Determining the Impact of Wind on System Costs via the Temporal Patterns of Load and Wind Generation

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Introduction

As wind generation comprises a larger share of states' generation portfolios, there is an increased need to understand the characteristics of wind generation and how it will impact other generating resource needs. Due to the intermittent nature of wind, increasing the level of energy generated from this resource will significantly alter the operational and capacity requirements of other generation resource types (e.g. baseload, cycling and peaking). This paper provides a framework for assessing wind generation's impact on other forms of generation, using the state of Indiana as an example. For this paper, the level of wind generation is the amount purchased by Indiana utilities through purchase power agreements.

Since wind generation is not dispatchable, meaning its level of energy output is not able to be increased at will, it is not able to meet increases in electricity demand. Not only is wind generation output not dispatchable, but its output is uncertain. Other forms of generation are required to make up for any shortfalls in wind generation in addition to the usual fluctuations in electricity demand. Non-dispatchability and uncertainty over energy output limit the ability of wind generation to offset the need for other generation resources.

Most of the existing work on valuing wind capacity has focused on the availability of wind to serve peak loads, from a reliability perspective. Milligan and Porter (2008) describe the problem of measuring the impact of wind on system reliability and review existing approaches. Billinton and Bai (2004) use a combination of Monte Carlo and regression methods to evaluate the impact of wind on generating system reliability. While this is an important dimension of the problem, it does not directly address the impact of investments in wind capacity on electricity prices. While there has been a fair amount of work on the cost of wind capacity (e.g. Junginger, Faaij and Turkenburg, 2003; Dale et al.), work on the value of capacity – i.e. the impact of wind on the average cost of serving load – in the context of an existing generating system is more limited. Karki and Billinton (2004) use simulation modeling to estimate the cost savings due to varying levels of installed wind capacity. They find that the offset fuel cost increases at a decreasing rate as wind turbines are added, and that wind utilization efficiency declines as wind turbines are added.

Puga (2010) shows that large amounts of wind capacity will require increased levels of combined cycle generating capacity, due to their fast-ramping capabilities. Puga (2010) treats combined cycle generation in the same manner as this report utilizes peaking capacity, where increases in wind capacity lead to larger requirements of peaking capacity. He also shows that high levels of wind capacity can lead to increased cycling of baseload units, particularly during periods of low load and high wind. Increased cycling may lead to higher O&M costs and have implications for unit lifetimes. Ummels, et al. (2007) use a unit commitment and economic dispatch model to assess the impacts of high levels of wind capacity in terms of cost, reliability, and environmental effects. Their results show that wind power production reduces operating costs and emissions levels, but does not consider the impact on capacity costs.

Previous studies considered many important aspects of wind generation, but do not put a dollar amount on the impacts to system costs, in terms of both energy and capacity costs, which is the aim of this current study. Our study uses actual observed load data for 2004-2006 for the state of Indiana and estimated wind generation data from the National Renewable Energy Laboratory. Baseload, cycling and peaking generation assets are based on different technologies (pulverized coal, natural gas combined cycle and natural gas combustion turbine, respectively), and are dispatched on a daily basis for baseload and on an hourly basis for cycling and peaking. Installed generation assets are based on 2007 capacity, and capacity additions to meet projected demand in 2025 are determined for alternative levels of wind generation capacity assuming a ten percent reserve margin. Thus, our results reflect not only the investment costs of the wind capacity expansion and fuel savings, but also the impact on investment in other generation capacity.

Background

This section is intended to show some important aspects of wind generation specifically for the state of Indiana. Figure 1, shows average hourly Indiana load and wind generation. The average hourly load in this figure is calculated from load data for Indiana from the years 2004 through 2006 (Indiana State Utility Forecasting Group, Dec. 2009). The average hourly wind generation is calculated from wind speed estimates at locations near existing 2009 Indiana wind purchase power agreement (PPA) sites (some of which are in other states). The data were then scaled to the appropriate levels as specified in the 2009 agreements, totaling 770 MW of wind capacity (Indiana State Utility Forecasting Group, Sep. 2009). As can be seen in the figure, wind generation exhibits a strong negative correlation with Indiana statewide load. This means that when wind generation is near its highest level in the late night and early morning hours, load tends to be near their lowest levels. This negative correlation has a significant impact on the capacity needs from other resources (baseload, cycling, and peaking capacity). All else equal, the more negative the correlation between load and wind generation the less wind capacity will be able to offset needs for capacity from other resources. Wind generation also exhibits seasonal variation that does not match well with load, with the strongest average wind occurring in the winter and spring and the highest load levels generally occurring in the summer.

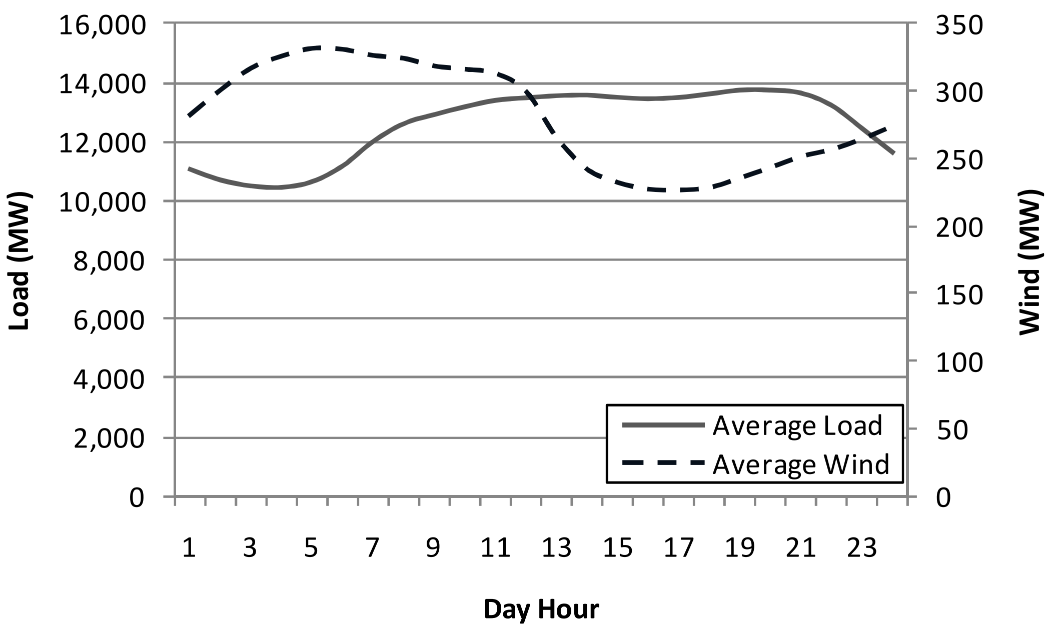

Figure 1. Average Indiana hourly load and simulated wind generation for the years 2004-2006

In addition to the negative correlation between wind generation and load, adding wind generation to the system tends to increase the variability in load that must be met by traditional generating resources. The table below shows the change in hourly and daily load differentials both with and without wind generation. These calculations were made using a load and load net of wind profile, where the load net of wind profile is calculated by subtracting hourly wind generation from hourly load. A load net of wind profile is a common method used to show the level of remaining load that must be satisfied by other generation. When including wind generation, the average change in hourly load from one hour to the next increases from 355 MW to 362 MW. A similar result is shown for the average daily differential, which is the difference between the daily maximum and minimum load. Not only does the average hourly differential increase by adding wind to the system, but so does its variability as reflected in the standard deviation of this differential. The last column shows that the addition of wind generation increases both the maximum hourly and daily differential, taken here as the maximum over all three years of data. These calculations were performed using the existing 2009 PPA level of 770 MW of wind capacity, so increases in wind capacity would be expected to further magnify these differences. For reference, 2009 system peak demand for Indiana was about 19,530 MW (Indiana State Utility Forecasting Group, Dec. 2009). In other words, wind capacity represented about four percent of system peak demand.

2004-2006	Average Differential (MW)	Standard Deviation of Differential (MW)	Maximum Annual Differential (MW)
Hourly Differential without Wind	355	307	1,969
Hourly Differential with Wind	362	310	1,977
Daily Differential without Wind	3,794	1,427	8,165
Daily Differential with Wind	3,893	1,472	8,524

Table 1. Summary of hourly and daily differential for load and load net of wind

The characteristics of wind outlined above are the main drivers of the changes in system resource requirements as wind capacity makes up an increasing portion of Indiana generating capacity. Due to the negative correlation between wind and load, one megawatt of added wind capacity does not offset one megawatt of one of the other forms of generation (e.g. pulverized coal, natural gas combustion turbine, etc.). Capacity requirements are determined by the annual peak load. The more positively correlated wind generation is with load, the more likely there will be a higher level of wind generation during the hour when annual load is at its maximum. This will lead to a reduction in the amount of load that must be satisfied using other resources.

Increased system variability due to wind will result in a need for more peaking and less baseload capacity. This is due to peaking generation generally being more cost-effective than baseload generation when satisfying a load with high variability. Also, peaking units are able to more easily meet the ramping requirements from this increased variability. So, not only does adding wind capacity change overall resource requirements, but the requirements for the different types of generation may shift as well.

While capital costs will most likely increase with increasing wind, total variable costs will most likely decrease, with the decrease being driven by the near zero variable costs associated with wind generation. Since wind purchase power agreements are take-or-pay, the utility is required to pay for the energy even if it is left unused. Thus, the PPA is not a variable cost for the utility and may be assumed to be zero for purposes of modeling the economic dispatch of generators.

Methodology

The introductory section developed the key components that the analysis presented here will incorporate. Based on these characteristics, the impacts of increased wind generation capacity on Indiana utilities generation portfolios are calculated in four areas. The first impacts considered are the changes in generating capacity needs for baseload, cycling, and peaking capacity due to increased wind capacity. As mentioned previously, the increased system variability added by wind generation will likely lead to an increased need for peaking and reductions in baseload capacity requirements. The next impact considered is the change in energy, in terms of MWhs, that is supplied by baseload, cycling, and peaking generating units. Again the increased variability added by wind will likely cause increases (decreases) in energy supplied by peaking (baseload) generating units. These changes in capacity and energy requirements ultimately drive the final two impacts. These are changes in capital costs due to changes in capacity requirements and changes in variable costs resulting from changes in energy requirements.

Hourly load data for the state of Indiana for the years 2004 through 2006 were used for the analysis (Indiana State Utility Forecasting Group, Dec. 2009). The load data were acquired directly from the individual utilities in the state and aggregated to a state-wide level. Wind generation data were acquired from the National Renewable Energy Lab's Eastern Wind Integration and Transmission Study (National Renewable Energy Lab, 2010). This study developed wind generation estimates at ten minute intervals for various sites throughout the eastern United States. The time period of the wind estimates coincides with the Indiana load data. The importance of wind generation data and load data being from the same period is due to wind speed having an effect on both data types. For instance, during the summer months higher wind speeds will lead to increased wind generation and reductions in load resulting from reduced cooling needs.

For the purpose of this analysis, sites were chosen that are in close proximity to 2009 Indiana wind purchase power agreement (PPA) sites (Indiana State Utility Forecasting Group, Sep. 2009). The wind data was aggregated from ten minute intervals to the hourly level, so as to correspond with the load data. The sites were initially scaled to the wind capacity agreed upon in the 2009 Indiana purchase power agreements, totaling 770 MW. The load data for each year was scaled from the respective year up to the year 2025. This was done by scaling each annual load profile such that annual energy consumption was equivalent to the projected consumption in 2025, which is 144,495 GWhs. The three years of load data were all scaled to the same year (2025) in order to generate three distinct annual load profiles. The scaling was done in order to assure that each year's contribution was analyzed on an equal footing with the other two years.

Also, since existing generation is sufficient to meet 2004 – 2006 loads, no new capacity would have been needed if the loads were not scaled to a future level. Thus, capital cost reductions of new fossil-fueled generation resulting from increased wind would not have been measurable. Impacts were calculated for each of the three years and then averaged to arrive at overall impacts. Using three years worth of data helps to give some sense of how year-to-year variations impact the results. Averaging these three years allows impacts to be calculated that are not driven by one year in particular, but a combination of the three. Thus, arriving at an average or expected year. This allows the model to arrive at results that are not driven by one year, which may or may not be representative of a typical year. Ideally, a sample of more than three years would be used. However the EWITS dataset is only available for 2004-2006.

