume estimates (EPRI, 1990, Vol. I, p. 9).

Deterministic Models Provide Limited Information

Even if predictions were more accurate, their use in deterministic models does not provide decision makers with all of the information that they need. A typical example of how the industry analyzes future gas prices is the Electric Power Research Institute (EPRI) report on ***Natural Gas Requirements for Electricity Generation Through 2000: Can the Natural Gas Industry Meet Them?*** (EPRI, 1990). The report examines over twenty natural gas supply and demand forecasts and over fifty different scenario estimates (EPRI, 1990, Vol. I, p. 4). The predictions are reported under different categories, such as ***base case, high oil price, low oil price, low resource base, high demand, high supply,*** and ***potential.*** The base case represents the most likely or expected future.

These different estimates provide future natural gas price streams that planners use to conduct their sensitivity analysis. Of course, the different scenarios that are constructed should include the situation that planners are concerned about. In the case of the twenty forecasts reviewed by this EPRI report, none of them considered the possible combination of higher natural gas demand resulting from accelerated electricity growth and air quality restrictions, coupled with a limitation on alternate fuel use also resulting from these same air quality constraints (EPRI 1990, Vol I, p. 15). This scenario is the type of situation that electric utilities are concerned about as they increase natural gas in their fuel mix.

Besides constructing the right scenarios, it is not easy to determine how many to build. The tradeoff is between having many scenarios, which increases the likelihood that one will be right versus the time constraints faced by planners along with the limits on their managers' mental capacity to consider all of these possibilities (Mintzberg, p. 248). Even once the set of scenarios is selected, it is not clear what to do when the analysis is complete. Does management bet on the most probable scenario, the one with the best outcome for the firm, hedge as to get satisfactory results no matter which one occurs, preserve flexibility, or go out and exert influence to make the most desirable scenario a reality (Mintzberg, p. 249)? Each one of these five choices has its own costs, and a clear means of convincing management to follow a specific course of action does not exist.

Deterministic models only provide a deterministic answer to the question that the modeler is asking: they cannot give a range of probabilities that the answer might assume. Using sensitivity analysis does not solve this problem. Although this analysis can help bound the answer generated, it cannot assign a weight to different outcomes. The selection of another set of assumptions to use in an evaluation does not give the decision maker any idea of the likelihood of this set. Usually sensitivity assumptions are selected to result in a different answer, otherwise there is little point in conducting the analysis. For example, in the evaluation of natural gas fired plants, planners use a ***high price*** scenario as a sensitivity case.

Since sensitivity analysis is usually directed at conditions that might reverse the conclusion suggested by a base case analysis, it does not consider conditions that make the base case even more favorable. Ignoring this potential upside results in underestimating the economic benefits of the project being evaluated. In the above example, the potential for natural gas prices to decrease and the associated economic value is not captured by sensitivity analysis. Not only is this type of sensitivity analysis not performed, there is a danger that the forecasts to support this analysis are not made either. This can further skew the analysis, resulting in the base case taking on the role of being the lower bound for natural gas prices when in fact it is the expected stream of future prices.

The Advantages of Modeling Natural Gas Prices Using a Random Walk

The difficulties in forecasting future prices combined with the shortcomings of deterministic models suggest using a different approach. "(I)t is worthwhile to recognize the complex and interconnected nature of uncertain quantities. When coupled with the realization that no one can reliably and accurately predict the future, as analysts we are left with having to quantify effects after setting reasonable limits of uncertain phenomena using judgement and some working knowledge of how one set of circumstances are linked to others. Often this can be accomplished using probabilities which capture both the uncertainty of data and judgement (EPRI 1993, pp. 2-3)."

One method is modeling natural gas price movements as a random walk using past price movements as a guide to price volatility. The ability to use such a model is fairly recent, not because the techniques were not available, but because of the regulated structure of the natural gas industry. EPRI acknowledged this in 1990: "An industry which has undergone the market and structural upheavals that natural gas has experienced, provides little reliable historic experience on which to base forecasts of the way that future supply and demand will respond to price (EPRI 1990, Vol I, p. 3)." However, the establishment of a natural gas spot and futures market in May of 1990 now provides the necessary data to base volatility estimates on.

The use of a random walk to model asset price movements is well established. The famous Black-Scholes formula that prices financial options assumes that asset prices have a random or Brownian motion component and evolve over time according to a Wiener process, also called log normal diffusion (Figlewski, ***et al***, p. 90). Given these assumptions about the random nature of the asset's value, its return over any period will be normally distributed and its price will be lognormal (Figlewski, ***et al***, p. 90). Using this framework, a quantity of natural gas is the asset, its price is the cost of that quantity, and its return is the percent change in price from one day to the next.

In the case of raw commodities, such as natural gas, their price movements have both been modeled as Brownian motion, which has the consequence of prices wandering far away from their starting point, or as a mean reverting process (Dixit and Pindyck, p. 62). In a mean reverting process, the price is assumed to return to its average at a specified rate. "In other words, while in the short run the price of oil might fluctuate randomly up and down (in response to wars or revolutions in oil-producing countries, or in response to the strengthening or weakening of the OPEC cartel), in the longer run it ought to be drawn back towards the marginal cost of producing oil (Dixit and Pindyck, p. 62)." A similar argument can be made for natural gas. However the same authors acknowledge that it usually requires many years of data to determine with any degree of confidence whether a variable is mean reverting (p. 77).

Two simplifications are made in the Monte Carlo simulation that is used. First, natural gas and coal prices are assumed not to be mean reverting or that their rate of reversion is slow enough that it can be ignored. This is consistent with the case of crude oil and many other economic variables for time periods of less than 40 years. The random walk hypothesis cannot be rejected over these lengths of time (Dixit and Pindyck, p. 78). Secondly, a discrete binomial model is used. Prices are assume to increase or decrease by a given amount based on their historical volatility. During every discrete increment in time, taken to be one year, prices have a equal probability of increasing or decreasing.

The advantages of using a binomial model is that it has an intuitive structure and mathematical tractability (Figlewski, ***et al***, pp. 80-81). By taking the binomial model to its limiting case, that is taking smaller price changes over shorter time intervals, it approaches the continuous-time model, which more advanced tools such as stochastic calculus can be employed (Dixit and Pindyck, p. 62). Although such methods will not be used here, it is important to note that they are available to refine the binomial model's conclusions.

A random walk model acknowledges that future prices are uncertain and is consistent with theories of market efficiency. It uses known information to project random movement of price over time. The asset's current price is known with certainty, and its volatility, subject to estimation errors, can be easily determined. This helps in eliminating potential biases in future price estimates. Since future prices only depend on the previous price, this model is consistent with weak-form market efficiency. This theory states that prices fully reflect past price information. Therefore, by basing price forecasts on market information, the model takes advantage of the market's knowledge about the asset without knowing specifically which piece of market information is driving prices. Most studies in the abundant literature testing market efficiency agree that capital markets are weak form efficient (Vila, p. 112). Even if market imperfections exist, they will be mitigated by arbitragers who will earn profits by bringing mispriced assets back to an equilibrium level consistent with available information.

For completeness, it should be mentioned that some authors disagree with the market efficiency hypothesis (Shiller, 1991). Their argument is that an excess in price volatility exists relative to predictions of efficient market theories due to psychological factors. These psychological factors are caused by popular mental models about the market that influences people's behavior resulting in excess volatility. This excess means that if prices movements were rescaled down to be less variable, then price would do a better job of forecasting fundamentals (Shiller, 1991, p. 2). If popular models result in exaggerating volatility, then the distribution in the net present cost of the binomial model will have an overstated variance. For the purpose of this model, it is assumed that this volatility excess is negligible or that over long periods of time, such as thirty years, upside excesses are negated by downside excess.

A specific example using oil prices illustrates how the natural gas market incorporates all available price information including data from other markets. As explained above, the inability to predict natural gas prices is partly due to the inability to predict oil prices. If oil prices are too high relative to natural gas, those that can switch from oil to natural gas will do so, pushing natural gas prices up and lowering oil prices. In this way the oil and natural gas markets are linked because of the potential arbitrage across markets. Some of the cross market arbitrage opportunities have become institutionalized. For example, the crack spread, which is the simultaneous purchase (sale) of crude oil futures and sale (purchase) of petroleum product futures, connects the crude oil market with the market of its refined products such as heating oil and gasoline (Edwards and Ma, p. 398).

Like any forecasting method, the binomial model bases future predictions on past information. This assumes that the relationship between the forces that drove past price movements do not change over time. Of course this is not the case, particularly with natural gas, which has a long history of being subject to various regulations. Table 2.2 lists the four major regulatory eras of natural gas. Moreover, other factors will change the underlining volatility, such as expansion of gas storage facilities or regulatory restrictions on dual-fired units. These structural changes impact all forecasting techniques; however, in the case of a random walk model, these changes can easily be incorporated into the analysis.

