IEEE Transactions on Power Systems, Vol. 9, No. 1, February 1994

ESTIMATING THE FLEXIBILITY OF UTILITY RESOURCE PLANS: AN APPLICATION TO NATURAL GAS COFIRING FOR SO_2 CONTROL

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Abstract — Utility planners must cope with large uncertainties concerning fuel prices, environmental laws, power demands, and the cost and availability of new resources. In this situation, flexibility is valuable. A flexible plan is one that enables the utility to quickly and inexpensively change the system's configuration or operation in response to varying market and regulatory conditions.

We present a decision tree-based method for quantifying the economic value of flexibility. The method is then used to compare the relative flexibility of natural gas cofiring with other strategies to comply with the acid rain control requirements of the 1990 U.S. Clean Air Act Amendments. For the utility studied, we conclude that cofiring gives the system significantly more flexibility than flue gas desulfurization or switching to low sulfur coal. The reason is that cofiring enables the utility to take advantage of low gas prices or high emissions allowance prices by burning more gas at those times. The value of this flexibility is approximately \$0.05 to \$0.35 per million BTU of natural gas, or \$0.03 to \$0.26/MWh of plant output. These values are significant compared to other types of benefits that have been previously quantified for cofiring.

We also compare our measure of flexibility with one based on the standard deviation of present worth. The latter perversely finds the least flexible technology (scrubbing) to be the most "flexible."

Keywords — Planning, Economics, Flexibility, Acid Rain, Air Quality, Natural Gas, Fuel Switching

INTRODUCTION

In response to new clean air requirements and increased availability of natural gas, U.S. utilities are considering building gas-fired generation and adding gas-burning capability to existing units [1,2]. One technology that may be attractive to many utilities is cofiring, the use of gas in the primary combustion zone continuously or seasonally as partial replacement for coal. Pratapas and Holmes [3] have quantified some of the potential economic benefits of cofiring. Examples include lower maintenance costs due to decreased slagging and erosion, decreased ash disposal expenses, alleviation of unit deratings caused by use of high-ash low sulfur coals, lower minimum-run capacity which allows for more dispatching flexibility, and decreased emissions. For instance, ash quality benefits were estimated to be about \$0.60/million British Thermal Units (mmBTU) of gas use.

Pratapas and Holmes [3] also concluded that cofiring would add flexibility to the generation system. Flexibility is the ability to adapt a system's design or operation to fluctuating conditions [4]. However, they could not quantify the economic value of that flexibility because they used a single forecast of fuel prices and environmental compliance costs. The value of flexibility is only apparent if the entire range of possible futures is considered [5,6,7].

93 WM 211-3 PWRS A paper recommended and approved by the IEEE Power System Engineering Committee of the IEEE Power Engineering Society for presentation at the IEEE/PES 1993 Winter Meeting, Columbus, OH, January 31 - February 5, 1993. Manuscript submitted August 24, 1992; made available for printing November 4, 1992.

Recognition of flexibility benefits may be crucial to gaining acceptance for cofiring. The questions we address are:

- o Does natural gas cofiring in coal-fired electric utility boilers add flexibility to an electrical generation system?
- o If cofiring adds flexibility, what is its economic value?

These questions are important because cofiring can help utilities comply with the acid rain control program of the U.S. Clean Air Act Amendments of 1990. This program is unique because it allocates SO_2 emission allowances to the nation's utilities and permits those allowances to be bought and sold. Utilities are prohibited from emitting more tons of SO_2 than the number of allowances they hold. If a utility owns too few allowances, it can lower emissions using not only traditional measures such as switching fuels, but also by novel strategies, including energy conservation and emissions dispatch. Emissions dispatch is the operation of a generation system so that cleaner units produce more power, resulting in cost-effective emissions reductions [8]. The utility can also just buy the allowances it needs in the market.

But the Act has also introduced new uncertainties. Compliance planning is now a market-oriented process, rather than just an engineering concern. The market price of allowances, which is not perfectly predictable, will drive utility decisions concerning how much, or how little to reduce their SO_2 emissions. There are also uncertainties regarding price premiums for low sulfur coal and possible technological developments that could lower the cost of emissions control equipment -- on top of the load and fuel price uncertainties that utilities already reckon with.

In this uncertain environment, flexibility is valuable. Cofiring would enhance a utility's flexibility because investments that leave more options open generally enhance flexibility [4]. For instance, cofiring gives the utility a dual fuel capability.

