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Modeling and Analysis of Wholesale Electricity Market Design: Understanding the Missing Money Problem

December 2013 — January 2015

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ECCO International, Inc.
San Francisco, California

NREL Technical Monitor: Kara Clark

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Subcontract Report
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May 2015

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List of Acronyms

AC	alternating current
DC	direct current
ERCOT	Electric Reliability Council of Texas
LMP	locational marginal price
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
VG	variable generation

Executive Summary

The National Renewable Energy Laboratory (NREL) has an interest in advancing the understanding of bulk power wholesale electricity market design issues related to capacity and flexibility in systems that have large amounts of variable generation (VG), mainly wind. NREL commissioned ECCO International, Inc. (ECCO), to study how high penetrations of VG will affect the outcomes of markets and incentives of the various pieces of the wholesale structure (energy, ancillary services, settlements, forward capacity) and what, if any, market design changes can improve incentives to ensure long-term power system reliability and efficiency.

This project examined the impact of renewable energy sources, which have zero incremental energy costs, on the sustainability of conventional generation. This "missing money" problem refers to market outcomes in which infra-marginal energy revenues in excess of operations and maintenance (O&M) costs are systematically lower than the amortized costs of new entry for a marginal generator. The problem is caused by two related factors: (1) conventional generation is dispatched less, and (2) the price that conventional generation receives for its energy is lower. This lower revenue stream may not be sufficient to cover both the variable and fixed costs of conventional generation. In fact, this study showed that higher wind penetrations in the Electric Reliability Council of Texas (ERCOT) system could cause many conventional generators to become uneconomic.

For continuity, all generator costs used in this paper were obtained from the 2013 U.S. Energy Information Administration report titled *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*. This ensured consistent data. Also, the current ERCOT fleet was constructed throughout many decades, which makes it difficult to compare capital costs, and therefore these results indicate the costs that could be expected if the ERCOT fleet were replaced with new generators of the same type but using the latest advances and technologies.

Two cases were examined: (1) the base case, in which 13% of the energy was met with wind; and (2) the high wind case, in which 30% of the energy was met with wind. An additional 2.2% of the load in the high wind case could have been met with wind, but the energy was curtailed because of network congestion.

Generation was impacted by higher wind production in the following ways:

- Conventional (nuclear, coal, gas) generation was most negatively impacted.
    - These units had dramatically reduced energy production, hours on, total revenue, and total profit.
    - Conventional generation cleared more spinning reserve, but this is because it produced less energy. This was offset, however, by the large spinning reserve ancillary service price drop in the high wind case, from $8.71/MWh to $4.33/MWh.
- Overall system-wide generator fixed costs increased, because additional wind generators were being built and maintained.
    - Overall fixed O&M costs rose from $2.4 billion to $3.2 billion.

    - Similarly, overall levelized capital costs rose from $1.2 billion to $1.5 billion per year.
- Overall system-wide generator variable costs dropped because of the reduced production from conventional generators.
    - Total system fuel costs dropped from $9.5 billion to $7.6 billion.
    - Overall variable O&M costs dropped from $1.4 billion to $1.1 billion.
- The largest impact was on overall system-wide generator revenues and profits.
    - Total system-wide revenue dropped from $16.8 billion to $11.4 billion because of the lower locational marginal prices (LMPs) and ancillary service prices.
    - Total system profit (revenue – costs) dropped from $2.2 billion to -$2.2 billion, a reduction of $4.4 billion.
    - Wind generator revenue increased marginally, from $1.74 billion to $1.82 billion, because of the depressed energy prices. With higher fixed costs, even wind generation lost money in the market in the high wind case. Note that this study did not consider production tax credits or other non-market incentives received by wind generators.
    - The magnitude of the generator revenues and profits depends on the market structure. The prevailing market design is based on the marginal cost of production, and therefore it will be significantly impacted by the addition of resources that do not have incremental fuel costs.
    - Note that conventional generation capacity in the high wind case was not adjusted. Economic theory is clear that additional generating capacity (wind or conventional) will lower prices and revenues. Further studies could examine the impact of a more optimal generation fleet, in which excess generating capacity would be minimized.
    - The observed levels of congestion and curtailment in the high wind case in this study are plausible and should not have an unreasonable impact on the missing money problem. If all congestion and curtailment were eliminated, this would add (on average) slightly more than 1,000 MW of wind generation each hour. This would incrementally depress the average prices, revenues, and profits, but it would not materially change the primary findings. In other words, if additional transmission upgrades materialized, they would reduce the congestion component of the LMP prices and thus somewhat reduce in relative terms the LMP prices and slightly magnify the missing money problem.

This study quantified the impact of increased wind production on conventional generation in the ERCOT system. This missing money in organized electricity markets has the potential to inhibit new construction of conventional generation, which may in turn lead to a less reliable electric power system.

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1 Introduction

The National Renewable Energy Laboratory (NREL) retained ECCO International, Inc. (ECCO), to analyze the "missing money" problem in wholesale energy markets arising from the substantial penetration of variable generation (VG) such as renewable energy resources, especially wind, into the energy mix. *Missing money* refers to market outcomes in which infra-marginal energy revenues in excess of operations and maintenance (O&M) costs are systematically lower than the amortized costs of new entry for a marginal generator. The purpose of this project was to study the impact of wind on the long-term revenue adequacy problem of independent system operator markets and the long-term incentives of resources that are needed to provide capacity and flexibility to the electric power system. A related objective was to propose a set of wholesale market design changes to ensure that revenue adequacy is addressed. NREL actively analyzes bulk power system wholesale market design and performance in the presence of large amounts of wind and solar generation. This work complements and expands upon these efforts.

Wind and solar generation have several characteristics that uniquely impact wholesale power markets. These resources increase the variability and uncertainty on the power system, which requires additional flexibility. The combination of variability, uncertainty, and the near-zero variable cost of renewable energy sources may result in generally lower but more volatile energy prices, higher ancillary service prices, and, depending on the market design, higher forward capacity prices. There is significant interest in the extent to which these changes will impact particular market designs and what, if any, market design modifications will be required to achieve the desired reliable and efficient power system operations.

For this study, ECCO applied its advanced proprietary energy simulation software platform ProMaxLT to the Electric Reliability Council of Texas (ERCOT) market to quantify the missing money problem. Based on prior work, it seems that wholesale energy-only markets may not provide sufficient revenue and certainty to support the new investments in generating capacity necessary to produce the required levels of resource adequacy and reliability. We examined and quantified the extent of this issue at various high levels of VG penetrations. This report provides analytical results about the potential outcomes on profit and revenue of different technologies for the ERCOT market. In addition, it presents quantitative results on the extent to which current market designs provide the opportunity for generating resources to recover both fixed and variable costs and can continue to incentivize resources to contribute to long-term system reliability.

2 Missing Money Problem

2.1 Overview

To analyze the impact of VG, such as wind, on long-term revenue adequacy and the long-term incentives of resources that are needed to provide capacity and flexibility to the electric power system, we focused on a high-penetration renewable supply scenario to illustrate how revenue may or may not achieve adequacy based on the supply mix under current market rules. We defined a base case study and a set of changes with predetermined penetration levels of intermittent supply using the unique software platform ProMaxLT to deploy a full and detailed network model of ERCOT.

VG increases the variability and uncertainty of the electric power system, reduces spot energy prices, and therefore exacerbates the capacity assurance problem.

2.2 Impact of VG

The electricity network can be generally divided into two subsystems: (1) the transmission (or bulk) system and (2) the distribution system. These networks are predominantly distinguished by different voltage levels. The transmission system primarily delivers electricity generated at central stations to locations close to load centers. In North America, the transmission system usually operates at voltage levels from 69 kV to 765 kV, and it is highly interconnected. The transmission system also has significant levels of monitoring, automation, and control.

The distribution system delivers electricity from transmission substations stepped down to lower voltages to customers. The distribution system typically operates at voltage levels ranging from 69 kV to 120 V. It is predominantly radial in structure, and it does not have the same level of automation as the transmission system, although this is changing with the onset of many "smart-grid" initiatives.

The introduction of VG can modify or exacerbate resource adequacy and revenue sufficiency in electric power systems. First, it is important to understand that VG's contribution to resource adequacy is very different than that of conventional generation. Although forced outage rates of an entire collection of wind turbines or photovoltaic cells are very rare and not likely to significantly contribute to their unavailability, these resources can be quite variable because of changing weather patterns. Thus, VG increases the amount of variability and uncertainty on power systems, which can therefore require an increased need for flexibility. Although certain changes to short-term energy and ancillary service markets may be needed to ensure that the flexibility that is available is provided, these changes may not guarantee that sufficient flexibility is built or available in the first place. This could lead to the need for new ways to perform resource adequacy evaluations. Finally, the costs of VG are almost entirely fixed capital costs rather than variable operating costs. This can bring energy prices down while potentially increasing (or keeping constant) the total variable and fixed costs in the power system. This could lead to further reliance on markets or incentives other than the energy market to ensure that the resources needed for long-term reliability can recover both variable and fixed capital costs—i.e., the need for capacity markets and revenues increases.

Actual experience with operational markets with high penetrations of VG and renewable energy sources indicates that the low marginal costs of these resources substantially decrease market prices and thus reduce the revenue of all suppliers in the energy market. This may add to revenue insufficiency and prevent suppliers from recovering variable and fixed costs. In addition to reducing electricity prices, VG displaces other resources via the merit-order effect, such that capacity factors for other generator types are also reduced. The question is how to ensure revenue sufficiency based on the combination of lower energy prices and lower capacity factors of existing plants. It may be possible that although the majority of prices are being depressed the occasional high-price spikes will increase and help to capture needed revenue. However, this may depend on price caps, market mitigation procedures, and the levels of administratively set scarcity pricing. Finally, the existence and design of forward capacity markets can have a large impact on the level of revenue sufficiency.

In part, this study examined whether there is any measurable impact by VG on the existing missing money problem and, if so, attempted to quantify how much. Wind and solar are two key VG resources that can clearly have a major impact on the missing money problem.

Wind power plants are typically located in areas where wind resources are plentiful and can satisfy certain requirements. Most onshore wind power plants are located in rural areas where the transmission system voltages typically range from 69 kV to 161 kV. The nominal terminal voltages at the wind turbines range from 575 V to 4,160 V, depending on the turbine ratings. The unit transformer at each wind turbine steps up the voltage and feeds power into a collector system that operates at voltages ranging from 12.5 kV to 34.5 kV. The high-side node of the collector system is then connected to the main substation transformer for the wind power plant, which again steps up the voltage to the desired level and connects the wind power plant to the transmission system in the geographical vicinity.

Distributed photovoltaic resources that have inverters produce alternating current (AC) output at the desired voltage. In residential neighborhoods, these connect the residences directly to the utility supply point. Utilities around the country have established standards for these connections to minimize the significant safety risks of the bidirectional flow in existing residential supply circuits if the customer sells power back to the utility. Commercial or utility-scale photovoltaic units have similar interconnection requirements. In most instances, however, they interconnect with the distribution system at slightly higher voltage levels than residential photovoltaic units, depending on their location and ratings.

Central solar thermal resources, on the other hand, have significantly higher ratings and connect to the transmission grid at high voltage levels ranging from 230 kV to 345 kV.

The increased penetration of renewable energy sources is beginning to significantly alter the traditional approach to operation and unit commitment processes. The variability of renewable resources requires measures to accommodate fast generation changes (e.g., from a few seconds to hours during transition periods) and account for sufficient commitment and dispatch of ancillary services to guarantee the reliability of the system in the event that a renewable resource suddenly becomes unavailable—for example, when the wind lightens or stops altogether or previously unanticipated cloud cover appears and significantly reduces photovoltaic output.[1]

To manage the uncertainty of these resources while making use of their many positive attributes, independent system operators around the world are making changes to their energy and ancillary service markets. At the same time, operators are adjusting to the new realities and becoming adept at monitoring and forecasting weather pattern changes.

[1] See https://www.nae.edu/Publications/Bridge/TheElectricityGrid/18587.aspx.

3 Study Description

The following specific tasks were executed during the course of this project.

ECCO prepared base case models for the year 2016 according to ERCOT data available through their planning Web site.[2] It included generation and load data, detailed transmission data, and renewable energy source generation data. As required, these models were augmented with planned changes to the transmission system to match the corresponding study year.

ECCO ran the representative base case and then the change case that contained the generation updates as identified for the renewable assets modeled and agreed to by NREL, as follows:

- Case-1—Base case year
- Case-2—Change case year with 30% penetration of renewables

In addition, ECCO analyzed critical data that assisted in leading to a more "fact-based" solution for consideration, including the

- ERCOT generation mix by type and age of the generation facilities
- Types of generation suppliers present in the ERCOT market
- Expected growth in load by type and category
- Expected near-term and long-term weather conditions
- Current volume of renewable resources by type and storage technologies by type that are online and planned in the near term and long term
- Houston Ship Channel Index natural gas prices since the inception of the Nodal market
- Historical bid prices from the ERCOT market for all plant types, including wind
- Real-time and day-ahead LMPs since the inception of the nodal market at all ERCOT generation nodes.

