Evaluating Transmission Costs and Wind Benefits in Texas: Examining the ERCOT CREZ Transmission Study

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INTRODUCTION

In 2005 the Texas legislature directed the PUC to designate competitive renewable energy zones (CREZ) in areas with suitable resources. The PUC asked ERCOT to determine what transmission enhancements would be required to reliably and economically move renewable energy from the prospective CREZs to load centers. The CREZ effort is part of a continuing trend. Wind generation is expanding rapidly in Texas with 2,508 MW currently in service and an additional 2,342 MW expected by the end of 2007. 17,000 MW of wind generation has requested interconnection analysis. As is common for wind generation, most is located far from load centers. Consequently, significantly expanding wind generation likely requires expanding the transmission system as well.

In December 2006 ERCOT released its report entitled “Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas”. The study was thorough and comprehensive. ERCOT developed a unique analysis methodology to determine what transmission enhancements will be required to reliably integrate increasing amounts of wind generation into the Texas power system. This computationally intense analysis studied the power system for every hour of the year with increasing amounts of wind generation. New wind generation was added in roughly 1000 MW increments in four geographic areas: the Gulf Coast, the McCamey area, central-western Texas, and the Texas Panhandle. Existing loads and generators were modeled to determine the most economic way to operate the power system each hour. When transmission constraints were identified (overloaded or potentially overloaded lines) transmission enhancements were designed. The least expensive designs that maintained reliability under all conditions were then selected. An unfortunate consequence of this incremental approach to transmission planning is that it is unable to value transmission enhancements that will support future load and wind growth.

Because ERCOT modeled all of the loads and generators along with the complete transmission system with a reliability constrained unit commitment and economic dispatch model they were able to learn a great deal more than simply what transmission enhancements are required for each CREZ. Increasing wind generation reduces the amount of fuel consumed by conventional power plants. ERCOT calculated the fuel savings each hour with and without the new wind plants. Fuel savings were compared with transmission enhancement capital costs to determine if the transmission enhancements make economic sense from a societal point of view. ERCOT also studied how the addition of wind plants will impact the hourly energy prices. Since wind generators have zero marginal cost they do not set energy market prices. When wind displaces the most expensive conventional generator, the market clearing price drops to that set by the next most expensive generator. This price drop results in a savings to all consumers. ERCOT provided an estimate of both the consumer savings and the revenue each wind plant would receive. The use of bilateral contracts can have an impact on the sharing of savings, but it is clear that the savings will be shared.

This report examines the ERCOT study to assess both the methodology used and the study results. It attempts to explain some of the report’s finding in language that may be more accessible. It also briefly discusses required next steps.

ERCOT STUDY METHODOLOGY

ERCOT designed a study methodology that incrementally added wind generation in ~1000 MW blocks to determine which wind locations are most economic (from a transmission system perspective, other perspectives were not considered) and what transmission enhancements are required to support the additional wind generation. A basic principal of the study method was that power system reliability must be maintained.

One difficulty the study had to cope with is that both wind and electric power loads are variable. Another difficulty is that conditions on one part of the electrical interconnection impact transmission line flows on all other parts of the transmission system. A third difficulty is that current conditions on a transmission system are rarely the limiting factor. The power system has to be continuously prepared to withstand the sudden failure of any generator or transmission line (see the *Preparing for Contingencies, Not Current Conditions, Determines Transmission System Capacity* text box).

ERCOT addressed these difficulties by modeling the entire power system for every hour of the year. When transmission constraints were identified transmission enhancements were designed and tested. The analysis was then run again. In this way the ability of the transmission system to support increasing amounts of wind generation was determined by location. The system benefits resulting from the added wind and the cost of the transmission enhancements were also determined.

Modeling the Power System

ERCOT decided to perform a detailed time-series analysis of the power system using a reliability constrained unit commitment and economic dispatch model. This method models all of the transmission lines, all of the loads, and all of the generators. Based upon the generators' efficiencies and fuel costs it determines which generators to operate and at what power levels to minimize cost without risking overloading the transmission system.[1] This type of modeling inherently simulates a snapshot in time. ERCOT repeated this basic modeling 8760 times to represent a full year of hourly operations.

The modeling returns four basic results. Three results are economic: total fuel consumed each hour, hourly energy market clearing price, and wind generators' market revenue are calculated. (Results for individual generators are also calculated.) The fourth result concerns any transmission lines that were congested. If the unit commitment and economic dispatch had to be altered to limit flows in a transmission line this was noted. Modeling results for the complete year were studied to determine if transmission enhancements were needed to alleviate transmission congestion.

Though it is computationally expensive this type of modeling is the best way to determine actual system costs and requirements.

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[1] Making sure that the transmission system is in a reliable state requires running the full set of contingency analysis to test if the system can withstand the failure of any generator or transmission line.

Preparing for Contingencies, Not Current Conditions, Determines Transmission System Capacity

There is essentially no electricity storage and little flow control in a modern power system. While technologies exist to both store electricity and to control transmission line flows both are too expensive to be widely utilized today. As a consequence the power system must be operated so that it can withstand the sudden failure of any generator or transmission line.

It is possible for two nuclear units to trip off line simultaneously, for example, so ERCOT always operates with 2300 MW of contingency reserve generation and responsive load poised ready to respond. Reserve generators can immediately ramp up production and reserve loads can immediately turn off. ERCOT runs hourly contingency reserve markets and pays the generators and loads for standing ready to respond. Without this response capability generation and load would be badly out of balance when a generator failed and the entire power system would rapidly blackout.

Similarly, transmission lines can fail suddenly. In a simple case there might be three transmission lines connecting a 900 MW generator to the power grid. It would not be adequate for each of those lines to be rated for only 300 MW. While all would be fine when all lines were in service (each carrying its rated 300 MW) the remaining two lines would be immediately overloaded and fail if one line tripped (perhaps due to a lightning strike). Instead, all three lines need to be rated for 450 MW each so that when one line fails the other two lines still have adequate capacity.

The actual situation is more complex. Flows in any given transmission line are impacted by the pattern of loads, generation, and connected transmission lines throughout the power system. To determine if the transmission system is secure it is necessary to model the existing conditions and then repeat the modeling with each transmission line and generator removed one at a time (simulating a generator or transmission line failure: a contingency). Flows in every transmission line must be checked to assure that no lines or transformers will be overloaded after each of the possible generator or transmission line failures. If a single transmission line is overloaded the pre-contingency situation has to be adjusted and the study run again.