We propose that flexibility be gauged by contrasting 1) how well a system performs under a single set of expected future conditions with 2) how well it performs, on average, if all possible conditions, and their probabilities, are considered [6,9]. A flexible system's mean cost will improve relative to an inflexible system when uncertainties are included. This is because inflexible systems incur higher cost penalties if conditions other than those expected occur. But a flexible system can adapt to a range of circumstances.

Our definition of flexibility resembles other definitions, and the related concepts of adaptability and robustness. Stigler [10] defines economic flexibility as the ability to adapt to a wide range of possible demand conditions in the short run at little additional cost. This has been measured in several ways [11]. One is to examine the sensitivity of total system cost should future conditions differ from a base set of conditions [12]. Sensitivity could be measured, for example, by the standard deviation of the present worth of cost; a lower value would imply a more flexible system. A related concept, "robustness", has been defined as the probability that the actual cost of the system will not exceed some multiple of the minimum possible cost of a system designed for the actual conditions that occur in the future [13]. In [14], robustness is instead defined as the proportion of possible futures a given plan would be best in. However, these proposed measures of flexibility/robustness make no explicit reference to adaptability. Indeed, a plan that cannot be adjusted at all might still be found to be "flexible" by these indices. Another proposed measure, which might be termed "adaptability," considers the number of irrevocable decisions that must be made now, versus the number and diversity of options left open [15].

In contrast to previously proposed indices, we measure the worth of flexibility in expected dollar terms so that it can be compared to other economic benefits of cofiring. Our measure is related to adaptability in that a plan that leaves options open is more likely to perform well under a wide range of future conditions and, thus, have a high value of flexibility as we define it.

Cofiring can enhance a generating system's flexibility in several ways. Cofiring's short lead time allows utilities to defer installation decisions until more information is available on market conditions. Its low capital cost makes it feasible to use cofiring as an interim control measure; this enables the utility to take advantage of possible future decreases in the cost of emissions control equipment. The ability to vary the amount of natural gas used allows the utility to adapt to changing natural gas and SO_2 allowance prices. The lower emissions resulting from cofiring would permit the utility to do more emissions dispatch if allowance prices are high. And, finally, cofiring's enhancement of the generating capability of some boilers would help utilities cope with load growth.

In the next section, we show how decision trees can be used to calculate flexibility benefits. Subsequent sections summarize the assumptions made in our analysis of cofiring's flexibility, the solution method we applied, and the results of the analysis. The last section compares our proposed measure of flexibility with an index based on the standard deviation of costs.

USING DECISION TREES TO CALCULATE FLEXIBILITY BENEFITS: A SIMPLE EXAMPLE

The following example illustrates how flexibility benefits can be calculated and why it is important to consider uncertainty in assessing the benefits of natural gas cofiring. Let's assume that the future price of interruptible natural gas might take on any of three values in the future: $2.40, $3.20, and $4.00/million British Thermal Units (mmBTU). Also assume that if a utility invests in the capability to cofire, at an annualized cost of $500,000/yr, it will find it worthwhile to burn some gas only if the price is $2.40/mmBTU. In that case the benefits would be $3.3 million/yr compared to burning coal.

A naive analysis of the net benefits of cofiring might be based on a single deterministic forecast of future gas prices. If the average value ($3.20) is used as the forecast, then no benefits would be anticipated for cofiring, and the $500,000/yr investment would seem unjustifiable. However, such a deterministic analysis is inappropriate, since it ignores the flexibility of cofiring: its ability to take advantage of lower gas prices if and when they occur. If the lower price ($2.40) has, say, a 1/3 chance of occurring in any year, then the average benefits of cofiring are actually 1/3*$3.3 million/yr. The expected net benefit of cofiring is therefore $1,100,000 - $500,000, or $600,000/yr. Thus, installing cofiring capability is justified if fuel price uncertainty is considered.

This also shows that price variations can be useful to electric utilities, rather than something to be avoided [see also 2].

The difference between the deterministic net benefits of cofiring (-$500,000/yr) and the expected benefits under uncertainty (+$600,000/yr) equals $1.1 million. This value we call the ***relative flexibility benefit*** of cofiring. In the remainder of this section, we show how this result can be obtained using a decision tree. Decision trees are often applied in utility planning [16,17,18,19,20,21], but have not been used to explicitly calculate the benefit of flexibility as defined here.