Impacts are calculated using a load and load net of wind profile for each of the three years, where the load net of wind profile is calculated by subtracting the hourly wind generation from the hourly load. In this analysis, there is no wind generation uncertainty and in terms of dispatch, the analysis effectively assumes a perfect wind forecast. Since wind generation has near zero variable costs, all energy generated by wind units will be used. Wind purchase power agreement contracts are take-or-pay, so all energy generated by wind is used in this analysis. A take-or-pay contract is like a sunk cost for the utility, so if any energy is left unused the utility is still required to pay for the energy. Thus, it makes sense to use all wind generation before any other generation resources.

Capacity Impact Calculations

Capacity requirements are calculated for the three forms of generation (baseload, cycling, and peaking), as wind capacity is added to the system. These impacts are calculated relative to a base resource case, which in addition to existing capacity levels also includes planned capacity changes. Included in these planned capacity changes are certified, rate base eligible generation additions, retirements, and de-ratings due to pollution control retrofits. The base resource case capacity levels are 16,426 MW of baseload, 2,500 MW of cycling, and 3,585 MW of peaking capacity.

A load duration curve (LDC) is created using the load net of wind profile at each level of wind capacity (Fig. 2). A load duration curve sorts the hourly load for each hour of the year from the highest to the lowest. The larger the difference between the highest (hour one) and lowest (hour 8,760) load hour of the year the more load varies throughout the year. The shape of the load duration curve will significantly impact generation resource needs, with a steeper curve requiring more peaking capacity and a flatter curve requiring higher levels of baseload capacity.

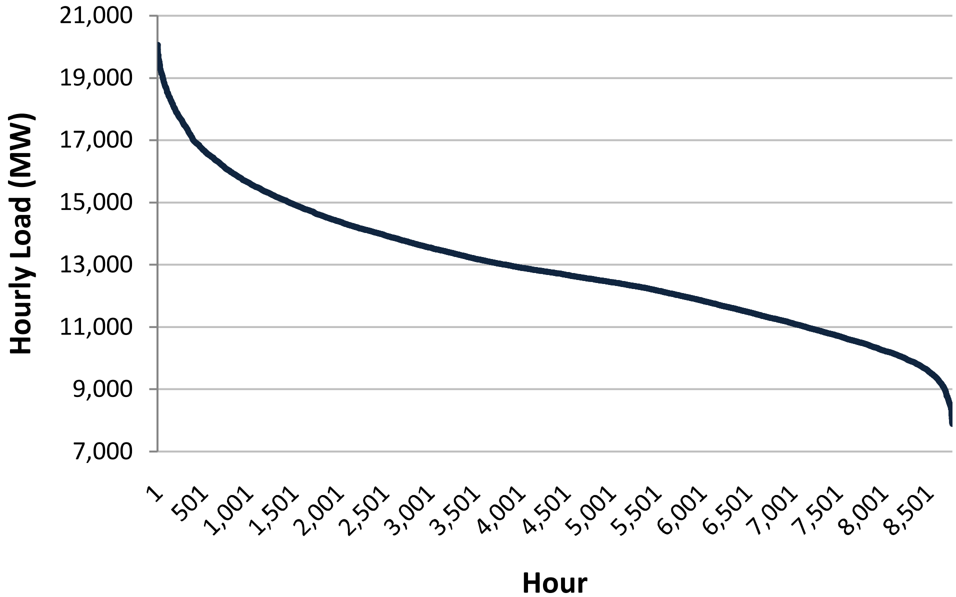

Figure 2. Load duration curve for 2005 Indiana load

This load duration curve is used to calculate peaking capacity requirements by taking the difference between the annual peak load (hour one of the load duration curve) and the 90th percentile of the load duration curve, shown below.

$$Peaking\ Capacity = Annual\ Peak\ Load - 90th\ Percentile\ of\ Load\ Duration\ Curve \tag{1}$$

Using this rule to assign peaking capacity levels determines the capacity required to meet the top ten percent of annual load hours with peaking generation. Subtracting off the base case peaking capacity level of 3,585 MW from the level calculated from (1) will determine the level of new peaking capacity required to meet demand.

Baseload requirements are determined using the same load net of wind profile and taking the difference between annual peak load (from the load duration curve) and the maximum daily load variation, shown below.

$$Baseload\ Capacity = Annual\ Peak\ Load - Maximum\ Daily\ Load\ Variation \qquad (2)$$

The maximum daily load variation is calculated by taking the difference between the daily maximum and minimum load for each day of the year and then selecting the maximum of these daily differences for the year. Calculating baseload needs in this way will ensure that there is enough baseload capacity to satisfy the daily minimum load throughout the year. Similar to calculating new peaking capacity needs, new baseload needs are determined by subtracting the 16,426 MW of base case baseload capacity from baseload needs calculated above. If the baseload capacity requirement is less than 16,426 MW, then no new baseload capacity is necessary and the excess base case baseload capacity will be treated as cycling capacity. This situation will become more prevalent as wind capacity increases and is necessary so as to avoid having idle baseload capacity.

The remaining load is satisfied using cycling units. The level of cycling capacity needed is calculated as the maximum daily load variation less peaking capacity, which is in turn equal to annual peak load less the 90th percentile of the load duration curve per (1). Summing across the three formulas used to calculate the capacity requirements will equal the annual peak load, demonstrating that this procedure arrives at the capacity level that just satisfies annual peak load. New cycling capacity needs are calculated by subtracting base case cycling capacity of 2,500 MW from the capacity calculated using (3).

$$Cycling\ Capacity = Maximum\ Daily\ Load\ Variation - Peaking\ Capacity \qquad (3)$$

The new capacity levels calculated for each type of generation are further increased by ten percent to account for forced outages. This additional increase will allow ten percent of all three forms of generation to be out of service on the annual peak and still meet the maximum annual load. These capacity levels are used when dispatching the hourly load, in order to calculate the energy impacts.

Energy Impact Calculations

The energy impacts are calculated by taking the difference in total generation (MWhs) between the load and load net of wind profiles for each of the three years and then averaging over these years. The load for each year has been scaled to 2025 energy consumption levels. Again, the load net of wind profile is calculated by subtracting the hourly wind generation from these scaled loads. Load is dispatched for each profile for every hour of the year, starting with baseload capacity. Baseload generation is used to meet the daily minimum load and is dispatched in this manner so that this resource is not used to meet the intra-day load variations. Any load in excess of the daily minimum will be satisfied with cycling capacity, with any remaining after that being served using peaking units. Dispatching generation in this manner is done to simulate a merit-order dispatch where units with lower variable cost are dispatched first and the higher variable cost, peaking units, are dispatched last. It is reasonable to net out the wind generation before dispatching remaining load because wind generation has the lowest variable cost of generation.

The difference in energy supplied by baseload capacity for the load and load net of wind profiles will determine the change in energy that must be supplied by baseload generation for a given level of wind capacity. Similar calculations are done to determine wind generation impacts on cycling and peaking generation. Adding the impacts across all three types of generation will determine the reduction in the amount of energy that must be supplied by these units. In other words, this reduction is the amount of energy supplied by wind generation. Again, these calculations are made for all three years and then averaged to arrive at an expected energy impact.

Capital Cost Impact Calculations

Capital costs for this analysis are on an annual basis. Baseload capacity is modeled using characteristics representative of a pulverized coal plant, cycling capacity as a combined-cycle gas turbine unit, and peaking capacity as a combustion turbine unit. Per unit annualized capital costs of these technologies, as well as wind generation are shown below in Table 2. Included in these capital costs are capital costs plus fixed operating and maintenance costs associated with generation. Since these are annualized capital costs the capital cost impact represents annualized capital costs of additions needed to serve the load in the year 2025, relative to base case capacity levels.

Generation Type	**Annualized Capital Cost (2007 $/MW/Yr)**
Baseload	694,000
Cycling	286,000
Peaking	159,250
Wind	402,500

Table 2. Annualized capital costs by generation type[1]

Variable Cost Impact Calculations

Variable costs are broken down by generation type as well. In addition to being distinguished by generation type, units are also disaggregated into new and base case

[1] Fixed Costs for Baseloadk, Peaking and Cycling Units are from Table 8.2 Cost and Performance Characteristics of New Central Station electricity Generating Technologies, Assumtptions to the Annual Energy Outlook 2009, (EIA 2009). Fixed Costs for Wind Units are from the 2009 Indiana Renewable Energy Resources Study, (Indiana State Utility Forecasting Group 2009).

capacity. This further distinction is made because newer technologies are generally more efficient in that they have lower heat rates, resulting in lower variable costs. Per unit variable costs are equal to per unit fuel costs plus per unit variable operations and maintenance costs. Variable costs for wind generation are not included in this table because wind generation is assumed to have zero variable cost.

Generation Type	Variable Cost ($/MWh)
New Units	
Baseload	21.32
Cycling	41.83
Peaking	65.76
Base Case Units	
Baseload	20.82
Cycling	45.59
Peaking	71.67

Table 3. Variable costs by generation type[2]

Variable cost impacts for a given level of wind capacity are calculated relative to variable costs by generation type without any wind generation. For example, the impact for new baseload variable cost is calculated as the difference between energy supplied by new baseload capacity without wind versus energy supplied by new baseload capacity given a specific level of wind generation, multiplied by new baseload variable cost. This calculation is performed for both new and base case units by type of generation and summed to arrive at the total impact. This is the annual impact for the year 2025, and it is calculated based on the data for each of the three years and then averaged to get the overall impact.

Modeling Scenarios

[2] Fuel costs are 2025 projections for the East North Central Region in the EIA 2010 Annual Energy Outlook (EIA 2010). Fuel prices are in 2008 dollars.

Four scenarios were chosen to show some key differences between adding wind at one location, as opposed to another to examine the impact of wind capacity additions in different regions. The results of the four scenarios chosen will show that location is important, but also that the proportion of the wind capacity from a particular location in the overall wind portfolio is important, as well. The four scenarios modeled in order to further draw out these distinctions are: 1) scaling all purchase power agreements (PPAs) in proportion to their existing level, 2) scaling in-state PPAs in proportion to their existing levels while holding out-of-state PPAs constant, 3) scaling out-of-state PPAs in proportion to their existing levels while holding in-state PPAs constant, and 4) equally scaling all existing PPAs and the five sites in Indiana that are least correlated with the existing PPAs. All four scenarios are scaled from a total of 770 MW of wind capacity to a total of 6,000 MW in steps of 500 MW (i.e. 770, 1,000, 1,500, …, 6,000). The scenarios are scaled to the same level, in order to make the scenarios comparable.

The first scenario scales all existing purchase power agreements in proportion to their existing levels. This has the effect of adding more wind capacity at sites that currently have a higher level of wind capacity and less at sites that currently have a lower level of wind capacity. For example, if two sites currently have 100 MW and 300 MW of wind capacity, then adding 100 MW of wind capacity will result in adding 25 MW at the 100 MW site and 75 MW at the 300 MW site. If the sites that currently have the most capacity are more likely to have wind additions than sites that currently have less capacity, then this scenario models that reality.

The second scenario scales all in-state wind sites proportionally in the same manner as the first scenario, while holding out-of-state sites at their existing levels. The third scenario scales the out-of-state sites proportionally, while holding the in-state sites at existing wind capacity levels. Scaling the first three scenarios in this way shows the effect on impacts resulting from changes in proportions of in-state and out-of-state sites.

The last scenario is intended to show the benefits additional geographic diversification of the wind portfolio can have. Adding the five least correlated sites to the existing wind sites is intended to reduce the variability of the total wind portfolio. Reducing this variability should decrease the capacity needs of other resources. Instead of scaling all sites in proportion to their existing levels, they are all are scaled equally. Since the scaling was done in a manner that did not hold the proportion of each site in the overall portfolio constant, impacts are the result of diversification and a changing portfolio make-up.

Again, these scenarios are intended to show the importance of location when choosing new wind sites and the portion each site comprises of the state's overall wind portfolio. The scenarios presented here are indicative of the likely impacts of adding wind PPAs from in-state, out-of-state, or both, as well as the fourth scenario that opportunistically selects sites that are least correlated with existing wind sites. The next section will present the results of the analysis of these four scenarios.

Modeling Results

This section will cover in detail the impacts from scaling the all purchase power agreement scenario, discussed in the previous section. Differences between the results for the other three scenarios are highlighted, and the detailed results of these scenarios are found in an appendix at the end of the report. The results of these three scenarios show the same qualitative trends as the first scenario, but with impacts of differing magnitudes. In this section, the four impacts are further decomposed by type of generation (baseload, cycling, and peaking). This is done to show that while an impact might show an overall decrease in energy, this could be the result of one generation load class showing an increase and another showing an even larger decrease. This effect is apparent in many of the results, due to the changes that added wind capacity impose on the system.

