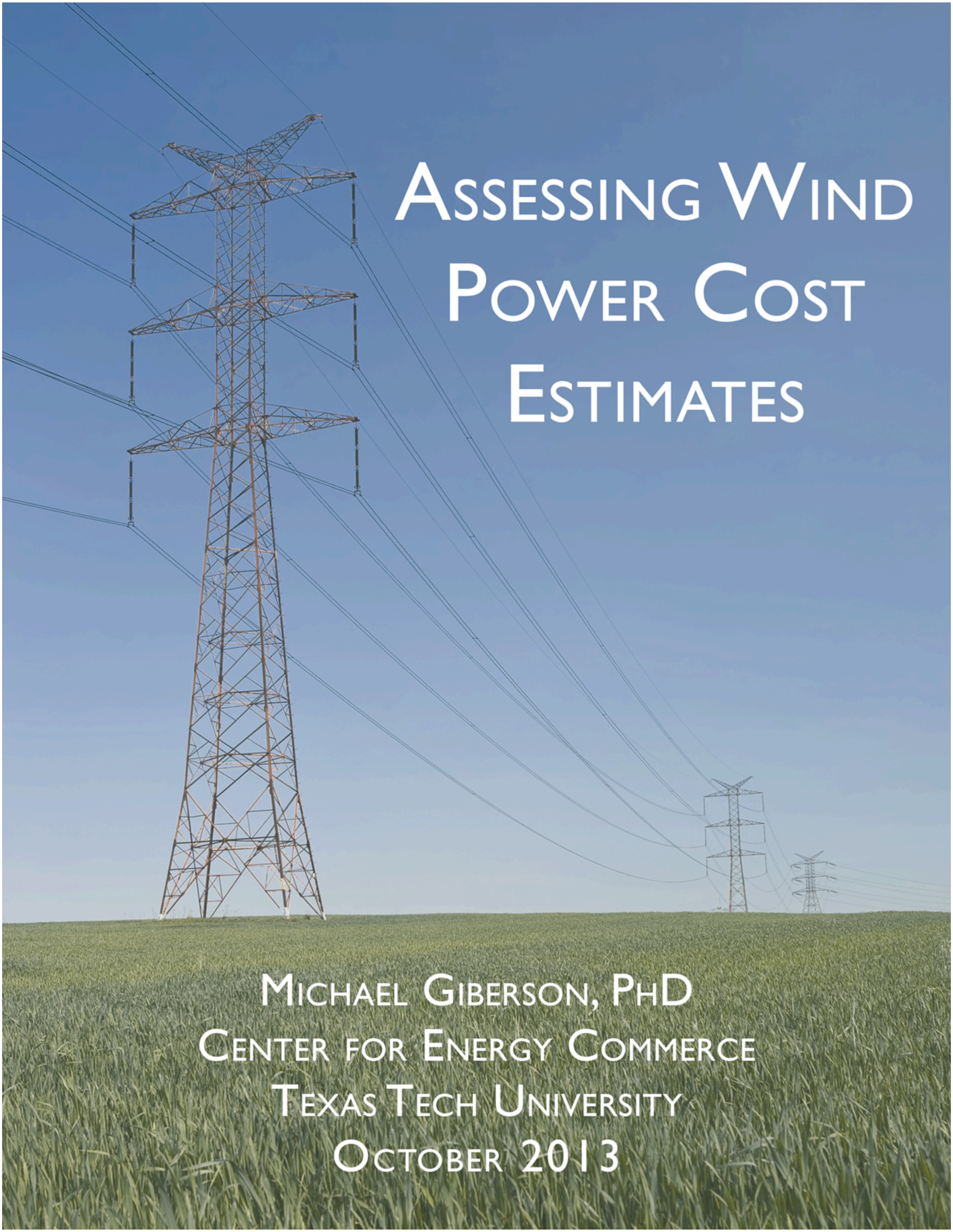

Assessing Wind Power Cost Estimates

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Table of Contents

About the Author

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Giberson has been published in Regulation magazine, the Electricity Journal, the Journal of Regulatory Economics, and the Pacific and Asian Journal of Energy, and has written on U.S. energy policies and federal electric power issues for trade publications. He received a BA in Economics from Texas Tech University, and an MA and PhD in Economics at George Mason University.

Executive Summary

This study examines estimates of the cost of wind power capacity produced by the U.S. government and provides additional context in order to better guide policy decisions concerning wind power. The federal government has devoted substantial resources to estimate the costs of wind power capacity and the associated costs of integrating wind power into transmission grids, but the complexity of the power grid and the technical nature of most research studies make it difficult for policymakers and non-specialist interested citizens to understand just what these studies mean. Numerous reports produced by the National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratory reveal a great deal about wind power costs. However, the most frequently cited numbers, concerning estimated Levelized Cost of Energy (LCOE) of wind power, do not capture all of the costs of wind power.

The federal government devotes substantially more financial resources to subsidize the production of wind power than it does to study wind power. The GAO counted over 80 separate federal programs offering economic support to wind power producers, though the largest program by a wide margin is the Production Tax Credit. State and local governments offer additional support. Government subsidies for wind power naturally raise questions concerning costs and benefits associated with the policy. Indeed, a complete policy analysis would assess both costs and benefits in a complete and consistent manner. Perhaps surprisingly given the extent of federal policy support for wind power, no systematic effort has been made to calculate the overall net benefit (or cost) of public policies supporting wind power. Given the importance of understanding the costs associated with wind power policies, this paper examines and assesses the most significant of the wind power cost estimates produced by the federal government.