A decision tree such as Fig. I consists of three basic elements: chance nodes, decision nodes, and outcomes. A tree shows how events may unfold and what decisions can be made over time. Time proceeds from left to right. Uncertainties are portrayed using chance nodes (round nodes), with possible events shown as distinct paths leading to the right, each having a probability associated with it. The probability of an event can be assigned based on historical data, modeling, or judgments by experts. Decision options, in contrast, are represented as paths to the right from a decision node (a square in Fig. I). When solving a tree, the decision maker must choose one option for each decision node. The ultimate consequence of a particular path through the tree (a series of events and decisions) is shown as an outcome at a terminal node on the right hand side of the tree.

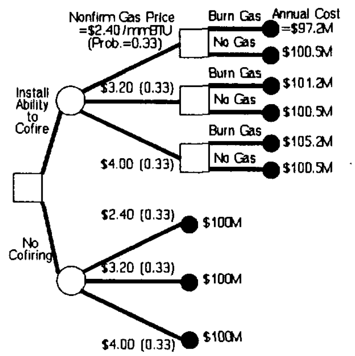

Figure I. Example Decision Tree Used to Calculate Flexibility

Fig. I represents a tree for the cofiring decision just described. It shows that the utility must choose between using 100% coal or installing the capability to cofire natural gas. Proceeding from left to right, we see that after the choice is made, gas prices can either be low, medium, or high in a given year. The probability of each is shown in parentheses. If the utility has invested in cofiring capability, then after knowing what the gas price is, the utility can decide whether or not to actually cofire gas. The outcomes (annual power supply cost) are shown next to the terminal nodes. For example, if cofiring is installed and gas prices are low, then if the utility decides to burn gas, the annual generation cost for the system is $97.2 million. This value is $3.3 million less than the cost if instead no gas is burnt. All of the outcomes in which cofiring capability is installed but 100% coal is burnt cost more ($100.5 million) than not having the ability to cofire ($100 million), due to the capital expense of cofiring ($0.5 million).

"Solving" a decision tree consists of identifying an optimal strategy and its expected performance. An optimal strategy defines the best decision for each decision node. To determine the optimal strategy for a decision tree, the tree must be "folded back." This procedure starts at the terminal nodes and moves backwards through the stages of the tree. At each chance node, the expected value of the outcomes is calculated. At each decision node, the option with the lowest expected cost is chosen. The procedure works its way backwards through the tree until the calculations for the first node on the left are completed.

Applying this procedure to Fig. I, the calculations are as follows. First, the best decision in each of the right-handmost nodes is determined. For the first such node, burning gas is cheaper than using 100% coal. However, for the other two nodes, burning coal is best. The next stage is to calculate the expected value at each of the two chance nodes. For installation of cofiring, this value is 1/3($97.2 + $100.5 + $100.5)x$10^6$, or $99.4 million. In the case of no installation, the expected value is instead $100 million.

What are cofiring's flexibility benefits relative to burning 100% coal? We answer this question by first calculating the system's flexibility under each option, and then comparing the two values. The flexibility of the system if cofiring is installed equals $1.1 million, the difference between the system's expected performance under uncertainty ($99.4 million) and its performance under certainty (i.e., under expected gas prices, $100.5 million). The system's flexibility without cofiring is zero, as its expected cost under gas price uncertainty is the same as its cost under expected prices. Thus, cofiring enhances the system's flexibility by $1.1 million: this is the relative flexibility benefit of cofiring.

Flexibility benefits are conceptually distinct from another quantity often calculated using decision trees, the expected value of perfect information (EVPI) [e.g., 16]. EVPI is the most that a decision maker would be willing to spend, before decisions are made, to find out how the uncertainties will be resolved.

Mathematically, the flexibility of a resource plan X (e.g., install cofiring) relative to another plan Y (e.g., install scrubbers instead) can be defined as follows. Let θ be a vector of uncertain variables (such as gas, low sulfur coal, and allowance prices) and $C(Z|\theta)$ be the cost of choosing plan Z, given that θ occurs. The flexibility F(Z) of generating system with plan Z is defined as:

$$F(Z) = C(Z|E(\theta)) - E(C(Z|\theta)) \qquad (1)$$

E( ) designates expectation. The relative flexibility of plan X compared to plan Y is then F(X)-F(Y), in our case $1.1 million.

Equation (1) shows that flexibility and the concavity of the cost function $C(Z|\theta)$ with respect to θ are intimately related. It can be shown from the mathematical definition of concavity that the more concave the function is, the larger is the right side of (1). Adding more options tends to make cost functions more concave by offering opportunities to decrease costs when θ deviates from its mean.