Scaling All Purchase Power Agreements

The first scenario, discussed in the previous section, is to scale all existing purchase power agreement sites proportionally to their existing levels. This scenario, as with the other three, will scale wind capacity from the existing level of 770 MW to a total of 6,000 MW.

Relative to 2007 existing capacity levels, total resource needs from non-wind resources decreases with increasing wind capacity, shown below in Figure 3. While there is an overall reduction in capacity requirements, peaking capacity requirements increase with wind capacity. This is due to the increasing volatility that wind generation adds to the system and hence the need for more peaking resources. The methodology used for assigning peaking capacity was to have it supply the top ten percent of annual load hours (the difference between hour one and hour 876 of the load duration curve). Increasing wind capacity causes the load duration curve to become steeper, so the difference between hours one and 876 increases. As wind and peaking capacities increase, new cycling and baseload capacities decrease.

At lower levels of wind capacity a small amount of new baseload capacity will be needed, but as wind capacity increases beyond 1,500 MW no new baseload capacity is necessary. In addition to no need for baseload additions with increasing wind capacity, base case baseload capacity is reclassified as cycling capacity and dispatched as such beyond the 1,500 MW wind capacity level. This reclassification of base case baseload capacity in large part drives the reduction in new cycling capacity as wind capacity increases. Thus at around 1,500 MW of wind capacity, cycling capacity needs begin decreasing at a faster rate as base case baseload capacity is being re-classified as cycling (Fig. 3). Scaling wind from the existing 770 MW to 6,000 MW, a net increase of 5,230 MW only offsets 456 MW of capacity requirements from other resources. Because additions in wind capacity do not offset an equivalent number of MWs of other resource needs, total capacity levels increase.

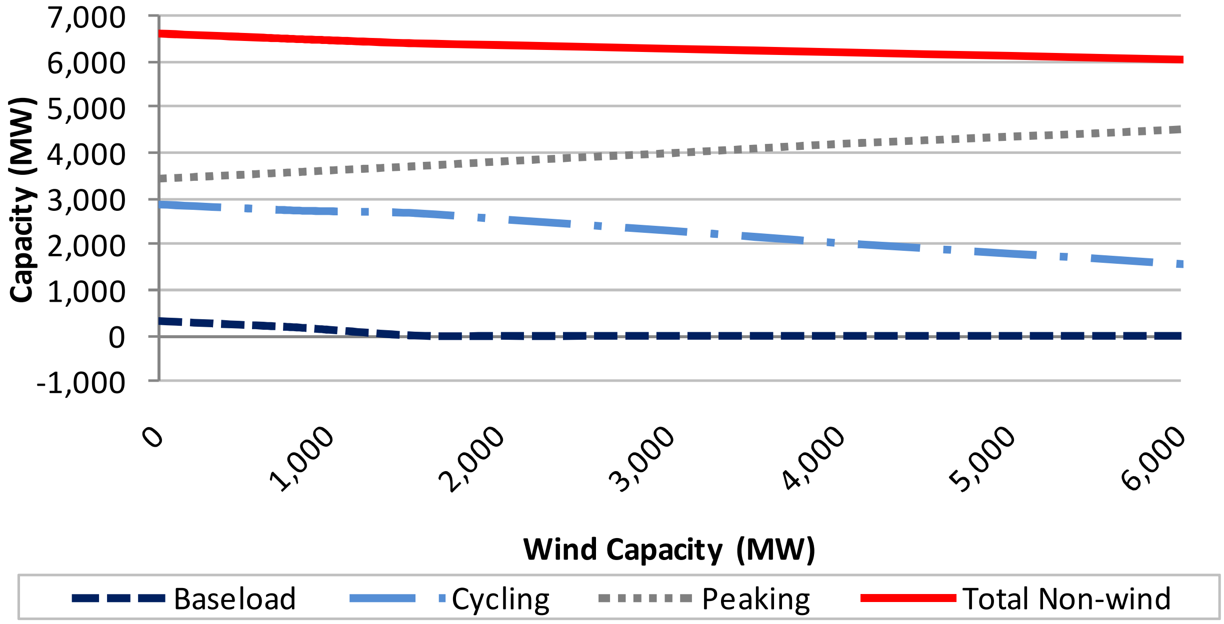

Figure 3. Change in capacity requirements (relative to base case capacity levels)

Increasing wind capacity results in decreasing amounts of energy that must be supplied by resources other than wind units. Similar to the capacity requirements, energy that must be met by baseload and cycling generation decreases, while energy supplied by peaking generation is initially increasing as wind generation increases. This result is shown in Figure 4. The changes are relative to energy supplied in 2025, by the three types of generation, with no wind generation. The energy supplied by peaking generation is initially increasing and then starts decreasing around 4,000 MW of wind capacity, while peaking capacity requirements continue to increase. After this point more peaking capacity is required to supply decreasing amounts of energy. In other words, more peaking capacity is needed to meet the annual peak demand but being used less, resulting in a decreasing peaking capacity factor.[3] Energy supplied by baseload generation is decreasing with increasing wind penetration. This result is driven by additional wind capacity causing the annual maximum daily load deviation to increase, thus decreasing baseload capacity needs and ultimately the energy supplied by this type of capacity. The decrease in energy supplied by cycling capacity is the result of excess baseload capacity being re-classified as cycling capacity, decreasing both cycling capacity and energy supplied by cycling capacity.

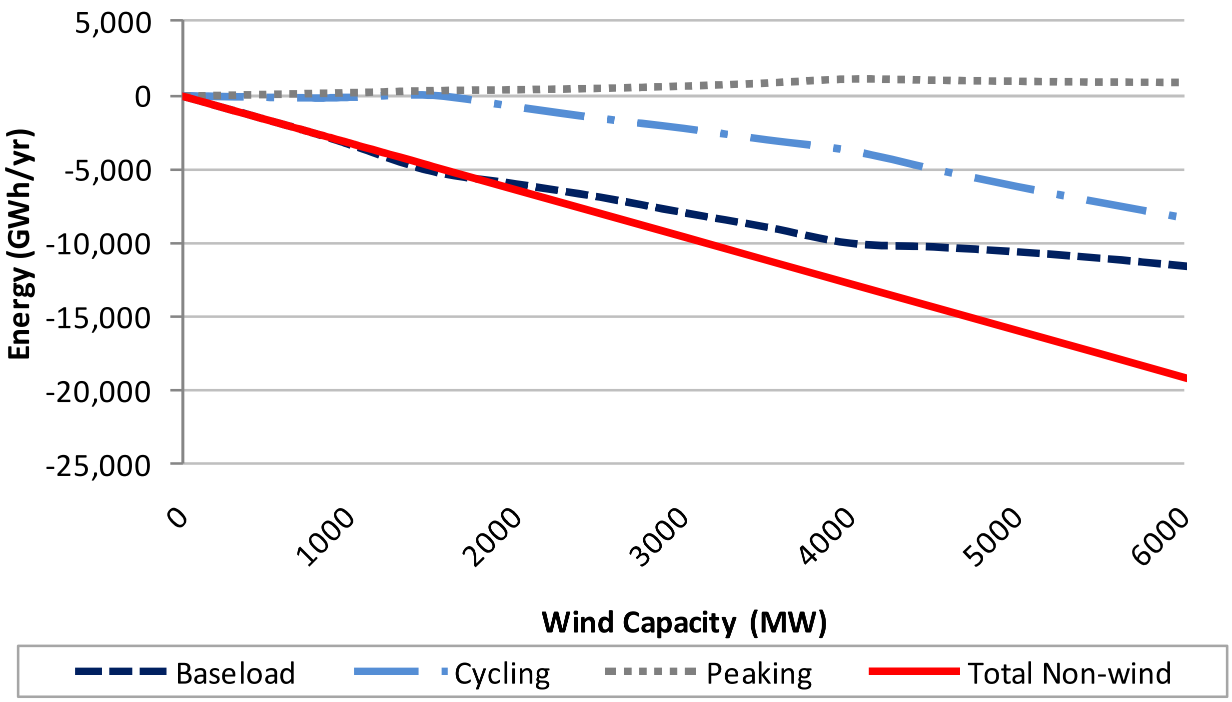

Figure 4. Change in energy requirements (relative to 2025 with no wind generation)

Changes in annualized capital costs, in aggregate, increase with wind capacity. These costs are a direct result of the changes in capacity requirements from increases in

[3] The capacity factor is the ratio of how much electricity is generated given a particular level of capacity divided by the amount of electricity that could have been generated if the unit was operating at full capacity continuously, with a larger number representing more generation per unit of capacity.

wind capacity. Figure 5 below, shows the same general trends for baseload, cycling, and peaking impacts as Figure 3. As shown in Figure 3, additions in wind capacity do not offset an equivalent amount of the other generation types, causing total capital cost to increase with wind capacity. Baseload and cycling capacity costs decrease due to a reduction in required additions, while capital costs associated with peaking capacity increase with wind capacity increases. As is illustrated in Figure 5, the increases in capital cost are largely attributable to additions of wind capacity – the changes in capital cost for non-wind capacity are relatively minor.

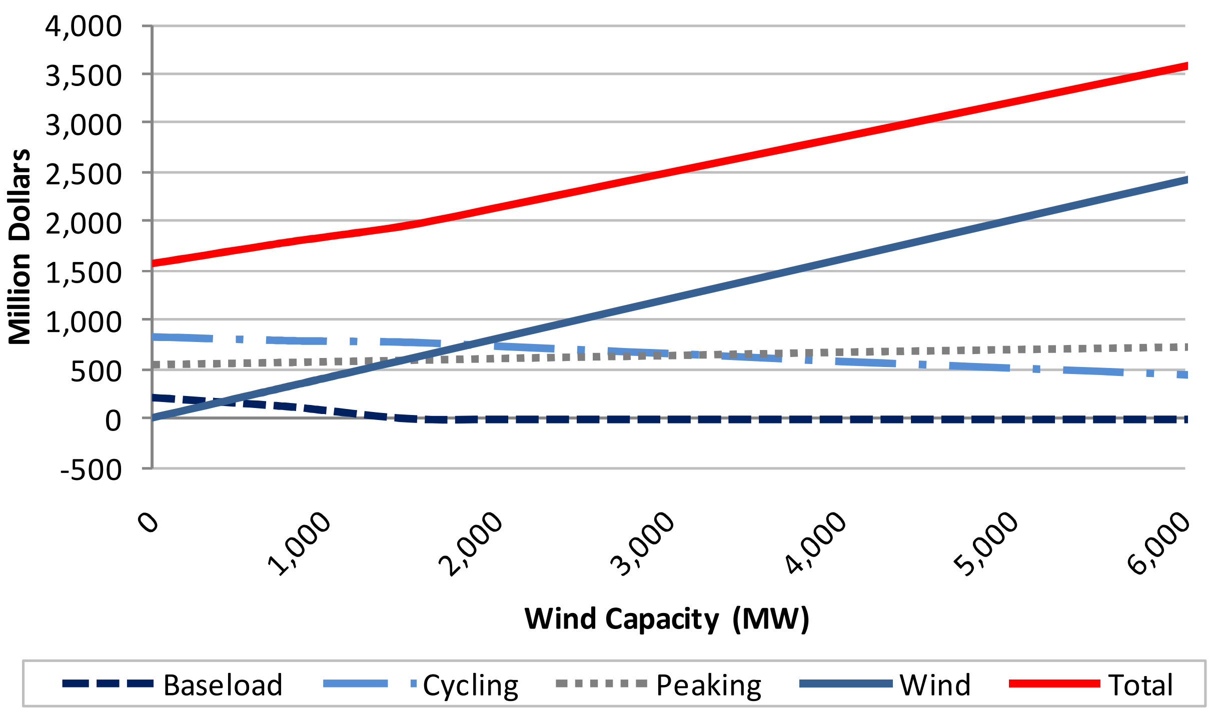

Figure 5. Change in capital costs (relative to base case capacity levels)

As illustrated below in Figure 6, increasing wind capacity results in large decreases in variable costs. This is due to variable costs associated with wind generation being nearly zero and assumed to be zero in this report. Changes in energy requirements drive the changes in variable costs. Variable costs associated with baseload and cycling generation decrease with increasing wind capacity, while variable costs for peaking generation increase. It is the increase in variability due to additional wind generation that causes energy supplied by peaking capacity and the associated variable costs to increase.