Suppose that regulators are considering restricting the use of oil in dual-fired units to reduce air pollution. Adoption of such restrictions will raise the price of natural gas. However, before the regulations are approved, speculators will enter the market betting one way or another that the regulations will be approved or disapproved in hopes of making a profit. As the regulations gain momentum, not only will more speculators take positions but so will firms who want to hedge their natural gas positions against price increases. These market movements will be captured by the random walk analysis in two ways. First, the initial price that the analysis uses, which is the current price, will change, reflecting the market's trend towards higher prices. Second, the volatility measurements will change, appropriately reflecting the best information about future trends.

Table 2.2 Eras of Federal Regulatory Involvement in the Natural Gas Industry

Time Period	Regulatory Policy
1816 - 1937	Total lack of federal involvement
1938 - 1953	Interstate transmission and sale regulation based on public convenience and necessity
1954 - 1977	Federal regulation of natural gas wellhead prices
After 1978	Gradual deregulation of gas-producing industry

Source: Castaneda 1993, pp. 2-3.

Unlike models that depend on expert forecasts, which take time to develop and are expensive to commission, recalculation of volatility can be done quickly, inexpensively, and at any frequency that management needs. Depending on the size of the changes in current price and volatility, management can decide whether or not it is worthwhile to perform additional evaluations of proposed projects. For instance, if a utility is comparing a coal versus a natural gas plant, and market conditions change sufficiently, the analysis can be updated. Not only will high profile structural changes be captured in the random walk model, but other less publicized changes will as well. If someone discovers a technological improvement, as it is used and its impacts are measured, those that know about it will take appropriate market positions, which will be reflected in the marketplace.

Section Two: Natural Gas Prices and Volatility

This section presents evidence that supports modeling natural gas price movements as a random walk. It is divided into two major parts. Part one presents natural gas prices since the start of the New York Mercantile Exchange (NYMEX) natural gas spot and futures market in 1990 through early 1994. The second part contains the volatility calculations used in the Monte Carlo simulation.

Figure 2.1 graphs natural gas prices over the four year period that the market has been in existence. It also includes four rolling averages based on the previous 60, 90, 120, and 240 trading days. As expected, longer period averages are flatter, which means during price increases they are lower than shorter period averages and during price drops they are relatively higher. The strong seasonal effects are also present: prices have ranged from \$2.30/MMBtu in the winter to \$1.25/MMBtu in the summer.

There appears to be an increasing trend in prices over the four years, most clearly shown by the 240 day rolling average, although part of this trend is due to inflation. The prices are reported in current dollars, meaning that they are not inflation adjusted.

The volatility measurements are based on the standard deviations of the change in the natural logarithm of gas prices and are expressed as an annual rate using a 260 day trading year. In order for this to be a reasonable approach to modeling fuel prices, these price changes should be a normal distribution (Dixit and Pindyck, p. 70). Figure 2.2 presents a frequency distribution of natural gas price changes over the four year period along with the theoretical normal distribution. As can be seen, the actual distribution is not a perfect match with its theoretical one. It is leptokurtic, meaning that it is more peaked than a normal distribution. For other commodities, Plourde and Watkins (1993, p. 9) have found that some of the underlying price distributions are platykurtic (copper, lead, nickel, zinc, gold, silver, and wheat), meaning that they are fatter than a normal distribution, whereas others (crude oil, aluminum, and tin) are leptokurtic. The actual distribution is slightly positively skewed, which reflects the upward trend denoted by the 240 day average line.

Although the match between the actual and theoretical distributions is not perfect, it is close enough to justify the assumption that natural gas prices move according to a log normal diffusion. First, the price change or actual distribution shown in Figure 2.2 has certain key characteristics of a normal distribution. Its values near its mean occur with more frequency than values further away from the mean, and the mean occurs in the middle of the distribution, not on one side or the other. Second, it is clear that a lognormal diffusion is only an approximation to actual price behavior (Figlewski, et al, p. 90). Price changes are discontinuous when the market is closed overnight or during weekends. Moreover, the volatility changes randomly over time, which will cause a mismatch between the actual and theoretical distributions. Finally, the differences noted are more important to those actually trading in natural gas, but are less important in planning over many years. In the case of planning, there are numerous assumptions that are approximations at best, which have at least the same order of magnitude mismatch that is occurring with the natural gas price modeling.

However, to try to capture some of the cause of the mismatch between actual and theoretical price change distributions, the volatility is assumed to be a random variable. Figure 2.3 graphs the frequency of various 60 day annualized volatilities over the four year period. Every 30 trading days the volatility is calculated using the past 60 prices and annualized based on a 260 day trading year. Figure 2.4 is a frequency plot of the volatilities, and Table 2.3 is a listing of some key statistical properties of this volatility distribution. The volatility is modeled as normal distribution in the Monte Carlo simulation.

The selection of the number of past prices to use in a volatility calculation involves a tradeoff between statistical accuracy and changing volatility over time. Moreover, there is no general agreement on whether it is better to use daily prices or those from longer periods of time. In practice, analysts estimate volatility based on using 1 to 6 months of past daily prices (Figlewski, ***et al***, p. 96). The sample size of sixty prices was selected to provide enough measurements over a four year period to determine if volatility changed over time while still having a large enough sample size to ensure sufficient statistical accuracy. Additional means of measuring volatility are presented in chapter thirteen of Figlewski, ***et al***.

Coal prices are assumed to behave similar to natural gas but with a normal volatility distribution with mean 10% and standard deviation of 5%. This is one of several areas identified in chapter four requiring additional research.

Table 2.3 Key Statistical Properties of 60 Day Annualized Volatility

Statistic	Value
Average	44.1%
Standard Deviation	15.52%
Maximum	70.91%
Minimum	10.64%
Sample Size	26

Section Three: Model Assumptions

The key characteristics of the natural gas and coal fired units are from a long range study prepared for the New England Power Pool (NEPOOL, 1991). These characteristics include the technical attributes of the power plants, their construction costs and lead times, operation and maintenance (O&M) charges, and fuel transportation costs. A utility's cost of capital is assumed to be 11.8%, which is based on the weighted average cost of capital for New England utilities (NEPOOL, 1991, p. 5). The major assumptions are presented in Table 2.4.

The assumptions used are generic to the New England region. Any specific comparison between two power plants would incorporate more detailed information. Since the Monte Carlo simulation is spreadsheet based, changing assumptions or adding more detail can be done quickly. The purpose of using the NEPOOL planning assumptions is not to replicate a specific comparison between two power plants, but to use a consistent set of assumptions to construct a stylized example.

Table 2.4 Major Technical and Cost Assumptions

Assumption	Value
General Assumptions	
Real Discount Rate	11.8%
In Service Date	January 1st, 2000
Plant Size	600 MW
Plant Life	25 years
Capacity Factor	80%
Inflation	3%
Natural Gas Unit	
Heat Rate (Btu/KWh)	8,374
Capital Costs ($/KW)	490
Construction Lead Time (months)	60
O&M Fixed ($/KW-Yr)	8.09
O&M Variable ($/MWh)	1.97
1995 Starting Fuel Price ($/MMBtu)	2.87
Coal Unit	
Heat Rate (BTU/KWh)	9,457
Capital Costs ($/KW)	1500
Construction Lead Time (months)	89
O&M Fixed ($/KW-Yr)	27.17
O&M Variable ($/MWh)	6.47
1995 Starting Fuel Price ($/MMBtu)	1.68

Note: All costs are in 1990 dollars.

Section Four: Model Details

Due to computational restrictions of the Monte Carlo simulation program that is used, several modeling limitations are imposed. The model starts with an estimate for the price of natural gas and coal for 1995. This price is taken from ***NEPOOL 1991*** and is escalated to 1995 using fuel escalators reported in the same document and includes delivery to New England. This price is then assumed to follow a random walk. However, since the natural gas and coal power plants have a twenty-five year life and do not come on line until the year 2000, the random walk must cover thirty years. This would result in 2^{30} or over one billion prices. Since the program used does not have the ability to calculate prices as it proceeds through its random walk, the potential prices have to be determined before hand. With over a billion prices, this was not possible.

Instead, it is assumed that every five years, starting in the year 2000, prices move randomly.[1] For the years in between the five year intervals, the fuel prices are escalated from the last previously selected random price at inflation. These rates are reported in Table 2.4. For example, in the year 2000, there are two possible prices for natural gas based on the volatility of 45% +/- 15%. The program randomly picks a volatility based on the distribution in Figure 2.4. Assume it selects 45% for its first random walk. Starting with the given 1995 price of $2.87/MMBtu, the two prices in 2000 are $4.82/MMBtu or $1.83/MMBtu, escalated for inflation. For the years 2001 through 2004, whatever price is selected for 2000, it is escalated yearly as described above.

