MANAGING RISK WITH RENEWABLE RESOURCES

Michael C. Brower[1]
Stephen Bernow and Max Duckworth[2]
Peter Spinney[3]

INTRODUCTION

The question of uncertainty and risk in electric utility resource planning has received considerable attention in recent years. During the 1980s, many utilities suffered losses because of unexpectedly high plant construction costs and low growth in electricity demand. Since then, the introduction of competition to the electric industry has created additional risks for power companies. No longer will utilities be able to count on regulatory protections and a base of captive consumers to provide a stable market and adequate return on their investments. New risk management strategies will have to be considered.

One approach to managing risk is for a utility company to invest in diverse power sources such as wind power plants. Since wind plants consume no fuel, can be built in relatively small increments with short construction lead times, and generate no pollutants, it is often said that they offer significant protection from risks associated with conventional fossil-fuel power plants. With assistance from Convergence Research, Charles River Associates, and the Tellus Institute, we tested this hypothesis by conducting an in-depth analysis of the risk implications of a decision to build a 1600 MW wind power plant instead of a 400 MW gas-fired combined cycle plant. (The two plants were assumed to have equal firm capacity.) The case study utility was Texas Utilities Electric, a very large investor-owned company serving an area with substantial, high-quality wind resources. The uncertain inputs included fuel prices, environmental regulations (specifically, CO_2 and air pollution controls), wind plant output, conventional plant availability, and load growth. Two different market scenarios were examined: traditional regulation and an unregulated wholesale market characterized either by a power pool or fixed-price contracts of varying duration.

Our conclusions are striking: Under traditional regulation, wind energy provides a net present-value risk-reduction benefit of $3.4 to $7.8/MWh. Since most risks under this system of regulation are passed on to customers, the customers would see virtually all of this benefit in the form of reduced variability in electricity prices. In the unregulated scenario, however, risks are divided differently among shareholders and consumers, so the benefits of the wind investment are divided differently as well. In a power pool setting, we found that utility shareholders would receive a benefit amounting to a remarkable 1 to 1.5 percent extra return on equity. These findings should apply equally well to other renewable plant investments involving low fuel costs with few environmental regulatory risks, such as photovoltaic systems and landfill methane.

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[1] Brower & Company, 154 Main Street, Andover, MA 01810.

[2] Tellus Institute, Boston, Massachusetts.

[3] Charles River Associates, Boston, Massachusetts.

In many cases, a risk reduction of the magnitude we observed could tip the scales in favor of higher cost renewable plants. Clearly, utility companies need to take risk factors into account in making their resource decisions, especially in a deregulated market environment where the risks fall more heavily on company shareholders.

OVERVIEW OF THE MODEL

The model we developed and used, the Strategic Resources Planning (SRP) model, generates resource expansion plans and estimates capital and operating expenses for the utility over a 20-year period. The resource plans and their estimated costs differ with each Monte Carlo draw of the uncertain inputs. For example, if gas prices increase sharply relative to coal prices in a particular draw, the model may select coal or wind instead of gas in its build decisions. The results of all the simulations are collected and presented as both an expected value and standard deviation of any indicator of interest (such as the present value of future revenue requirements or annual net income). Simulations are run until statistical errors fall to an acceptable level; this usually takes about 300 runs. The wind and gas scenarios are run simultaneously, using the same uncertain inputs, resulting in a very precise determination of the differences between them.

The capital costs and operating characteristics of new and existing fossil plants are based on TU Electric data. The wind capital cost is assumed to decrease from $908/kW in 1996 to $845/kW in 2003. The wind capacity factor, 36 percent, is derived from DOE Candidate Wind Site data collected near Amarillo, Texas, assuming a 40 meter tower height and a power curve for the Enercon E-40 wind turbine. The initial 1600 MW of wind capacity is assumed to have a capacity value of 25 percent, which is in accordance with several studies of capacity value on other utility systems.

Fuel Price Trends and Variations

The purchase of fossil fuels for use in power plants is one of TU Electric's largest expense items, constituting about $1.2 billion out of total operating revenues of $5.6 billion in 1994. It is also one of the most variable and unpredictable. From 1976 to 1985, gas prices paid by TU Electric rose at an average real (inflation-adjusted) rate of 15.7 percent, while coal prices rose at an average rate of 10.2 percent; from 1986 to 1993, however, gas prices fell at a 5.8 percent rate, while the rate of decline of coal prices averaged 1.5 percent. These large variations are reflected in the standard deviation of annual real price changes, which from 1976 to 1993 was 16.6 percent for gas and 10.2 percent for coal.

