Wind Generation's Contribution to the Management of Average Cost and Cost Volatility for Indiana

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March 2011

Executive Summary

This report represents a first attempt at including wind energy in a model that examines the balancing of expected cost and volatility in generation resource planning. A potential benefit of investment in wind capacity is to diversify the generating portfolio, and thereby reduce the adverse impacts of cost increases associated with specific fuels. The goals of this report are to analyze diversification effects of using renewable energy sources such as wind and to help policymakers understand the contribution of wind within the portfolio of generation technologies towards managing the average cost of system-wide generation, as well as its volatility.

The study uses a mathematical method for determining the optimal mix of multiple fuels and electricity generation technologies that balance reducing average system cost and the volatility of system cost. The model used in this study is similar to the mean-variance portfolio optimization models used by financial advisors for determining a diversified portfolio of stocks, bonds and other financial instruments for individual investors. An investor with a greater aversion to variability of returns will typically be willing to accept a portfolio that has a lower average return in order to obtain a less variable return. In the fuel diversification context, a system planner with a greater aversion to variability (often called risk aversion) in the cost of electricity generation will be willing to accept a mix of generating assets with a higher average cost of generation, but a lower variability in that generating cost over time.

The mean-variance portfolio optimization, or fuel diversification, approach requires the estimation of the mean and variance statistics of per unit of energy generation costs for each technology/fuel combination. The mean of the cost is the long-run average cost of generation. The variance of the cost is a measure of the volatility of the cost of generation. The technology/fuel combinations modeled for this analysis are pulverized coal, integrated gasification combined cycle coal, oil-fired, natural gas combustion turbine, natural gas combined cycle, nuclear, and wind backed up by purchases off the wholesale market.

The data estimation for the fossil-fueled and nuclear powered technologies is relatively straightforward, using cost data from the Energy Information Administration. Since wind generation is not dispatchable in the sense of the model, it is paired with wholesale market purchases to fill in the gaps when the wind output is at less than full power. These purchases should be viewed as the opportunity cost of including an intermittent resource in the generation mix. Wind data were estimated using the National Renewable Energy Laboratory's Eastern Wind Integration and Transmission Study and market data were determined from Midwest ISO and PJM data for the corresponding hours as the wind data. Throughout this report the technology that represents the combination of wind and market purchases is referred to as "wind plus market."

Hourly load data for the study were developed by escalating actual 2006 hourly loads for the state of Indiana to meet the State Utility Forecasting Group's projected 2025 levels. This was done in order to create a situation where significant additional resources would be needed while maintaining a load profile that is indicative of the state's.

The objective of the fuel diversification problem is to minimize the expected cost plus a weighting factor times the variance of cost. As the weight on the variance of cost is increased, the portfolio will typically shift towards a more diversified mix of generation that has a higher average system cost but lower volatility of cost. By ranging the weight from low to high values, the tradeoff between the mean and variance of cost can be traced as is illustrated in the Mean-Variance plot displayed in Figure ES-1. As the weight on the variance increases (indicated on the graph by higher values of β), the optimum portfolio shifts from down (lower mean) and to the right (higher variance) to up (higher mean) and to the left (lower variance) on this graph. The curve is often referred to as the Efficient Mean-Variance Frontier.

Points above and to the right of this curve are considered inefficient in the sense that it is possible to obtain a lower mean and/or variance of costs. Points below and to the left of the curve cannot be achieved with the available fuel/technology options and are infeasible.

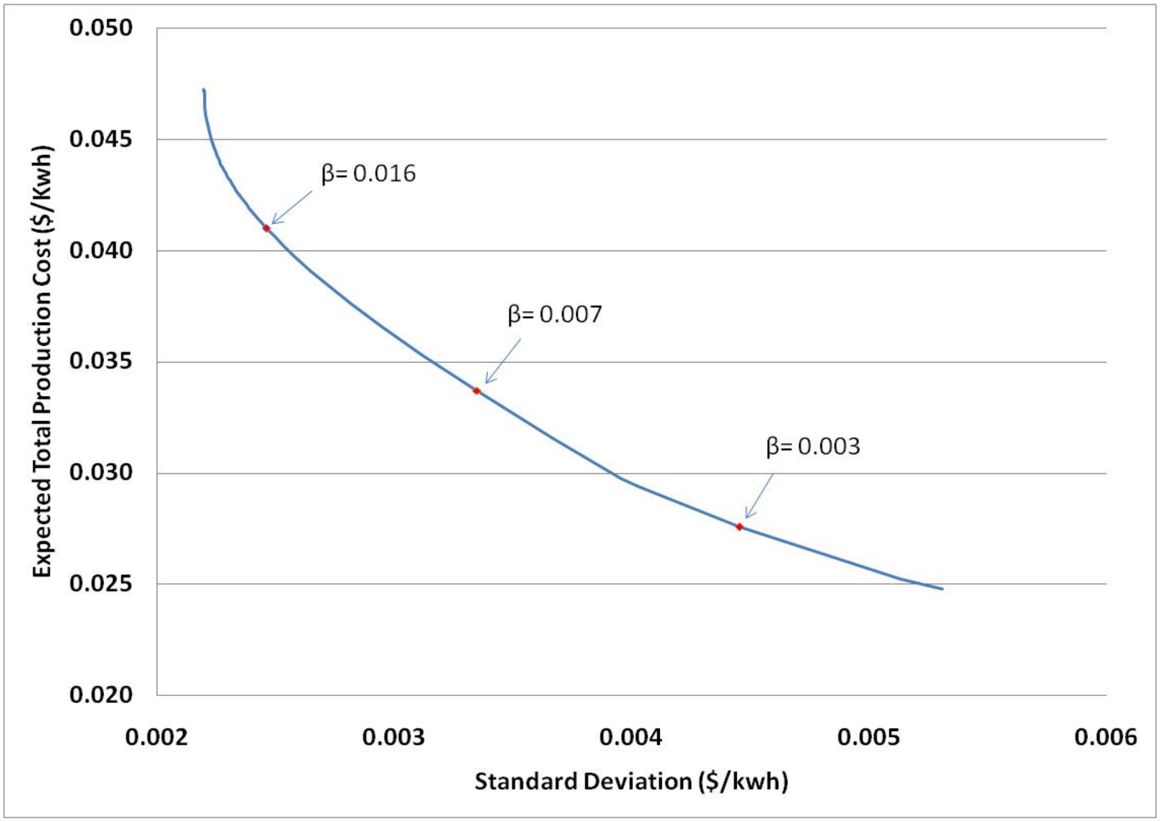

Figure ES-1. Cost Mean/Standard Deviation Efficient Frontier–Base Case Scenario

The model is used to determine mean-variance efficient portfolios of generating capacity for two scenarios. The first scenario is the base case, which reflects business as usual (i.e. under current regulations and policies), the results of which are illustrated in Figure ES-1. The second scenario considers the case where carbon costs are assessed on all generating technologies with carbon emissions.

The percentage share of the various generation resources at different levels of risk aversion is shown in Figure ES-2. This graph shows that as risk aversion increases the mix of generation shifts. Shares are initially stable with the vast majority being pulverized coal up to a level of about $\beta = 0.003$. Wind plus market is initially at about 5 percent. Beyond this point, the shares shift towards less pulverized coal, more IGCC, more NGCC, and eventually more nuclear. The dramatic shift towards nuclear generation is a reflection of the low volatility of nuclear fuel costs. Wind plus market increases to just under 10 percent by the point where $\beta = 0.01$ and remains there for higher levels of risk aversion. The results for high levels of risk aversion are likely unrealistic due to the very large share of nuclear generation, which is likely to be limited by factors that are not reflected in the model.

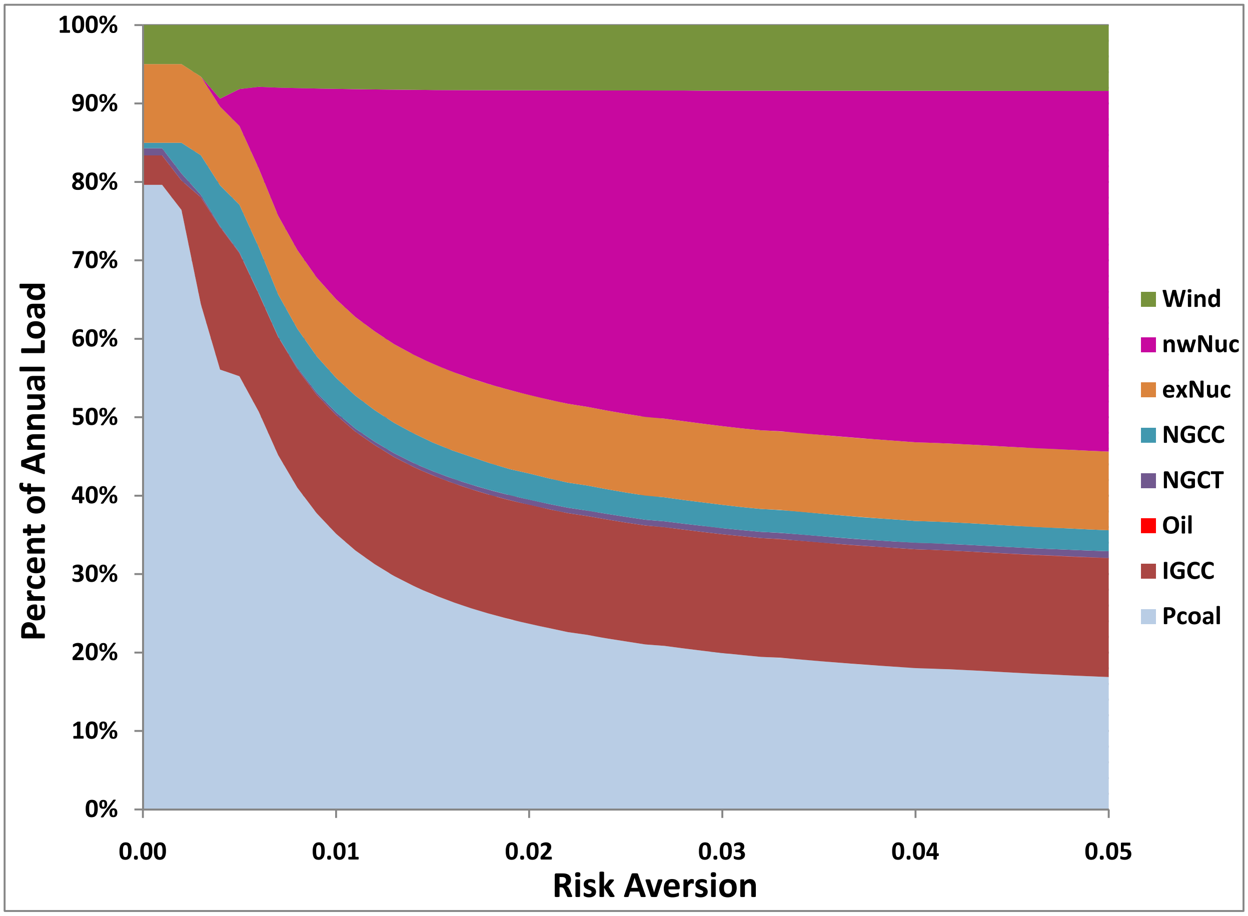

Figure ES-2. Capacity Share as Risk Aversion Increases–Base Case Scenario

The portfolio for a scenario that incorporates carbon costs is largely dominated by nuclear generation. As a result, the cost of serving load is higher and the variance is lower than in the base case for all levels of risk aversion. While some additions to wind capacity are indicated in the carbon cost scenario they are smaller than in the base case.