The relative flexibility of cofiring, when calculated in this manner, can be added to other economic benefits of cofiring estimated using traditional engineering economic methods under certainty [e.g., 3]. For instance, say that one study shows that the benefits of cofiring compared to burning 100% low sulfur coal would be $1/MWh of output under a given forecast of fuel prices. Further, let the relative flexibility benefit of cofiring in comparison to low sulfur coal be estimated to be $0.20/MWh when assessed considering a range of prices. Then a more realistic estimate of cofiring's total benefit -- realistic because it recognizes the uncertainties faced by planners -- is $1.20/MWh. Mathematically:

$$[E(C(Y|\theta)) - E(C(X|\theta))] = [C(Y|E(\theta)) - C(X|E(\theta))] + [F(X)-F(Y)] \qquad (2)$$

In words, the benefit of choosing X over Y under uncertainty is the net benefit of X under certainty plus X's relative flexibility benefit.

APPLICATION TO COFIRING

The Case Study

The flexibility benefits of cofiring are assessed for an actual midwestern U.S. utility which we call "Utility X." Details on the analysis are given in [22]. The utility will have 6756 MW of predominantly nuclear and coal capacity in 1995, serving a peak load of 4719 MW. Combustion turbines will make up all generation additions after that year.

In response to the new Clean Air Act, the utility must make decisions about installation of emissions control at two pulverized coal units, A and B. Their combined capacity is 651 MW. Utility X is considering the possibility of cofiring gas at units A and B in combination with either high or low sulfur coal. Other options for those units include switching to low sulfur coal, installing flue gas desulfurization, and burning high sulfur coal. We assume that if the utility has insufficient emissions allowances, it will buy what it needs from the market at the prevailing price, while if it has more allowances than it needs, it will sell the surplus.

Our focus is on units A and B, but the utility wishes to minimize the present worth of the entire system's capital and operating expenses for the period 1995-2010. The whole system is considered because emissions controls at one generating unit will affect that unit's capacity, variable costs, outage rate, and emissions, which, through dispatch decisions, impact the output of other units in the system [23]. The cost of operating the generating system under a given set of controls and fuel prices is calculated using a probabilistic production costing model that allows emissions dispatch [24]. The calculations include the opportunity cost of emissions allowances, equal to the tons of SO_2 emitted times the price of allowances. Considering this cost is appropriate, as any allowances consumed must either 1) be bought or, if the utility already owns them, 2) not sold to other utilities and the revenue foregone.

The Decision Tree

Fig. II displays the decision tree summarizing the options Utility X has in each year and the uncertainties it faces. The sequence of the utility's decisions concerning emissions controls at units A and B are described below. All costs are in 1990 dollars.

- <u>In 1991, the utility must decide whether to install flue gas desulfurization at units A and B immediately ("scrub now") or to delay the decision to scrub ("wait and see")</u>. The scrubber's capital cost is $275/kW, which we annualize over the remaining life of the generating units.

- If "scrub now" is chosen, the scrubber is built to come on line in 1995. Then, <u>in each year of the planning period (1995-2010), the utility must decide how to dispatch its entire generation system</u>, given the level of low sulfur coal, gas, and allowance prices in that year (shown as "C,G,A Uncertainty" chance nodes). (For simplicity, Fig. II does not show these year-to-year operating decisions explicitly.)

- If instead the utility decides to "wait and see", then in 1994 <u>it must decide which of four control options it will choose to implement at A and B starting in 1995</u>. These options include burning high or low sulfur coal, and installing the ability to cofire 15% natural gas in combination with either coal. The capital cost of cofiring, including burners and piping on the plant site, is $7.5/kW of capacity. In addition, cofiring would increase nonfuel variable O&M costs and the units' heat rates, decrease their forced outage rates, decrease their minimum run levels, and, if low sulfur coal is burnt, boost generating capacity by 3%. We assume that which option the utility chooses