In real-time operations the system operator is continuously running simulations to assure that the power system can withstand any generator or transmission line failure. When the computer model shows that the power system could not withstand a sudden transmission line or generator failure it notifies the system operator. The operator then has to change conditions on the power system to restore security. Since lines can not be built within minutes typically the solution is to change the pattern of generation. Some generators are ordered to turn on or increase output, others are ordered to reduce output or turn off. Responsive loads can also be adjusted. Transmission lines that are out of service for maintenance can sometimes be placed back in service. Occasionally taking a transmission line out of service can restore system security. Changing generation output to maintain reliability is called Security-Constrained Unit Commitment and Economic Dispatch. The most economic solution is followed, subject to reliability limitations.

System planners model not only current conditions but expected conditions for days, months and years to come. They have the added flexibility that they can add transmission lines (or generators) to alleviate problems. By running numerous studies transmission planners can determine what transmission enhancements are most effective and least expensive at assuring power system reliability under a host of future operating conditions.

Selecting a Base Year

Detailed time-series analysis requires large amounts of data. Specific conditions are modeled as they are expected to exist at some time in the future. When evaluating the impact of long-lived assets such as power plants (wind or conventional) it is desirable to select a year that is far enough into the future to represent conditions throughout the life of the asset. Modeling conditions in 2015 or 2020, for example, would reflect the higher fuel and capital costs, additional transmission enhancements that will be built to accommodate load growth, and greater environmental benefits that will exist for most of the service lives of the wind plants. Unfortunately, in today's competitive electricity environment, it is difficult to generate precise transmission and load models that far into the future. ERCOT felt that 2009 was as far into the future as they could precisely predict. Choosing the base year to model is always a compromise.

Modeling the Wind

This type of power system modeling requires a great deal of wind data. Actual wind generation is required at every proposed wind location for every hour of the year. In fact, a single year is not sufficient because wind conditions vary from year to year. This type of wind data does not exist so it too has to be computed based upon known conditions in the atmosphere. Recent advances in weather modeling now make this possible and the technique has been used for large wind integration studies in Minnesota, Colorado, New York, California, the Pacific Northwest, Canada, and other locations.

AWS Truewind was selected to provide wind resource expertise and modeling. A combination of stakeholder input and wind resource evaluation led to the selection of the windiest (not necessarily the best) sites capable of supporting 100 MW of wind generation each in each of four general regions: the Gulf Coast, the McCamey area, central-western Texas, and the Texas Panhandle.

AWS Truewind performed the mesoscale modeling necessary to generate hub-height wind speeds and hourly wind plant generation data for each 100 MW site. Modeling consists of back-casting (as opposed to forecasting) based upon an extensive atmospheric database of 15 years of time-series data, and observations from numerous public and private meteorological towers. The physics-based model simulated how the atmosphere behaves and interacts with the ground.

Modeling results consist of a typical year of hourly wind generation amounts from hundreds of 100 MW wind sites.[2] These hourly wind generation amounts can be added to the power system model to simulate increasing amounts of wind generation being added to the Texas power system.

[2] This type of wind modeling wind generation requires careful attention to assure that the 100 MW wind generation site displays the correct characteristics. It is not appropriate to simply scale a single wind speed reading based upon a wind turbine production curve ratioed up to the total site power level. Significant aggregation (reduction in impact due to partial cancellation of variability from one turbine to another) occurs within a 100 MW site and this must be accounted for. This is a more important problem when calculating ancillary service requirements in a wind integration study.

Modeling the Power System with Wind

Once the loads, generators, and transmission system had been modeled and hourly wind generation data was available it was possible to model the integrated wind/power system. A beauty of this type of modeling is that any correlation (or lack thereof) between wind generation and system load on a seasonal or daily basis is automatically accounted for. Impacts on peak and minimum generation requirements get included. Similarly, correlations between different wind sites and aggregation benefits resulting from wind diversity are automatically included. It may take some effort to quantify each individual impact but they are all included in the total cost and benefit results.

The transmission system is always being worked on. This study started with the transmission system as it is expected to be in 2009 with several additional projects, which have already been approved, added. Additional wind generation is also expected to be in service in the near future. Wind generation was modeled as starting at 4,850 MW for this study.

ERCOT used a combination of modeling tools. A reliability constrained unit commitment and economic dispatch model was used to perform the year-long hourly analysis. This tool identified generator costs, market clearing prices, *and* transmission constraints. When transmission constraints were found, a more detailed load flow analysis package was used to help design transmission enhancements to alleviate the congestion. Once transmission enhancements were developed the annual analysis was run again. In this way incremental amounts of wind generation were analyzed to determine the required transmission enhancements and the production benefits they offered.

Transmission Enhancement Constraints

Transmission system planners are faced with a difficult design problem when expanding the transmission system. As shown in Figure 1, both transmission line cost and the amount of land required drop as voltage is increased (per MW transmitted). Unfortunately the minimum line size increases. This creates two related problems for transmission planners. The simpler problem is that higher voltage lines have higher minimum sizes. A 765 kV line costs only about one-third as much as a 345 kV line per MW of capacity but the minimum size is about six times larger. As *incremental* transmission capacity is required (either due to load growth or due to generation additions – this is not a wind-specific problem) the full capacity of a 765 kV line may not be required for many years. A shortcoming of incremental analysis is that it can be difficult to justify building the 765 kV line *now* even if it will be the better solution *later*. Consideration of broader factors than those included in the CREZ report may justify 765kV use.

Contingency concerns present a somewhat more complex version of the same minimum line size problem. The largest single failure currently on the ERCOT system is the loss of a 1250 MW generator. The current study adopted a rule that no new transmission enhancement should create the potential for a single failure to result in the loss of more than 1500 MW of generation. This rule makes it very difficult to justify voltages above 345 kV in the short run and to obtain the economic, land use, and electrical benefits higher voltages provide. Once fully developed a 765 kV network would provide significant reliability benefits related to the inherent stiffness of the network along with the economies of being able to move large amounts of power but it is difficult to incrementally get to that future. This is a problem that is worth considering further within ERCOT. In particular, expanding the report's five-year time horizon would significantly improve the evaluation of long-term transmission needs.