While the model estimates the optimal portfolio of generating technologies and fuels, factors outside of those considered in this study may also impact the results. These include the existence of government subsidies for installing wind energy projects; data limitations regarding nuclear operations and maintenance costs, wind availability and market prices; the feasibility of the development of new nuclear facilities on a large scale; the costs of cycling generating units on and off; the frequency of planned and unplanned generating unit outages; and factors that may change fuel price volatility in the future.

In conclusion, an initial analysis of the impact of wind as a generating option on the long-term strategic portfolio of generation capacity based on a fuel diversity model was developed. For the "business as usual" base case, increasing the emphasis on reducing the volatility of costs causes large shifts in the generation mix from one which is heavily reliant on coal to one with a significantly larger percentage of the load served by nuclear. The impact of this shift on expected costs is substantial, with a roughly equal mix between coal and nuclear resulting in about a 50 percent increase in the long-run average cost of electricity and a reduction in the volatility of electricity costs of about 45 percent. The role of wind generation in this base case is moderate with wind augmented by market purchases serving 6.5 to 8.5 percent of load.

Introduction

In Indiana, electricity generated from wind has increased rapidly in the last three years. The 2010 Indiana Renewable Energy Resource Study produced by the State Utility Forecasting Group (SUFG) reports that wind capacity in the state increased from 20 kW in 2007 to 1,039 MW at the end of 2009, and wind capacity was expected to further increase by 203 MW by the end of 2010. One potential benefit of investment in wind capacity is to diversify the generating portfolio, and thereby reduce the adverse impacts of cost increases associated with specific fuels. The goals of this report are to analyze diversification effects of using renewable energy sources such as wind and to help policymakers understand the contribution of wind within the portfolio of generation technologies towards managing the average cost of system-wide generation, as well as its volatility.

Fuel price uncertainty is an important factor to consider when making a long-run strategic choice of the best portfolio of generating resources to serve the system load. If fuel price volatility is ignored, the mix of generating assets would be chosen to minimize the average system costs. This leads to over-specialization in technologies that have low average fuel costs. While average system costs over time will be low with this approach, the volatility of the cost of generated electricity may be high. Using a variety of fuels to generate electricity provides operational flexibility to the generating system, avoids over-dependence on a single fuel, and helps to moderate the volatility of generation costs.

This study uses a mathematical method for determining the optimal mix of multiple fuels and electricity generation technologies that balance reducing average system cost and the volatility of system cost. The measure of volatility of system cost used in this study is the variance of total fuel cost. The model used in this study is similar to the mean-variance portfolio optimization models used by financial advisors for determining a diversified portfolio of stocks, bonds and other financial instruments for individual investors. In that context, the financial advisor will select a portfolio that strikes a balance between the average (or expected) returns to the portfolio and the variability (or variance) of returns. An investor with a greater aversion to variability of returns will typically be willing to accept a portfolio that has a lower average return in order to obtain a less variable return. In the fuel diversification context, a system planner with a greater aversion to variability (often called risk aversion) in the cost of electricity generation costs will be willing to accept a mix of generating assets with a higher average cost of generation, but a lower variability in that generating cost over time. The analysis considered here is forward looking and treats existing capacity investments as sunk costs. From this base, the analysis determines investments in new generating plants that will be needed to meet forecasted load for 2025.

Related Literature

The Markowitz Mean-Variance (M-V) optimization portfolio analysis method, originally applied in finance, has been extensively used in other fields. While various implementations of this model have been applied in the electric generation sector, the results have often been dismissed by policymakers as unrealistic. In particular, many of these models have a tendency to produce portfolios of generating assets that are overspecialized.

Gotham et al. (2009) propose a modification of the mean-variance model for managing the trade-off between average system cost and variability of cost through fuel diversification that was designed to respond to the criticisms of prior work. They argue that an important cause of the overspecialization observed in prior studies is due to the fact that the models do not take the load duration curve into account. By explicitly designing the model to select capacity that is tailored to serve alternative segments of the load curve, Gotham et al. were able to generate results that were much more in line with intuition and experience. Their model formulation divides the load curve into three segments (baseload, cycling and peaking), and dedicates capacity of alternative generating technologies to serve these segments. The overall goal is similar to the prior work – to balance the tradeoff between average system cost over time and the variability of cost. Results indicated that the model behaves intuitively in response to variations in model parameters and produced more realistic portfolios of generating assets than models that do not take the load curve into account.

More recently, Ruangpattana (2010) took this formulation further by demonstrating that the trade-offs could be more precisely evaluated by further dividing the load curve into a greater number of segments. He developed a practical formulation for dividing the load curve into an arbitrarily large number of segments, resulting in a model that takes full account of the shape of the load curve.

All of this previous work focused on assessment of the tradeoffs between average costs and variability of costs for the electric generating system for conventional electricity generation fuel types. The study presented here develops an approach to incorporating wind as one of the generating technologies. The challenge occurs because, while this model implicitly captures the dispatch problem, wind is not a dispatchable technology. This gives rise to the need for specialized treatment of wind, which is addressed in the data section of this report.

Background on the Mean-Variance Model Applied to Fuel Diversification

The mean-variance portfolio optimization, or fuel diversification, approach requires the estimation of the mean and variance statistics of per unit of energy generation costs for each technology/fuel combination. The mean of the cost is the long-run average cost of generation. The variance of the cost is a measure of the volatility of the cost of generation. Here all costs of generation except fuel costs are considered to be known with certainty. While this is not precisely true, the majority of the variability in future costs is related to fuel costs. The covariance of the costs of two technologies is a measure of the degree to which the costs of those technologies move together. A positive value of the covariance occurs when the fuel costs tend to move in the same direction (i.e., if the cost of fuel A goes up, then the cost of fuel B tends to go up), and a negative value occurs when the fuel costs tend to move in opposite directions (i.e., if the cost of fuel A goes up, then the cost of fuel B tends to go down).

Both fixed and variable costs contribute to the mean cost. The fixed costs include capital expenditures for constructing, operating and maintaining the generation unit that are independent of the level of generation. These are summed over the life of the project and then an equivalent annualized expense is calculated using standard annuity formulas. Variable operation and maintenance costs and long-run average fuel costs constitute the variable portion of the mean cost that depends on the level of generation. These average or mean costs are calculated per unit of generation (MWh) for each of the technologies/fuels. Because fuel prices are treated as volatile, they drive the variance of total system cost. (Because total fuel cost is the sum of individual technology fuel use weighted by fuel price and the level of generation using that technology/fuel, the variance of total system cost is equal to a summation of terms involving generation using the technology/fuel and the fuel price variances and covariances.)

The objective of the fuel diversification problem is to minimize the expected cost plus a weighting factor times the variance of cost. As the weight on the variance of cost is increased, the portfolio will typically shift towards a more diversified mix of generation that has a higher average system cost but lower volatility of cost. By ranging the weight from low to high values, the tradeoff between the mean and variance of cost can be traced as is illustrated in the Mean-Variance plot displayed in Figure 1. As the weight on the variance increases, the optimum portfolio shifts from down (lower mean) and to the right (higher variance) to up (higher mean) and to the left (lower variance) on this graph. The curve in Figure 1 is often referred to as the Efficient Mean-Variance Frontier. Points above and to the right of this curve are considered inefficient in the sense that it is possible to obtain a lower mean and/or variance of costs.

Points below and to the left of the curve cannot be achieved with the available fuel/technology options and are infeasible. The mix of generation technology associated with each point on the curve is also determined when the model is solved. These are not usually indicated on a graph as in Figure 1, but rather provided in tables for specific values of the weight on the variance of cost.

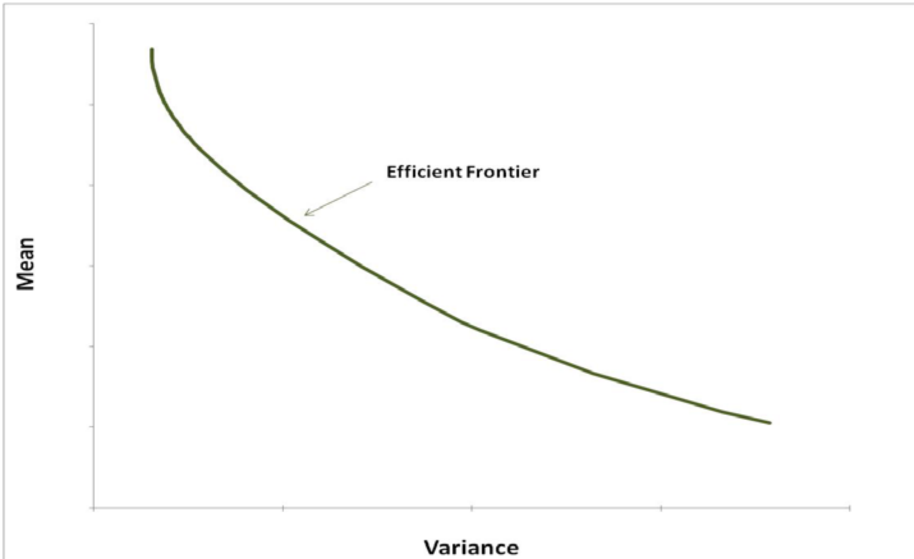

Figure 1. Plot of a Mean-Variance Efficient Frontier

Data

There are several pieces of key data that drive the mean-variance fuel diversification model. These are the fixed and variable portions of the average cost of capacity and operations (including maintenance and fuel), the variances and covariances of fuel costs (per MWh of generation), the level of existing capacity (MWs) for each technology/fuel choice, and the load duration curve.

Traditional Technologies

Fixed costs, variable costs and historical electric power sector fuel prices[1] (1970 through 2007) for generating technologies powered by coal, residual fuel, natural gas and nuclear were obtained from the Energy Information Administration (EIA). Table 1 shows the estimates of total fixed cost, variable operations and maintenance (O&M) costs, and average fuel cost expressed in 2007 dollars. The Personal Consumption Deflator (BEA 2010) was used to convert the nominal data to 2007 dollars. Since, Indiana does not have any commercial nuclear facilities located in the state; nuclear fuel prices for Michigan were used reflecting the D.C. Cook nuclear station in Michigan, which primarily serves Indiana load. While variable O&M and fuel costs are already expressed per unit of energy, fixed capacity costs ($/MW) have been converted to dollars per unit of energy, $/GWh, by dividing the annual total by the number of hours in a year (i.e., 8,760) divided by one thousand. (Average fuel cost for “Wind Plus Market” was estimated based on the idea that in order to make it dispatchable, some other technology must complement wind generation when the wind stops blowing. Conceptually, the dips in wind output are filled in by wholesale electricity purchases. This treatment is described in greater detail in the Wind Cost Parameters section.) The total fixed cost reflects the sum of the fixed O&M cost and the total overnight capital cost. Total

[1] Prices reported in nominal dollars per Million Btu, approximate heat rates for fossil and nuclear fuel plants for electricity.

overnight capital cost represents the levelized[2] capital cost of new projects initiated in 2008, assuming a useful life of 20 years for new generating units.