TU Electric's recent fuel price projections indicate that the company expects fuel prices to be much more stable in the future. Filings for the 1995 Integrated Resource Plan show an expected real growth rate in gas prices of 1.9 percent per year from 1994 to 2014, with a possible high rate of 2.8 percent and low rate of 0.5 percent. Little or no change is expected in the price of coal or lignite.

In the SRP model, it is assumed that fuel price variations follow a random-walk process, with an adjustment for temporary price "shocks" caused by weather, temporary supply shortages or surpluses, and other factors. This approach is easy to model and can readily reproduce historical price behavior. In a random walk, each annual change in price establishes a new starting point from which the next year's price is calculated. Price shocks are assumed to disappear after one year.

The random changes in price are drawn from a normal (Gaussian) distribution. The mean of this distribution is taken from TU Electric's median price forecasts, i.e., 1.9 percent for gas and zero for coal. For the standard deviations, we consider two cases. In the high-risk case, we assume that prices will be about as unpredictable and volatile in the future as they have been in the past 25 years. This implies, for gas, a standard deviation of 12 percent in the random walk and 10 percent in the price shocks, resulting in a combined standard deviation of 16 percent. The random walk process results in a long-term range of variation in price that is about three times as large as TU's forecast range. The low risk case is defined by TU's forecast range, which leads to a standard deviation of 4 percent in the random walk and of 6 percent in the price shocks. The volatility of coal prices is assumed to be about two-thirds that of gas prices in both cases.

Load Growth

Unexpected changes in loads can affect the utility company's revenues and profits as well as prices paid by its customers. The past record shows that loads have been variable in the past, although not as variable as gas or even coal prices have been. From 1977 to 1993, the standard deviation in annual changes in TU's peak load was 5 percent. TU Electric's 1995 load forecast suggests a continuation of historical load behavior in the future. The company predicts an average rate of growth in peak loads of 2.5 percent (compared to the historical 3.4 percent) from 1994 to 2004, with a 40 percent chance that the rate may be as high as 3.9 percent and a 40 percent chance that it may be as low as 0.9 percent.

Loads are modeled in the same way as fuel prices, with a combination of a random walk and one-year load shocks due to weather, short-term economic activity, and other factors. As before, the random variables are generated from a normal distribution. Based on TU Electric's projections (and taking into account planned demand-side management efforts), we assume a mean rate of increase of 1.93 percent, with a standard deviation of 3.8 percent to match the range of TU Electric's ten-year forecast. The one-year load shocks are assumed to have a standard deviation of 3.25 percent, yielding a combined standard deviation in load changes of 5 percent.

Environmental Costs

Environmental regulatory risks are more difficult to simulate than other parameters because of the paucity of meaningful historical data on which to base predictions. Nevertheless, the potential liability for electric utilities and their customers appears to be large. According to EIA data, investor-owned utilities have invested about $60 billion in environmental compliance costs over the past several decades; TU electric's cumulative investment is $2.4 billion. The greatest future cost may be that of greenhouse-gas regulation, although additional NO_x and SO_x controls as well as limits on toxic metals such as mercury and cadmium may also prove expensive. For simplicity, we have chosen to represent all potential environmental regulatory costs as a CO_2 tax or fee, which may be implemented through an emissions allowance trading system like the SO_2 trading system.

The characterization of the CO_2 regulatory risk in the SRP model has two components. The first is the probability that CO_2 controls will be imposed. We assume that in the high-risk case, that probability is 70 percent over the 20 years after the first year of operation of the wind or gas plant. In the low risk case, the probability that some kind of controls will be imposed over the same period is assumed to be just 30 percent.

The second component is the probability distribution of CO_2 taxes or emissions allowance costs. In an emissions allowance trading regime, the price of an allowance should be equal to the average marginal cost of reducing CO_2 emissions to the level mandated by law. Different studies have produced estimates of the marginal control cost ranging from $10 to $150 per ton for reductions of 20 to 50 percent. Costs near the upper end of this range are not likely to be politically supportable, however, unless the impacts of greenhouse warming prove very severe indeed. We believe a fair range of estimates for the probable cost of control under an emissions trading regime would be $5 to $35 per ton, with a mean value of $25 per ton. The assumed probability distribution is Gaussian with a zero mean from which only positive values are drawn. In order to yield the desired mean control cost, the standard deviation of this distribution is $31.3 per ton.