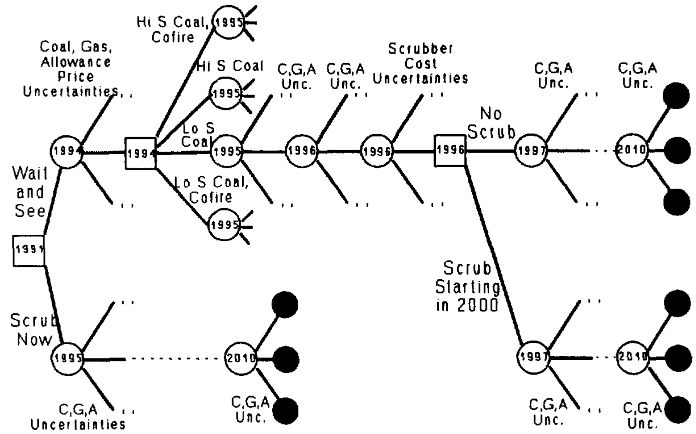

Figure II. Decision Tree for Flexibility Analysis of Cofiring (Dispatch and Gas Use Decisions Not Shown)

can depend on what coal, gas, and allowance prices prevail in 1994. For instance, if allowance prices are high in that year, while gas and low sulfur coal prices are low, then the option "Lo S Coal, Cofire" will appear more attractive because future prices would be anticipated to be similar. The "wait and see" option gives flexibility to defer decisions about the exact means of emissions control until 1994, when more is known.

- After a compliance technology has been chosen under the "wait and see" option, <u>the utility must choose how to operate its system in 1995 and 1996</u>. If one of the cofiring options has been picked in 1994, then the utility not only can decide how to dispatch its units in each season of each year, it can also decide whether to use its cofiring capability and burn 15% gas.

- Under the "wait and see" option, <u>the utility must decide at the end of 1996 whether or not to retrofit a scrubber in time for operation by the year 2000</u>. This decision will be based on two factors: 1) the prices of fuels and allowances in 1996; and 2) whether the cost of scrubbing has increased, decreased, or stayed the same since 1991. For instance, high prices for allowances and low sulfur coal, together with low scrubber costs would make a retrofit more appealing in 1996. Then, after its retrofit decision has been made, <u>the utility must decide whether to burn gas (if cofiring is installed) and how to dispatch the system in the years 1997-2010</u>, considering what emissions control options have been chosen and the prevailing fuel and allowance prices.

We model four uncertainties in the tree:

- <u>The price premium for low sulfur coal in each year</u>. We assume that the premium can fluctuate from year to year among three states: low (15-25% premium), medium, and high (about a 50% premium). A Markov chain is used to describe the stochastic process [25,26]. In a Markov chain, the chance of being in a state j in period t+1 depends only on what state i the system was in during t.

- <u>The price of natural gas in each year</u>. Summer non-firm gas costs only 75% as much as winter firm supplies. Like low sulfur coal prices, annual fluctuations of gas prices are described by a Markov chain with three states: low, medium, and high. The low state represents zero real escalation from present gas prices. In the high state, gas prices escalate 2.3% per year from 1995 to 2000, and 4.5%/yr afterwards.

- <u>The price of SO_2 allowances in each year</u>. Uncertainty in these prices is anticipated to be very high, at least in Phase I, because there is no prior experience with this market. As in the case of fuel prices, a three state Markov chain describes the movement of allowance prices. Low prices fall between \$310 and \$360/ton SO_2, depending on the year, while high prices lie in the range \$930-\$1080/ton. We assume that allowance prices can be positively correlated with low sulfur coal prices, but are independent of natural gas prices.

- <u>The capital cost of scrubbers whose construction starts in 1996</u>. Further R&D may result in scrubbers that are 15% less costly than in 1991, with probability 0.3. But we assume a 0.2 chance that solid waste disposal regulations will be tightened, making costly regenerable scrubbers the only feasible choice. In that case, the capital cost would be 22.5% higher.

For simplicity, the coal, gas, and allowance price chance nodes are collapsed into a single node in Fig. II. In general, each of those nodes has 27 possible outcomes (3x3x3). Probability distributions were based on consultations with experts and analyses of past prices [22]. Various assumptions concerning autocorrelations, which describe the persistence of prices over time, were tested and did not significantly alter the conclusions.

<u>Solving the Tree and Calculation of Flexibility Benefits</u>

The decision tree in Fig. II is huge. As shown, it has over 10^{25} terminal nodes and is impossible to solve. However, the Markovian structure of the fuel and allowance uncertainties allow us to solve the tree quickly using stochastic dynamic programming [25,27]. This method solves the following equation iteratively, starting at t = summer, 2010 and ending at t = winter, 1991:

$$C_t(X_t|\theta_{jt}) = \underset{\{Y_t,X_{t+1}\}}{\mathrm{MIN}} \left[c_t(Y_t|X_t,\theta_{jt}) + \Sigma_k P_{jkt} C_{t+1}(X_{t+1}|\theta_{kt+1})/(1+I)\right] \qquad (3)$$

where:

θ_{jt} = Realization number j of random variables (fuel and allowance prices, scrubber costs) during period t. There are two periods per year: summer and winter.