In brief, the primary focus of the National Renewable Energy Laboratory report, the *2011 Cost of Wind Energy Review*, is to provide an estimate of the cost *to the developer* of installing wind power capacity. The Lawrence Berkeley *Laboratory's Wind Technologies Market Report* series seeks to provide an overview and details on trends affecting the wind power industry, including cost and performance trends. The Berkeley Lab report, like the NREL report, focuses primarily on the cost of wind power to the wind project developer. While expenses faced by wind project developers are an important element of the overall cost of wind power, addition of wind power to the power grid involves a number of other costs. If a more reasonable estimate of the installed cost of capital is $88 per MWh and operating costs are $21 per MWh, we can estimate a reasonable LCOE for wind power near $109 per MWh rather than NREL's estimate of $72 — a more than 50 percent increase.

Such costs include the expense of transmission expansions needed to develop wind power, other grid integration expenses, and added grid reliability expenses. Both the costs to the developer and the other costs are examined in this study.

1. Reviewing Wind Power Policy

The Production Tax Credit (PTC) for wind power was scheduled to expire at the end of December 2012. At the last minute, as part of the "fiscal cliff" negotiations over the federal budget, Congress passed the American Taxpayer Relief Act which, among other things, extended the PTC to all wind facilities that 'start construction' by year-end 2013.[1] The change in language from the wind plant being required to be 'in service' to simply requiring it be 'under construction' will allow wind projects completed in 2014 and 2015 to qualify for the subsidy, so long as a small amount of expense is incurred in 2013.[2] The one-year renewal is projected to eventually cost the federal budget more than $12 billion in revenue. [3]

Other proposals were also offered in dealing with the PTC expiration. As 2012 came to a close, the American Wind Energy Association lobbied for a multi-year phase out of the subsidy. Critics of the subsidy urged Congress to let it expire as scheduled. Notwithstanding the wind industry's proposal to phase-out the PTC, President Obama proposed making the tax break permanent in his February 2013 budget proposal.[4]

The PTC is not the only federal program offering support for the wind power industry. A U.S. Government Accountability Office (GAO) report counted 82 different programs spread across nine agencies that provided tax breaks, loan guarantees, or other economic assistance to the wind industry.[5] At the same time, many state and local governments also provide support for wind power through programs ranging from renewable power purchase mandates to local property tax breaks. A single wind power project may benefit from multiple federal, state, and local subsidies.

The diverse and sometimes duplicative policies, along with the strong differences in vision among policymakers for the future of government assistance to the wind power industry, have led to oversight and reform efforts in Congress. A number of Congressional committees have held hearings on wind power policies in the first half of 2013, and additional hearings are anticipated. Key among the issues raised in these hearings are questions over wind power costs, the effects of wind power on grid operations and reliability, and the effects of wind power subsidies on the market price of electric power.[6]

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These issues have been studied by the federal government as well as by industry specialists and academic researchers, but the resulting reports are often framed in highly technical language that presents a barrier to the interested non-specialist reader. This study provides a non-technical guide to wind power cost estimates and the effects of wind power subsidies on power grid operations and markets.

2. Understanding the Levelized Cost of Energy for Wind Power

2.1 Introduction

The federal government has devoted significant research effort into estimating wind power costs, much of it conducted by the National Renewable Energy Lab (NREL) and the Lawrence Berkeley National Lab (Berkeley Lab). The latest results from these research programs are presented in the *2011 Cost of Wind Energy Review* report by NREL ("*Cost of Wind Report*") and the *2012 Wind Technologies Market Report*, produced by the Berkeley Lab ("*Wind Tech Report*").[7] NREL intended the *Cost of Wind Report* to provide an estimate of the levelized cost of wind energy in 2011.[8] The *Wind Tech Report* is the most recent edition of a series of annual reports that began with the *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*. These two reports are used in the U.S. Department of Energy's Wind Program and are among the most widely cited studies on wind power costs in the U.S.

Wind power costs would be of interest primarily to renewable power developers, electric utilities, power system operators, and other industry experts but for the fact that much of the growth of the wind power industry has been driven by federal, state, and local public policies. Government subsidies for wind power naturally raises questions concerning costs and benefits, and especially, *who* pays the costs and *who* gains the benefits from public policy. While numerous reports have been produced addressing aspects of the costs and benefits associated with wind power, no systematic effort has been made to calculate the overall net benefit (or cost) of key public policies supporting wind power.

2.2 Counting Costs

Estimating the cost of electric power across different generator technologies is more complicated than it may at first appear. Some technologies, such as wind power and solar, have relatively high upfront capital costs but relatively low operating costs. On the other hand, coal and natural gas fueled generators tend to have low upfront capital costs, but higher operating costs.[9] A standard industry practice is to calculate the levelized cost of energy (LCOE), a metric that seeks to calculate the average cost of power production per Megawatt-hour (MWh) of output over the full lifetime of a power plant. The LCOE includes both capital costs and operating costs.

Importantly, the LCOE attempts to capture the cost of the wind facilities to the owner, but may not include the cost of transmission upgrades, grid integration costs, and other costs that may be associated with the wind project.[10] A full assessment of the cost of wind energy must include both the LCOE and these other costs.

2.3 The NREL LCOE Estimate

NREL *Cost of Wind Report* provided an LCOE estimate of $72 per MWh for a "reference project" intended to reflect a typical U.S. wind project built at a Midwestern or "heartland" site in 2011.[11] However, as NREL stated, wind projects "are subject to considerable uncertainty" and variability in the input data and assumptions – concerning capital costs, operating expenses, and capacity factor, among others – will yield a wide range of LCOE estimated results.[12] This sensitivity of the LCOE to data choices and input assumptions requires a closer look.