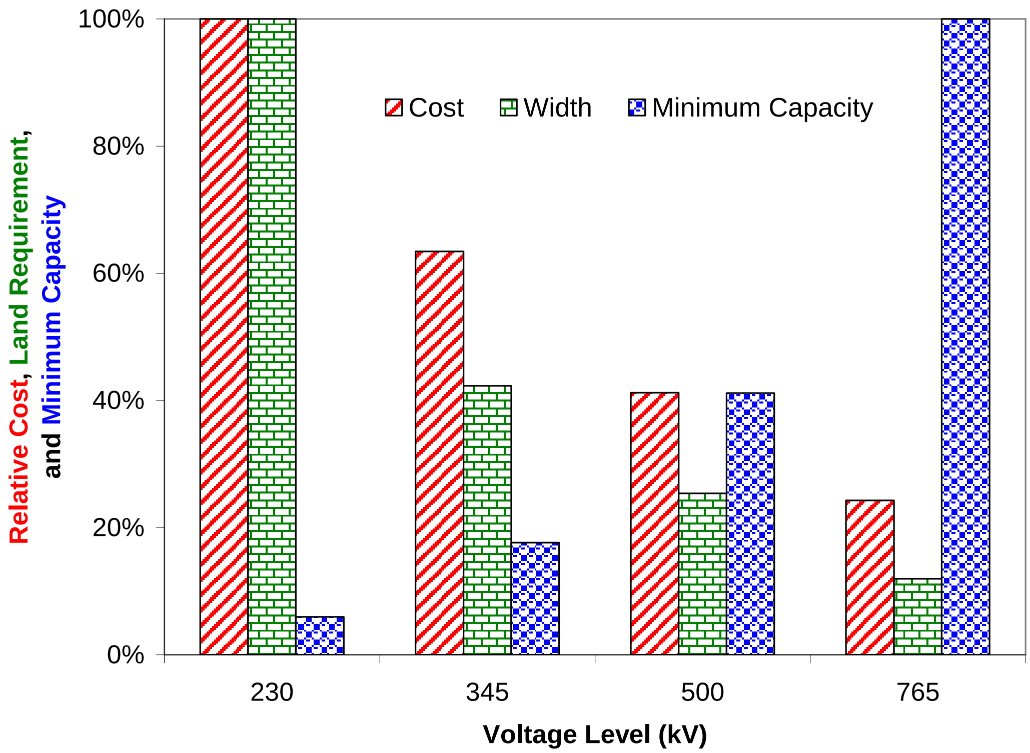

Figure 1 Transmission line relative cost and land requirements drop with increasing voltage but minimum capacity rises.

ERCOT did examine a high penetration case with 12,000 MW of wind generation. Wind curtailment due to transmission congestion was allowed to go up to 6.3%, a possibly reasonable *study* strategy early in the development of a higher voltage transmission backbone. This case required a $2.8 billion 765 kV transmission enhancement and reduced annual production costs by about $870 million. Admittedly, this is not as economically attractive as other enhancements studied but it is important to note that the numbers above compare *total* transmission costs to *annual* production cost savings. It is unrealistic to assume that the cost of transmission upgrades will be paid for in a single year, so the transmission costs must be converted to an annual number in order to make an accurate comparison. Such a comparison is provided later in this paper and clearly indicates the significant net benefit of transmission construction. This case was not included in the report or considered further because of concerns over the largest single contingency.

Summary

In summary, the methodology ERCOT used to identify CREZs and evaluate the technical requirements for and the direct cost economic viability of transmission enhancements needed to reliably integrate large incremental amounts of wind generation throughout the state is excellent for this type of scoping study. The five-year time horizon is adequate for determining the immediate transmission solutions to integrate wind resources, although a long term analysis can provide significant value to transmission planning decisions. The use of mesoscale meteorological modeling to generate time series wind speed and wind generation data is state of the art. Using a reliability constrained unit commitment and economic dispatch tool with the time series wind generation data and a year of hourly load data provides the most realistic analysis of expected system costs, electricity market behavior, and transmission system performance. Switching to a load flow analysis package facilitated good *conceptual* design of transmission enhancements. This methodology is computationally intensive but provides an especially thorough scoping study of a broad array of options.

RESULTS

The objective of the ERCOT study was to determine if, from the perspective of the transmission system, there are discrete areas of attractive wind development (other perspectives were not considered). The study determined that there are four such areas; the Gulf Coast region, the southwest region, the central-western Texas region, and the Texas Panhandle region. The study found that transmission requirements differ in each area but that transmission enhancements are both needed and economically justified in each. Economic justification was based on the societal benefit of reduced electricity production costs when compared with the cost of enhancing the transmission system. The simple and clear results of the ERCOT study are that 1) significant wind generation can be developed throughout Texas, 2) transmission enhancements are required to reliably deliver the wind generated electricity to loads, and 3) the benefits exceed the costs. Specific enhancement details will not be reviewed here as they are fully explained in the ERCOT report. Other intervenors have also submitted transmission enhancement plans. Instead, additional insights will be explored based upon the study findings. The wide geographic scope of the study coupled with the excellent methodology employing mesoscale modeling of the wind coupled with a year of load and generation data resulted in a study that sheds light on many aspects of wind generation in Texas.

General Trends

It can be difficult to gain a comprehensive view of the overall results of such a broad study. The wind characteristics and the transmission requirements differ in each region, and costs and savings are specific to each case. But some interesting trends can be seen when all of the information is grouped together. Figure 2 attempts to provide such a view of the overall results. Four important trends are shown plotted against increasing amounts of additional wind generation: transmission enhancement capital cost (*capital* – not annual), annual production cost savings, annual net generator revenue reduction, and wind energy real-time price. The wide scatter in the data points indicates that the trend lines should be used to gain insight rather than to make specific decisions about individual projects.

Annual production cost savings (purple diamonds) rise as wind is added to the power system. Fossil fuel consumption is displaced resulting in a genuine societal savings. This trend too is reasonably linear and does not show a tendency towards diminishing returns at the levels studied (i.e. up to 5 GW incremental).

Annual net generator revenues (blue circles) drop (plotted curve rises) nearly twice as fast as the production cost savings. This is the net reduction in total generator revenue; the reduction in revenue for existing generators less the increase in revenue going to the new wind generators. This is either good or bad, depending on your point of view. It is bad for generators (conventional and wind) because it reduces their profits. It is good for loads since they are the ones that pay the generators and this is the amount the aggregate load saves annually.