In order to determine what level of wind capacity is cost-effective, it is necessary to assess whether increases in capital costs are offset by even larger decreases in variable costs. As calculated above, capital costs are relative to base case capacity levels. Comparing these capital cost increases to the reductions in variable costs would be inappropriate. The appropriate comparison is between increases in capital costs in 2025 without wind capacity and reductions in variable costs. This comparison is analyzed in a later section of this report.

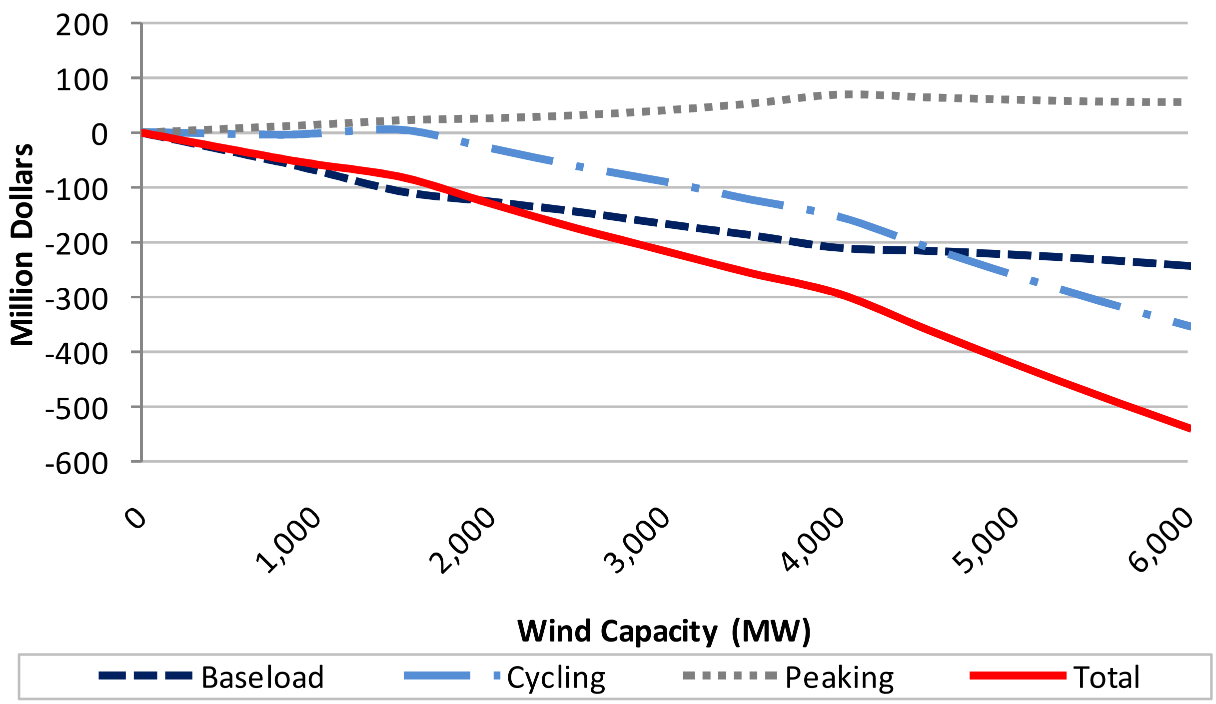

Figure 6. Change in variable costs (relative to 2025 with no wind generation)

Table 4 below, summarizes impacts at varying levels of wind capacity. The capacity requirements impact represents total capacity needs by resource in 2025 for a given wind capacity. The energy impact is energy that must be supplied by each resource type in 2025. The variable cost impact represents variable costs by resource type in 2025. Capital costs are annualized capital costs in 2025 for capacity needs relative to existing capacity.

Impact Area	**Existing[4] Capacity**	**0 MW Wind Capacity**	**1,000 MW Wind Capacity**	**3,000 MW Wind Capacity**	**6,000 MW Wind Capacity**
Capacity					
Baseload (MW)	16,426	16,722	16,549	16,426	16,426
Cycling (MW)	2,500	5,393	5,242	4,805	4,052
Peaking (MW)	3,585	7,025	7,202	7,576	8,092
Total (MW)	22,511	29,141	28,993	28,807	28,569
Energy					
Baseload (GWh)	-	120,324	117,016	112,349	108,688
Cycling (GWh)	-	21,733	21,627	19,498	13,351
Peaking (GWh)	-	2,328	2,551	2,966	3,203
Total (GWh)	-	144,384	141,194	134,813	125,241
Variable Cost					
Baseload (million $)	-	2,507	2,438	2,340	2,264
Cycling (million $)	-	932	929	842	583
Peaking (million $)	-	155	170	197	212
Total (million $)	-	3,594	3,537	3,379	3,058
Capital Cost[5]					
Baseload (million $)	-	206	85	0	0
Cycling (million $)	-	827	784	659	444
Peaking (million $)	-	548	576	636	718
Wind (million $)	-	0	403	1,208	2,415
Total (million $)	-	1,581	1,848	2,502	3,576

Table 4. Summary of impacts for All PPA scenario at various wind capacity levels

[4] The existing capacity column represents existing 2007 capacity levels adjusted for planned capacity changes. Included in these planned capacity changes are certified, rate base eligible generation additions, retirements, and de-ratings due to pollution control retrofits. Existing capacity is taken from the Indiana State Utility Forecasting Group.

[5] Capital costs are annualized capital costs relative to the base resource case.

Comparisons Across Scenarios

This section compares the impacts of scaling up wind capacity across the four scenarios. The results show that while one scenario may result in a larger impact in one area, another may show a larger impact in another area. Also, while one scenario may result in the largest impact at a lower level of wind capacity another may show a larger impact at a higher level of wind capacity. This indicates that the locations of the wind capacity additions are important to the analysis.

As can be seen in Figure 7, at higher wind capacity levels, increasing all existing purchase power agreements by equal amounts while increasing the five least correlated sites by the same amount results in the largest reduction in the need for new generating capacity. By scaling all sites by equal amounts (MWs), all sites are moving from their initial levels towards each site representing an equal portion of the overall wind portfolio. The results show that this scenario slightly edges out the scenario where all PPA sites are scaled proportionally, showing that a slightly larger impact is achieved due to the additional geographic diversification. The scenario where only out-of-state sites are scaled causes the out-of-state sites to dominate the portfolio at higher wind penetration levels. This negates some of the benefit from geographic diversification and is why this scenario results in the smallest impact on capacity requirements. The same reasoning explains the result for the scenario where only in-state sites are scaled. As compared to scaling out-of-state sites, at higher wind capacity levels scaling in-state sites results in a smaller increase in peaking capacity needs, resulting in a larger overall reduction in capacity needs. This is the result of the load duration curve for the out-of-state scenario becoming steeper at higher levels of wind capacity.

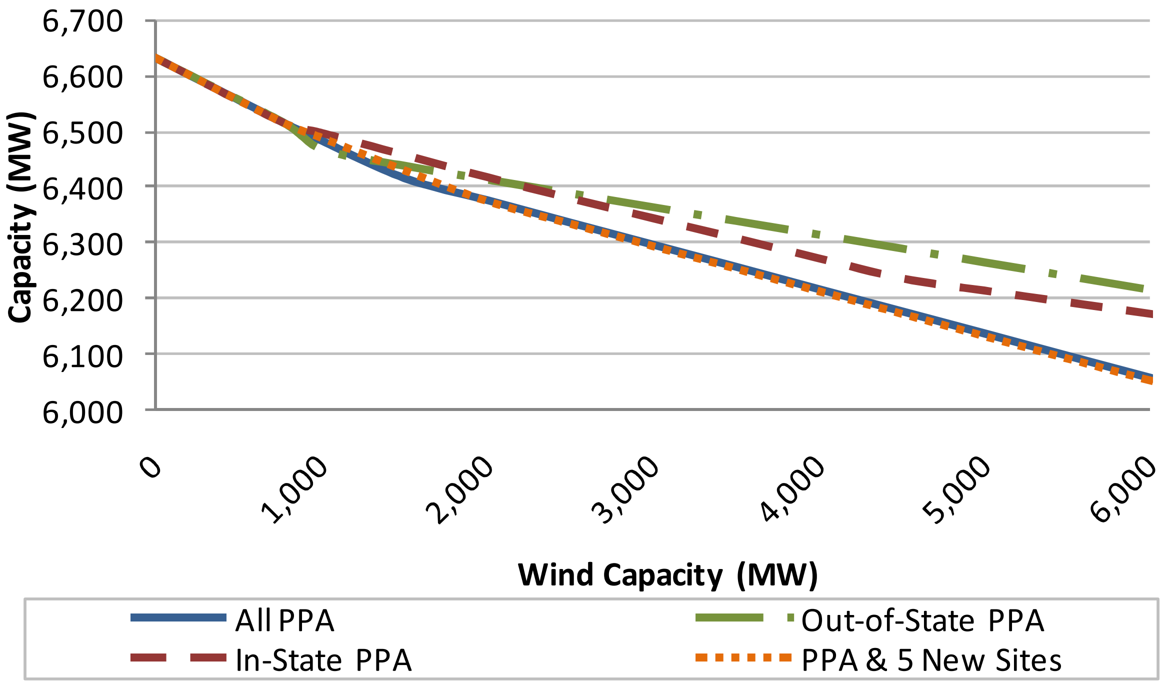

Figure 7. Change in capacity requirements across scenarios

As shown in Figure 8, total energy impacts are similar across scenarios. The scenario where only out-of-state sites are scaled results in the largest energy impact, but the differences between the cases is small in terms of the change in energy requirements. This scenario exhibits the largest impact because the out-of-state sites have slightly higher capacity factors than the in-state sites. As this scenario is scaled up, the out-of-state sites make-up a larger portion of the overall wind portfolio. A larger capacity factor for the out-of-state sites means that a given level of wind capacity installed at an out-of-state site will result in a larger energy reduction than the same level of capacity installed at an in-state site. While the out-of-state scenario has the highest energy impact, it was shown earlier that it has the lowest impact on capacity. This is due to the out-of-state wind portfolio having a more negative correlation with load, relative to the other scenarios.

Generally a wind site that is more highly correlated with load will have a larger impact on capacity, while a site with a larger capacity factor will result in a larger impact on energy, though this will not always be true. It would be possible for a site to have such a large capacity factor relative to another site that even if it was less correlated with load it could still lead to a larger capacity impact. This could happen if the high capacity factor was sufficient to make the wind generation from the site higher during on-peak times despite being less correlated with load. Another way a site that is highly correlated with load could result in a smaller reduction in capacity would be if this site had a single, rather anomalous hour with very low output, which happened to be a relatively high load hour. As this discussion has shown, the impact of the correlation between wind generation and load and the wind site capacity factor cannot be considered entirely separate from each other.

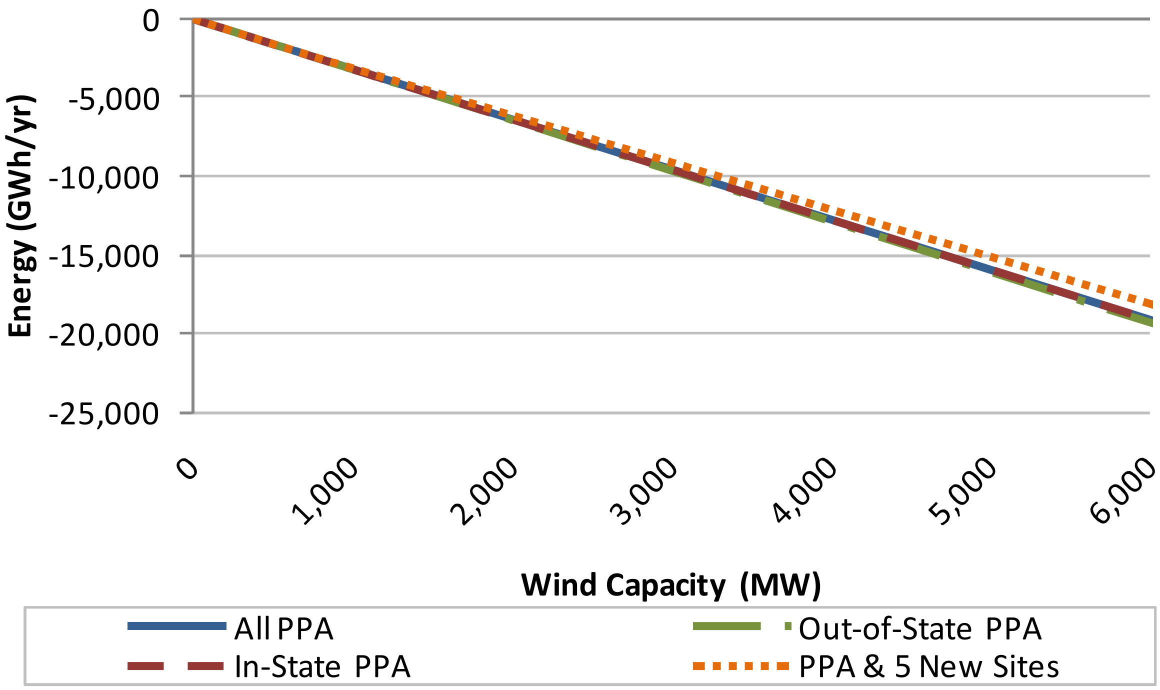

Figure 8. Change in energy requirements net of wind across scenarios

Figure 9 shows that changes in capital costs are nearly identical across scenarios and are driven by the increase in capital costs from additional wind capacity. For all scenarios, this is the result of additional wind capacity only offsetting a small amount of the capacity requirements for the other forms of generation. In other words, the incremental costs for installing wind capacity outweigh any other changes in capacity costs. The scenario where capacity of all PPA sites is scaled proportionally results in the smallest increase in capital costs, a value of $3,576 million at 6,000 MW of wind capacity. It was shown earlier that the scenario where scaling existing PPA sites with the five least correlated sites resulted in the largest reduction in new capacity needs, though it did not result in the smallest increase in capital costs. This is due to this scenario requiring more cycling capacity and less peaking capacity, where cycling capacity has a larger capital cost than peaking capacity. This result shows that while offsetting more capacity is generally better, it is also important to consider the type of unit the additional wind capacity is replacing.