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LCOE estimates rely on four key pieces of data: installed capital cost, annual operating expenses, annual energy production, and the "fixed charge rate." Installed capital costs are the initial investment expenses — everything from preliminary wind data collection through the purchase and installation of wind turbines. Annual operating expenses include maintenance, overhead, replacement parts as needed and similar expenses. Annual wind energy production depends upon the designed capacity value of the wind project and the project's assumed capacity factor. The fixed charge rate reflects the assumed discount rate, depreciation and the assumed lifetime of the project.

2.3.1 Installed Capital Costs

The NREL *Cost of Wind* report estimated average installed capital costs of $2,098 per kW of wind power capacity, with a range of $1,400 to $2,900 per kW.[13] This cost figure represents the costs of the wind turbines and towers including transportation and installation, balance of plant wiring and equipment, design and engineering costs, financing, and other costs necessary to develop and build a wind power facility. Assuming a 38 percent capacity factor and a discount rate of 8 percent, NREL calculated an average installed capital cost per MWh of power output of $61.[14]

NREL's 38 percent capacity factor may be reasonable for a new power project built in a location with a high quality wind resource (which is the kind of facility their "reference project" is intended to represent), but it certainly appears high relative to data reported in the 2012 *Wind Tech Report* for existing commercial projects. The Berkeley Lab's latest calculations of average capacity factors ranged from a low near 28 percent in 1999 to a high of about 34 percent in 2007. Since 2008, average capacity factors nationwide have ranged from 31.1 to 33.5 percent.[15]

The selection of a capacity factor for analysis is important because the results are very sensitive to the values assumed. At the highest (53 percent) and lowest (18 percent) capacity factors NREL used to examine the sensitivity of the results to the assumption, average installed cost of capital ranged from near $43/MWh to about $126/MWh. Obviously, the choice of capacity factor matters a great deal to the LCOE.

While a well-designed, well-located wind power project may attain a capacity factor of 38 percent or higher, over the past several years average capacity factors have been nearer 33 percent. Recalculating the installed capital costs per MWh with the more reasonable 33 percent capacity factor would generate estimated installed capital costs of $69/MWh rather than $61 MWh.[16]

NREL assumed a nominal discount rate of 8 percent. Often energy development projects are evaluated using nominal discount rates over 11 percent, making the 8 percent assumption seem unduly generous.[17] A lower discount rate reduces the cost estimate. In general, riskier projects are usually evaluated with higher discount rates and less risky projects are evaluated with lower discount rates.[18] At the lowest (6 percent) and highest (13 percent) rates NREL used to examine the sensitivity of the results to the discount rate assumption, average installed cost of capital ranged from near $52/MWh to more than $88/MWh.[19]

Recalculating installed capacity costs with just the change in the discount rate from 8 percent to a somewhat more reasonable 10 percent raises the estimate from $61 MWh to $71 MWh. With reasonable adjustments to both the capacity factor and discount rates, the estimated average installed cost of capital increases to $80/MWh, about a 31 percent increase.

Assumptions concerning the depreciation schedule can also dramatically affect the estimated installed cost of capacity. NREL employed the 5-year Modified Accelerated Cost-Recovery System (MACRS) approach that Federal Tax Code provides for qualified renewable energy technologies.[20] Accelerated depreciation has the effect of deferring tax liability from the first years of plant operation to the later years of plant operation. One assessment concluded that employing a standard 20-year depreciation schedule rather than the MACRS would increase estimated installed capital costs by about 10 percent – raising our "reasonable" case installed cost of capital estimate from $80/MWh to $88/MWh.[21]

2.3.2 Annual Operating Expenses

The NREL *Cost of Wind Energy Review* employed an $11 per MWh estimate for annual operating expense, with possible values ranging from $9 to $20 per MWh.[22] Carrying over the adjustment in capacity factor from 38 percent to 33 percent but keeping other assumptions the same results in a slight increase in the estimates operations and maintenance cost, from $11 per MWh to $12 per MWh. Changes in the discount rate do not affect annual operating expenses.

The estimate of $11/MWh may also be biased downward. The most recent *Wind Tech Report* indicated a $10 per MWh average cost for annual operating expenses for projects built since 2000, but it added that this estimate is likely below actual average operation and maintenance costs. The *Wind Tech Report* stated that most wind power operators consider operating and maintenance cost data information to be commercially sensitive and prefer not to disclose it. As a result, the annual operating cost estimates reflect only one-fifth of the capacity included in the installed capacity cost calculation.[23]

In addition, Berkeley Labs reported that the data collected was not standardized across sources. Some operators reported operation and maintenance costs including insurance, local taxes, administrative overhead, wages and materials, but in other cases the data submitted included only wages and materials.

Significantly, the two wind power projects for which Berkeley Lab has the most complete information showed annual operation costs averaging over $21 per MWh, about twice the $11 average employed by NREL.[24] If a more reasonable estimate of the installed cost of capital is $88 per MWh and operating costs are $21 per MWh, we can estimate a reasonable LCOE for wind power near $109 per MWh rather than NREL's estimate of $72 — a more than 50 percent increase.

3. Costs Not Included in the LCOE Calculation

The LCOE calculation is intended to summarize the cost of the wind power facilities, but omits transmission expenses, the costs of integrating wind power into the grid, and various indirect environmental costs associated with wind power. Some of these costs have been studied in some detail, while others have proved hard to pin down. This section examines some of these additional costs associated with wind power.