The capital cost of required transmission upgrades (red triangles) rises as expected when significant amounts of wind generation are added to the power system. One should not read too much into a trend line plotted through data points with such large diversity but the second order polynomial does not have much curvature indicating that there is not a dramatic trend towards requiring exponentially greater amounts of transmission as wind generation increases. It is interesting that the trend line for the *annual* customer savings (annual generator revenue reduction) is so close to the trend line for the transmission upgrades *capital* cost, implying that a single year of customer savings would typically pay for the transmission enhancements.

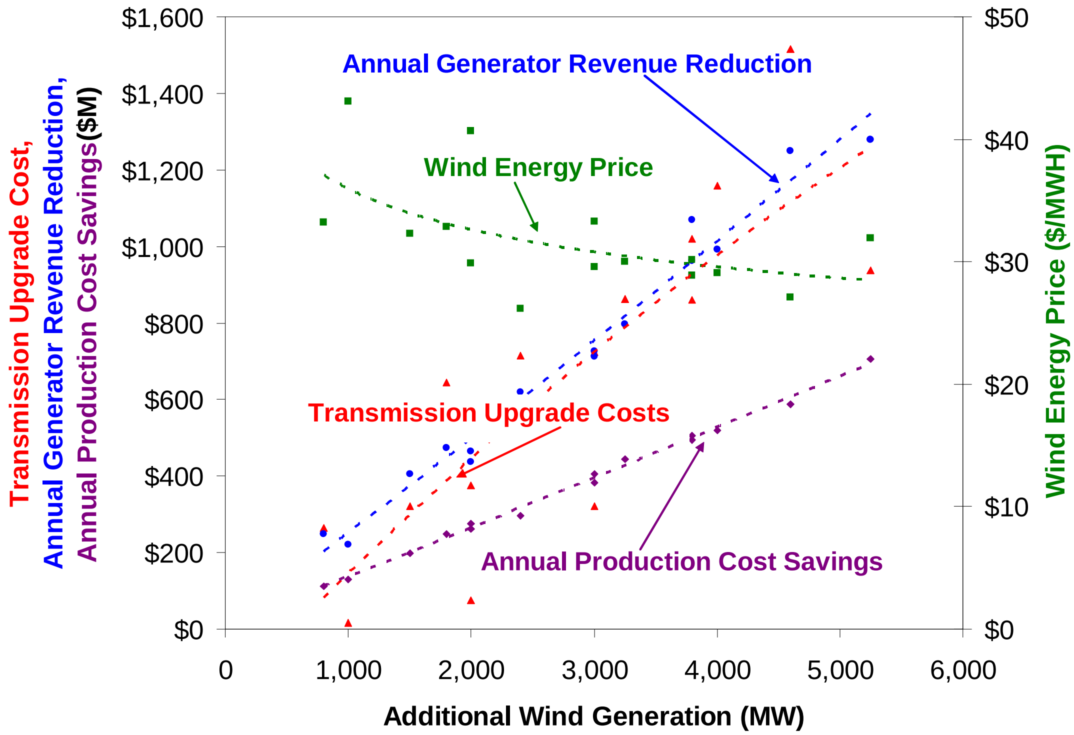

Figure 2 Adding wind generation increases transmission capital costs but reduces generation production costs. It also reduces generator revenues and the market clearing prices wind and other generators receive.

Generator revenues drop more/faster than the production costs because sufficient wind is added to do more than simply save fuel for the marginal generator. If only a small amount of wind were added then the marginal generator would reduce production, fuel would be saved at that generator, fewer MWH would be purchased at the marginal price, and the production cost savings would equal generator revenue reduction. As more wind is added in a given hour the marginal generator turns off and the next most expensive generator in the stack sets the hourly energy clearing price. This changes the price for all generators and all energy sold in the market for that hour. Consumer payments to generators dropped by $221 million to $1,278 million per year.

The impact additional wind generation has on the market price can be seen in the wind energy price curve (green squares).[3] The average price wind generation receives in the hourly energy market drops as more wind is added because wind is pushing down the market clearing price. This is good for consumers but bad for wind (and conventional generators). This amounts to a $0.60/MWH to $3.47/MWH reduction in the consumers energy price for the wind plant additions studied. Based on this analysis, the *existing* wind generators saved Texas electricity customers about $476 million in 2006 or $1.56/MWH. The 2342 MW of additional wind capacity that was assumed in the base case provides a similar consumer savings. These price reductions are additive.

Shifts in Generation

As wind generation is added to the power system other generation must back down. Which generation backs down determines what fuel, emissions, and economic savings there are. With an efficient energy market, as with a centrally optimized economic dispatch, it is the most expensive marginal unit that is reduced each hour.

Figure 3 shows the mix of generation capacity in Texas (red vertical bars), the $/MWH production cost of each technology (purple brick bars), and how the generation is utilized to produce energy (blue horizontal bars).[4] Coal and lignite account for about 21% of the generating capacity but they supply 34% of the energy due to their low fuel cost ($17/MWH production cost including fuel, variable operating and maintenance, and unit startup costs). Gas fired generation accounts for 71% of the capacity and 50% of the energy. Combined cycle units dominate the gas fired generation accounting for 41% of the total capacity and supplying 45% of the total energy ($56/MWH). Gas steam reheat units account for 23% of the capacity but only supply 2% of the energy due to their high energy cost ($73/MWH). Nuclear power accounts for 6% of the capacity but supplies 10% of the energy ($8/MWH). Wind also has a nameplate capacity equal to 6% of the total generation in the base case and supplies about 5% of the energy. Wind has no significant production cost. Capital costs are not included for any generators in this production cost analysis.

The pattern of which existing generators back down is fairly constant as more wind is added. Figure 3 shows the average effect from four cases run by ERCOT ranging from 1800 MW to 3800 MW of additional wind (green diagonal bars). Gas fired generation accounts for nearly 80% of the reduction with combined cycle units accounting for 75%. Perhaps surprisingly coal and lignite account for 21% of the reduction, apparently due to the amount of wind generation at night when there is no gas fired generation to back down. While reducing coal and lignite production does not provide as high an economic incentive as backing down gas fired generation it does have a larger impact on reducing emissions (discussed later).

