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The Full Cost of Electricity (FCe-)

Capacity Expansion and Dispatch Modeling: Model Documentation and Results for ERCOT Scenarios

PART OF A SERIES OF WHITE PAPERS

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THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FCe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FCe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

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This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

Other white papers produced through the study can be accessed at the University of Texas Energy Institute website: **energy.utexas.edu**

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Capacity Expansion and Dispatch Modeling: Model Documentation and Results for ERCOT Scenarios

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ACRONYMS

AC	Alternating current
AEN	Austin Energy load zone
BATT	Battery
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CFE	Comisión Federal de Electricidad, Mexico's state-owned electric utility
CHP	Combined heat and power
CPS	CPS Energy load zone (San Antonio area)
DC	Direct current
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Cooperative of Texas
FCe	UT Energy Institute Full Cost of Electricity Study
FERC	Federal Energy Regulatory Commission
FOM	Fixed operating and maintenance costs
FOR	Forced outage rate
IC	Reciprocating internal combustion engine
IGCC	Integrated gasification combined cycle
LACE	Levelized avoided cost of electricity
LCOE	Levelized cost of electricity
LCRA	Lower Colorado River Authority load zone
LFG	Landfill gas
LIG	Lignite coal
LNG	Liquefied natural gas
LT	Long-term
LTDEF	Long-term Demand and Energy Forecast
MIP	Mixed-integer programming
MISO	Midcontinent Independent System Operator
NG	Natural gas
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OCGT	Open cycle gas turbine
PUCT	Public Utility Commission of Texas
PV	Solar photovoltaic
RCEC	Rayburn Country Electric Cooperative load zone
RMT	Resource modifier table
SCM	Screening curve method
SPP	Southwest Power Pool
SRMC	Short-run marginal cost
ST	Steam turbine
SUB	Subbituminous coal
TCEQ	Texas Commission on Environmental Quality
VFC	Variable fuel costs
VOM	Variable operating and maintenance costs
WIND-C	Wind in coastal county as defined by ERCOT
WIND-O	Offshore wind
WT	Wind turbine

1 | CAPACITY EXPANSION AND DISPATCH MODELING

The Full Cost of Electricity project (FCe) intends to capture and present costs associated with delivering customers one unit of electricity (kWh or MWh) by different generation technologies. Typically, the levelized cost of electricity (LCOE) is used to provide a quick comparison across technologies. The LCOE considers overnight capital cost, operating and maintenance costs, fuel costs (if applicable), average capacity factor of a typical plant for a given technology (i.e., what percentage of the hours in a year the plant can generate at its nameplate capacity), and interest rate associated with capital cost.

Although the LCOE is commonly used and is valuable because of its simplicity, Rhodes et al. (2017)—as part of the FCe project—demonstrate that the standard treatment of LCOE ignores regional differences in capital and operating costs, availability of resources across locations (e.g., sufficient amounts of wind speed or solar insolation), access to fuels infrastructure (e.g., natural gas pipelines, railways for coal delivery), geographic and electric power grid topography, and generation mix and load profiles in different grids, among other possible challenges. Rhodes et al. (2017) further improve upon the traditional LCOE calculations by incorporating costs of certain externalities including emissions of sulfur dioxide, nitrogen oxides, particulate matter, and greenhouse gases (carbon dioxide and methane).

Recently, the U.S. Energy Information Administration (EIA) has developed the levelized avoided cost of electricity (LACE) as a complement to LCOE. Rather than costs, LACE estimates the weighted average revenue that a certain technology would provide per unit of electricity in $/kWh like LCOE (Namovicz 2013). LACE captures differences in generation portfolio mixes, grid topographies and load profiles across electricity systems. The same technology might have a different LACE value in different systems. One interpretation of the LACE of a power plant is that it represents the cost to generate the additional electricity that would be required if that power plant were not available (EIA 2016d). If LACE is greater than LCOE, that technology can be considered competitive in that system.[1]

Electricity systems are complex and require real-time matching of demand and supply, which comes with additional costs. In addition, load growth and generation siting can require new investment in the transmission and distribution networks. In the meantime, there could be congestion on the transmission lines that could prevent the flow of electricity to certain regions, raising new costs. Sometimes, the cheapest units may not be fully dispatched. Independent system operators (ISOs) manage these costs via the ancillary services markets and, sometimes, non-market payments. These and other practices by ISOs target grid reliability while meeting demand in real-time at minimum cost and are known as security-constrained economic dispatch and unit commitment. Neither LCOE nor LACE can fully capture these costs.

Dispatch modeling does not capture all costs, either (e.g., cost of new transmission), but by construct, it approximates security-constrained economic dispatch and unit commitment. As such, it follows economic dispatch subject to price signals (including energy, capacity and some ancillary services when applicable), operational characteristics of generation units, and transmission capacities across zones or nodes.

Dispatch modeling also allows users to investigate multiple scenarios in terms of generation mixes as well as any other policies or sensitivities. In the long-term capacity expansion mode, dispatch models build and retire units based on the economic viability of each individual unit. The results provide information on total capital expenditures; operating costs; fuel costs; emissions; revenues by unit; average, hourly,

1 A detailed discussion of LCOE, LACE, and net value is provided in Appendix B.

and regional prices; realized capacity factors over time; and reserve margins, among others. Although our models do not build or retire transmission, users can investigate the need for new transmission given the model results from different scenarios (e.g., location of new builds and price signals in different parts of a grid).

In this way, users can evaluate whole system costs from multiple dimensions. Moreover, assumptions on capacity factors, fuel, capital costs, operating costs, and other characteristics can be changed over time if there are reasons to do so. In the calculation of LCOE, such inputs are typically treated as constant over the assumed life of a typical plant of any technology. Such detailed model runs also improve LACE calculations since they provide the hourly wholesale price estimates at different zones or nodes.

In the hourly mode over one year, dispatch modeling allows users to capture dispatch under various scenarios (e.g., weather perturbations or unit outages). Users can also capture some of the ancillary services, the costs of which can be significant, especially during peak demand seasons. The incorporation of more variable resources, distributed energy resources, and storage can necessitate additional ancillary services and increase total cost of energy. The models cannot calculate the cost of ancillary services that do not currently exist. However, they can indicate when such additional services might be necessary to balance the market and their potential value.

We use two commercial software programs for dispatch modeling in addition to two other approaches. In this paper, we describe these four models and present results from two basic scenarios to demonstrate the importance of acknowledging system costs, the versatility and usefulness of different modeling tools, and shortcomings of each model.

BRIEF MODEL DESCRIPTIONS

For long-term resource capacity expansion in ERCOT (2015 to 2030), we utilize AURORAxmp (EPIS LLC 2016), a commercial economic dispatch tool, and an Excel-based model.[2] Then, we employ AURORAxmp, PLEXOS (Energy Exemplar Pty Ltd 2016), another commercial economic dispatch tool, and the Excel model for hourly dispatch simulations for 2030 (8,760 hours). In these runs, we use the 2030 generation portfolios from the long-term capacity expansion simulation of AURORAxmp to compare results consistently. Finally, the screening curve methodology (SCM) employs the 2030 demand forecast to estimate the minimum-cost generation portfolio to meet that demand.

For consistency across models, we employ the same assumptions to the extent possible: the portfolio of existing units, cost structures for potential new resources, operational characteristics, and fuel prices, among others. However, the Excel model, by its very nature, has simplifying assumptions and does not capture all the complexities of dispatch models. For example, generation units are aggregated by fuel/technology type. Similarly, the SCM aggregates thermal generation units into technology groups while treating wind and solar generation as negative load.

The Excel and SCM models are attractive because their simplicity makes them user-friendly and creates the opportunity to implement them as online tools. In this paper, we show that, using the same set of critical assumptions, all models yield mostly similar results for long-term or hourly simulations if some key assumptions are carefully captured. We can explain most of the discrepancies by inherent differences across models.

AURORAxmp

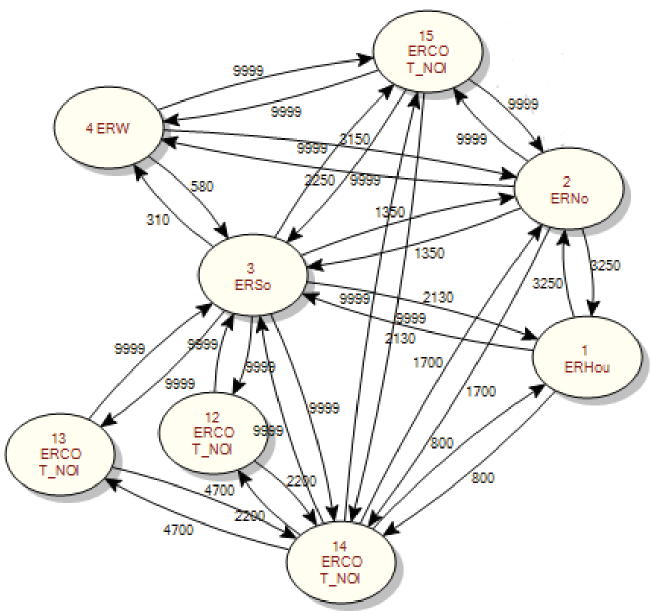
In AURORAxmp, many of the input parameters can be modified by users. These parameters include heat rates, ramp rates, start-up costs, fixed and variable operating costs, minimum run times, forced outages, scheduled maintenance outages, and many more. These parameters are included while calculating economic dispatch and long-term capacity expansion decisions. Some of the key parameters for the units modeled are reported in Appendix A.

2 The Excel model discussed in this paper was developed by FCe team members.

AURORAXMP is flexible and allows the configuration of a wide scope and level of granularity in both zonal and nodal network representations. In this study, we utilize a zonal configuration with the transmission network and power flow as represented in Figure 1, which allows users to run scenarios via adjustment of transmission capacities across eight zones. An example hourly flow is provided in Figure 2. (*Graphics used with permission of EPIS LLC.)*

FIGURE 1

Example AURORAxmp System Diagram for ERCOT



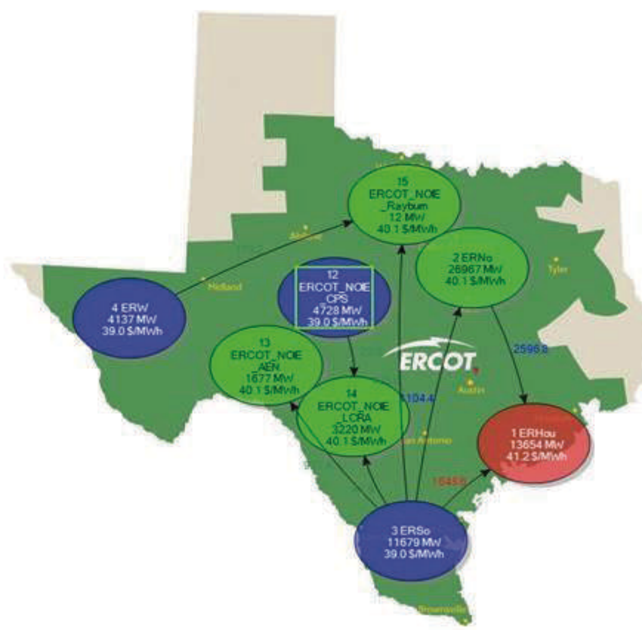
1 Houston; 2 North; 3 South; 4 West; 12 CPS; 13 Austin Energy; 14 LCRA; 15 Rayburn; 9999 represents effectively unconstrained flow.

Transmission losses across these lines vary by 0.5% to 1%; the wheeling charge is $0.66/MWh for all lines except for two DC connections to Southwest Power Pool (SPP). Some of the transmission lines are capacity-constrained; for example, the capacity of the line between zones 1 and 14 is 800 MW. This constraint can become significant if more generation is built in zone 14 and needs to be shipped to zone 1 (the greater Houston area), a growing load center where local air quality constraints limit generator permitting and construction. A similar constraint exists between zones 3 and 4, where much wind capacity has been built and more installations are planned. There are two DC-tie resources for importing electricity into or exporting out of ERCOT, with a total of 820 MW capacity, although this is relatively small when compared to installed or operational capacity in ERCOT (Table 2).

We use the mixed-integer programming (MIP) algorithm with the objective function to maximize the value of the resources being built and retired for the long-term (LT) capacity expansion.[3] Our study horizon is 2015 through 2030. However, we expanded the LT study planning horizon to 2040 in order to have better simulation convergence in the later years (e.g., 2025 to 2030). This way, even the decision to build a new unit or retire an existing unit in 2030 is based on 11-year economics.[4]

FIGURE 2

Example Snapshot of an Hourly Flow



3 In LT simulation, the mixed-integer programming (MIP) is formulated internally and passed to a third-party solver (MOSEK) to get a solution. AURORAxmp provides three optimization options: Traditional LT Logic, MIP logic with the objective function to minimize total system cost, and MIP logic with the objective function to maximize value (i.e., a mix of resources that are most profitable). We decided to employ the MIP logic with the objective to maximize value because it provides better stability in energy-only markets such as the one in ERCOT. The developer of the AURORAxmp, EPIS Inc., concurred with this choice. For further details, see www.epis.com.

4 EPIS recommends a minimum of five years of extension beyond the study horizon.

AURORAxmp assumes that new generators will be built and existing generators will be retired based on economics. The model's forward-looking economic evaluation algorithm decides all new builds and retirements and covers all future years through the final year of the planning horizon. The model calculates annual value (revenues less cost) over the planning horizon, converts them to real values using an inflation rate, and calculates the net present value (NPV) using a real discount rate. However, new build and retirement decisions are made on an annual basis.

In each LT simulation iteration, the model uses an updated set of new resource candidates and retirement candidates to perform the standard chronological commitment and dispatch logic. The model tracks the resource costs and value of all new and existing resources based on the market prices developed in the iteration. The long-term logic with the MIP algorithm simultaneously makes retirement and new-build decisions with the objective function of maximizing the sum of the net present value of resources on the system. It makes the build and retirement decisions while also adhering to user defined constraints which may include annual minimum or maximum builds, overall minimum or maximum resource additions, and retirement limits.

The model also includes extra constraints to limit the amount of change in system capacity that can happen between each iteration, to facilitate an optimal solution and to promote convergence. At the end of each iteration, the MIP logic adjusts the current set of new builds and retirements. When the simulations converge, the model will write the final Resource Modifier Table (RMT) with the new build and retirement decisions to the database. Convergence is deemed to have been met when the build decisions and resulting market prices have only changed within a tolerance chosen for the LT study from one iteration to the next.

PLEXOS

PLEXOS is a commercial energy market modeling software that can be used to model power, gas, and water markets. The PLEXOS model of the ERCOT grid (Texas Interconnection) is based upon previous work that modeled historical wholesale electricity prices for the year 2011 (Garrison, 2014). PLEXOS uses a combination of linear programming and mixed-integer programming to find optimal solutions for unit commitment and economic dispatch. The Xpress-MP solver was used for all simulations.

The PLEXOS model simulates a single, hourly day-ahead market using only the short-term schedule optimization module (ST Schedule). The ancillary services markets for frequency regulation, spinning reserves and non-spinning reserves were not modeled. The planning horizon is set to one year with intervals of one hour (8,760 hours total). The chronological phase is set to daily steps to simulate a day-ahead market. Additionally, the Transmission Detail parameter is set to Nodal[5] and the Heat Rate set to Detailed.

The PLEXOS model uses a subset of the parameters used by the AURORAxmp model. Some of the specific parameters used are provided in Appendix A. The ST Schedule module uses short-run marginal costs (SRMC) to determine the bids from each generator according to the following equation:

(1)

$$SRMC = (Fuel\ Price \times Marginal\ Heat\ Rate) + (Variable\ O\&M\ Cost)$$

Other possible short-run costs, including grid service charges, emissions costs, and heat production values, are not included in the model and are thus ignored.

The transmission system is set up as a reduced zonal network as depicted in Figure 1. It is solved using a DC optimal power flow approximation using a variable shift factor method and a single slack bus. Line limits are enforced, while transformers, contingencies and losses are ignored. Unserved energy and dump energy (i.e., over-generation) are not allowed to ensure that demand and generation are fully balanced.

5 Nodal here refers to transmission network modeling in PLEXOS only. Setting this parameter to Nodal preserves full detail of the transmission network and calculates optimal power flow. The other options, Regional and Zonal, calculate flows via a truck-route algorithm.

Excel Model

For many purposes, including annual hourly dispatch and long-term capacity expansion, it is possible to develop a simpler Excel-based model that can represent economic dispatch principles. One simple approach would be to choose the cheapest available facilities without exceeding their maximum capacity. Mathematically, this model can be expressed as the following:

(2)

$$\min_{\mathrm{AAG}_{n,t}} \left(\sum_{t=1}^{T} \sum_{n=1}^{N} MP_t \times AAG_{n,t} \right)$$

subject to

$$\sum_{n=1}^{N} AAG_{n,t} = D_t, \quad \forall\, t$$

$$0 \leq AAG_{n,t} \leq MG_{n,t}, \quad \forall t, \forall n$$

where N is the total number of power plants, T is the total number of hours in the generation window (8,760 hours for a year), MP_t market price in period t, $AAG_{n,t}$ is the total generation produced by power plant n during period t, $MG_{n,t}$ is the maximum generation available for power plant n during period t , and D_t is the demand during period t. Typically, MP_t is the cost of the most expensive dispatched technology, but we do account for price spikes in the ERCOT market as we describe below.

The second constraint limits the generation to the maximum capacity available for each power plant. For base load power plants, we adjust the maximum capacity on a percentage basis by technology and by month to approximate maintenance periods. For example, we reduced the maximum capacity of all existing coal plants by 20% in March, April, October, November and December to reflect historical maintenance activities.

Unlike the eight zones in AURORAxmp and PLEXOS, the Excel model treats ERCOT as a single node. Accordingly, the model implicitly assumes that every market participant sees the same market price, that there are no transmission constraints, and that differences in load growth across the zones are not captured.

Also unlike AURORAxmp and PLEXOS, power plants can be dispatched and turned-off instantaneously in the Excel model (i.e., there is no consideration of ramp rates). These start-up costs are not considered in the economic dispatch rule implied by (2); however, they are added to the total system cost. Further, there is no consideration of minimum production limits. Demand is satisfied hour by hour ignoring unit commitments in the previous or future hours and ignoring any minimum run times.

This myopic assumption may lead to unrealistic solutions on an hour-by-hour basis. For example, the model may turn on and off a coal-fired power plant in consecutive hours, which is physically unlikely because these thermal generators require several hours to safely ramp turbines up and down. In situations where coal is required to satisfy demand, the model will tend to underestimate coal generation due to the technology switching off more quickly than reality. However, even with this simplifying assumption, the model matches reality well on aggregate for 8,760 dispatch runs, and the assumption may not preclude near-optimal solutions for long-term capacity expansion.

The dispatch problem is solved by ordering all available power plants from the cheapest to the most expensive variable costs[6] and then deploying them in merit order to satisfy demand at any given hour. This approach assumes that the relative efficiencies between plants are fixed within a year in the model, although they can vary from year to year. Likewise, because fuel prices are correlated in the short run, they are changed annually in the Excel model forecasts, but not hour to hour. If the order of the marginal, or variable costs, is known, the problem of determining which power plants should be dispatched in any given hour is trivial. This methodology is known as merit order dispatch.

To clarify this proposed solution methodology, consider a simple example of a market with five power plants, each with a capacity of 100 MW: PP1, PP2, PP3, PP4 and PP5, where their marginal prices ($MP_{n,t}$) are \$10, \$40, \$70, \$120 and \$160/MWh

6 Variable costs in the Excel model include variable O&M costs plus fuel costs, which is the same as equation (1) used in PLEXOS.

FIGURE 3

Merit order example with constant capacity.

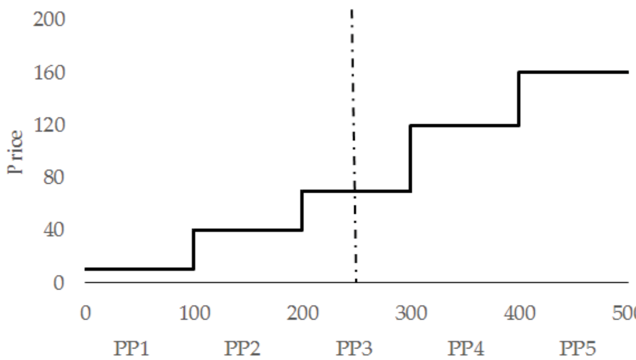
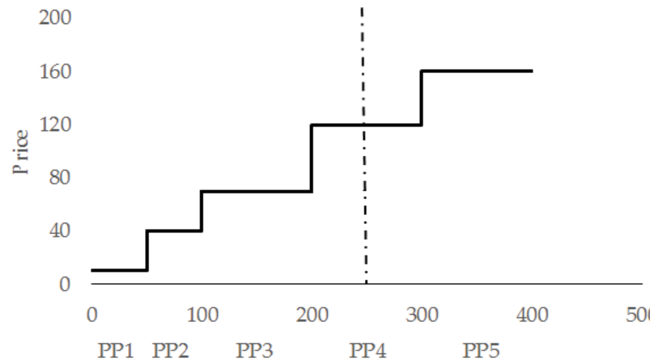


FIGURE 4

Merit order example with modified capacity.



respectively (Figure 3). The addition of incremental power plants as we move right on the x-axis gives shape to the supply curve. If the supply curve does not change over time, the only variable that sets the market price is the quantity demanded. If one hour of demand is 250 MW, the market price, MP_t, would be \$70/MWh, with a generation profile of $AAG_{PP1,1} = 100\ MW$, $AAG_{PP2,1} = 100\ MW$ and $AAG_{PP3,1} = 50\ MW$.

As an alternative, suppose that power plants 1 and 2 (PP1 and PP2) only have capacities of 50 MW each, but the dispatch prices for all five plants remain unchanged from the previous example. The dispatch order for the five plants will remain the same, but the supply curve will shift to the left (Figure 4). Now, with the same demand of 250 MW, the market price would be \$120/MWh, with generation profile $AAG_{PP1,1} = 50\ MW$, $AAG_{PP2,1} = 50\ MW$, $AAG_{PP3,1} = 100\ MW$ and $AAG_{PP4,1} = 50\ MW$. Repeating this process for the 8,760 hours over a year results in the annual observed generation mix and system costs given the available capacity of each technology and hourly demand levels.

Considering the number of power plants and the fast processing objective for the Excel model, ERCOT power plants are aggregated into different groups that are each managed as one modular unit. These groups are formed considering whether the plants were pre-existing or constructed during the capacity planning horizon, as well as the fuel type and heat rate. Each group of generators will be referred to as a technology. The fact that each technology group is analyzed as one unit means that all individual units will share the same LACE, LCOE, net value, and costs, simplifying the model runs for both capacity expansion and 8,760 dispatch analyses.[7] The existing technology categories used in the ERCOT model for 2015 are defined below:

- **Existing Coastal Wind**: Coastal & offshore wind generation (13 wind farms, 1,845.4 MW)
- **Existing Inland Wind**: Onshore wind generation (137 wind farms, 14,041.7 MW)
- **Existing Solar Photovoltaic (PV)**: All utility-scale PV generation (15 power plants, 287.7 MW)
- **Hydro**: All hydro-electric generation (29 power plants, 555.1 MW)
- **Biomass**: All biomass generation (7 power plants, 243.5 MW)
- **Nuclear**: All nuclear generation (4 power plants, 5,133 MW)
- **Existing Lignite:** All lignite coal-fueled generation (12 power plants, 7,142.0 MW)
- **Existing Bituminous:** All bituminous coal-fueled generation (21 power plants, 12,637.0 MW)
- **Existing Non-Cycling Gas**: All non-cycling natural gas fueled generation (138 power plants, 47,762.4 MW)
- **Existing Cycling Gas:** All cycling natural gas fueled generation (56 power plants, 3,789.2 MW)

7 A detailed discussion of LCOE, LACE and net value is provided in Appendix B.

The Excel model can be utilized as a dispatch model by simply ignoring new technologies beyond the assumed hardwired additions. In this mode, the results are analogous to all other models where the objective is simply to provide the cheapest electricity possible given the existing technologies (e.g., minimize total system cost while meeting demand).

In the long-term capacity expansion mode, this model starts from the available capacity and adds plants to the system from the next most "valuable" technology to meet growing demand or to replace units that have been retired in previous periods. Expansion and contraction occur in steps that represent an average power plant capacity in a technology group. For example, coal adjustments are in 500 MW increments.

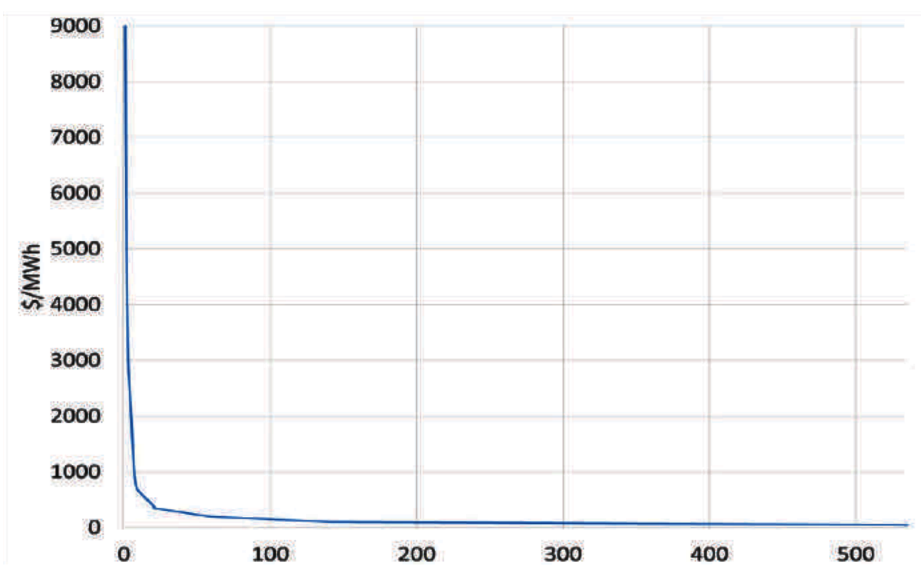
The difference between LACE and LCOE, referred to as net value, accounts for revenues and cost, making it possible to estimate the profit of each technology in each year. The net value is used to calculate an ordered list of plants that are candidates to be added to the system. This merit order is recalculated every year because of changes in demand, capital costs, operating and maintenance costs, subsidies, and fuel costs. It is important to note that these expansion decisions in the Excel model are myopic in that they only look at the revenue and cost for a given year. In contrast, the more complex dispatch algorithms may look at the revenues and costs over the forecast life of the plant (or through the last year of model run) when making expansion and retirement decisions.

When considering expansion decisions past 2015, the Excel model also considered adding six new technology categories designed to represent the likely characteristics of new builds: **New Coastal Wind, New Inland Wind, New PV, New Coal, New Cycling Gas, New Non-Cycling Gas.** The Excel model also includes a "Big M" technology to ensure that demand would be satisfied in every hour of the year. The cost of Big M generation is not added to the costs reported by the model, but it provides a signal to the model of the value of the last needed units of generation. Further, large levels of unserved generation (e.g., high levels of electricity provided by Big M) indicate that the electricity system may be in peril: it is not economic to serve unfilled load. The marginal cost of Big M was set to be $1 more than the most expensive available technology so that it would always dispatch last. During the runs of the model, the percentage of load that was provided by Big M was about 6%, which was treated as additional gas generation in the results presented below.

The Excel model does not include random events that might influence price like unexpected outages or extreme weather events. However, capturing

FIGURE 5

Approximate ERCOT Price Duration Curve – Top 6% of Hours



those inevitable high price periods is critical to the model system behavior. To mimic the likely price behavior in ERCOT, we used price data between 2011 and 2015, when on average there were 531 hours per year (about 6%) with prices above $50 in ERCOT, and an average of 18 hours where prices were $0 (Figure 6 of Potomac Economics, 2016).

We used a linear interpolation between the provided data points to produce our price distribution in Figure 5. To apply these prices, each hour was ranked in terms of its "thermal stress" (load provided by thermal technologies / installed thermal capacity). Our belief was that prices would be the highest when the thermal technologies were utilized the most, so the hour with the highest thermal stress was assigned the highest price, here $9,000/MWh, the next highest hour was assigned $4,500/MWh, and so on for the top 6% of hours in the thermal stress distribution. For the remaining 94% of hours, the marginal price of the highest dispatched technology was applied with the exception that the 18 hours with the lowest thermal stress were assigned prices of $0/MWh.

Every time a new megawatt of generation capacity is added, the capacity factor for all other technologies drops because the new project's generation will displace other power plants, assuming demand is constant and there are no retirements. Therefore, for every new megawatt constructed, LACE for all technologies will drop until there are no more profitable projects left to add. This point is when LCOE = LACE for the next most valuable project, and we call this the equilibrium point. If demand grows between years, the most efficient plants will be dispatched more due to the merit order. Thus, the LACE for these plants will rise with demand, and new capacity of this technology will be added to the market until the equilibrium point is reached again.

Before considering capacity additions, the model will consider removing plants from technologies that are not economically viable to keep online. The observation that LACE < LCOE in a given year does not necessarily mean that plants will be removed, because plant managers may keep operating while they recover fixed and variable O&M costs: FOM + VOM < LACE. Moreover for any older technology, LACE < LCOE simply means that no more capacity will be added. However, when LACE < FOM, managers would gain more benefit (i.e., lose less) by shutting down the unit rather than operating it. During this removal process, for each eliminated megawatt of capacity, the remaining power plants will increase production to satisfy the demand, increasing their capacity factors and reducing their LCOE, until the point where the LACE for the lowest *net value* technology equals its fixed cost. Capacity expansion and contraction occurs in steps that represent an average power plant capacity in a technology group. Like the expansions decision, retirement decisions are myopic and only look at the current year's LACE and FOM.