Plant Availability

Uncertainty in plant availability has frequently been ignored in utility resource planning, even though it can have a powerful impact on reliability and cost of service when a utility system is dominated by a few very large plants. It is especially important to consider in this study because the availability of wind plants is likely to vary much more than that of fossil-fuel plants.

The variability in the annual output of wind power plants is well understood and easily modeled. To estimate its magnitude we simulated the performance of a wind plant using the Enercon E-40 wind turbine and four years of wind data collected in the DOE Candidate Wind Site program near Amarillo, Texas. The resulting annual average capacity factor of the wind plant is approximately 36 percent (assuming a 5 percent wind speed reduction due to wake losses and a 2 percent average power reduction caused by individual turbine outages), with a standard deviation of 6.5 percent.

The uncertainty in wind plant output is incorporated into the model by randomly selecting a capacity factor in each year from a normal distribution with the given mean and standard deviation. When the capacity factor is lower than expected, the model draws more generation than usual from fossil resources. When the capacity factor is higher than expected, the opposite occurs.

Estimates of fluctuations in the availability of fossil-fuel and nuclear plants are more difficult to come by directly, but can be derived from five-year historical data for large numbers of plants published in the National Electric Reliability Council *Generating Availability Report*. Since the figures in this report no doubt include some plants that are especially prone to failure, we scaled down the resulting estimates for this study. For existing plants as well as new coal plants, we assume a standard deviation in FOR of 10 percent. For gas-fired combustion turbines and combined cycle units, the standard deviation was assumed to be 5 percent.

RESULTS

First, we review the base (fossil) and alternate (wind) plans under expected conditions, that is, allowing no deviations in fuel prices, load growth, environmental costs, or plant availability. The cost streams are discounted at two different discount rates, the utility’s weighted average cost of capital (WACC), 9.64 percent, and the presumed risk-free discount rate, 7.5 percent. In either case, the forced addition of the wind plant in 2003 increases revenues and net income and decreases costs. (Note that net income equals revenue minus cost.) The higher net income is necessary to compensate company shareholders for their larger investment in the wind plant, as is evident from the fact that the return on equity (ROE) in both cases is the same.

Table 1. Comparison of Base and Alternate Plans (million 1996 dollars)*

Parameter	Discounted at WACC			Discounted at Risk-Free Rate		
	Base Plan	Alternate Plan	Change	Base Plan	Alternate Plan	Change
PV of Revenues	$69,737	$70,059	$322	$83,598	$83,906	$308
PV of Costs	$63,817	$63,685	-$132	$76,674	$76,469	-$205
PV of Net Income	$5,920	$6,374	$454	$6,924	$7,437	$513
Average ROE (%)	10.76%	10.76%	0.00%	10.76%	10.76%	0.00%

*Under expected conditions, i.e., no uncertainty in any variables.

If risks and environmental externalities were ignored, the gas-fired combined cycle unit would appear to be the preferred choice, since it is approximately $300 million less expensive for ratepayers. The following sections describe the effects of taking risk into account on the expected means and variances of the key parameters. Two market scenarios are examined: a regulated market and an unregulated market. The latter is characterized either by a power pool market similar to the UK Pool or by fixed-price contracts.

Regulated Market Scenario

In this scenario, electricity prices are not market-determined but set by the regulatory system to achieve a target rate of return on equity (ROE) for TU Electric's stockholders. Changes in fuel prices and environmental costs are passed on to customers through a fuel-cost adjustment to the base electricity rate. Consequently, it can be expected that shareholders will have the least to gain from investing in wind as a risk-management strategy, whereas ratepayers will have the most to gain.

Table 2. Summary of Results (High Risk Assumptions)

Scenario		Revenues		Costs		Net Income		ROE	
		Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
Regulated Market	Gas	$91,159	$17,503	$83,629	$16,337	$7,530	$1,843	10.70%	1.14%
	Wind	$91,180	$17,039	$83,154	$15,846	$8,026	$1,857	10.71%	1.11%
	Change	$21	-$464	-$474	-$492	$496	$14	0.00%	-0.03%
Unregulated Market	Gas	$100,270	$23,705	$88,111	$17,973	$12,159	$7,379	21.80%	11.32%
Power Pool	Wind	$100,053	$23,759	$87,595	$17,667	$12,459	$7,523	21.50%	11.01%
	Change	-$216	$55	-$516	-$306	$300	$144	-0.31%	-0.31%
Unregulated Market	Gas	$91,902	$16,143	$84,079	$15,954	$7,823	$2,098	11.01%	2.68%
Fixed-Price Contracts	Wind	$91,984	$15,755	$83,609	$15,474	$8,375	$2,085	11.14%	2.47%
	Change	$82	-$388	-$470	-$480	$552	-$13	0.13%	-0.21%

*All figures are present values over 20 years (2003-2022) discounted at 7.5 percent, converted to 1996 dollars. Revenu and net income are in millions of dollars. Standard deviations reflect variations between iterations, not between years.