3.1 Transmission Additions

High-quality wind resources are often distant from areas of high electric power demand, and therefore require investment in significant transmission additions to accommodate wind power additions. However, the cost of needed transmission additions will vary greatly depending on location and existing transmission capability. In a 2009 review, Berkeley Labs researchers surveyed 40 studies of wind power and transmission and found cost estimates ranging from $0 to $79 per MWh.[25] The median cost of transmission improvements to support wind power was $15 per MWh.

Certainly wind is not unique in this regard, as other renewable energy sources tend to have similar location-dependent characteristics. The best geothermal and hydropower resources are also often distant from large customer bases and require significant investments in transmission. Hoover Dam was built in part to serve electrical needs in Los Angeles, which is 250 miles away. The Bonneville Power Administration in the Pacific Northwest maintains over 15,000 miles of transmission lines, mostly to help it market power from federal hydropower dams along the Columbia and Snake Rivers to population centers throughout the Pacific Northwest.

While all new generating plants require transmission expenditures, it is important to note that power plant developers tend to have a greater range of choices to site natural gas and other power plants, and can choose locations that reduce transmission expenses. In fact, new fossil fueled power plants are often located at or near existing plants in part to minimize new transmission costs. Such options are less available for location-dependent renewable resources.

3.2 Integration of Wind Power to Grid

Integration of wind power to the electric power grid can require power system operators to need additional generation resources on reserve to help smooth out the inherent variability and unpredictability of wind power output. This additional demand for reserves can vary dramatically from system to system depending on existing reserves practices and other power system policies. The *Wind Tech Report* reported a range of cost estimates from wind power integration studies, with all studies but one falling below $12 per MWh and some studies below $5 per MWh.[26] However, the *Wind Tech Report* emphasized the differences in methods and goals in the studies surveyed and warned that the various studies may not be directly comparable.[27]

Generally speaking, integration expenses increase as installed wind power capacity becomes a larger share of the power system's generation mix. Large, competitive Regional Transmission Organization (RTO) power markets tend to have less difficulty accommodating wind, while utility systems operating outside of RTOs experience relatively higher integration expenses. In addition, wind power projects with lower capacity factors tend to be more costly to integrate into power systems relative to wind power projects with higher capacity factors.[28]

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3.3 Additional Cycling of Baseload Units

Variable wind power output can cause additional "cycling" of baseload power plants, which have traditionally been powered by sources like coal and nuclear. Cycling is the process of shutting down a power plant for a few hours and then restarting the plant. During the cycling process the plant is able to sell little to no power, but it burns fuel and puts additional stress on generating equipment. Industry research group Intertek APTECH has estimated that additional cycling of baseload units adds about $2 per MWh to overall power system costs.[29]

Wind power is typically strongest in the early morning hours, periods during which consumer load is low and primarily baseload power plants are the only generators providing power. Baseload power plants are designed for low cost operations rather than operational flexibility, which can make it difficult to manage wind power variability. Typically nuclear and coal power plants serve in a baseload capacity.

During such low-load periods, high winds will increase wind energy output and can threaten to push energy supply and energy consumption out of balance. As a result, when high wind power output occurs, some baseload plants have to be taken offline for a few hours. A brief analysis by the Energy Information Administration showed that increasing wind power output in the Southwest Power Pool was reducing the value and use of baseload generating capacity.[30] The shut down-restart cycle can take some types of generators several hours to complete, cause additional mechanical stress on power plant components, and lead to additional fuel consumption and emissions. The added costs associated with the cycling of baseload generators due to excess wind generation depends a great deal on the nature of power system and the power plants affected.

Low natural gas prices in recent years have made some natural gas plants cheaper to operate than some coal plants. Also, natural gas power plants are frequently more capable of responding to wind power's variability. This change may have reduced the amount of excessive cycling caused by wind generation. However, the U.S. Energy

Information Administration projects that natural gas prices will rise more quickly than coal prices in the near term, shifting market dynamics back toward less flexible coal powered baseload plants.[31]

One related effect arises from the ten-year duration of the PTC. As the $23 per MWh PTC[32] is equivalent to about $35 in pre-tax income, a wind power project can usually earn money with power market prices as low as negative $35 per MWh. This means that wind facilities can afford to pay the electrical grid to take their power as long as they are able to collect the PTC. Once a project's PTC eligibility expires, the project will offer power to the market closer to its marginal cost of power production.[33] Baseload plants in regions with significant amounts of PTC-subsidized power can face very low or negative power prices during low load-high wind conditions, which may encourage some generation to retire early. However, as wind project PTC-eligibility expires after 10-years in service, market prices during low load conditions will increase and some of the retired baseload generation could become economic again.[34]

The predictable short-term shifting of market conditions due to the subsidies presents the owner of a marginal baseload power plant with a difficult choice: stay in service while the wind power projects are subsidized, mothball the power plant—take it out of service, but maintain it well enough that it can be brought back online later—or retire the unit early and give up expected future profits.[35]

3.4 Environmental Costs

Wind power is promoted for its low environmental impact, but low impact is not zero impact. Wind farms in operation lead to very few direct air or water emissions, but some pollutants are emitted during construction and maintenance. Life cycle analysis of wind power suggests utility-scale wind power projects produce approximately 11 kilograms of CO_2-equivalent per MWh of energy, though emissions vary a great deal across projects.[36] Wind power projects with lower than average capacity factors have higher than average emissions per MWh, while projects with high capacity factors yield fewer emissions per MWh.