Screening Curve Method[8]

The Screening Curve Method (SCM) uses annual load shape information together with the costs of competing power plant technologies, such as annualized capital costs and variable fuel costs, to find a least-cost generation mix solution. The actual construction dates of units in that portfolio as well as retirements might occur at any year between the present and 2030. So, the calculated generation mix is a cost-based result independent of market behavior.

The SCM does not specify generator sizes, and each generator is assumed to be the same (100 MW each in this exercise). A 1 GW generator is assumed to be the same as 10 generators of 100 MW capacity each. The generators are assumed to be operated in one of three possible states at any given time: 100% output, 30% output (corresponding to the minimum output level for the generator), or off. No other intermediate output levels are considered. The 30% level is chosen to approximately correspond to typical minimum capacity for daily cycling units. Another minimum capacity level could be assumed instead.[9]

8 For more details, see Zhang, Baldick, & Deetjan (2015) and Zhang & Baldick (2016). An executable version of the model is available at http://users.ece.utexas.edu/~baldick/screening_curve_method_tool/scm.html

9 In PLEXOS and AURORAxmp, each thermal unit has a minimum stable level ranging from 20% to 55% (Appendix A).

The unit commitment and economic dispatch problems are approximated based on the trade-off between maintaining a generator at minimum output level and shutting it down. To balance the fluctuating load, the SCM calculates the associated costs of operating at minimum output level versus shutting down and chooses the cheaper option.

Unlike AURORAxmp and PLEXOS, but similar to the Excel model, the SCM aggregates all the generators in different ERCOT zones to form a single node. No transmission lines or congestion are considered. The new generation technologies are assumed to be available in all zones; there is only one set of characteristics for each potential new unit. Also, the SCM assumes one load growth profile rather than regional profiles, and scales up ERCOT load to 81.2 GW peak in 2030, the same as other models.

Unlike the other models, wind and solar resources are not dispatched. Using the same wind and solar profiles as other models, the SCM treats them as negative load to calculate net load. The portfolio of chosen generators is economically adapted to this net load. The 2030 wind and solar capacity are the same as the LT expansion results from AURORAxmp (see results section below). No hydro, demand response, nor any types of storage are modeled in the SCM. Existing thermal technologies are combined into six categories for this study; more categories can be used, but the result will not differ significantly.

The long-term average forced outage rates (FORs) were obtained for different generation technologies. For example, if the forced outage rate of a coal-fired generator is 10% and its capacity is 100 MW, it is assumed that it can only reliably supply a 90-MW load. The operating and start-up costs are reflected by a 90-MW generation slice, while the fixed cost of 100 MW is accounted for in expansion costs.

Unlike AURORAxmp and the Excel model, which build or retire based on the economic value of individual units, the SCM assumes operational lives for each of the technologies: 65 years for coal power plants, 55 years for combined-cycle gas turbine (CC as shorthand for CCGT) and simple-cycle combustion turbines (CT), 60 years for nuclear, and 25 years for wind based on Ventyx historical data. If a power plant is due to retire before year 2030, it will be removed from the existing capacity and counted as retirement. The SCM also considers economic retirement when retrofit cost plus variable fuel cost (VFC) is higher than building and running a new unit of any technology type. For details, see Zhang and Baldick (2016).

Each new technology can be viewed as a function of load levels as illustrated in Figure 6, where three technologies are plotted (New Coal, New CC, and New CT). The vertical axis represents the total cost, which includes VFC, VFC at minimum output level of 30%, Annualized Capital Cost, Start-up Cost (SC), FOM and VOM (see Zhang et al., 2015 for more details).

The lower load level corresponds to higher operating hours (equivalently higher capacity factor) for a generating unit, which then corresponds to higher total cost (VFC times longer operating hours). The three competing technologies have different total cost curves because of different capital costs and VFCs. Since coal units have higher capital cost but lower VFC, it is more economical to run them for longer operating hours, which occurs at lower load levels. Accordingly, the total cost of coal units is the least expensive among the three candidates at lower load levels. The SCM chooses the least-cost segments from the three curves and forms a least-cost curve. The crossing points where two curves cross separate the generation system into three regions, each region balanced by one technology. If the whole system were to

FIGURE 6

Screening Curve Method for New Technologies

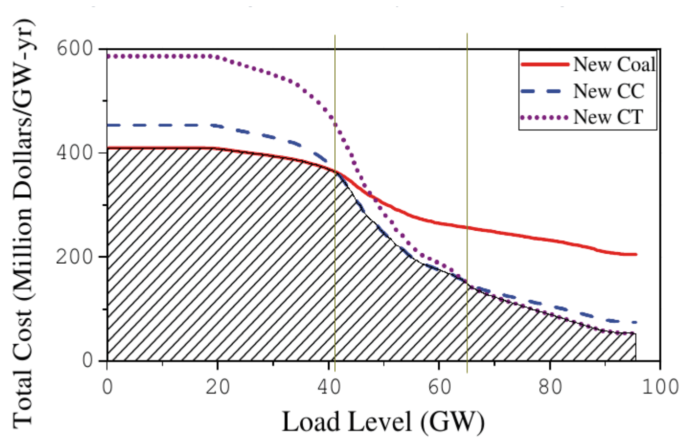
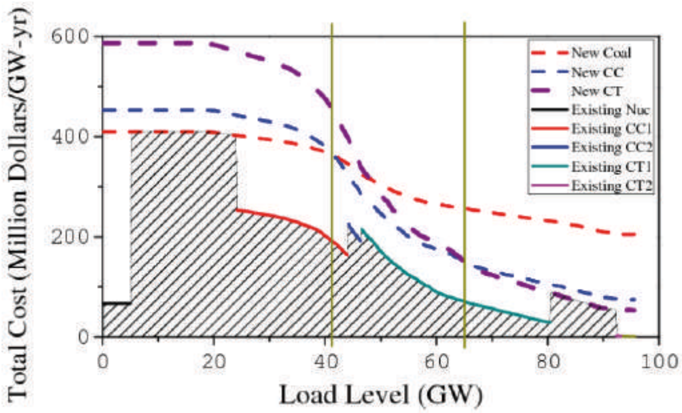


FIGURE 7

Screening Curve Method Considering Existing Technologies



be built from the ground up, the cost-minimizing portfolio would be about 41 GW of new coal, 24 GW of new CC, and 30 GW of new CT.

The cost curves of the existing capacity can be calculated in a similar way except that their fixed costs are already sunk. Based on the cost curve shapes, the existing capacity blocks are then fitted into the screening curves of the new technologies. The objective of positioning the existing capacity is to minimize the overall system cost, the shaded area in Figure 7. Some of the potential new technology cost segments are replaced by the blocks of the existing technologies. Now, the least-cost curve (upper bound of the shaded area) is a piece-wise curve that consists of both new technologies and existing technologies. Note that, in this case, the potential new CC is completely replaced by the existing capacity, which means that there will be no new CC built for this particular set of assumptions.

Summary of Key Differences across the Models

There are some key differences across the modeling approaches (Table 1). Two commercial software programs (AURORAxmp and PLEXOS) represent every single generating unit in a system and their operational characteristics. In contrast, existing generation units are grouped into 10 technology sets in the Excel model and 6 thermal technologies for net load in SCM. New technology groups are also treated differently: eight in AURORAxmp, six in the Excel model, and six thermal technologies in the SCM. Eight zones are modeled in AURORAxmp and PLEXOS versus a single ERCOT zone in the Excel model and SCM.

The fundamental economic concepts used in the Excel model and the dispatch software programs are similar but different in potentially critical ways. For the long-term capacity expansion, the algorithm of AURORAxmp (MIP with value maximization) searches for the mix of resources that would maximize the overall profit, building new or retiring existing units simultaneously based on NPV over the planning horizon. In contrast, the Excel model retires a certain capacity of a technology for which LACE is less than the FOM, and then decides to build new generation to meet demand as long as LACE is greater than LCOE in

TABLE 1

Key Differences across Four Models

	Technologies	New Builds	Retirements	Renewables	Zones*
AURORAxmp	Individual units	NPV over planning horizon	NPV over planning horizon	Dispatched via wind & solar shapes	8
PLEXOS	Individual units	N/A	N/A	Dispatched via wind & solar shapes	8
Excel	All units grouped into 10 existing and 6 new technology groups	LACE > LCOE per year	LACE < FOM per year	Dispatched via wind & solar shapes	1
SCM	All units grouped into 6 existing and 6 new thermal technology groups	Least-Cost	VFC	Deducted from load to obtain net load	1

* There are different assumptions for energy and peak load growth, some generation characteristics across the zones. Transmission capacity between the zones impacts congestions and zonal prices, which can be important for new build or retirement decisions.

TABLE 2

Resource Capacity by Fuel Type and Primary Mover

Fuel Type	Net Capacity 2015 (MW)	Primary Mover
Biogas	93.5	Internal Combustion Engine
Biomass	150.0	Steam Turbine
Coal, lignite	7,142.0	Steam Turbine
Coal, subbituminous	12,637.0	Steam Turbine
Natural Gas	51,551.6	Total
	34,629.2	*Combined-Cycle Gas Turbine*
	11,970.0	*Steam Turbine*
	4,724.8	*Open-Cycle Gas Turbine*
	227.6	*Internal Combustion Engine*
Solar	287.7	Photovoltaic
Water	555.1	Hydraulic Turbine
Wind	15,887.1	Wind Turbine
Uranium	5,133.0	Steam Turbine
TOTAL*	**93,437.0**	

* Note that this number represents installed capacity and is significantly larger than operational capacity reported in ERCOT (2015c). There are two main reasons. First, roughly 8,700 MW of combined heat and power (CHP) capacity is included (see detailed description of these units below). Second, we report nameplate capacity for wind; ERCOT assumes 14% peak average capacity contribution for non-coastal wind and 58% for coastal wind. We calculate annual hourly wind profiles for use in dispatch models (see below).

a given year. Both the Excel model and the SCM are designed to minimize total cost. Because the Excel model considers ERCOT as a single zone, a 35% "availability factor" for natural gas was imposed to mimic the transmission constraints in the actual system. In other words, natural gas plants cannot run more than 35% of the time.

The SCM is a different approach in that, in its simplest form, does not separate commitment and dispatch, but rather incorporates the cost of dispatch into the annualized cost model. In more advanced versions, SCM considers daily commitment based on the potential "off-line" time duration of each generator. In the version of SCM used for this study, if the potential off-line time is less than 8 hours, then the generator is maintained at minimum production during these hours; if the duration is more than 8 hours, the unit is shut down.[10] SCM seeks the least-cost generation portfolio for a target year using six existing and six new thermal technologies. The renewables are not dispatched but are deducted from load to obtain net load.

10 More sophisticated dynamic thresholds can be incorporated, as described in Zhang et al. (2015).

COMMON INPUTS

In the following sections, we describe parameters and assumptions reconciled among all four models, as needed, for 2015. This is the common departure point for the long-term simulations and for the 8,760 hourly dispatch runs in 2030.

Resources

The net capacity in ERCOT through the end of 2015 is summarized in Table 2. The operational parameters for each individual unit included in this database were gathered and reconciled from various sources.[11]

11 The following sources were referenced: (EIA 2015), (EIA 2016a), (EPA 2016), (ERCOT 2015c), (FERC 2016), (ICF 2016), (PUCT 2015), (TCEQ 2015), (TCEQ 2016), (TCPA 2016). The list of units and key operational parameters are provided in Appendix A.

Fuels

The following thermal generator fuels are included in our baseline model (Table 3). The EIA Form 923 fuel code is listed in parentheses. For the model runs, we used price projections for natural gas, lignite and subbituminous coal (Figure 26 and Figure 27); the numbers in Table 3 are for the purposes of a quick comparison. Other fuels do not have a significant market share (biogas and biomass) or the price does not change significantly over time to impact capacity factor of the plants (uranium).

TABLE 3

Fuels Included in Modeling

Category	Fuel	Baseline Price [$2015/MMBtu]
Biogas	Landfill gas (LFG)	-
Biomass	Wood and wood waste solids (WDS)	0.05
Coal	Lignite coal (LIG)	2.68
Coal	Subbituminous coal (SUB)	2.07
Gas	Natural gas (NG)	2.63
Uranium	Uranium (NUC)	0.51

Some generators may use secondary fuels for restart, backup or market reasons. These fuels, including some biogas, agricultural byproducts, black liquor, petroleum coke, distillate fuel oil, and jet fuel, typically represent a small fraction of overall fuel consumption in ERCOT, and they are not likely to increase their market share in the future. As such, we have excluded them for simplicity.

Wind

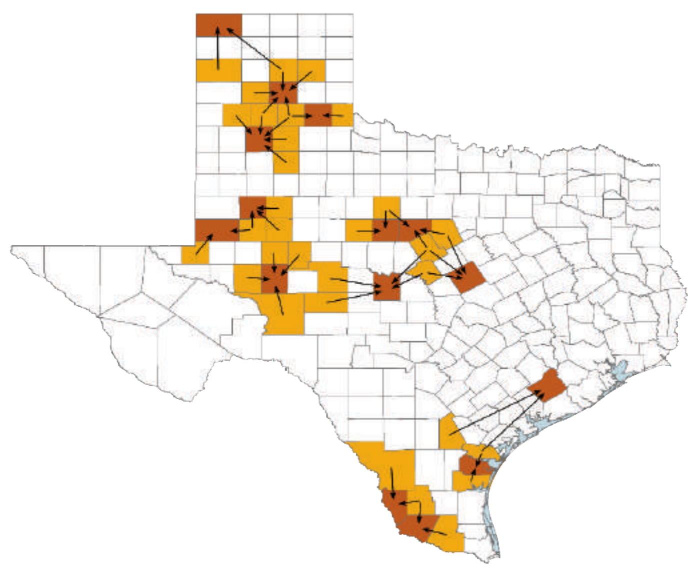
Wind generator outputs are based on an hourly wind plant dataset produced for ERCOT by AWS Truepower (ERCOT, 2015b; AWS, 2012). The dataset consists of hourly wind generator output profiles for existing and hypothetical wind sites throughout Texas from 1997 through 2014. These profiles were generated using the Weather Research and Forecasting Model, a mesoscale numerical weather prediction model, along with composite power curves for different turbine classes. We used the updated 2014 dataset since a 2015 dataset was not available at the time of conducting the analysis.

ERCOT separates wind generators into three categories: inland, coastal and offshore. However, we wanted to strike a balance between reduced modeling complexity and capturing more localized variance for the implementation of the AURORAxmp and PLEXOS models. To do this, we took the capacity-weighted average of all wind generators in each county to create county-level output profiles. These were then normalized between 0 and 1 and used as rating factors (% of maximum output at each hour).

Some of the counties did not contain any wind sites and thus lacked any output profiles. In this case, we created composite profiles based on the output profiles of adjacent counties (Figure 8). We used a minimum of two different counties for each composite county. Where no adjacent counties were available, we continued the search radially outward. Only three composite counties needed two hops, and just one county needed more than two hops.

FIGURE 8

Composite Wind Counties. Composite counties in orange; source counties in yellow.

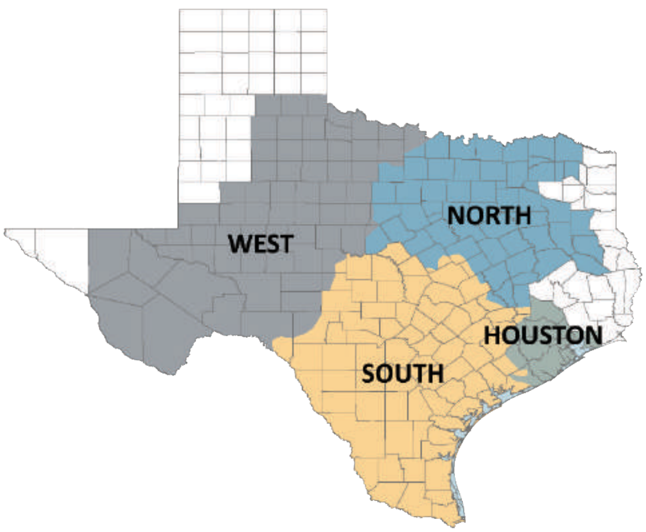


Finally, we composed three representative annual hourly wind profiles for ERCOT load zones (Figure 9) based on county-level data, including

ERCOT North (Figure 10), ERCOT South (Figure 11), and ERCOT West (Figure 12), as inputs for the subsequent long-term modeling.[12]

FIGURE 9

ERCOT Load Zones



Source: ERCOT

Summary statistics are provided in Table 4. There is significant variability of capacity factor across the year and some variability across the three load zones. For example, there are hours where there is no wind generation in each of the load zones and there are hours where wind generation can be above 90% of installed capacity, with an annual average of about 40% in the North and West load zones and 36% in the South load zone.

However, the wind output distributions are not normal nor identical across the three zones. The distribution for the North zone is U-shaped: there are more instances of very low and very high capacity factors than the average values. The distributions for the South and West zones are right-skewed: most of the observations fell below the average capacity factor. On average, capacity factors are higher in June (50% to 56%) than in September (23% to 30%).[13] There is also variability across counties; a version of Table 4 by county is provided in Appendix C.

FIGURE 10

2014 Hourly Wind Profile for ERCOT North Load Zone

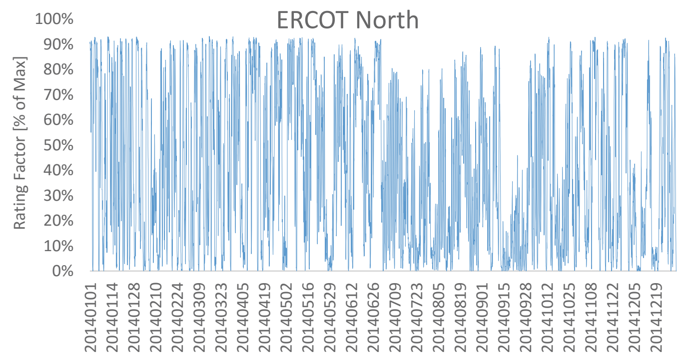


FIGURE 11

2014 Hourly Wind Profile for ERCOT South Load Zone

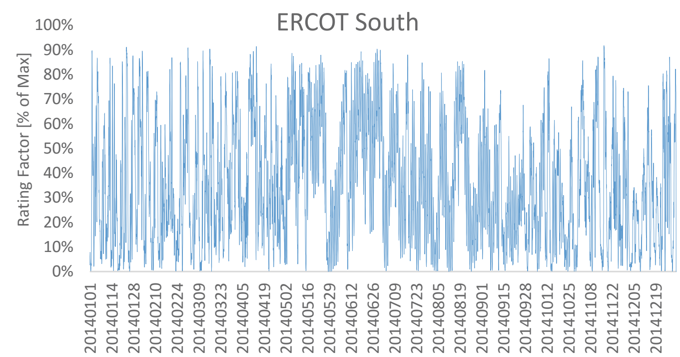
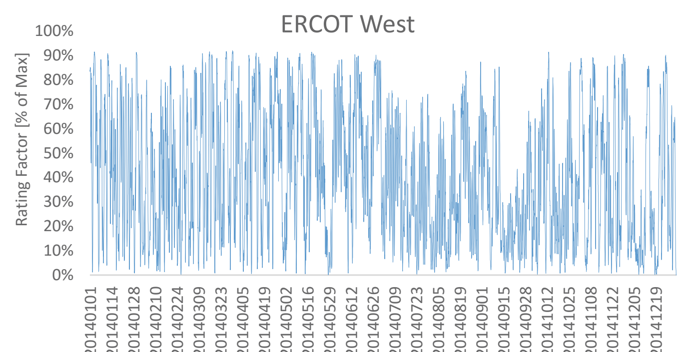


FIGURE 12

2014 Hourly Wind Profile for ERCOT West Load Zone



12 The allocation of counties into these load zones is provided in the generator list of Appendix C. The data for a handful of Houston counties are also reported although we do not discuss those in this section. There are a limited number of projects in the Houston zone.

13 Note that these observations are based on the 2014 data used in this analysis. Historically, the highest wind generation in Texas has occurred in spring or fall months, and the lowest generation in the summer months. However, these periods vary over the years along with weather patterns. Note that the highest-energy day and the lowest-energy day are more consistent with historical expectations.

TABLE 4

Wind Rating Factors by Load Zone (%)

Load Zone	Annual			June			September		
	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
North	0.0	40.3	93.2	0.1	55.2	92.5	0.0	22.9	89.3
South	0.0	35.7	91.9	0.7	50.1	90.4	0.1	26.7	82.3
West	0.0	40.7	91.8	1.1	55.8	90.0	0.7	29.9	87.2

The highest wind-energy day (aggregate ERCOT average) in 2014 occurs on March 26, a shoulder month with low total system demand (Figure 13). Although wind generation is fairly high and stable throughout the day in the West and North load zones (70%-90% rating factor), it starts low (about 43%) in the South load zone and peaks at about 81% rating factor in mid-day before starting to decline.

The lowest-energy day in 2014 occurs on May 29, which might be considered the beginning of summer in Texas (Figure 14). Again, the South load zone has a somewhat different profile than the other zones, but wind generation is very low in all three load zones. The highest rating factor occurs in the South load zone at about 17% in the early evening. The North load zone peaks at about 5% and the West load zone peaks at about 10% in the evening.

FIGURE 13

Wind Energy Production on Highest-Energy Day

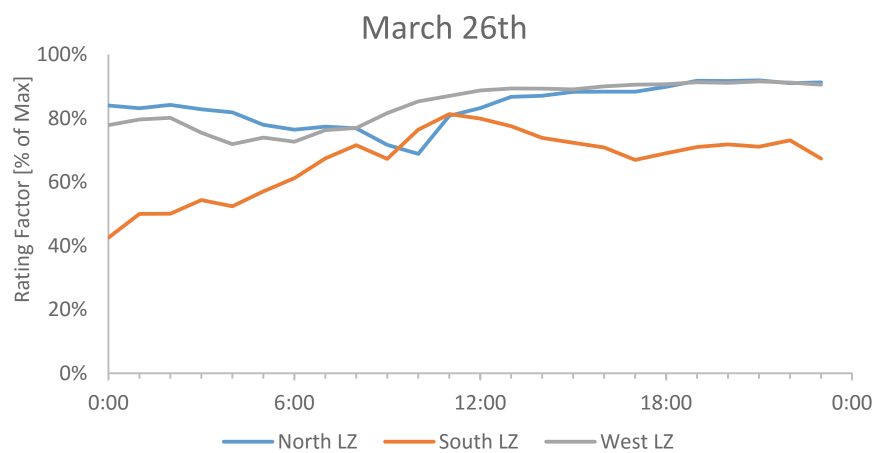
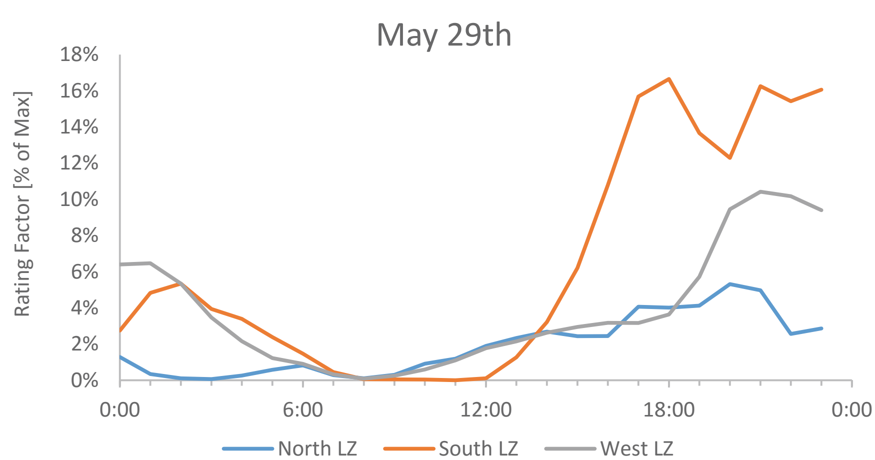


FIGURE 14

Wind Energy Production on Lowest-Energy Day



Solar

The solar generation profile used for this study was created by approximating the location and distribution of future solar resources and combining their unique solar generation profiles (Table 5). The ERCOT "Generator Interconnection Status Report" for February 2015 (ERCOT 2015a) was used to find the county location of proposed solar projects.

A unique generation curve was calculated for each location using the PVWatts calculator published by the National Renewable Energy Laboratory (NREL 2016). This calculator uses information about the solar array along with typical meteorological year (TMY) data to calculate an array's hourly solar output over one year. The arrays in this study were modeled as one-axis tracking arrays with 96% efficient inverters and a 1.1 DC-to-AC size ratio.

Figure 15 and Figure 16 show the capacity factors for each of the arrays on a typical winter and summer day, respectively. In winter, more frequent cloudy weather reduces the rating factor and increases the volatility of most of the solar arrays. Table 6 shows the statistical distribution of rating factors for each array.

By adding the generation curves together and weighting them based on the interconnection distribution (Table 5), a conglomerate solar generation curve was created and used in

TABLE 5

Distribution of Solar Resources in ERCOT

Location	% of Total Capacity
Marfa	55.38
Midland	22.12
Laredo	7.04
Amarillo	5.49
Abilene	4.75
Del Rio	3.38
Dallas	1.83

FIGURE 15

Typical Winter Day Solar PV Production by Region

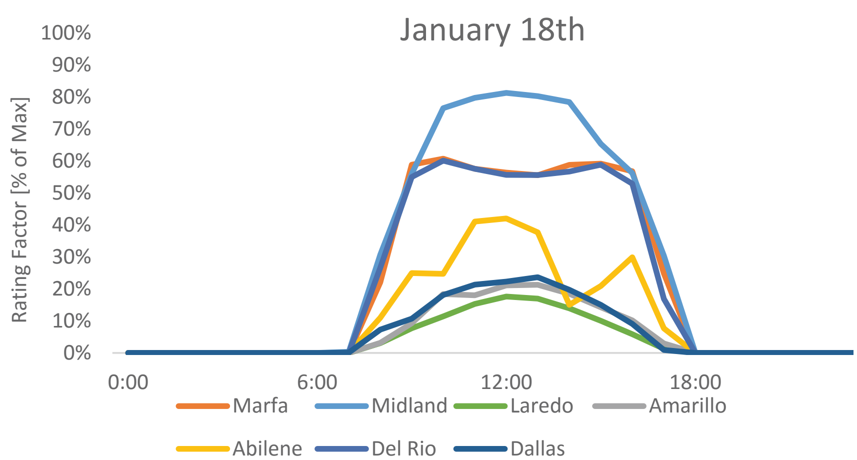


FIGURE 16

Typical Summer Day Solar PV Production by Region

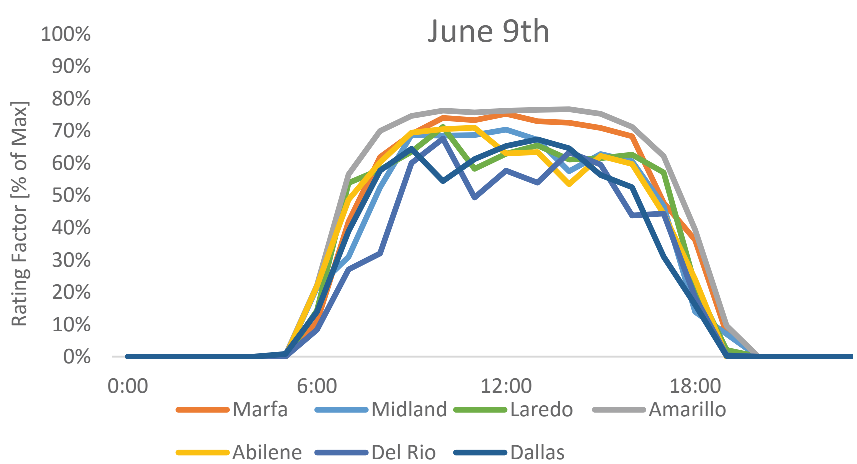


TABLE 6

Solar Rating Factors by Region (%)

	Annual			Winter			Summer		
	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
Midland	0.0	24.0	91.0	0.0	20.0	91.0	0.0	25.0	76.0
Marfa	0.0	24.0	83.0	0.0	17.0	77.0	0.0	30.0	81.0
Amarillo	0.0	22.0	84.0	0.0	15.0	71.0	0.0	28.0	79.0
Dallas	0.0	20.0	79.0	0.0	13.0	71.0	0.0	26.0	77.0
Abilene	0.0	22.0	82.0	0.0	15.0	70.0	0.0	27.0	75.0
Del Rio	0.0	18.0	77.0	0.0	13.0	70.0	0.0	24.0	74.0
Laredo	0.0	20.0	81.0	0.0	13.0	71.0	0.0	25.0	76.0

the models. This conglomerate curve can be scaled up to any installed capacity to produce a representative ERCOT solar generation curve. Figure 17 shows the typical winter solar generation curve. Capacity factors tend to be lower in the winter than in the summer due to the lower angle of the sun and the shorter amount of daylight.

Figure 18 shows the typical summer solar generation curve. The peak is less than 1.0 due to inverter losses, the projection of the sun onto the 0-degree horizontal panels used by 1-axis tracking arrays, and other inefficiencies in the system.