To determine the extent of the missing money, we conducted a counterfactual simulation of unit commitment and real-time dispatch that dispatched a generic unit at each of the generation nodes against the historical day-ahead and real-time LMP at that node under the assumption that the unit offered its supply at true marginal cost and, if dispatched, was paid the LMP. The marginal cost was calculated by assuming a specific heat rate and fuel cost set to the Houston Ship Channel Index natural gas price at the time the power was supplied. The annual net income to the generic unit was calculated as a function of heat rate ranging from 7,000 Btu/kWh to 22,000 Btu/kWh in increments of 1,000 Btu/kWh. Start-up and no-load costs were assumed based on industry averages using Energy Information Administration data. These costs were incorporated into the simulation along with a daily make-whole assumption, which reflected ERCOT market rules. The objective of this simulation was to determine the threshold heat rate, if any, at which a unit's net

[2] See http://www.ercot.com/gridinfo/planning/index.html. As of November 15, 2014 the Planning and Operation Information (POI) website has been retired with its content moved to the Market Information System (MIS). See http://www.ercot.com/content/meetings/rpg/keydocs/2014/0819/POI_to_MIS_Transition.ppt.

income (under truthful bidding assumptions) would cover the annual costs of new entry, which would then be determined based on data from the Energy Information Administration.

The above simulation studies were repeated under a variety of assumptions regarding load growth, renewable penetration, demand response policies, and variation in LMP patterns as a result of transmission expansion, and the results were analyzed.

3.1 Input Data

The following information was obtained from ERCOT's planning website.[3]

1. The hourly load forecasts were obtained from http://planning.ercot.com/content/25446.[4] These were scaled for consistency with more recent annual load forecasts.
2. The network models and contingency constraints were obtained from http://planning.ercot.com/content/28448.[5]
3. The bids were obtained directly from ERCOT via a disclosure request. The real-time bids were used in the market simulations, but the day-ahead bids included in the disclosure were co-optimized with the financial transmission rights market and not suitable for this type of simulation.
4. The unit outage state was also obtained via the disclosure.

3.2 Input Data for the High Wind Case

For the study, we assumed that all wind power plants would bid with negative prices.

Wind profiles for new wind power plants in the high wind case were obtained by using NREL's Wind Toolkit.[6] These wind power plants were located in zones according to the latitude and longitude of the facilities provided. The generation profiles were then assigned to 345-kV buses in each zone, as described below and summarized in Table 1.

1. The buses were chosen so that there would be sufficient local network capability to handle their full output without local congestion.
2. Explicit plant sizes were not imposed on these wind power plants, because the maximum values used in the simulations were downloaded from the tool kit.
3. The network model in the high wind case was augmented with planned network additions to accommodate wind resources according to ERCOT's *Panhandle Renewable Energy Zone (PREZ) Study Report* (2014).
4. The Panhandle stability limit was set to 7,500 MW in the high wind case.
5. Per the Panhandle report, additional 345-kV lines were added to the following locations:
    A. Oklaunion-Bowman
    B. Ogallala–Long Draw
    C. Windmill–Edith Clarke

[3] Please refer to footnote 1 on page 5.
[4] Please refer to footnote 1 on page 5.
[5] Please refer to footnote 1 on page 5.
[6] See http://developer.nrel.gov/docs/wind/wind-toolkit-extract/.

D. Gray-Riley
E. Houston Import Project—a double-circuit 345-kV line from Limestone–Gibbons Creek–Zenith
F. Jacksboro–South Clay line—a line being upgraded and reconductored to relieve congestion caused by the competitive renewable energy zone projects.

Table 1. New Wind Power Plant Profiles

Wind Power Plant	Bus	Factor	Bus	Factor	Bus	Factor	Bus	Factor	Bus	Factor
NORTH Wind	79500 Abilates	0.2	79505 Pan-handle Wind	0.2	79000 Gray	0.2	79503 Tule Canyon	0.2	79502 Windmill	0.2
FAR_ WEST Wind	1058 Longshore	0.25	59900 Longdraw	0.25	11406 Central Buff	0.25	59905 Faraday	0.25		
WEST Wind	1030 Morgan Creek	1	0	0	0	0	0	0		

Figure 1 shows the transmission network upgrades.

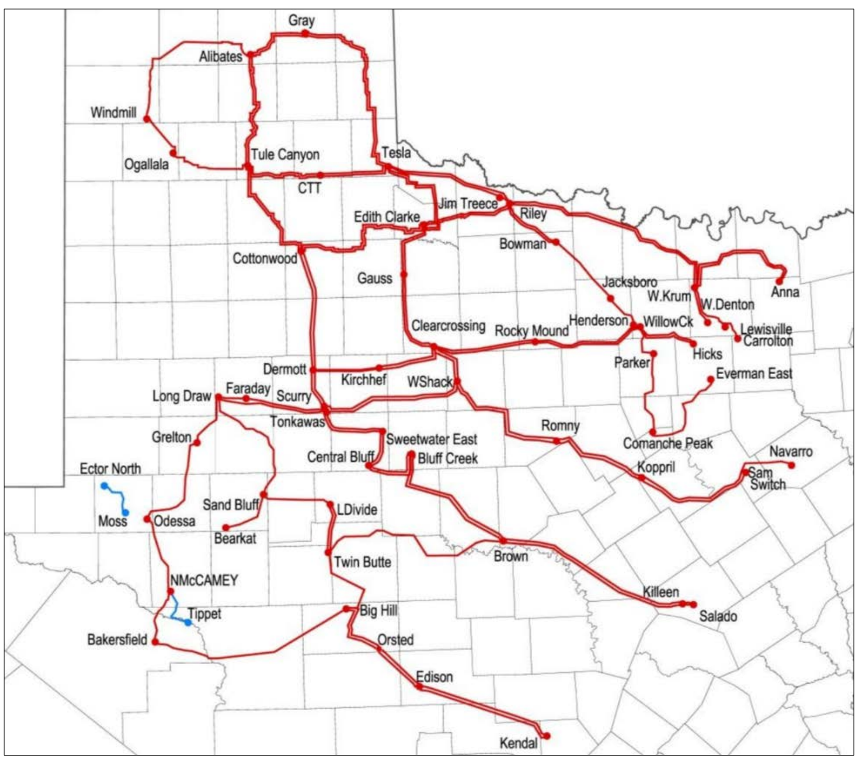

Figure 1. ERCOT transmission network upgrades[7]

[7] See http://www.ercot.com/content/news/presentations/2014/2013%20Constraints%20and%20Needs%20Report.pdf, map on page 23.

The study also included data for plant costs from the Energy Information Administration.[8]

Table 2. Costs Used in the Modeling

Resource Type	Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Capital Cost Levelized ($/kW-yr)
Biomass	50	13,500	$4,114.00	$105.63	$5.26	$318.42
Combined Cycle	620	7,050	$917.00	$13.17	$3.60	$70.98
Combustion Turbine Gas	85	10,850	$973.00	$7.34	$15.45	$75.31
Hydro	500	n/a	$2,936.00	$14.13	$0.00	$227.25
Internal Combustion Gas	85	10,850	$973.00	$7.34	$15.45	$75.31
Nuclear	2,234	n/a	$5,530.00	$93.28	$2.14	$428.02
Solar	150	n/a	$3,873.00	$24.69	$0.00	$299.77
Steam Turbine Coal	650	8,800	$3,246.00	$37.80	$4.47	$251.24
Steam Turbine Gas	620	7,050	$917.00	$13.17	$3.60	$70.98
Storage	250	n/a	$5,288.00	$18.00	$0.00	$409.29
Tie	n/a	n/a	n/a	n/a	n/a	n/a
Wind	100	n/a	$2,213.00	$39.55	$0.00	$171.29

[8] See http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf, page 6.

4 Modeling Approach

4.1 Simulation Model

ECCO used its proprietary energy market simulation software package ProMaxLT[9] to perform the modeling and simulation runs for these studies.

ECCO's ProMaxLT software platform was developed during the course of the last 10 years. It deploys a mixed integer programming–based security constrained unit commitment and an advanced linear programming–based security constrained economic dispatch with a full and detailed transmission network model. The transmission model can have either AC or direct current (DC) power flow, which iterates with the mixed integer programming commitment and dispatch engine to explicitly represent the network constraints and calculate meaningful shadow prices from the dual variables of the binding constraints. Contingency constraints are explicitly enforced using sensitivities derived from the network impedance matrices so that tens of thousands of contingencies can be enforced in the dispatch and their corresponding shadow prices can be calculated.

ECCO used the ProMaxLT day-ahead market simulation platform to compute hourly LMPs for the study scenarios using a full mixed integer programming formulation iterating with the DC power flow in the same manner as performed by the ERCOT day-ahead market clearing process. All transmission constraints were enforced so that curtailment of wind and other plants would occur when insufficient network capacity was available.

4.2 Wind Power Plant Model

Wind power plants were modeled as variable plants with zero start-up costs and negative bid prices. Minimum up and down times were not enforced. Hourly wind profiles for the existing plants were obtained from ERCOT's expansion wind data.[10]

NREL's Wind Toolkit was deployed to create the wind profiles in the high wind case according to the following process:

1. Each potential plant was allocated to a particular ERCOT weather zone according to its latitudinal and longitudinal coordinates.
2. The wind power plants were sorted in descending order of average production.
3. Hourly wind profiles were read for each plant until the desired 30% energy production targets were met.
4. The MW value from the Wind Toolkit was used as the maximum limit for each plant for each interval. These plants were allowed to vary between zero and the maximum obtained from the profile with a bid price of -$25/MWh. This bid price was the most commonly used setting for wind generators with the production tax credit (PTC). Wind power plants were not allowed to participate in the ancillary services market.

[9]See http://www.eccointl.com/our-services/reliability-assessment-studies.html.
[10] See
http://www.ercot.com/content/committees/other/lts/keydocs/2013/expansion_wind_unit_data_used_in_LTS.xls.

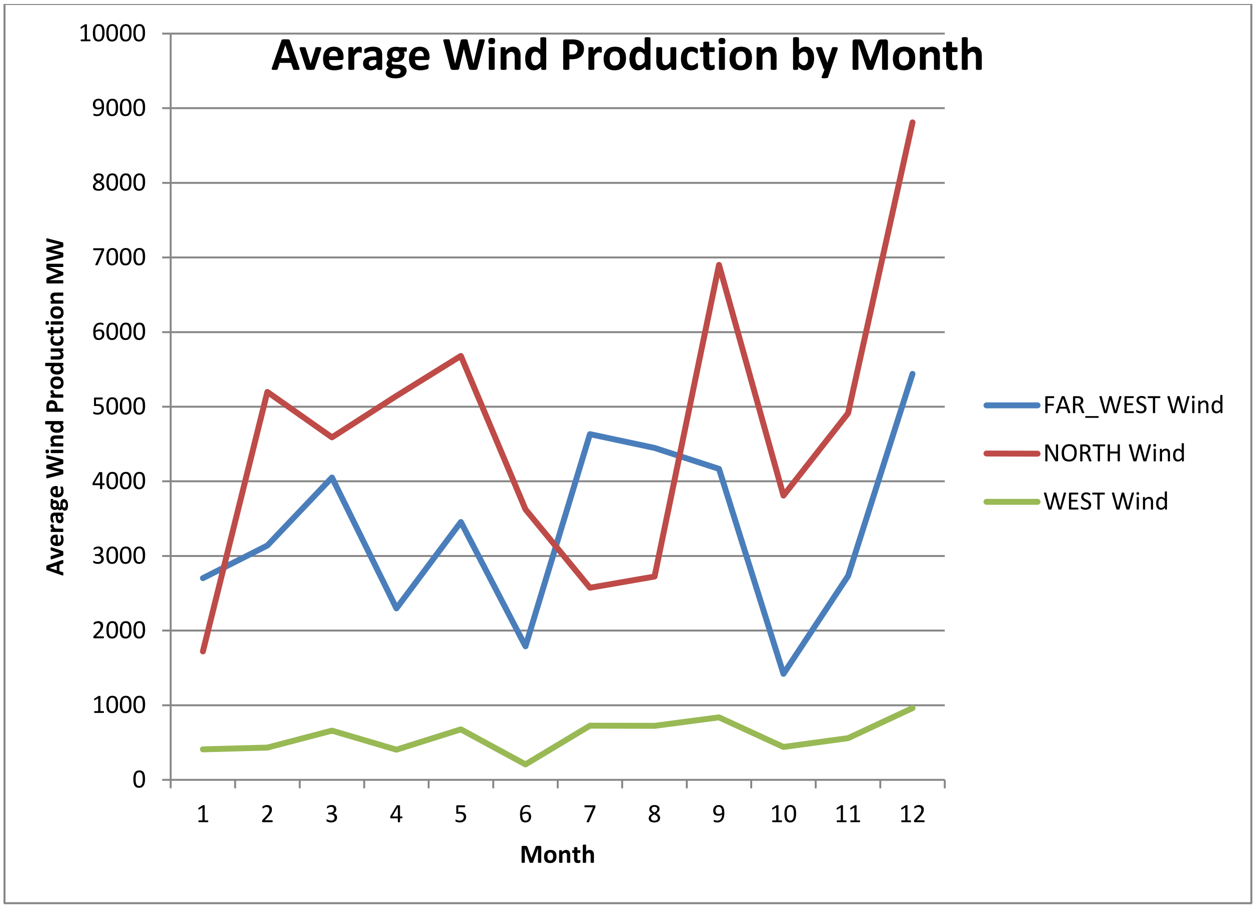

Figure 2. Average monthly wind production profile used in the high wind case

5 Benchmarking

The benchmarking process is fairly standard across industries. The objective is to calibrate and validate software models by deploying past data and then use the calibrated software to execute various studies. In this project, the objective was to be able to reliably and accurately calculate LMPs for the ERCOT energy market using actual past prices.