In addition, to the extent that wind power leads power systems to require additional generation reserves to be maintained online and generators are required to more frequently adjust power output to offset variations in wind power output, wind power will indirectly be the cause of additional air emissions. The direct costs of fossil fuel plants that provide additional reserve capacity and balancing services are noted above, but the environmental costs associated with the related emissions are not included. A modeling analysis of wind and solar power found that back-up and balancing services provided by fossil-fueled generators reduced expected emissions savings from 20 percent to as much as 50 percent.[37]

Wind farms have been criticized for contributing to excess bird and bat mortality, but valuation of this cost is difficult. In addition, the impact of wind power on bird and bat populations will depend heavily on site-specific factors and will vary widely from location to location.[38] A compensating factor comes from any net reduction in air emissions, which will be as beneficial for bird and bat health as it will be for human health.[39] Because of the difficulty in quantifying these costs, no cost estimate is presented for these indirect emissions and avian mortality impacts.

3.5 Additional Costs of Policy Support for Wind Power

Certain costs associated with wind power policies are not described above. For example, to the degree that the PTC reduces overall tax collection, taxpayers who do not obtain the tax credit pay larger taxes to accommodate the policy. Accelerated depreciation treatment also shifts the tax burden of investors in wind power. Economically speaking, however, the tax breaks shift responsibility for paying some of the costs of wind power from wind project developers to other taxpayers without causing overall costs to be higher. Similarly, a large number of state and local governments have extended policy support for wind power, ranging from purchase mandates, subsidies for production facilities, and state and local tax breaks. Again, the primary effect of the policy is to benefit wind developers and shift costs to other taxpayers, without dramatically affecting the cost of wind power. While some resources will have been expended in lobbying for, developing, implementing and administering these policies, these costs will be small compared to the costs reported here.

4. The Impact of PTC-Subsidized Wind Power on Power Markets

Some costs of wind power are easy to see, while others are less visible. The direct costs to the developer of buying and installing wind turbines, wind farm site improvements, and on-site transmission lines are all fairly obvious. The costs imposed elsewhere in power systems, such as the additional energy balancing services needed to compensate for wind's variability or transmission system upgrades needed that are distant from the wind power plant itself, as well as line losses from getting wind power from remote locations to load centers, can be harder to see. Understanding a few fundamentals of reliable power system operations and power markets can help reveal these indirect costs. This section of the report will explain the power system and the market fundamentals needed to better understand the indirect costs associated with wind power operations.

4.1 Balancing Power Supply and Demand

The reliable operation of electric power systems requires that power generated be kept in nearly perfect balance with power consumed. If the power generated and consumed gets out of balance, system voltages and power frequency will move out of their normal range. If the imbalance becomes too big, then electrical equipment connected to the system is at risk. Power quality variation can damage everything from generators and transmission lines to local utility systems and even a consumer's home computer.

To prevent this damage, generators and transmission lines have protective equipment that disconnects them from the system, much like a home's circuit breaker or the home computer's protective power strip. Sometimes these large disconnections help stabilize the grid, but other times they can create even bigger problems. The August 2003 blackout in the Midwest and Northeast was an example of a large problem that started small, but grew fast. When one overloaded line in Ohio dropped out of service, other lines in the Midwest also quickly overloaded and switched out as well. In a few moments the imbalance between power supplied and power consumed became too large, and the blackout resulted. Power system operators take several steps to help prevent problems like these from developing in the first place.

Power system operators manage energy balance on several time scales to protect system reliability: from seconds to minutes, from tens of minutes to hours, and day-ahead.[40] Different approaches are used to keep the system in balance in each of these time frames.

Automatic generation control (AGC, also called Regulation service), addresses the seconds to minutes variability in generation and consumer loads. AGC works through generator equipment that detects and automatically responds to small changes in power quality on the system and through instructions sent from the system operator to generators directing them to produce a little more or less power as needed to maintain system balance.

Wind power systems can add to the minute-to-minute variability of power output put onto the power system, and as such can increase the use of AGC services. However, because this very short-term variability is not correlated across multiple wind power projects, adding wind power capacity need not substantially increase the use of AGC.[41] To some degree, the variability of individual turbines cancels itself out.[42] To the extent that wind power does add to the cost of AGC service, the cost is in "grid integration costs" described above.

"Load following" focuses on the minute to hourly time frame. As the name "load following" suggests, balancing the system minute-to-minute and hour-to-hour is mostly a matter of adjusting generation in response to changing consumer load. Generators vary in the degree to which they can rapidly increase output—called ramping up—and decrease output—called ramping down. Power system operators try to ensure that enough generators with ramping capability are available to the system to meet expected shifts in consumer load.

Wind power systems can increase the need for ramping capability in power systems. Unlike the very short-term variability addressed by AGC, multiple wind power projects in the same region of the country will find their output somewhat correlated by large-scale wind events. Over the course of 30 minutes to an hour, wind projects can move from nearly no power output up to their maximum, or from full output down to nearly nothing. Because wind power output is typically not dispatched or limited, this means the system operator has to be prepared to ramp controllable generators up or down to offset the combined changes in consumer load and wind power output. The costs of managing wind power variability in this time frame are also captured in the grid integration costs listed.

Day ahead the power system operator engages in scheduling activities, also with the goal of keeping the system in near continuous balance. A key part of scheduling activities is the "unit commitment" process, deciding which generators may be needed the next day to provide energy, AGC, ramping, and other system services. Some generators require notice hours ahead of time to be ready to deliver power. Large coal plants may take as long as a day of advance notice. Other generators can start up more quickly—most natural gas generators, for example—but may require day-ahead notice to secure the fuel needed to run.[43]

Wind forecasts are used during the day-ahead scheduling process, but the uncertainty surrounding the forecasts means that power system operators need to have some reserves available in case wind output is unexpectedly low. Of course, power systems already maintain reserves on their systems to respond to other possible problems, and whether wind power leads to more reserves being employed will depend upon the amount of wind power on the system and current reserves policies.