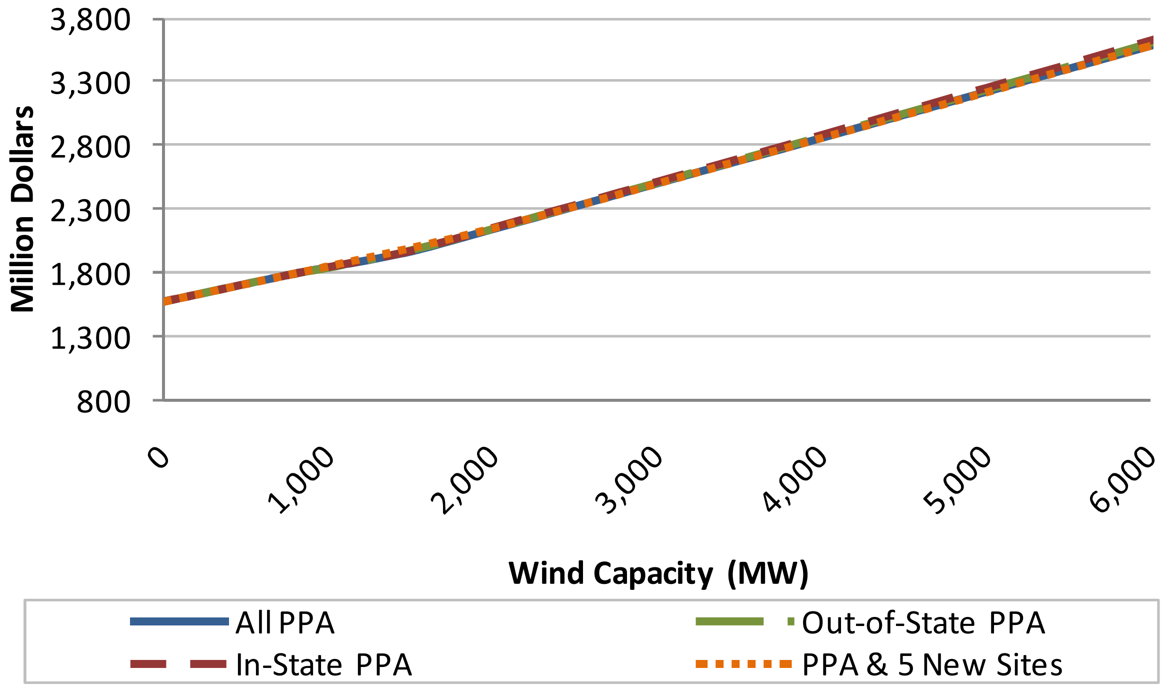

Figure 9. Change in capital costs across scenarios

The energy impacts have the most significant impact on variable costs. All scenarios, except for the PPA & 5 New Sites scenario, result in nearly identical energy impacts (see Figure 8), but show more variation in their impact on variable cost (see Figure 10). Two factors are driving the variable cost impact. They are the reduction in total energy and the type of generation this reduction impacts, because one MWh supplied by a baseload unit has less variable cost than one MWh supplied by a peaking unit. The first factor affects the energy impact, while both factors affect the variable cost impact. Thus, it is the change in composition of the generating units that makes the variable cost impacts different across scenarios while the energy impacts are quite similar.

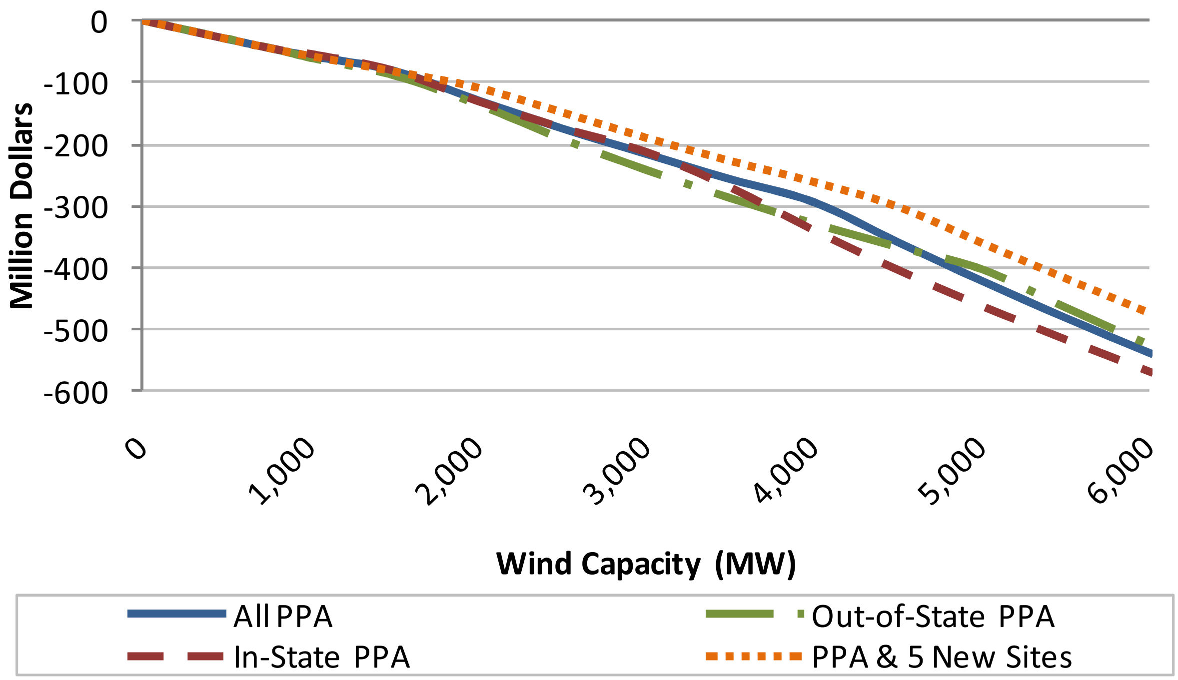

Figure 10. Change in variable costs across scenarios

These comparisons across scenarios highlight some key characteristics of wind generation. First, while one scenario may result in the largest impact in one area (e.g. capacity, energy, or cost) it may not in another area. This means that it is important to define the ultimate goal of the wind capacity that is being added to the system. However as a general rule, it will usually be most advantageous to add wind capacity at sites with high capacity factors and high correlation with load.

Cost-effectiveness of Additional Wind Capacity

This section addresses the cost-effectiveness of wind capacity additions by considering the scaling All PPA scenario, only. The other three scenarios will show the same qualitative results, although the optimal wind capacity will be either greater or less than the scenario considered in this section. In addition to the variable costs and capital costs considered up to this point, a wind production subsidy and carbon prices are considered as well. Currently, a wind production subsidy exists in the form of the federal Production Tax Credit and the level used in this analysis is the 2009 level of 21 $/MWh. The wind production subsidy was not included in calculations to this point in the analysis because it is uncertain whether the subsidy will be in existence in 2025. Even if a subsidy remains in 2025 it is uncertain what its level would be.

Another important factor in determining the cost effectiveness of wind capacity additions relates to the value of reductions in carbon emissions. The carbon prices considered in this section were derived from the Bingaman bill proposed in the U.S. Senate (Bingaman 2010). The bill proposes a price ceiling of $25/ton and a price floor of $10/ton for calendar year 2012. The price ceiling will increase each year by five percent in real terms. The carbon price ceiling of $25/ton in 2012, increasing at a rate of five percent per year in real terms, will result in a ceiling of $47.14/ton in 2025. Similarly, the price floor will increase at a rate equal to three percent per year in real terms. This results in a carbon price floor of $10/ton in 2012 rising to $14.69/ton in 2025. For modeling purposes, these low and high carbon prices were converted to dollars per megawatt hour and are listed below in Table 4.

Baseload generation is modeled using the characteristics of a pulverized coal unit, which emits the highest levels of carbon dioxide. Cycling units, modeled using natural gas fired combined cycle technology, emit the lowest levels of carbon dioxide. Cycling units have the lowest emission levels because this type of generation combines a gas turbine and steam turbine, where the exhaust heat from powering the gas turbine is then used to power the steam turbine, resulting in highly efficient generation. This highly efficient generation of combined cycle units uses less natural gas per MWh and ultimately emits less carbon dioxide per MWh. Peaking units are modeled as combustion turbine units, resulting in emissions per MWh between baseload and cycling units.

Capacity Type	Low Carbon Price ($/MWh)	High Carbon Price ($/MWh)
New Capacity		
Baseload	17.08	54.84
Cycling	5.86	18.80
Peaking	9.61	30.86
Base Case Capacity		
Baseload	17.27	55.44
Cycling	6.74	21.62
Peaking	10.32	33.13

Table 4. Carbon price by type of generation

The optimal level of wind capacity is defined here as the capacity where the total cost of serving the load in 2025 with wind is lowest. For purposes of calculating the optimal level of wind capacity, the capacity cost impact will be calculated relative to 2025 capacity requirements without any wind, whereas previously capacity impacts were calculated relative to base case capacity levels. The goal in this section is to determine the optimal level of wind capacity in 2025, making the 2025 total cost without wind the relevant basis for comparison. Figure 11 below shows the impact on total costs from increasing wind capacity, without the inclusion of a production subsidy or carbon price. The decreases in variable costs are not able to offset the larger increases in capital costs at any level of wind capacity. Total costs from wind generation are always higher than in the no wind case. In terms of the optimal level of wind, no wind capacity is optimal. This answer may change in the presence of production subsidies or carbon costs.