I = Discount rate per period.

P_{jkt} = Transition probability from θ_{jt} in t to θ_{kt+1} in t+1.

X_t = Vector of emission control investments in place at the start of period t (investments in cofiring capability or scrubbers; coal choice).

Y_t = Vector of operating variables for period t (dispatch decisions, use of gas for cofiring). These variables are omitted for 1991-1994.

$C_t(X_t|\theta_{jt})$ = Optimal expected cost from start of period t through 2010, given emission controls X_t and values of random variables θ_{jt}.

$c_t(Y_t|X_t,\theta_{jt})$ = Cost of operating the generating system, given system configuration X_t and random variable values θ_{jt}, plus X_t's annualized capital cost.

The solution is found by first performing production costing simulations (i.e., finding MIN $c_t(Y_t|X_t,\theta_{jt})$) for each discrete X_t and θ_{jt} in each period. The most such simulations that have to be done in any t are 54 for each of the two alternative cofiring options (accounting for the 27 possible combinations of allowance, coal, and gas prices, both with and without burning 15% gas) and 9 each for the coal alone and scrubber alternatives (considering just coal and allowance prices). Computational effort is further reduced by estimating the production cost in some years by interpolating between adjacent years. The second step is then to solve the above recursive equation using a spreadsheet.

The expected cost $E(C(Z|\theta))$ of a particular control option Z is obtained by solving a version of the tree in which the other control options are eliminated. For example, if Z = "wait and see" followed by "cofire with low sulfur coal", the three other 1994 options plus "scrub now" would be dropped. $C(Z|E(\theta))$ is calculated similarly, except that we also assume that $E(\theta)$ occurs with probability 1. Flexibility benefits F(Z) can then be estimated using (1).

We contrast cofiring's flexibility benefit with that of other technologies to obtain a relative flexibility benefit of cofiring. If positive, this indicates that cofiring results in more flexibility than the technology it is compared with. This relative benefit is expressed in two ways: as total dollars (present worth) and as a levelized benefit per MWh of energy production from units A and B. For the purpose of calculating the levelized benefit, only the present worth of summer MWh generation is included in the denominator of the levelization formula. The reason is that cofiring almost never takes place in the winter in our solutions.

RESULTS

Cost-Effectiveness

For Utility X, the "wait and see" strategy is the best choice in 1991 if uncertainties are considered. Further, the combination of low sulfur coal and cofiring is preferred in 1994, no matter what prices are realized in that year. Even if the utility was to choose high sulfur coal in 1994, it would also want to install cofiring.

Fig. III portrays these results in terms of the relative present worth of system costs, including the value of emissions allowances that are consumed. The values are relative to the present worth of the best option, "wait and see" with low sulfur coal plus cofiring in 1994. Let W define that best plan, and Z designate any other plan. The figure shows two sets of values: one derived assuming complete certainty $(C(Z|E(\theta))-C(W|E(\theta)))$ and the other an expected value calculated under uncertainty $(E(C(Z|\theta))-E(C(W|\theta)))$. Thus, for example, cofiring with low sulfur coal is less than \$1 million less expensive than "scrub now" under certainty, but is over \$5 million cheaper if the full range of possible prices is considered. These savings are relatively small compared to, say, the investment cost of scrubbers, but are nonetheless worth pursuing.

Cofiring is optimal for two reasons. First, because cofiring is assumed to increase the generating capability of the two units studied, the utility needs to build less generation capacity in the future. The cost of installing cofiring is less than half of the cost of the combustion turbine capacity that the utility can avoid adding.

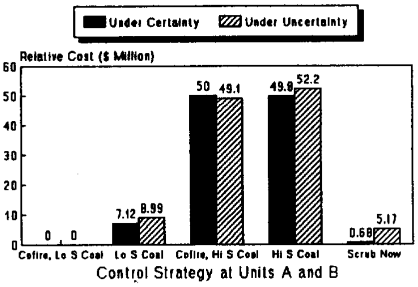

Figure III. PW of System Costs for Control Options at Units A and B (651 MW) Relative to Cofiring with Low Sulfur Coal

The other reason for cofiring's superiority is that it is more flexible than the other technologies. By installing cofiring, the utility can take advantage of low gas prices or high prices for SO_2 allowances or low sulfur coal to switch from 100% coal to 85% coal/15% natural gas. Even though fuel costs increase as a result, the value of the emissions allowances freed up makes burning gas worthwhile in those cases. This lowers the utility's total cost in many circumstances, even though under *average* conditions cofiring might be, at best, only marginally economic.