Toward that end, ECCO collected the data required, including the published LMP data from ERCOT market runs along with historical bids and publicly available offer data. Based on past experience, the bidding process of market participants can be simulated in two ways:

1. Use marginal-based bids and offers (heat rate times spot fuel price) for the generating units participating in the market.
2. Use historical bids and publicly available offers.

In most markets, it has been our observation that participants do not bid marginal-based offers; however, we needed to verify whether this is valid for ERCOT. Thus, ECCO executed the first option, and if the results were not acceptable, ECCO executed the second option as well.

5.1 Description

Prior to performing the analysis, benchmarking was performed to ensure that the results provided a realistic and plausible simulation of nodal prices in the ERCOT market. Actual historical 2013 loads were used with real-time bids and unit outage statuses obtained via the public disclosure process.

The primary measure of the benchmarking exercise is the cleared hub prices for the simulated and actual cases. A complete 8,760-hour simulation was performed for all of 2013 using actual loads and real-time bids downloaded from the ERCOT Web site. Benchmarking was performed by comparing the simulated hub prices to the historical hub prices provided on the site.

5.2 Issues

The benchmarking process using the first option (i.e., heat rate times fuel price and heuristically generated outage schedules) did not yield sufficiently accurate comparisons between the simulated and actual results. We believe these differences were because of the following:

1. As expected, based on a review of actual bid and offer data for the ERCOT day-ahead market, it was observed that ERCOT market participants do not normally bid on heat rate times the spot fuel price. Market participants typically have long-term fuel supply contracts that dictate the prices they would pay for fuel, and therefore their bidding behavior is not always driven by the spot fuel price. The terms of these fuel supply contracts are generally confidential. This observation is consistent with our conclusions about other markets.
2. ERCOT market participants can utilize bilateral contracts with load-serving entities that govern the actual price paid for energy. These market participants often bid lower prices to make sure that their contract position clears.

3. Unit outage schedules can substantially influence simulated prices. If historical outage schedules are not available, then these schedules need to be generated manually or by some other automated heuristic process. In benchmarking, this can lead to substantial differences between the simulated and actual prices.

5.3 Adjustments

To address these difficulties with price benchmarking, ECCO executed the second option. Toward that end, actual historical bids and offers and associated outage schedules were obtained via a disclosure request to ERCOT, which provided the entire set of 2013 real-time and day-ahead bids and outage schedules. These data were used in the simulations in this study.

ECCO deployed the available historic bids and offers and mapped them through reverse engineering onto the ERCOT transmission grid and backcasted the ERCOT market runs to predict and match the resulting LMPs to the actual published LMPs.

5.4 Sample Results

The sections below provide samples illustrating the results obtained during the benchmarking process using the second option.

5.4.1 Price Duration Curves

Figure 3 illustrates the results of the benchmarking calculations for the West hub prices as a price duration curve. This graph is a cumulative probability distribution of the simulated and historical hub prices.

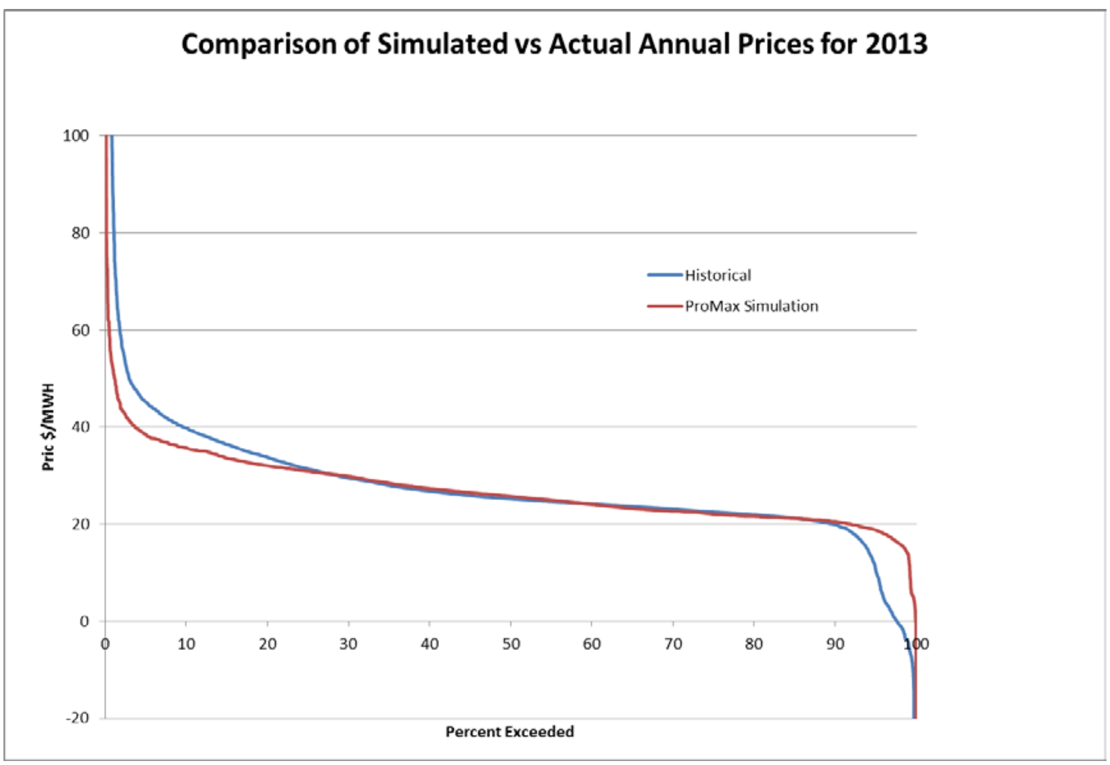

Figure 3. Comparison of annual price duration curves

5.4.2 Hourly Price Comparisons

In addition to the price duration curves, a comparison was performed of ERCOT hub prices to the actual real-time prices recorded in the market for selected days that were simulated. The purpose of this comparison was to ensure that the simulation results for the ERCOT hub prices were within an acceptable tolerance of the historical values of the ERCOT hub prices.

Figure 4 through Figure 7 show both the historical price curves and the simulation results for the major hub prices.