Combined Heat and Power Plants

Industrial combined heat and power plants (CHP), also known as cogeneration plants, are designed to supply heat to industrial processes and to allow excess heat to produce electricity.

FIGURE 17

Typical Winter Day Conglomerate Solar PV Production by Region

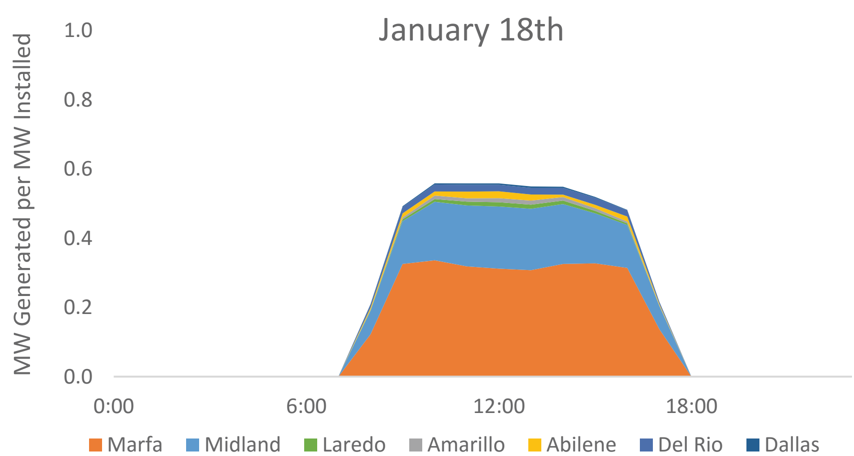
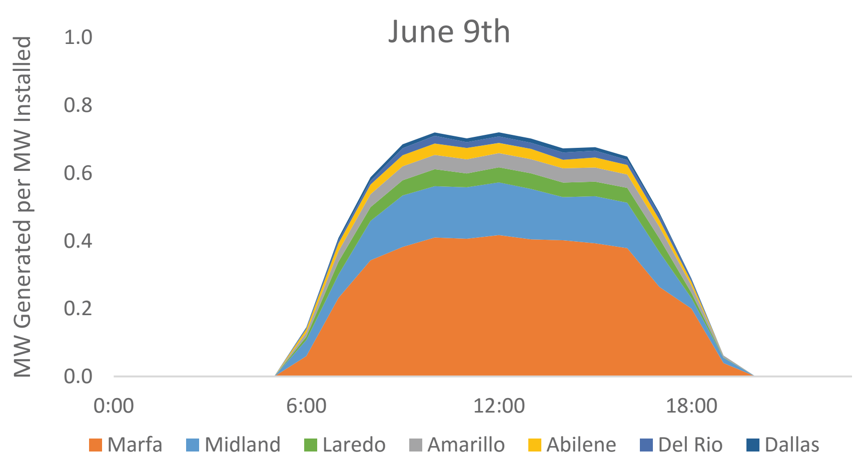


FIGURE 18

Typical Summer Day Conglomerate Solar Production by Region



The CHP plants in ERCOT can choose when to use power themselves and when to sell to the market; in other words, they are self-dispatched. In some cases, the amount of capacity available for selling to the market may only be a fraction of the net power capacity of a CHP plant.

Following a method developed previously (Garrison, 2014), the yearly percent electricity generation was calculated for each CHP plant based on EIA Form 923 data for years 2010–14. Plants with zero to minimal electricity generation over this period were ignored. Next, the average yearly percent electricity generation was calculated for these five years. The rated capacity was then calculated by taking the average of EIA Form 860 summer and winter net capacities. Finally, the rated capacity was multiplied by the average yearly percent electricity generation to obtain the dispatchable capacity for modeling purposes (Table 7). At close to 9,000 MW dispatchable capacity, CHP represents a significant portion of the ERCOT market.

Switchable Plants

A switchable generator is one located adjacent to two synchronous grids that has interconnection agreements with two different balancing authorities. As of 2015, there were four power plants in ERCOT that could be switched to other synchronous grids: Frontera Generation (CFE/

TABLE 7

Capacities for Combined Heat and Power Plants in ERCOT

	2014 Mean Rated Capacity [MW]	2010-2014 Mean Generation [%]	2015 Dispatchable Capacity [MW]
Bayou Cogen Plant	309.0	53.6%	165.6
Baytown Energy Center	807.5	98.4%	794.8
Baytown Energy Center Chiller Upgrade (2016)	270.0	98.4%	265.7
BP Chemicals Green Lake Plant	38.8	20.7%	8.0
C R Wing Cogen Plant	212.0	98.0%	207.7
Channel Energy Center	796.0	86.3%	686.6
Channelview Cogen Plant	865.0	99.5%	861.0
Clear Lake Cogeneration Ltd	384.9	100.0%	384.9
Corpus Christi Energy Center	468.0	98.4%	460.5
Deer Park Energy Center 1	1,152.0	100.0%	1,152.0
Equistar Corpus Christi	37.0	32.5%	12.0
ExxonMobil Baytown Refinery	157.5	2.7%	4.3
Freeport Energy Center	239.1	26.5%	63.4
Green Power 2	836.0	34.4%	287.2
Gregory Power Facility	388.5	100.0%	388.5
Houston Chemical Complex Battleground	281.5	18.7%	52.6
Ingleside Cogeneration	484.0	98.8%	478.4
Optim Energy Altura Cogen	580.3	82.5%	478.8
Oyster Creek Unit VIII	404.5	100.0%	404.5
Pasadena Cogeneration	762.5	97.5%	743.6
Sweeny Cogen Facility	470.0	91.6%	430.7
Texas City 1	467.5	98.1%	458.5
Texas Gulf Sulphur (New Gulf)	78.3	75.2%	58.9
Victoria Texas Plant	81.5	10.9%	8.9
Wichita Falls Cogeneration Plant	78.0	100.0%	78.0

Mexico), Tenaska Frontier (MISO), Tenaska Gateway (SPP) and Tenaska Kiamichi (SPP). Frontera Generation has announced that it will connect solely to CFE starting in 2016, so it will be excluded from the ERCOT area in our models. Additionally, the Antelope Elk Energy Center is being built in phases and will be switchable between ERCOT and SPP. Although these plants may technically be able to switch between grids given sufficient lead time, we assume that they are all available to ERCOT year-round. Shell has stated that it connects the Tenaska Frontier and Tenaska Gateway plants to ERCOT the vast majority of the time under its tolling agreements (FERC 2011).

Mothballed Plants

ERCOT allows plants to enter a temporary mothball status rather than permanently shutting down. In these cases, a generator can be called upon to "provide voltage support, stability or management of localized transmission constraints" (ERCOT 2016c) until a remedial transmission project can be completed or the reliability concerns are otherwise mitigated. ERCOT usually does this by entering into reliability must-run contracts with these plants. However, these contracts are meant to be stop-gap solutions, and plants that are mothballed rarely become full-time generators again.

Mothballed units, especially if they are coal-fired, require at least several weeks of advance notice to get ready. For simplicity, we assume that any unit mothballed through 2015 or announced to be mothballed is permanently retired. We do not attempt to model a mothball status in LT capacity expansion (840 MW of coal capacity in the future). These units represent a small percentage of the installed capacity in ERCOT.

Water

Hydroelectric generators are modeled based on maximum monthly capacity factors from EPIS (Table 8). The models then choose when to dispatch based on hourly conditions. Since the capacity factor is calculated from energy produced, the total capacity factor sets the maximum amount of energy produced each month.

Hydroelectric capacity is relatively small in ERCOT (Table 2). Therefore, these assumptions are not likely to have a significant impact on long-term capacity expansion runs, but they are important to capture for 8,760 runs.

TABLE 8

Monthly Maximum Capacity Factors for Hydroelectric Generators in ERCOT

Month	Max Capacity Factor [%]
January	11.2
February	20.8
March	36.4
April	32.2
May	33.6
June	31.0
July	21.6
August	12.6
September	8.4
October	8.8
November	10.4
December	13.6

Energy Storage

There are two large-scale battery systems operating in ERCOT: the Presidio NaS Battery and the Notrees Battery Facility. The Presidio facility is designed for reliability only. The 36-MW NoTrees Battery Facility is co-located with the Notrees Wind Farm, a 152.6 MW nameplate wind farm in Winkler County. It is set up to charge from the output of the wind turbines only, but it can then discharge back into the grid. This captive setup does not allow the batteries to be charged from the grid. Battery capacity is insignificant relative to the size of the ERCOT market and is not modeled in the base scenarios discussed in this paper.

Market structure

ERCOT has a nodal market design. There are thousands of electrical buses (nodes). Locational marginal prices (LMPs) are reported for each of these nodes every 5 minutes, consistent with security-constrained economic dispatch (SCED). These LMPs are aggregated to calculate prices at about 630 settlement points. These settlement prices can be different between certain nodes, sometimes significantly so. These differences are often due to weather anomalies, unscheduled generation or transmission outages, or transmission bottlenecks. In daily grid operations, these price signals are extremely important for the system operator to maintain reliability while meeting load in all zones at least cost.

Nevertheless, most of the time, prices are roughly the same across the ERCOT grid. Persistently significant price differences are recognized by market participants as arbitrage opportunities and they are mitigated by the appropriate investment in generation, transmission and/or demand response. As such, in a 15-year capacity expansion run, a nodal model does not add much value compared to a zonal model. Accordingly, we use the zonal version of AURORAxmp for long-term capacity expansion analysis (Figure 1). The Excel model and the SCM treat ERCOT as a single zone (or node).

The hourly dispatch models of AURORAxmp and PLEXOS are designed to simulate the day-ahead energy market. The real-time energy market is not modeled since it focuses on short-term reliability at timescales of seconds to minutes. Both models can include four types of ancillary services for reserves: Regulation Up, Regulation Down, Spin and Non-Spin. We have been unable to identify the resources that provided such services on a regular basis and revenues generated from such services. On the basis of reporting by the independent market monitor,[14] we estimate that the per-MWh value of these ancillary services has been only 4% of the energy price between January 2011 and December 2015.

Accordingly, we exclude ancillary services in long-term optimization for the base case scenarios presented in this paper. This way, AURORAxmp results are more readily comparable to results from the Excel model and the SCM, which do not include ancillary services. We do note, however, that these services can become more significant in the future to capture the value of storage technologies as well as balancing provided to compensate for variability in wind and solar generation, especially when the shares of these technologies reach certain threshold levels.

ERCOT does not have a long-term capacity market. Instead, it has instituted an operating reserve demand curve (ORDC) as of June 2014 to provide additional revenues to marginal resources during tight market conditions. AURORAxmp captures this market function by providing a price adder to units that may be needed to meet operating reserve margin in a zone. However, given the short history of the ORDC in ERCOT, we do not have sufficient data to represent it confidently via a price adder in the model. According to Potomac Economics (2016), the ORDC Adder averaged $1.41/MWh in 2015, its first full year of implementation. The average was raised owing to high value in August 2015 (about $9) but, the ORDC adder is expected to fluctuate from year to year subject to market conditions. As such, one year's data is hardly sufficient to develop long-term assumptions. Also, ERCOT (2016a) indicates the ERCOT market currently has more than adequate reserves for the next several years, which would likely suppress the value of the ORDC adder as well as other ancillary services. Therefore, we did not impose a price adder to reflect the scarcity of reserve margin in the runs discussed in this paper but, it is straightforward to incorporate as a sensitivity in future analysis.

AURORAxmp and PLEXOS also include Demand Side Curtailment resources, which may be dispatched when energy output from all other resources does not meet zonal loads. For the purposes of this study, we priced Demand Side Curtailment resources at $9,000/MWh, the same as the current energy price cap in ERCOT. Our goal is to make sure that the model will try to dispatch all available resources, as well as exhaust all new build options that are economically feasible, before it decides to dispatch a Demand Side Curtailment resource. According to ERCOT (2016a), standard offer load management programs amount to 208 MW, and emergency response service to 1,507 MW. There is also 1,153 MW of load resources providing responsive reserve services. Although these capacities appear low, they can still have a significant impact on peak prices. We will incorporate these in a sensitivity analysis in the future.

14 http://www.potomaceconomics.com/index.php/markets_monitored/ERCOT.

2 | Long-Term Capacity Expansion Scenarios

We explore two scenarios: Current Trends (CT) and Aggressive Renewables (AR). We use AURORAxmp, the Excel model, and SCM for the long-term capacity expansion analysis to obtain the generation portfolio in 2030. The 2030 generation portfolio resulting from the AURORAxmp long-term capacity expansion simulations is used for the hourly runs (8,760 hours) using AURORAxmp, PLEXOS, and the Excel model.

COMMON ASSUMPTIONS

In addition to common inputs to all models discussed earlier, there are some key assumptions that are common across all models (Table 9).

In the following sections, we discuss in greater detail key input parameters that we modified or added for the long-term resource expansion modeling: demand forecast and escalation; new resource candidates and their capital cost structures; hardwired capacities (especially for wind and solar); environmental compliance costs; and fossil fuel prices. These parameters are used across all models when applicable and unless otherwise noted.

TABLE 9

Key Long-Term Capacity Expansion Scenario Assumptions

Scenarios	Basic Assumptions
CT	• Demand growth forecasts by zone: ERCOT (2015d) • Capital cost forecasts: ERCOT (2015e) • PTC, ITC for new wind and solar projects • Hardwired units under construction: 5,180 MW of gas including 266 MW of CHP, 4,413 MW of wind, 642 MW of solar* • Cost of compliance with environmental regulations (excluding CPP): ERCOT (2011) • Natural gas price forecast: Hahn (2016)
AR	• Same as CT: demand growth, capital costs, PTC/ITC, environmental compliance costs, natural gas price • Additional hardwired capacity (including those under development and announced): 12,106 MW of wind, 2,162 MW of solar

* A list of hardwired plants in two scenarios analyzed in this paper along with their FOM, VOM and CAPEX are provided in Appendix D: ERCOT Hardwired Plant Additions for the CT Scenario and Appendix E: ERCOT Hardwired Plant Additions for the AR Scenario (in addition to the CT scenario).

CURRENT TRENDS (CT) SCENARIO

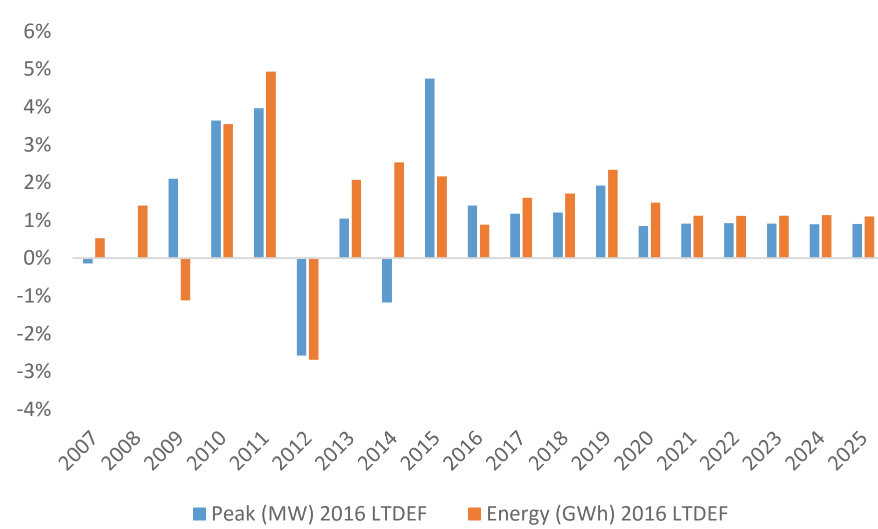
Load growth

We adopt the load growth assumptions from ERCOT (2015d), known as the Long-Term Demand and Energy Forecast (LTDEF): peak load (MW) grows at an average annual rate of 1.1% and energy load (MWh) grows at an average annual rate of 1.4% through 2025 (Figure 19).

Note that both peak load and energy demand grow faster in the near future, but the growth rate is lower and flat in later years. Also, note that growth rates have been much more volatile in the past. Some of these variations are driven

FIGURE 19

Year-on-Year Load Growth Rates: Historical (2007–15), Forecast (2016–25); from ERCOT (2015d)



by macroeconomic events such as the 2008–09 financial crisis, but weather also plays an important role. The extreme conditions in 2011 (the freeze in February, record temperatures and drought in the summer) fueled the high growth rates in 2011 and explain the contraction in 2012.

FIGURE 20

ERCOT Weather Zones (ERCOT 2016d)

The LTDEF uses actual weather data from 2002–14 (13 years) to forecast "normal weather" for each of the ERCOT weather zones (Figure 20) 13 times. Each forecast is ordered from the highest value to the lowest value. Then, for each ordered value, the average is calculated to obtain the "normal weather." These values are then mapped to 2003 data, which has been used as the representative year in recent ERCOT forecasts.[15]

However, these average growth rates vary across weather zones over the years. For example, in recent years, there has been significant load growth in the Far West weather zone owing to increased drilling activity in the Permian Basin (Figure 21).

Similarly, increased drilling activity in the Eagle Ford Shale fueled faster than historical growth in the South and partially in the South Central weather zones. Drilling activity declined significantly in both regions because of low oil prices but is expected to pick up again when oil and gas prices recover. Also, new industrial facilities such as LNG export terminals and petrochemicals facilities are under development, and their loads will have an impact primarily on the Coast and South weather zones. The LTDEF considers these factors.

We use the recent historical contribution of each region into overall energy demand (Figure 22) and peak demand (Figure 23) in ERCOT to distribute LTDEF forecasts across weather zones. We also extrapolate LTDEF forecasts through 2040[16] for our long-term capacity expansion runs with AURORAxmp (LTDEF forecasts run

15 For details, please see ERCOT (2015d).

16 In Figure 21 and Figure 22, we only display data through 2030 because that is our study horizon. We run the model through 2040 to allow the model's algorithm to calculate economics over at least 11 years of future cash flows.

FIGURE 21

Historical Energy Load Growth Rates by ERCOT Weather Zone, Calculated from ERCOT (2016e)

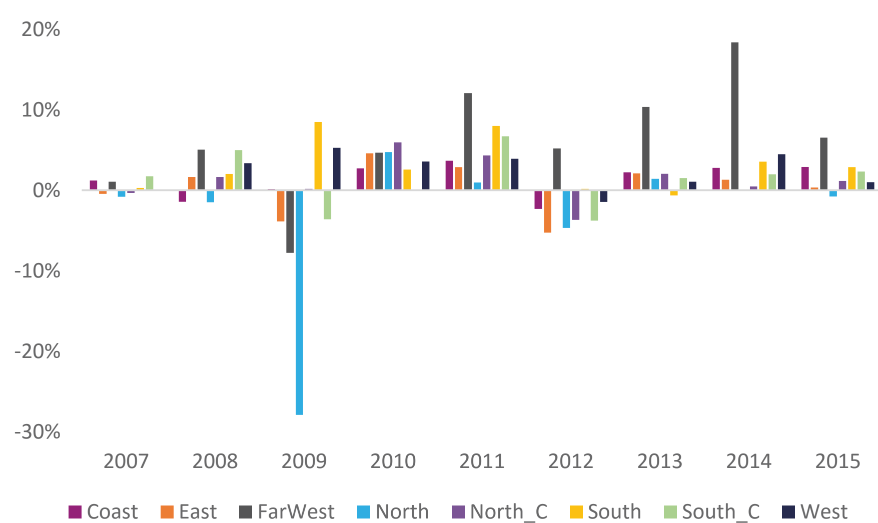


FIGURE 22

Historical and Forecast Energy Load Growth Rates by Weather Zone

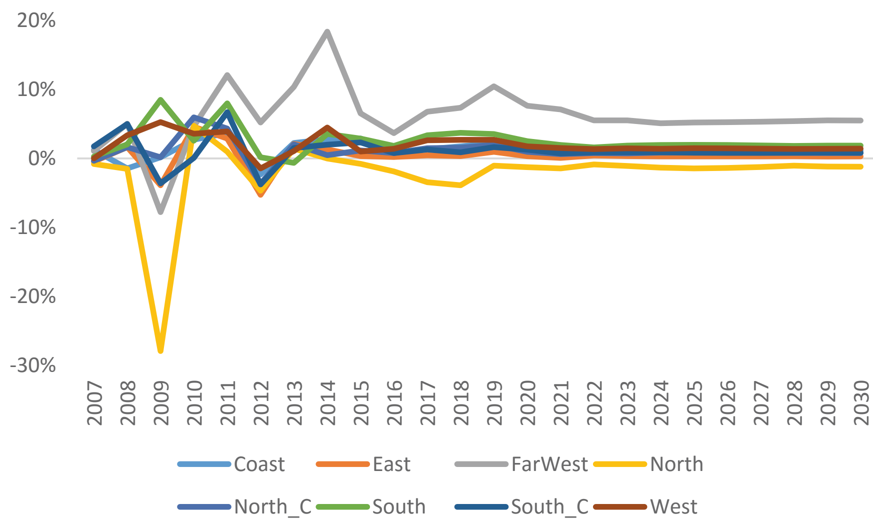


FIGURE 23

Historical and Forecast Peak Load Growth Rates by Weather Zone

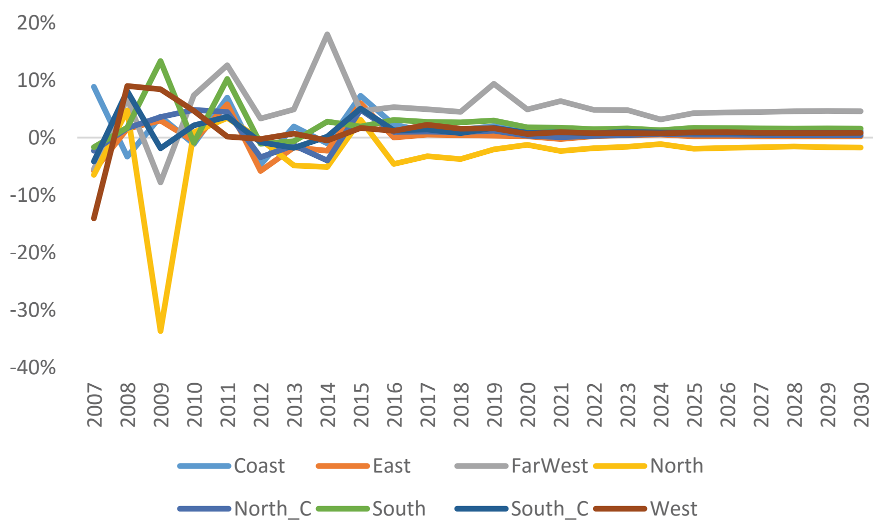


FIGURE 24

Annual Energy Demand Growth Rates in Four Main AURORAxmp Zones for ERCOT

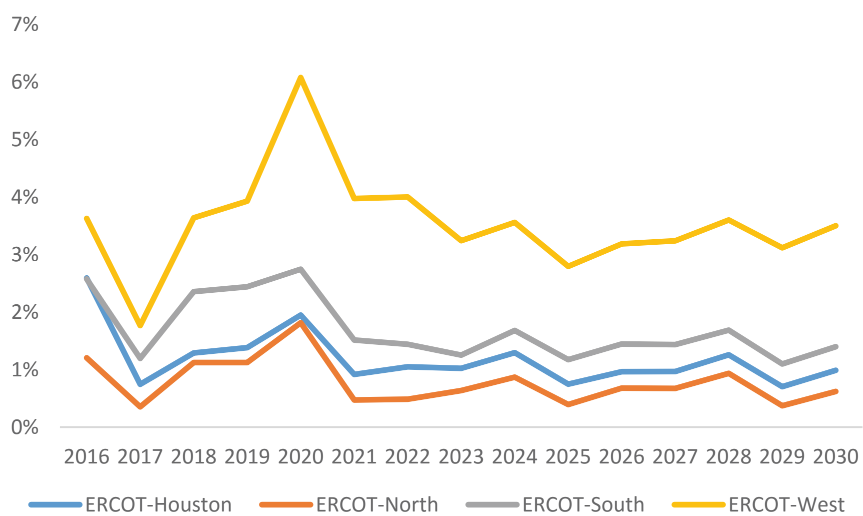


TABLE 10

Overnight Capital Expenditures by Generation Technology [$2015/kW], adapted from ERCOT (2015e)

Year	CC	CT	Coal	Nuclear	IGCC	Wind	Solar PV	Biomass	Geo	Battery	CAES
2015	1,073	791	3,202	6,395	4,307	1,740	1,781	3,903	5,025	718	1,051
2016	1,073	791	3,202	6,395	4,307	1,682	1,541	3,903	5,025	677	1,044
2017	1,073	791	3,202	6,395	4,307	1,627	1,352	3,903	5,025	633	1,039
2018	1,073	791	3,202	6,395	4,307	1,573	1,241	3,903	5,025	575	1,033
2019	1,073	791	3,202	6,395	4,307	1,521	1,191	3,903	5,025	543	1,028
2020	1,073	791	3,202	6,395	4,307	1,477	1,149	3,903	5,025	512	1,022
2021	1,073	791	3,202	6,395	4,307	1,436	1,110	3,903	5,025	496	1,016
2022	1,073	791	3,202	6,395	4,307	1,395	1,074	3,903	5,025	480	1,011
2023	1,073	791	3,202	6,395	4,307	1,355	1,045	3,903	5,025	465	1,005
2024	1,073	791	3,202	6,395	4,307	1,317	1,024	3,903	5,025	463	999
2025	1,073	791	3,202	6,395	4,307	1,280	1,005	3,903	5,025	461	995
2026	1,073	791	3,202	6,395	4,307	1,253	986	3,903	5,025	458	989
2027	1,073	791	3,202	6,395	4,307	1,226	968	3,903	5,025	456	983
2028	1,073	791	3,202	6,395	4,307	1,201	950	3,903	5,025	453	978
2029	1,073	791	3,202	6,395	4,307	1,176	932	3,903	5,025	451	973
2030	1,073	791	3,202	6,395	4,307	1,151	915	3,903	5,025	448	967
2031	1,073	791	3,202	6,395	4,307	1,127	898	3,903	5,025	446	962

through 2025). Since the Excel model treats ERCOT as a single zone, it only uses the aggregate demand growth figures for ERCOT. The SCM optimizes the ERCOT system for year 2030.

The growth outlooks we use in AURORAxmp and Excel model are very close to the LTDEF projections. For ERCOT energy demand, the difference between our model inputs and ERCOT LTDEF forecasts is less than 0.9% on average. For peak load, the difference is about 2.7% for only two years and mostly less than 2% in other years, averaging 1.6%.

Regional forecasts used by AURORAxmp are also consistent with the LTDEF forecasts, and, importantly, capture the expectation of faster growth in the Far West (or West in AURORAxmp terminology) relative to other zones (Figure 24). However, the eight load zones in AURORAxmp do not perfectly correspond to ERCOT weather zones.[17] We matched the growth rates in the model as closely as possible to the LTDEF projections. This regional treatment of load growth in AURORAxmp, compared to the single-zone treatment in the Excel model and SCM, is one of the factors that could lead to differences in results.

Capital costs

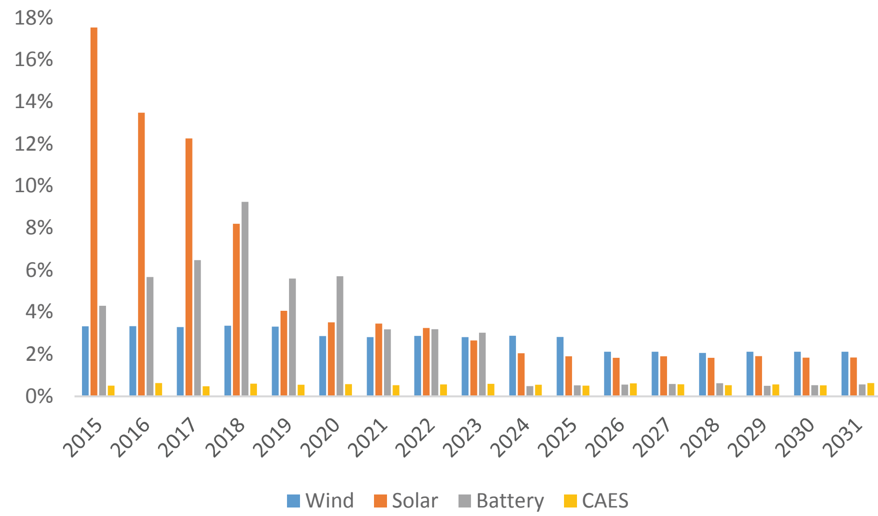
For the long-term capacity expansion analysis, an important input is the overnight capital expenditures for building a new plant. There are various sources for such data such as Black & Veatch (2012), EIA (2013), and Lazard (2014). In addition, there are forecasts from industry associations and reports from the Lawrence Berkeley National Laboratory on past cost performance. There is no consensus on future forecasts. Even the past data indicate significant regional variability. Updates are provided regularly because of technological improvements and the economies of scale resulting from the expansion of installed capacity of newer technologies.

Although the cost estimates for conventional technologies such as combined cycle and combustion turbines are fairly well established,

17 The four main zones in AURORAxmp are aggregations of the eight zones used by ERCOT; AURORAxmp also has four relatively small zones for Austin Energy, CPS, LCRA and Rayburn territories.