Table 1. Costs for Electricity Generation Technologies (in 2007 $/MWh) and Existing Capacity (MW)

Technology	Total Fixed Cost	Variable O&M		Fuel Cost	Total Summer Capacity
	(New)	(Existing)	(New)		(MW)
Pulverized Coal (PCoal)	28.229	4.282	4.590	19.678	16,155
Integrated Gasification Combined Cycle (IGCC)	33.401	2.920	2.920	17.430	619
Oil	9.549	11.774	3.570	113.451	366
Natural Gas Combustion Turbine (NGCT)	8.930	9.154	3.170	54.449	3,931
Natural Gas Combined Cycle (NGCC)	12.891	2.000	2.000	35.893	1,148
Nuclear (Nuc)	50.722	0.490	0.490	9.678	1,655
Wind and Market (Wind)	26.900	0.0	0.0	27.406	820

Sources: EIA, NREL, PJM, MISO and SUFG[3]

The same historical Indiana and Michigan fuel prices used to estimate the expected fuel prices were used to calculate the fuel cost variances and covariances (Table 2). The diagonal terms represent the variance for that fuel/technology option, while the off-diagonal terms indicate the covariances of the fuel/technology options for that particular row and column. The historical stability of the price of nuclear fuel is reflected by the very small nuclear fuel cost variance as compared to the variance of fossil fuels.

[2] Capital cost was levelized using a present worth annual payment formula with a projected 10 percent annual interest rate.

[3] Fixed and Variable O&M Costs are from Table 8.2 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies, Assumptions to the Annual Energy Outlook 2009, (EIA 2009). Expected fuel costs estimated from 1970-2007 price data in Consumption, Prices and Expenditures by Energy Source, (EIA 2008). Expected wind fuel costs estimated from 2004-2006 PJM and MISO wholesale prices and Eastern Wind Integration and Transmission Study (NREL). Existing Electric Generating Units in the United States, 2008, Form EIA-860 Database, Annual Electric Generator Report, (EIA 2008). Power purchase agreements, 2010 Indiana Renewable Energy Source Study (SUFG 2010).

Table 2. Fuel Price Covariance Estimates for the Electric Sector, Indiana (Prices in $/MWh)

	PCoal	IGCC	Oil	NGCT	NGCC	Nuc	Wind
PCoal	43.8639	37.8312	110.1792	66.4626	43.8125	10.1749	9.7089
IGCC		34.4156	97.5941	58.8710	38.8080	9.0127	8.5999
Oil			2289.8081	918.4298	605.4338	-52.2254	-5.7584
NGCT				557.2667	357.6860	-16.9690	57.8960
NGCC					242.1612	-11.1861	38.1654
Nuc						10.3200	1.1510
Wind							61.6081

Sources: EIA, NREL, PJM, and MISO[4]

Wind Cost Parameters

The fuel diversification model makes an approximation to the economic dispatch of each technology/fuel. This is a problem for wind, which is not dispatchable due to the intermittent nature of wind. In order to extend the analysis to include wind it was necessary to augment the wind technology to what is referred to as "wind plus market." The idea is that in order to be dispatchable, the wind plus market technology must be available at all times. Conceptually this requires that whenever wind output falls below its peak output for the year, the difference must be made up by purchases on the wholesale electricity market. These purchases should be viewed as occurring at the system level rather than as falling on a particular utility, and they should be viewed as the opportunity cost of including an intermittent resource in the generation mix.

The procedure for calculating the average cost of wind is as follows. The Eastern Wind Integration and Transmission Study (EWITS)[5] performed by the National Renewable Energy Laboratory (NREL) provides wind generation output estimates at ten minute intervals for 2004, 2005, and 2006 for various sites across the eastern United States. For calculating the average cost of wind, sites were selected that are in close proximity to the locations of wind projects that have signed purchase power agreement (PPA) with Indiana utilities.[6] The output data were prorated to the levels of wind energy purchases specified in each PPA, totaling 820 MW of wind capacity. The 10-minute scaled wind generation data was aggregated to the hourly level and then used to identify the annual peak hourly wind generation for the year, which is equal to the total existing capacity. Historical hourly real-time wholesale prices for the Cinergy hub (the only one geographically located in Indiana) were collected from the Midwest ISO website.[7] Since the

[4] Fossil and nuclear fuel price covariances estimated from 1970-2007 price data in Consumption, Prices and Expenditures by Energy Source (EIA 2008). Wind fuel price covariance estimated using 2004-2006 PJM and MISO wholesale prices and Eastern Wind Integration and Transmission Study (NREL)

[5] Eastern Wind Dataset. Wind Integration Datasets. National Renewable Energy Laboratory. Accessed: 16 August 2010 <http://www.nrel.gov/wind/integrationdatasets/eastern/data.html>.

[6] Information of wind farms capacities and sites are collected from the report 2010 Indiana Renewable Energy Resource Study (SUFG 2010). Wind projects are: Benton County, Fowler Ridge I and II, Hoosier Wind, Agriwind, Story Cty., Buffalo Ridge, Barton Windpower, Lakefield Wind, Crystal Lake Wind.

[7] Hourly real-time locational marginal price (LMP). Midwest ISO. Accessed: 23 June 2010. <http://www.midwestmarket.org/publish/Folder/67519_1178907f00c_-7fef0a48324a>.

MISO market did not exist prior to April 2005, Cinergy hub prices were not available for 2004 and early 2005. The missing prices were estimated using the prices of another nearby hub, PJM's WEST INT hub, for which a complete set of price data was available. Information for the WEST INT hub was acquired from the PJM Interconnection web site.[8] Thus, Cinergy hub data for January 2004 through March 2005 were estimated based on the concurrent WEST INT hub data and the relationships between the prices for those two hubs from April 2005 through December 2006. These hourly wholesale market prices were multiplied by the hourly difference between actual wind output and peak hourly wind generation and summed to obtain the total cost of using the wholesale market to fill in for any shortfall in wind output. This total cost is then divided by total MW of power from wind output and wholesale purchases during the time period (i.e., the maximum wind output over the time period times the number of hours in the time period). The resulting cost ($/MWh) is the average cost for the wind plus market technology used for the analysis. It is implicitly assumed that these wholesale purchases are not sufficiently large to have a significant impact on the hourly wholesale electricity price. If the capacity of the wind plus market technology expands substantially, this assumption may be questionable.

To obtain an estimate of the wind plus market cost variance the procedure used to obtain the average cost of wind plus market is applied on a monthly basis to get monthly average costs for this technology and then calculate the variance from this monthly data. The resulting variance is higher than the coal and nuclear fuel cost variances but lower than the variances of the highly volatile oil and natural gas prices. Because the estimated wind output data is only available for 2004-2006 and the time scales for fossil fuel price data (months to years) is different than for wind (minutes to hours), it was necessary to use different periods as the unit of observation for calculating the cost variances (months for wind plus market versus years for other fuels). To address this inconsistency sensitivity analysis is performed on the level of wind plus market cost variance, which is reported in the results section. In addition to the cost variance estimate for wind plus market, it was also necessary to estimate the covariance of the costs of wind plus market with each of the other technology/fuel combinations. The estimation proceeds in two steps. First, monthly cost data for wind plus market and for each of the other fuels is used to calculate a monthly cost covariance. To calculate the covariance between the cost of wind plus market and the cost of other fuels, data series for the same time periods are needed. The estimated monthly cost for wind plus market and reported monthly fossil and nuclear fuel costs obtained from the Form FERC-423 Database (EIA 2007)[9] for 2004-2006 were used to estimate these covariance matrixes. Second, the covariance between each fuel and wind plus market is divided by the standard deviation (square root of the variance) of the cost for the other fuel and then multiplied by the estimate of the standard deviation based on the annual data for the 1970-2007 for the other fuel. This is done to reflect two facts. First, the use of monthly data will likely result in an underestimate of the variances for the other fuels. Second, the consistent use of monthly data for both the other fuels and wind plus market will likely produce reasonably accurate estimates of the correlations (covariances between the other fuel and wind plus market costs divided by the standard deviations for the other fuel and wind plus market) between these costs. While this procedure was not ideal, it was the only method that seemed both practical and consistent given the short time series of estimated wind output data available. The resulting covariance parameters are found in the last column of Table 2.

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[8] Hourly real-time locational marginal price (LMP). PJM Interconnection. Accessed: 24 June 2010. < http://www.pjm.com/markets-and-operations/energy/real-time/lmp.aspx>.

[9] Form FERC-423 Database. Monthly Cost and Quality of Fuels for Electric Plants Data. Energy Information Administration (EIA). Accessed: 17 June 2010 < http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html>.

Load Duration Curve

One of the principal reasons that the mean-variance approach to modeling fuel diversity has performed poorly appears to be related to the omission of the load duration curve from the problem. A load duration curve (LDC) is a representation of the electricity demand in which the demand level is arranged in descending order of magnitude rather than chronologically. Thus, any point on the curve indicates the number of hours that experienced load equal to or greater than that value. Figure 2 shows a load duration curve representation of Indiana's 2006 electricity consumption.

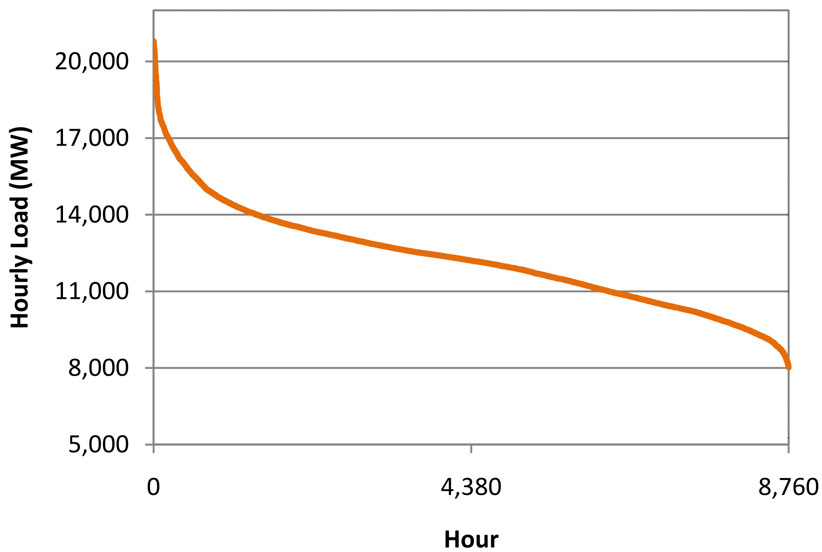

Figure 2. Load Duration Curve for 2006 Indiana Load

The curve is often divided into three load segments corresponding to peaking periods of when electricity usage is very high for short amounts of times, intermediate periods of moderate demand for longer periods and base periods to meet minimum demands that always exist. Although, the division using these three periods is a common practice, the curve conceptually can be subdivided into any number of periods or load classes.