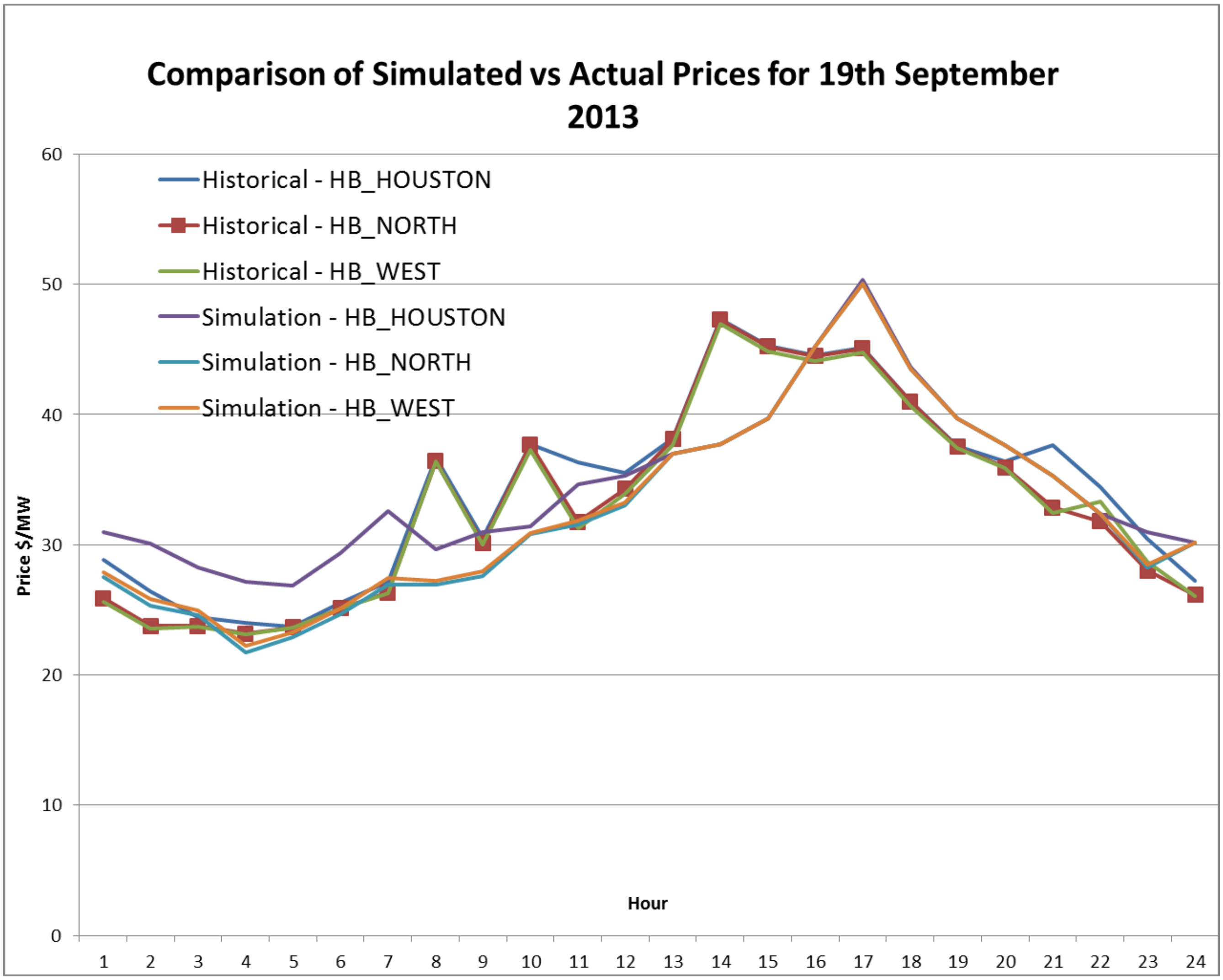

Figure 4. Comparison of simulated prices to actual prices for September 19, 2013

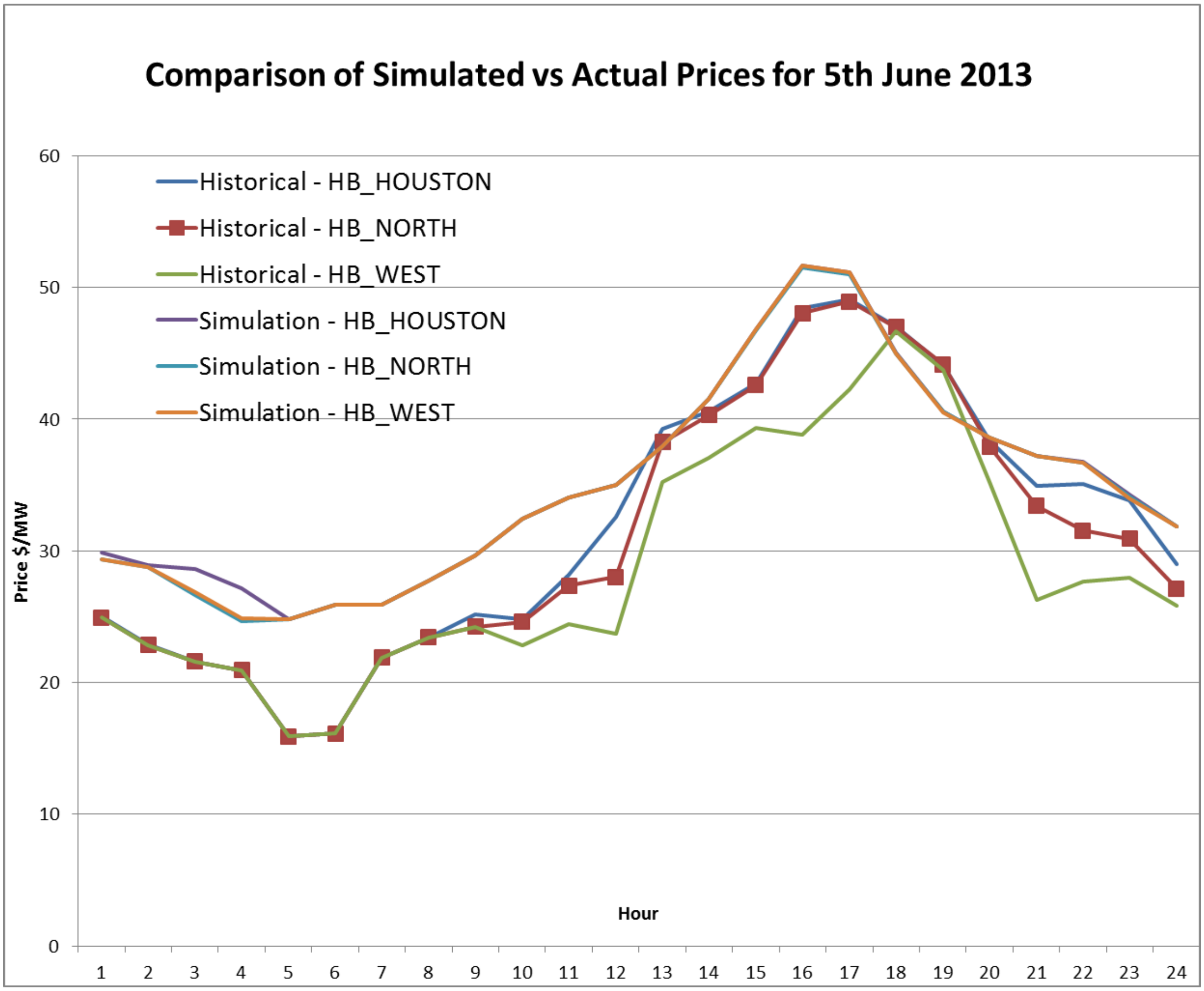

Figure 5. Comparison of simulated prices to historical prices for June 5, 2013

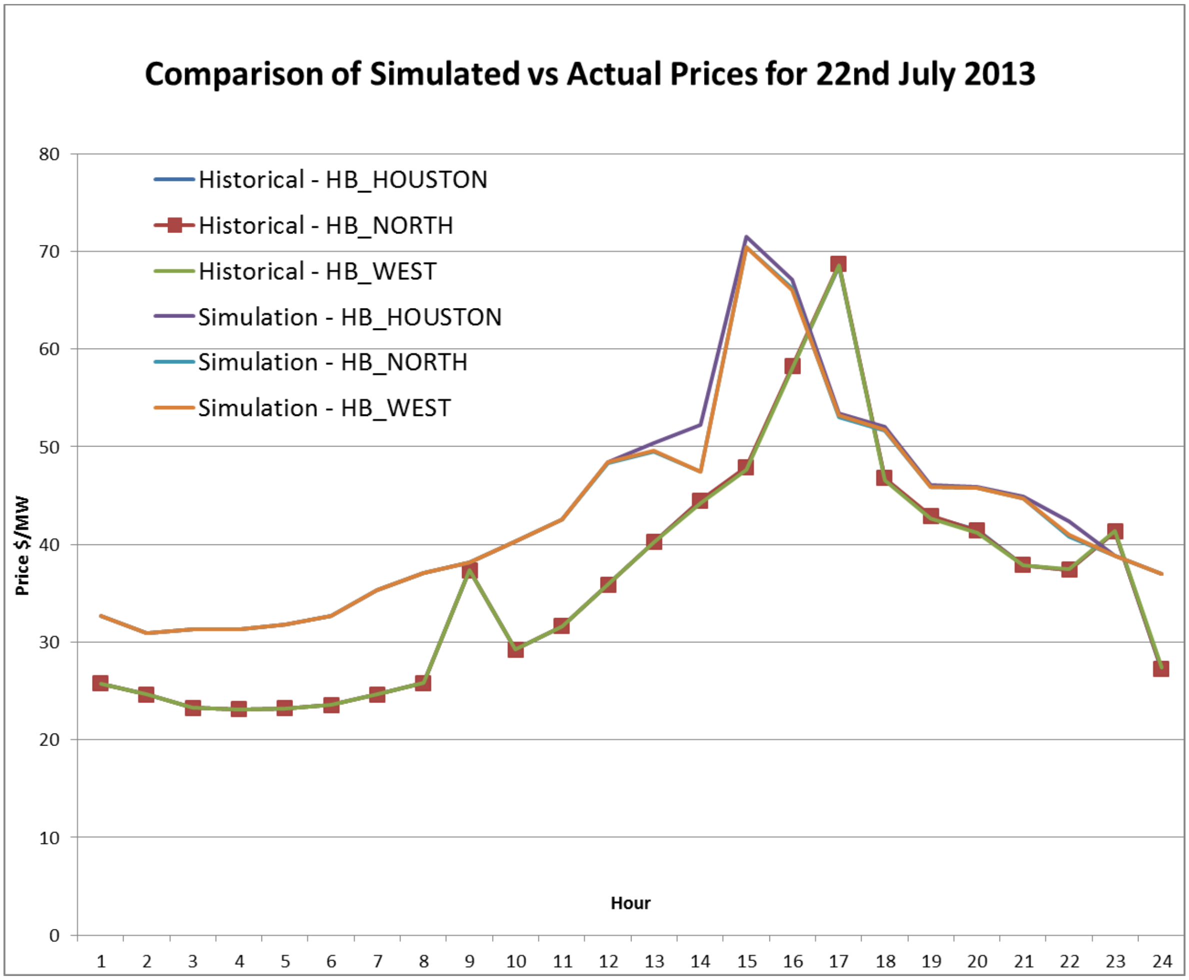

Figure 6. Comparison of simulated prices to actual prices for July 22, 2013

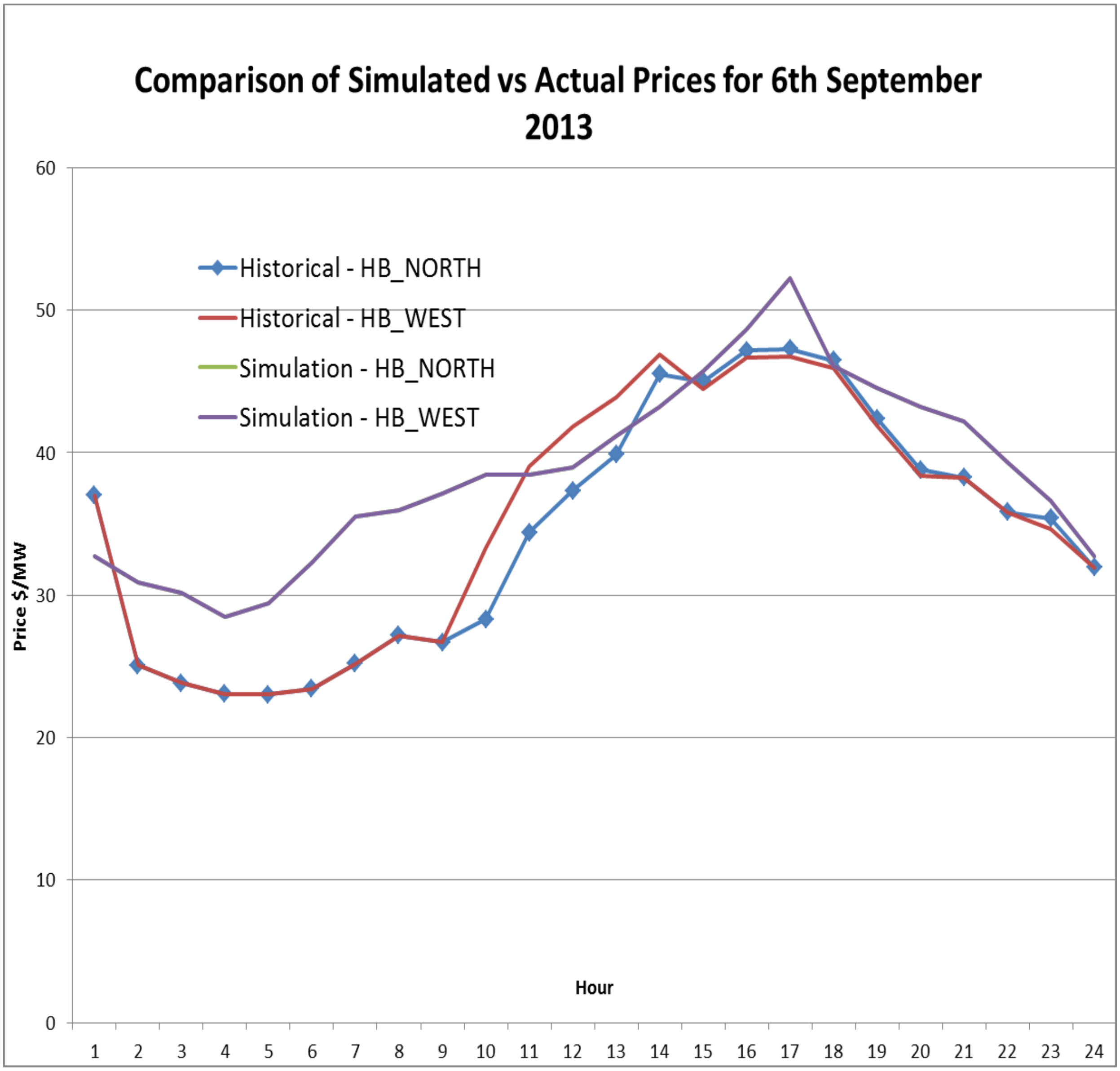

Figure 7. Comparison of simulated prices to actual prices for September 6, 2013

6 Results and Analysis

This section presents the results and analysis of the base case and the high wind case and considers the following factors:

- Hub prices
    - Hourly averages
    - Monthly averages
- Generator economics
    - Cost assumptions
    - Cost components
    - Energy and ancillary service awards
    - LMPs, revenue, and profits
- Wind curtailments
- Network congestion.

6.1 Hub Prices

6.1.1 Average Hourly Hub Prices

In the base case, the prices rose during the peak afternoon hours, as shown in Figure 8. The four hub prices were nearly the same, which indicates that there was not a significant amount of congestion in the base case. The congestion that did exist moved the West hub prices down slightly.

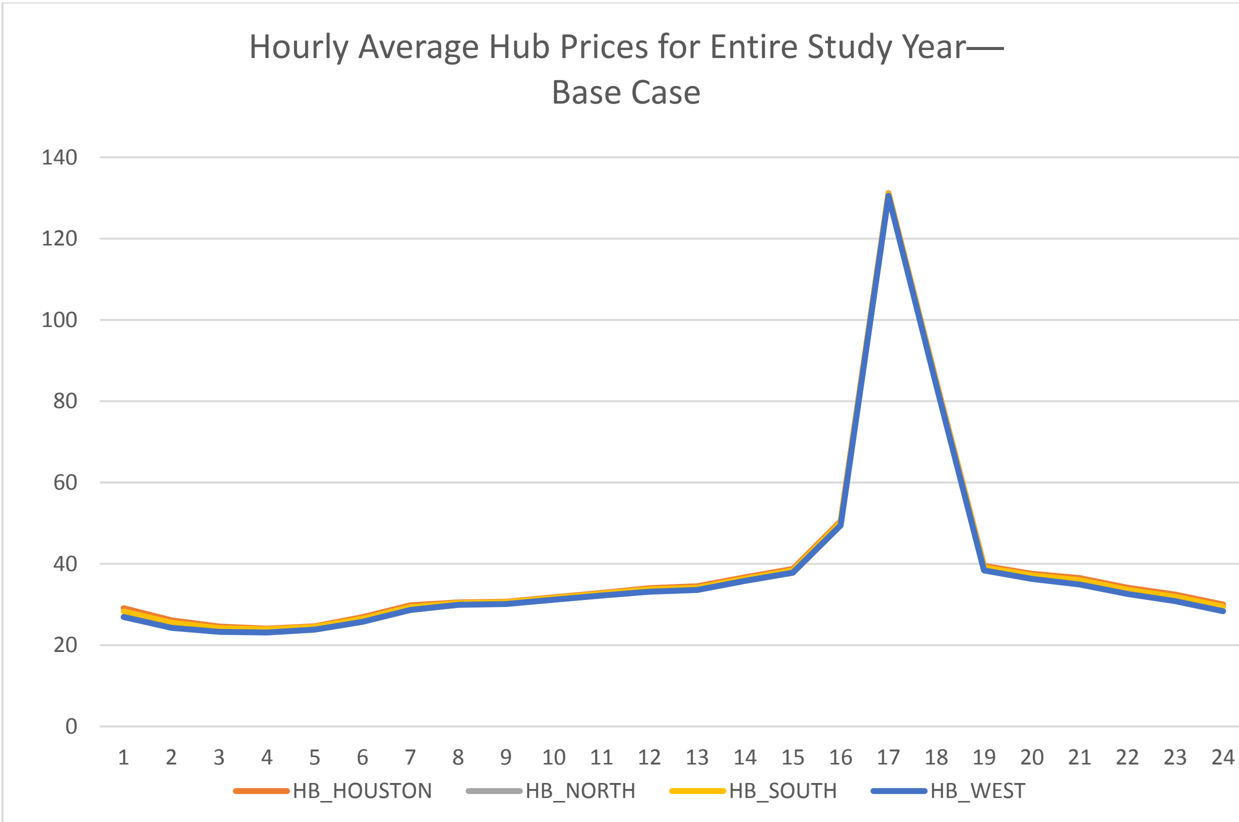

Figure 8. Average hourly hub prices for the entire study year—base case

Figure 9 shows the average hourly prices for the high wind case. The peak LMPs also occurred during the late afternoon hours, as they did in the base case. The average LMPs, however, dropped for all hours. In addition, there was some spread between the hubs, and the West and North hubs had the lowest prices. The primary load centers were located in the South and Houston hubs, which experienced higher prices. This was caused by the additional wind generation, which was sited primarily in the North and West regions of the system. This resulted in network congestion, which lowered the LMPs of North and West hubs.