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[1] The implicit effect of this assumption is that natural gas price volatility is modeled as the fifth root of the annual volatility based on daily variations. The same is true of the assumed coal price volatility. Converting annual volatilities to a five year period results in a volatility greater than 100%, which makes it impossible to model a down price movement.

In the year 2005 the process is repeated. This time there are four possible prices: \$6.99/MMBtu, \$2.65/MMBtu (twice), and \$1.01/MMBtu. These four prices are associated with two increases, an increase and then a decrease, a decrease and then an increase, and two decreases respectively starting with the price in 1995. This process is repeated for the years 2010, 2015, and 2020, with the same price escalation occurring between each five year random price selection. At the end of the random walk through the year 2020, the net present fuel cost is calculated and recorded. This process is repeated for a total of 2000 times. The result is a net present price distribution. The next chapter reports the model results for different scenarios.

Fig. 2.1 Natural Gas Prices & Averages

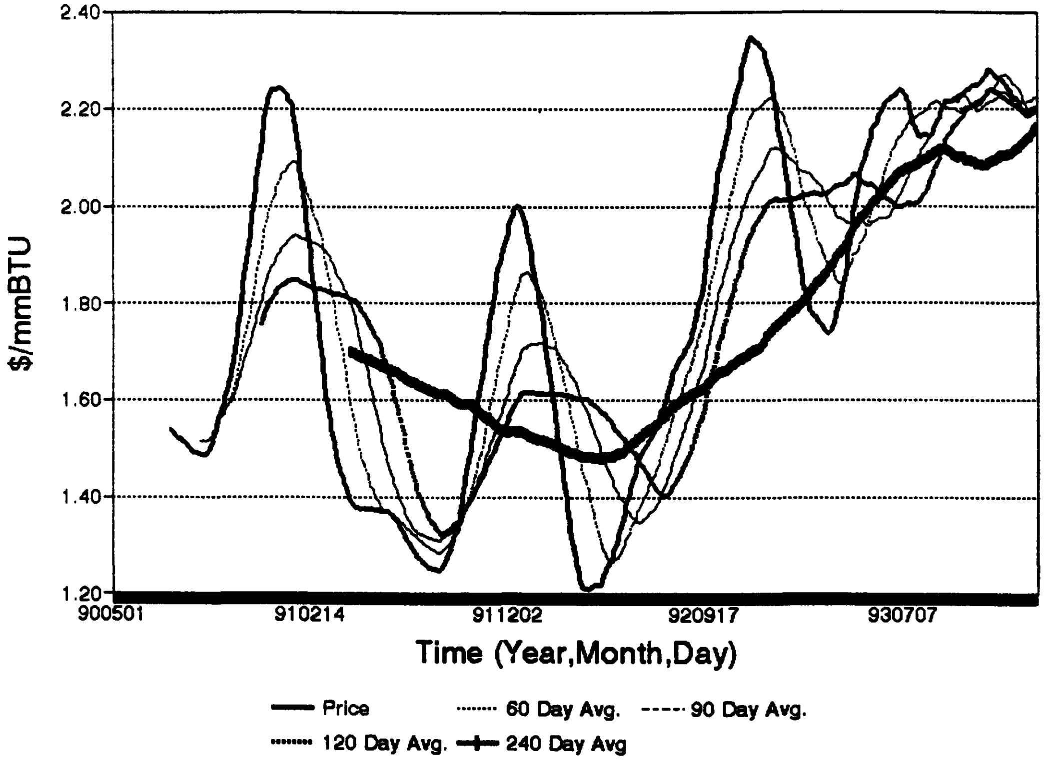


Fig 2.2 Frequency Plot of Price Change

Natural Gas Prices 1990-1994

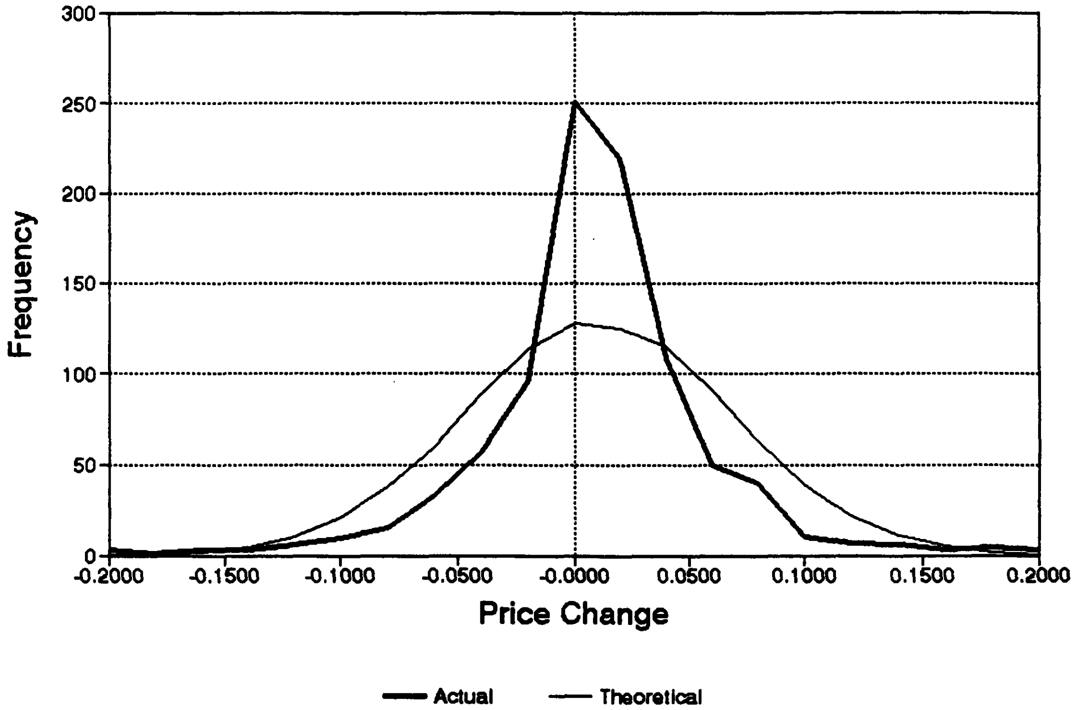


Fig 2.3 Annual Volatility vs Time
Every 30 Days Using Past 60 Prices

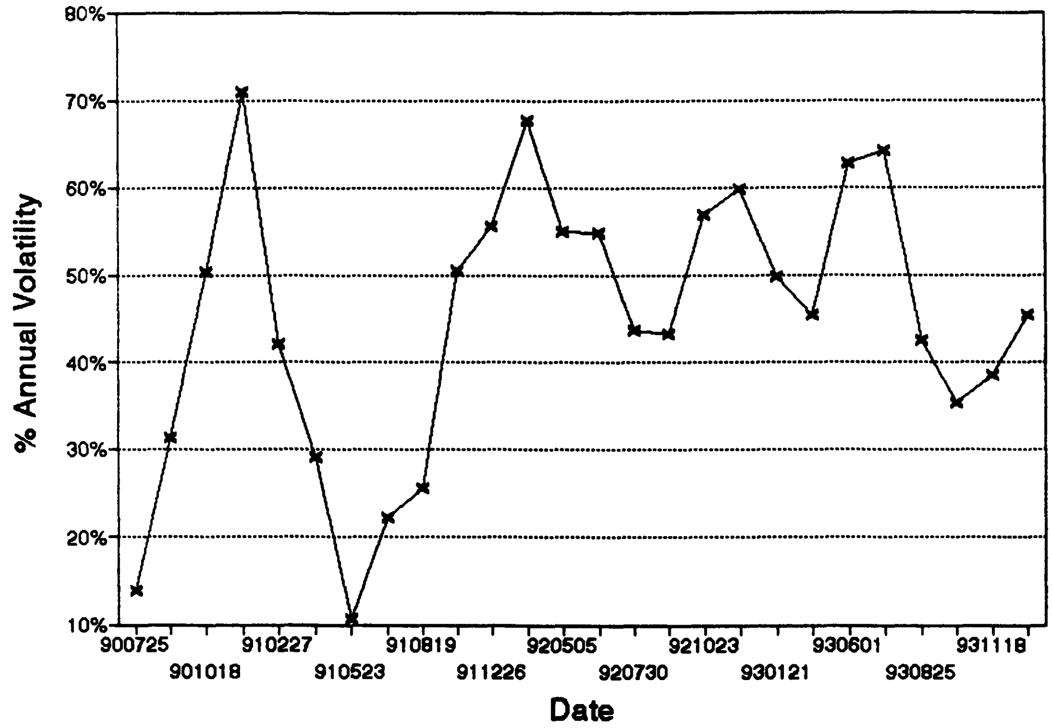
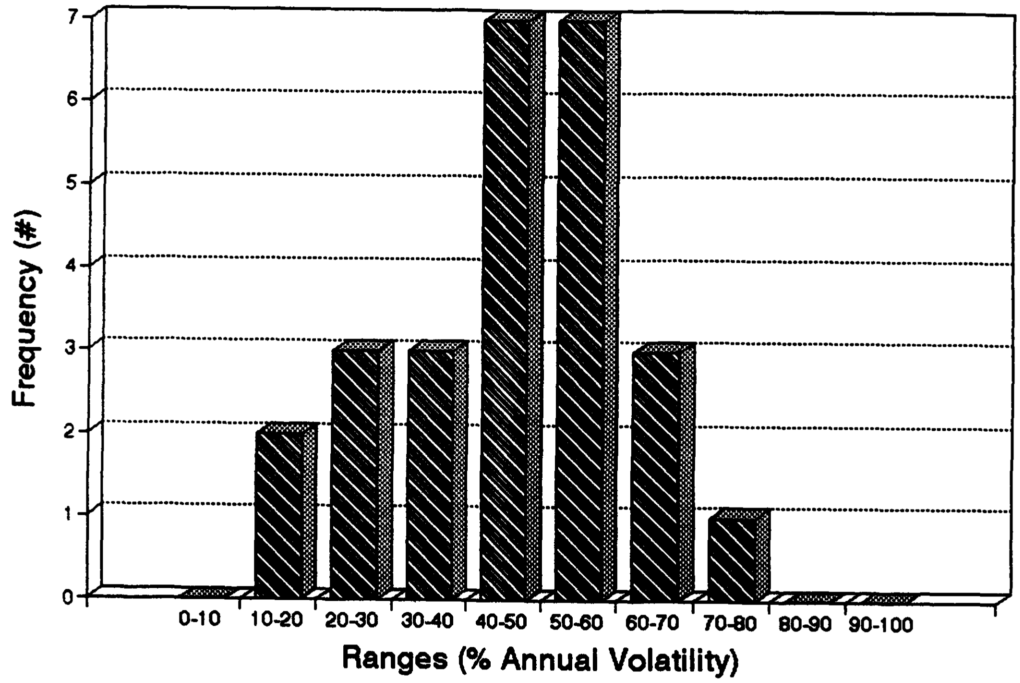