FIGURE 25

Annual Decline Rates in Overnight Capital Expenditures of Wind, Solar, Battery Storage, CAES*



* Currently, AURORAxmp long-term resource expansion algorithm does not include either battery or CAES as new resource candidates. Therefore the algorithm will not decide to build these energy storage resources although we can hardwire storage.

there are regional variations even for those, and technological improvement cannot be ruled out (e.g., current combined cycle plants are more efficient and have better ramping capabilities). More uncertain are the expectations on capital expenditures of wind and solar as well as other technologies with currently limited market share (e.g., storage). On the other hand, in times of high economic growth, costs of capital-intensive projects such as power plants are likely to increase driven by increased competition for engineering, procurement and construction services as well as steel, specialized equipment, and other supplies.

Given these complexities, it is possible for different analysts to develop divergent forecasts for capital costs of different technologies. In fact, although keeping overnight capital expenditures for conventional technologies the same over the years in real terms[18] seems to be commonly (though not universally) accepted, there are a variety of assumptions on emerging technologies. Since we wanted to maintain our results' comparability to scenarios developed by ERCOT, we used the ERCOT LTSA 2016 assumptions (Table 10).

These estimates imply the same cost every year in real terms for conventional thermal technologies as well as IGCC and biomass. In contrast, wind and solar costs in real terms decline roughly 2.7% and 4.9% per year but faster in the near future (Figure 25). In contrast, the EIA assumes about $2,600/kW for solar PV in 2015 as compared to about $1,800/kW by ERCOT.[19]

For the long-term capacity expansion simulation with AURORAxmp, we convert the capital cost ($/kW) shown in Table 10 into Base Capital Carrying Cost in $/MW-week, an annuitized fixed payment after accounting for assumed tax rates, depreciation schedule, book life for various generation types, capital structure, and costs of debt and equity (Table 11).

For example, advanced CC gas units have overnight capital cost of $1,073/kW (Table 10). Utilizing assumptions in Table 11, we convert $1,073/kW overnight cost into an annuitized fixed Base Capital Carrying Cost of $1,693 / MW-week. If the model decides to build a new Advanced CC unit in year 2016, then this unit will incur fixed Base Capital Carrying Cost for every year from 2016–35 (20-year book life), in addition to any fixed and variable O&M costs.

The most significant differences between the parameters assigned to generation technologies

18 Real costs here mean adjusted for inflation.

19 AEO 2016 cost assumptions for other technologies, which are based on an engineering analyses, are also somewhat different: see EIA (2016e).

TABLE 11

Financial Parameters for Calculating Base Capital Carrying Cost for Potential New Resources

	Adv. CC	Adv. CC 1x1	Adv. CT	CT	Biomass	Geothermal	IGCC	Nuclear	Pulv. Coal	Solar Thermal	Solar PV	Wind
Debt Return	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	4.8%	4.8%	4.8%	12.0%	12.0%	8.0%
Equity Return	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	8.0%	8.0%	8.0%	7.0%	7.0%	9.6%
Debt %	65%	65%	40%	40%	40%	40%	40%	40%	40%	60%	60%	55%
Equity %	35%	35%	60%	60%	60%	60%	60%	60%	60%	40%	40%	45%
Composite Cost	8.0%	8.0%	8.4%	8.4%	8.4%	8.4%	6.7%	6.7%	6.7%	10.0%	10.0%	8.7%
Interest Deduction	1.7%	1.7%	1.1%	1.1%	1.1%	1.1%	0.7%	0.7%	0.7%	2.5%	2.5%	1.5%
After Tax Cost of Capital	6.32%	6.32%	7.35%	7.35%	7.35%	7.35%	6.04%	6.04%	6.04%	7.48%	7.48%	7.18%
Real After Tax Cost of Capital	3.73%	3.73%	4.73%	4.73%	4.73%	4.73%	3.45%	3.45%	3.45%	4.86%	4.86%	4.57%
Book Life Years	20	20	20	20	20	20	30	30	30	20	20	20
Tax Recovery Period	20	20	15	15	5	5	20	15	20	5	5	5

Notes: (1) We assume 2.5% for general inflation and 35% Federal Business Income Tax; in Texas, there is no state income tax. (2) The Tax Recovery Period is based on IRS Modified Accelerated Cost Recovery System (MACRS). (3) For debt/equity returns and ratios, we refer to (i) Washington State Department of Revenue (2016); (ii) NREL (2013); and (iii) NREL (2014).

are the capital structure and costs of debt and equity. Although we tried to reflect these financing terms as realistically as possible, these terms are often project-specific and data are not always publicly available. As such, it is possible for these assumptions to contribute to differences between our results and those of ERCOT, among other analyses. Still, their impact on capital carrying costs is less significant than the impact of the federal subsidies (PTC and ITC). The Excel model uses the same underlying discount rates as other approaches.

Tax credits

The federal production and investment tax credits (PTC and ITC) are applied to wind and solar as outlined in the Consolidated Appropriations Act, 2016[20] in both AURORAxmp and Excel models. The Act extended the expiration date for PTC and ITC, with a phase-down schedule.[21] To reflect the law, for wind facilities that have begun commercial operation after 2006, we added a negative adder ($/MWh) to its variable cost in a nested structure. Prior to 2018, each wind facility had a production tax credit of $23/MWh for 10 years, which will be reduced to $18.40, $13.80, and $9.20 per year for 10 years in 2018, 2019 and 2020 respectively. For solar facilities, we incorporated ITC similarly as a negative cost adder, but this time as capital cost converted to $/MW-week basis and included in the fixed-cost input of solar resources (Table 12).

TABLE 12

Levelized Investment Tax Credit for Solar PV Facilities [$/MW-Week]

Year	2015	2016	2017	2018	2019	2020	2021	2022
Levelized ITC	-596	-516	-453	-416	-399	-333	-272	-120

Note: The decline trend of Levelized Investment Tax Credit reflects the combination of overnight cost improvement and phase-down of ITC.

20 See United States Congress (2015).

21 See Renewable Electricity Production Tax Credit (PTC) at DOE (2016); Federal Investment Tax Credit (ITC) at DSIRE (2016).

Hardwired new builds and retirements

There are several power plants in ERCOT that are already under construction or in advanced stages of development. The model is not likely to capture these capacities as its logic requires a multi-year forward look. We also do not want the model to build extra capacity because price signals are misled by the absence of these units in our resources database. This is particularly an issue for renewables. AURORAxmp typically does not build as much renewables capacity as is under construction; when the model builds any wind or solar capacity, it occurs in late 2020s when the overnight CAPEX of these technologies are expected to be lower than that of gas units. Similarly, the Excel model adds 1.5 GW of Coastal Wind in 2029, 2 GW of Inland Wind in 2030, and 1.5 GW of PV in 2029 in the absence of assumed hardwired constructions.

We have seen this result repeatedly over the last five years of running the AURORAxmp model. The main reason appears to be that we cannot consistently capture long-term power purchase agreements that are granted to wind and solar projects by utilities and cooperatives, local tax and other benefits offered by municipalities, or revenues from the sale of Renewable Energy Certificates (the latter has not been significant in Texas for a long time but it matters in other jurisdictions).

As such, we hardwire those projects that are already under construction in the CT scenario, including roughly 4,900 MW of natural gas units, 640 MW of utility scale solar, and 4,400 MW of wind resources (Table 9).[22] For thermal resources, having a signed interconnection agreement with ERCOT is sufficient as this process requires developers to meet numerous technical criteria and acquire all environmental permits in addition to demonstration of access to water (e.g., acquisition of water rights).[23]

We also hardwire the retirement of roughly 840 MW of coal plants at the announced date of mothballing. Otherwise, the model uses its economic logic to decide whether to retire a unit. Wind turbines are said to have an economic life of 25 years. However, industry news suggests that most wind turbines will be retrofitted before reaching that age and will continue to operate. Ideally, we would want to introduce a cost-adder for this retrofit similar to cost adders to comply with environmental regulations discussed in the next section. However, we do not have data on the cost of wind turbine retrofits at this time. We decided to extend the life of wind capacity beyond 25 years to keep them operational throughout our study horizon.

Environmental regulations compliance

There are a series of environmental regulations that threaten the retirement of some thermal units. Outside ERCOT, the threat of these environmental regulations has already caused many retirements (primarily coal but also some older gas units). This threat was made stronger by shrinking revenue margins driven by low natural gas prices and increasing share of renewables dispatched at low or sometimes negative prices owing to their near-zero marginal costs and PTC revenues. Shrinking revenues seem to be the main reason for some early nuclear retirements as well. We do not consider the impacts of the Clean Power Plan.

TABLE 13

Retrofit Costs for Coal Power Plants ($/MW-Week).

Retrofit Cost ($/kW)	Fixed Cost Adder ($/MW-Week) from 2015 to 2024
50	115
200	460
300	690
400	920
450	1,035
650	1,495
700	1,610

ERCOT (2011) provides cost estimates for coal and gas units in ERCOT to comply with Clean Water

22 The following sources were used for projects under construction and future projects: ERCOT (2015c), ERCOT (2016b), EIA (2016b), EIA (2016c), PUCT (2015), SNL (2016), SEIA (2016), TCEQ (2015), TCEQ (2016), and TCPA (2016). Operational details of these units are provided in Appendix E.

23 We excluded some projects because they did not meet any of our selection criteria or were insignificant capacity: CAES: 911 MW (storage), CCGT: 16,589 MW, CCGT+CCS: 500 MW, Hydro: 10 MW, IC: 94 MW (NG, biomass), IGCC+CCS: 240 MW (coal), OCGT: 9,666 MW, ST: 5,010 MW (nuclear).

Act Section 316(b), coal combustion residuals disposition (coal ash), Clean Air Act – Hazardous Air Pollutants (HAP), and Clean Air Transport Rule (CATR). Although not identical laws, we treat HAP compliance as a substitute for Mercury and Air Toxics Standards (MATS) and CATR as a substitute for Cross-State Air Pollution Rule (CSAPR). Also, based on ERCOT (2014), we assume that scrubber costs provided in ERCOT (2011) also provide compliance with the Regional Haze rule.

Accordingly, we first estimate the potential retrofit cost ($/kW) for coal units to comply with these environmental regulations. We then convert these costs into a fixed-cost adder in $/MW-week basis between 2015–24 (Table 13). The estimated retrofit costs of individual coal units in ERCOT are reported in Table 14. Since we impose these retrofit costs, we run the model without emissions costs for SO_2 and NO_X to avoid penalizing these plants twice.

Candidates for new thermal builds are assumed to be compliant with these new regulations. These costs are considered only in the AURORAxmp runs. However, units with the highest retrofit costs are not the units that retire in the AR scenario contrary to what one might expect. Still, most of the units that retire have retrofit costs of $200-300/kW.

TABLE 14

Retrofit Costs Assignment based on ERCOT (2011)

Name	Retrofit Cost Assignment [$/kW]
Big Brown #1	650
Big Brown #2	650
Coleto Creek #1	50
Fayette Power Prj #1	400
Fayette Power Prj #2	400
Fayette Power Prj #3	450
Gibbons Creek #1	300
JK Spruce #1	200
JT Deely #1	50
JT Deely #2	50
Limestone #1	200
Limestone #2	200
Martin Lake #2	400
Martin Lake #3	400
Monticello #1	700
Monticello #2	700
Monticello #3	400
Oklaunion #1	200
San Miguel #1	300
Sandow #4	200
WA Parish #5	50
WA Parish #6	50
WA Parish #7	50
Martin Lake #1	400

Fuel Price Forecasts

The natural gas price is the most important fuel price in ERCOT given that more than half of generation has been from gas-fired power plants in recent history. More importantly, natural gas fired generation is often the marginal supplier of electricity. Coal prices (both subbituminous and lignite) have been much more stable than natural gas prices. Given the volatile history of natural gas prices, the current turmoil in the oil and gas industry, and the uncertainty associated with natural gas demand from various sectors, there are many forecasts available.

ERCOT uses an average forecast for Henry Hub natural gas price from EIA scenarios (Reference and High Oil & Gas Resource) employed in the Annual Energy Outlook 2015.[24] This forecast is significantly higher than any of the other more recent forecasts and lacks cyclicality (Figure 26). In our analysis, we use the mean Henry Hub natural gas price forecast produced via statistical modeling by Hahn (2016) rather than any of these alternative forecasts.

In AURORAxmp, we impose monthly natural gas shapes from the IHS forecast on annual natural gas price forecast generated by Hahn (2016), and then extrapolate monthly prices through 2040 to input into the model, which also has basis differentials across different ERCOT zones. The Excel model uses the annual averages. The large differences between the forecast used by the ERCOT LTSA and forecast by Hahn (2016) are likely to have a significant impact on capacity expansion runs. Given that basis differentials across ERCOT are

24 The average of natural gas price forecasts from AEO 2016 Reference and High Oil & Gas Resource scenarios is on average $0.38 lower than the AEO 2015 estimates, with larger differences in the early years of the forecast.

FIGURE 26

Henry Hub Natural Gas Price Forecasts [$2015/MMBtu]

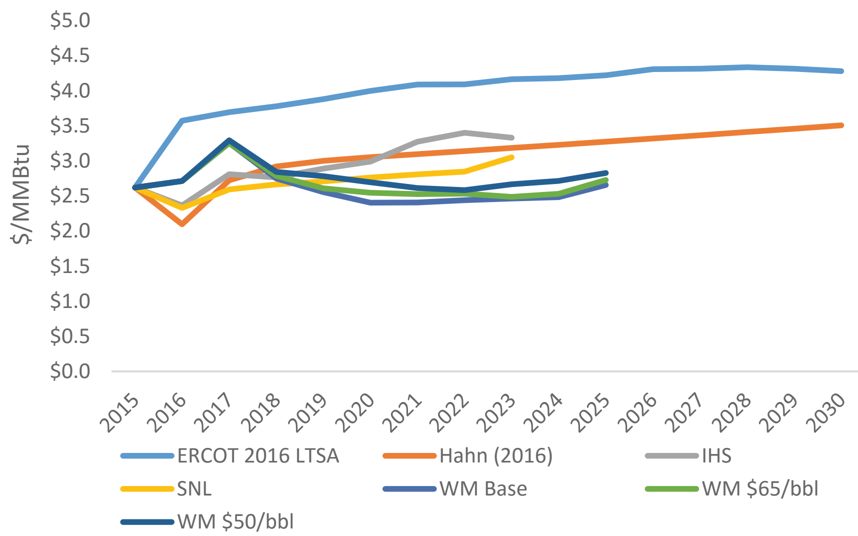
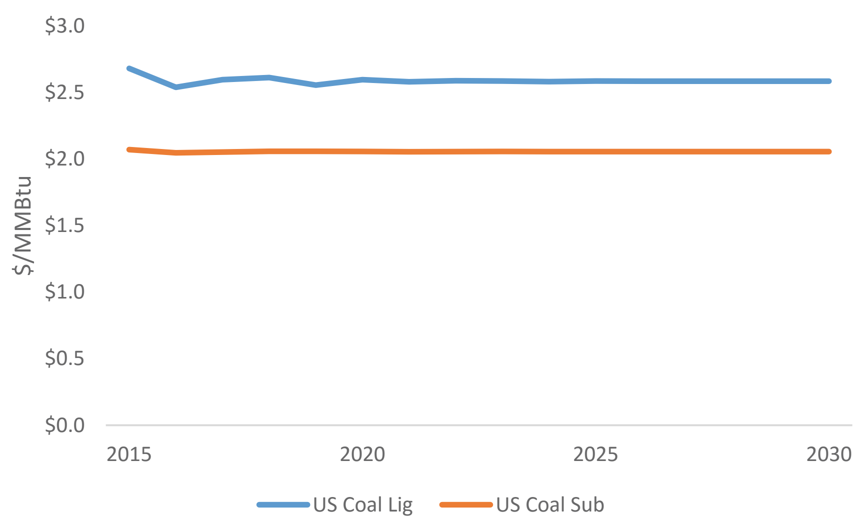


FIGURE 27

Coal Price Forecasts [$2015/MMBtu]



small, the way natural gas price forecasts are captured in AURORAxmp and the Excel model are not likely to cause significant discrepancy in results.

For coal prices, we first retrieved historical prices (2011–15) for lignite and subbituminous coal from EIA Form 923 Schedule 2: Fuel Receipts and Costs. We then took a five-year rolling average and extrapolated out to 2040 (Figure 27). Accordingly, we also assume coal units in Texas use either lignite or subbituminous coal based on EIA Form 923 Schedule 3 generator data (Appendix A).

AGGRESSIVE RENEWABLES (AR) SCENARIO

All of the assumptions and inputs described above for the CT scenario also apply in the AR scenario. The only difference is the additional hardwired renewables capacity: more than 12 GW of wind and a little over 2 GW of solar projects. These projects are either recently announced, or in various stages of development (Appendix E).

3 | Long-Term Capacity Expansion Results

Although we use the same set of input data and assumptions as much as possible, the three models used for long-term capacity expansion simulations are structurally different as discussed earlier. They also yield different outputs in addition to common outputs. As such, we discuss the results by model first before providing a comparison.

AURORAxmp

New Builds and Retirements

Under the AR scenario, a significant portion of coal capacity is retired between 2015–30 (Table 15). Given that we roughly quadrupled each of wind and solar hardwired capacities in this scenario, this result is not surprising. However, in the CT scenario, only 840 MW of coal capacity is retired, despite the environmental retrofit costs discussed earlier. The model does not retire any natural gas units in either scenario, potentially owing to the low natural gas price forecast. The model builds no new wind and only 450 MW of solar in the AR scenario beyond the hardwired wind and solar capacities.

Because of low to moderate coal capacity retirements and hardwired renewable capacities, new gas-fired capacity builds remain relatively low given low gas prices: about 4,700 MW in the CT scenario and about 6,400 MW in the AR scenario, all of which are advanced CC units in the Houston area.

Annual Capacity Changes, Average Wholesale Prices and Reserve Margins

All of the coal retirements in both scenarios happen by 2019 with the exception of 600 MW retired in 2023 in the AR scenario (Figure 28), probably in response to hardwired gas, wind and solar units leading to relatively low prices and relatively high reserve margins in the early years of the study horizon (Figure 29).

Natural gas price remains below $3 in real terms throughout the study period (2030) (Figure 26), helping to suppress energy market prices along with near-zero marginal cost wind and solar capacity. There are negative price periods as well owing to PTC credits received by wind farms, especially in the AR scenario. For example, prices were negative in 7% of the hours in 2016 in the West zone, and 5-6% of the hours in other zones except for the Houston zone, where prices were almost always positive. In 2017, there were more hours with negative prices: 9% in the West zone, and 6-7% in other zones (except the Houston zone). Even in 2018 and 2019, 3-4% of prices were negative in all zones except Houston. The additional cost of emission control equipment (Table 13) probably undermined the economics of these plants in this low-price environment.

These conditions encourage new advanced CCs in several-year cycles, especially in the CT scenario.

TABLE 15

Summary of Resources under the Two Scenarios (MW) with AURORAxmp

	Coal Retire	NG Retire	NG Hardwire	Wind Hardwire	Solar Hardwire	NG New Build	Wind New Build	Solar New Build	Net Additions 2015-30	Total Installed in 2030
CT	840	0	5,180	4,413	642	4,690	--	--	14,085	106,794
AR	6,433	0	5,180	16,519	2,800	6,360	--	450	24,876	117,585

There are fewer negative prices under the CT scenario (2-3% in 2016 and about 1% in 2017); coal retirements are limited in this scenario.

The average prices are roughly the same across the two scenarios until the mid-2020s after which they are higher in the CT scenario (Figure 29). This can be expected given the higher share of low-cost renewables in the AR scenario. Also, reserve margins are higher in the AR scenario in many years. Given that peak wind generation in ERCOT does not typically overlap with peak load hours, this result might appear surprising at first. However, hardwired wind capacity is large and some of it is in coastal areas where wind generation is more coincident with peak load.

Total Generation

The main difference between the two scenarios in terms of generation concerns wind and coal. There is more wind generation to replace primarily coal and some natural gas generation in the AR scenario as compared to the CT scenario (Figure 30). Coal generation is reduced by 495 million MWh (about 31%). Wind generation increases by about 581 million MWh (about 49%) and natural gas generation declines by 114 million MWh (about 4%). There is more solar generation (about 48 million MWh) in the AR scenario. However, solar generation is relatively small: 73 million MWh in the AR scenario.

System Costs

The comparison of total system costs from 2015 to 2030 across the two scenarios is informative. Total system costs include fixed and variable O&M costs, base capital carrying costs of new plants built by the model (i.e., overnight capital cost distributed over the life of the plant), and fuel costs of all resources. Total system costs are slightly larger (about $10 billion) in the AR scenario (Figure 31).

Although the capital costs for wind and solar decline over time (Table 10), they remain more expensive than gas units through the early 2020s, when most hardwired capacity were added to the resources database. As a result, capital costs in the AR scenario add up to almost $40 billion as compared to about $19 billion in the CT scenario. The associated fixed costs are also higher by about $3 billion. However, there are significant fuel cost savings in the AR scenario (roughly $12 billion) and operating cost savings (about $3.5 billion).

FIGURE 28

Annual Capacity Additions and Retirements with AURORAxmp

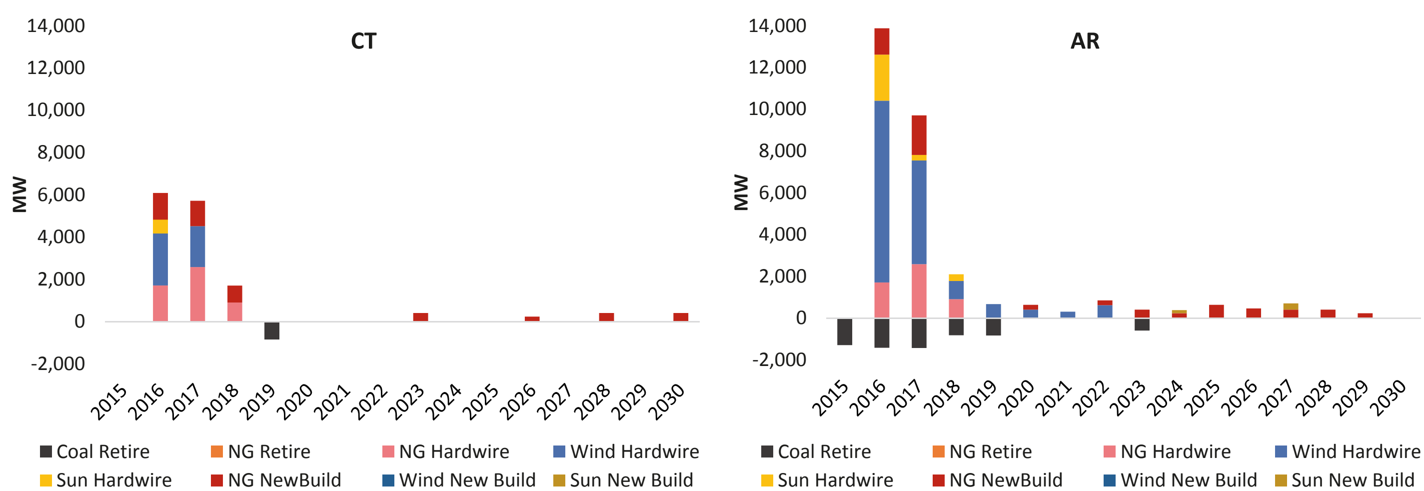


FIGURE 29

Annual Average Prices and Reserve Margins with AURORAxmp

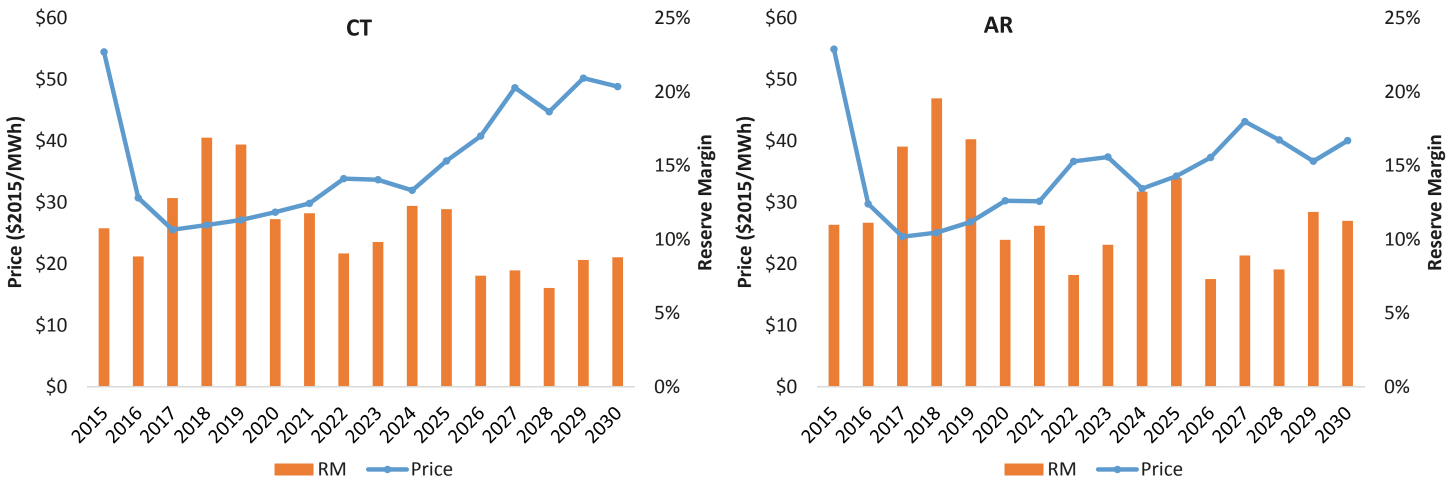


FIGURE 30

Total Generation Output by Fuel Type from 2015 to 2030 with AURORAxmp

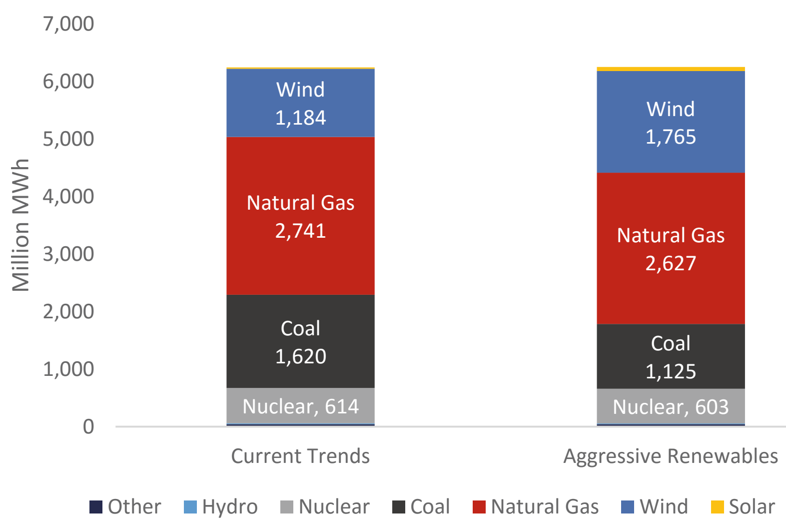
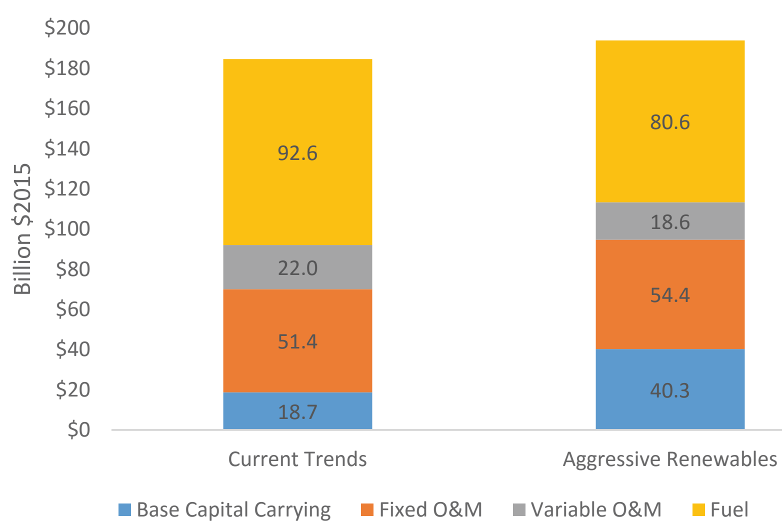


FIGURE 31

Total System Costs from 2015 to 2030 with AURORAxmp



Excel Model

New Builds and Retirements

Under the CT scenario, the Excel model makes minor adjustments beyond the assumed hardwired plants: only 500 MW of Coastal Wind are added (Table 16). Under the AR scenario, the Excel model does not make any additions or retirements beyond hardwires. By comparison, the primary difference is that AURORAxmp expanded gas capacity by 4.7 GW and 6.4 GW under the CT and AR scenarios, respectively. This gas build-out contributes to the higher installed 2030 capacities in AURORAxmp compared to Excel, especially in the CT scenario. The difference is negligible in the AR scenario because gas additions in AURORAxmp mostly compensate for coal retirements, which do not occur with the Excel model. As a reminder, the Excel model did not include coal retrofit costs which may contribute to less coal retirement and natural gas expansion.

Annual Capacity Changes, Average Wholesale Prices and Reserve Margins

Unlike AURORAxmp, the Excel model does not retire any more coal units than the hardwired 840 MWs in the AR scenario. Partially because of the lack of coal retirements, there are no new gas builds. However, the Excel model does not build any new gas capacity even in the CT scenario although both AURORAxmp and Excel only have the 840-MW hardwired coal retirement in this scenario. The only other difference is the 500 MW of new wind capacity built in the CT scenario with the Excel model.