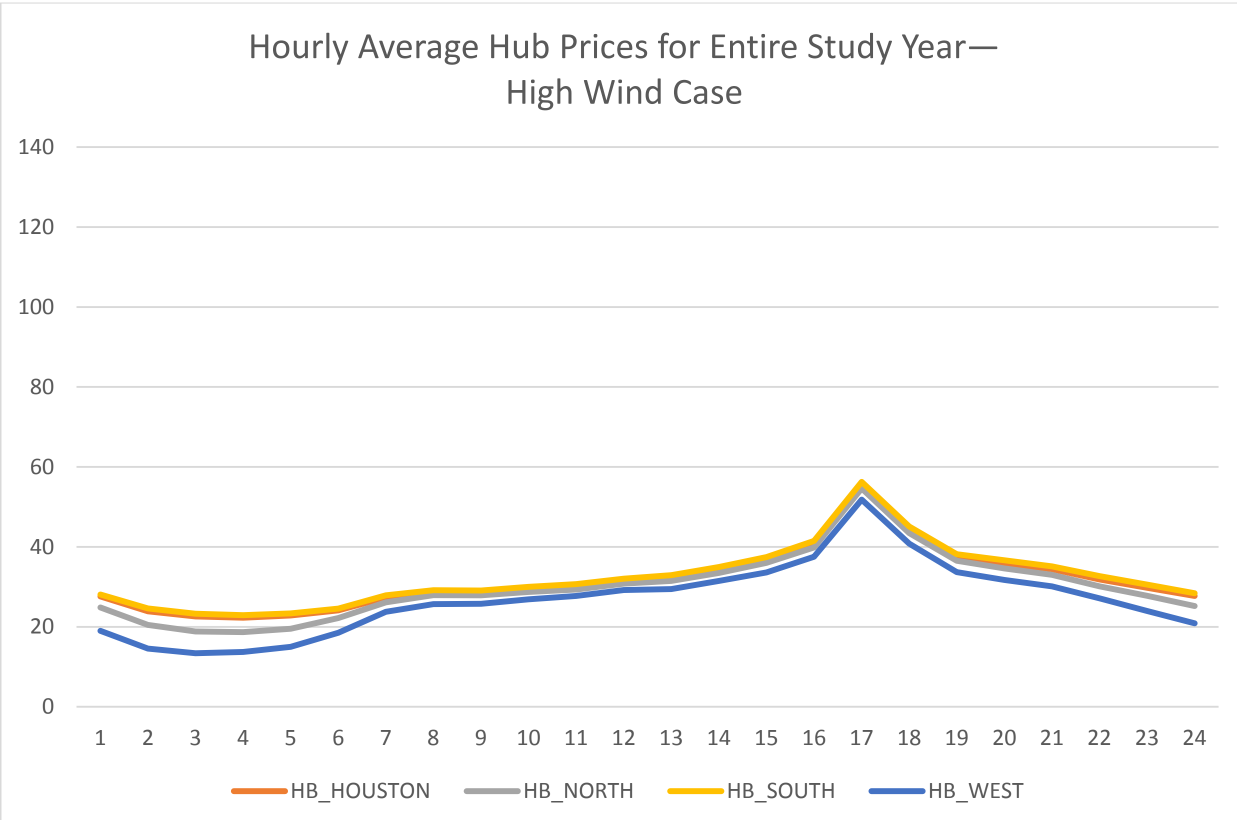

Figure 9. Average hourly hub prices for the entire study year—high wind case

Figure 10 shows a direct comparison of the average hub price for the base case and the high wind case. The high wind case had lower average LMPs during all hours, but the price drop was the greatest during the peak afternoon hours (HE15–HE 18). The additional production from the wind generation reduced the net load to be served by conventional generation. This resulted in fewer price spikes during the hours of generation capacity shortage.

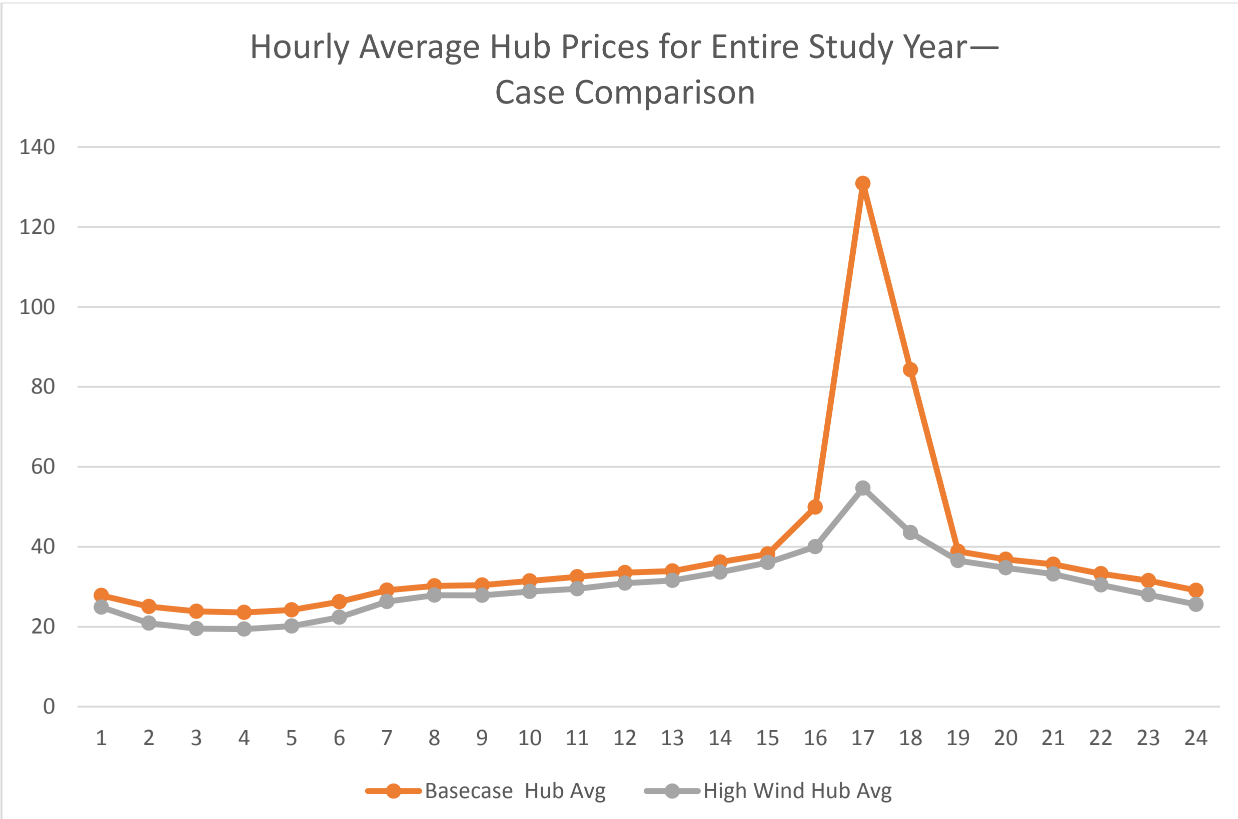

Figure 10. Average hourly hub prices for the entire study year—case comparison

6.1.2 Average Monthly Hub Prices

Figure 11 through Figure 13 show the average monthly LMPs for the base case and the high wind case. Figure 11 shows that the highest LMPs occurred during July. This is consistent with the summer-peaking load of ERCOT.

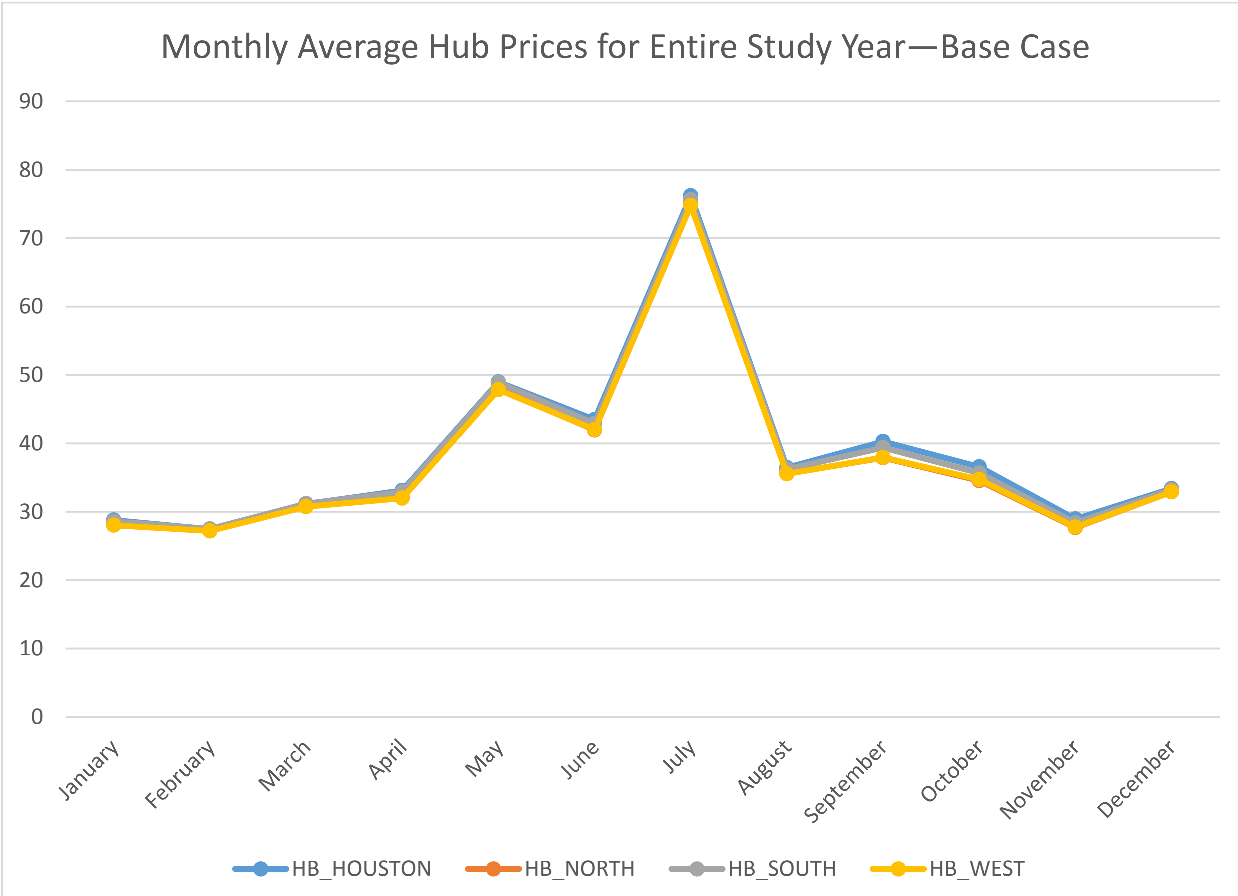

Figure 11. Average monthly hub prices for the entire study year—base case

Figure 12 shows that the LMP spikes experienced in the base case were reduced in the high wind case. This is the result of the reduced net load during the peak summer months, which must be met with conventional generation.

The lowest prices occurred in the West and North regions because of the increase amount of wind generation. The South and Houston hubs had higher average prices because of the network congestion between the wind generation and the major load centers.

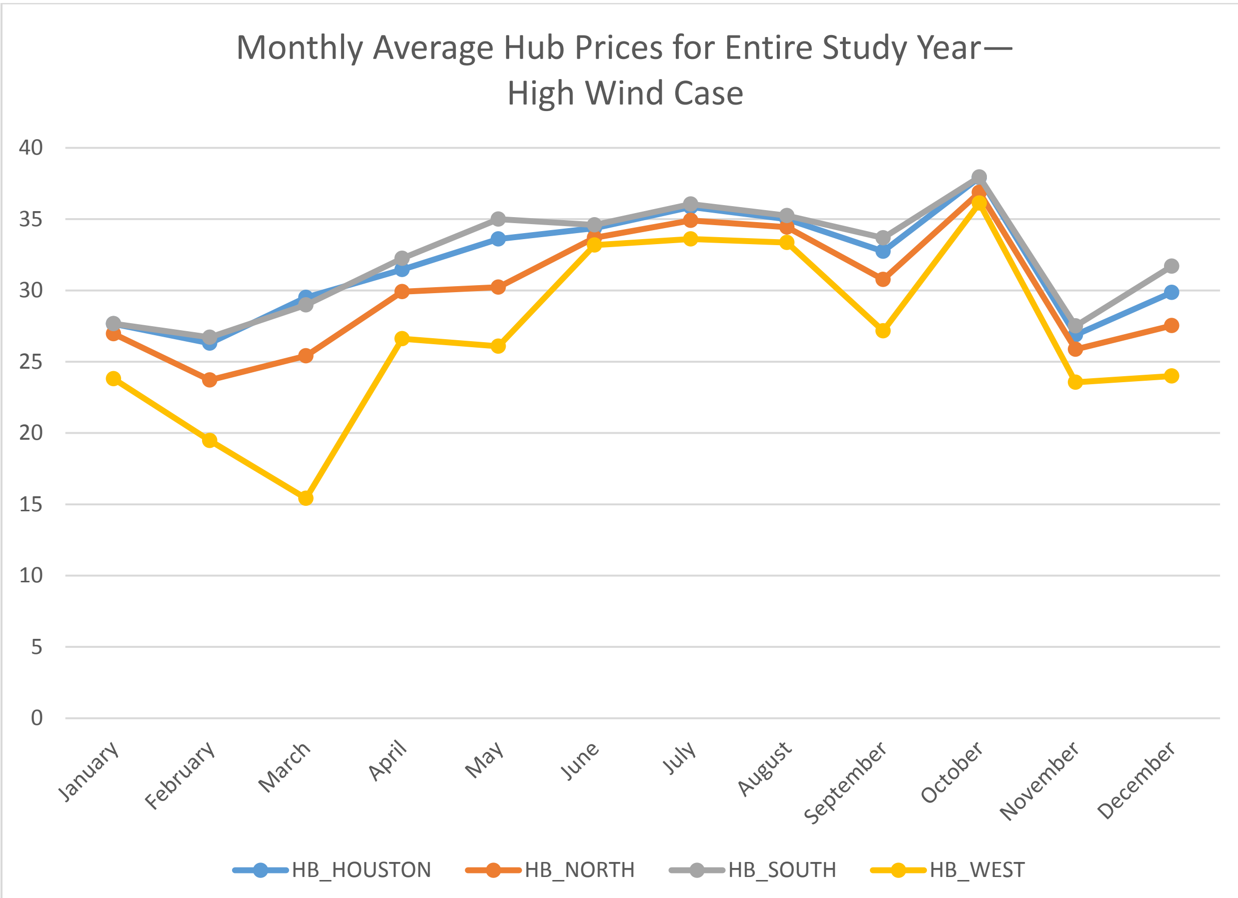

Figure 12. Average monthly hub prices for the entire study year—high wind case

To better compare the results, Figure 13 shows the average hub prices plotted together. The price drop in the high wind case was most pronounced during the peak summer months. In addition, the prices were consistently lower in the high wind case than they were in the base case, except in October. It turns out that approximately $4/MWh can be attributed to a capacity shortage in one single hour: HE17 on October 4, 2016. During this hour, system-wide prices for energy and spinning reserve rose from approximately $140/MWh to nearly $3,000/MWh. Because this did not occur in the base case, this price spike can be attributed to the interaction of the higher wind variability and constraints related to conventional generation commitments.