Fig 2.4 Annual Volatility Distribution
Every 30 Days Using Past 60 Prices



Chapter 3

Analytical Framework and Simulation Results

Chapter Overview

This chapter presents the analytical framework that is used to evaluate the model's results. Section one describes the framework using the assumptions listed in chapter two. The mean variance efficient portfolio using two assets, a coal plant and a natural gas plant, are calculated. A riskless asset is introduced and is assumed to be a fixed price gas contract. Section two draws some conclusions.

Section One: Analytical Framework Simulation Results

Financial portfolio theory is used to compare a natural gas fired plant to a coal fired one. One underlying assumption is when the given investments have the same mean return, investors prefer projects that have a lower variance or standard deviation. For electric power plants, regulators prefer projects with lower cost variance, when expected costs are equal. This is reflected in Figure 3.1 (a). It graphs the net present cost (NPC) of two hypothetical projects versus their mean plus and minus their first and second standard deviations. Since both projects have the same expected cost, regulators prefer the one with less variance, the coal fired power plant.

Unfortunately, the situation may not be so clear cut. The question becomes what should regulators prefer if the means of the two projects are not equal, with the higher variance project having the lower expected NPC? This question is illustrated in Figure 3.1 (b). The answer depends on the covariance between the two projects. For example, assume that the projects are perfectly correlated, meaning that when the cost of one project increases, the other increases as well. For 75% (within one standard deviation) of the time, the cost of the coal power plant will be more expensive than the natural gas fired plant. If the covariance is less than one, there will be situations that the coal project's cost is less than the natural gas fired plant. For any given covariance, there exists a probability in which the coal plant may be cheaper than the natural gas plant.

The results presented in Table 3.1, Figure 3.2 (a) and Figure 3.2 (b) shows that a gas fired plant is a clear winner over coal. Figure 3.2 (a) is a graphical representation of Table 3.1. The large difference in capital costs are driving this phenomenon. In addition, the coal plant has larger NPCs for both fixed and variable O&M than the gas plant. As a result, the large natural gas fuel net present costs and potential increases do not overcome coal's capital and O&M NPC disadvantages except two standard deviations away.

The fuel net present cost distributions for coal and natural gas are presented in Figures 3.2 (c) and 3.2 (d). Since natural gas volatility is so large, it has a significant probability of reaching values near zero over a period of twenty five years. These extremely small values for natural gas prices become the minimum value for the fuel NPC and as a result, restrict natural gas' volatility compared to that of coal. This results in coal's volatility being disproportionately large compared to that of natural gas.

Table 3.1 Results of Analysis

	Coal		Natural Gas	
	NPC (Millions 1990 $)	Percent of Total Cost	NPC (Millions 1990 $)	Percent of Total Cost
Capital	466.6	48.8%	152.4	22.6%
Fixed O&M	80.4	8.4%	23.9	3.5%
Variable O&M	134.2	14.0%	40.9	6.1%
Fuel	274.1	28.7%	457.3	67.8%
TOTAL	955.3		674.5	

Note: Numbers may not add up to 100 percent due to rounding.

The distributions of net present fuel costs presented in Figures 3.2 (c) and 3.2 (d) have several characteristics that should be commented on. First, they are jagged. This is an artifact of the modeling described in chapter two, section four. Since price movements are modeled as a discrete process following a random walk every five years, this results in discontinuities in the fuel cost distributions. Second, it should be noted that these fuel distributions have a lognormal shape. This is characterized by a minimum value, a peak, and an extended tail of maximum values. The implications of being a lognormal distribution is that the standard deviation no longer identifies with equal probabilities both an increase and decrease in net present fuel costs, which is the case with a normal distribution. The impact is that upward movements will be understated. However, since this effect is relatively minor, it can be ignored without distorting the conclusions derived from the results.

Before financial portfolio theory is introduced to address these issues, a simple method of modeling the two plants' variances needs to be presented. The actual variances are determined from the modeling process, which explains their difference from the ones calculated using this simple model. It is assumed that a plant consists of two factors, capital (K) and fuel (F). The NPC of a plant depends on the sum of these two factors, and the fractions that each factor contributes to the total NPC are k and f. Equations 3.1 and 3.2 express NPC both in terms of dollars and percent.

$$NPC(\$) = K + F \tag{3.1}$$

$$NPC(\%) = k*K + f*F \tag{3.2}$$

The variance (STD^2) for the NPC(%) is

$$STD^2 = k^2*STD^2_k + f^2*STD^2_f + 2*k*f*STD_{k,f} \tag{3.3}$$

where STD^2_k and STD^2_f are the capital and fuel variances respectively and $STD_{k,f}$ is the covariance between fuel and capital.

Both this simple model and the actual model assume that the capital expenses have a variance of zero, which implies that its covariance with fuel is also zero. For the purposes of this simple model, all non-fuel costs are considered capital expenditures. Equation (3.3) simplifies to

$$STD^2_T = f^2 * STD^2_f \qquad (3.4)$$

This is a reasonable simplification. First, utilities can sign turnkey contracts, which insulate them from the risk of cost overruns, increases in interest rates, and other changes that effect a power plant's construction charges. Second, in a comparison between a coal and a natural gas plant, both are susceptible to the same capital risk, although the coal plant has a larger exposure because it has larger capital costs. The implication is that the covariance between each of these two plants' capital costs is very close to one. Therefore, if capital costs do increase or decrease for one plant, the same occurs with the other. Table 3.2 calculates the total standard deviation using the simple model (Equation 3.4) and reports the standard deviations from the actual model. The disproportionate effect mentioned above due to the limits on natural gas price movements due to the floor of zero is reflected in Table 3.2 in the total standard deviation for the actual model.