Annual average reserve margins with the Excel model are highly correlated with those from AURORAxmp (comparing Figure 33 to Figure 29): 0.87 in the CT scenario and 0.8 in the AR scenario. The average over the study horizon is the same in the CT scenario across the two models; but it is almost 3% higher with the Excel model in the AR scenario. A possible explanation is that AURORAxmp calculates the average ERCOT reserve margin internally, taking into account differences (e.g., wind and solar shapes) across eight zones and plant availabilities. In the Excel model an ex-post calculation is conducted for the whole of ERCOT with nameplate capacities for thermal units, a single wind shape, and a single solar shape.

Average prices smoothly rise in both scenarios with the Excel model. Although the overall upward trend after 2017 is consistent with the average prices obtained from AURORAxmp runs, the correlation between price series from two model runs is only moderately correlated in either scenario (0.55). The prices follow a more cyclical pattern in the AURORAxmp runs. Again, ERCOT prices reported in Figure 29 are averages of hourly zonal prices internally calculated by AURORAxmp whereas an ex-post calculation is conducted for all of ERCOT in the Excel model. Given that gas is almost always on the margin, especially in the CT scenario, average ERCOT prices increase at the same pace as the price of natural gas (Figure 26). The correlation between average wholesale electricity prices and natural gas prices is 0.95 in the CT scenario and 0.89 in the AR scenario.

Total Generation

The Excel model yields very similar results to those from AURORAxmp, especially in the AR scenario. In CT scenario, the Excel model substitutes about 200 million MWh of coal with gas.

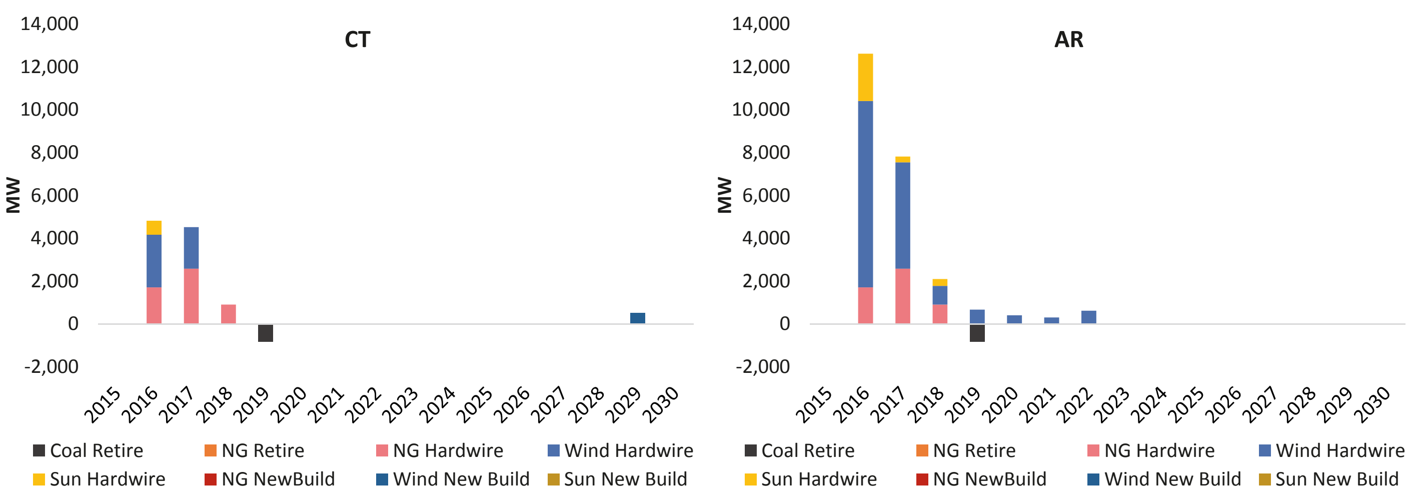
TABLE 16

Summary of Resources under the Two Scenarios (MW) with the Excel model

	Coal Retire Hardwire	NG Retire	NG Hardwire	Wind Hardwire	Solar Hardwire	NG New Build	Wind New Build	Solar New Build	Net Additions 2015-30	Total Installed in 2030
CT	840	--	5,180	4,413	642	--	500		9,895	103,332
AR	840	--	5,180	16,519	2,800	--	--	--	23,660	117,097

FIGURE 32

Annual Capacity Additions and Retirements with the Excel model



System Costs

System costs with the Excel model are consistent with those from AURORAxmp (Figure 35). Total costs are almost the same with the CT scenario and within 3% with the AR scenario. With both models, the shares of different cost categories are roughly the same in each scenario. Fuel costs account for about half of the total costs in the CT scenario but only 42% in the AR scenario. Despite the fuel cost savings, capital costs more than double in the AR scenario, leading to an increase in total costs.

The total cost in the AR scenario is roughly 7% larger than in the CT scenario with the Excel model, whereas the increase is only 5% with AURORAxmp. Cost estimates for each category in the AR scenario are closer to each other (3–9%) across the two models but there is a significant difference in base capital carrying cost in the CT scenario: $14.6 billion in the Excel model versus $18.7 billion in AURORAxmp (28% difference). This difference can be explained by the cost of the 4,700-MW new gas builds with AURORAxmp; the Excel model does not build any new units other than 500-MW wind in this scenario.

Relatively minor differences in other categories in either scenario can be explained by the fundamentally different approaches of the two

FIGURE 33

Annual Average Prices and Reserve Margins with the Excel model

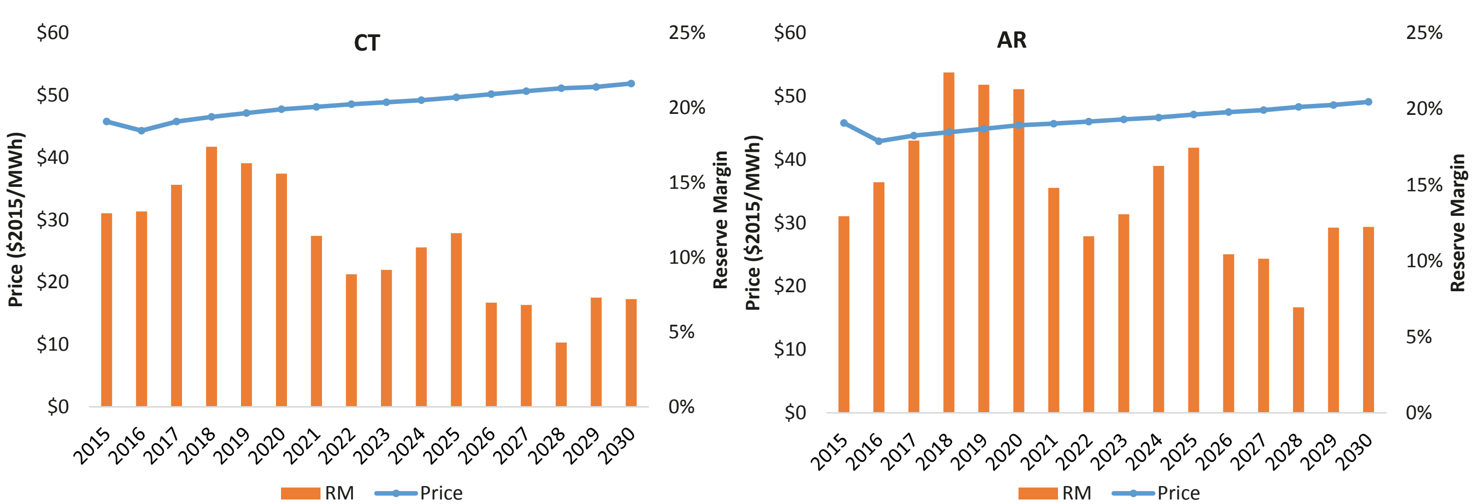


FIGURE 34

Total Generation Output by Fuel Type from 2015 to 2030 with the Excel model

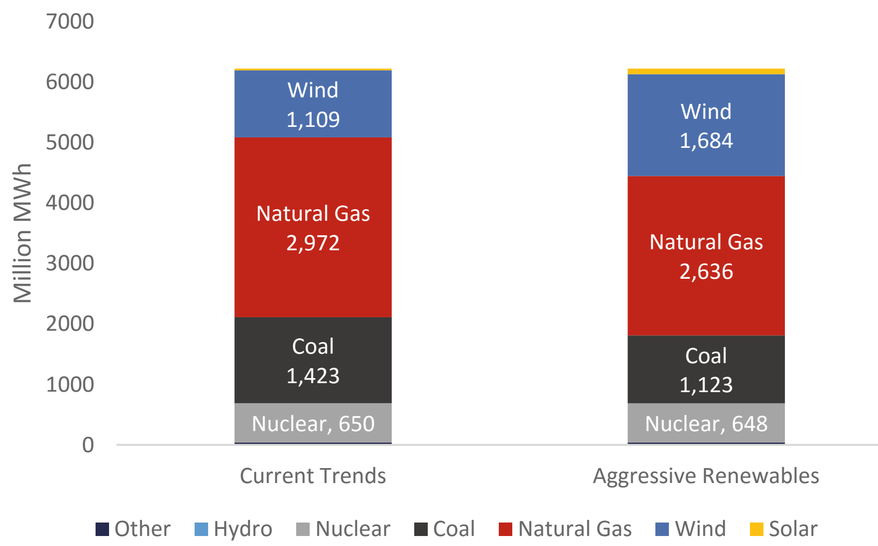
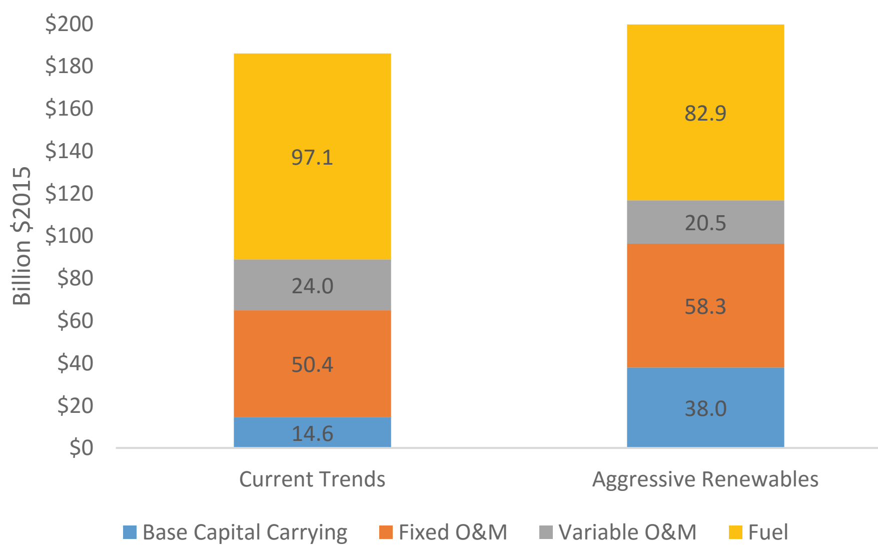


FIGURE 35

Total System Costs from 2015 to 2030 with the Excel model



models. AURORAxmp calculates each cost item on an hourly basis across eight zones. As such, individual plant characteristics, transmission constraints across zones, natural gas price basis differentials and seasonal variations, and other factors all impact the results. In contrast, cost calculations for the Excel model are ex-post annual calculations based on aggregate assumptions such as annual average natural gas price applied to all gas generation across ERCOT.

Screening Curve Method

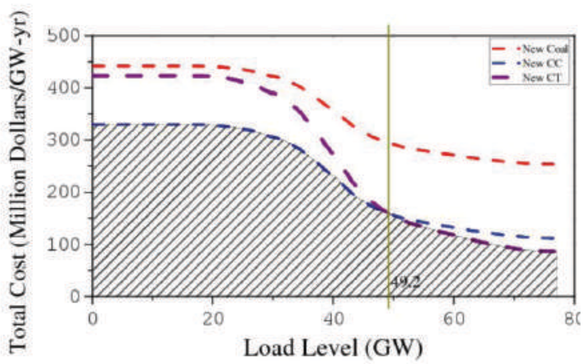
Among the six potential technologies, we chose the cheapest three to plot in Figure 36. New coal power plants are not added because they are not economic at any load level from this case study. There is one CC type dominating most of the baseload levels due to the relatively low fixed cost and low fuel cost (low heat rate). One CT type is the cheapest technology at peak load levels, having the lowest fixed cost. When existing capacity is not considered, the system consists of 49.2 GW of New CC and 21.4 GW of New CT. When the forced outage rates are considered, the New CC needed is 51.8 GW with a forced outage rate of 5% (49.2/(1-0.05)), and the New CT needed is 22.5 GW.

Next, we consider the retirement of existing capacity. A generation unit will retire when it is more expensive to retrofit than to build a new unit of any technology. Existing units usually have lower efficiency (and thus higher fuel cost), but the annual retrofit cost is usually cheaper than the annualized capital cost of the new units. A generator owner would only retrofit an existing unit if it is cheaper than building a new unit. Therefore, we need to compare the total cost curve of the existing generation with the new generation to check if existing generators are "qualified" to remain in operation or should be retired. Note that their capital cost is already sunk, and only a retrofit cost is incurred. Furthermore, in this study, different coal power plants have different retrofit costs, so we need to test them one by one.

In most cases, the retrofit costs are low enough such that the existing coal unit, with retrofit costs and lower efficiency, is still cheaper than all other new units (left panel of Figure 37). However, some coal units with higher retrofit costs lose their place in the least-cost solution from SCM (right panel of Figure 37). As a result, a total of 3.3 GW of coal capacity will be retired before 2030. Hence, only 16.5 GW of existing coal capacity is included for the following calculations.

FIGURE 36

SCM: ERCOT 2030 CT Scenario without Existing Capacity



The remaining existing capacity and new technologies are positioned on the horizontal axis to minimize the overall system cost (shaded area in Figure 38). The existing technology curves are added in the bottom denoted by solid curves, and the new technology curves remain the same denoted by dashed curves. When the existing units are added, all potential CTs are replaced by the existing CC2, CT1, and CT2; some potential CC capacity is replaced by existing nuclear, coal, CC1, and CC2. Thus, there is only new CC added to the existing system.

A high-level explanation about the existing capacity positions is that they are ranked by their variable fuel costs (VFCs) along with the new technologies (Table 17). The SCM dispatches the technology with the lowest VFC first and then searches for the next cheapest technology. Hence, the cheaper technologies are dispatched as baseload generation and are allocated to lower load levels. Similarly, the most expensive technology in VFC is dispatched last.

Note that existing nuclear has lower operating costs than any new technology, so it is located at the lowest load level; while existing CT1, CT2, and CC2 units are more expensive to operate than any new technology, so they are located at the highest load level. Existing coal and CC1 units have VFCs

FIGURE 37

SCM: The Retirement of a Coal Unit. Left: Not retired. Right: Retired.

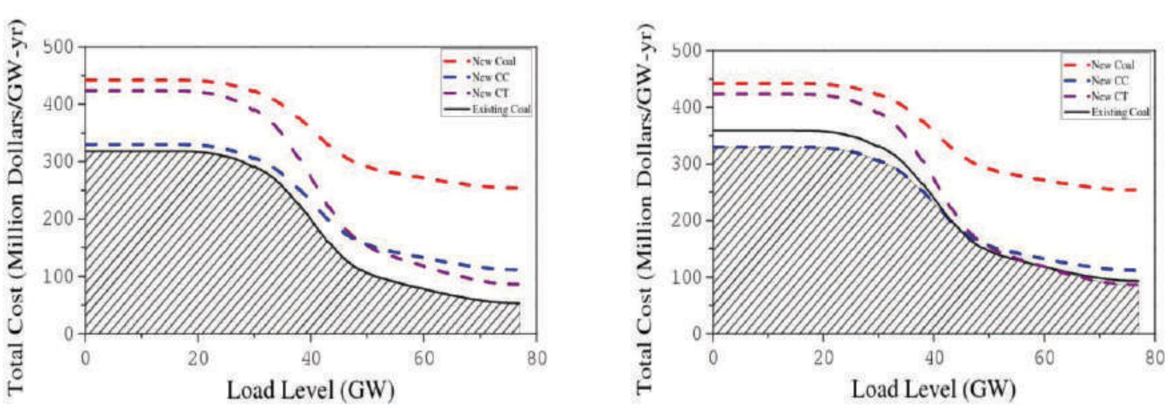


FIGURE 38

SCM: ERCOT 2030 CT Scenario

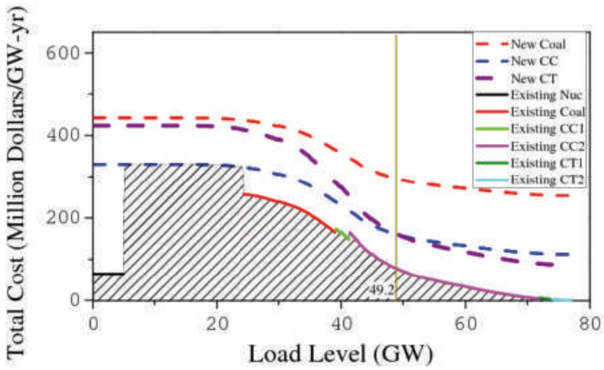
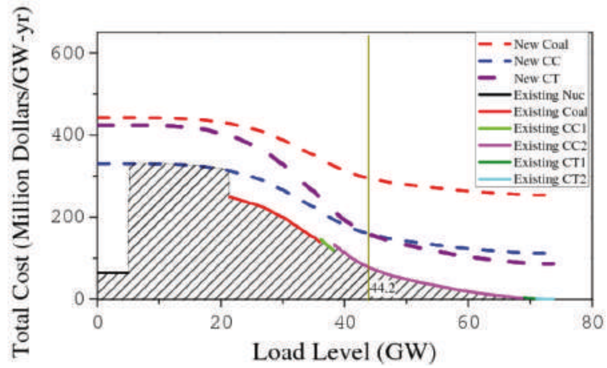


FIGURE 39

SCM: ERCOT 2030 AR Scenario



between New CC and new CT, so their load level should have been between New CC and New CT (around 49.2 GW crossing point in Figure 38). However, the total capacity of existing CC2, CT1, and CT2 is more than the potential new CT, so the existing coal and CC1 are pushed to the left of the crossing point. The consideration of existing units also results in no new CT being built.

The values showing on the horizontal axis are after de-rating. In order to obtain the actual capacity MW or convert actual capacity to the values on the horizontal axis, we need to use forced outage rates (FOR). For example, when we consider 16.5 GW of existing coal, it can only reliably balance $16.5 \times (1 - 0.1) = 14.9\ GW$ of load because it has a 10% FOR. So, the length of the projection of the red solid curve on the horizontal axis is 14.9 GW instead of 16.5 GW. Similarly, the calculated new CC from SCM is the de-rated capacity of 19.2 GW. Its capacity should be converted to the actual capacity, which is $19.2/(1 - 0.05) = 20.2\ GW$.

The only difference between the AR and the CT scenarios is that the wind and solar capacities are increased, and consequently the net load is reduced. In this case, total thermal capacity is decreased from the Current Trends scenario, resulting in fewer new CC units needed (Figure 39).

A summary of the simulation results is provided in Table 18. Under the CT scenario, we have 3.1 GW more CC as compared to the AR scenario, which has 12 GW more of wind and 2.6 GW more of solar than the CT scenario.

TABLE 17

VFC Rankings

Rank	1	2	3	4	4	5	6	7
Tech	Exst. Nuc	New CC	Exst. coal	Exst. CC1	New CT	Exst. CC2	Exst. CT1	Exst. CT2
VFC	6.3	22.7	25.2	29.5	29.9	35.1	42.1	45.6

TABLE 18

SCM 2030 Capacities under the Two Scenarios (GW)

	New CC	Total Wind	Total Solar	Existing Nuclear	Existing Coal	Existing CC1	Existing CC2	Existing CT1	Existing CT2	Total Capacity
CT	20.2	20.3	0.9	5.1	16.5	2.4	32.2	2	3	102.6
AR	17.1	32.4	3.5	5.1	16.5	2.4	32.2	2	3	114.2

TABLE 19

Comparison of 2030 Capacities from the Three Models (GW)

	Model	Total Nuclear	Total Coal	Total NG	Total Wind	Total Solar	Total Capacity*
	AURORAxmp	5.1	18.9	60.9	20.3	0.9	106.8
CT	SCM	5.1	16.5	59.8	20.3	0.9	102.6
	Excel	5.1	18.9	56.7	20.8	0.9	103.3
	AURORAxmp	5.1	13.3	62.6	32.4	3.5	117.6
AR	SCM	5.1	16.5	56.7	32.4	3.5	114.2
	Excel	5.1	18.9	56.7	32.4	3.1	117.1

* AURORAxmp and Excel totals include other generation such as hydro and biomass.

Comparison of Capacity Expansion Results

The SCM and Excel models treat the whole generation system as a single node, whereas AURORAxmp has eight zones as depicted in Figure 1. However, in test runs with and without transmission constraints, we did not find that transmission constraints in AURORAxmp caused large deviations in capacity results. Accordingly, we are reporting the AURORAxmp capacity results from the transmission-constrained case as it is more realistic (Table 19).

All three models yield similar results. Total capacity estimates are within 4% for the CT scenario and 3% for the AR scenario. The SCM does not consider wind and solar new builds, but this does not matter as AURORAxmp and Excel do not build much wind or solar beyond those hardwired. The most noticeable differences occur for coal and gas capacities. AURORAxmp yields more gas-fired capacity than the other two models, especially in the AR scenario. The SCM gas capacity is only 1.1 GW less than that of AURORAxmp in the CT scenario, but Excel gas capacity is 4.2 GW less. Both SCM and Excel have the same gas capacity in the AR scenario, which is 5.9 GW less than that of AURORAxmp. The AR scenario results can be explained by AURORAxmp retiring 5.6 GW more coal capacity than the Excel model and 3.2 GW more than the SCM. ■

4 | 2030 Hourly Dispatch Results

Total Generation in 2030

Generation by fuel is highly consistent across all three hourly dispatch models: AURORAxmp, Excel, and PLEXOS (Figure 40). With all models, wind and solar generation increase, nuclear generation stays roughly the same, coal generation declines significantly, and gas generation falls less than 10%.

In the CT scenario, the PLEXOS and Excel model results are very similar, but they display a wider discrepancy for gas and coal compared to AURORAxmp. Here, the PLEXOS and Excel models replace some coal generation with gas generation. For example, roughly 20,000 GWh of coal generation is replaced by about the same amount of gas generation when compared to the AURORAxmp results.

With the AR scenario, both the PLEXOS and Excel models generate more from gas plants than AURORAxmp (about 10,000 GWh and 20,000 GWh, respectively). This is at the expense of coal (9,000–18,000 GWh) and wind (4,000–8,000 GWh). Differences in wind generation are relatively small across the models (3–8%). The PLEXOS and Excel results for coal and gas differ by more than 10% from AURORAxmp.

The AURORAxmp coal generation is 14–30% larger than the PLEXOS and Excel models. One possible reason for these differences could be the costs included in merit order by different models. AURORAxmp and PLEXOS include start-up costs, which can be significant for fast-start units. In turn, this could lead to more coal-fired generation being dispatched. These cost comparisons are fruitful areas for further investigation.

Price Duration Curve

Running hourly dispatch also allows us to compare the price duration curves (PDCs) between the two scenarios across the models (Figure 41). The results are similar for most of the hours, but the PDCs of the two scenarios are much closer with PLEXOS than with AURORAxmp, which has a much wider range between the highest and lowest prices. Nevertheless, annual average prices are close once some extreme prices are taken into account.

There are significant differences at the extremes, yielding different annual averages: $32–33/MWh in both scenarios with PLEXOS versus $49/MWh in the CT scenario and $40/MWh in the AR scenario with AURORAxmp. The vertical axis in Figure 41 is truncated at $150/MWh, but in the AURORAxmp

FIGURE 40

Total Generation Output by Fuel Type in 2030 - Comparison of AURORAxmp, PLEXOS and Excel Results

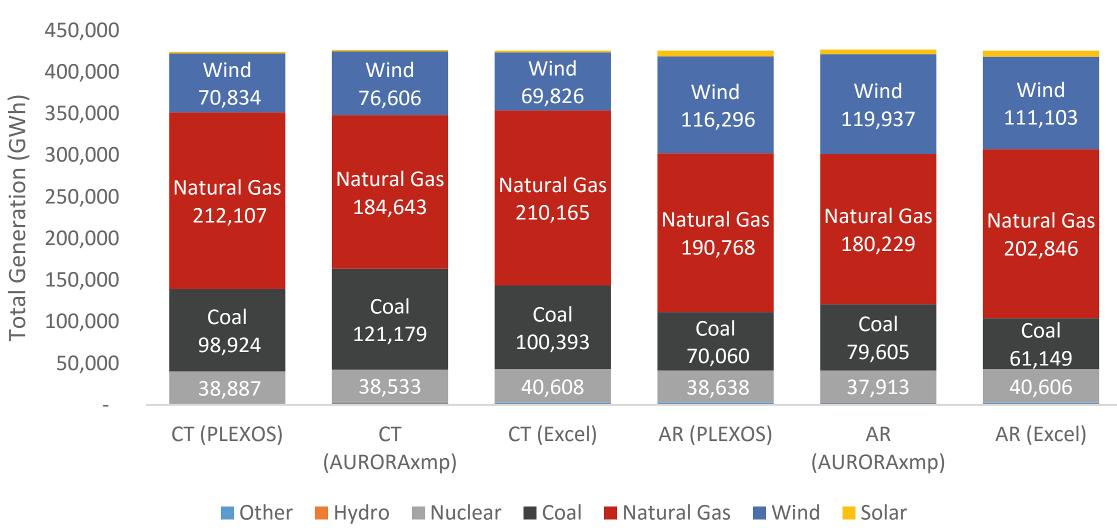


FIGURE 41

Price Duration Curves for 2030 - Comparison of AURORAxmp and PLEXOS Results

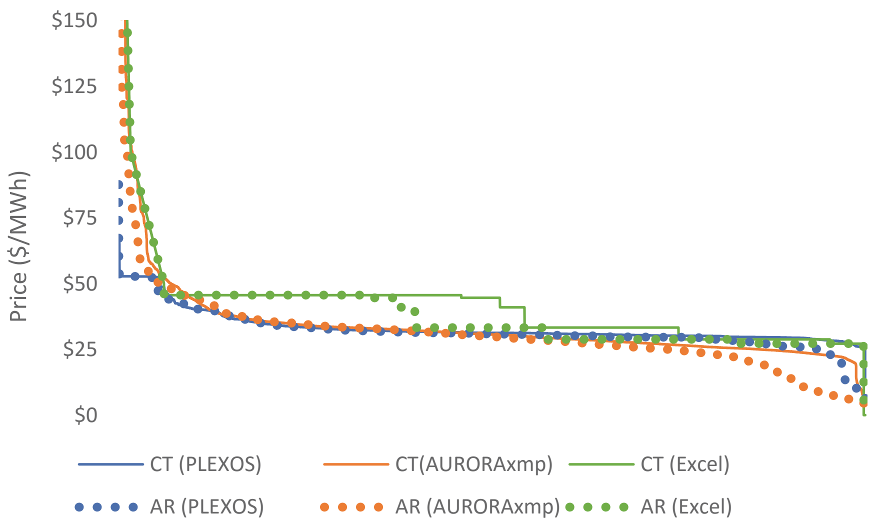
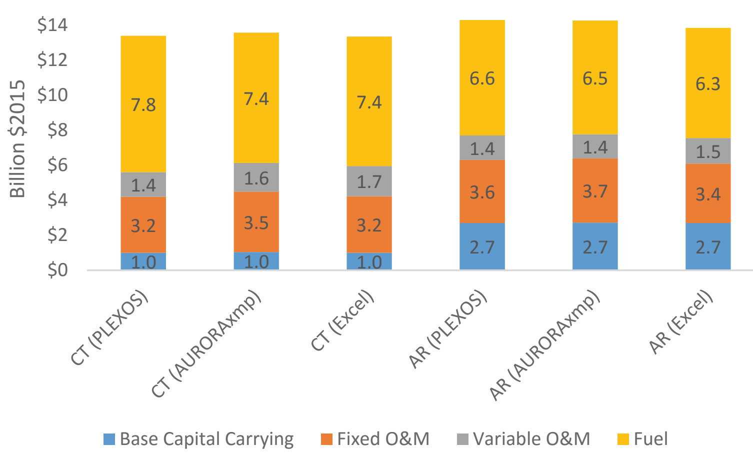


FIGURE 42

Total System Cost in 2030



model, there are 22 hours in the CT scenario and 13 hours in the AR scenario with prices higher than $1,000/MWh. In contrast, the maximum price with PLEXOS is $68/MWh in the CT scenario and $88/MWh in the AR scenario.[25] Annual average prices are much closer: $33 and $34 in the CT scenario; and $32 and $31 in the AR scenario for PLEXOS and AURORAxmp, respectively.

25 Note that the version of the PLEXOS model used in this study does not have scarcity pricing other than the value of lost load ($10,000/MWh). Given the high reserve margin with our 2030 load profile and generation capacity, the model finds a feasible solution without allowing unserved energy at VoLL.

Beyond the scarcity hours, AURORAxmp prices are higher than the PLEXOS prices for the first 1,000 hours (50% or larger difference for the first 280 hours in the CT scenario, and the first 176 hours for the AR scenario). These differences explain why the average prices are higher with AURORAxmp even after excluding the prices higher than $1,000/MWh.