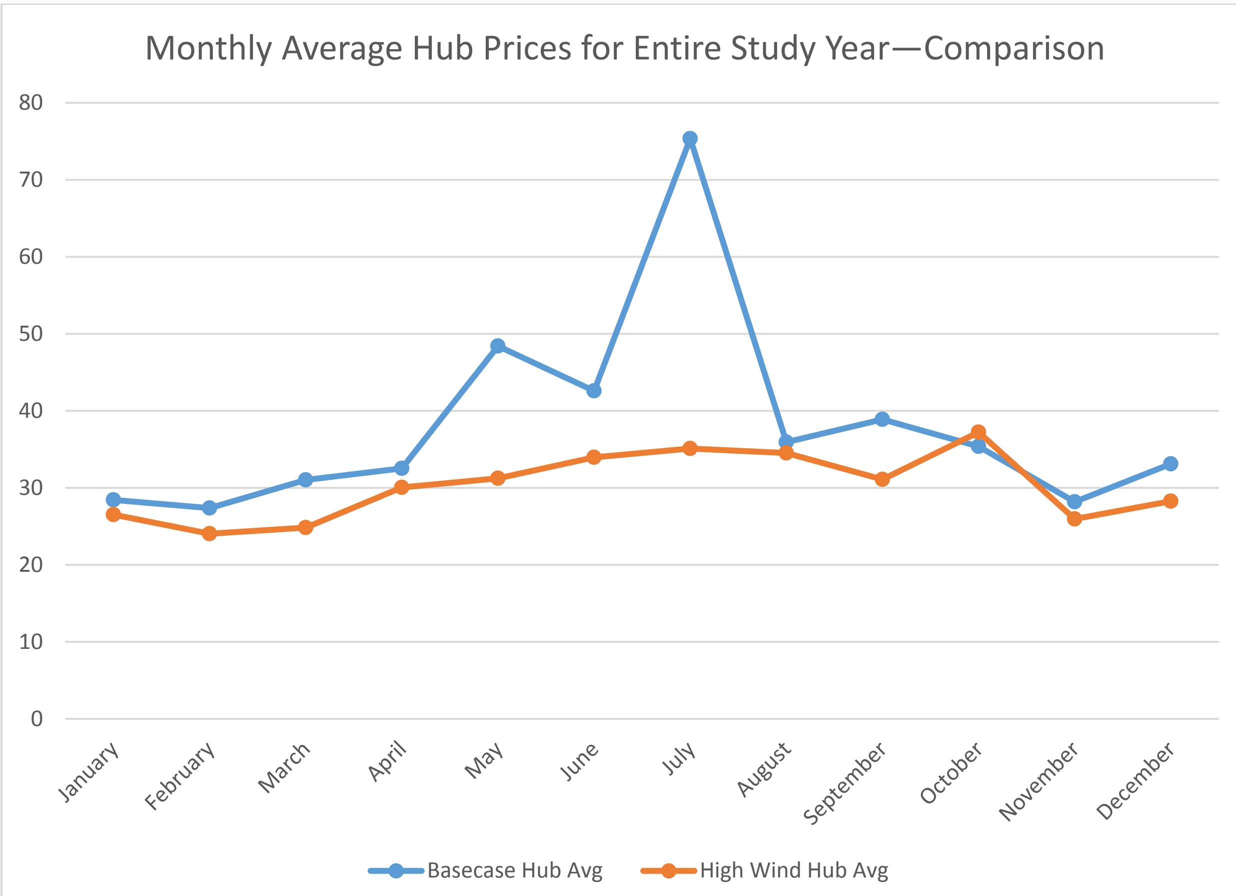

Figure 13. Average monthly hub prices for the entire study year—case comparison

6.2 Generator Results

This section discusses the important generator results. First, the cost assumptions for the various generator types are presented. Next, the actual cost components that comprise the total generator costs are itemized—these include fuel costs, variable O&M costs, fixed O&M costs, and levelized capital costs. Finally, the generator revenues and profits are summarized by fuel type, and results from a comparison of the base case to the high wind case are presented.

6.2.1 Generator Costs Breakdown

This project utilized publicly-available data. Generator cost data is considered proprietary and was not shared publicly by either ERCOT or the market participants. Therefore, in the absence of actual proprietary data, representative generator costs were obtained from the 2013 U.S. Energy Information Administration report titled *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*.[11] Table 3 summarizes the data used for the ERCOT generating plants.

Using a common set of data improves consistency, but it also does not completely reflect the economics of the current generator fleet. The ERCOT generation fleet was constructed throughout many decades, and it includes generator types (e.g., natural gas boilers) that have been supplanted by newer technologies (e.g., combined-cycle plants). Therefore, these results indicate the costs that could be expected if the ERCOT fleet were replaced with new generators of the same type but using the latest advances and technologies. These simplifying assumptions may have impacted the absolute value of the generator revenues and profitability, but they had a smaller impact on the relative cost differences between the study scenarios.

Table 3. Assumed Generator Costs for ERCOT

Fuel Type	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Capital Cost Levelized ($/kW-yr)	Notes
Biomass	$4,114.00	$105.63	$5.26	$318.42	Bubbling fluidized bed
Combined Cycle	$917.00	$13.17	$3.60	$70.98	Conventional combined cycle
Combustion Turbine Gas	$676.00	$7.04	$10.37	$52.32	Advanced combustion turbine
Hydro	$2,936.00	$14.13	$0.00	$227.25	Not pumped hydro
Internal Combustion Gas	$973.00	$7.34	$15.45	$75.31	Conventional combustion turbine (Only a few small units use this designation.)
Nuclear	$5,530.00	$93.28	$2.14	$428.02	Dual unit nuclear
Solar	$3,873.00	$24.69	$0.00	$299.77	Large photovoltaic
Steam Turbine Coal	$3,246.00	$37.80	$4.47	$251.24	Single unit, advanced pulverized coal, no carbon capture
Steam Turbine Gas	$917.00	$13.17	$3.60	$70.98	Conventional combined cycle (This fits best with the size of the ERCOT units.)
Storage	$5,288.00	$18.00	$0.00	$409.29	Used pumped hydro costs
Wind	$2,213.00	$39.55	$0.00	$171.29	Assumed onshore. Offshore is two to three times higher.

[11] See http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf, page 6.

Note the following about the values in the table above. First, the capital costs were decreased by 7%, because the cost of construction in Texas is lower, according to the same Energy Information Administration report. In addition, the levelized capital costs were computed by taking the entire capital cost and assuming a 30-year recovery period, with 6.6% value of money.

Using the input data shown in Table 3, ProMaxLT simulated generated generator costs for the base case, as shown in Table 4.

Table 4. Generator Costs Breakdown (U.S. $) for the Entire Study Year—Base Case

Generator Type	Capacity	Fuel Cost	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-yr)	Capital Cost ($/kW-yr)	Total Cost ($)
Biomass	224	249,587	28,958	22,194,592	6,223,216	28,779,198
Combined Cycle	18,372	4,882,819,510	592,157,771	478,274,281	239,790,810	6,249,328,460
Combustion Turbine Gas	5,642	437,906,287	108,002,514	36,500,527	25,240,273	615,712,729
Hydro	541	0	0	6,814,274	10,191,981	17,099,855
Internal Combustion Gas	228	23,453,210	7,353,602	1,666,047	1,598,423	34,919,109
Nuclear	5,150	802,233,300	79,576,700	475,196,000	202,785,477	1,559,791,477
Solar	124	523	0	3,834,090	4,329,354	8,163,966
Steam Turbine Coal	19,493	3,394,963,700	613,387,756	672,636,650	415,720,184	5,125,101,563
Steam Turbine Gas	14,567	246,891,194	19,905,124	168,259,609	84,334,418	544,244,570
Storage	77	14,167	0	1,375,094	2,907,926	4,297,187
Tie	500	-240,923,000	0	0	0	-240,923,000
Wind	18,350	3,177	0	513,032,976	206,378,125	719,414,277
Grand Total	83,267	9,547,611,655	1,420,412,425	2,379,784,139	1,199,500,187	14,665,929,390

Table 5 shows the generator costs for the high wind case.

Table 5. Generator Costs Breakdown (U.S. $) for the Entire Study Year—High Wind Case

Generator Type	Capacity	Fuel Cost	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-yr)	Capital Cost ($/kW-yr)	Total Cost ($)
Biomass	224	160,865	16,588	22,194,592	6,223,216	28,664,980
Combined Cycle	18,372	3,765,382,034	465,621,939	478,274,281	239,790,810	5,031,144,694
Combustion Turbine Gas	5,642	368,087,822	92,306,256	36,500,527	25,240,273	531,633,437
Hydro	541	1	0	6,814,274	10,191,981	17,121,455
Internal Combustion Gas	228	20,827,767	6,491,927	1,666,047	1,598,423	31,296,235
Nuclear	5,150	760,144,000	75,689,770	475,196,000	202,785,477	1,513,815,247
Solar	124	522	0	3,834,090	4,329,354	8,163,966
Steam Turbine Coal	19,493	2,772,255,100	501,089,290	672,636,650	415,720,184	4,391,320,818
Steam Turbine Gas	14,567	142,619,257	11,467,286	168,259,609	84,334,418	420,256,676
Storage	77	7,403	0	1,375,094	2,907,926	4,290,423
Tie	500	-261,048,000	0	0	0	-261,048,000
Wind	39,350	3,159	0	1,346,945,976	541,822,615	1,888,771,750
Grand Total	104,267	7,568,439,929	1,152,683,057	3,213,697,139	1,534,944,677	13,605,431,681

By comparing Table 4 to Table 5, the following can be noted:

1. Total system fuel costs in the high wind case dropped from $9.5 billion to $7.6 billion. This is because of the increased amount of wind production, which has no fuel cost.
2. For similar reasons, overall variable O&M dropped, from $1.4 billion to $1.1 billion. Conventional generation ran less, so there was less wear-and-tear on the machines. Wind generators did not have any assigned variable O&M.
3. Fixed O&M increased, however, because there were now more wind generators to maintain. Overall fixed O&M costs rose from $2.4 billion to $3.2 billion.
4. Similarly, overall levelized capital costs rose, from $1.2 billion to $1.5 billion, because of the increased number of wind generators. The number of conventional generators did not change between the base case and the high wind case.
5. An additional 21,000 MW of wind capacity was added to the high wind case. Astrape Consulting recently published a study for ERCOT on the planning reserve margin for

2016.[12] They determined a wind capacity factor of 56% for coastal wind and 12% for non-coastal wind. Given that this study used non-coastal wind, it would have a capacity value of 12% * 21,000 = 2,520 MW, based on the current ERCOT planning parameters.

6.2.2 Generator Profits

Table 6 through Table 8 show a comparison of the generator revenues and profits for the base case and the high wind case.

Table 6. Generator Summary for the Entire Study Year—Base Case

Generator Type	Capacity	Total Revenue ($)	Total Cost ($)	Total Profit ($)	Energy (MWh)	Spin (MWh)	Hours On	Average LMP ($)
Biomass	224	584,508	28,779,198	-28,194,690	5,464	0	639	$106.98
Combined Cycle	18,372	7,567,874,890	6,249,328,460	1,318,546,430	164,488,135	22,614,561	714,485	$44.90
Combustion Turbine Gas	5,642	539,362,134	615,712,729	-76,350,595	10,417,864	405,021	274,836	$51.03
Hydro	541	8,473,960	17,099,855	-8,625,895	1,293	34,587	91	$41.57
Internal Combustion Gas	228	30,723,207	34,919,109	-4,195,902	475,970	3,866	10,829	$64.05
Nuclear	5,150	1,407,191,900	1,559,791,477	-152,599,577	37,185,240	23,410	28,500	$37.84
Solar	124	51,273,780	8,163,966	43,109,814	1,346,562	3,069	61,283	$38.07
Steam Turbine Coal	19,493	5,171,190,600	5,125,101,563	46,089,038	137,221,991	1,471,643	230,852	$37.61
Steam Turbine Gas	14,567	497,034,807	544,244,570	-47,209,763	5,529,206	32,288	22,449	$88.82
Storage	77	24,821,286	4,297,187	20,524,099	659,584	6,637	17,833	$37.59
Tie	500	-209,900,000	-240,923,000	31,023,000	-6,188,170	0	1,230	$33.92
Wind	18,350	1,736,806,006	719,414,277	1,017,391,729	52,336,207	0	929,422	$33.19
Grand Total	83,267	16,825,437,077	14,665,929,390	2,159,507,688	403,479,346	24,595,084	2,292,449	$41.17

[12] See http://www.astrape.com/expected-unserved-energy-and-reserve-margin-implications-of-various-reliability-standards/.