This is confirmed by the first block of data in Table 2, which shows the expected present value and standard deviation of revenues, costs, net income, and average return on equity for both the gas and wind cases and the differences between them. (High-risk environmental and fuel cost distributions are assumed.) The mean present value of revenues in the regulated scenario is $21 million greater with wind than without wind, indicating that this case is still likely to be slightly more expensive for ratepayers, despite the possibly of CO_2 regulation. However, the standard deviation in revenues is $464 million less, indicating that the wind investment is significantly less risky. By contrast, the mean return on equity is virtually the same in both cases.

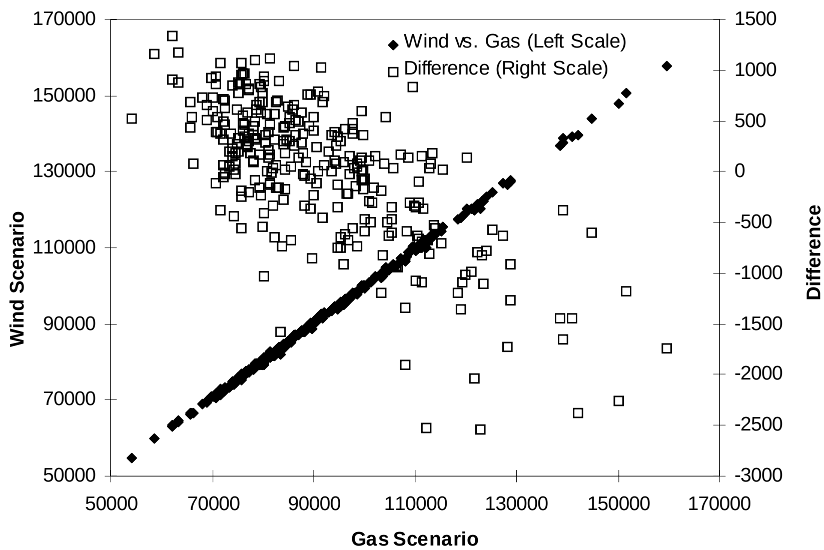

Figure 1. Present value of revenues, regulated market

Different views of the data provide additional insights into the effects of replacing the gas-fired plant with the wind plant. Figure 1 shows a scatter plot of present-value revenues for the wind and gas cases in the regulated market scenario. The points in the closely spaced, upward sloping group show the intersection of values for the wind and gas cases. The points in the larger, downward sloping group show the difference in revenues between the wind and gas cases as a function of the gas case revenues. The important thing to observe is that when the present value of revenues in the gas case is high, the wind case tends to be less expensive than the gas case (points fall in the lower half of the chart), whereas when the present value of revenues is low, the converse is true. This graphically illustrates the point that wind plants can act as an insurance policy or hedging strategy against fossil-fuel risks.

Yet another view of the data is provided in Figure 2, which shows the differences between the mean revenues and standard deviations of the gas and wind cases for each year of the study period. As might be expected, the wind case starts out more expensive than the gas case on average, but then becomes less expensive as fuel prices rise and the higher wind plant capital investment is paid off. In every year but the first, the standard deviation for the wind case is lower than that of the gas case by amounts ranging up to $150 million.

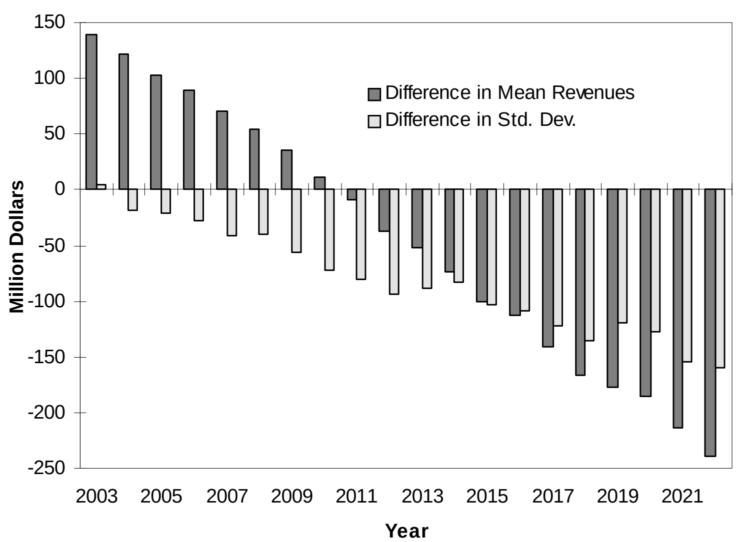

Figure 2 Difference between wind and gas scenario revenues (regulated market)