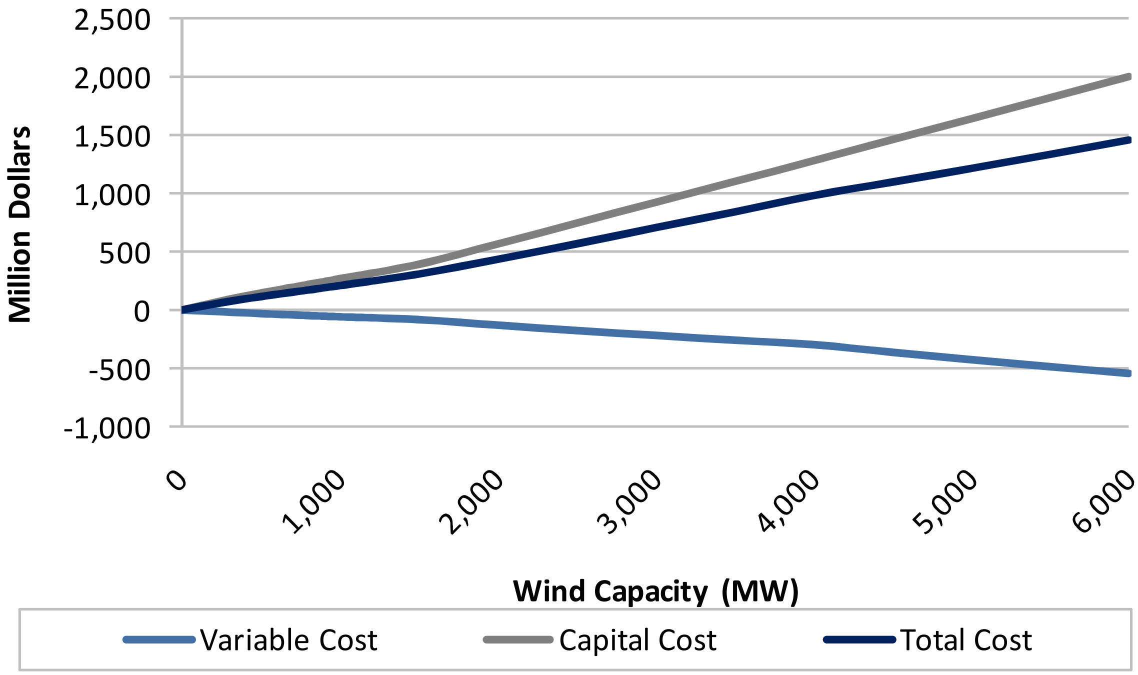

Figure 11. Breakdown of costs from scaling All PPA scenario (without subsidy or carbon cost)

Including the wind production subsidy and/or the carbon prices makes wind more cost effective. Since both the production subsidy and the carbon price are in terms of dollars per unit of electricity generated, they will lead to further reductions in variable costs. The variable cost curve will decrease more quickly pulling down the total cost curve (see Figure 11). This impact on total cost is shown below in Figure 12 for all possible combinations of the wind production subsidy of 21 dollars per MWh and the high and low levels for the carbon price under the Bingaman climate change bill.

When the subsidy or either of the two carbon prices is included by itself, zero wind capacity additions is still optimal. In fact, including both the subsidy and the low carbon price is still not enough to make a positive level of wind additions optimal. However, inclusion of both the subsidy and the high carbon price results in a situation where wind additions are optimal. Under this case the curve in the figure below first crosses zero on the vertical axis at 460 MW of wind capacity. This is the threshold where wind capacity first becomes cost effective. All levels of wind capacity below this level are not cost-effective. In terms of the capital and variable costs, below 460 MW of wind capacity capital costs are increasing faster than variable costs are decreasing. Wind capacity ceases to be cost-effective again at 2,435 MW of wind capacity and remains cost-ineffective for all higher levels of wind capacity. Relative to no wind capacity costs, all levels of wind capacity between 460 MW and 2,435 MW are cost-effective. In other words, in this region total costs with wind are lower than total costs without wind.

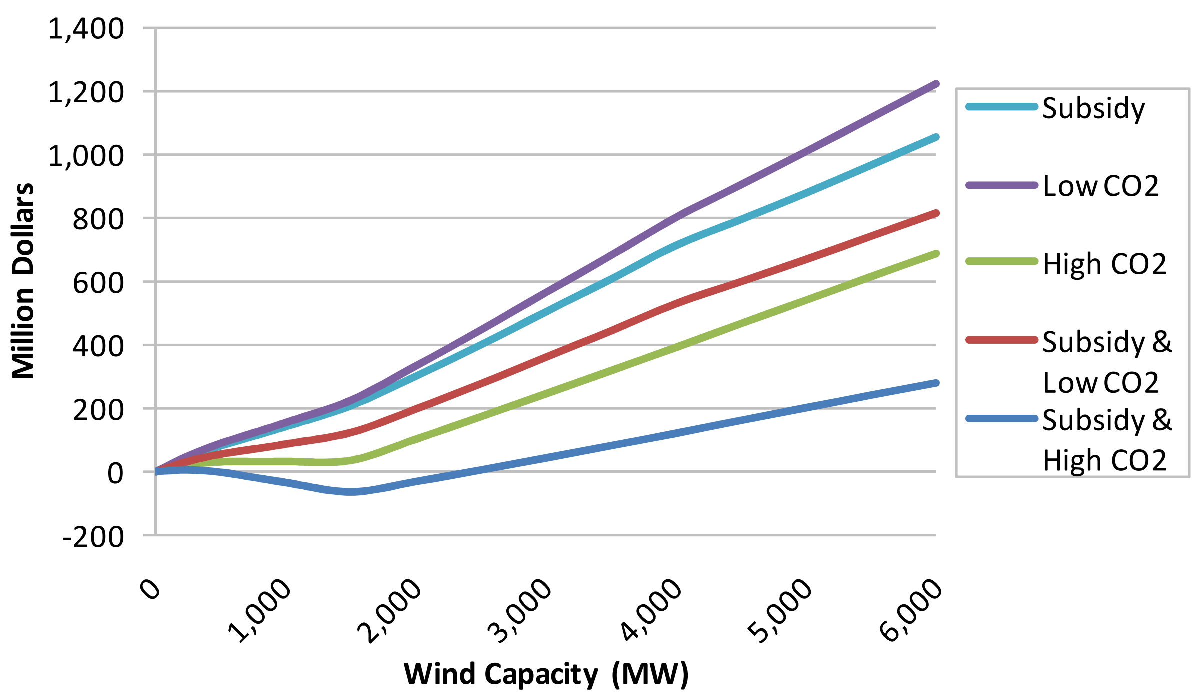

Figure 12. Total cost from scaling All PPA scenario

The cost minimizing level of wind capacity with the subsidy and high carbon costs is 1,540 MW. This level of wind capacity results in a total annual cost savings of $65.7 million relative to total costs with no wind capacity. Past this minimum point, total costs begin to increase with increasing wind. This increase in total costs, after the minimum point, is driven by reductions in baseload capacity requirements leveling-off and ceasing slightly above 1,540 MW. Cycling capacity requirements continue to decline, while peaking capacity requirements increase. This leveling off of reductions in baseload requirements causes capital costs to begin to increase faster than decreases in variable costs, thus causing total costs to increase.

Table 5 shows the impacts of various levels of wind capacity on 2025 retail rates for all combinations of the subsidy and carbon prices. The values in this table are calculated by dividing the total cost quantities used in Figure 12 by 2025 estimated retail energy sales of 144,495 GWh, thus arriving at values representing the change to 2025 retail rates in real 2009 dollars. For purposes of comparison, average Indiana retail rates in 2008 were 7.09 cents/kWh. Thus, the 1,000 MW wind scenario with the federal subsidy and no CO2 costs represents a 1.4 percent increase in rates from their present level. Using the optimal level of wind capacity, with the inclusion of the subsidy and high carbon price, the total cost savings is $65.7 million or a reduction to 2025 retail rates of 0.045 cents/kWh.

Program	1,000 MW Wind (cents/kWh)	3,000 MW Wind (cents/kWh)	6,000 MW Wind (cents/kWh)
Subsidy	0.10	0.35	0.73
Low CO2	0.11	0.39	0.84
High CO2	0.02	0.17	0.47
Subsidy & Low CO2	0.06	0.25	0.56
Subsidy & High CO2	-0.02	0.03	0.19

Table 5. Wind capacity's impact on retail rates in 2025 under various scenarios (2009 Dollars)

Conclusions

The primary distinguishing factor between wind generation and other forms of generation is the intermittency in output from wind generation. Since wind generation is not controllable, an important consideration is the relationship wind generation exhibits relative to load. Indiana's existing wind generation exhibits a strong negative correlation with Indiana load, and this relationship directly affects resource requirements for other forms of generation. Generally, though it is not always the case, a stronger negative correlation will lead to an increase in needs for peaking capacity because wind generation will typically not be available at full capacity during peak demand. The capacity factor of the wind will also have an effect on other resource needs. As mentioned earlier, the capacity factor is the ratio of how much electricity is generated given a particular level of capacity divided by the amount of electricity that could have been generated if the unit was operating at full capacity continuously, with a larger number representing more generation per unit of capacity. For the purpose of this paper the capacity factor shows how much a given level of wind capacity will be able to reduce generation needs from other resources, with a higher factor generally reducing other resource needs by a larger amount. In addition to energy requirements, a higher capacity factor can affect capacity requirements, as well. For example, two sites exhibiting the same correlation with load, the site with a higher capacity factor will typically be generating more electricity during the annual peak, which will have a direct effect on capacity requirements. In summary, when considering the addition of wind resources, sites that are more nearly correlated with load and exhibit a higher capacity factor will generally lead to the largest reduction in capacity and energy needs from other generation resources.

For all scenarios without the inclusion of a wind production subsidy or carbon price, total costs increased with wind capacity because reductions in variable costs of generation from other sources due to the additional wind capacity were not able to offset the increases in capital costs. The results of the model showed that for the Scaling All PPA scenario, wind capacity is cost-effective with the inclusion of the wind production tax credit and the high carbon price. Other technologies to aid wind generation were not considered in this paper. For example, some form of energy storage could potentially make wind generation more cost-effective by shifting energy generated from wind from lower value, off-peak periods to higher value, on-peak periods. In addition to the potential for energy storage to reduce increases in peaking capacity needs from additional wind generation, demand response programs may serve in this capacity, as well. Future research could allow for the use of energy storage and/or demand response as an alternative to increases in peaking capacity requirements.

As with any model, factors outside of those considered in the model may significantly impact the results. In particular, the time horizon considered makes it highly likely that changes in technology and policy will have an impact on the results. Changes in operations and maintenance (O&M) costs and fuel costs could change the cost-effectiveness of wind generation. Sensitivity analysis could be used to determine the factors that have the largest impacts on the results. While using three years of wind data allowed for the inclusion of some annual variation in wind output, a longer time series would enable an analysis that would be less susceptible to the influence of a single anomalous year on the results. The scenarios covered in this report were chosen to highlight important differences between wind sites, and to illustrate the critical factors in deciding where and how much to expand the wind portfolio. Future work may consider scaling up wind sites in a manner that optimizes the allocation of a portfolio of capacity across wind sites.

The model used in this paper is a good foundation for future work on valuing the impact of wind generation on system costs. The results of this paper highlight the importance of accounting for impacts on system costs when considering future wind generation investments, where not properly assessing these costs will misrepresent the value of wind generation. The results also shed light on some of the factors that the choice of location for expanding wind generation capacity.

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Appendix

Scaling In-State Purchase Power Agreements

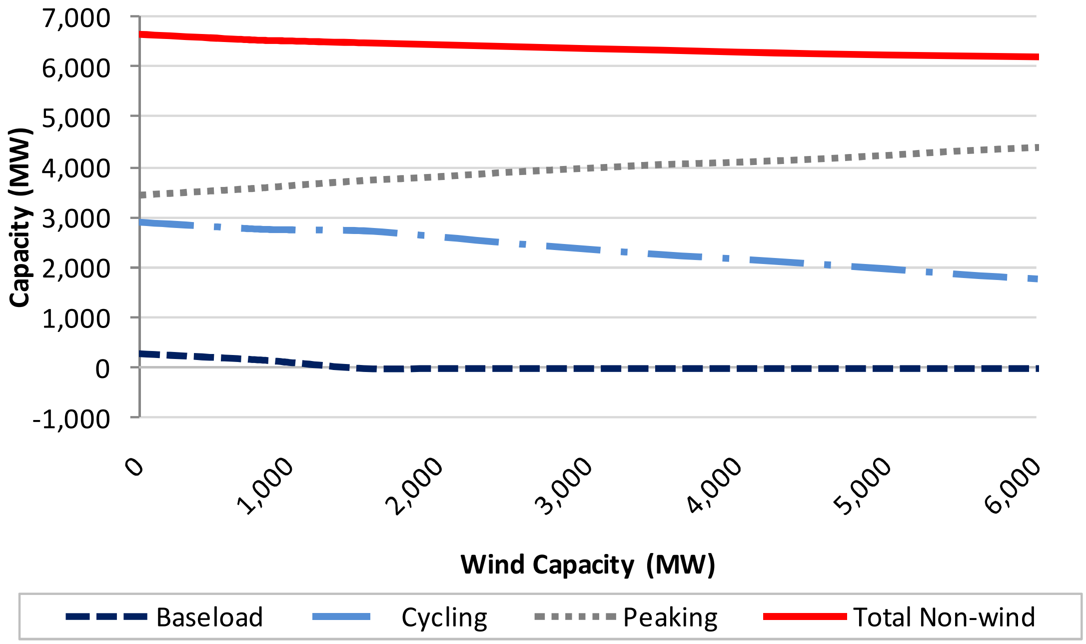

Figure 13. Change in capacity requirements (relative to base case capacity levels)