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[3] Note that this discussion of electricity market prices does not reflect capital costs for any generators (wind or conventional) or any compensation generators may receive through bilateral contracts or otherwise. It only reflects the real-time electricity market price impacts during the hours when wind plants produced.
[4] Data from "ERCOT Response to Questions, Second Technical Conference, February 21, 2007"

There are two additional shifts that are worth noting. Gas fired steam reheat generators account for about 5% of the reduction as wind generation is added in spite of their already low operating time. Conversely, simple cycle combustion turbines actually increase production slightly, presumably because their flexibility is needed to respond to the wind variability and forecast errors in spite of their high operating cost ($79/MWH).

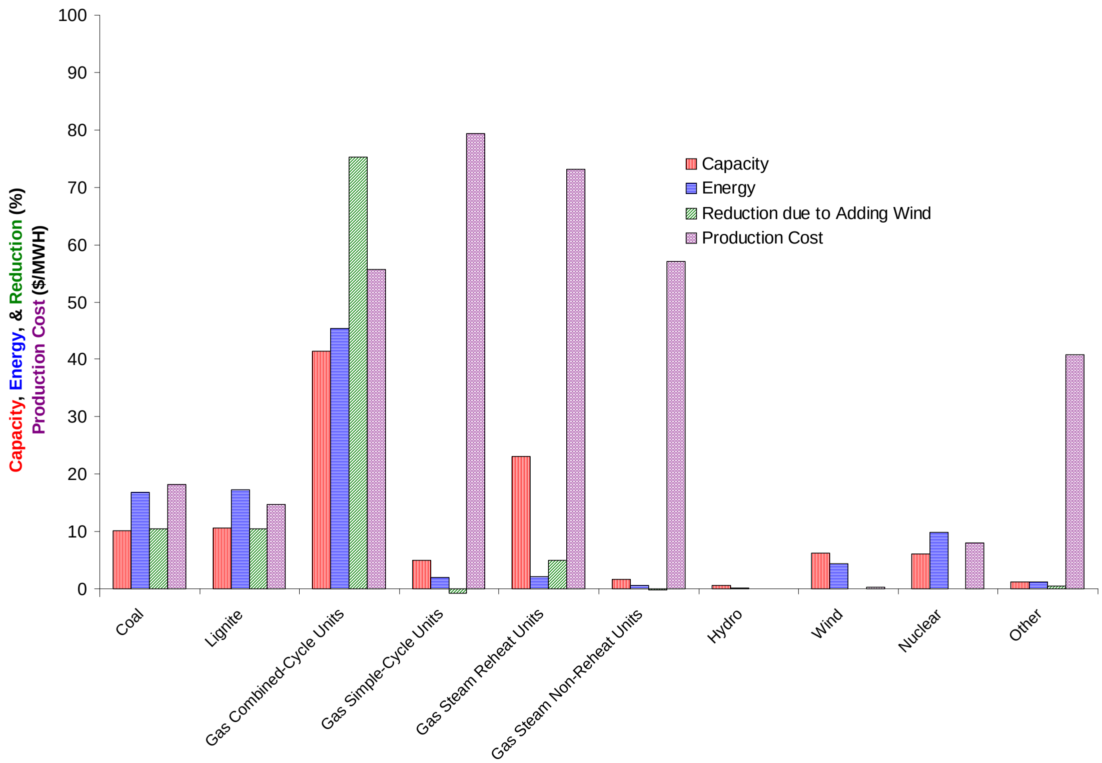

Figure 3 The generation capacity mix remains constant as wind generation is added to the power system but generation operations change.

Aggregation Benefits

Diversity in the wind resource greatly reduces integration costs by reducing the net volatility and the reserves required to respond to that volatility. Diversity was inherently included in the ERCOT analysis; that is a benefit of mesoscale modeling. Any correlations that physically exist among individual wind projects or between wind generation and load are included regardless of whether you are aware of them or not. As ERCOT notes "Model results showed reduced transmission constraints and reduced overall wind curtailment, given a specific set of transmission improvements, for combinations of similar-sized CREZs with greater overall diversity."

The large geography of Texas helps add diversity and reduce wind volatility. Figure 4 shows the correlation between wind plants drops dramatically with distance. The coastal area, for example, is 350 miles from Abilene and 500 miles from Floyd County. The hourly correlation between the coast and the rest of Texas is essentially zero. Diversity benefits will become even more apparent when the integration study is performed later this year. Diversity between zones will likely be near zero in the minute-to-minute regulation time frame and low even among some individual turbines within a single wind plant.

Transmission Enhancement Viability

ERCOT judged the transmission enhancement economic viability based upon the capital cost of the transmission enhancement judged against the annual *production cost* savings from the aggregate generation fleet that the transmission enhancement enabled based on the wind generation it facilitated. Production cost savings will be less than the reduction in market prices paid by consumers so this is a tougher test for the transmission enhancement to pass. It is reasonable, however, because the reduction in production cost represent a physical savings (reduced fuel consumption). One could argue that projects that produce only market price savings should be paid for by the ones receiving the market savings. Total required transmission project capital costs ranged $15 million to $1,515 million; 1.5% to 36% of the capital cost of the wind plants themselves.