4.2 Transmission Interconnection

The additional transmission expenses associated with wind power will include relatively obvious elements and some less obvious elements as well. Obviously the costs of power lines linking the wind power project to the existing transmission grid should count as a cost of wind power. And nearly as obvious, the costs of improvements to existing power lines linking wind farms to consumers should be counted, too. Less obvious are the costs of transmission system upgrades when those upgrades are far from wind power projects. Such upgrades are sometimes just as critical to the delivery of power from the wind project as other system additions.

On today's interconnected power transmission systems, power flows on one part of the system can affect power flows everywhere else on the system. Every transaction—power generated in one spot and consumed in another—will shift power flows along all possible connections between the two spots on the grid. The most direct connection, electrically speaking, will see the greatest effect of the power flow, but even indirect connections between the two spots will reflect the transaction. For this reason, new generator interconnections sometimes require transmission system upgrades distant from the site of the generator itself.

The variability of wind power contributes to making transmission costs a more significant topic than it is for dispatchable power plants. Typical capacity factors for wind power projects in the United States are about 33 percent.[44] To illustrate the point, imagine a transmission line devoted solely to wind power built large enough to handle peak power output. On average two-thirds of the transmission capability will be unused.[45] Or to put the matter another way, average transmission expense will be nearly three times higher per MWh of energy output for wind power than for the most efficient dispatchable generator. And, as previously noted, while many new generators can be located to reduce transmission costs, the distance between consumer markets and quality wind power locations often leave wind project developers with fewer options for limiting transmission investments. Transmission can cost from $1 million to $4 million per mile, and the combination of capacity factors and location issues means wind power is especially exposed to such costs.[46]

4.3 Markets: Negative Prices and Inefficient Production

The goal of power markets integrated into RTO system operations is to match generation and consumer load at the lowest cost consistent with reliable operations. At the core of the markets is the supply stack. Generators submit supply offers to the market indicating how much energy they are willing to supply to the system at different price levels. Generators capable of providing AGC or other support services may also submit offer prices for those services as well, but to keep it simple we will focus on energy.

The RTO collects generator supply offers, creates a supply stack by ordering supply offers from cheapest to most expensive, and then selects generators in order, beginning with the cheapest, until sufficient generation

will be available to meet expected consumer load. The most expensive generator needed to meet consumer load will set the energy price for the system.[47]
Because lower priced offers are selected before higher priced offers, generators usually must bid low to sell power. On the other hand, the generator doesn't want to operate if its costs will be greater than the price it is paid. The combination of these two points means that generators usually have an incentive to offer energy to the market at or just above their marginal cost of producing the energy.

While wind power plants are expensive to build, they have a very low marginal cost of operation. Once a wind project is built, the additional costs associated with actually generating energy, the wind power plants marginal costs of operation, are low compared to most other generating plants.[48]. For wind power projects not receiving production subsidies, owners would likely offer wind energy into the market at near their marginal costs.

However, wind power projects often obtain additional production subsidies, and these subsidies allow the wind project owner to profit even when power prices go negative. A negative price means generators have to pay the power system to accept their power output. A PTC-subsidized wind power project can bid as low as nearly a negative $35 per MWh and still profit from generating power because of the PTC. State policy supports or other payments may allow a wind project to bid even less than negative $35 per MWh in the power market and still earn some profit.

Most of the time the market price is positive, even when a significant number of wind power generators submit negative-priced offers into the market. That is because PTC-subsidized wind power units that submit negative offers receive the same positive market price that every other operating generator receives. In organized electricity markets, the price is set by the offer price of the most expensive generator that is called upon to operate, frequently a coal or natural gas unit. These units' fuel costs and usual lack of a significant production subsidy ensure they submit a positive price offer to the market, and so the market usually produces a positive price.

However, relatively-inflexible baseload generators sometimes offer their units as "must-run," i.e., they will take whatever price the market bears. When an inflexible generator responds to negative prices as an economic signal to go offline, it can be several hours or as much as several days (for a nuclear plant) before it can return to service. A generator cycled off during the low load early morning hours may not be able to be back in service in time to serve the higher demand, higher priced afternoon and evening hours when the plants are most needed for reliability. Potentially as important as remaining available to serve customers later in the day, the process of cycling a generator off-line and then back on-line can be expensive for the power plants owner. Industry consultant Intertek-Aptech estimated in 2008 that cycling off and back on could cost a 500 MW coal plant from $93,000 to $173,000 in added operations and maintenance expense.[49] Owners of such generators are willing to pay the power system to take their energy for a few hours, if those payments will enable the power plant to stay connected, avoid the wear and tear of cycling operations on the power plant, and sell power later in the day.

Wind power without production subsidies would not conflict so directly with inflexible baseload power units during low load, high wind periods. Unsubsidized wind power would offer power to the market at a low but positive price. In that case, as the power market price is reduced to zero or becomes negative, wind power units are priced out of the market and temporarily shut down, a simple and not-at-all costly process. In the absence of the PTC, costs associated with excess cycling of baseload power are mostly eliminated.[50]

Wind power projects often obtain additional production subsidies, and these subsidies allow the wind project owner to profit even when power prices go negative.

5. Conclusion

A summary of costs associated with a subsidy invites attention to questions of who pays the costs and who benefits from the subsidy. It hasn't been the purpose of this study to answer these questions, but some remarks will be useful. At a very first approximation, project owners incur the initial cost of construction and operations, the main costs captured in the widely-cited LCOE calculations. State and federal regulations and RTO market rules govern who pays the costs of transmission enhancements and power system integration needed to support wind power additions. In some cases, all consumers within a power market share these costs, while in other cases wind project owners or wind power purchasers directly pay some portion of these costs. The additional costs of excess cycling by baseload generators will initially be imposed on the owners of the baseload plants.