Table 3.2 Fuel and NPC Variances Using Base Case Results

	f	STD_f	STD_T Simple Model	STD_T Actual Model
Natural Gas	52.2%	45.0%	23.5%	17.6%
Coal	16.2%	10.0%	1.6%	4.6%

Financial portfolio theory compares the return of various combinations of several assets to the associated risk of these assets (Sharpe & Alexander, Chapters 7 and 8). This theory can be applied to power plants by replacing the plants' returns with their cost (Awerbuch, October 1993). The equations that map the risk-cost relationship are

$$STD^2 = g^2*STD^2_g + c^2*STD^2_c + 2*g*c*STD_{g,c} \qquad (3.5)$$

$$NPC = g*E(NPC_g) + c*E(NPC_c) \qquad (3.6)$$

$$STD_{g,c} = c_{g,c} *STD_g *STD_c \qquad (3.7)$$

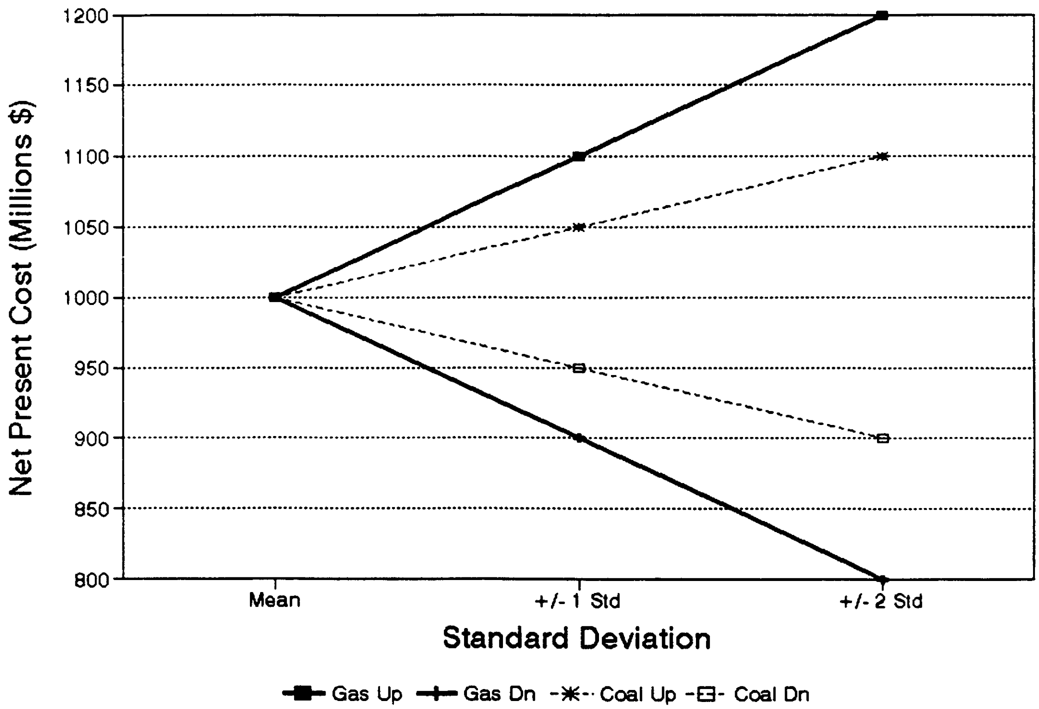
where g and c are the fractions of gas and coal assets, and E(NPC) represents the expected net present cost of the power plant corresponding to its subscript. Equation 3.7 states the relationship between the correlation coefficient, c, and the covarinces and standard deviations. Figure 3.3 plots the results. Each solid block represents a 10% change in the fuel mix between natural gas and coal. (The correlation coefficient of 1 does not have solid blocks for clarity.) As the graph demonstrates, the risk-cost relationship is heavily dependent on the covariance between the two assets, which means the covariance between natural gas and coal prices. One author has reported a covariance of 0.94 (Awerbuch, October 1993, Table 1), although this was based on only 16 data points using U.S. wide averages for coal and gas prices.

Different correlation coefficients are selected to demonstrate parametricly the effect that covariance has on risk diversification. A correlation coefficient of zero means that the fuel movements are independent of one another. Although this may not be a good assumption for natural gas and coal, it illustrates how this same portfolio analysis can be

volatility) reduction at a large cost when starting near the 100% natural gas point. This conclusion is driven by two factors working together. Coal prices are assumed to be very stable, and, since coal costs are only a small portion of the total plant's cost, the impact of coal price volatility is reduced furthered. If coal price volatility played a larger role in a coal plant's NPC, then fuel diversification would make more sense, particularly if coal prices move counter to natural gas prices. However, the benefits of diversification, which occurs when the lines in the portfolio graphs become curved, are small and only occur when moving from a very large percentage of coal in the fuel mix towards natural gas. In fact, natural gas plants should be built to diversify away from coal.

Sensitivity analysis confirms these results for larger coal price volatility, increasing natural gas prices in real terms, and decreasing coal prices in real terms over the life of the power plants, although the magnitude of the difference between the expected NPC of the two plants does change. Any analysis performed on actual investment opportunities would use updated assumptions and site specific values.

Figure 3.1 (a) Natural Gas vs Coal
Illustrative Example



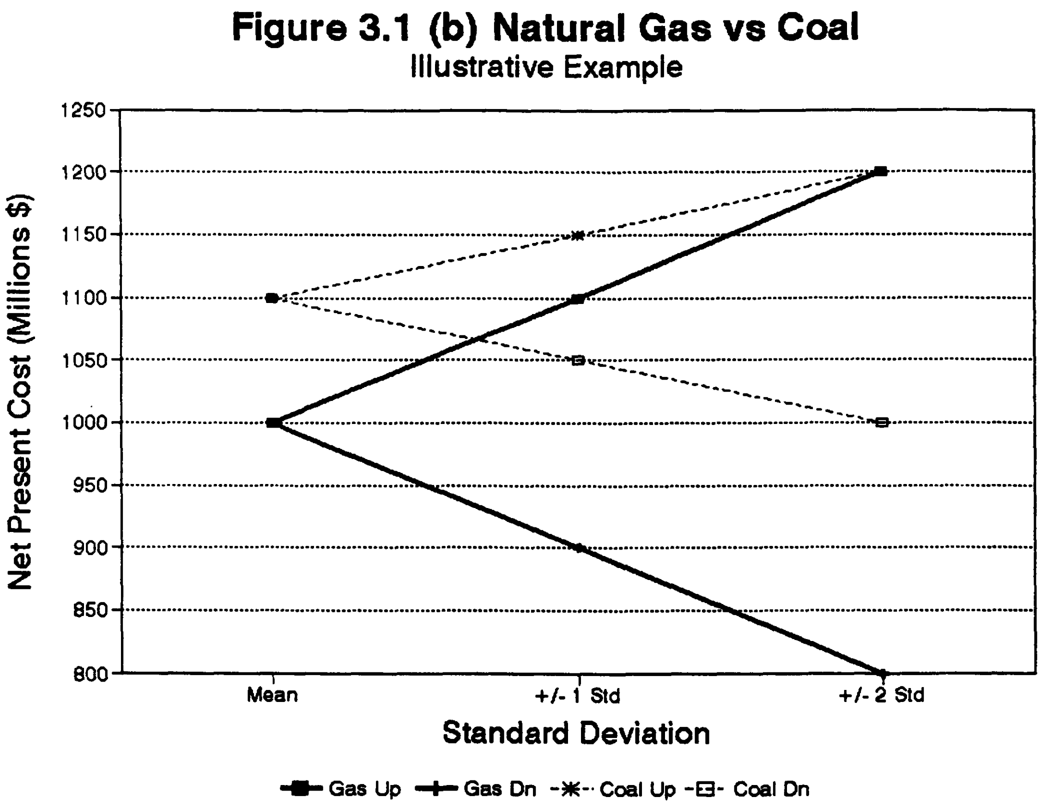


Figure 3.1 (b) Natural Gas vs Coal
Illustrative Example
Net Present Cost (Millions $)
1250
1200
1150
1100
1050
1000
950
900
850
800
Mean
+/- 1 Std
+/- 2 Std
Standard Deviation
Gas Up
Gas Dn
Coal Up
Coal Dn