Unregulated Market Scenarios

The unregulated market is more complicated to model than the regulated market. The risks seen by the utility and its customers depend on many factors, such as the nature and degree of competition, corporate structures, the role of regulation, the design and functioning of the power pool, and the contractual relationships between the utility company and its customers and fuel suppliers. We cannot incorporate all such factors into the model. Instead, we consider two scenarios that illustrate a plausible range of sensitivity to risk: a power pool scenario, and a fixed-price contract scenario.

The critical difference between the two scenarios is that, in the power pool, TU Electric's plants compete against comparable fossil, nuclear, and renewable plants on the basis of short-term variable operating costs. Capacity payments are proportional to loss-of-load probability, as is done in the UK Pool. In the fixed-price contract scenario, the price of power is fixed for periods ranging from one to five years. In both cases, the capacity build decisions are assumed to be the same as in the regulated market scenario.

The results are summarized in the bottom two blocks of data in Table 2. It is important to note, first, that the power pool scenario poses much greater risks for both customers and company shareholders than the fixed-price contract scenario (i.e., the standard deviations are larger), whether wind is present or not. The reason is that the capacity payments in the power pool are highly volatile, as they depend on loss-of-load probability, which fluctuates greatly with peak load.

Moreover, the effect of substituting wind for gas varies strikingly between the two unregulated market scenarios. In the power pool scenario, the addition of wind appears to *increase* the standard deviation of revenues, but it decreases the standard deviation of the return on equity. The expected revenues, net income, and return on equity are all somewhat lower with wind, to the benefit of electricity consumers but to the detriment of company shareholders. The main reason is that the wind plant slightly reduces the amount of high-cost fossil generation needed to supply loads at the margin and therefore reduces the variable portion of the electricity price. The results of the contract scenario, on the other hand, closely resemble those of the regulated market scenario. The main difference is the reduction in the standard deviation of return on equity resulting from the wind addition, which is accompanied by a slight increase in the mean ROE.

VALUING RISK REDUCTION

A critical issue in interpreting the results of a study like this one is estimating the value of changes in risk either for customers or utility company shareholders. There is, first, the possibility of a change in the expected, or mean, outcome, which occurs if the probability distributions of the input parameters are skewed in some fashion. In our study, the only such skewed distribution is that of environmental regulatory costs, which we believe are far more likely to increase than to decrease. The effect of this bias is easy to account for, and indeed we already see its effect in the difference in mean revenues between the gas and wind cases in the regulated market scenario, which in Table 1 (with no variations in the input parameters) is $308 million, but in Table 2 is $21 million. Thus, one can say that accounting for high environmental regulatory risks reduces the mean revenues of the wind case relative to the gas case by $287 million.

More challenging is the problem of assigning a value to changes in the variability of a cash flow. This is accomplished in decision analysis by calculating a risk premium, which is proportional to the variance (or standard deviation squared) of some cash flow, an approach derived from expected utility theory. The *certainty equivalent* of the cash flow, which is the amount it is worth to a decision maker absent any risks, combines the mean with the risk premium in the equation,

$$CE = \langle CF \rangle - \frac{\alpha}{2} \sigma_{CF}{}^{2} ,$$

where α is known as the risk aversion coefficient. In the case of future cash flows, the certainty equivalent can be converted to a present value by discounting at a suitable risk-free discount rate.

Table 3. Summary of Wind Risk Benefits*

Scenario	Risk	Ratepayer Perspective			Shareholder Perspective		
		Change in Mean Revenue	Change in Risk Premium	Total Wind Risk Benefit	Change in Mean ROE	Change in Risk Premium	Total Wind Risk Benefit
Regulated Market	High	($287)	($98)	$385	0.00%	-0.02%	0.02%
	Low	($144)	($27)	$171	0.00%	-0.02%	0.02%
Power Pool	High	$29	$36	($65)	0.52%	-0.97%	1.48%
	Low	($100)	$35	$65	0.13%	-0.89%	1.03%
Contract	High	($260)	($78)	$338	0.12%	-0.38%	0.50%
	Low	($123)	($21)	$145	0.05%	-0.12%	0.17%

*Figures for the ratepayer perspective are in millions of 1996 dollars.