The Flexibility Benefit of Cofiring

The relative flexibility of cofiring, the second reason for the technology's cost-effectiveness, can be quantified by examining Fig. III. It shows that cofiring's relative cost advantage increases if uncertainty is considered. For example, low sulfur coal alone is about \$7 million more costly than cofiring with low sulfur coal under certainty; but if uncertainty is considered, then cofiring's cost advantage grows to \$9 million. Thus, the relative flexibility benefit of cofiring compared to low sulfur coal alone is about \$2 million for this utility (=F(W)-F(Z), for W = cofire with low sulfur coal and Z = low sulfur coal alone).

When compared to scrubbing, the flexibility advantage of cofiring becomes even more pronounced. As noted above, scrubbing is less than \$1 million more expensive under certainty but is five times that amount more costly under uncertainty. Thus, cofiring has a \$4 million relative flexibility benefit in that comparison, as its cost advantage increases by that amount when uncertainties are considered. When burning high sulfur coal, the results are similar. Under certainty, cofiring with high sulfur coal costs more than not cofiring. But if uncertainties are considered – e.g., by acknowledging the possibility of high allowance prices or low natural gas prices – cofiring with high sulfur coal becomes \$3 million less expensive than high sulfur coal alone.

Expressed on a levelized basis, this relative flexibility benefit of cofiring ranges from \$0.03 to \$0.26/MWh or more. The exact values depend on the technology cofiring is compared to. The values also reflect the assumptions made concerning the capital costs of different technologies, their effect upon generator capacity, and the probability distributions of prices. Another important factor is the stringency of pending U.S. Environmental Protection Agency (EPA) rules preventing "underutilization" of generating units that are subject to the allowance system in 1995-1999 [28].

Cofiring's relative flexibility benefit is highest when cofiring is compared to scrubbing, which is a comparatively inflexible technology; in situations in which cofiring significantly increases boiler capacity; or if the probability distributions of fuel and allowance prices have a high variance. Smaller values of benefits result if cofiring is compared to just burning low sulfur coal; if EPA's underutilization regulations significantly restrict emissions dispatch; or if probability distributions have a low variance.

Most of cofiring's flexibility benefit arises from its ability to take advantage of low gas prices or high allowance prices. Under such favorable circumstances, Utility X burns gas, reduces emissions, and, thus, frees up valuable allowances. In contrast, cofiring does not greatly enhance the system's ability to respond to changing low sulfur coal prices. These results are derived by estimating cofiring's flexibility when only the price of one commodity at a time (gas, allowances, or low sulfur coal) is random. When just coal prices are varied, cofiring's flexibility benefits are much less than if only allowance or gas prices are uncertain.

Furthermore, little or none of cofiring's flexibility benefit is due to its giving Utility X the ability to defer decisions concerning scrubbing. The option of installing a scrubber by the year 2000 if its capital cost drops by 15% (Fig. II) does not enhance cofiring's attractiveness in most cases. This occurs because such a drop in capital cost is insufficient to compensate for the shorter period of time over which the investment must be recovered.

Some of the cofiring's flexibility derives from being able to do more emissions dispatch. Surprisingly, we found that this additional emissions dispatch results from units A and B generating *less* energy under cofiring. This occurs in Phase I (1995-99) because cofiring decreases those units' minimum run capacity. Generation from other units with lower emission rates increases in compensation. We had instead expected that the cofired units would increase their output at the expense of dirtier facilities. This may still occur in other utility systems if much of the capacity consists of dirtier units and allowance prices are high. Alternatively, if EPA's underutilization regulations impose a severe constraint on the output of Phase I units, then, if gas prices are low and allowance prices high, it may be best to boost the output of cofired Phase I units at the expense of other Phase I units.

STANDARD DEVIATION OF COSTS AS A MEASURE OF FLEXIBILITY

A common-sense definition of a robust plan is one whose cost varies little with changes in assumptions. Synonyms for this idea might be "predictability" or "stability," which are desirable to financial planners. This concept has also been proposed as a definition of flexibility [12]. An index corresponding to this idea is the standard deviation SD of the present worth of system cost. That index has been widely used as a measure of risk in the economics and management science literature [29] (although that use has also been criticized [30]). But is it a useful measure of flexibility?