On the other hand, prices are lower with AURORAxmp in 2,599 hours and 3,347 hours, under the CT and AR scenarios, respectively. However, these occur during low price periods (the tail of PDC curves in Figure 41) and, hence, do not influence the annual average price significantly. The larger number of lower priced hours in the AR scenario is expected given the much larger amount of wind and solar capacity.

Prices in the Excel model reflect the marginal price of the highest dispatched technology to meet the total ERCOT demand (as compared to eight zones in other models). There are two exceptions: the highest 6% of the hours were approximated based on historical prices (Figure 5), and the 18 hours with the lowest *thermal stress* were assigned prices of $0/MWh.

At a high level, the Excel and AURORAxmp prices are close for the highest 300 to 400 hours, especially in the CT scenario. For the lowest 2,000 hours or so, the Excel results are close to those from PLEXOS, especially for the CT scenario. Otherwise, Excel prices are higher than prices from both PLEXOS and AURORAxmp: $10–15/MWh in many hours. Prices from the Excel model are basically the same across the two scenarios except for a period between hours 3,200 and 6,400. The Excel model prices also conform to recent history, which may explain some of the differences. For example, under the AR scenario the renewable buildout could lead to more than 18 hours with marginal prices of $0/MWh as assumed, lowering the average price.

System Costs in 2030

Total system costs depict the same distribution of capital and fuel costs across all three models used for the 8,760 runs (Figure 42) as the long-term results discussed earlier (Figure 31). Capital costs, as represented by the base capital carrying cost, are larger with the AR scenario, but fuel cost savings help to compensate. As a result, total costs under the AR scenario are only slightly larger.

5 | CONCLUSIONS AND FUTURE WORK

The Full Cost of Electricity project aims to provide a multifaceted understanding of costs associated with generating and delivering electricity to end-users as well as costs associated with fuel procurement and externalities. As part of the project, an improved version of LCOE was offered, with regional variability and some externality costs included. Other studies investigated costs of transmission and distribution investments, integration of distributed energy resources, and related topics.

In this paper, using the ERCOT grid as an example, we simulated different capacity expansion paths to compare costs associated with different generation portfolios. These were measured by capital and operating costs, average electricity prices, and reserve margins, among others. These metrics do not form an exhaustive list but offer sufficient insight for the purposes of this paper. We use three different approaches for long-term capacity expansion analysis: a commercial dispatch software, AURORAxmp; an Excel model; and the screening curve method. We have also used PLEXOS, another dispatch software, AURORAxmp, and the Excel model to conduct hourly runs for 2030 under two scenarios with distinctly different generation portfolios.

The results are consistent in terms of overall capacity, but there are some differences in terms of how capacity is built or retired over time, the mix of the generation portfolio, average prices, and reserve margins. This conclusion is not surprising given the differences across these approaches. However, we demonstrated that it is possible to obtain similar results once key assumptions are identified and key dispatch characteristics are captured. As such, all models can be useful for certain types of analyses.

Future work may include more detailed investigation of scenario results. For example, we only provided annual averages for prices and reserve margins across ERCOT. Looking at some of these prices at an hourly and/or zonal level could reveal some localized issues like the need for new transmission. Also, we would like to evaluate the sensitivity of results to key inputs such as the price of natural gas and capital cost trends for various generation technologies. More challenging, but equally important, would be the investigation of incorporating emerging technologies such as storage and distributed energy resources. ■

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Appendix A: ERCOT Plant Database for End-of-Year 2015[26]

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/MW-start]	Forced Outage Rate [%]
Austin Area LFG	Travis	AEN	2007	Biogas	IC	6.4	9,800	7.50	3.00	20	25	1	1	20.00	0
Dallas-Fort Worth Area LFG	Dallas	North	2015	Biogas	IC	35.8	9,800	7.50	3.00	20	25	1	1	20.00	0
Houston Area LFG	Harris	Houston	2002	Biogas	IC	24.5	9,800	7.50	3.00	20	25	1	1	20.00	0
San Antonio Area LFG	Bexar	CPS	2013	Biogas	IC	26.8	9,800	7.50	3.00	20	25	1	1	20.00	0
Lufkin Biomass	Angelina	North	2012	Biomass	ST	45	9,894	29.82	4.83	25	0.54	6	8	0.00	0
Nacogdoches Power	Nacogdoches	North	2012	Biomass	ST	105	9,894	29.82	4.83	25	0.54	6	8	0.00	0
Big Brown 1	Freestone	North	1971	Coal-Lig	ST	606	10,744	43.56	6.33	48	0.264	12	24	42.00	10
Limestone 2	Limestone	North	1986	Coal-Lig	ST	858	9,578	43.56	6.33	48	0.264	12	24	42.00	10
Martin Lake 1	Rusk	North	1977	Coal-Lig	ST	800	11,129	43.56	6.33	48	0.264	12	24	42.00	10
Martin Lake 2	Rusk	North	1978	Coal-Lig	ST	805	11,063	43.56	6.33	48	0.264	12	24	42.00	10
Monticello U2	Titus	North	1975	Coal-Lig	ST	535	10,949	43.56	6.33	48	0.264	12	24	42.00	10
Oak Grove SES Unit 1	Robertson	North	2010	Coal-Lig	ST	840	9,344	43.56	6.33	48	0.264	12	24	42.00	10
Oak Grove SES Unit 2	Robertson	North	2011	Coal-Lig	ST	825	9,305	43.56	6.33	48	0.264	12	24	42.00	10
San Miguel 1	Atascosa	South	1982	Coal-Lig	ST	391	12,179	43.56	6.33	48	0.264	12	24	42.00	10
Sandow U4	Milam	South	1981	Coal-Lig	ST	570	9,323	43.56	6.33	48	0.264	12	24	42.00	10
Sandow U5	Milam	South	2010	Coal-Lig	ST	600	11,118	43.56	6.33	48	0.264	12	24	42.00	10
Twin Oaks 1	Robertson	North	1990	Coal-Lig	ST	156	10,887	43.56	6.33	48	0.264	12	24	42.00	10
Twin Oaks 2	Robertson	North	1991	Coal-Lig	ST	156	10,838	43.56	6.33	48	0.264	12	24	42.00	10
Big Brown 2	Freestone	North	1972	Coal-Sub	ST	602	10,684	43.56	6.33	48	0.264	12	24	29.00	10
Coleto Creek	Goliad	South	1980	Coal-Sub	ST	660	10,163	43.56	6.33	48	0.264	12	24	29.00	10
Fayette Power Project 1	Fayette	AEN	1979	Coal-Sub	ST	604	10,692	43.56	6.33	48	0.264	12	24	29.00	10
Fayette Power Project 2	Fayette	LCRA	1980	Coal-Sub	ST	599	10,710	43.56	6.33	48	0.264	12	24	29.00	10
Fayette Power Project 3	Fayette	LCRA	1988	Coal-Sub	ST	437	10,673	43.56	6.33	48	0.264	12	24	29.00	10
Gibbons Creek 1	Grimes	North	1983	Coal-Sub	ST	470	9,990	43.56	6.33	48	0.264	12	24	29.00	10
J K Spruce 1	Bexar	CPS	1992	Coal-Sub	ST	560	10,822	43.56	6.33	48	0.264	12	24	29.00	10
J K Spruce 2	Bexar	CPS	2010	Coal-Sub	ST	775	10,800	43.56	6.33	48	0.264	12	24	29.00	10
J T Deely 1	Bexar	CPS	1977	Coal-Sub	ST	420	14,056	43.56	6.33	48	0.264	12	24	29.00	10
J T Deely 2	Bexar	CPS	1978	Coal-Sub	ST	420	14,093	43.56	6.33	48	0.264	12	24	29.00	10
Limestone 1	Limestone	North	1985	Coal-Sub	ST	831	9,643	43.56	6.33	48	0.264	12	24	29.00	10
Martin Lake 3	Rusk	North	1979	Coal-Sub	ST	805	11,077	43.56	6.33	48	0.264	12	24	29.00	10
Monticello U1	Titus	North	1974	Coal-Sub	ST	535	10,926	43.56	6.33	48	0.264	12	24	29.00	10
Monticello U3	Titus	North	1978	Coal-Sub	ST	795	10,936	43.56	6.33	48	0.264	12	24	29.00	10
Oklaunion 1	Wilbarger	West	1986	Coal-Sub	ST	650	10,634	43.56	6.33	48	0.264	12	24	29.00	10
Sandy Creek 1	McLennan	North	2013	Coal-Sub	ST	970	9,335	43.56	6.33	48	0.264	12	24	29.00	10
W A Parish 5	Fort Bend	Houston	1977	Coal-Sub	ST	659	10,413	43.56	6.33	48	0.264	12	24	29.00	10
W A Parish 6	Fort Bend	Houston	1978	Coal-Sub	ST	658	10,349	43.56	6.33	48	0.264	12	24	29.00	10
W A Parish 7	Fort Bend	Houston	1980	Coal-Sub	ST	577	10,354	43.56	6.33	48	0.264	12	24	29.00	10
W A Parish 8	Fort Bend	Houston	1982	Coal-Sub	ST	610	10,349	43.56	6.33	48	0.264	12	24	29.00	10
Hydro LCRA LZ	Travis	LCRA	1951	Hydro	HYDRO	280	-	0.00	0.00	0	25	0	0	0.00	50
Hydro North LZ	Bosque	North	2014	Hydro	HYDRO	51.6	-	0.00	0.00	0	25	0	0	0.00	50
Hydro RCEC LZ	Grayson	RCEC	1948	Hydro	HYDRO	80	-	0.00	0.00	0	25	0	0	0.00	50
Hydro South LZ	Starr	South	2005	Hydro	HYDRO	67.7	-	0.00	0.00	0	25	0	0	0.00	50
Hydro West LZ	Val Verde	West	1983	Hydro	HYDRO	75.8	-	0.00	0.00	0	25	0	0	0.00	50
Arthur Von Rosenberg 1	Bexar	South	2000	NG	CCGT	458	8,017	25.28	4.73	25	0.42	6	14	34.63	0
B M Davis 3	Nueces	South	2010	NG	CCGT	633	8,318	25.28	4.73	25	0.42	6	14	34.63	0

26 FOM and VOM values represent average values used by the Excel model and SCM for the aggregate generation technologies. In AURORAxmp and PLEXOS, each unit has different values.