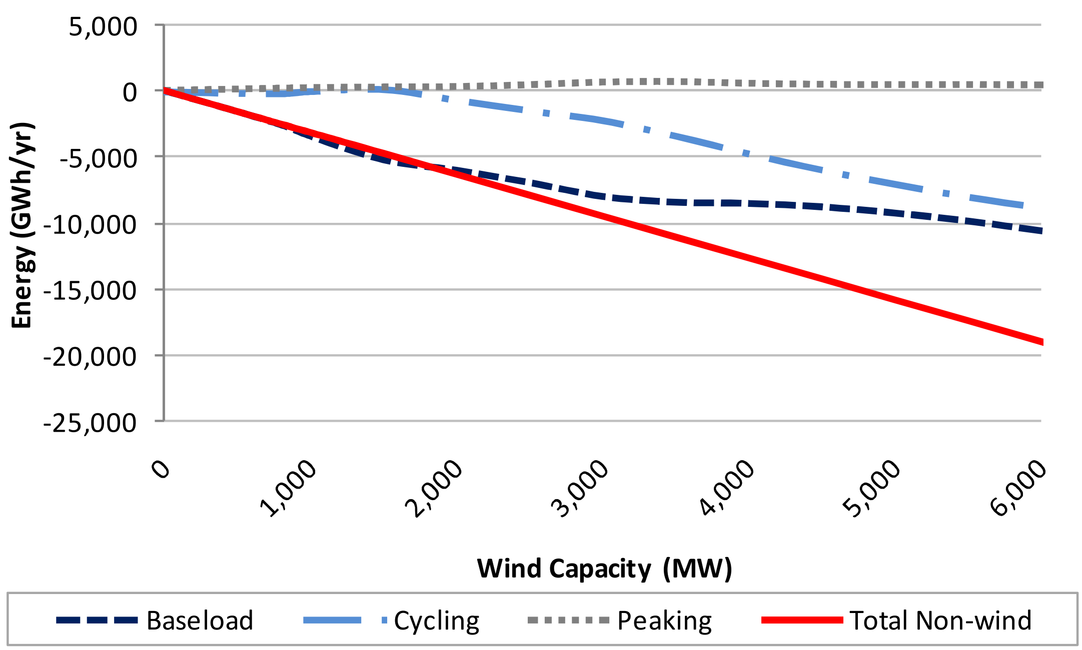

Figure 14. Change in energy requirements (relative to 2025 with no wind generation)

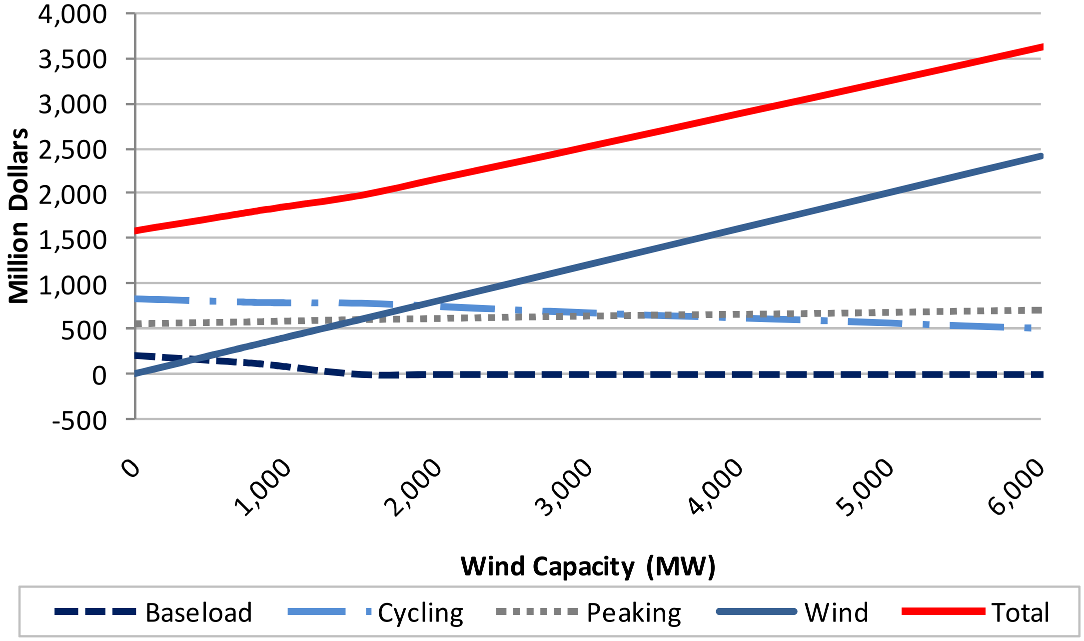

Figure 15. Change in capital costs (relative to base case capacity levels)

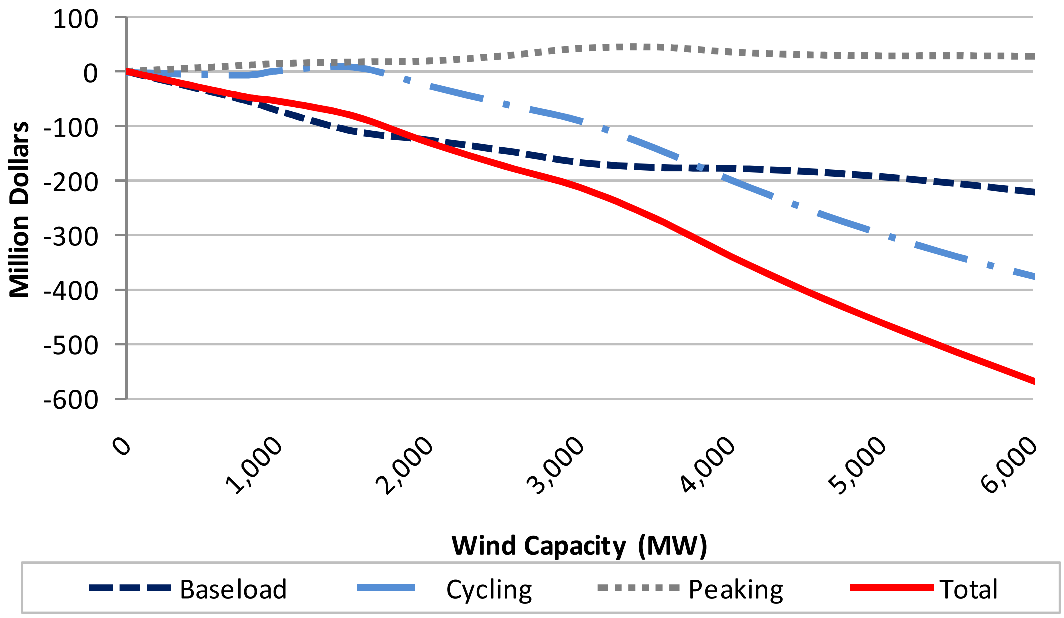

Figure 16. Change in variable costs (relative to 2025 with no wind generation)

Scaling Out-of-State Purchase Power Agreements

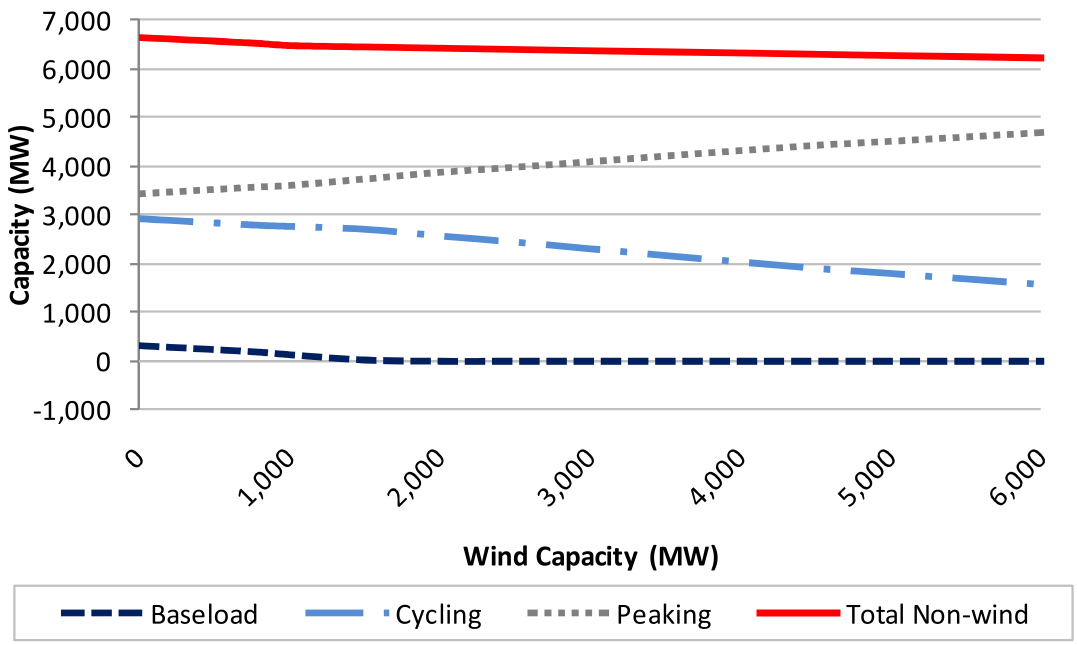

Figure 17. Change in capacity requirements (relative to base case capacity levels)

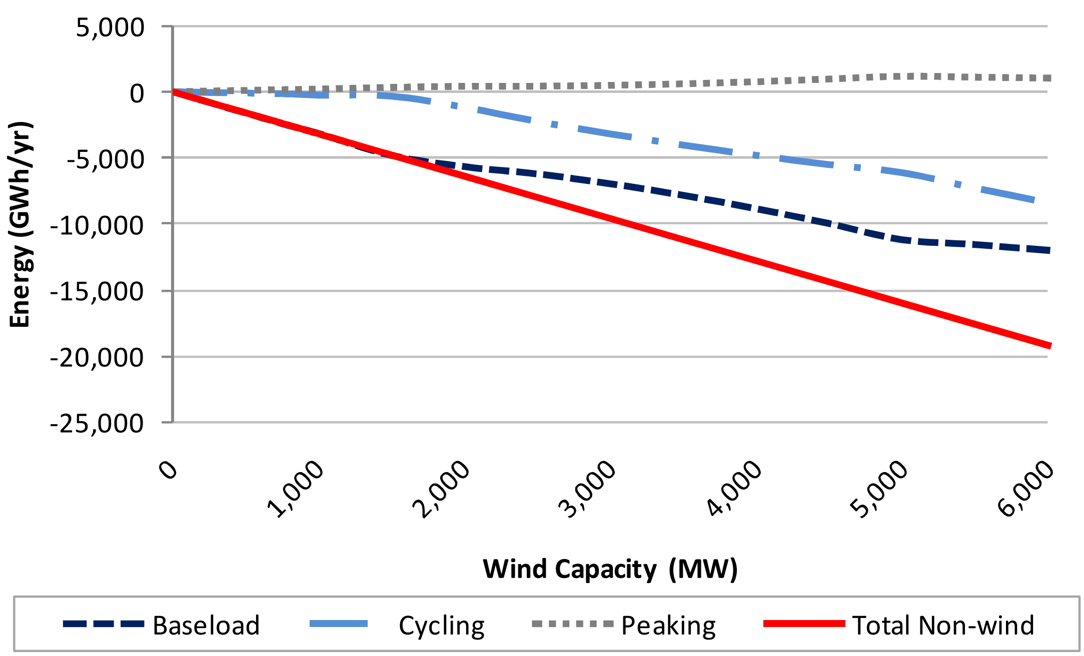

Figure 18. Change in energy requirements (relative to 2025 with no wind generation)