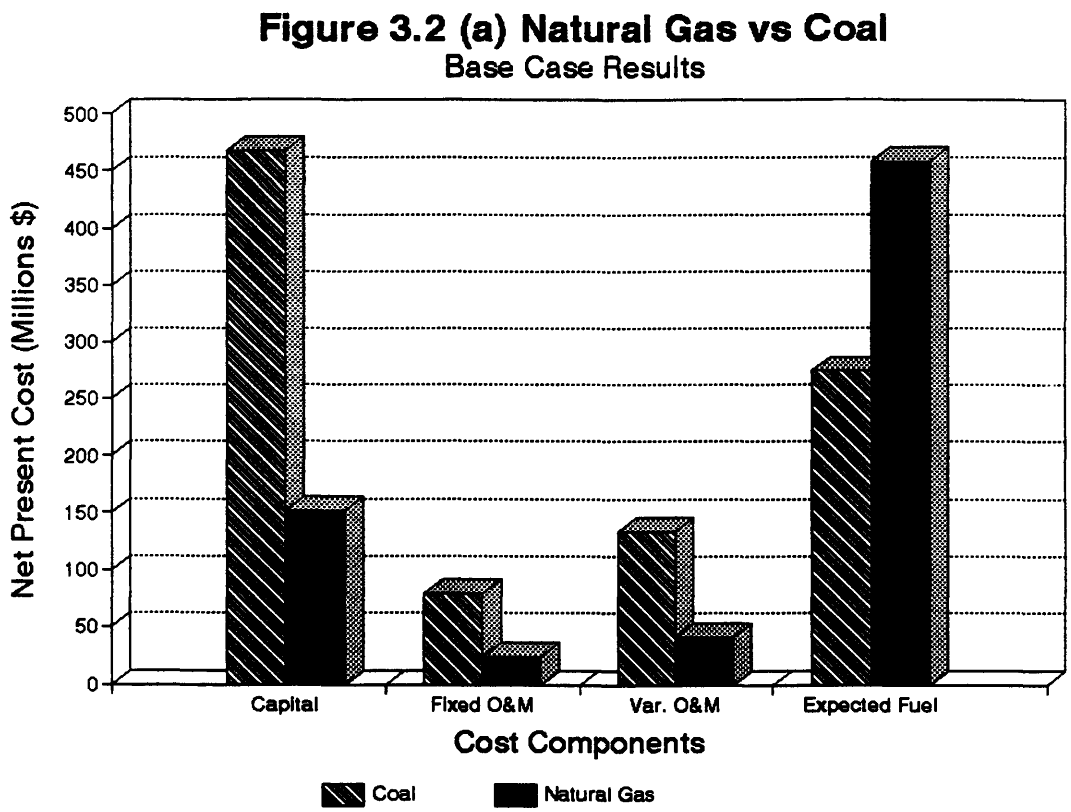


Figure 3.2 (a) Natural Gas vs Coal
Base Case Results
Net Present Cost (Millions $)
500
450
400
350
300
250
200
150
100
50
0
Capital
Fixed O&M
Var. O&M
Expected Fuel
Cost Components
Coal
Natural Gas