Capacity factor and load factor are important features in measuring a plant's operation and the entire system's operation. Capacity factor (CF) is defined as the ratio of the actual electrical energy supplied by a generating unit over a period of time to the electrical energy that would have been generated if the generating unit had operated at full nameplate capacity for the entire period.

$$CF = \frac{energy\ generated}{capacity\ \text{x}\ time\ period},\ 0 \le CF \le 1$$

Load factor (LF) is defined as the ratio of the electrical energy generated by the entire generating system (with one or more generating units) over a period of time to the maximum load that occurred during the same period (2). By definition, these two factors can only take values between zero and one.

$$LF = \frac{energy\ generated}{peak\ load\ \text{x}\ time\ period},\ 0 \le LF \le 1$$

Alternative generating units typically have differing fixed and variable operating costs. Some units (e.g. pulverized coal) have very high fixed costs and low operating costs. It is economically attractive to use these units at high capacity factors to serve the portion of the load curve that has a high load factor (e.g. baseload). Other units may have lower fixed costs but higher variable operating costs (e.g. natural gas combustion turbines). Even though the operating costs are high, it is economically advantageous to use these units at low capacity factors to serve the portion of the load curve that has a low load factor (e.g. the peak class of load).

In formulating the mean-variance fuel diversification planning problem, it is important to reflect the varying levels of load across the year. These varying levels of load give rise to varying levels of the load factor and lead to a natural diversification of generating units even when volatility of fuel prices is not considered. When fuel price volatility is considered, there is additional incentive to diversify the generating fleet, but with the alternative focus of reducing the variability of fuel prices over time.

Existing Capacity

The generation capacity levels in Indiana for all existing and planned capacities were combined for each technology/fuel combination and are shown in Table 3. Existing generation capacities are based on data from the EIA and data obtained directly from electricity producers' filings with the Federal Energy Regulatory Commission. Planned generation includes generators that have been approved by the Indiana Utility Regulatory Commission. Wind capacity data were acquired from the 2010 Indiana Renewable Energy Source Study (SUFG 2010) that reports the Power Purchase Agreements (PPAs) signed by Indiana utilities with wind farms both within and outside Indiana. Most of the generation capacity is geographically located in Indiana, with exceptions like the D.C. Cook nuclear plant (1,655 MW), some wind farms (384 MW), and some fossil-fueled generation. Generators that are physically located in Indiana but are not owned by an Indiana utility are excluded.

Table 3. Existing and Planned Generation Capacities for Indiana by Energy (Fuel) Sources

Energy Source	Total Summer Capacity (MW)*
Coal	16,155
Integrated Gasification Combined Cycle	619
Oil	366
Natural gas combined cycle	1,148
Natural Gas Combustion Turbine	3,931
Nuclear	1,655
Wind	820
Total	24,174

Sources: EIA and SUFG[10]

[10] Existing Electric Generating Units in the United States, 2008, Form EIA-860 Database, Annual Electric Generator Report, (EIA 2008). Power purchase agreements, 2009 Indiana Renewable Energy Source Study (SUFG 2009).

Hydroelectric capacity is omitted from the analysis because it is all run of river and hence not dispatchable, there are limited opportunities for expansion, and it represents a small fraction of total capacity. While Wabash Valley Power Association's Wabash River 1 unit was converted to integrated gasification combined cycle technology in the early 1990's, it is treated as part of the installed coal-fired capacity in the model. The integrated gasification combined cycle capacity listed in the table is for Duke's Edwardsport facility.

Electricity Requirements

Hourly load data for the state of Indiana for 2006 were obtained from the individual utilities in the state and aggregated to a state-wide level. For the purposes of this study, the load curve for 2006 was scaled up by a multiplicative factor to obtain a total demand of 144,495 GWh, which is the amount projected in the 2009 Forecast Indiana Electricity Projections (SUFG, 2009) for 2025. This was done in order to create a situation where significant additional resources would be needed while maintaining a load profile that is indicative of the state's. This load curve is subdivided into 100 equally spaced load classes (along the load dimension of the load curve) with differing load factors. The model results specify not only how much generation should come from existing and new capacity for each technology/fuel combination, but how that generation should be allocated to each load segment.

Model Description

The mean-variance fuel diversification model is a constrained optimization problem. The decisions addressed by the model are how much existing and new capacity of each technology/fuel should be used, and how that capacity should be used to serve the load (i.e., what segments of the load curve are served by each technology). In making these choices, several constraints must be satisfied. First, for each technology/fuel the sum across all load segments of the amount of existing generation capacity (MW) that is assigned to serve that load segment is limited to the total existing capacity. Second, the amount of total generation (GWh) dedicated to serving each segment of the load curve must equal the energy demand in that segment.

The model has the goal of minimizing the average cost of serving Indiana load plus a factor, called the risk aversion coefficient, times the variance of cost. Because it is difficult to precisely assess an appropriate risk aversion level, the model results are produced for a range of values of this coefficient ranging from zero (at which point volatility of fuel costs is ignored) to a relatively high level where considerable emphasis is placed on reducing cost volatility.

Results

The model is used to determine mean-variance efficient portfolios of generating capacity for two scenarios. The first scenario is the base case, which reflects business as usual with demand expanded to projected 2025 levels. The second scenario considers the case where carbon costs are assessed on all generating technologies with emissions at a rate of $45.37 per ton of CO_2, which is the 2025 reference case price in EIA's analysis of H.R.2454.[11] (Sensitivity analysis results are included in an appendix that examines the impact of changes in the cost parameters for wind. This analysis was done due to the short data series for the wind data, and assesses the impact of changes in the variance of the cost of wind and the impact of changes in the wholesale price series that generates the cost of wind. The former analysis impacts only the mean cost of wind, while the latter affects both the mean and the variance of the cost of

[11] Energy Market and Economic Impacts of H.R.2454, the American Clean Energy and Security Act of 2009, August 2009, (EIA 2009).

wind.) Both scenarios include the following generating technology/fuel combinations: pulverized coal (Pcoal), integrated gasification combined cycle coal (IGCC), oil-fired (Oil), natural gas combustion turbine (NGCT), natural gas combined cycle (NGCC), nuclear (Nuc), and wind plus market (Wind).

The base case serves as the basis for comparison with the results from the carbon cost scenario. The carbon cost scenario presented here is indicative of the likely impacts of penalizing emissions of carbon dioxide. The scenario shows the outcome of treating a CO_2 emission cost of \$45.37/ton as a cost per unit parameter of energy generated and adding it to the fuel cost term. However, since various fossil fuels have different net heat rates and carbon contents for each technology, this penalty impacts the various fuels and technologies in different ways.

Base Scenario

The results of the base case scenario in terms of the tradeoff between average cost and cost volatility is illustrated in Figure 3, which displays the mean-variance efficient frontier with the standard deviation on the horizontal axis and the expected total production cost per unit of energy on the vertical axis. The points along the curve correspond to different values of the risk aversion parameter β. The point at the lower right end of the curve corresponds to near zero risk aversion and thus has a very high level of volatility (as measured by the standard deviation of cost), but a low level of average cost. Three points are highlighted on this graph: $\beta = 0.003$, $\beta = 0.007$ and $\beta = 0.016$. (These levels of risk aversion will be used to focus the discussion of the detailed resource allocations below.) As risk aversion increases, the model solution shifts to a more diversified generation mix to reduce the volatility at the expense of a greater expected cost. Therefore, points to the left have higher values of the risk aversion parameter, with a willingness to pay higher average costs to reduce exposure to cost volatility. As β increases to values higher than those shown in Figure 3, the curve is nearly vertical, which indicates that in order to achieve very small reductions in volatility, the mean cost must increase substantially. These points are of little practical value and are not presented.

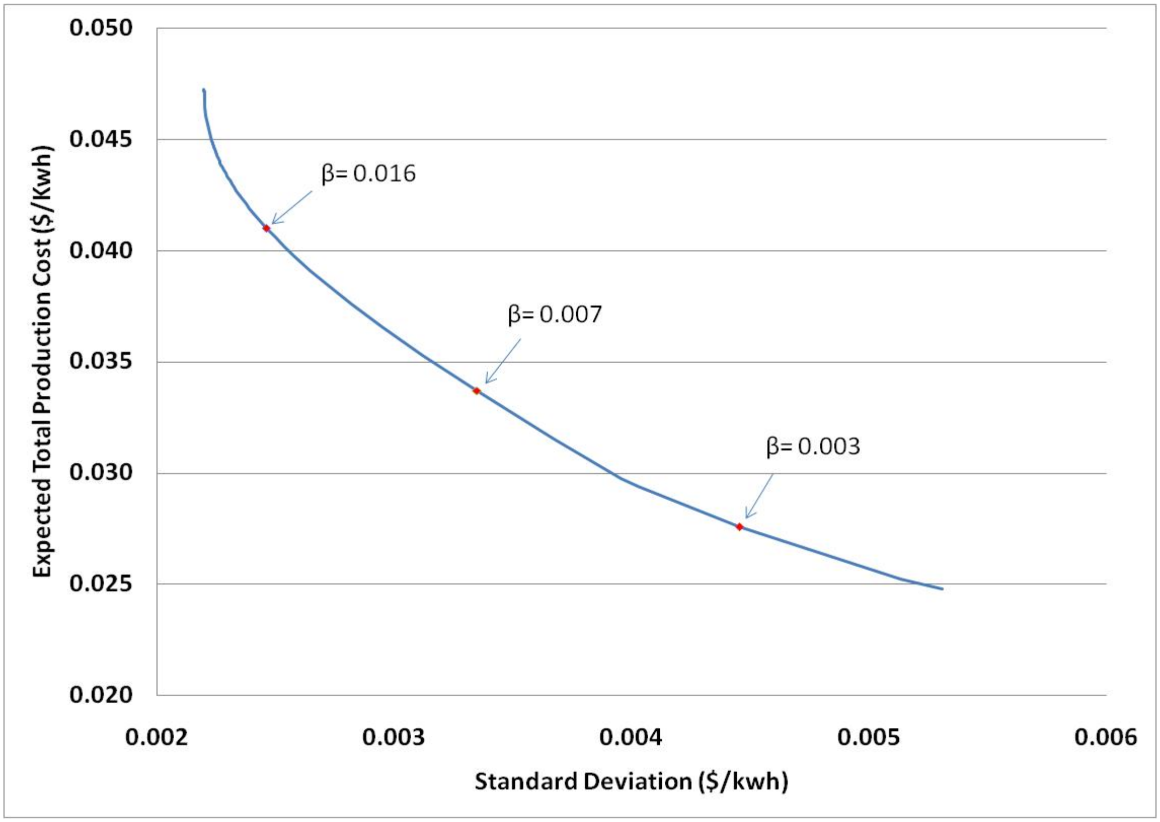

Figure 3. Cost Mean/Standard Deviation Efficient Frontier–Base Case Scenario

The percentage share of the various generation resources at different levels of risk aversion is shown in Figure 4. This graph shows that as risk aversion increases the mix of generation shifts. Shares are initially stable with the vast majority being pulverized coal up to a level of about $\beta = 0.003$. Wind plus market is initially at about 5 percent. Beyond this point, the shares shift towards less pulverized coal, more IGCC, more NGCC, and eventually more nuclear. The dramatic shift towards nuclear generation is a reflection of the low volatility of nuclear fuel costs. Wind plus market increases to just under 10 percent by the point where $\beta = 0.01$ and remains there for higher levels of risk aversion. The results for high levels of risk aversion are likely unrealistic due to the very large share of nuclear generation, which is likely to be limited by factors that are not reflected in the model.