Table 7. Generator Summary for the Entire Study Year—High Wind Case

Generator Type	Capacity	Total Revenue ($)	Total Cost ($)	Total Profit ($)	Energy (MWh)	Spin (MWh)	Hours On	Average LMP ($)
Biomass	224	274,007	28,664,980	-28,390,974	3,130	14	617	$87.50
Combined Cycle	18,372	4,719,444,468	5,031,144,694	-311,700,226	129,339,276	21,855,066	599,648	$35.79
Combustion Turbine Gas	5,642	349,774,719	531,633,437	-181,858,717	8,903,791	648,174	257,483	$38.79
Hydro	541	1,903,422	17,121,455	-15,218,033	1,883	87,316	146	$39.85
Internal Combustion Gas	228	19,877,772	31,296,235	-11,418,463	420,197	9,284	10,455	$47.13
Nuclear	5,150	1,059,305,200	1,513,815,247	-454,510,047	35,369,070	78,607	27,323	$29.94
Solar	124	43,341,780	8,163,966	35,177,814	1,345,456	2,985	61,260	$32.20
Steam Turbine Coal	19,493	3,414,555,400	4,391,320,818	-976,765,418	112,099,560	1,832,034	193,202	$30.39
Steam Turbine Gas	14,567	186,890,178	420,256,676	-233,366,499	3,185,353	20,889	14,422	$58.46
Storage	77	19,100,674	4,290,423	14,810,251	606,012	60,706	16,145	$31.06
Tie	500	-258,691,000	-261,048,000	2,357,000	-6,710,640	0	814	$38.55
Wind	39,350	1,820,121,524	1,888,771,750	-68,650,226	118,916,587	0	905,978	$15.31
Grand Total	104,267	11,375,898,144	13,605,431,681	-2,229,533,537	403,479,674	24,595,075	2,087,493	$27.93

By comparing Table 6 to Table 7, the following can be noted:

1. Conventional generation capacity stayed the same, and there was 21,000 MW of additional wind capacity. The new wind generators were aggregated and located in the North and West regions of the ERCOT system. They were put on the bulk high-voltage portion of the grid, because it is reasonable to assume that the necessary sub-transmission system in the North and West will be built up to support new wind generation. Therefore, it was most important to capture the impact on the bulk transmission system from these remote areas to the Texas load pockets of Dallas, Austin, and Houston.
2. Total system-wide revenue dropped from $16.8 billion to $11.4 billion because of the lower LMPs and ancillary service prices.
   A. Generator total revenues were generated by both energy and spinning reserve products.
   B. Note that the wind revenue increased only from $1.74 billion to $1.82 billion because of the depressed energy prices.
3. Total costs also dropped, from $14.7 billion to $13.6 billion. As discussed above, this was caused by lower fuel costs and variable O&M costs. Higher fixed O&M costs and capital costs counteracted some of these reductions.
4. Total system profit (revenue – costs) dropped from $2.2 billion to -$2.2 billion, a reduction of $4.4 billion. This clearly demonstrates that adding too much wind generation to a system will cause dramatically lower revenues (if all else is even). Even the wind generators lost money in the high wind case. Note that wind generators receive production tax credits of $22/MWh, which will change their overall economics.

5. Total wind production increased from 52 TWh to 119 TWh. Note that this is the amount of delivered wind energy, because a non-trivial amount of wind was curtailed by the system. The exact wind curtailment is presented in Section 6.3.
6. Average generator LMP dropped from $41.17 in the base case to $27.93 in the high wind case. This drove lower generator revenues, which then resulted in reduced profitability for the generator fleet.
7. The magnitude of the generator revenues and profits depends on the market structure. The prevailing market design is based on the marginal costs of production, and therefore they will be significantly impacted by the addition of resources that do not have incremental fuel costs.
8. Note that conventional generation capacity in the high wind case was not adjusted. Economic theory is clear that the addition of generating capacity (wind or conventional) will lower prices and revenues. Further studies could examine the impact of a more optimal generation fleet, in which excess generating capacity would be minimized.

Table 8 shows the percentage change in results from a comparison of Table 6 to Table 7.

Table 8. Generator Summary for the Entire Study Year—Difference between Cases (%)

Generator Type	Capacity	Total Revenue ($)	Total Cost ($)	Total Profit ($)	Energy (MWh)	Spin (MWh)	Hours On	Average LMP ($)
Biomass	0.0%	-53.1%	-0.4%	-0.7%	-42.7%	100.0%	-3.4%	-18.2%
Combined Cycle	0.0%	-37.6%	-19.5%	-123.6%	-21.4%	-3.4%	-16.1%	-20.3%
Combustion Turbine Gas	0.0%	-35.2%	-13.7%	-138.2%	-14.5%	60.0%	-6.3%	-24.0%
Hydro	0.0%	-77.5%	0.1%	-76.4%	45.6%	152.5%	60.4%	-4.1%
Internal Combustion Gas	0.0%	-35.3%	-10.4%	-172.1%	-11.7%	140.1%	-3.5%	-26.4%
Nuclear	0.0%	-24.7%	-2.9%	-197.8%	-4.9%	235.8%	-4.1%	-20.9%
Solar	0.0%	-15.5%	0.0%	-18.4%	-0.1%	-2.7%	0.0%	-15.4%
Steam Turbine Coal	0.0%	-34.0%	-14.3%	-2219.3%	-18.3%	24.5%	-16.3%	-19.2%
Steam Turbine Gas	0.0%	-62.4%	-22.8%	-394.3%	-42.4%	-35.3%	-35.8%	-34.2%
Storage	0.0%	-23.0%	-0.2%	-27.8%	-8.1%	814.6%	-9.5%	-17.4%
Tie	0.0%	-23.2%	-8.4%	-92.4%	-8.4%	0.0%	-33.8%	13.6%
Wind	114.4%	4.8%	162.5%	-106.7%	127.2%	0.0%	-2.5%	-53.9%
Grand Total	25.2%	-32.4%	-7.2%	-203.2%	0.0%	0.0%	-8.9%	-32.2%

Red values indicate a drop in the results from the high wind case, whereas green values indicate an increase in the results from the high wind case. Note the following:

1. Conventional (nuclear, coal, gas) generation was most negatively impacted, including in the areas of energy production, hours on, total revenue, and total profit.
2. Conventional generators cleared more spinning reserve, but this is because they were producing less energy and had more unloaded capacity. However, this additional of available spinning reserve caused the average spin price to drop from $8.71/MWh in the base case to $4.33/MWh in the high wind case (not shown in table). This is consistent with the basic market fundamentals that prices drop when supplies increase, and demand remained constant. Therefore, conventional generators produced less energy and faced lower spinning reserve prices because of the system surplus of spin capacity.
3. Hydro showed a modest increase in production (45.6%), but hydro is a very small player in ERCOT. In the studies, hydro averaged less than 1MW production each hour, although it did provide some additional spinning reserve.
4. Wind production was up 127.2%, but wind revenue increased only 4.8%. With the additional wind generator costs, this resulted in a market loss (negative profit) for the wind generators. Wind generators also have non-market revenue streams, however, which would likely make them profitable. For example, since 1992 there has been a federal production tax credit of $22/MWh for wind generation.

6.3 Wind Curtailment

This section summarizes the amount of wind curtailment. Table 9 and Table 10 summarize the top 10 curtailed wind resources in the base case and the high wind case and show the total for all wind power plants.

Table 9. Top 10 Curtailed Wind Generators—Base Case

Number	Wind Generator	Total Curtailment (MWh)	Curtailment Hours	Average Curtailment (MW)
1	HHGT_HHOLLOW1	220,519	2067	107
2	SWEETWN2_WND2	39,293	1920	20
3	TTWEC_G1	35,850	658	54
4	SWEETWN2_WND24	18,436	1531	12
5	HHGT_HHOLLOW3	6,561	184	36
6	CEDROHIL_CHW1	6,084	401	15
7	SWEETWN3_WND3B	4,914	201	24
8	HHGT_HHOLLOW2	4,005	128	31
9	COTTON_PAP2	3,977	95	42
10	HHGT_HHOLLOW4	3,106	139	22
Total		356,180	7711	46

Table 10. Top 10 Curtailed Wind Generators—High Wind Case

Number	Wind Generator	Total Curtailment (MWh)	Curtailment Hours	Average Curtailment (MW)
1	FAR_WEST Wind	3,153,436	3,571	883
2	NORTH Wind	1,775,648	1,920	925
3	PC_SOUTH_PANTHER3	461,576	4,585	101
4	TTWEC_G1	385,013	4,871	79
5	PC_NORTH_PANTHER1	316,938	4,350	73
6	PC_SOUTH_PANTHER2	260,048	4,417	59
7	HHGT_HHOLLOW1	251,958	2,267	111
8	ELB_ELBCREEK	210,324	3,720	57
9	LGD_LANGFORD	183,728	1,771	104
10	TRENT_TRENT	163,941	1,454	113
Total		9,193,283	70,767	130

Note that the total wind curtailment increased from 0.356 TWh to 9.193 TWh. This is an increase of more than 25 times. However, 9.193 TWh of curtailed wind compared favorably to 118.9 TWh of delivered wind generation in the high wind case. In the high wind case, 7.2% of the potential wind production was curtailed. This would have been higher, except that the network was built out as proposed in the ERCOT transmission planning studies.

The top two curtailed generators in the high wind case were the aggregated generators created to accommodate higher levels of wind penetration.

Figure 14 shows how the curtailed MWh vary during the 12 months of the study. The increase in curtailment in December was mostly likely caused by the increase in wind production, which was obtained from NREL’s Wind Toolkit.

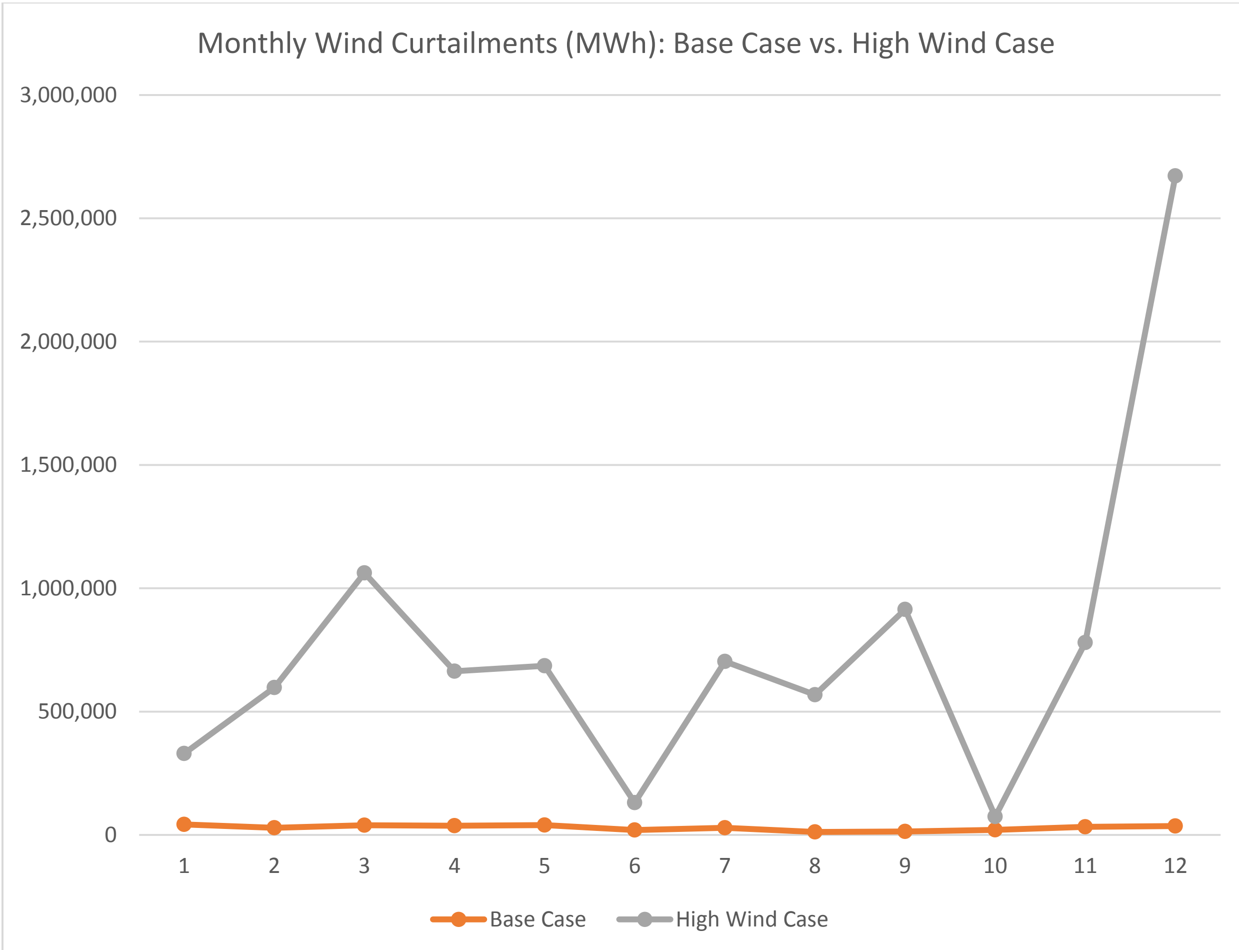

Figure 14. Monthly wind curtailments (MWh)—base case compared to high wind case

7 Binding Constraints

This study deployed a full and detailed network model that allowed the results to capture the impacts of the transmission constraints. As described above in Section 3.2, the network model was augmented with additional lines per the ERCOT planning study.