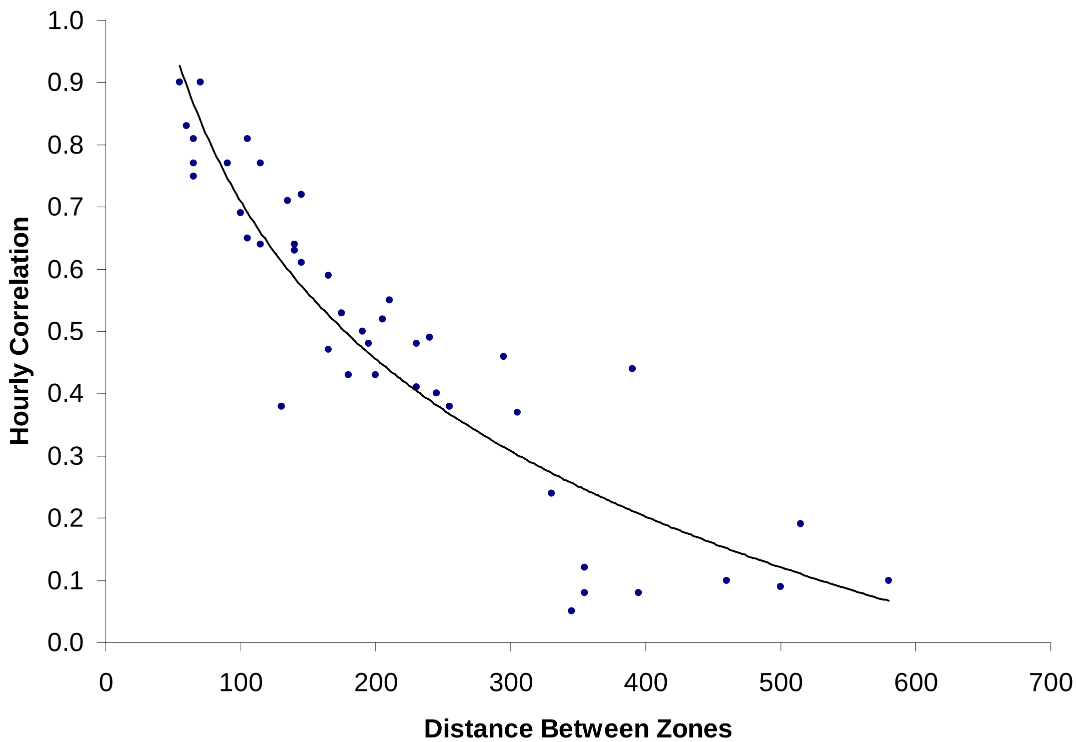

Figure 4 Wind variability hourly correlation drops dramatically with distance between wind zones.

Annual production cost savings (blue diamonds) and annual carrying cost of the associated transmission upgrades (green triangles) are shown in Figure 5. In all cases ERCOT selected transmission enhancements with annual costs that are well below the associated annual savings.

Quality of the Wind Resource

Mesoscale modeling inherently provides a great deal of detailed information concerning the wind resources that is useful apart from analyzing transmission issues. Of the 131,320 MW of wind capacity modeled 100,291 MW has a capacity factor of 35% or greater. Of that amount 33,209 MW has a capacity factor of 40% or greater.

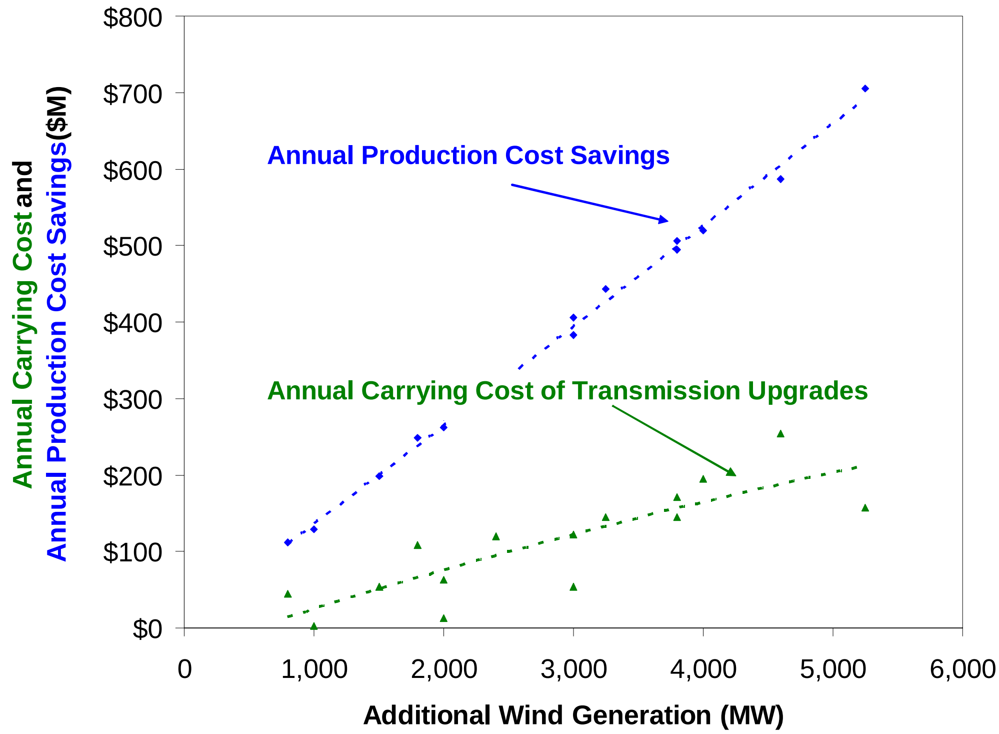

Figure 5 Transmission upgrade annual carrying costs are well below annual production cost savings indicating that the transmission projects are economically viable.

Emissions Reductions

Simulating the full unit commitment and economic dispatch process for the entire generation fleet allowed ERCOT to calculate reductions in SO_2, NO_X, and CO_2 emissions that result from each wind generation scenario. Figure 6 shows that all three emissions are significantly reduced, as expected, with increasing amounts of wind. The fact that the wind is not perfectly correlated with load and has significant output during the off peak hours is unfortunate in terms of the electricity market price when wind generates but it does result in greater emissions savings. As mentioned above, 21% of the wind energy backs down coal and lignite generation.

Reductions in other emissions (mercury, for example) were not quantified. Reductions in the amount of water consumed by the conventional generation fleet were not calculated either but represent an additional benefit.