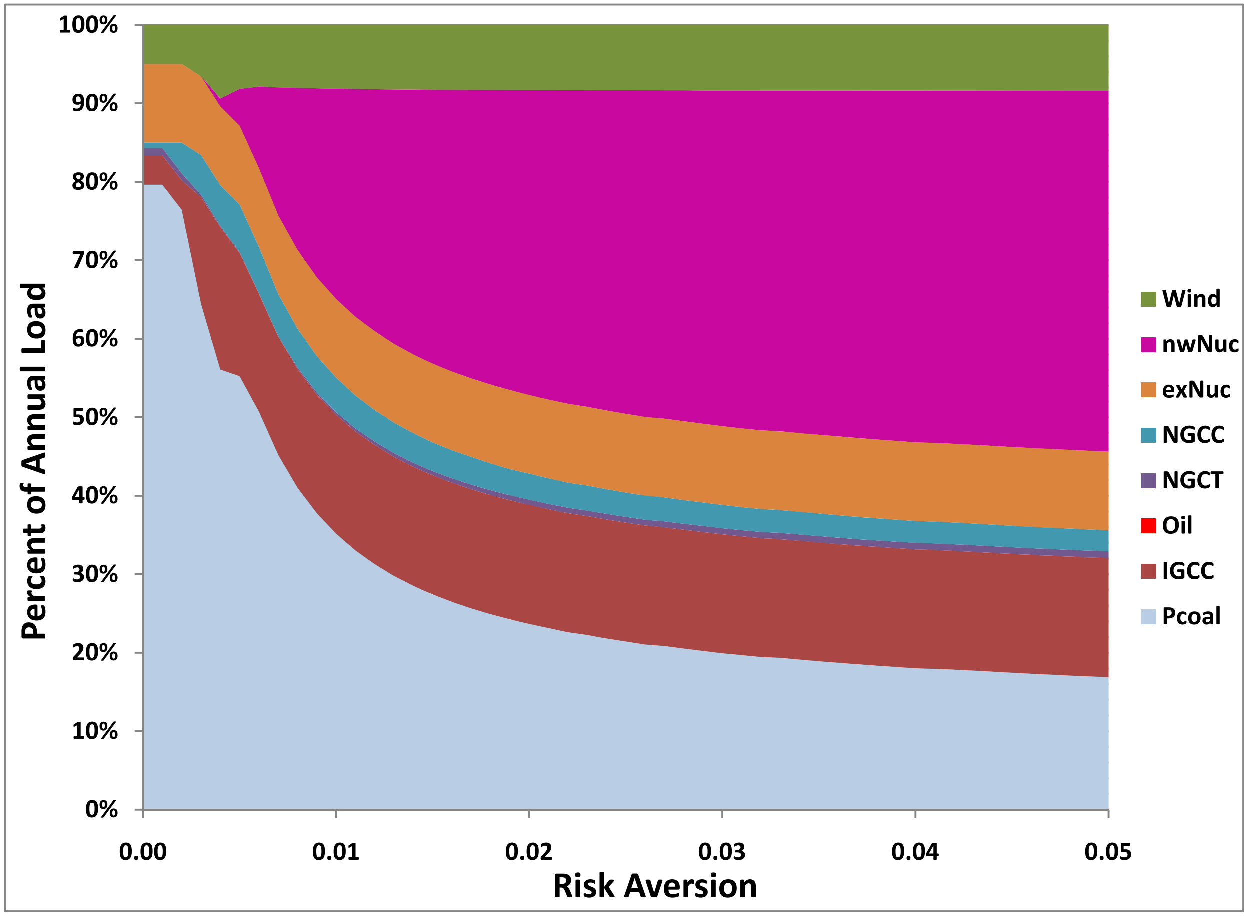

Figure 4. Capacity Share as Risk Aversion Increases–Base Case Scenario

Table 4 displays the detailed generation portfolios for each of the three representative values of β highlighted in Figure 3. Results are grouped by fuel type (coal, oil, natural gas, nuclear and wind), within fuel type by technology (pulverized coal and IGCC for coal and combustion turbine and combined cycle for natural gas), and within technology by existing versus new capacity. For each fuel/technology group, energy production, capacity and average load factor are provided.

The resulting optimal portfolio at the lower level of β (= 0.003) includes the use of just over 16 GW of existing capacity of pulverized coal. This capacity is used with an average load factor of about 66 percent to generate approximately 93,000 GWh of energy. No new pulverized coal capacity is added in the base case. Existing IGCC capacity of about 0.6 GW is used to generate about 5.4 thousand GWh of energy at a load factor of 100 percent. For this technology, about 1.6 GW of new capacity is added, generating about 14 thousand GWh of electricity with a load factor of 100 percent. For this portfolio, IGCC new capacity accounts for about 9 percent share of the total coal generation capacity and about half of the total capacity additions to the entire system. Existing oil fired capacity of 366 MW is fully utilized to generate just under 1.7 GWh of energy at a load factor of 0.05 percent. The small load factor reflects the usefulness of this existing capacity for serving extreme peak loads despite its high variable cost. At the 0.003 risk aversion level, the optimal combination of technologies is attained without the addition of new oil capacity. Existing capacity of natural gas fired generation is fully utilized with the existing combustion turbines having a capacity factor of about 0.5 percent and the existing combined cycle units having a capacity factor of nearly 73 percent. Natural gas combustion turbine capacity is increased by 1,384 MW with a capacity factor of about 2 percent. The addition of new gas fired combustion turbine capacity in preference to new gas fired combined cycle capacity underscores the value of combustion turbine technology for serving peak load. The existing nuclear capacity is used to produce about 14.5 thousand GWh of energy at a capacity factor of 100 percent. No new nuclear capacity is added. Existing wind capacity is fully utilized and the 820 MW[12] is used to generate about 7.2 thousand GWh of energy with a load factor of 100 percent[13]. Wind capacity is increased by almost a third and generates about 9,491 GWh with a load factor of 100 percent. At this level of risk aversion, the total expected cost of meeting this projected consumption is about $3.99 billion which corresponds to a $0.0276 on a per kWh basis with a standard deviation of $0.00445.

The columns in Table 4 are arranged in order of increasing risk aversion. As risk aversion increases, the energy supplied by coal, oil and natural gas decreases, while the energy supplied by nuclear and wind increases. The energy production from coal drops mainly due to a reduction in the capacity factor for existing pulverized coal. The reductions in energy production from coal, oil and natural gas technologies are replaced primarily by nuclear generation. While no new nuclear capacity is added at the lower risk aversion level, nuclear capacity increases by a factor of 2.6 at the intermediate risk aversion level and 4.6 at the high level. While the full existing coal capacity is used in the 0.003 and 0.007 risk aversion cases, existing coal capacity is not fully utilized in the 0.016 risk aversion case. A small amount of oil capacity is fully utilized at the 0.003 risk aversion level, but unused in the cases with higher risk aversion, reflecting the impact of the high fuel price variability of oil. Natural gas energy production drops by roughly half from the lower to the intermediate and from the intermediate to the higher risk aversion levels due to a large decline in natural gas fired capacity utilization. (It is noted that in the highest risk aversion case that the existing natural gas combustion turbine load factor increases substantially to nearly 25 percent. This appears to be offset by a large reduction in capacity factor for the existing natural gas combined cycle capacity.) The results also show that wind plus market capacity grows only modestly as risk aversion increases. Expected costs increase by about $1 billion as risk aversion moves from 0.003 to 0.007 and again from 0.007 to 0.016. On a per kWh basis, expected costs increase from $0.0276 to $0.0337 to $0.0410, while the standard deviations decrease from $0.00445 to $0.00335 to $0.00246, respectively.

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[13] Because of the design of the wind plus market technology with wholesale purchases being used to make up for any shortfall from peak output, this technology always operates at a 100% load factor and is therefore restricted to serve only the baseload portion of the load curve.

Table 4. Base Case Results for Three Levels of Risk Aversion

Technology	Risk Aversion (β)		
		Base case	
	0.003	0.007	0.016
Pcoal existing energy (GWh)	93,092.53	65,264.95	38,250.86
Pcoal existing capacity (MW)	16,155.50*	16,155.50*	14,995.47
Pcoal existing average load factor	65.78	46.12	29.12
Pcoal new energy	0.00	0.00	0.00
Pcoal new capacity	0.00	0.00	0.00
Pcoal new average load factor	0.00	0.00	0.00
IGCC existing energy	5,422.44	5,422.44	5,411.06
IGCC existing capacity	619.00*	619.00*	619.00*
IGCC existing average load factor	100.00	100.00	99.79
IGCC new energy	14,246.18	16,360.35	16,516.41
IGCC new capacity	1,626.28	1,867.62	1,886.15
IGCC new average load factor	100.00	100.00	99.96
Total Coal Energy	112,761.15	87,047.74	60,178.33
Total Coal Capacity	18,400.78	18,642.12	17,500.62
Oil existing energy	1.67	0.00	0.00
Oil existing capacity	366.40*	0.00	0.00
Oil existing average load factor	0.05	0.00	0.00
Oil new energy	0.00	0.00	0.00
Oil new capacity	0.00	0.00	0.00
Oil new average load factor	0.00	0.00	0.00
Total Oil Energy	1.67	0.00	0.00
Total Oil Capacity	366.40	0.00	0.00
NGCT existing energy	176.11	94.58	822.93
NGCT existing capacity	3,930.60*	2,514.80	377.53
NGCT existing average load factor	0.51	0.43	24.88
NGCT new energy	264.53	0.00	0.00
NGCT new capacity	1,383.98	0.00	0.00
NGCT new average load factor	2.18	0.00	0.00
NGCC existing energy	7,301.12	7,740.69	5,159.71
NGCC existing capacity	1,147.70*	1,147.70*	1,147.70*
NGCC existing average load factor	72.62	76.99	51.32
NGCC new energy	0.00	0.00	0.00
NGCC new capacity	0.00	0.00	0.00

NGCC new average load factor	0.00	0.00	0.00
Total Gas Energy	7,741.75	7,835.27	5,982.64
Total Gas Capacity	6,462.28	3,662.50	1,525.23
Nuclear existing energy	14,499.55	14,499.55	14,499.55
Nuclear existing capacity	1,655.20*	1,655.20*	1,655.20*
Nuclear existing average load factor	100.00	100.00	100.00
Nuclear new energy	0.00	23,582.75	51,861.04
Nuclear new capacity	0.00	2,692.10	5,920.21
Nuclear new average load factor	0.00	100.00	100.00
Total Nuclear Energy	14,499.55	38,082.30	66,360.59
Total Nuclear Capacity	1,655.20	4,347.30	7,575.41
Wind existing energy	7,183.20	7,183.20	7,183.20
Wind existing capacity	820.00*	820.00*	820.00*
Wind existing average load factor	100.00	100.00	100.00
Wind new energy	2,307.68	4,346.48	4,790.23
Wind new capacity	263.43	496.17	546.83
Wind new average load factor	100.00	100.00	100.00
Total Wind Energy	9,490.88	11,529.68	11,973.43
Total Wind Capacity	1,083.43	1,316.17	1,366.83
Total Energy(MWh)	144,495.000	144,495.000	144,495.000
Total Capacity (MW)	27,968.091	27,968.091	27,968.091
Expected total cost (million $)	3,987.771	4,869.095	5,924.696
Variance of cost (million $)	414,184.043	233,782.487	126,308.692
S.D. of cost (million $)	643.571	483.511	355.399
Risk adjusted cost (million $)	5,230.323	6,505.573	7,945.635
Expected unit cost ($/kWh)	0.02760	0.03370	0.04100
Unit S.D. of cost ($/kWh)	0.00445	0.00335	0.00246

*Denotes existing capacity that is fully utilized.