The risk aversion coefficient can be measured directly by surveying the opinions or observing the investment behavior of the key decision makers or stakeholders. Absent such information, decision analysts generally assume that it is approximately equal to the reciprocal of one to two times expected income. In this study, we assume that, from the perspective of ratepayers, the risk aversion coefficient equals the reciprocal of 1.25 times revenues, whereas from the perspective of shareholders, it equals the reciprocal of 1.25 times expected return on equity.[4]

When the above equation is applied to the annual means and standard deviations calculated by the model, and the wind and gas cases are compared, the result is an estimate of the total risk-reduction benefit of wind energy, shown in Table 3.

The total benefit has two components, a change in mean revenues (due in our study entirely to environmental regulatory risks), and a change in the risk premium. Together, they indicate the consequences of taking risks into account in the comparison of the two resource options. For example, the total wind risk benefit from the ratepayer perspective in the high-risk, regulated market scenario is $385 million, which includes the $287 million shift in mean revenues noted previously, and a $98 million shift due to a reduction in the risk premium. This implies that when risks are considered, the certainty equivalent of the wind case revenues will be $77 million less ($308 million minus $385 million) than the certainty equivalent of the gas case revenues, making the wind plant the more attractive option for ratepayers. If low risks are assumed, the total ratepayer benefit is $171 million, which is not enough to tip the scales in favor of the wind plant.

Regardless of its ultimate effect on the build decision, the risk benefit of the wind plant for ratepayers in the regulated market and contract market scenarios appears substantial. In the regulated market scenario, for example, the benefit is equivalent in real levelized terms to $3.4 to $7.8/MWh of wind generation. In contrast, the wind risk benefit for the ratepayer in the power pool scenario appears to be much smaller, and under high risk assumptions, is actually negative. The explanation for this effect is unclear, but is likely connected to the way wind energy affects the dispatch of high-cost fossil-fuel plants operating at the margin.

The risk benefits from the shareholder perspective are the mirror image of those from the ratepayer perspective. In the power pool scenario, shareholders receive a major risk benefit from the wind plant that is equivalent to an extra return on equity of 1 to 1.5 percentage points. In the contract scenario, the benefit to shareholders appears smaller but still substantial—0.17 to 0.5 percentage points. As already noted, there is little or no risk benefit for shareholders in the regulated market scenario.

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[4] Support for these assumptions is provided in Jonathan M. Jacobs and Thomas E. Huntley, Pacific Gas and Electric Company, "Valuation of Fuel Diversity," Submitted for Hearings before the California Energy Commission (February/March 1992).

CONCLUSIONS

The initial findings of this study suggest that risk should be an important consideration in evaluating competing wind and gas-fired combined cycle plants. For the most part, accounting for risk acts to the benefit of wind energy. The benefits of reduced exposure to fuel-price and environmental regulatory risks are not offset by the greater uncertainty in the annual average availability of wind plants compared to conventional plants.

Risks are distributed much differently in a regulated market than in an unregulated market, however. In a regulated market, utility company shareholders see few of the risks of fossil fuels and hence have little incentive to invest in risk-mitigation options such as wind power. This may help explain why many utilities have not eagerly embraced wind and other renewable resources in the past. An unregulated market may provide greater incentive for utility investment in wind energy based on risk considerations. Although this incentive is theoretically largest in a power pool, the extreme volatility of prices in such a market may serve to mask the incentive to a considerable degree. A market dominated by fixed-price contracts may be most favorable to wind, as the risk benefits will then be distributed more or less evenly between customers and utility company shareholders, giving both a modest incentive to go with wind. (This analysis did not consider the possibility that fossil-fuel risks may be passed on to or shared with fuel suppliers, however, which may reduce the risk benefits of wind but could also result in higher fuel prices.)

Perhaps most importantly, this study has demonstrated that decision analysis can be a useful tool for estimating the risk-reduction benefits of wind energy under a range of market conditions. Analytical tools like the SRP model should be used to help inform traditional methods of utility resource planning as well as regulatory and legislative efforts to create a level playing field for wind and other renewable technologies in a deregulated electricity market.