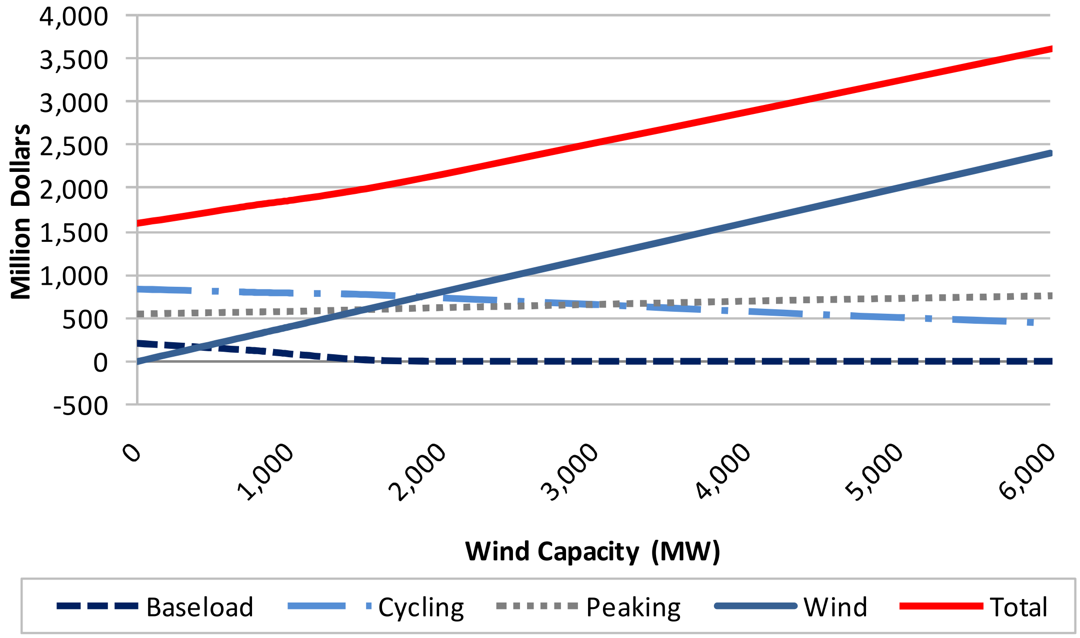

Figure 19. Change in capital costs (relative to base case capacity levels)

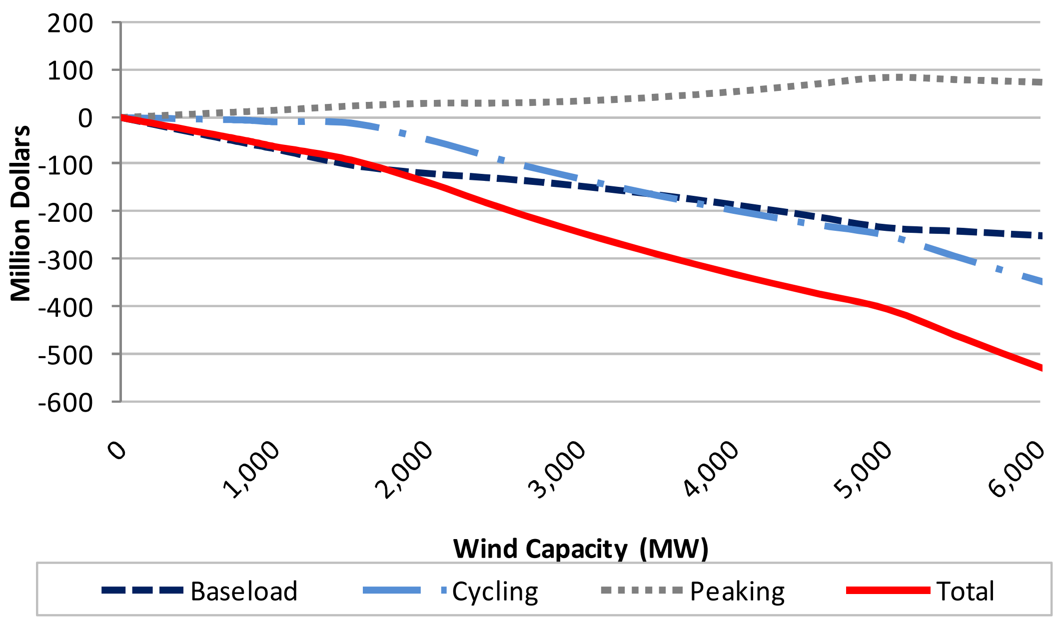

Figure 20. Change in variable costs (relative to 2025 with no wind generation)

Scaling Existing Purchase Power Agreements and Five Least Correlated Sites

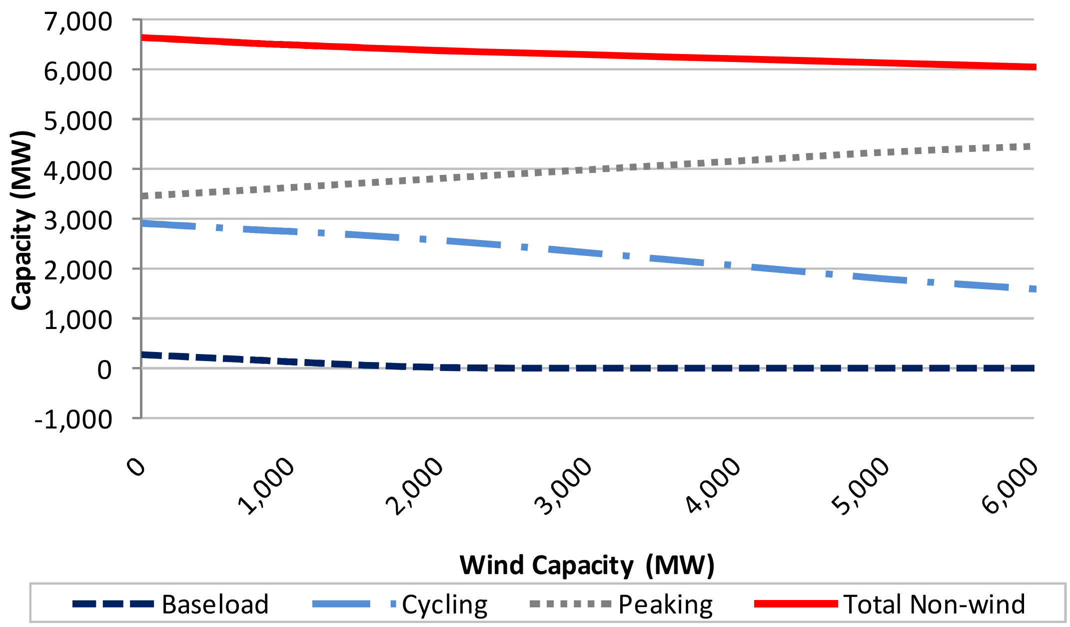

Figure 21. Change in capacity requirements (relative to base case capacity levels)

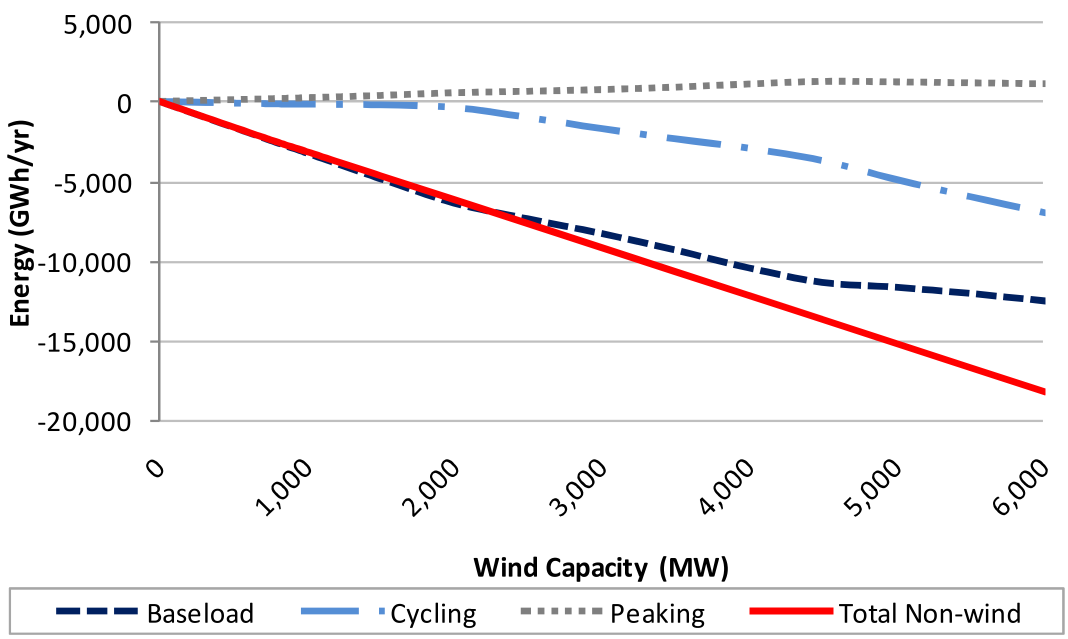

Figure 22. Change in energy requirements (relative to 2025 with no wind generation)

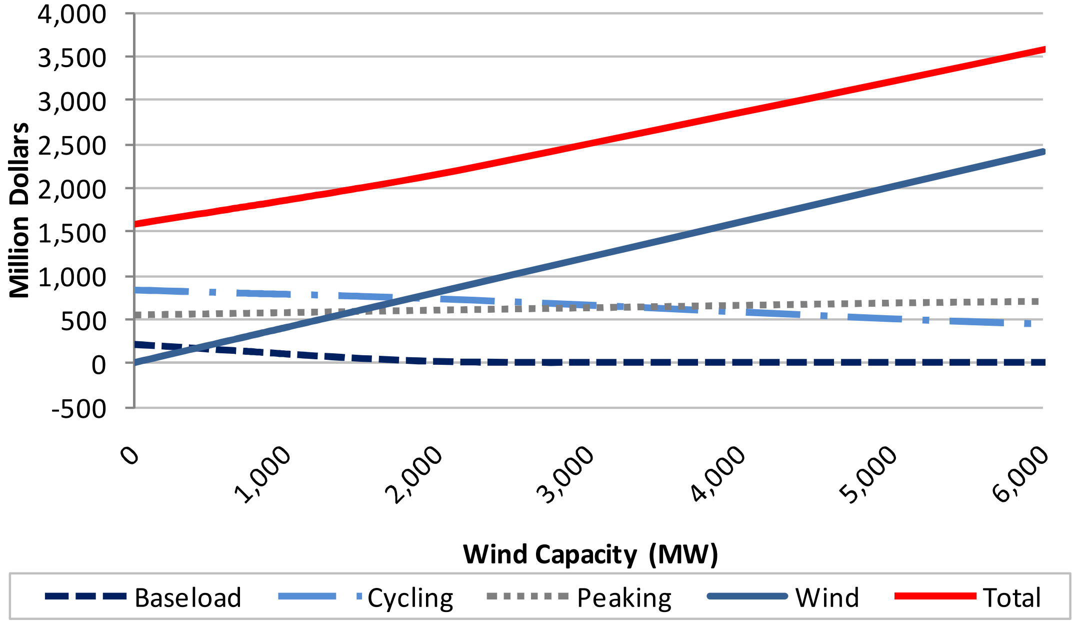

Figure 22. Change in capital costs (relative to base case capacity levels)

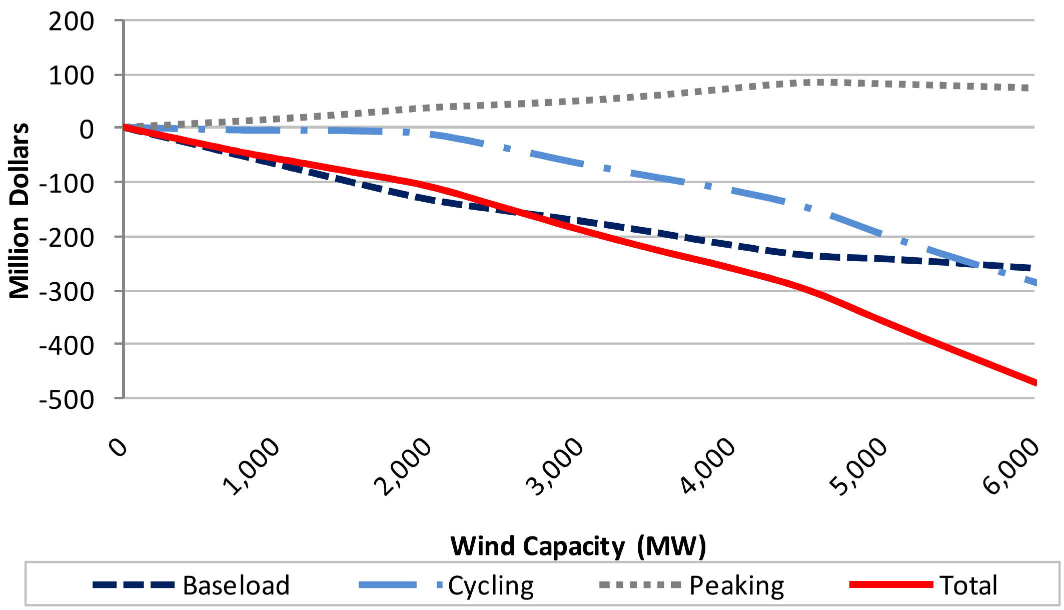

Figure 23. Change in variable costs (relative to 2025 with no wind generation)