But these are only assessments of the initial incidence of the costs and not an assessment of the ultimate economic burden. The PTC and other subsidies and purchase mandates available to wind investors and developers mean that federal taxpayers and state electric power ratepayers also share the cost of construction and operation. The federal subsidies, for example, mean a significant proportion of the costs of meeting the requirements of the Texas RPS has been shifted to federal taxpayers outside of the state. Electric power consumers also, ultimately, pay the cost of integration and transmission enhancements needed. While the cost of excess cycling by baseload generators initially hits the owners' bottom line, the owners will respond by raising their offer prices in capacity and energy markets. Ultimately, the owners' shareholders and power consumers will share these costs.

Supporters of wind power and the Production Tax Credit sometimes point to wind power's price suppression effect as a benefit of wind power. It is, of course, not surprising that subsidies directed to some power generators can lead to lower prices, but a bit of reflection undermines the idea that price suppression is good policy. So long as wind power remains more expensive than the alternatives, adding wind power cannot reduce the overall cost of power to the economy. The policy just shifts the costs of electricity from consumers to federal taxpayers. At the same time, lower prices reduce earnings to those electric power generators that do not qualify for the subsidy, which for some older and for less efficient generators may push them into earlier retirement. Lest this last report be taken as an environmental bonus, conservationists should note that subsidized electric power increases energy consumption. The mix of an increased amount of subsidized wind power and reduced amounts of non-subsidized conventional generation also raises long run reliability concerns, as Texas is beginning to realize.[51]

So far as we were able to determine while researching these costs, no one in or out of the U.S. government has provided a systemic cost-benefit analysis of the PTC. This serious lack of analysis has been recognized by renewable policy experts, but remains unaddressed. Dr. Ryan Wiser of the Berkeley Lab testified to the Senate Finance

Committee in 2007 on the many benefits expected from an extension of the PTC, but explained “these possible benefits must be judged against the costs to the Treasury … as well as the alternative uses of the funds requirement to support such an extension.”[52] Six years have passed since this testimony to Congress, but no comprehensive assessment of the costs and benefits associated with the Production Tax Credit for wind has been produced.

Our report focuses just on the costs of wind energy, so it too is not yet the complete analysis needed to understand whether benefits of the PTC exceed or fall short of the costs of the policy. A full assessment of the PTC would require expanding the total cost calculation to the entire United States, quantifying as many of the benefits of wind power as possible, and then assessing the net benefits or net costs of the policy.

6. References

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7. Endnotes

1 LaMonica, "Wind Tax Credit Survives in Fiscal Cliff Deal," 2013.

2 Del Franco, "IRS Provides Certainty For Wind Developers To Move Forward With PTC-Eligible Projects," 2013.

3 U.S. Congress Joint Committee on Taxation, 2013.

4 See American Wind Energy Association, 2012; North American Windpower, April 11, 2013.

5 U.S. Government Accountability Office, 2013.

6 U.S. House of Representatives, Committee on Science, Oversight Subcommittee and Energy Subcommittee Joint Hearing, "Assessing the Efficiency and Effectiveness of Wind Energy Incentives," April 16, 2013. U.S. House of Representatives, Energy and Commerce Committee, "American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape," May 9, 2013.

7 Wiser and Bolinger, 2013; Tegen et al., 2013.

8 Tegen et al., 2013, p. v.

9 The intermittent nature of the output from wind or solar doesn't much affect the cost of wind power, but does affect the value of the output compared to readily controllable generators such as most natural gas generators. The issue is addressed briefly a bit later in this study.

10 Tegen et al., 2013, p. 2: "LCOE is not traditionally defined as a measure of all societal costs and benefits associated with power generation resources." In the prior year's report the authors explained in more detail (Tegen et al., 2012, p. 1):

> [The report] does not capture the full spectrum of wind energy's costs. It does not consider policy incentives (such as the production tax credit), issues that developers face when planning and deploying wind projects (e.g., permitting, siting, public involvement), the current economic recession, transmission, or integration. These are important areas that can significantly impact costs for individual wind projects.

11 The "reference project" data and assumptions are described in Tegen et al., 2013, p. 11-12, and in Appendix B, Table B1. The estimate is described in Table 1 and Table 6. Note that NREL reports calculations for both on-shore and off-shore projects. In this study we are only considering the on-shore estimates; as of 2011 no off-shore wind projects were operating in the United States.

12 Tegen et al., 2012, p. 14.

13 The data are based on the 2011 Wind Tech Report, which is based upon a survey of 564 wind projects accounting for 40,022 MW of installed capacity. The 564 projects represent approximately 85% of all wind projects built in the United States through 2011.

14 A "capacity factor" indicates how productive an electric generator has been over a period of time as compared to the theoretical maximum power output. For example, if a 1 MW wind turbine produces 2,628 MWh of electric energy over a year, then it has a 30 percent capacity factor (2,628 MWh / (1 MW x 8760 hours in a year) = 0.30).

15 See Wiser et al. (2013) Figure 28, p. 45. Data files for figure available from Berkeley Labs at http://emp.lbl.gov/publications/2012-wind-technologies-market-report.

16 This recalculation and the others reported here were performed as described in Tegen et al. (2013), pp. 1-3.

17 See, for example, FERC Opinion No. 489 which set the Return on Equity for electric transmission owners participating in ISO-New England at 11.14 percent. The connection between Return on Equity and the discount rate is described in the document listed in footnote 18. (Note that the conclusions of Opinion No. 489 are currently under discussion in FERC Docket EL11-66-001.)