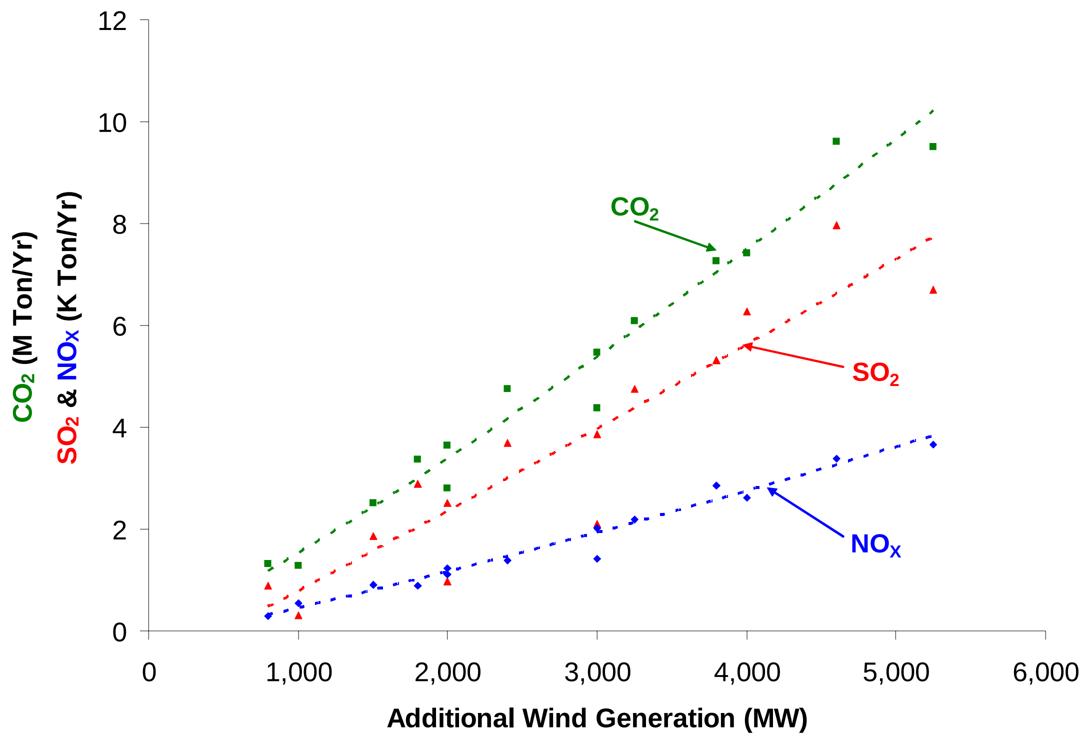

Figure 6 Adding wind significantly reduces SO2, NOX, and CO2 emissions from the conventional generation fleet.

Who Benefits Financially?

As we have seen, adding significant quantities of wind generation in Texas will necessarily result in conventional generators burning less fuel and reducing costs. The ERCOT study determined both the fuel cost savings and the shift in electricity market price assuming that all energy transacts in the hourly market. Knowing how market prices shift makes it possible to calculate how loads and wind generators split the savings. A cursory look at the structure of the hourly electricity market would indicate that wind generators, with zero-marginal-cost, could capture most of the benefits associated with displacing fuel based generation while electricity consumers would only capture savings associated with the reduction in market price, but this is too simplistic. The reality is that wind generators and electricity consumers will likely negotiate a shared savings through bilateral transactions. Wind generators have an incentive to share the savings with loads in return for financial commitments.

Hourly Electricity Market Prices

Thinking too simplistically about the ERCOT conventional generation fleet and the electricity market also leads to incorrect conclusions. Hourly electricity prices might significantly decline, and electricity customers might benefit, only if enough wind generation were added to the power system to change the *type* of conventional generator that is on the margin and setting the price. It is not enough to reduce the output of the marginal generator or even to force the marginal generator off line with this reasoning. If the hourly price is being set by a gas fired combustion turbine with a $65/MWH marginal cost that price would only decline significantly if enough wind were added that hour to displace *all* combustion turbines with a similar marginal cost. Simply displacing a single combustion turbine would only reduce the market clearing price by the efficiency difference between one combustion turbine and another.[5] Conversely, prices would decline dramatically if a coal fired thermal plant, for example, became the marginal generator. These assumptions are to simplistic, however, and understate differences between similar generator's marginal production costs.

In actuality wind *is* able to significantly impact the market price of electricity in ERCOT. The existing wind plants reduced the average energy price by about $1.56/MWH in 2006 saving Texas electricity consumers about $476 million per year. The additional 2342 MW of wind generation that was assumed in the base case for 2009 will provide a similar electricity market price reduction. The additional wind plants in the ERCOT study are expected to further reduce prices by an additional $0.60/MWH to $3.47/MWH.

In the hourly market electricity consumers only benefit to the extent that additional wind reduces the hourly energy market price. If prices remain largely unchanged then the wind generators capture most of the benefit. Alternatively, if gas is pushed off of the margin (or if a cheaper gas fired generator sets the price) then consumers capture not only the fuel savings but they also capture much of the profit that coal fired and nuclear units currently make. This is the hourly electricity market impact of adding wind that the ERCOT study determined. Because the majority of ERCOT energy does not pass through the hourly market it is worth looking at possible bilateral market impacts.

Bilateral Market Impacts

The bilateral electricity market volume is much greater than the hourly market. Customers can and do protect themselves from high and volatile hourly prices by entering into long term contracts with generators for most of their needs. Bilateral contracts benefit both parties by removing future uncertainty.

Bilateral contracts are especially attractive to wind generators. Capital costs and financing concerns dominate the wind cost structure. Long term contracts are necessary for wind developers to obtain favorable financing. Wind generators do not face volatile fuel prices and do not need to recover high gas costs through electricity prices. Wind plant owners and electricity consumers will likely share the economic benefits of saved fuel through bilateral contract negotiations. Unfortunately, from an academic point of view, bilateral contracts do not have the transparency of open markets: it is not possible to examine how savings are split based upon publicly available documents. It is clear, however, that the savings will be shared.

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[5] Adding significant amounts of wind *may* reduce electricity market prices without changing the type of generator that is on the margin by influencing the gas market. Reducing gas consumption may reduce gas prices or mitigate gas price spikes.

Wind Curtailment

The ERCOT study wisely elected not to design a transmission system that will never be congested. That would be both excessively expensive and wasteful since the last increment of transmission capacity would rarely be used. ERCOT took a reasonable approach in establishing an arbitrary allowable 2% wind curtailment for this initial scoping study. Once a pattern of wind development is established and a transmission expansion plan is selected the economically appropriate amount of congestion and wind curtailment can be determined. It is not practical to perform the detailed analysis required to definitively establish the exact level of appropriate wind curtailment when evaluating the broad range of options covered by this ERCOT study. Assuming a 2% curtailment is reasonable for this stage of the analysis.

Note that this endorsement of allowing curtailment when performing a scoping study is completely unrelated to any discussion of operating practices. Curtailment in a scoping study is a useful tool in place of having a refined transmission expansion plan. Establishing a two percent aggregate curtailment target is a good technique in this type of study to obtain an economically reasonable transmission enhancement design.