Figure 3.2 (b) Natural Gas vs Coal

Base Case Results

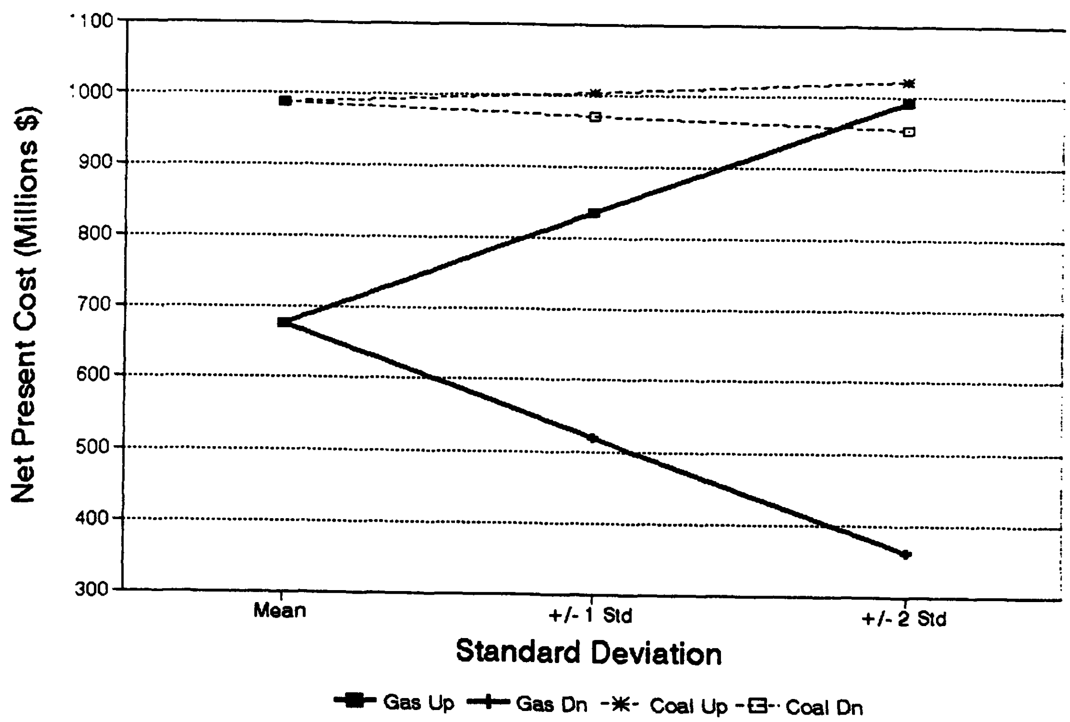


Fig. 3.2 (c) Coal NPC Distribution

Base Case

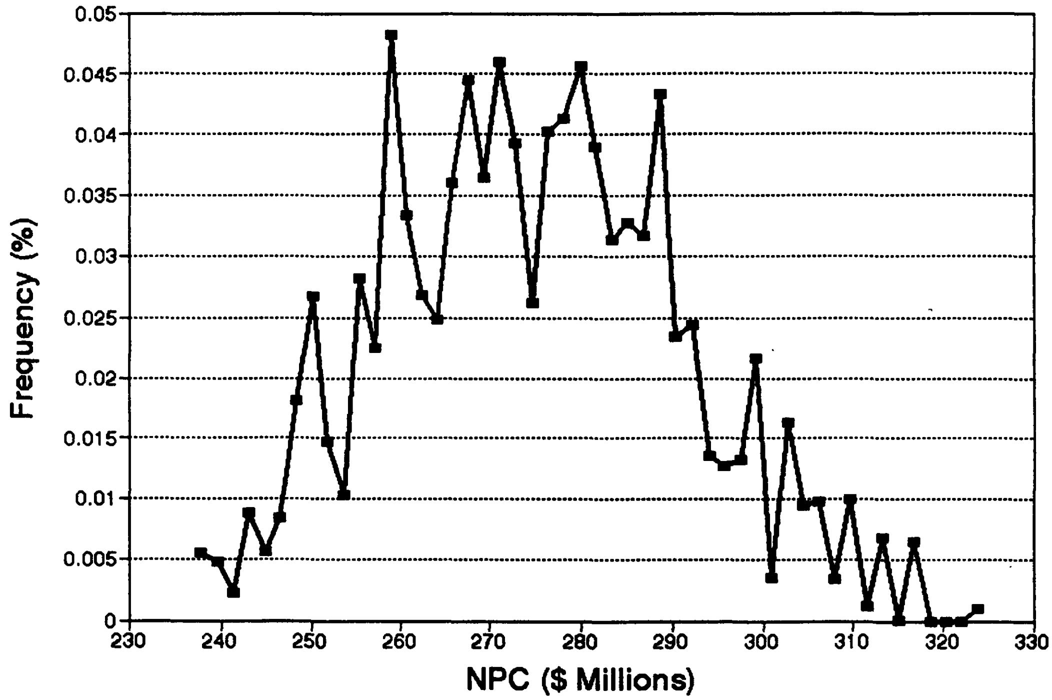


Fig. 3.2 (d) Nat Gas NPC Distribution

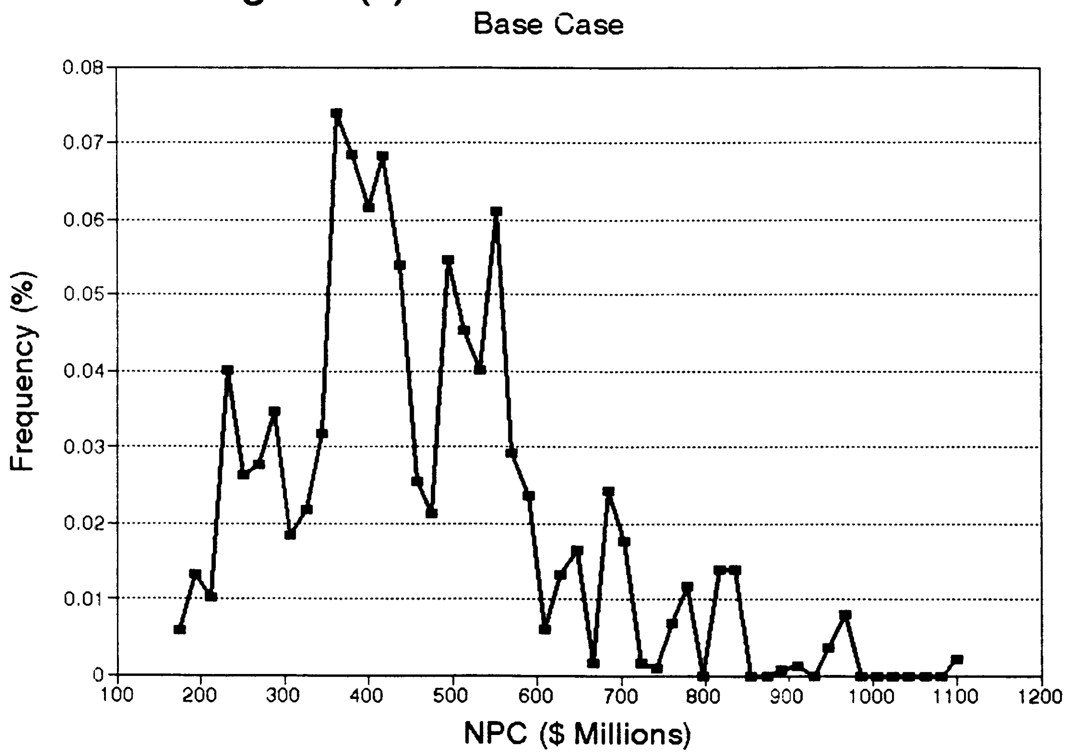


Figure 3.3 Base Case Assumptions
Various Correlation Coefficients

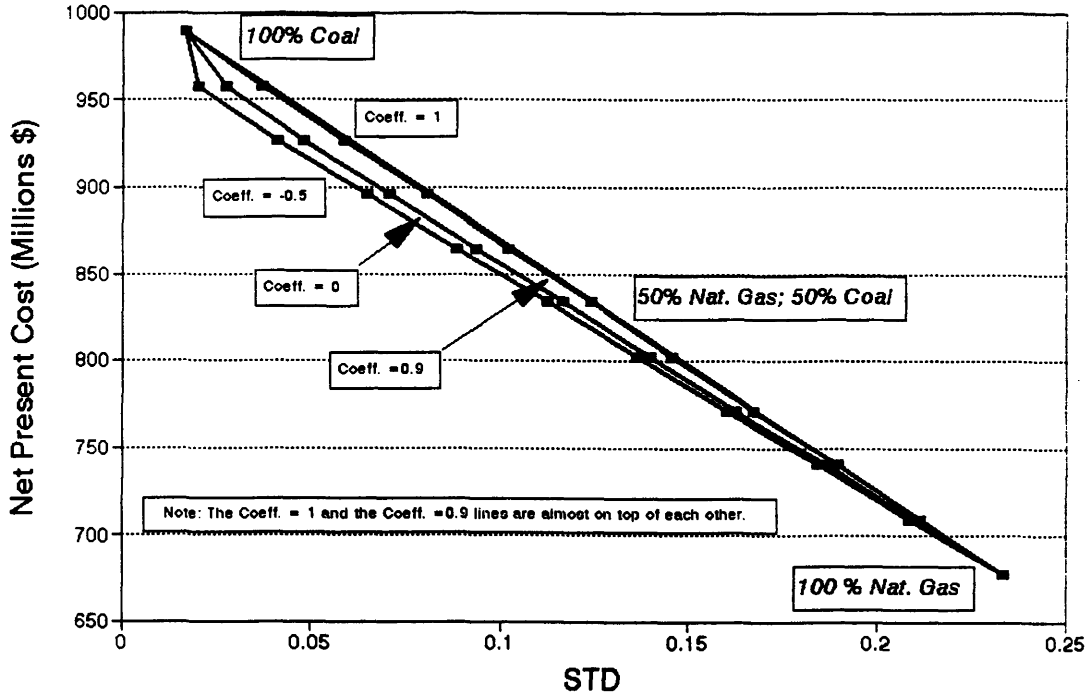
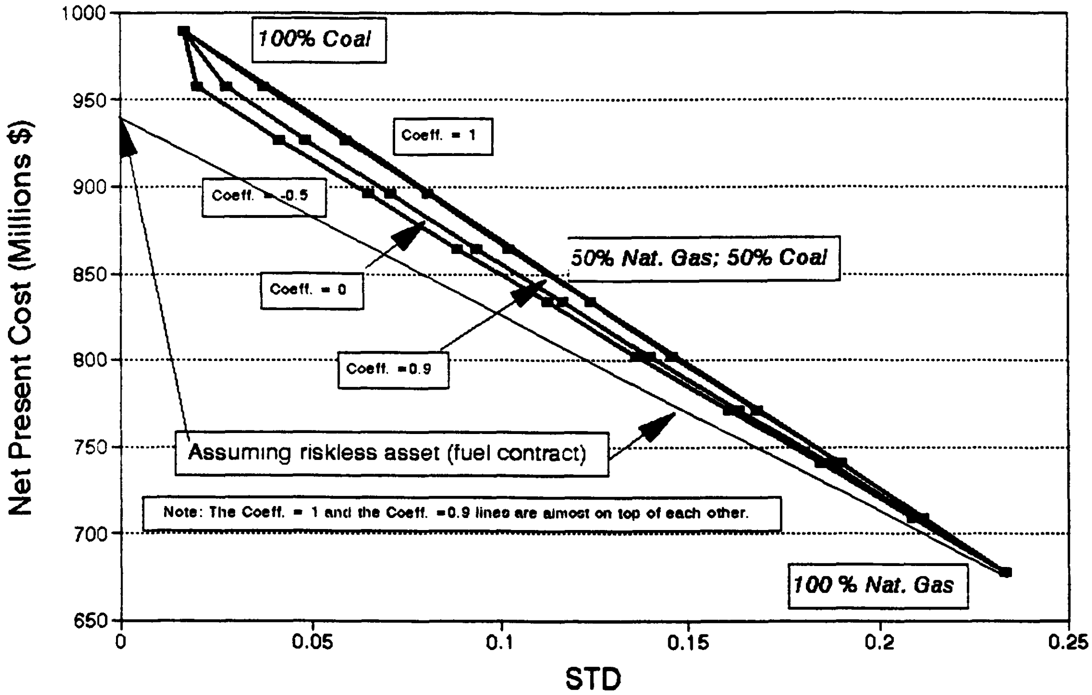


Figure 3.4 Riskless Asset
Various Correlation Coefficients



Chapter 4

Implications and Limitations of the Results

Chapter Overview

This chapter places the results in a policy framework and proposes areas for additional research. Section one answers two questions:

> Should electric utilities adopt measures to mitigate the risk of natural gas price increases?
>
> Assuming that some type of hedging strategy should be adopted, should utilities use fuel switching or financial contracts as a means of protecting themselves from natural gas price increases?

Definite answers will not be provided, but instead reasonable decision making criteria will be proposed. Section two suggests areas for additional research. This includes discussions on empirical questions, such as measuring coal fuel price volatility, and theoretical issues, such as methods of placing an economic value on fuel diversity.

Section One: Policy Framework

Should Measures be Adopted to Mitigate the Risk of Natural Gas Price Increases?

The large natural gas volatility measurements presented in chapter two, combined with the large fraction that fuel costs contribute to total power plant costs, result in a $150 million potential up or down swing in the

NPC of a natural gas plant at one standard deviation for the base case (see figure 3.2 (b)). This $150 million is 22.6% of the NPC of the natural gas plant and is large enough to consider price mitigation strategies. These strategies must cost less than the potential worse case they are preventing. This depends on the risk level that is desired. For one standard deviation, the mitigation strategy should not cost more than approximately $150 million. However, if a two standard deviation risk level must be met, then a strategy should not cost more than $300 million. For simplicity, the following analysis will use the base case numbers assuming that one standard deviation risk level is desired. The selection of this risk level is arbitrary

A distinction needs to be made between the absolute cost of the strategy and its expected payoff. A price mitigation strategy might have a negative expected value but still be an intelligent option so long as its total cost is less than the potential downside that is being hedged. For example, insurance has a negative expected payoff, but no one would purchase a policy whose total premiums are $100 to protect a $50 piece of property. However, they may pay $25 in premiums to protect the same property with an expected payoff of -$10. In the base case, $150 million serves as a cost cap for any mitigation strategy.

After establishing that there exists enough volatility to warrant mitigation, the next step is to identify a reason to protect against price increases. There are two generic reasons why a utility would want to hedge natural gas prices. The first is to raise capital for future investments. The argument is that as electricity rates rise, particularly dramatic increases relative to other parts of the country, the cost of capital increases. Hedging fuel price increases would allow utilities to save overall by limiting their capital expenses. In general, this argument is not persuasive. Due to the industry's large capital structure, it has access to financial markets. Moreover, under current regulatory policy, the assets that the industry builds are guaranteed a return, which makes capital acquisition easier for the utility industry than for other firms. Finally, when electricity prices increase, demand for electricity decreases. This means that the need for future power projects is reduced, which translates into less capital demand.

The second possible reason for price hedging is to provide a service to utility customers. This argument assumes that customers desire fuel price hedging and that the utility can provide a hedging solution at a lower price than the customer. If this is not the case, then the customer would hedge the price risk without the utility's involvement. A utility has several ways in which it can have a comparative advantage in hedging over its customers. These comparative advantages may come from a utility's information resources or economies of scale.

Moreover, customers may be in a position that they cannot afford to hedge fuel prices and if prices increase dramatically enough they will leave the service area by moving or closing their business. As customers leave the area, fixed costs are spread over fewer consumers, further increasing rates. This can result in a vicious circle, and if it is significant enough can also depress economic growth, further reducing electricity demand and raising rates. In this way, the preservation of rate base by hedging prices can be viewed as an investment undertaken by the utility. This means that standard net present value techniques can be used to evaluate whether different price mitigation strategies should be undertaken.