18 See for example, the discussion of discounting in the Manual for Discounting Oil and Gas Income, which uses a 16.7 percent discount rate as an example. Online at http://www.window.state.tx.us/taxinfo/proptax/ogman/. For a related discussion in the context of wind energy see Krohn, ed. (2009) pp. 115-121.

19 NREL converted the nominal discount rate of 8 percent to a real (inflation adjusted) discount rate of 5.7 percent assuming 2.2 percent inflation and using the Fisher equation, a standard technique. See the 2010 Cost of Wind Energy Review, footnote 16 on p. 21. A nominal discount rate of 10 percent is equivalent to a real discount rate of 7.63 percent using the same assumption and method.

20 The MACRS depreciation bonus was initially allowed only to small wind power projects, but extended to most wind projects in the Energy Policy Act of 2005. For more information on the federal MACRS see IRS Publication 946: How to Depreciate Property.

21 Taylor and Tanton, 2012, p. 26.

22 Tegen et al. (2013), p. 14.

23 The Wind Tech Report indicated that their operation and maintenance data reflected reports from 133 wind power projects with a total of 7,965 MW of installed capacity.

24 Tegen et al., 2013, p. 41.

25 Mills, Wiser, and Porter (2009). Transmission expenses are highly dependent on siting issues, distance to market, and existing transmission capability. For these reasons, the wide range in cost estimates is not surprising.

26 Wiser et al. (2013), p. 65.

27 Wiser et al. (2013), p. 62.

28 Wiser et al. (2013), p. 65; Katzenstein and Apt, 2012.

29 Kumar, et al., 2012.

30 U.S. Energy Information Administration, 2013a.

31 U.S Energy Information Administration, 2013b.

32 The PTC increased to $23/MWh on Jan 1, 2013. "Credit for Renewable Electricity Production, Refined Coal Production, and Indian Coal Production, and Publication of Inflation Adjustment Factors and Reference Prices for Calendar Year 2013," Federal Register, 78 (April 3, 2013): 20176-20177.

33 No public estimate of the marginal cost of wind power appears available. Because there is no fuel expense, analysts sometimes assume wind power has a zero marginal cost of production. The average operations and maintenance costs discussed above include a mix of both variable and fixed costs, but some portion of these costs represent the marginal cost of wind power—the additional costs incurred by the operator when a turbine operates rather than sits idle. See Wiser et al., Wind Tech Report, p. 38.

34 For example, Dominion Resources, Inc. cited lower market prices as a key factor in driving the retirement of its Kewaunee, Wisconsin-based nuclear power plant. Matthew Wald, "As Price of Nuclear Energy Drops, a Wisconsin Plant is Shut," New York Times, May 7, 2013; Entergy Corp. cited lower power market prices and higher costs in its decision to close the Vermont Yankee nuclear plant in 2014. Dave Gram, "Vermont Yankee Nuke Plant to Close by End of 2014," Associated Press, August 27, 2013.
For a related discussion see "State Subsidization of Electric Generating Plants and the Threat to Wholesale Electric Competition," report by Continental Economics, Inc., for COMPETE Coalition, December 2012.

35 The additional costs of PTC-induced short-term shifting of investment signals are not included in our estimate, and so far as can be determined have not been estimated by industry analysts. Related issues are mentioned but not developed in EPRI, 2011, p. 6.

36 Dolan, S. L. and Heath, G. A. (2012). For a detailed life cycle analysis of wind turbines see Garrett, P. and Rønde, K. (2012).

37 Katzenstein and Apt, 2009. See also Lew, et al., 2012.

38 See National Wind Coodinating Collaborative, 2013.

39 See Sovacool, 2013, for one attempt to assess these offsetting gains.

40 See, for example, Ch. 25 in Milligan, et al., (2012)

41 However, in practice AGC is often used to help keep the system in balance during longer-period shifts in consumer load and changes in overall wind power output, at least until the power system operator can deploy "load following" resources.

42 Lennart Soder and Thomas Ackerman, "Wind Power in Power Systems: An Introduction," Ch. 1 in Ackerman, ed., 2012.

43 For more discussion of power market basics see: Federal Energy Regulatory Commission, 2012, Ch. 3, "Wholesale Electricity Markets." Related discussion is in Brown, 2012.

44 IEA Wind, 2011 Annual Report, (2012), p. 13.

45 Actual transmission expansions depend on expected power flows by many different system users. Expect for the transmission lines linking from a wind project to its point of interconnection with the power grid, few transmission projects are so closely tied to the output of a particular power plant an in this illustration.

46 American Electric Power, 2008.

47 See Federal Energy Regulatory Commission, 2012, Ch. 3, "Wholesale Electricity Markets." Note that most generators sell power through contracts.

48 See the discussion of marginal cost at footnote 27 above.

49 Lefton and Hilleman, 2011.

50 In addition to cycling off and back on more frequently, relatively inflexible baseload plants likely become called upon for additional load following services during lower-load periods with fewer flexible intermediate-type generators on the system. Such additional load following service and the associated expense, estimated by Lefton and Hillman at from an additional $8,000 to $20,000 per load-following cycle.
Additional analysis of negative prices in power markets is presented in Huntowski et al., 2012.

51 Texas PUC Chair Donna Nelson said, "The market distortions caused by renewable energy incentives are one of the primary causes I believe of our current resource adequacy issue." Quoted in Lesser, October 2012, p. 2.

52 Wiser, 2007, p. 11.

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