Table 11 and Table 12 summarize the top 20 binding constraints in the base case and the high wind case. To capture only strongly binding constraints, a shadow price (dual) cutoff of $100/MW was enforced.

Table 11. Top 20 Binding Constraints (Shadow Price > $100)—Base Case

Constraint Name	Rating (MVA)	Voltage (kV)	Hours
CHAD4A (6325)-BALG4A (6340) 1 OUT L_006442SARC4A-006458CRM24AC1	135	138	715
NUECES_B4A (8441)-MORRIS4A (8474) 1 OUT MUTUAL BRANCH 1121710240 138KV	206	138	239
L_WIRTZ_8_1Y (7104)-L_FLATRO8_1Y (7111) 1 OUT MARBLE FALLS-LAKEWAY & STARCKE-PALEFACE	128	138	178
L_BANDER8_1Y (7438)-L_MASOCR8_1Y (7441) 1 OUT CAGNON_5 - L_KENDAL5_1Y/L_CICO__8_1Y - COMFORT	221	138	108
DOW_A_E_138 (42514)-starbus210150 (210150) 43 OUT 3WT: DOW_____345A - 3 (42500 110149 110150)	500	1	61
DOW_____345A (42500)-starbus210149 (210149) 3 OUT 3WT: DOW_____345A - 4 (42500 42514 110151)	500	1	60
DOW_1_8 (110149)-starbus210149 (210149) 33 OUT 3WT: DOW_____345A - 4 (42500 42514 110151)	500	1	59
DOW_____345A (42500)-starbus210150 (210150) 4 OUT 3WT: DOW_____345A - 3 (42500 110149 110150)	500	1	59
ATMEL1_T8 (1996)-HACKBRY1_8 (2388) 1 OUT 3WT: HACKBRY1_5 - 1 (2387 2388 12388)	215	138	58
MORRIS_D2_8 (1864)-EAGLEMNT2_8 (11860) 1 OUT L_002065EMCS1_8-002066ROSEN1_T8C1	191	138	31
DWNTWN__138A (47500)-POLK____138A (47730) 91 OUT GREENS BAYOU - GABLE STREET CKT.&1 & CROCKETT - HARDY CKT.&1	334	138	31
L_COMFOR8_1Y (7155)-L_RAYMBA8_1Y (7158) 1 OUT L_007156L_CYPRCR8_1Y-007158L_RAYMBA8_1YC1	128	138	29
DFW_DE1T1_8 (15020)-DFW_CE1_8 (15045) 1 OUT 3WT: HACKBRY1_5 - 1 (2387 2388 12388)	215	138	27
BRNWD_S_8 (1656)-CAMPBOW_P8 (1657) 1 OUT L_001441COMCHESS1_8-001654ZEPHYR_P8C1	124	138	15
RAYBURNPLNT8 (5513)-RAY_RAYBURG9 (110036) 1	75	13.8	12
AIRLINE4A (8490)-CABANISS4A (8882) 1 OUT L_008458B_DAVIS4A-008883RODD_FLD4AC1	320	138	7
TWIN_OAK_N5 (3400)-TWIN_OAK_S5 (13694) 1 OUT L_003400TWIN_OAK_N5-013690OAKGROVE_5C2	1631	345	6
L_KERRST8_1Y (7138)-L_HARPRO8_1Y (7140) 1 OUT VERDECRK-STADIUM/RAYBARKER	128	138	6
SNGLTN_345 (44645)-ZENITH__345A (44900) 99 OUT SINGLETON - TOMBALL 345 CKT.74 & ROANS PRAIRIE - KING CKT.&1	1450	345	5
THOUSE__5 (3405)-SAMSW (68090) 1 OUT L_013405THOUSE_A_5-068090SAMSWC1	1072	345	5
Total			1,249

Table 12. Top 20 Binding Constraints (Shadow Price > $100)—High Wind Case

Constraint Name	Rating (MVA)	Voltage (kV)	Hours
CHAD4A (6325)-BALG4A (6340) 1 OUT L_006442SARC4A-006458CRM24AC1	135	138	2,538
BALG4A (6340)-COLE_IVI4A (6360) 1	151	138	1,477
L_BANDER8_1Y (7438)-L_MASOCR8_1Y (7441) 1 OUT CAGNON_5 -L_KENDAL5_1Y/L_CICO__8_1Y - COMFORT	221	138	1,230
LEONSW_8 (1624)-PUTN2B (6310) 1 OUT L_0063176317-006670PUTN4CC1	79	138	1,059
LONGSHORE_5 (1058)-ODESEHV2_5 (11028) 1 OUT L_001030MRGNCRK_5-001058LONGSHORE_5C1	1072	345	1,023
CHAD4A (6325)-OAKC4A (6335) 1 OUT L_006442SARC4A-006458CRM24AC1	151	138	865
HAMILTON4A (8255)-MAVERICK4A (8692) 1	122	138	854
BLUFCKTA_8 (1309)-CHINAGRV_8 (1318) 1 OUT L_001310KNAPP_8-001312SCURYCHV_8C1	143	138	823
LONGSHORE_5 (1058)-ODESEHV2_5 (11028) 1 OUT MRGNCRK_5 - LONGSHORE_5 & MRGNCRK_5 - LONGSHRFLY_5	1072	345	466
LONGSHORE_5 (1058)-ODESEHV2_5 (11028) 1 OUT QUAILSW_5-MRGNCRK_5 & MRGNCRK_5-LONGSHORT_5	1072	345	462
MORRIS_D2_8 (1864)-EAGLEMNT2_8 (11860) 1 OUT L_002065EMCS1_8-002066ROSEN1_T8C1	191	138	448
EVRMNTIE1_5 (1885)-COURTLND1_5 (1931) 1 OUT EVRMAN_W5-VENUS_S5 & EVRMAN_E5-VENUS_N5	1072	345	434
EXSHARNR_8 (1300)-WILLOWVAL_8 (1301) 1	186	138	383
YELWJCKT4B (6365)-SAPS4A (6483) 1	179	138	352
BLUFCKTA_8 (1309)-CHINAGRV_8 (1318) 1 OUT SNYDER - SUN SW 138 KV (SINGLE B TO B)	143	138	229
L_COMFOR8_1Y (7155)-L_RAYMBA8_1Y (7158) 1 OUT L_007156L_CYPRCR8_1Y-007158L_RAYMBA8_1YC1	128	138	220
MRGNCRK_5 (1030)-LONGSHORE_5 (1058) 1 OUT L_001058LONGSHORE_5-011028ODESEHV2_5C1	1072	345	215
CHAD4A (6325)-BALG4A (6340) 1	135	138	205
MRGNCRK_5 (1030)-LONGSHORE_5 (1058) 1 OUT ODEHV2_5 - QUAILSW_5 & LONGSHOE_5	1072	345	186
L_WIRTZ_8_1Y (7104)-L_FLATRO8_1Y (7111) 1 OUT MARBLE FALLS-LAKEWAY & STARCKE-PALEFACE	128	138	181
Total			16,035

Because of the higher amount of wind generation in remote locations, more congestion was experienced in the high wind case. Overall, the number of binding constraints with a shadow price > $100 increased from 1,249 constraint hours to 16,035 constraint hours.

The dominant constraint in both cases was the post-contingent constraint CHAD4A (6325)-BALG4A (6340) 1 OUT L_006442SARC4A-006458CRM24AC1. In the base case, it bound in 715 hours. In the high wind case, it bound in 2,538 hours.

At a high-level, the impact of the transmission system had the expected impact on the simulation results.

- In the base case, congestion was minimal (Table 11). Hub prices were nearly identical, which indicates that there was very little intra-zonal congestion (Figure 8).
- In the high wind case, there was significantly more congestion (Table 12).
- There was a differential in the hub prices (Figure 9). The lower prices were experienced in the North and West hubs, which is where the new wind generation was sited.
- The amount of curtailment was 7.2% of the total potential wind production (high wind case), which indicates that there was congestion between the wind generation and the main load regions, but also that it was not overly excessive at this wind penetration level.
- The observed levels of congestion and curtailment in the high wind case in this study are plausible, and they should not have an unreasonable impact on the missing money problem. If all congestion and curtailment were eliminated, this would add (on average) slightly more than 1,000 MW of wind generation each hour. This would incrementally depress the average prices, revenues, and profits, but it would not materially change the primary findings.

8 Conclusion

This project examined the impact of renewable energy sources, which have zero incremental energy costs, on the sustainability of conventional generation. This missing money problem is caused by two related factors: (1) conventional generation is dispatched less, and (2) the prices that conventional forms of generation receive for its energy are lower. This lower revenue stream may not be sufficient to cover both its variable and fixed costs. In fact, this study showed that higher wind penetrations in the ERCOT system could cause many conventional generators to become uneconomic.

For continuity, all generator costs used in this paper were obtained from the 2013 U.S. Energy Information Administration report titled *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*. This ensured that any inconsistencies in the data could be eliminated. Also, the current ERCOT fleet was constructed throughout many decades, which makes it difficult to compare capital costs, and therefore these results indicate the costs that could be expected if the ERCOT fleet were replaced with new generators of the same type but using the latest advances and technologies.

Two cases were examined: (1) the base case, in which 13% of the energy was met with wind; and (2) the high wind case, in which 30% of the energy was met with wind. An additional 2.2% of the load in the high wind case could have been met with wind, but the energy was curtailed because of network congestion.

The ERCOT base case simulation was reasonable based on recent performance. Specifically:

- The average generator LMP was $41.17.
- LMPs increased during peak afternoon hours and during peak summer months.
- With the current network build out, there was little congestion with the current levels of wind production.

The high wind case also resulted in reasonable metrics:

- The average generator LMP dropped to $27.93.
- When compared to the base case, prices were depressed across almost all hours and seasons because of the increased amount of wind generation with no marginal costs.
- Congestion in the network resulted in lower hub prices in the West and North. Load centers in the South and Houston saw relatively higher prices.

Because of the higher amount of wind generation in remote locations, more congestion was experienced in the high wind case. Overall, the number of binding constraints with a shadow price > $100 increased from 1,249 constraint hours in the base case to 16,035 constraint hours in the high wind case.

Generation was impacted by higher wind production in the following ways:

- Conventional (nuclear, coal, gas) generation was most negatively impacted. These units had dramatically reduced energy production, hours on, total revenue, and total profit.

    - Conventional generation cleared more spinning reserve, but this is because it produced less energy. This was offset, however, by the large spinning reserve ancillary service price drop in the high wind case, from $8.71/MWh to $4.33/MWh.
- Overall system-wide generator fixed costs increased, because additional wind generators were being built and maintained.
    - Overall fixed O&M costs rose from $2.4 billion to $3.2 billion.
    - Similarly, overall levelized capital costs rose from $1.2 billion to $1.5 billion per year.
- Overall system-wide generator variable costs dropped because of the reduced production from conventional generators.
    - Total system fuel costs dropped from $9.5 billion to $7.6 billion.
    - Overall variable O&M costs dropped from $1.4 billion to $1.1 billion.
- The largest impact was on overall system-wide generator revenues and profits
    - Total system-wide revenue dropped from $16.8 billion to $11.4 billion because of the lower LMPs and ancillary service prices.
    - Total system profit (revenue – costs) dropped from $2.2 billion to -$2.2 billion, a reduction of $4.4 billion.
    - Wind generator revenue increased marginally, from $1.74 billion to $1.82 billion, because of the depressed energy prices. With higher fixed costs, even wind generation lost money in the market in the high wind case. Note that wind generators receive non-market production tax credits, which will improve their financial viability.
    - The magnitude of the generator revenues and profits depends on the market structure. The prevailing market design is based on the marginal costs of production, and therefore it will be significantly impacted by the addition of resources that do not have incremental fuel costs.
    - Note that conventional generation capacity in the high wind case was not adjusted. Economic theory is clear that additional generating capacity (wind or conventional) will lower prices and revenues. Further studies could examine the impact of a more optimal generation fleet, in which excess generating capacity would be minimized.
    - The observed levels of congestion and curtailment in the high wind case in this study are plausible and should not have an unreasonable impact on the missing money problem. If all congestion and curtailment were eliminated, this would add (on average) slightly more than 1,000 MW of wind generation each hour. This would incrementally depress the average prices, revenues, and profits, but it would not materially change the primary findings.

This study quantified the impact of increased wind production on conventional generation in the ERCOT system. This missing money in organized electricity markets has the potential to inhibit new construction of conventional generation, which may in turn lead to a less reliable electric power system.

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