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/MW-start]	Forced Outage Rate [%]
Bastrop Energy Center 1	Bastrop	South	2002	NG	CCGT	533	8,066	25.28	4.73	25	0.42	6	14	34.63	0
Bosque County CC 1	Bosque	North	2009	NG	CCGT	514	7,500	25.28	4.73	25	0.42	6	14	34.63	0
Bosque County CC 2	Bosque	North	2001	NG	CCGT	230.3	7,413	25.28	4.73	25	0.42	6	14	34.63	0
Brazos Valley 1	Fort Bend	Houston	2003	NG	CCGT	602	7,823	25.28	4.73	25	0.42	6	14	34.63	0
Cedar Bayou 4	Chambers	Houston	2009	NG	CCGT	504	7,041	25.28	4.73	25	0.42	6	14	34.63	0
Colorado Bend Energy Center 1	Wharton	Houston	2007	NG	CCGT	233	7,416	25.28	4.73	25	0.42	6	14	34.63	0
Colorado Bend Energy Center 2	Wharton	Houston	2008	NG	CCGT	235	7,349	25.28	4.73	25	0.42	6	14	34.63	0
Ennis Power Station 1	Ellis	North	2002	NG	CCGT	312	6,678	25.28	4.73	25	0.42	6	14	34.63	0
Ferguson Replacement	Llano	LCRA	2014	NG	CCGT	509.8	7,050	25.28	4.73	25	0.42	6	14	34.63	0
Forney Energy Center 1	Kaufman	North	2003	NG	CCGT	911	7,365	25.28	4.73	25	0.42	6	14	34.63	0
Forney Energy Center 2	Kaufman	North	2003	NG	CCGT	911	7,358	25.28	4.73	25	0.42	6	14	34.63	0
Freestone Energy Center 1	Freestone	North	2002	NG	CCGT	957.3	7,520	25.28	4.73	25	0.42	6	14	34.63	0
Frontera 1	Hidalgo	South	1999	NG	CCGT	524	6,840	25.28	4.73	25	0.42	6	14	34.63	0
Guadalupe Generating Station 1	Guadalupe	South	2000	NG	CCGT	986	7,433	25.28	4.73	25	0.42	6	14	34.63	0
Hays Energy Facility 1	Hays	South	2002	NG	CCGT	882	7,750	25.28	4.73	25	0.42	6	14	34.63	0
Hidalgo 1	Hidalgo	South	2000	NG	CCGT	458	7,167	25.28	4.73	25	0.42	6	14	34.63	0
Jack County Generation Facility 1	Jack	North	2005	NG	CCGT	595	8,752	25.28	4.73	25	0.42	6	14	34.63	0
Jack County Generation Facility 2	Jack	North	2011	NG	CCGT	595	7,050	25.28	4.73	25	0.42	6	14	34.63	0
Johnson County	Johnson	North	1997	NG	CCGT	269	8,368	25.28	4.73	25	0.42	6	14	34.63	0
Lamar Power Project 1	Lamar	North	2000	NG	CCGT	1,040	7,240	25.28	4.73	25	0.42	6	14	34.63	0
Lost Pines 1	Bastrop	LCRA	2001	NG	CCGT	528	7,651	25.28	4.73	25	0.42	6	14	34.63	0
Magic Valley Station	Hidalgo	South	2001	NG	CCGT	670.2	7,326	25.28	4.73	25	0.42	6	14	34.63	0
Midlothian 1	Ellis	North	2001	NG	CCGT	940	8,074	25.28	4.73	25	0.42	6	14	34.63	0
Midlothian 2	Ellis	North	2002	NG	CCGT	504	7,639	25.28	4.73	25	0.42	6	14	34.63	0
Nueces Bay 8	Nueces	South	2010	NG	CCGT	633	8,231	25.28	4.73	25	0.42	6	14	34.63	0
Odessa Ector Generating Station 1	Ector	West	2001	NG	CCGT	998.5	6,826	25.28	4.73	25	0.42	6	14	34.63	0
Panda Sherman	Grayson	North	2014	NG	CCGT	717	7,050	25.28	4.73	25	0.42	6	14	34.63	0
Panda Temple 1	Bell	North	2014	NG	CCGT	702	7,050	25.28	4.73	25	0.42	6	14	34.63	0
Panda Temple II CTG1	Bell	North	2015	NG	CCGT	191.2	7,050	25.28	4.73	25	0.42	6	14	34.63	0
Panda Temple II CTG2	Bell	North	2015	NG	CCGT	191.2	7,050	25.28	4.73	25	0.42	6	14	34.63	0
Panda Temple II STG	Bell	North	2015	NG	CCGT	334.7	7,050	25.28	4.73	25	0.42	6	14	34.63	0
Paris Energy Center 1	Lamar	North	1990	NG	CCGT	239	7,395	25.28	4.73	25	0.42	6	14	34.63	0
Quail Run Energy 1	Ector	West	2008	NG	CCGT	488	6,500	25.28	4.73	25	0.42	6	14	34.63	0
Rio Nogales 1	Guadalupe	South	2002	NG	CCGT	785	8,050	25.28	4.73	25	0.42	6	14	34.63	0
Sam Rayburn 10	Victoria	South	2003	NG	CCGT	190	7,591	25.28	4.73	25	0.42	6	14	34.63	0
Sand Hill Energy Center 5a	Travis	AEN	2004	NG	CCGT	295	8,069	25.28	4.73	25	0.42	6	14	34.63	0
Silas Ray 9	Cameron	South	1996	NG	CCGT	58	10,075	25.28	4.73	25	0.42	6	14	34.63	0
T H Wharton 3	Harris	Houston	1974	NG	CCGT	332	9,441	25.28	4.73	25	0.42	6	14	34.63	0
T H Wharton 4	Harris	Houston	1974	NG	CCGT	332	8,922	25.28	4.73	25	0.42	6	14	34.63	0
Tenaska Frontier Station	Grimes	Houston	2000	NG	CCGT	880	7,307	25.28	4.73	25	0.42	6	14	34.63	0
Tenaska Gateway Station	Rusk	North	2001	NG	CCGT	846	7,200	25.28	4.73	25	0.42	6	14	34.63	0
Tenaska Kiamichi Station 1	Fannin	North	2003	NG	CCGT	623	7,345	25.28	4.73	25	0.42	6	14	34.63	0
Tenaska Kiamichi Station 2	Fannin	North	2003	NG	CCGT	623	7,345	25.28	4.73	25	0.42	6	14	34.63	0
Victoria Power Station	Victoria	South	2009	NG	CCGT	285	8,844	25.28	4.73	25	0.42	6	14	34.63	0
Wise County Power LP	Wise	North	2004	NG	CCGT	665	7,596	25.28	4.73	25	0.42	6	14	34.63	0
Wolf Hollow Power Proj 1	Hood	North	2002	NG	CCGT	705	7,911	25.28	4.73	25	0.42	6	14	34.63	0
Baytown Energy Center	Chambers	Houston	2002	NG	CCGT-CHP	794.8	9,347	25.28	4.73	25	0.42	6	14	34.63	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/ kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/ MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/ min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/ MW-start]	Forced Outage Rate [%]
C R Wing Cogen Plant	Howard	West	1988	NG	CCGT-CHP	207.7	8,034	25.28	4.73	25	0.42	6	14	34.63	0
Channel Energy Center	Harris	Houston	2001	NG	CCGT-CHP	686.6	9,228	25.28	4.73	25	0.42	6	14	34.63	0
Channelview Cogen Plant	Harris	Houston	2008	NG	CCGT-CHP	861	6,614	25.28	4.73	25	0.42	6	14	34.63	0
Clear Lake Cogeneration Ltd	Harris	Houston	1985	NG	CCGT-CHP	384.9	8,096	25.28	4.73	25	0.42	6	14	34.63	0
Corpus Christi Energy Center	Nueces	South	2002	NG	CCGT-CHP	460.5	7,263	25.28	4.73	25	0.42	6	14	34.63	0
Deer Park Energy Center 1	Harris	Houston	2014	NG	CCGT-CHP	1,203	6,043	25.28	4.73	25	0.42	6	14	34.63	0
Freeport Energy Center	Brazoria	Houston	2007	NG	CCGT-CHP	63.4	8,017	25.28	4.73	25	0.42	6	14	34.63	0
Green Power 2	Galveston	Houston	2009	NG	CCGT-CHP	287.2	12,251	25.28	4.73	25	0.42	6	14	34.63	0
Gregory Power Facility	San Patricio	South	2000	NG	CCGT-CHP	388.5	7,262	25.28	4.73	25	0.42	6	14	34.63	0
Houston Chemical Complex Battleground	Harris	Houston	2005	NG	CCGT-CHP	52.6	9,500	25.28	4.73	25	0.42	6	14	34.63	0
Ingleside Cogeneration	San Patricio	South	1999	NG	CCGT-CHP	478.4	8,000	25.28	4.73	25	0.42	6	14	34.63	0
Optim Energy Altura Cogen	Harris	Houston	1995	NG	CCGT-CHP	478.8	11,783	25.28	4.73	25	0.42	6	14	34.63	0
Oyster Creek Unit VIII	Brazoria	Houston	1994	NG	CCGT-CHP	404.5	10,753	25.28	4.73	25	0.42	6	14	34.63	0
Pasadena Cogeneration	Harris	Houston	2000	NG	CCGT-CHP	743.6	7,554	25.28	4.73	25	0.42	6	14	34.63	0
Texas City 1	Galveston	Houston	2000	NG	CCGT-CHP	458.5	14,485	25.28	4.73	25	0.42	6	14	34.63	0
Wichita Falls Cogeneration Plant	Wichita	West	1987	NG	CCGT-CHP	78	7,241	25.28	4.73	25	0.42	6	14	34.63	0
Greenville Powerlane IC1	Hunt	North	2010	NG	IC	8.4	9,833	19.49	13.41	20	25	1	1	19.37	0
Greenville Powerlane IC2	Hunt	North	2010	NG	IC	8.4	9,761	19.49	13.41	20	25	1	1	19.37	0
Greenville Powerlane IC3	Hunt	North	2010	NG	IC	8.4	9,828	19.49	13.41	20	25	1	1	19.37	0
Pearsall IC Engine Plant A	Frio	South	2012	NG	IC	50.6	9,784	19.49	13.41	20	25	1	1	19.37	0
Pearsall IC Engine Plant B	Frio	South	2012	NG	IC	50.6	9,789	19.49	13.41	20	25	1	1	19.37	0
Pearsall IC Engine Plant C	Frio	South	2012	NG	IC	50.6	9,794	19.49	13.41	20	25	1	1	19.37	0
Pearsall IC Engine Plant D	Frio	South	2012	NG	IC	50.6	9,788	19.49	13.41	20	25	1	1	19.37	0
Bryan Atkins 7	Brazos	North	1973	NG	OCGT	18	14,451	16.95	13.41	25	20	1	1	19.17	0
Dansby 2	Brazos	North	2004	NG	OCGT	45	10,584	16.95	13.41	24	44	1	1	18.98	0
Dansby 3	Brazos	North	2010	NG	OCGT	47	9,470	16.95	13.41	24	44	1	1	18.98	0
Decker Creek G1	Travis	AEN	1989	NG	OCGT	48	9,500	16.95	13.41	24	44	1	1	20.10	0
Decker Creek G2	Travis	AEN	1989	NG	OCGT	48	9,500	16.95	13.41	24	44	1	1	20.10	0
Decker Creek G3	Travis	AEN	1989	NG	OCGT	48	9,500	16.95	13.41	24	44	1	1	20.10	0
Decker Creek G4	Travis	AEN	1989	NG	OCGT	48	9,500	16.95	13.41	24	44	1	1	20.10	0
DeCordova 1	Hood	North	1990	NG	OCGT	71	9,850	16.95	13.41	25	14	1	1	36.96	0
DeCordova 2	Hood	North	1990	NG	OCGT	70	9,850	16.95	13.41	25	14	1	1	37.45	0
DeCordova 3	Hood	North	1990	NG	OCGT	69	9,850	16.95	13.41	25	14	1	1	37.96	0
DeCordova 4	Hood	North	1990	NG	OCGT	68	9,850	16.95	13.41	25	14	1	1	38.48	0
Ector County Energy	Ector	West	2015	NG	OCGT	294	9,983	16.95	13.41	25	14	1	1	35.00	0
ExTex La Porte Power Station AirPro 1	Harris	Houston	2009	NG	OCGT	38	9,250	16.95	13.41	24	44	1	1	18.75	0
ExTex La Porte Power Station AirPro 2	Harris	Houston	2009	NG	OCGT	38	9,250	16.95	13.41	24	44	1	1	18.75	0
ExTex La Porte Power Station AirPro 3	Harris	Houston	2009	NG	OCGT	38	9,250	16.95	13.41	24	44	1	1	18.75	0
ExTex La Porte Power Station AirPro 4	Harris	Houston	2009	NG	OCGT	38	9,250	16.95	13.41	24	44	1	1	18.75	0
Greens Bayou 73	Harris	Houston	1976	NG	OCGT	46	10,268	16.95	13.41	25	21	1	1	20.71	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/ kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/ MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/ min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/ MW-start]	Forced Outage Rate [%]
Greens Bayou 74	Harris	Houston	1976	NG	OCGT	46	10,268	16.95	13.41	25	21	1	1	20.71	0
Greens Bayou 81	Harris	Houston	1976	NG	OCGT	46	10,268	16.95	13.41	25	21	1	1	20.71	0
Greens Bayou 82	Harris	Houston	1976	NG	OCGT	58	10,268	16.95	13.41	25	21	1	1	20.45	0
Greens Bayou 83	Harris	Houston	1976	NG	OCGT	56	10,268	16.95	13.41	25	21	1	1	20.45	0
Greens Bayou 84	Harris	Houston	1976	NG	OCGT	46	10,268	16.95	13.41	25	21	1	1	21.16	0
Laredo Peaking 4	Webb	South	2008	NG	OCGT	90.1	10,056	16.95	13.41	50	21	1	1	19.37	0
Laredo Peaking 5	Webb	South	2008	NG	OCGT	87.3	10,056	16.95	13.41	50	21	1	1	20.00	0
Leon Creek Peaking 1	Bexar	South	2004	NG	OCGT	46	9,888	16.95	13.41	24	44	1	1	19.38	0
Leon Creek Peaking 2	Bexar	South	2004	NG	OCGT	46	9,888	16.95	13.41	24	44	1	1	19.38	0
Leon Creek Peaking 3	Bexar	South	2004	NG	OCGT	46	9,888	16.95	13.41	24	44	1	1	19.38	0
Leon Creek Peaking 4	Bexar	South	2004	NG	OCGT	46	9,888	16.95	13.41	24	44	1	1	19.38	0
Morgan Creek 1	Mitchell	West	1988	NG	OCGT	68	10,173	16.95	13.41	25	14	1	1	36.11	0
Morgan Creek 2	Mitchell	West	1988	NG	OCGT	68	10,173	16.95	13.41	25	14	1	1	36.11	0
Morgan Creek 3	Mitchell	West	1988	NG	OCGT	68	10,173	16.95	13.41	25	14	1	1	36.11	0
Morgan Creek 4	Mitchell	West	1988	NG	OCGT	68	10,173	16.95	13.41	25	14	1	1	36.11	0
Morgan Creek 5	Mitchell	West	1988	NG	OCGT	68	10,173	16.95	13.41	25	14	1	1	36.11	0
Morgan Creek 6	Mitchell	West	1988	NG	OCGT	67	10,173	16.95	13.41	25	14	1	1	36.11	0
Permian Basin 1	Ward	West	1988	NG	OCGT	68	10,173	16.95	13.41	25	14	1	1	32.98	0
Permian Basin 2	Ward	West	1988	NG	OCGT	65	10,173	16.95	13.41	25	14	1	1	34.68	0
Permian Basin 3	Ward	West	1988	NG	OCGT	68	10,173	16.95	13.41	25	14	1	1	34.62	0
Permian Basin 4	Ward	West	1990	NG	OCGT	69	10,078	16.95	13.41	25	14	1	1	34.14	0
Permian Basin 5	Ward	West	1990	NG	OCGT	70	10,078	16.95	13.41	25	14	1	1	34.36	0
R W Miller 4	Palo Pinto	North	1994	NG	OCGT	104	13,400	16.95	13.41	25	14	1	1	34.88	0
R W Miller 5	Palo Pinto	North	1994	NG	OCGT	104	12,873	16.95	13.41	25	14	1	1	34.88	0
Ray Olinger 4	Collin	North	2001	NG	OCGT	75	13,892	16.95	13.41	25	14	1	1	35.10	0
Sam Rayburn GT 1	Victoria	South	1963	NG	OCGT	11	14,572	16.95	13.41	25	21	1	1	20.35	0
Sam Rayburn GT 2	Victoria	South	1963	NG	OCGT	11	14,503	16.95	13.41	25	21	1	1	20.35	0
San Jacinto SES CTG 1	Harris	Houston	1995	NG	OCGT	81	13,488	16.95	13.41	25	14	4	4	37.04	0
San Jacinto SES CTG 2	Harris	Houston	1995	NG	OCGT	81	13,567	16.95	13.41	25	14	4	4	37.04	0
Sand Hill Energy Center GT 1	Travis	AEN	2001	NG	OCGT	47	9,888	16.95	13.41	24	44	1	1	18.78	0
Sand Hill Energy Center GT 2	Travis	AEN	2001	NG	OCGT	47	9,888	16.95	13.41	24	44	1	1	18.37	0
Sand Hill Energy Center GT 3	Travis	AEN	2001	NG	OCGT	47	9,888	16.95	13.41	24	44	1	1	19.18	0
Sand Hill Energy Center GT 4	Travis	AEN	2001	NG	OCGT	47	9,888	16.95	13.41	24	44	1	1	20.00	0
Sand Hill Energy Center GT 6	Travis	AEN	2010	NG	OCGT	47	9,888	16.95	13.41	24	44	1	1	18.78	0
Sand Hill Energy Center GT 7	Travis	AEN	2010	NG	OCGT	47	9,888	16.95	13.41	24	44	1	1	18.78	0
Silas Ray 10	Cameron	South	2004	NG	OCGT	46	9,888	16.95	13.41	24	44	1	1	18.98	0
T H Wharton G 1	Harris	Houston	1967	NG	OCGT	13	10,268	16.95	13.41	25	20	1	1	19.37	0
T H Wharton GT 51	Harris	Houston	1975	NG	OCGT	57	9,983	16.95	13.41	25	14	1	1	33.89	0
T H Wharton GT 52	Harris	Houston	1975	NG	OCGT	57	9,983	16.95	13.41	25	14	1	1	33.80	0
T H Wharton GT 53	Harris	Houston	1975	NG	OCGT	57	9,983	16.95	13.41	25	14	1	1	33.80	0
T H Wharton GT 54	Harris	Houston	1975	NG	OCGT	57	9,983	16.95	13.41	25	14	1	1	33.80	0
T H Wharton GT 55	Harris	Houston	1975	NG	OCGT	57	9,983	16.95	13.41	25	14	1	1	33.80	0
T H Wharton GT 56	Harris	Houston	1975	NG	OCGT	57	9,983	16.95	13.41	25	14	1	1	33.80	0
V H Braunig 5	Bexar	South	2009	NG	OCGT	48	9,894	16.95	13.41	24	44	1	1	18.78	0
V H Braunig 6	Bexar	South	2009	NG	OCGT	48	9,894	16.95	13.41	24	44	1	1	18.78	0
V H Braunig 7	Bexar	South	2009	NG	OCGT	48	9,894	16.95	13.41	24	44	1	1	18.78	0
V H Braunig 8	Bexar	South	2009	NG	OCGT	47	9,894	16.95	13.41	24	44	1	1	18.78	0
W A Parish Petra Nova	Fort Bend	Houston	2013	NG	OCGT	74	9,983	16.95	13.41	25	14	1	1	35.00	0
W A Parish T1	Fort Bend	Houston	1967	NG	OCGT	13	14,467	16.95	13.41	25	20	1	1	19.17	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/MW-start]	Forced Outage Rate [%]
Winchester Power Park 1	Fayette	LCRA	2009	NG	OCGT	44	9,475	16.95	13.41	24	44	1	1	19.09	0
Winchester Power Park 2	Fayette	LCRA	2009	NG	OCGT	44	9,454	16.95	13.41	24	44	1	1	19.09	0
Winchester Power Park 3	Fayette	LCRA	2009	NG	OCGT	44	9,466	16.95	13.41	24	44	1	1	19.09	0
Winchester Power Park 4	Fayette	LCRA	2009	NG	OCGT	44	9,508	16.95	13.41	24	44	1	1	19.09	0
Bayou Cogen Plant	Harris	Houston	1985	NG	OCGT-CHP	165.6	9,927	16.95	13.41	25	14	1	1	33.89	0
BP Chemicals Green Lake Plant	Calhoun	South	1997	NG	OCGT-CHP	8	11,500	16.95	13.41	25	14	1	1	33.88	0
Equistar Corpus Christi	Nueces	South	1989	NG	OCGT-CHP	12	8,500	16.95	13.41	25	14	1	1	33.89	0
ExxonMobil Baytown Refinery	Harris	Houston	1989	NG	OCGT-CHP	4.3	14,451	16.95	13.41	25	14	1	1	33.90	0
Sweeny Cogen Facility	Brazoria	Houston	2001	NG	OCGT-CHP	430.7	9,000	16.95	13.41	25	14	1	1	33.89	0
Texas Gulf Sulphur (New Gulf)	Wharton	Houston	1985	NG	OCGT-CHP	58.9	14,553	16.95	13.41	25	14	1	1	33.90	0
Victoria Texas Plant	Victoria	South	1987	NG	OCGT-CHP	8.9	9,000	16.95	13.41	24	44	1	1	19.37	0
B M Davis 1	Nueces	South	1974	NG	ST	330	10,500	19.49	15.43	38	0.54	2	2	47.94	0
Cedar Bayou 1	Chambers	Houston	1970	NG	ST	745	10,265	19.49	15.43	28	0.54	2	2	47.94	0
Cedar Bayou 2	Chambers	Houston	1972	NG	ST	749	10,271	19.49	15.43	28	0.54	2	2	47.94	0
Dansby 1	Brazos	North	1978	NG	ST	107	11,435	19.49	15.43	38	0.54	2	2	47.94	0
Decker Creek 1	Travis	AEN	1971	NG	ST	315	10,406	19.49	15.43	38	0.54	2	2	48.31	0
Decker Creek 2	Travis	AEN	1978	NG	ST	420	10,725	19.49	15.43	38	0.54	2	2	48.39	0
Graham 1	Young	West	1960	NG	ST	234	11,942	19.49	15.43	38	0.54	2	2	47.94	0
Graham 2	Young	West	1969	NG	ST	390	11,937	19.49	15.43	38	0.54	2	2	47.94	0
Greens Bayou 5	Harris	Houston	1973	NG	ST	371	13,460	19.49	15.43	38	0.54	2	2	50.00	0
Handley 3	Tarrant	North	1963	NG	ST	395	13,692	19.49	15.43	38	0.54	2	2	47.94	0
Handley 4	Tarrant	North	1976	NG	ST	435	13,692	19.49	15.43	38	0.54	2	2	48.42	0
Handley 5	Tarrant	North	1977	NG	ST	435	13,692	19.49	15.43	38	0.54	2	2	48.05	0
Lake Hubbard 1	Dallas	North	1970	NG	ST	392	12,162	19.49	15.43	38	0.54	2	2	47.94	0
Lake Hubbard 2	Dallas	North	1973	NG	ST	523	12,105	19.49	15.43	38	0.54	2	2	47.94	0
Mountain Creek 6	Dallas	North	1956	NG	ST	122	10,826	19.49	15.43	43	0.55	2	2	48.33	0
Mountain Creek 7	Dallas	North	1958	NG	ST	118	11,519	19.49	15.43	43	0.54	2	2	48.55	0
Mountain Creek 8	Dallas	North	1967	NG	ST	568	10,000	19.49	15.43	28	0.54	2	2	48.06	0
O W Sommers 1	Bexar	South	1972	NG	ST	420	12,058	19.49	15.43	38	0.54	2	2	46.79	0
O W Sommers 2	Bexar	South	1974	NG	ST	410	10,477	19.49	15.43	38	0.54	2	2	45.65	0
Pearsall 1	Frio	South	1961	NG	ST	19	14,500	19.49	15.43	43	0.52	2	2	47.94	0
Pearsall 2	Frio	South	1961	NG	ST	22	14,500	19.49	15.43	43	0.54	2	2	50.00	0
Pearsall 3	Frio	South	1961	NG	ST	20	14,500	19.49	15.43	43	0.54	2	2	50.00	0
Powerlane Plant 1	Hunt	North	1966	NG	ST	20	14,500	19.49	15.43	43	0.55	2	2	47.94	0
Powerlane Plant 2	Hunt	North	1967	NG	ST	26	14,500	19.49	15.43	43	0.54	2	2	48.86	0
Powerlane Plant 3	Hunt	North	1978	NG	ST	41	14,500	19.49	15.43	44	0.56	2	2	48.99	0
R W Miller 1	Palo Pinto	North	1968	NG	ST	75	10,947	19.49	15.43	43	0.53	2	2	47.94	0
R W Miller 2	Palo Pinto	North	1972	NG	ST	120	11,381	19.49	15.43	38	0.53	2	2	47.94	0
R W Miller 3	Palo Pinto	North	1925	NG	ST	208	10,335	19.49	15.43	38	0.54	2	2	47.94	0
Ray Olinger 1	Collin	North	1967	NG	ST	78	12,290	19.49	15.43	43	0.54	2	2	47.94	0
Ray Olinger 2	Collin	North	1971	NG	ST	107	11,351	19.49	15.43	38	0.53	2	2	47.94	0
Ray Olinger 3	Collin	North	1975	NG	ST	146	11,350	19.49	15.43	38	0.53	2	2	47.94	0
Sim Gideon 1	Bastrop	LCRA	1965	NG	ST	130	10,961	19.49	15.43	38	0.54	2	2	51.62	0
Sim Gideon 2	Bastrop	LCRA	1968	NG	ST	135	10,801	19.49	15.43	39	0.56	2	2	49.71	0
Sim Gideon 3	Bastrop	LCRA	1972	NG	ST	336	11,507	19.49	15.43	38	0.54	2	2	48.43	0
Spencer 4	Denton	North	1966	NG	ST	61	14,500	19.49	15.43	55	0.54	2	2	50.00	0
Spencer 5	Denton	North	1973	NG	ST	61	14,195	19.49	15.43	55	0.54	2	2	50.00	0
Stryker Creek 1	Cherokee	North	1958	NG	ST	167	13,850	19.49	15.43	39	0.55	2	2	49.08	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/MW-start]	Forced Outage Rate [%]
Stryker Creek 2	Cherokee	North	1965	NG	ST	502	13,908	19.49	15.43	38	0.54	2	2	50.00	0
Trinidad 6	Henderson	North	1965	NG	ST	235	13,510	19.49	15.43	38	0.54	2	2	47.94	0
V H Braunig 1	Bexar	South	1966	NG	ST	220	10,736	19.49	15.43	38	0.54	2	2	47.94	0
V H Braunig 2	Bexar	South	1968	NG	ST	230	10,278	19.49	15.43	38	0.53	2	2	47.94	0
V H Braunig 3	Bexar	South	1970	NG	ST	412	11,638	19.49	15.43	38	0.54	2	2	47.94	0
W A Parish 1	Fort Bend	Houston	1958	NG	ST	169	10,963	19.49	15.43	39	0.55	2	2	49.35	0
W A Parish 2	Fort Bend	Houston	1958	NG	ST	169	11,513	19.49	15.43	39	0.55	2	2	49.35	0
W A Parish 3	Fort Bend	Houston	1961	NG	ST	246	12,080	19.49	15.43	38	0.54	2	2	51.65	0
W A Parish 4	Fort Bend	Houston	1968	NG	ST	536	11,002	19.49	15.43	28	0.54	2	2	47.94	0
Acacia Solar	Presidio	West	2012	Solar	PV	10	-	25.79	0.00	-	-	-	-	-	0
Barilla Solar (FS, Pecos)	Pecos	West	2014	Solar	PV	22	-	25.79	0.00	-	-	-	-	-	0
Blue Wing 1 Solar	Bexar	South	2010	Solar	PV	7.6	-	25.79	0.00	-	-	-	-	-	0
Blue Wing 2 Solar	Bexar	South	2010	Solar	PV	7.3	-	25.79	0.00	-	-	-	-	-	0
Downie Ranch Solar (OCI Alamo 5)	Uvalde	South	2015	Solar	PV	95	-	25.79	0.00	-	-	-	-	-	0
OCI Alamo 1 Solar	Bexar	South	2013	Solar	PV	39.2	-	25.79	0.00	-	-	-	-	-	0
OCI Alamo 2-St. Hedwig Solar	Bexar	South	2014	Solar	PV	4.4	-	25.79	0.00	-	-	-	-	-	0
OCI Alamo 3-Walzem Solar	Bexar	South	2014	Solar	PV	5.5	-	25.79	0.00	-	-	-	-	-	0
OCI Alamo 4 Solar (Bracketville)	Kinney	South	2014	Solar	PV	37.6	-	25.79	0.00	-	-	-	-	-	0
Renewable Energy Alternatives CCS1	Denton	North	2015	Solar	PV	2	-	25.79	0.00	-	-	-	-	-	0
SunEdison CPS3 Somerset 1 Solar	Bexar	South	2012	Solar	PV	5.6	-	25.79	0.00	-	-	-	-	-	0
SunEdison Rabel Road Solar	Bexar	South	2012	Solar	PV	9.9	-	25.79	0.00	-	-	-	-	-	0
SunEdison Somerset 2 Solar	Bexar	South	2012	Solar	PV	5	-	25.79	0.00	-	-	-	-	-	0
SunEdison Valley Road Solar	Bexar	South	2012	Solar	PV	9.9	-	25.79	0.00	-	-	-	-	-	0
Webberville Solar	Travis	AEN	2011	Solar	PV	26.7	-	25.79	0.00	-	-	-	-	-	0
Notrees Battery Facility	Winkler	West	2012	Storage	BATT	36	-	0.00	0.00	-	-	-	-	-	0
Comanche Peak U1	Somervell	North	1990	Uranium	ST	1,205	10,501	17.99	1.33	30	0.26	24	168	96.84	8
Comanche Peak U2	Somervell	North	1993	Uranium	ST	1,195	10,499	17.99	1.33	30	0.26	24	168	96.84	7
South Texas U1	Matagorda	South	1988	Uranium	ST	1,286	10,502	16.85	1.33	30	0.26	24	168	96.84	10
South Texas U2	Matagorda	South	1989	Uranium	ST	1,295	10,498	16.85	1.33	30	0.26	24	168	96.84	15
Anacacho Wind	Kinney	South	2012	Wind	WT	99.8	-	41.18	0.00	-	-	-	-	-	0
Barton Chapel Wind	Jack	North	2007	Wind	WT	120	-	41.18	0.00	-	-	-	-	-	0
Blue Summit Wind 5	Wilbarger	West	2013	Wind	WT	9	-	41.18	0.00	-	-	-	-	-	0
Blue Summit Wind 6	Wilbarger	West	2013	Wind	WT	126.4	-	41.18	0.00	-	-	-	-	-	0
Bobcat Bluff Wind	Archer	North	2012	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Briscoe Wind Farm	Briscoe	West	2015	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Buffalo Gap Wind Farm 1	Taylor	West	2006	Wind	WT	120.6	-	41.18	0.00	-	-	-	-	-	0
Buffalo Gap Wind Farm 2_1	Taylor	West	2007	Wind	WT	115.5	-	41.18	0.00	-	-	-	-	-	0
Buffalo Gap Wind Farm 2_2	Taylor	West	2007	Wind	WT	117	-	41.18	0.00	-	-	-	-	-	0
Buffalo Gap Wind Farm 3	Taylor	West	2008	Wind	WT	170.2	-	41.18	0.00	-	-	-	-	-	0
Bull Creek Wind Plant U1	Borden	West	2009	Wind	WT	88	-	41.18	0.00	-	-	-	-	-	0
Bull Creek Wind Plant U2	Borden	West	2009	Wind	WT	90	-	41.18	0.00	-	-	-	-	-	0
Callahan Wind	Callahan	West	2004	Wind	WT	114	-	41.18	0.00	-	-	-	-	-	0
Camp Springs Wind 1	Scurry	West	2007	Wind	WT	130.5	-	41.18	0.00	-	-	-	-	-	0
Camp Springs Wind 2	Scurry	West	2007	Wind	WT	120	-	41.18	0.00	-	-	-	-	-	0
Capricorn Ridge Wind 1	Sterling	West	2007	Wind	WT	214.5	-	41.18	0.00	-	-	-	-	-	0
Capricorn Ridge Wind 2	Sterling	West	2008	Wind	WT	186	-	41.18	0.00	-	-	-	-	-	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/ kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/ MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/ min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/ MW-start]	Forced Outage Rate [%]
Capricorn Ridge Wind 3	Sterling	West	2007	Wind	WT	149.5	-	41.18	0.00	-	-	-	-	-	0
Capricorn Ridge Wind 4	Coke	West	2008	Wind	WT	112.5	-	41.18	0.00	-	-	-	-	-	0
Cedro Hill Wind 1	Webb	South	2010	Wind	WT	75	-	41.18	0.00	-	-	-	-	-	0
Cedro Hill Wind 2	Webb	South	2010	Wind	WT	75	-	41.18	0.00	-	-	-	-	-	0
Champion Wind Farm	Nolan	West	2008	Wind	WT	126.5	-	41.18	0.00	-	-	-	-	-	0
Desert Sky Wind Farm 1	Pecos	West	2002	Wind	WT	84	-	41.18	0.00	-	-	-	-	-	0
Desert Sky Wind Farm 2	Pecos	West	2002	Wind	WT	76.5	-	41.18	0.00	-	-	-	-	-	0
Elbow Creek Wind	Howard	West	2008	Wind	WT	118.7	-	41.18	0.00	-	-	-	-	-	0
Forest Creek Wind Farm	Glasscock	West	2007	Wind	WT	124.2	-	41.18	0.00	-	-	-	-	-	0
Goat Wind	Sterling	West	2008	Wind	WT	80	-	41.18	0.00	-	-	-	-	-	0
Goat Wind 2	Sterling	West	2010	Wind	WT	69.6	-	41.18	0.00	-	-	-	-	-	0
Goldthwaite Wind 1	Mills	North	2014	Wind	WT	148.6	-	41.18	0.00	-	-	-	-	-	0
Grandview 1 (Conway) GV1A	Carson	West	2014	Wind	WT	107.4	-	41.18	0.00	-	-	-	-	-	0
Grandview 1 (Conway) GV1B	Carson	West	2014	Wind	WT	103.8	-	41.18	0.00	-	-	-	-	-	0
Green Mountain Wind (Brazos) U1	Scurry	West	2003	Wind	WT	99	-	41.18	0.00	-	-	-	-	-	0
Green Mountain Wind (Brazos) U2	Scurry	West	2003	Wind	WT	61	-	41.18	0.00	-	-	-	-	-	0
Green Pastures Wind 1	Knox	West	2015	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Green Pastures Wind 2	Knox	West	2015	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Hackberry Wind Farm	Shackelford	West	2008	Wind	WT	163.5	-	41.18	0.00	-	-	-	-	-	0
Hereford Wind G	Deaf Smith	West	2015	Wind	WT	99.9	-	41.18	0.00	-	-	-	-	-	0
Hereford Wind V	Deaf Smith	West	2015	Wind	WT	100	-	41.18	0.00	-	-	-	-	-	0
Horse Hollow Wind 1	Taylor	West	2005	Wind	WT	206.6	-	41.18	0.00	-	-	-	-	-	0
Horse Hollow Wind 2	Taylor	West	2006	Wind	WT	158	-	41.18	0.00	-	-	-	-	-	0
Horse Hollow Wind 3	Taylor	West	2006	Wind	WT	208	-	41.18	0.00	-	-	-	-	-	0
Horse Hollow Wind 4	Taylor	West	2006	Wind	WT	108	-	41.18	0.00	-	-	-	-	-	0
Inadale Wind	Nolan	West	2008	Wind	WT	196.6	-	41.18	0.00	-	-	-	-	-	0
Indian Mesa Wind Farm	Pecos	West	2001	Wind	WT	82.5	-	41.18	0.00	-	-	-	-	-	0
Javelina Wind Energy	Zapata	South	2015	Wind	WT	250	-	41.18	0.00	-	-	-	-	-	0
Jumbo Road Wind 1	Deaf Smith	West	2015	Wind	WT	146.2	-	41.18	0.00	-	-	-	-	-	0
Jumbo Road Wind 2	Deaf Smith	West	2015	Wind	WT	153.6	-	41.18	0.00	-	-	-	-	-	0
Keechi Wind 138 KV Joplin	Jack	North	2014	Wind	WT	110	-	41.18	0.00	-	-	-	-	-	0
King Mountain Wind NE	Upton	West	2001	Wind	WT	79.3	-	41.18	0.00	-	-	-	-	-	0
King Mountain Wind NW	Upton	West	2001	Wind	WT	79.3	-	41.18	0.00	-	-	-	-	-	0
King Mountain Wind SE	Upton	West	2001	Wind	WT	40.3	-	41.18	0.00	-	-	-	-	-	0
King Mountain Wind SW	Upton	West	2001	Wind	WT	79.3	-	41.18	0.00	-	-	-	-	-	0
Langford Wind Power	Tom Green	West	2009	Wind	WT	155	-	41.18	0.00	-	-	-	-	-	0
Logan's Gap Wind I U1	Comanche	North	2015	Wind	WT	103.8	-	41.18	0.00	-	-	-	-	-	0
Logan's Gap Wind I U2	Comanche	North	2015	Wind	WT	106.3	-	41.18	0.00	-	-	-	-	-	0
Lone Star Wind 1 (Mesquite)	Shackelford	North	2006	Wind	WT	200	-	41.18	0.00	-	-	-	-	-	0
Lone Star Wind 2 (Post Oak) U1	Shackelford	North	2007	Wind	WT	100	-	41.18	0.00	-	-	-	-	-	0
Lone Star Wind 2 (Post Oak) U2	Shackelford	North	2007	Wind	WT	100	-	41.18	0.00	-	-	-	-	-	0
Longhorn Wind North U1	Floyd	West	2015	Wind	WT	100	-	41.18	0.00	-	-	-	-	-	0
Longhorn Wind North U2	Floyd	West	2015	Wind	WT	100	-	41.18	0.00	-	-	-	-	-	0
Loraine Windpark I	Mitchell	West	2009	Wind	WT	49.5	-	41.18	0.00	-	-	-	-	-	0
Loraine Windpark II	Mitchell	West	2009	Wind	WT	51	-	41.18	0.00	-	-	-	-	-	0
Loraine Windpark III	Mitchell	West	2011	Wind	WT	25.5	-	41.18	0.00	-	-	-	-	-	0
Loraine Windpark IV	Mitchell	West	2011	Wind	WT	24	-	41.18	0.00	-	-	-	-	-	0
Los Vientos Wind III	Starr	South	2015	Wind	WT	200	-	41.18	0.00	-	-	-	-	-	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/ kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/ MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/ min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/ MW-start]	Forced Outage Rate [%]
McAdoo Wind Farm	Dickens	West	2008	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Mesquite Creek Wind 1	Dawson	West	2015	Wind	WT	105.6	-	41.18	0.00	-	-	-	-	-	0
Mesquite Creek Wind 2	Dawson	West	2015	Wind	WT	105.6	-	41.18	0.00	-	-	-	-	-	0
Miami Wind G1	Gray	West	2014	Wind	WT	144.3	-	41.18	0.00	-	-	-	-	-	0
Miami Wind G2	Gray	West	2014	Wind	WT	144.3	-	41.18	0.00	-	-	-	-	-	0
Notrees Wind Farm 1	Winkler	West	2009	Wind	WT	92.6	-	41.18	0.00	-	-	-	-	-	0
Notrees Wind Farm 2	Winkler	West	2009	Wind	WT	60	-	41.18	0.00	-	-	-	-	-	0
Ocotillo Wind Farm	Howard	West	2008	Wind	WT	58.8	-	41.18	0.00	-	-	-	-	-	0
Panhandle Wind 1 U1	Carson	West	2014	Wind	WT	109.2	-	41.18	0.00	-	-	-	-	-	0
Panhandle Wind 1 U2	Carson	West	2014	Wind	WT	109.2	-	41.18	0.00	-	-	-	-	-	0
Panhandle Wind 2 U1	Carson	West	2014	Wind	WT	94.2	-	41.18	0.00	-	-	-	-	-	0
Panhandle Wind 2 U2	Carson	West	2014	Wind	WT	96.6	-	41.18	0.00	-	-	-	-	-	0
Panther Creek 1	Howard	West	2008	Wind	WT	142.5	-	41.18	0.00	-	-	-	-	-	0
Panther Creek 2	Howard	West	2008	Wind	WT	115.5	-	41.18	0.00	-	-	-	-	-	0
Panther Creek 3	Howard	West	2009	Wind	WT	199.5	-	41.18	0.00	-	-	-	-	-	0
Pecos Wind (Woodward 1)	Pecos	West	2001	Wind	WT	82.5	-	41.18	0.00	-	-	-	-	-	0
Pecos Wind (Woodward 2)	Pecos	West	2001	Wind	WT	77.2	-	41.18	0.00	-	-	-	-	-	0
Pyron Wind Farm	Scurry	West	2008	Wind	WT	249	-	41.18	0.00	-	-	-	-	-	0
Rattlesnake Den Wind 1 G1	Glasscock	West	2015	Wind	WT	104.3	-	41.18	0.00	-	-	-	-	-	0
Rattlesnake Den Wind 1 G2	Glasscock	West	2015	Wind	WT	103	-	41.18	0.00	-	-	-	-	-	0
Red Canyon Wind	Borden	West	2006	Wind	WT	84	-	41.18	0.00	-	-	-	-	-	0
Roscoe Wind Farm	Nolan	West	2008	Wind	WT	209	-	41.18	0.00	-	-	-	-	-	0
Route 66 Wind	Carson	West	2015	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Sand Bluff Wind Farm	Glasscock	West	2008	Wind	WT	90	-	41.18	0.00	-	-	-	-	-	0
Senate Wind	Jack	North	2012	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Shannon Wind	Clay	West	2015	Wind	WT	200	-	41.18	0.00	-	-	-	-	-	0
Sherbino 1 Wind	Pecos	West	2008	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Sherbino 2 Wind	Pecos	West	2011	Wind	WT	147.5	-	41.18	0.00	-	-	-	-	-	0
Silver Star Wind	Eastland	North	2008	Wind	WT	60	-	41.18	0.00	-	-	-	-	-	0
Snyder Wind Farm	Scurry	West	2007	Wind	WT	63	-	41.18	0.00	-	-	-	-	-	0
South Plains Wind 1	Floyd	West	2015	Wind	WT	102	-	41.18	0.00	-	-	-	-	-	0
South Plains Wind 2	Floyd	West	2015	Wind	WT	98	-	41.18	0.00	-	-	-	-	-	0
South Trent Wind Farm	Nolan	West	2008	Wind	WT	98.2	-	41.18	0.00	-	-	-	-	-	0
Spinning Spur 3 Wind 1	Oldham	West	2015	Wind	WT	96	-	41.18	0.00	-	-	-	-	-	0
Spinning Spur 3 Wind 2	Oldham	West	2015	Wind	WT	98	-	41.18	0.00	-	-	-	-	-	0
Spinning Spur Wind Two	Oldham	West	2014	Wind	WT	161	-	41.18	0.00	-	-	-	-	-	0
Stanton Wind Energy	Martin	West	2008	Wind	WT	120	-	41.18	0.00	-	-	-	-	-	0
Stephens Ranch Wind 1	Borden	West	2014	Wind	WT	211.2	-	41.18	0.00	-	-	-	-	-	0
Stephens Ranch Wind 2	Borden	West	2015	Wind	WT	165	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 1	Nolan	West	2003	Wind	WT	36.6	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 2A	Nolan	West	2006	Wind	WT	15.9	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 2B	Nolan	West	2004	Wind	WT	97.5	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 3A	Nolan	West	2011	Wind	WT	28.5	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 3B	Nolan	West	2011	Wind	WT	100.5	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 4-4A	Nolan	West	2007	Wind	WT	117.8	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 4-4B	Nolan	West	2007	Wind	WT	103.7	-	41.18	0.00	-	-	-	-	-	0
Sweetwater Wind 4-5	Nolan	West	2007	Wind	WT	79.2	-	41.18	0.00	-	-	-	-	-	0
Texas Big Spring Wind A	Howard	West	1999	Wind	WT	27.7	-	41.18	0.00	-	-	-	-	-	0
Texas Big Spring Wind B	Howard	West	1999	Wind	WT	6.6	-	41.18	0.00	-	-	-	-	-	0
Trent Wind Farm	Nolan	West	2001	Wind	WT	150	-	41.18	0.00	-	-	-	-	-	0
Trinity Hills Wind 1	Young	North	2012	Wind	WT	117.5	-	41.18	0.00	-	-	-	-	-	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/ kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/ MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/ min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/ MW-start]	Forced Outage Rate [%]
Trinity Hills Wind 2	Young	North	2012	Wind	WT	107.5	-	41.18	0.00	-	-	-	-	-	0
TSTC West Texas Wind	Nolan	West	2008	Wind	WT	2	-	41.18	0.00	-	-	-	-	-	0
Turkey Track Wind Energy Center	Nolan	West	2008	Wind	WT	169.5	-	41.18	0.00	-	-	-	-	-	0
West Texas Wind Energy	Upton	West	1999	Wind	WT	80.3	-	41.18	0.00	-	-	-	-	-	0
Whirlwind Energy	Floyd	West	2007	Wind	WT	57	-	41.18	0.00	-	-	-	-	-	0
Whitetail Wind Energy	Webb	South	2012	Wind	WT	91	-	41.18	0.00	-	-	-	-	-	0
Windthorst 2	Archer	North	2014	Wind	WT	67.6	-	41.18	0.00	-	-	-	-	-	0
WKN Mozart Wind	Kent	West	2012	Wind	WT	30	-	41.18	0.00	-	-	-	-	-	0
Wolf Flats Wind (Wind Mgt)	Hall	West	2007	Wind	WT	1	-	41.18	0.00	-	-	-	-	-	0
Wolf Ridge Wind	Cooke	North	2008	Wind	WT	112.5	-	41.18	0.00	-	-	-	-	-	0
Cameron Wind	Cameron	South	2015	Wind-C	WT	165	-	41.18	0.00	-	-	-	-	-	0
Gulf Wind I	Kenedy	South	2010	Wind-C	WT	141.6	-	41.18	0.00	-	-	-	-	-	0
Gulf Wind II	Kenedy	South	2010	Wind-C	WT	141.6	-	41.18	0.00	-	-	-	-	-	0
Harbor Wind	Nueces	South	2012	Wind-C	WT	9	-	41.18	0.00	-	-	-	-	-	0
Los Vientos Wind I	Willacy	South	2013	Wind-C	WT	200.1	-	41.18	0.00	-	-	-	-	-	0
Los Vientos Wind II	Willacy	South	2013	Wind-C	WT	201.6	-	41.18	0.00	-	-	-	-	-	0
Magic Valley Wind (Redfish) 1A	Willacy	South	2012	Wind-C	WT	99.8	-	41.18	0.00	-	-	-	-	-	0
Magic Valley Wind (Redfish) 1B	Willacy	South	2012	Wind-C	WT	103.5	-	41.18	0.00	-	-	-	-	-	0
Papalote Creek Wind Farm	San Patricio	South	2009	Wind-C	WT	179.9	-	41.18	0.00	-	-	-	-	-	0
Papalote Creek Wind Farm II	San Patricio	South	2010	Wind-C	WT	200.1	-	41.18	0.00	-	-	-	-	-	0
Penascal Wind 1	Kenedy	South	2009	Wind-C	WT	160.8	-	41.18	0.00	-	-	-	-	-	0
Penascal Wind 2	Kenedy	South	2009	Wind-C	WT	141.6	-	41.18	0.00	-	-	-	-	-	0
Penascal Wind 3	Kenedy	South	2011	Wind-C	WT	100.8	-	41.18	0.00	-	-	-	-	-	0

Appendix B: LCOE, LACE, and Net Value

Levelized cost of energy (LCOE)

The *LCOE* is a method that quantifies the long-term average cost for an electricity generation technology or facility, typically expressed in \$/kWh (Rhodes et al. 2017). The basic concept behind *LCOE* is to combine the capital cost for an electric generation technology *n* with its variable and fixed power generation costs ($VOM_{n,t}$ + $FOM_{n,t}$) in year *t*. The capital costs are converted into an annuity of equal sized payments over the generation period so that the present value of the annuity is the total overnight capital cost.