Carbon Dioxide Emission Costs

This scenario estimates the impacts of adding a carbon dioxide emission cost to the average fuel cost terms for coal, natural gas and oil. The level of the cost is consistent with the EIA estimates of the impact of the Waxman-Markey cap and trade bill at \$45.37 per ton of CO_2. Inclusion of this cost is also expected to have an impact on the wholesale price of electricity, which the EIA estimates to be an increase of 25.82 percent. Thus, the parameters relating to the average variable costs for fossil fuels are increased by an adder reflecting the volume of CO_2 emissions per MWh, and the means, variances and covariances for wind plus market, which are based on wholesale prices, are recalculated with wholesale prices increased by 25.82 percent. The values of these parameters for this scenario are displayed in Table 5.

Table 5. Fuel Costs and Covariance Estimates for a Carbon Cost Scenario (in 2007 \$/MWh)

	Average Fuel Cost	Covariance with Wind Plus Market
PCoal	62.511	12.2158
IGCC	55.370	10.8204
Oil	157.696	-7.2453
NGCT	82.220	72.8448
NGCC	54.200	48.0197
Nuc	9.678	1.4482
Wind	34.483	97.5298

Figure 5 displays the efficient frontier for the carbon case along with the base case efficient frontier, highlighting the same selected values of the risk aversion parameter β. The frontier for this scenario is located above the efficient frontier for the base case, reflecting the additional costs. Focusing on the points for the specific β values, these risk aversion levels shift above and to the left of the corresponding base case values. They are above due to the substantial increase in costs, and they are to the left because the carbon cost scenario indicates a significantly higher amount of new nuclear generation, which has a low volatility.

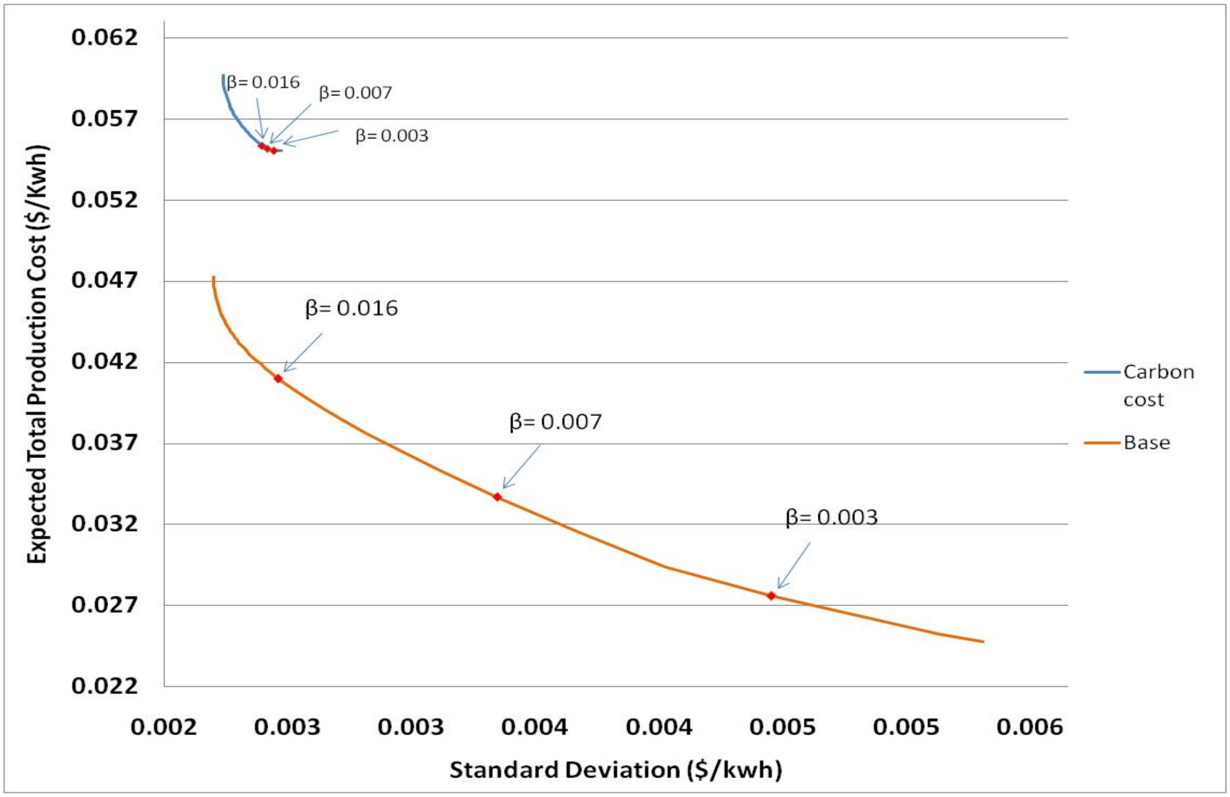

Figure 5. Cost Mean/Standard Deviation Efficient Frontier–Carbon Cost Scenario

Figure 6 shows the percentage of the annual load served by each technology at different levels of risk aversion for the carbon cost scenario. As can be seen in the figure, including a carbon cost penalty reduces the capacity shares of fossil fuel-fired generation capacity dramatically. Energy from coal-fired plants drops from about 85 percent in the base case with risk neutrality ($\beta = 0$) to about 13 percent with a β value of zero, with a corresponding increase in generation primarily from new nuclear. Unlike the base case, the percentages of load served by the alternative technologies are relatively stable as risk aversion increases with the most noticeable effect being a shift from pulverized coal toward IGCC and a moderate *reduction* in the percentage for nuclear. The percentage of load served by wind is nearly constant at about 6 percent. The reason for this is that the introduction of carbon costs shifts the mean costs in favor of nuclear, which has a low fuel cost variance. Thus even with low risk aversion, a generation portfolio with low variance is already optimal.

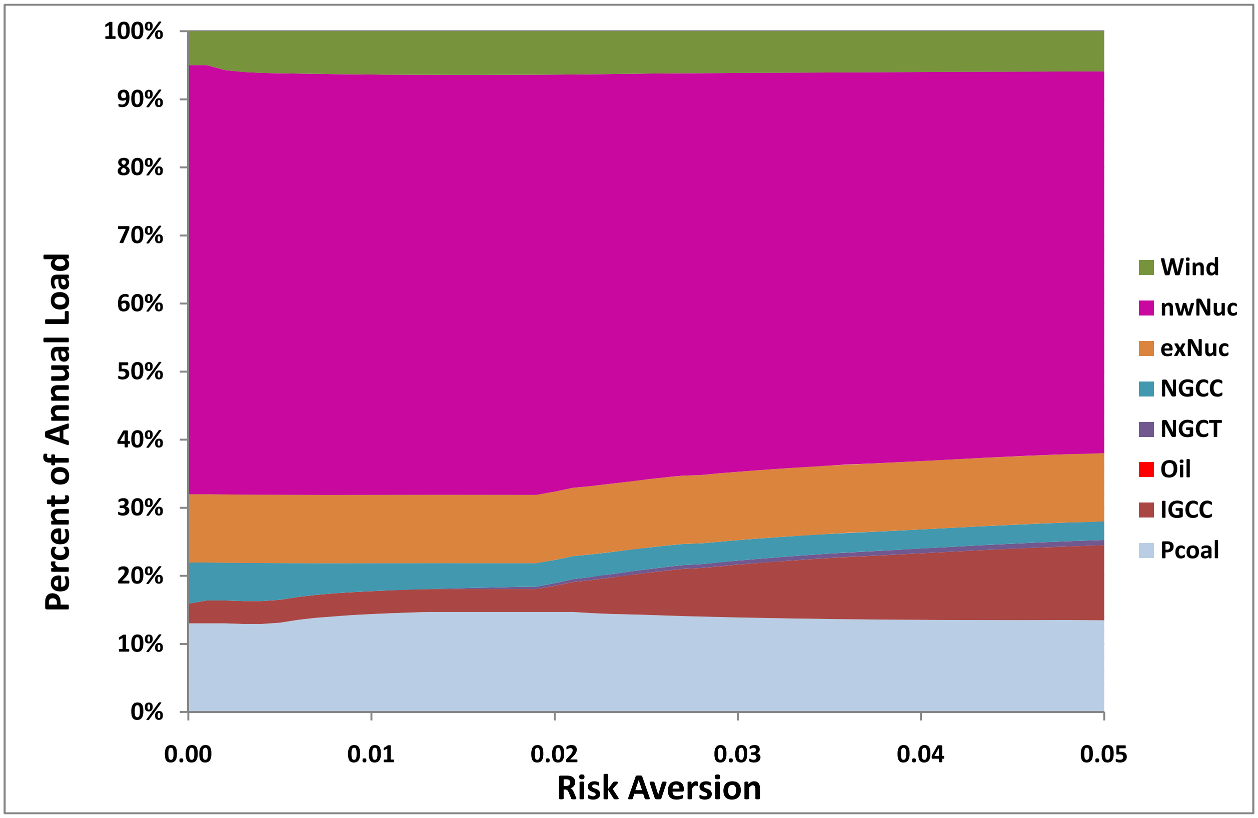

Figure 6. Capacity Share as Risk Aversion Increases–Carbon Cost Scenario

The detailed results of the carbon cost scenario are presented in Table 6 for the same three risk aversion levels that were the focus in the base case. Compared to the base case at the lower level of risk aversion, only about one fifth of the energy (19 thousand GWh) is generated from existing pulverized coal capacity. This capacity has a considerably lower average load factor of just over 16 percent and is not fully utilized. Existing IGCC capacity is fully utilized but generates just under 5 thousand GWh of energy at a lower load factor than in the base case. While new IGCC capacity was added in the base case, no new IGCC capacity is added when carbon emissions are penalized. Both new and existing capacity of oil and natural gas-fired CT technologies are removed from this generation portfolio because of the carbon emissions cost except in the highest risk aversion case considered. As can be seen in Figure 6, existing NGCT capacity plays a very minor role at higher levels of risk aversion. Existing natural gas combined cycle capacity is fully utilized, but no new NGCC capacity is installed.