Using the base case results, customers are exposed to a potential \$150 million increase in net present cost for benefits of 4,204,800 MWh each year for twenty five years. Discounting these benefits at the same rate that the costs are, consumers receive 12,339,858 MWh of net present benefits (NPB). Spreading the \$150 million over these benefits, the price exposure is \$0.0122/KWh or slightly more than one cent per KWh. For the average household using 7,500 KWh/year, this translates into a price exposure of \$91.17. Given this small risk exposure, a blanket hedging strategy to protect all consumers does not seem to be worthwhile. These increase on a per KWh basis are over the twenty-five year life of the power plants.

This does not mean that none of the customer classes should not be protected. Industrial customers in which electricity constitutes a large component of their costs and who are operating on thin margins, are an example. These customers pay lower prices per KWh than residential consumers because they receive their power at higher voltages, which means they do not pay for the same level of distribution equipment services that residential customers do. As a result, their electric bill is more sensitive to fuel price increases than residential customers. In addition, by definition these customers are using a lot of electricity, which helps spread the utility's large fixed costs over more KWh sales. Whether or not a price mitigation strategy should be pursued for these customers depends on a host of empirical questions, such as the customer's price elasticity for electricity, their total usage, and their ability to withstand price increases given the industry they are in.

To answer the question that leads off this section, there does not appear to be a compelling reason for electric utilities to hedge natural gas price increase for all customers. While potential increases in natural gas prices may result in large absolute NPC, these costs are relatively small in terms of their effect on customers' electric bills. There may be situations in which certain classes of customers could benefit from a hedging strategy, but this depends on a case by case basis.

If Utilities Decide to Pursue a Hedging Strategy, Should They Use Fuel Switching or Financial Contracts as a Means of Protecting Themselves from Natural Gas Price Increases?

There are many methods of hedging natural gas price increases, but they tend to fall into two categories: engineering solutions and financial contracts. Engineering methods include fuel diversification and fuel switching. Fuel switching includes the use of distillate oil in the winter instead of natural gas, and other options such as building a coal gasifier next to an existing natural gas fired plant. Financial options include fixed price contracts, payment swaps between utilities or customers, options, and futures contracts. All of these financial and engineering options depend on their efficiency in trading the upside potential of decreased natural gas prices for protection from the downside of raising prices.

The preceding analysis concludes that is probably not worth trying to protect all customers from natural gas price increases. This suggests that blanket engineering solutions, such as building coal plants to diversify a utility's fuel mix, are not the most efficient strategy because customers that do not need price protection end up paying for it. In addition, the results from chapter three clearly show that a coal plant costs approximately $300 million more in net present costs than the natural gas plant. This is $150 million more than the net present cost of high natural gas price exposure at one standard deviation.

However, engineering solutions that behave similarly to a financial option may be worth pursuing. For example, it may be prudent to purchase extra land near a combined cycle natural gas fired plant that can be used to build a coal gasifier. If natural gas prices increase above a threshold level, then building the gasifier becomes economical and acts as a hedge against further price hikes. A similar argument can be made for other engineering solutions such as conservation measures. One key characteristic of these types of ***option*** approaches is that their initial cost (the amount that has to be spent before it is determined whether or not to exercise the option; in the case of the gasifier, this cost is the additional land) must be less than the worse case price exposure. Another factor is that a decision can be made at a later time based on additional information to determine whether to exercise the option, and that the option can be implemented quickly enough to have some benefit. For example, if it takes five years to build the gasifier, its value is less than if it takes only two years.

Financial tools to hedge price risk have the advantage over engineering solutions in that they can be tailored more easily to the risk and do not have the costs associated with constructing the equipment that is used to hedge the risk. However, financial options introduce ***third party risk***, or the possibility of whomever ends up holding the losing side of the transaction will not pay according to previously agreed upon terms. This fear is well founded in New England due to the numerous oil contracts that were broken as a result of the oil embargo in the early 1970s.

Some of the financial and engineering risk mitigation strategies can be implemented dynamically. This means that the mitigation strategy does not have to be implemented when the natural gas plant is built. It can be purchased at a later time. For example, the land for a coal gasifier could be bought when natural gas prices become high enough. If they continue to increase, then the gasifier itself can be built. The same is true with future or option contracts. A strategy of hedging natural gas prices by purchasing future contracts can be adjusted as prices change: the higher natural gas prices go the more contracts are purchased and the greater the percentage of the risk is hedged.

Although it is impossible here to examine in detail all possible engineering and financial strategies available to hedge natural gas prices, several litmus tests can be proposed. First, the expected cost of the hedging strategy must be less than the worse case situation it is designed to mitigate. The random walk model provides a reasonable method to estimate these possible worse cases as well as able to assign probabilities to these outcomes. Second, mitigation methods that can be tailored to those that have the most to benefit from hedging provide the most value added. Third, strategies that have flexibility are worth pursuing particularly if their initial costs are low and they can be implemented quickly.

Section Two: Limitations of the Model and Areas for Additional Research

Empirical Values

The results presented in chapter three are based on a variety of assumptions, some of which require additional research. The first set of assumptions are empirical ones. These involve values such as the correlation coefficient between natural gas and coal prices, the variance of coal, the mean reversion tendency if any of natural gas, and the differences in these values among different markets. As the base case portfolio graph in chapter three demonstrates (Figures 3.3), different correlation coefficients can result in different levels of risk reduction for a given cost.

Market differences impact a variety of assumptions. The results assume that the same natural gas volatility that occurs at Henry Hub occurs in New England, although there is an additional expense that is not volatile to account for transportation. Although this is reasonable since most contracts at Henry Hub are not taken for delivery, this assumption may not hold true. Regional variations could also impact other values, such as coal's volatility and its correlation with local natural gas markets. The importance of nailing down these regional specific values depends on the use of random walk modeling. Long term planning does not require as precise measurements given the host of other assumptions made over many years, and its goal of identifying trends and relationships instead of precisely predicting future values. However, if a random walk model is used for shorter horizon risk management, these regional variations become much more important. In any event, it is worthwhile to have estimates on these regional differences even if they serve to confirm the assumption that they can be ignored.

Theoretical Considerations

Besides the empirical values that need to be estimated, there are some important theoretical considerations. Two will be examined in some detail. The first is system interactions. The model compares two plants in isolation from the system that they operate in. It could do this because it assumed that the plants are baseload facilities and would be dispatched every year at a specified rate. This is also a reasonable assumption under contracting situations in which an operator of a power plant promises to deliver power at a certain price over many years.

However, there is another system interaction that must be accounted for. The portfolio curves compares various levels of a coal and natural gas plant without reference to the current fuel mix that these plants operate in and without consideration of how these fuel mixes will change over time.

In fact, the premise behind the two questions addressed previously is that in the future, after utilities have significantly increased natural gas in their fuel mix, they should use coal to diversify their dependance on gas. If full use of the random walk model is to occur, it must also address current fuel mixes as they evolve over time. Portfolio theory can easily calculate fuel diversity statically using results generated by the random walk model, but combining this dynamically with a dispatch model is much more difficult computationally.

The only quick fix is to use the random walk model with portfolio theory to generate snapshots of fuel diversity impacts. Since there are commercial portfolio models that can handle many assets, the random walk model can be used for all of the different power generating assets a utility has and then imported into a portfolio model. In collecting the required data for all of these assets, the same empirical difficulties mentioned previously exist. This difficulty will be compounded by nontraditional resources, such as conservation techniques and renewable energy resources, since there is little long term experience with them. To move beyond the quick fix, a model will have to be built mainly from scratch to combine the dispatching elements with random walk modeling and portfolio analysis.

The second area of additional theoretical research that will be discussed is placing a value on fuel diversity. This is motivated by the question: How much of a fuel price premium should electric utilities be willing to pay to ensure themselves of long term fuel supplies at a predetermined price? This question is extremely important (chapter one, page 18) to secure financing for pipeline expansions, NUG additions, and natural gas exploration and development. Moreover, the agreed upon price premium must hold ***ex post*** as well as ***ex ante.*** Years into the contract, when the current price moves away from the contracted price, a huge incentive exists to find means of breaching the contract. This is currently happening in New England. Power contracts signed in the late eighties at high prices based on the expectations of future under capacity are now being challenged given the region's current power surplus and its corresponding low market price.

A random walk model can help in answering this price premium question in two ways. First, it can quantify the impacts and probabilities of various price movements. This allows the utility to determine whether or not price risk is substantial enough to warrant mitigation. Second, the random walk model can also be used to determine how natural gas moves relative to the economy as a whole; in other words, its beta can be determined. Knowing this, the premium that should be paid to reduce its beta to an acceptable level should be able to be calculated.

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