Additional Work

Though thorough and extensive the ERCOT study was essentially a scoping study. It was not intended to produce a final design or to address all considerations. Additional studies are required but these are expected to refine the design rather than to fundamentally change it. Some of these additional studies should go forward only after the locations and amounts of additional wind generation have been decided upon. Other studies, such as an evaluation of the long-term transmission needs of Texas which considers load growth and resource additions over a 20+ year timeframe, can commence immediately to maximize the benefits of right-of-way acquisition and to minimize ultimate costs to consumers.

The ERCOT study only addressed the immediate fuel-savings and electricity market benefits of adding wind power. CO_2, SO_2, and NO_X emissions were calculated, and allowance costs were included in the generator bid prices, but additional societal benefits of reduced emissions of these and other pollutants were not quantified. Reductions in water consumption at other power plants was not quantified or valued. The study did not consider the benefits of supply diversity in reducing electricity market volatility. It did not consider the strategic benefits of reducing the need for foreign fuels.[6] These benefits are legitimate concerns of the PUC and state legislature in setting energy policy. ERCOT may not be able to quantify the monetary value of each of these but studies can quantify the physical impacts which the PUC can then value.

Reactive power and voltage performance will have to be studied to determine what transmission and generation reactive power resources will be needed. Both static and dynamic reactive power requirements will have to be addressed. Similarly, the dynamic stability of the power system will have to be studied with the addition of significant

[6] Though wind power in Texas tends to displace domestic natural gas that natural gas can then displace foreign oil and/or LNG.

amounts of wind power. These technical studies will refine the transmission design, generator interconnection requirements, reserve requirements, and operating procedures.

Locations for major wind interconnection substations will have to be selected to best accommodate connecting the proposed wind projects to the power system. Work will also be required to mitigate the disproportionate curtailment of existing wind plants.

Wind Integration Study and Costs

A wind integration study is required (and has been initiated) to determine the impact additional wind generation will have on the power system's ancillary service and ramping requirements. As with the transmission enhancement study, the ancillary services study will start with the requirement that power system reliability be maintained or improved with the addition of wind power. The wind integration analysis will determine what additional amounts of additional ancillary services are required, and what the added cost will be, to deal with the variability and unpredictability of wind. These costs should be modest because of both the wind resource and the ERCOT electricity markets. Wind resources are spread over a large geographic area. Aggregating multiple wind projects reduces variability and forecast error. ERCOT's robust ancillary service and sub-hourly energy markets greatly reduce the cost of the power system's response to both wind volatility and unpredictability. For example, the 2006 Xcel-MISO wind integration study calculated operating impact costs of $2.11 to $4.41 per MWh of wind integrated when integrating 15% to 25% wind on an energy basis. [7] This compares with the 5% to 10% energy based wind integration in the current ERCOT report.

All of this work is very important; it will refine the impact and cost analysis and it is necessary to select needed transmission enhancements and complete their design. The additional work is unlikely to change the basic findings of the ERCOT Competitive Renewable Energy Zone Study, however.

[7] *Final Report - 2006 Minnesota Wind Integration Study, Volume II - Characterizing the Minnesota Wind Resource,* The Minnesota Public Utilities Commission, Mr. Ken Wolf, Reliability Administrator, November 30, 2006

CONCLUSIONS

ERCOT developed a comprehensive analysis methodology to investigate the need for transmission enhancements to reliably integrate large amounts of additional wind generation in the Texas power system. This is new wind generation in addition to the 4,850 MW of wind that is expected to be in service for the 2009 base case. They found that transmission enhancements are both needed and are economically justified in all of the identified Competitive Renewable Energy Zones. The methodology is comprehensive in that it included wind resources throughout the state. It used a full year of hourly load, wind and generation data in a reliability constrained unit commitment and economic dispatch model to provide a thorough analysis. Hourly wind generation data was developed by AWS Truewind through mesoscale modeling. The mesoscale wind modeling captures the diversity and correlations between the various wind sites and the load.

Running a year of data through the reliability constrained unit commitment and economic dispatch model, evaluating the full range of contingencies, identified transmission constraints for each level of wind modeled. Wisely ERCOT did not elect to eliminate all congestion in the scoping study but instead established a 2% curtailment criteria for wind generation. When transmission constraints were identified, system planners developed enhancement plans to mitigate the congestion. The cost of the transmission enhancements was compared with the production cost savings which the wind generation enabled. Production cost savings (primarily fuel savings) were used to evaluate transmission enhancements rather than electricity market price savings.

Use of the mesoscale wind modeling and the reliability constrained unit commitment and economic dispatch produced a wealth of additional insights into the costs and benefits of significantly increasing wind generation in Texas:

- Economic Interactions: transmission enhancement costs, annual net generator operating cost reductions, annual net generator revenue reductions (and customer savings), electricity market price reductions were all determined as a function of the amount of wind generation that was added.
- Generation Reduction Impacts: As expected it is primarily gas fired generation that is displaced as wind generation increases. Reductions in lignite and coal generation account for 21% of the reduction. While this reduces the wind generation revenue (because the price of lignite and coal is well below the price of gas) it increases the emissions savings.
- Wind Diversity and Distance: this type of modeling inherently values diversity in the wind resource. Production costs, energy prices, and transmission congestion are all lower with a diverse wind resource. The modeling inherently captures the benefit.
- Emissions: Emissions are easily calculated since the hourly output of each generator is known for the year.
- Curtailment: not surprisingly curtailments fall disproportionately on the existing generators because they are connected at the lower voltages of the existing

transmission system. Several fixes are available to address this untenable result. Appropriate solutions will have to be identified and developed or each individual situation. Still, this should not represent a significant overall cost or change the basic conclusions of the study.

- Additional Work: The ERCOT CREZ study was fundamentally a scoping study. Much additional work is required to identify the wind sites to develop, to design the wind interconnection points, to perform detailed transmission enhancement designs, to identify and address any stability or dynamic voltage problems, to quantify societal benefits, and to perform a wind integration study to identify ancillary service costs and ramping needs. Further analysis of the long-term transmission needs of Texas can also result in better decisions than series of short-term analyses that lower immediate costs but can result in a suboptimal and ultimately more expensive transmission system.

The ERCOT study provided far more information than simply determining if transmission enhancements are economically justified and identifying competitive renewable energy zones though those goals were met too.