Existing nuclear capacity is fully utilized with a 100 percent load factor as it was in the base case. New nuclear capacity additions replace most of the decline in pulverized coal capacity and generation. Finally while existing wind capacity is fully utilized as it was in the base case, additions to wind capacity are substantially less for this scenario. This is explained in part by the fact that the variance of nuclear fuel cost is lower than the variance of wind plus market. Total expected cost rises dramatically with a total expected cost of about $8 billion and a standard deviation of cost of about $350 million. These totals translate to expected unit costs of about 5.5 cents per kWh and a standard deviation of about 0.24 cents per kWh.

Table 6. Results for Carbon Cost for Three Levels of Risk Aversion

Technology	Risk Aversion (β) Carbon Cost case		
	0.003	0.007	0.016
Pcoal existing energy (GWh)	18,699.77	20,003.53	21,225.41
Pcoal existing capacity (MW)	13,260.10	13,260.10	13,218.08
Pcoal existing average load factor	16.10	17.22	18.33
Pcoal new energy	0.00	0.00	0.00
Pcoal new capacity	0.00	0.00	0.00
Pcoal new average load factor	0.00	0.00	0.00
IGCC existing energy	4,861.25	4,861.25	4,861.25
IGCC existing capacity	619.00*	619.00*	619.00*
IGCC existing average load factor	89.65	89.65	89.65
IGCC new energy	0.00	0.00	0.00
IGCC new capacity	0.00	0.00	0.00
IGCC new average load factor	0.00	0.00	0.00
Total Coal Energy	23,561.02	24,864.78	26,086.67
Total Coal Capacity	13,879.10	13,879.10	13,837.08
Oil existing energy	0.00	0.00	0.00
Oil existing capacity	0.00	0.00	0.00
Oil existing average load factor	0.00	0.00	0.00
Oil new energy	0.00	0.00	0.00
Oil new capacity	0.00	0.00	0.00
Oil new average load factor	0.00	0.00	0.00
Total Oil Energy	0.00	0.00	0.00
Total Oil Capacity	0.00	0.00	0.00
NGCT existing energy	0.00	0.00	314.15
NGCT existing capacity	0.00	0.00	42.03
NGCT existing average load factor	0.00	0.00	85.33
NGCT new energy	0.00	0.00	0.00
NGCT new capacity	0.00	0.00	0.00
NGCT new average load factor	0.00	0.00	0.00
NGCC existing energy	8,029.52	6,725.76	5,189.73
NGCC existing capacity	1,147.70*	1,147.70*	1,147.70*
NGCC existing average load factor	79.87	66.90	51.62
NGCC new energy	0.00	0.00	0.00
NGCC new capacity	0.00	0.00	0.00
NGCC new average load factor	0.00	0.00	0.00
Total Gas Energy	8,029.52	6,725.76	5,503.88
Total Gas Capacity	1,147.70	1,147.70	1,189.73

Nuclear existing energy	14,499.55	14,499.55	14,499.55
Nuclear existing capacity	1,655.20*	1,655.20*	1,655.20*
Nuclear existing average load factor	100.00	100.00	100.00
Nuclear new energy	89,748.38	89,312.96	89,129.25
Nuclear new capacity	10,297.90	10,248.19	10,227.22
Nuclear new average load factor	99.49	99.49	99.49
Total Nuclear Energy	104,247.93	103,812.51	103,628.80
Total Nuclear Capacity	11,953.10	11,903.39	11,882.42
Wind existing energy	7,183.20	7,183.20	7,183.20
Wind existing capacity	820.00*	820.00*	820.00*
Wind existing average load factor	100.00	100.00	100.00
Wind new energy	1,473.32	1,908.75	2,092.46
Wind new capacity	168.19	217.89	238.87
Wind new average load factor	100.00	100.00	100.00
Total Wind Energy	8,656.52	9,091.95	9,275.66
Total Wind Capacity	988.19	1,037.89	1,058.87
Total Energy(MWh)	144,495.000	144,495.000	144,495.000
Total Capacity (MW)	27,968.091	27,968.091	27,968.091
Expected total cost (million $)	7,957.344	7,971.369	7,995.452
Variance of cost (million $)	124,367.939	121,871.853	119,695.202
S.D. of cost (million $)	352.658	349.101	345.970
Risk adjusted cost (million $)	8,330.448	8,824.472	9,910.575
Expected unit cost ($/kWh)	0.05507	0.05517	0.05533
Unit S.D. of cost ($/kWh)	0.00244	0.00242	0.00239

*Denotes existing capacity that is fully utilized.

Conclusions

An initial analysis of the impact of wind as a generating option on the long-term strategic portfolio of generation capacity based on a fuel diversity model was developed. The analysis evaluates the tradeoff between long-run expected costs and the volatility of those costs, and traces the impacts on the optimal generation portfolio as the emphasis shifts from minimizing expected cost towards minimizing the volatility of costs. For the "business as usual" base case, increasing the emphasis towards reducing the volatility of costs causes large shifts in the generation mix from one which is heavily reliant on coal to one with a significantly larger percentage of the load served by nuclear. The impact of this shift on expected costs is substantial, with a roughly equal mix between coal and nuclear resulting in about a 50 percent increase in the long-run average cost of electricity and a reduction in the volatility of electricity costs of about 45 percent. The role of wind generation in this base case is moderate with wind augmented by market purchases serving 6.5 to 8.5 percent of load.

A second scenario was constructed to estimate the probable impact of carbon legislation on the optimal generation portfolio. The scenario is based on a $45.37/ ton carbon emissions cost. The results indicate that the generation portfolio shifts dramatically away from fossil fuel-fired generation alternatives relative to the base case. Pulverized coal generation is largely replaced by nuclear energy. As the emphasis shifts from minimizing long-run average costs to controlling cost volatility, the generation portfolio is essentially unchanged. This reflects nuclear being a dominant technology (i.e., it has low average generation costs and low fuel cost volatility) in a world with CO_2 costs on the order of $45 per ton. Wind plus market plays a smaller role than in the base case with capacity expansions in the range of 150-250 MW.

Limitations

While the model estimates the optimal portfolio of generating technologies and fuels, factors outside of those considered in this study may also impact the results.

<u>Government incentives</u>: Federal and state incentives for installing wind energy projects reduce the costs for wind turbines which in turn reduce the total generation cost. These wind investment incentives, depending on their magnitude, may improve the cost-efficiency of wind relative to the other fuels resulting in more wind being added to the optimal generation mix.

<u>Nuclear O&M costs</u>: The potential variation between the actual operation and maintenance cost of a nuclear plant and the cost used in the model would affect the results. Since values vary from one plant to another, the cost reported in EIA's Annual Energy Outlook 2009 does not exactly represent the actual cost and performance of the D.C. Cook nuclear station that primarily serves Indiana load. Due to confidentiality issues this type of data is not available to public, but clearly would impact the final outcome considering the importance of nuclear generation in the optimal generation mix.

<u>Wind data</u>: The three years of wind output data used to estimate the average wind plus market cost and its variance/covariances may not be a large enough sample. Since the data period is very short, one atypical year would have a major influence on the results. Furthermore, the available data represent estimations rather than actual wind generation output since the wind farms had yet to be developed. Thus, the wind generation has no effect on the wholesale market price.

<u>Market price data</u>: Since the MISO market did not exist prior to April 2005 additional data estimations were performed to produce a complete set of market data. Ideally, the analysis would be performed using actual market data that corresponds chronologically with actual wind generation data. Furthermore, the

market prices in the carbon dioxide scenario were determined using a constant percentage increase across all hours, which is unlikely to occur in such circumstances since the marginal generators that set the market price will be affected to different degrees.

Large scale nuclear development: Two other factors that are not reflected in the model that could have an impact on the ability to make large shifts in capacity from coal-fired generation to nuclear relate to the ability to site and build so many nuclear facilities, and the economic development impacts of a large reduction in coal use.

Unit commitment: Due to the use of load duration curves in the model rather than chronological load shapes, start-up and shut-down costs associated with the unit commitment problem are not included. This would tend to overstate the attractiveness of units that have substantial start-up and shut-down costs, such as nuclear. As a future modification to the model, it may be desirable to limit the load segments for which nuclear generation can be used to adjust for this issue.

Unit outages: Planned and unplanned outages are not modeled, so units are available 100 percent of the time. The attractiveness of units with below average availability may be overstated.

Changes in fuel price volatility: Historical price variances are used to model volatility. If current and future developments result in fundamental changes in price variances, different results would be expected. The recent development of shale gas may have such an effect on natural gas prices.

Future Research

This study appears to be the first to incorporate an intermittent generation resource in an analysis of fuel diversification. Future work could use a longer time series of data for both wind output and wholesale electricity prices. To account for the current trend in Indiana of using more renewable resources to generate electricity, including more fuel types is a potentially useful extension of the model. There is also a need to properly develop economic evaluation of other energy resources such as solar, water and organic waste biomass. Finally, energy storage technology paired with intermittent generating capacity may play an important role in reducing the impact of wind intermittency.

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Appendix

<u>Additional Model Results</u>

Sensitivity Analysis–4 Times Low and High Wind Price Variance Scenario

Table A.1. Results for 4 Times Low and High Wind Price Variance Scenario for Three Levels of Risk Aversion

Technology	Risk Aversion (β)					
	Wind Prices Variance at 1/4			Prices Variance 4 Times Higher		
	0.003	0.007	0.016	0.003	0.007	0.016
Pcoal existing energy (MWh)	88,128.60	61,639.39	34,832.30	94,023.40	65,906.34	39,063.85
Pcoal existing capacity (MW)	16,155.50*	16,155.50*	14,526.66	16,155.50*	16,155.50*	15,388.14
Pcoal existing average load factor	62.27	43.55	27.37	66.44	46.57	28.98
Pcoal new energy	0.00	0.00	0.00	0.00	0.00	0.00
Pcoal new capacity	0.00	0.00	0.00	0.00	0.00	0.00
Pcoal new average load factor	0.00	0.00	0.00	0.00	0.00	0.00
IGCC existing energy	5,422.44	5,422.44	5,388.21	5,422.44	5,422.44	5,413.16
IGCC existing capacity	619.00*	619.00*	619.00*	619.00*	619.00*	619.00*
IGCC existing average load factor	100.00	100.00	99.37	100.00	100.00	99.83
IGCC new energy	7,305.14	11,755.58	11,732.71	15,414.07	17,177.43	17,545.00
IGCC new capacity	833.92	1,341.96	1,343.43	1,759.60	1,960.89	2,003.02
IGCC new average load factor	100.00	100.00	99.70	100.00	100.00	99.99
Total Coal Energy	100,856.19	78,817.41	51,953.23	114,859.91	88,506.21	62,022.01
Total Coal Capacity	17,608.42	18,116.46	16,489.09	18,534.10	18,735.39	18,010.16
Oil existing energy	1.67	0.00	0.00	1.67	0.00	0.00
Oil existing capacity	366.40*	0.00	0.00	366.40*	0.00	0.00
Oil existing average load factor	0.05	0.00	0.00	0.05	0.00	0.00
Oil new energy	0.00	0.00	0.00	0.00	0.00	0.00
Oil new capacity	0.00	0.00	0.00	0.00	0.00	0.00
Oil new average load factor	0.00	0.00	0.00	0.00	0.00	0.00