For our cofiring case study, the answer is no. We calculated SD for the five major alternatives using the method described in the Appendix, with the results shown in Table 1. The values are in the range of 260 to 344 million dollars, which are approximately 3-5% of the present worth of fuel expenses, allowance opportunity costs, and investment costs of emissions controls. The most "flexible" option by this measure is to scrub now, because it has the lowest SD. This occurs because installing scrubbers leaves the system relatively invulnerable to fluctuations in allowances, low sulfur coal, and natural gas prices. However, scrubbing is actually the least flexible strategy, since it leaves few options open for the future; this reality is reflected in our economic measure of flexibility, which finds scrubbing to be less flexible than cofiring.

Table 1. Standard Deviation of Present Worth of Costs

Cofiring Capability, Low Sulfur Coal	$304,200,000
Low Sulfur Coal Alone	$306,400,000
Cofiring Capability, High Sulfur Coal	$338,500,000
High Sulfur Coal Alone	$344,400,000
Scrub Now	$259,600,000

Note: No recourse to scrubbing in 1996 assumed in calculation.

On the other hand, burning coal with neither cofiring nor scrubbing results in a greater standard deviation than cofiring. This is true whether high sulfur or low sulfur coal is burned. In this case, the truly more flexible technology (cofiring) does indeed have a lower standard deviation. The reason is that cofiring lowers emissions, lessening the system's sensitivity to allowance prices.

We conclude that the standard deviation of costs is a poor measure of flexibility. However, it may still be a useful index of risk. A utility might reasonably decide that the predictability of scrubber costs, as reflected in its lower standard deviation, is worth paying a few extra million dollars in expected value (Fig. III). However, we have assumed that there is no uncertainty in the cost of scrubbers built today; this is manifestly untrue.

CONCLUSION

We have demonstrated a decision tree-based method for quantifying the economic value of flexibility. This approach can be used to estimate, for example, the contribution that demand-side management, short-lead time power plants, and bulk power purchases could make to system flexibility [see, e.g., 20].

An application to natural gas cofiring is presented. Although cofiring's flexibility benefits are too small by themselves to justify the price premium of gas, for some utilities they might mean the difference between positive and negative net benefits for cofiring.

However, the exact value of flexibility benefits depends on highly subjective judgments concerning probabilities of fuel prices, regulatory changes, and other factors. Thus, our method is best interpreted as a way of showing the economic implications of such judgments, rather than as a scientific technique that yields "objective" results. Sensitivity analysis is crucial.

ACKNOWLEDGMENTS

This work was sponsored by the Gas Research Institute, Project 5086-254-1382. However, any opinions expressed in this paper are the authors' responsibility. Computational assistance by Sushil Nelson and Wenxiong Huang is gratefully acknowledged.

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APPENDIX: CALCULATION OF STANDARD DEVIATION OF THE PRESENT WORTH OF A STRATEGY

Let C be a given strategy's present worth of cost, and let X_t' be the assumed emission control investments in place at the start of each period t. (In general, X_t' depends on what values of the random variables $\{\theta_1,..,\theta_{t-1}\}$ were realized in the previous periods 1,..,t-1; however we assume here that the investments in controls are known ahead of time.) E(C) is calculated from the decision tree using (3) and the assumed values of X_t'. The standard deviation of C is obtained as the square root of $E(C^2)-[E(C)]^2$. $E(C^2)$ is obtained by the following recursive formula:

$$E[C_t(X_t'|\theta_{jt})^2] =$$

$$C_t(X_t',\theta_{jt})^2 + 2C_t(X_t',\theta_{jt})\Sigma_k P_{jkt}C_{t+1}(X_{t+1}|\theta_{kt+1})/(1+I) +$$

$$\Sigma_k P_{jkt}E[C_{t+1}(X_{t+1}'|\theta_{kt+1})^2]/(1+I)^2 \quad (4)$$

where: $E[C_t(X_t'|\theta_{jt})^2]$ is the expected value of the present worth of squared system cost from year t on, given θ_{jt}

$C_t(X_t',\theta_{jt}) = MIN_{\{Yt\}}\ c_t(Y_t|X_t',\theta_{jt})$, the production cost and annualized capital cost during t, given X_t' and θ_{jt}

This equation is solved recursively starting at the last t. $E(C^2)$ is the left side of (4) when the calculation is completed for t=1.

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