Formally, we express the capital investment cost as:

(1)

$$\Pi CAP_{n,t} = \sum_{t=1}^{T} \frac{\bar{R}}{(1+i)^t}$$

where $\bar{R}$ is the equivalent uniform annual payment, *i* is the discount rate and *T* is the total number of periods to service the debt (loan period). Solving for $\bar{R}$:

(2)

$$\bar{R} = \Pi CAP_{n,t} \times \underbrace{\left[\sum_{t=1}^{T} \frac{1}{(1+i)^t}\right]^{-1}}_{CRF}$$

The factor on the right side of the capital investment cost in equation (2) is the capital recovery factor (*CRF*) and can be simplified as follows.

(3)

$$CRF = \left[\sum_{t=1}^{T} \frac{1}{(1+i)^t}\right]^{-1} = \frac{i(1+i)^T}{(1+i)^T - 1}$$

The annual *LCOE* can be calculated as (Tidball et al. 2010):

(4)

$$LCOE_{n,t} = \underbrace{\frac{\Pi CAP_{n,t} \times CRF + FOM_{n,t}}{8{,}760 \times CF_{n,t}}}_{Annualized\ Fixed\ Costs} + \underbrace{VOM_{n,t} + HR_n \times \Pi Fuel_t}_{Annual\ Variable\ Costs} = \frac{\$}{kWh}$$

where $CF_{n,t}$ is the capacity factor for technology *n* in period *t*, $\Pi Fuel_t$ is the cost of fuel in period *t*, and is the heat rate of the technology. The heat rate is the thermal energy needed to generate a unit of electrical energy in plant *n*.

As shown in equation (4), the larger the capacity factor, the smaller the fixed and capital costs relative to each unit of energy, which lowers *LCOE*. This concept—decreasing cost per unit of energy as a function of an increasing capacity factor—is the key to understanding the competitive advantage of certain technologies over others.

One of the desirable properties of *LCOE* is that various technologies with different characteristics can be compared under the same cost basis. For example, annual variable costs for wind and solar are zero since VOM is zero and these technologies do not require fuel. But, wind and solar have relatively high capital costs when compared to a natural gas-fired power plant that does require fuel. *LCOE* allows for these disparate features of each technology to be fairly compared in a single cost figure.

While *LCOE* is a convenient measure of the overall cost of different generating technologies, one of its biggest limitations is that it does not consider the revenue or value of a technology, which, among other factors, is dependent on grid topography, load profiles, generation portfolio, and fuel prices at various hubs in any given system. As a result, an intermittent resource like wind may have the lowest *LCOE* of all available technologies, but if this technology can be only dispatched at night in a system, when the wholesale price of electricity is low, the technology may not be viable, even though it has the cheapest average cost per unit at the time that it is dispatched.

Levelized avoided cost of energy (LACE)

In recent years, the U.S. Energy Information Administration (EIA) has developed the levelized avoided cost of electricity (*LACE*) as a complement to *LCOE*. Rather than costs, *LACE* estimates the revenue that a power plant creates per each unit of electricity (Namovicz 2013). *LACE* can be calculated as the weighted average revenue that a certain technology would provide per unit of electricity, in a particular period, in $/kWh like *LCOE*.

One interpretation of the *LACE* of a power plant is that it is a measure of how much it would cost the grid to generate the additional electricity that would be required if that power plant were not available (EIA 2016d). The word "avoided" is included in the *LACE* acronym to reflect the cost savings associated with avoiding the less efficient generation that is replaced by the analyzed technology.

The first concept to understand before calculating *LACE* is the market price (MP_t), which is the price that a generator would receive in the market if it sells one unit of energy during period. It is defined as the highest of the dispatched prices of the online plants in period *t*. A calculation of revenue must reflect that fact that each power plant generates a different amount of electricity at different times.

LACE can be calculated as the weighted average of the market price of the power source that it generates (Namovicz 2013).

(5)

$$LACE_{n,t} = \frac{\sum_t^T AAG_{n,t} \times MP_t}{\sum_t^T AAG_{n,t}}$$

where $AAG_{n,t}$ is the actual production of technology *n* in time *t*. Noting that for a year, $\Sigma_t^T AAG_{n,t} = 8{,}760 \times CF_{n,t}$ we can substitute into the denominator of (5) to obtain:

(6)

$$LACE_{n,t} = \frac{\sum_t^T AAG_{n,t} \times MP_t}{8{,}760 \times CF_{n,t}}$$

From equation (6) we can infer that a power plant which is always available but is not dispatched would have a *LACE* of $0/MWh, because it does not sell any units of electricity, i.e. $AAG_{n,t} = 0 \ \forall \ t$,

In order to be dispatched, a conventional power plant must offer to generate electricity at a price that is low enough to enter into the market; less efficient plants are dispatched only at periods of higher demand when power prices are high enough to cover their higher costs. This highlights an important feature of *LACE*: for conventional power plants, *LACE* does not only depend on each particular technology, but also on the market as a whole. For example, a certain technology in a market with high prices would have a much higher *LACE* than the same technology in a low-price market. Therefore, *LACE* is not an appropriate way to compare technologies across markets.

Renewable plants have a marginal cost of $0/MWh, and so they are always dispatched when available. Therefore, their *LACE* only depends on the market price and the availability of the generator that determines the market price for the grid. In Texas, wind plants are relatively more available during the night when market prices are low, while solar plants, for example, produce during the day when market prices are higher. Thus, the *LACE* of a solar plant tends to be higher than *LACE* for a wind plant; a solar plant allows the system to avoid more expensive electricity compared to a wind plant.

In summary, *LACE* is the average value of revenue per unit of energy sold in the market, ignoring the costs of generation. Therefore, it cannot be used independently to make comparisons across different markets.

Net value

As mentioned before, *LACE* and *LCOE* cannot be used independently to determine the best generation technology to construct or the worst technology to decommission. However, the difference between *LACE* and *LCOE*, referred to as *net value*, accounts for revenues and cost, making it possible to calculate the profit of each technology (Namovicz 2013):

(7)

$$Net\ Value_{n,t} = LACE_{n,t} - LCOE_{n,t} = \frac{NPV_{n,t} \times CRF_{n,t}}{\overline{AAG_{n,t}}}$$

The *net value* can be also calculated as the net present value (NPV) annualized with the *CRF* and divided by the annual average generation, $\overline{AAG_{n,t}}$. Therefore, if the *net value* is positive, the net present value of the project will be positive, and vice-versa. As a result, the *net value* can give us insight into which technologies are profitable at a given time in a given market and should therefore be expected to see increases in installed capacity relative to technologies with lower *net values*.

Appendix C: Wind Rating Factors by Aggregate County (%)

County	Load Zone	Annual			June			September		
		Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
Andrews	West	0.00	40.18	94.21	0.04	57.93	93.63	0.00	34.50	90.80
Archer	West	0.00	42.52	95.87	0.00	60.63	95.00	0.00	28.04	95.20
Armstrong	West	0.00	42.74	92.52	0.39	53.42	92.17	0.00	34.46	90.64
Borden	West	0.00	38.98	94.17	0.00	54.49	92.80	0.00	27.27	90.49
Briscoe	West	0.00	38.99	94.21	0.00	49.31	93.47	0.00	27.72	90.82
Callahan	West	0.00	39.09	93.28	0.00	55.63	92.82	0.00	22.99	89.61
Cameron	South	0.00	39.33	94.70	0.33	50.87	91.39	0.00	26.39	86.56
Carson	West	0.00	44.92	94.62	0.00	57.42	94.02	0.00	40.19	92.69
Castro	West	0.00	41.00	93.57	0.00	48.05	93.00	0.00	31.58	90.93
Childress	West	0.00	39.20	96.49	0.00	55.20	93.81	0.00	29.78	92.53
Clay	West	0.00	41.34	97.00	0.00	58.03	95.80	0.00	28.05	93.91
Coke	West	0.00	35.48	95.44	0.00	49.55	94.40	0.00	22.45	84.48
Comanche	North	0.00	42.59	95.74	0.00	59.07	93.97	0.00	22.39	93.35
Cooke	North	0.00	37.51	96.98	0.00	50.56	95.73	0.00	22.85	95.91
Coryell	North	0.00	40.64	94.52	0.02	55.93	92.87	0.00	21.09	89.98
Crockett	West	0.00	40.94	93.17	0.00	64.20	92.86	0.00	31.86	91.45
Crosby	West	0.00	41.49	96.55	0.00	54.69	95.34	0.00	29.37	90.90
Dallam	West	0.00	44.63	93.50	0.21	55.23	93.19	0.00	40.88	91.49
Dawson	West	0.00	38.85	93.50	0.00	54.51	92.17	0.00	27.10	88.94
Deaf Smith	West	0.00	42.53	94.42	0.00	48.15	93.02	0.00	36.32	92.33
Dickens	West	0.00	44.04	96.67	0.00	58.12	96.00	0.00	30.37	93.47
Eastland	North	0.00	39.52	93.37	0.11	55.78	92.31	0.00	22.13	91.79
Erath	North	0.00	30.29	97.00	0.00	44.59	94.17	0.00	14.75	90.00
Floyd	West	0.00	41.34	93.68	0.00	53.50	92.65	0.00	29.52	92.06
Galveston (Offshore)	Houston	0.00	30.76	97.00	0.00	23.53	80.54	0.00	20.74	94.60
Glasscock	West	0.00	40.84	94.22	0.00	56.91	92.75	0.00	29.33	91.76
Gray	West	0.00	44.94	93.32	0.00	55.98	93.24	0.00	38.23	91.79
Hale	West	0.00	40.58	92.65	0.07	50.66	91.88	0.00	29.67	90.91
Hall	West	0.00	39.03	93.98	0.00	50.53	93.24	0.00	28.14	90.24
Haskell	West	0.00	40.53	94.65	0.00	57.61	93.63	0.00	28.13	92.17
Hidalgo	South	0.00	36.98	95.26	0.00	49.22	91.92	0.00	23.89	89.08
Howard	West	0.00	39.78	94.08	0.00	55.37	93.31	0.00	27.82	92.42
Jack	North	0.00	39.63	94.45	0.00	54.36	92.80	0.00	24.04	91.72

County	Load Zone	Annual			June			September		
		Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
Jim Hogg	South	0.00	39.72	96.30	0.09	59.32	96.30	0.00	33.60	94.31
Kenedy	South	0.00	33.21	93.67	0.11	46.45	93.05	0.00	25.18	87.86
Kent	North	0.00	39.85	96.24	0.00	54.01	95.09	0.00	25.84	93.21
Kinney	South	0.00	31.57	93.79	0.00	53.04	91.54	0.00	27.21	92.86
Kleberg	South	0.00	39.04	95.10	0.25	51.11	93.00	0.00	31.15	89.46
Knox	West	0.00	39.13	96.40	0.00	55.67	94.55	0.00	27.63	91.66
Live Oak	South	0.00	33.62	96.80	0.00	49.07	95.90	0.00	27.61	92.99
Martin	West	0.00	34.43	95.79	0.00	51.53	94.01	0.00	23.33	89.97
McCulloch	South	0.00	41.91	94.21	0.04	57.86	92.75	0.00	23.72	91.54
Mills	North	0.00	40.94	96.35	0.00	55.22	93.81	0.00	21.18	94.31
Mitchell	West	0.00	37.92	95.27	0.00	55.14	93.87	0.00	27.92	93.57
Nolan	West	0.00	39.99	92.91	0.00	56.31	92.71	0.00	26.08	90.49
Nueces	South	0.00	38.44	93.59	0.24	50.67	92.73	0.00	30.77	91.19
Oldham	West	0.00	44.26	95.19	0.00	52.33	93.88	0.00	41.79	92.15
Parmer	West	0.00	40.78	94.08	0.00	46.39	92.25	0.00	31.22	91.30
Pecos	West	0.00	43.44	93.29	2.65	69.20	93.29	0.00	43.16	92.11
Randall	West	0.00	43.44	95.28	0.00	52.56	95.09	0.00	34.95	94.80
Reagan	West	0.00	39.16	92.47	0.08	59.36	91.52	0.01	29.87	90.39
San Patricio	South	0.00	38.27	93.90	0.24	50.54	93.05	0.00	30.66	91.69
Schleicher	West	0.00	42.71	96.90	0.00	60.60	96.15	0.00	28.68	93.47
Scurry	West	0.00	41.53	95.15	0.00	57.16	94.00	0.00	27.20	92.79
Shackelford	West	0.00	39.00	94.20	0.00	55.36	93.60	0.00	22.78	91.58
Starr	South	0.00	37.95	93.90	0.06	52.81	91.10	0.00	27.34	87.32
Sterling	West	0.00	35.82	95.05	0.00	50.72	92.34	0.00	23.88	89.70
Stonewall	West	0.00	37.71	96.99	0.00	51.53	96.46	0.00	24.85	96.16
Swisher	West	0.00	40.41	93.89	0.00	49.99	91.98	0.00	29.73	91.31
Taylor	West	0.00	39.14	93.87	0.00	55.80	93.40	0.00	23.12	91.41
Tom Green	West	0.00	41.68	96.80	0.00	58.04	95.47	0.00	26.64	89.20
Upton	West	0.00	36.59	93.63	0.00	61.50	93.24	0.00	31.89	91.10
Val Verde	West	0.00	39.23	95.66	0.00	65.85	94.73	0.00	32.40	93.40
Webb	South	0.00	37.62	93.74	0.00	59.19	92.98	0.00	30.27	91.84
Wharton	Houston	0.00	37.69	93.85	0.26	50.35	92.63	0.00	30.28	91.53
Wilbarger	West	0.00	43.09	94.70	0.00	60.92	93.53	0.00	31.44	93.72
Willacy	South	0.00	33.40	93.65	0.03	44.72	90.90	0.00	22.30	82.63
Winkler	West	0.00	44.84	96.92	0.00	63.12	96.92	0.00	43.55	96.53
Young	North	0.00	36.81	96.13	0.00	52.98	95.16	0.00	22.93	90.44
Zapata	South	0.00	38.13	93.22	0.04	59.22	93.20	0.00	31.08	91.34

Appendix D: ERCOT Hardwired Plant Additions for the CT Scenario

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/MW-start]	Forced Outage Rate [%]
Colorado Bend III	Wharton	Houston	2017	NG	CCGT	1,148	7,468	18.00	3.19	32	0.53	10.7	5.7	23.80	0
DeCordova 5 & 6	Hood	North	2018	NG	CCGT	450	7,468	18.00	3.19	32	0.53	10.7	5.7	23.80	0
Wolf Hollow II	Hood	North	2017	NG	CCGT	1,118	7,468	18.00	3.19	32	0.53	10.7	5.7	23.80	0
Antelope Station	Hale	West	2016	NG	IC	168	8,500	22.72	4.73	30	25	4	4	52.00	0
Red Gate Power Plant	Hidalgo	South	2016	NG	IC	225	8,500	22.72	4.73	30	25	4	4	52.00	0
Sky Global Power One	Colorado	South	2016	NG	IC	51	8,500	22.72	4.73	30	25	4	4	52.00	0
Elk Station I	Hale	West	2016	NG	OCGT	202	9,000	10.60	15.06	25	14	16	16	25.00	0
Elk Station II	Hale	West	2016	NG	OCGT	202	9,000	10.60	15.06	25	14	16	16	25.00	0
Elk Station III	Hale	West	2016	NG	OCGT	202	9,000	10.60	15.06	25	14	16	16	25.00	0
Lake Creek 3	McLennan	North	2018	NG	OCGT	450	9,000	10.60	15.06	25	14	16	16	25.00	0
P. H. Robinson Peaker	Galveston	Houston	2016	NG	OCGT	388	9,000	10.60	15.06	25	14	16	16	25.00	0
Pecan Creek Energy Center	Nolan	West	2017	NG	OCGT	270	9,000	10.60	15.06	25	14	16	16	25.00	0
Castle Gap Solar Project	Upton	West	2016	Solar	PV	116	-	25.79	0.00	-	-	-	-	-	0
RE Roserock Solar	Pecos	West	2016	Solar	PV	160	-	25.79	0.00	-	-	-	-	-	0
Riggins Solar (SunEdison Buckthorn Westex, Oak Solar)	Pecos	West	2016	Solar	PV	150	-	25.79	0.00	-	-	-	-	-	0
Solara Solar (OCI Alamo 7, Paint Creek)	Haskell	West	2016	Solar	PV	106	-	25.79	0.00	-	-	-	-	-	0
West Texas Solar (OCI Alamo 6)	Pecos	West	2016	Solar	PV	110	-	25.79	0.00	-	-	-	-	-	0
Bearkat Renewable Energy Project	Glasscock	West	2017	Wind	WT	240	-	41.18	0.00	-	-	-	-	-	0
Changing Winds	Castro	West	2017	Wind	WT	288	-	41.18	0.00	-	-	-	-	-	0
Colbeck's Corner Wind Farm	Carson	West	2016	Wind	WT	200	-	41.18	0.00	-	-	-	-	-	0
Easter Renewable Energy Project	Castro	West	2017	Wind	WT	300	-	41.18	0.00	-	-	-	-	-	0
Fluvanna Renewable 1	Scurry	West	2017	Wind	WT	240	-	41.18	0.00	-	-	-	-	-	0
Goodnight Wind Energy	Armstrong	West	2017	Wind	WT	240	-	41.18	0.00	-	-	-	-	-	0
Gunsight Mountain Wind	Howard	West	2016	Wind	WT	120	-	41.18	0.00	-	-	-	-	-	0
Horse Creek Wind	Haskell	West	2016	Wind	WT	200	-	41.18	0.00	-	-	-	-	-	0
Los Vientos Wind IV	Starr	South	2016	Wind	WT	200	-	41.18	0.00	-	-	-	-	-	0
Los Vientos Wind V	Starr	South	2016	Wind	WT	110	-	41.18	0.00	-	-	-	-	-	0
Mariah del Norte	Parmer	West	2016	Wind	WT	230	-	41.18	0.00	-	-	-	-	-	0
Mariah del Sur	Parmer	West	2017	Wind	WT	230	-	41.18	0.00	-	-	-	-	-	0
Rock Springs Val Verde Wind	Val Verde	South	2016	Wind	WT	180	-	41.18	0.00	-	-	-	-	-	0
Salt Fork 1 Wind	Gray	West	2016	Wind	WT	200	-	41.18	0.00	-	-	-	-	-	0
Sendero Wind Energy	Jim Hogg	South	2016	Wind	WT	78	-	41.18	0.00	-	-	-	-	-	0
South Plains Wind Phase II	Floyd	West	2016	Wind	WT	152	-	41.18	0.00	-	-	-	-	-	0
Texas Wind Farm	Haskell	West	2017	Wind	WT	400	-	41.18	0.00	-	-	-	-	-	0
Wake Wind	Dickens	West	2016	Wind	WT	300	-	41.18	0.00	-	-	-	-	-	0
Baffin Wind (Penascal 3)	Kenedy	South	2016	Wind-C	WT	202	-	41.18	0.00	-	-	-	-	-	0
San Roman Wind	Cameron	South	2016	Wind-C	WT	103	-	41.18	0.00	-	-	-	-	-	0
South Texas Wind Farm	Kenedy	South	2016	Wind-C	WT	200	-	41.18	0.00	-	-	-	-	-	0

Appendix E: ERCOT Hardwired Plant Additions for the AR Scenario (in addition to the CT scenario)

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/MW-start]	Forced Outage Rate [%]
Andrews 7 Solar	Andrews	West	2016	Solar	PV	80	-	25.79	$0.00	-	-	-	-	-	0
Austin Community Solar	Travis	South	2016	Solar	PV	3.2	-	25.79	$0.00	-	-	-	-	-	0
Barilla Solar 1B	Pecos	West	2016	Solar	PV	7	-	25.79	$0.00	-	-	-	-	-	0
Barilla Solar 2	Pecos	West	2016	Solar	PV	21	-	25.79	$0.00	-	-	-	-	-	0
Bluebell Solar	Sterling	West	2016	Solar	PV	173	-	25.79	$0.00	-	-	-	-	-	0
BNB Lamesa Solar	Dawson	West	2016	Solar	PV	200	-	25.79	$0.00	-	-	-	-	-	0
Brewster Solar Project	Brewster	West	2016	Solar	PV	30	-	25.79	$0.00	-	-	-	-	-	0
Capricorn Ridge Solar	Coke	West	2016	Solar	PV	100	-	25.79	$0.00	-	-	-	-	-	0
Center for Solar Energy	Bell	North	2018	Solar	PV	50	-	25.79	$0.00	-	-	-	-	-	0
East Pecos Solar	Pecos	West	2016	Solar	PV	100	-	25.79	$0.00	-	-	-	-	-	0
Horseshoe Bend Solar Project	Parker	North	2016	Solar	PV	140	-	25.79	$0.00	-	-	-	-	-	0
Kingsberry Community Solar	Travis	South	2016	Solar	PV	3.2	-	25.79	$0.00	-	-	-	-	-	0
Mesquite Solar Project	Tom Green	West	2016	Solar	PV	10	-	25.79	$0.00	-	-	-	-	-	0
Nazareth Solar	Castro	West	2016	Solar	PV	201	-	25.79	$0.00	-	-	-	-	-	0
Pearl Solar (OCI Alamo 6 Phase B)	Pecos	West	2016	Solar	PV	50	-	25.79	$0.00	-	-	-	-	-	0
Pecos County Solar Project (Hanwha)	Pecos	West	2018	Solar	PV	170	-	25.79	$0.00	-	-	-	-	-	0
Pecos Solar Power I	Pecos	West	2017	Solar	PV	108	-	25.79	$0.00	-	-	-	-	-	0
Pflugerville Solar Farm (RRE Austin Solar)	Travis	South	2017	Solar	PV	60	-	25.79	$0.00	-	-	-	-	-	0
SolaireHolman 1	Brewster	West	2016	Solar	PV	50	-	25.79	$0.00	-	-	-	-	-	0
Synergy Community Solar Project	Grimes	North	2016	Solar	PV	1.2	-	25.79	$0.00	-	-	-	-	-	0
Unity Solar Project	Deaf Smith	West	2018	Solar	PV	100	-	25.79	$0.00	-	-	-	-	-	0
Upco Power 1 (SP-TX-12)	Upton	West	2016	Solar	PV	180	-	25.79	$0.00	-	-	-	-	-	0
Upco Power 2 (SP-TX-12 Phase B)	Upton	West	2016	Solar	PV	120	-	25.79	$0.00	-	-	-	-	-	0
Upton Solar	Upton	West	2017	Solar	PV	102	-	25.79	$0.00	-	-	-	-	-	0
White Camp Solar Farm	Kent	West	2016	Solar	PV	102.02	-	25.79	$0.00	-	-	-	-	-	0
Albercas Wind	Zapata	South	2016	Wind	WT	250	-	41.18	$0.00	-	-	-	-	-	0
Buckthorn Wind 1	Erath	North	2016	Wind	WT	96	-	41.18	$0.00	-	-	-	-	-	0
Cameron Wind Phase 2	Cameron	South	2019	Wind-C	WT	150	-	41.18	$0.00	-	-	-	-	-	0
Canyon Wind Project	Scurry	West	2017	Wind	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Caprock Wind	Castro	West	2017	Wind	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Chapman Ranch Wind I	Nueces	South	2016	Wind-C	WT	250	-	41.18	$0.00	-	-	-	-	-	0
Comanche Ridge Project	Stonewall	West	2018	Wind	WT	24	-	41.18	$0.00	-	-	-	-	-	0
Comanche Run Wind	Swisher	West	2016	Wind	WT	500	-	41.18	$0.00	-	-	-	-	-	0
Cotton Plains Wind 1 (Blanco Canyon)	Floyd	West	2016	Wind	WT	50	-	41.18	$0.00	-	-	-	-	-	0
Cotton Plains Wind 2 (Blanco Canyon)	Floyd	West	2016	Wind	WT	150	-	41.18	$0.00	-	-	-	-	-	0
Crosby County Wind Farm	Crosby	West	2016	Wind	WT	150	-	41.18	$0.00	-	-	-	-	-	0
Dallam Ranch Wind	Dallam	West	2018	Wind	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Electra Wind	Wilbarger	West	2016	Wind	WT	230	-	41.18	$0.00	-	-	-	-	-	0
Espiritu Wind	Cameron	South	2019	Wind-C	WT	150	-	41.18	$0.00	-	-	-	-	-	0

Generator	County	Load Zone	Online	Fuel	Prime Mover	Net Capacity [MW]	Average Heat Rate [Btu/ kWh]	Fixed O&M Charge [$/kW-yr]	Variable O&M Charge [$/ MWh]	Minimum Stable Level [%]	Maximum Ramp Rate [%/ min]	Minimum Down Time [hrs]	Minimum Up Time [hrs]	Start Cost [$/MW-start]	Forced Outage Rate [%]
Galveston-Offshore Wind	Galveston	Houston	2018	Wind-O	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Grandview Wind Farm Phase 3	Carson	West	2016	Wind	WT	188	-	41.18	$0.00	-	-	-	-	-	0
Gulf Wind III	Kenedy	South	2016	Wind-C	WT	187.2	-	41.18	$0.00	-	-	-	-	-	0
Hale Community Energy I	Hale	West	2016	Wind	WT	136.35	-	41.18	$0.00	-	-	-	-	-	0
Hale Community Energy II	Hale	West	2019	Wind	WT	363.6	-	41.18	$0.00	-	-	-	-	-	0
Happy Whiteface Wind	Deaf Smith	West	2016	Wind	WT	157	-	41.18	$0.00	-	-	-	-	-	0
Haynes Wind Farm	Gray	West	2020	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Hidalgo & Starr Wind	Hidalgo	South	2016	Wind	WT	250	-	41.18	$0.00	-	-	-	-	-	0
Live Oak Wind Project	Schleicher	West	2017	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Longhorn Wind South	Briscoe	West	2016	Wind	WT	160	-	41.18	$0.00	-	-	-	-	-	0
Magic Valley Wind (Redfish) 2A	Willacy	South	2017	Wind-C	WT	115	-	41.18	$0.00	-	-	-	-	-	0
Magic Valley Wind (Redfish) 2B	Willacy	South	2017	Wind-C	WT	115	-	41.18	$0.00	-	-	-	-	-	0
Mariah del Este	Parmer	West	2017	Wind	WT	139	-	41.18	$0.00	-	-	-	-	-	0
M-Bar Wind	Andrews	West	2020	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Miami Wind G3	Gray	West	2016	Wind	WT	111	-	41.18	$0.00	-	-	-	-	-	0
Midway Farms Wind	San Patricio	South	2016	Wind-C	WT	161	-	41.18	$0.00	-	-	-	-	-	0
Palo Alto Farms West Wind Project	Nueces	South	2021	Wind-C	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Palo Duro Wind	Deaf Smith	West	2016	Wind	WT	203	-	41.18	$0.00	-	-	-	-	-	0
Pampa Wind	Gray	West	2017	Wind	WT	500	-	41.18	$0.00	-	-	-	-	-	0
Panhandle Wind Ph 3	Carson	West	2016	Wind	WT	248	-	41.18	$0.00	-	-	-	-	-	0
Patriot Wind (Petronilla)	Nueces	South	2016	Wind-C	WT	180	-	41.18	$0.00	-	-	-	-	-	0
Pullman Road Wind	Randall	West	2016	Wind	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Rattlesnake Den Wind 2	Glasscock	West	2017	Wind	WT	158	-	41.18	$0.00	-	-	-	-	-	0
RTS Wind	McCulloch	South	2016	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Salt Fork 2 Wind	Carson	West	2016	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Santa Rita Wind	Reagan	West	2016	Wind	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Scandia Wind Ph D (Mariah)	Parmer	West	2017	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Scandia Wind Ph E (Mariah)	Parmer	West	2017	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Scandia Wind Ph F (Mariah)	Parmer	West	2017	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Silver Canyon Wind Farm	Briscoe	West	2017	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Smart Wind Ranch (Spinning Star)	Upton	West	2022	Wind	WT	615	-	41.18	$0.00	-	-	-	-	-	0
South Plains Wind Phase III	Floyd	West	2016	Wind	WT	148	-	41.18	$0.00	-	-	-	-	-	0
Stella Wind Farm	Kenedy	South	2016	Wind-C	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Stella Wind Farm II	Kenedy	South	2017	Wind-C	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Swisher Wind	Swisher	West	2016	Wind	WT	300	-	41.18	$0.00	-	-	-	-	-	0
Tecovas Wind Project	Briscoe	West	2017	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Torrecillas Wind A	Webb	South	2016	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Torrecillas Wind B	Webb	South	2016	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0
Tyler Bluff Wind (Muenster)	Cooke	North	2016	Wind	WT	118	-	41.18	$0.00	-	-	-	-	-	0
Unity Wind	Deaf Smith	West	2016	Wind	WT	203	-	41.18	$0.00	-	-	-	-	-	0
Wharton Wind Project	Wharton	Houston	2018	Wind	WT	250	-	41.18	$0.00	-	-	-	-	-	0
Willow Springs Wind	Haskell	West	2016	Wind	WT	200	-	41.18	$0.00	-	-	-	-	-	0