Total Oil Energy	1.67	0.00	0.00	1.67	0.00	0.00
Total Oil Capacity	366.40	0.00	0.00	366.40	0.00	0.00
NGCT existing energy	176.11	38.10	554.21	176.11	141.56	887.29
NGCT existing capacity	3,930.60*	2,019.52	348.54	3,930.60*	2,606.65	102.39
NGCT existing average load factor	0.51	0.22	18.15	0.51	0.62	98.92
NGCT new energy	104.21	0.00	0.00	303.51	0.00	0.00
NGCT new capacity	696.43	0.00	0.00	1,514.09	0.00	0.00
NGCT new average load factor	1.71	0.00	0.00	2.29	0.00	0.00
NGCC existing energy	6,402.37	7,084.03	4,540.07	7,471.06	7,856.87	5,305.03
NGCC existing capacity	1,147.70*	1,147.70*	1,147.70*	1,147.70*	1,147.70*	1,147.70*
NGCC existing average load factor	63.68	70.46	45.16	74.31	78.15	52.77
NGCC new energy	0.00	0.00	0.00	0.00	0.00	0.00
NGCC new capacity	0.00	0.00	0.00	0.00	0.00	0.00
NGCC new average load factor	0.00	0.00	0.00	0.00	0.00	0.00
Total Gas Energy	6,682.69	7,122.13	5,094.28	7,950.67	7,998.43	6,192.32
Total Gas Capacity	5,774.73	3,167.22	1,496.24	6,592.39	3,754.35	1,250.09
Nuclear existing energy	14,499.55	14,499.55	14,499.55	14,499.55	14,499.55	14,499.55
Nuclear existing capacity	1,655.20*	1,655.20*	1,655.20*	1,655.20*	1,655.20*	1,655.20*
Nuclear existing average load factor	100.00	100.00	100.00	100.00	100.00	100.00
Nuclear new energy	0.00	8,226.47	35,826.66	0.00	26,307.61	55,287.77
Nuclear new capacity	0.00	939.09	4,089.97	0.00	3,003.15	6,311.39
Nuclear new average load factor	0.00	100.00	100.00	0.00	100.00	100.00
Total Nuclear Energy	14,499.55	22,726.02	50,326.21	14,499.55	40,807.16	69,787.32
Total Nuclear Capacity	1,655.20	2,594.29	5,745.17	1,655.20	4,658.35	7,966.59
Wind existing energy	7,183.20	7,183.20	7,183.20	7,183.20	7,183.20	6,493.35
Wind existing capacity	820.00*	820.00*	820.00*	820.00*	820.00*	741.25

Wind existing average load factor	100.00	100.00	100.00	100.00	100.00	100.00
Wind new energy	15,271.70	28,646.24	29,938.08	0.00	0.00	0.00
Wind new capacity	1,743.35	3,270.12	3,417.59	0.00	0.00	0.00
Wind new average load factor	100.00	100.00	100.00	0.00	0.00	0.00
Total Wind Energy	22,454.90	35,829.44	37,121.28	7,183.20	7,183.20	6,493.35
Total Wind Capacity	2,563.35	4,090.12	4,237.59	820.00	820.00	741.25
Total Energy(MWh)	144,495.000	144,495.000	144,495.000	144,495.000	144,495.000	144,495.000
Total Capacity (MW)	27,968.091	27,968.091	27,968.091	27,968.091	27,968.091	27,968.091
Expected total cost (million $)	4,102.694	4,890.831	5,935.040	3,966.393	4,865.646	5,938.553
Variance of cost (million $)	366,156.376	211,606.282	105,110.030	431,246.251	245,094.537	136,434.913
S.D. of cost (million $)	605.109	460.007	324.207	656.693	495.070	369.371
Risk adjusted cost (million $)	5,201.163	6,372.075	7,616.800	5,260.132	6,581.308	8,121.511
Expected unit cost ($/kWh)	0.02839	0.03385	0.04107	0.02745	0.03367	0.04110
Unit S.D. of cost ($/kWh)	0.00419	0.00318	0.00224	0.00454	0.00343	0.00256

*Denotes existing capacity that is fully utilized.

Sensitivity Analysis–25 Percent Times Lower and Higher Wind Expected Cost Scenario

Table A.2. Results for 25 Percent Times Lower and Higher Wind Expected Cost Scenario for Three Levels of Risk Aversion

	Risk Aversion (β)					
Technology	Wind Expected Cost 25% Times Lower			Wind Expected Cost 25% Times Higher		
	0.003	0.007	0.016	0.003	0.007	0.016
Pcoal existing energy (MWh)	83,051.69	62,379.14	36,450.78	94,024.72	65,906.11	38,954.43
Pcoal existing capacity (MW)	16,155.50*	16,155.50*	14,749.83	16,155.50*	16,155.50*	15,258.56
Pcoal existing average load factor	58.68	44.08	28.21	66.44	46.57	29.14
Pcoal new energy	0.00	0.00	0.00	0.00	0.00	0.00
Pcoal new capacity	0.00	0.00	0.00	0.00	0.00	0.00
Pcoal new average load factor	0.00	0.00	0.00	0.00	0.00	0.00
IGCC existing energy	5,422.44	5,422.44	5,398.09	5,422.44	5,422.44	5,412.24

IGCC existing capacity	619.00*	619.00*	619.00*	619.00*	619.00*	619.00*
IGCC existing average load factor	100.00	100.00	99.55	100.00	100.00	99.81
IGCC new energy	141.53	12,694.81	14,064.19	15,414.07	17,177.42	17,417.05
IGCC new capacity	16.16	1,449.18	1,607.07	1,759.60	1,960.89	1,988.42
IGCC new average load factor	100.00	100.00	99.90	100.00	100.00	99.99
Total Coal Energy	88,615.66	80,496.38	55,913.06	114,861.23	88,505.97	61,783.72
Total Coal Capacity	16,790.66	18,223.68	16,975.90	18,534.10	18,735.39	17,865.98
Oil existing energy	1.67	0.00	0.00	1.67	0.00	0.00
Oil existing capacity	366.40*	0.00	0.00	366.40*	0.00	0.00
Oil existing average load factor	0.05	0.00	0.00	0.05	0.00	0.00
Oil new energy	0.00	0.00	0.00	0.00	0.00	0.00
Oil new capacity	0.00	0.00	0.00	0.00	0.00	0.00
Oil new average load factor	0.00	0.00	0.00	0.00	0.00	0.00
Total Oil Energy	1.67	0.00	0.00	1.67	0.00	0.00
Total Oil Capacity	366.40	0.00	0.00	366.40	0.00	0.00
NGCT existing energy	176.11	41.88	681.61	176.11	141.85	878.67
NGCT existing capacity	3,930.60*	2,119.69	361.81	3,930.60*	2,606.65	216.30
NGCT existing average load factor	0.51	0.23	21.51	0.51	0.62	46.37
NGCT new energy	0.00	0.00	0.00	303.51	0.00	0.00
NGCT new capacity	0.00	0.00	0.00	1,514.09	0.00	0.00
NGCT new average load factor	0.00	0.00	0.00	2.29	0.00	0.00
NGCC existing energy	5,482.81	7,217.99	4,833.24	7,469.73	7,856.87	5,286.71
NGCC existing capacity	1,147.70*	1,147.70*	1,147.70*	1,147.70*	1,147.70*	1,147.70
NGCC existing average load factor	54.53	71.79	48.07	74.30	78.15	52.58
NGCC new energy	0.00	0.00	0.00	0.00	0.00	0.00
NGCC new capacity	0.00	0.00	0.00	0.00	0.00	0.00
NGCC new average load factor	0.00	0.00	0.00	0.00	0.00	0.00
Total Gas Energy	5,658.92	7,259.88	5,514.85	7,949.35	7,998.72	6,165.38

Total Gas Capacity	5,078.30	3,267.39	1,509.51	6,592.39	3,754.35	1,364.00
Nuclear existing energy	14,499.55	14,499.55	14,499.30	14,499.55	14,499.55	14,499.55
Nuclear existing capacity	1,655.20*	1,655.20*	1,655.20*	1,655.20*	1,655.20*	1,655.20*
Nuclear existing average load factor	100.00	100.00	100.00	100.00	100.00	100.00
Nuclear new energy	0.00	11,358.94	43,652.26	0.00	26,307.56	54,863.15
Nuclear new capacity	0.00	1,296.68	4,983.24	0.00	3,003.15	6,262.92
Nuclear new average load factor	0.00	100.00	100.00	0.00	100.00	100.00
Total Nuclear Energy	14,499.55	25,858.49	58,151.55	14,499.55	40,807.11	69,362.70
Total Nuclear Capacity	1,655.20	2,951.88	6,638.44	1,655.20	4,658.35	7,918.12
Wind existing energy	7,183.20	7,183.20	7,183.20	7,183.20	7,183.20	7,183.20
Wind existing capacity	820.00*	820.00*	820.00*	820.00*	820.00*	820.00*
Wind existing average load factor	100.00	100.00	100.00	100.00	100.00	100.00
Wind new energy	28,536.01	23,697.04	17,732.34	0.00	0.00	0.00
Wind new capacity	3,257.54	2,705.14	2,024.24	0.00	0.00	0.00
Wind new average load factor	100.00	100.00	100.00	0.00	0.00	0.00
Total Wind Energy	35,719.21	30,880.24	24,915.54	7,183.20	7,183.20	7,183.20
Total Wind Capacity	4,077.54	3,525.14	2,844.24	820.00	820.00	820.00
Total Energy(MWh)	144,495.00	144,495.00	144,495.00	144,495.00	144,495.00	144,495.00
Total Capacity (MW)	27,968.09	27,968.09	27,968.09	27,968.09	27,968.09	27,968.09
Expected total cost (million $)	3,976.27	4,674.74	5,760.72	4,015.59	4,914.87	5,970.06
Variance of cost (million $)	357,301.39	231,142.60	120,579.52	423,503.90	237,344.74	129,895.74
S.D. of cost (million $)	597.75	480.77	347.25	650.77	487.18	360.41
Risk adjusted cost (million $)	5,048.170	6,292.736	7,689.996	5,286.103	6,576.286	8,048.393
Expected unit cost ($/kWh)	0.02752	0.03235	0.03987	0.02779	0.03401	0.04132
Unit S.D. of cost ($/kWh)	0.00414	0.00333	0.00240	0.00450	0.00337	0.00249

*Denotes existing capacity that is fully utilized.