# Least-cost optimal expansion of the ERCOT grid

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February 2021

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## Executive Summary

This analysis built and utilized a generation capacity expansion model of the ERCOT power grid to assess how the transmission system would need to evolve to deliver the least-cost grid of the future, given projections of growing electricity demand, fuel, and technology costs. The model utilized is based solely on economics and included no technology mandates, targets, subsidies, or emissions taxes. While the analysis did not specifically address transmission congestion issues, modeling points to new infrastructure that will relieve congestion while deploying Texas's lowest-costs resources. The analysis found that:

- The least-cost pathway for the ERCOT grid involves deploying approximately 1,700 miles of new transmission capacity with the ability to move almost 27,000 MW of power, or about 3.2 million MW-miles of new transmission, an investment roughly 2/3 the size of the original CREZ projects.
- The majority of the upgraded transmission capacity is deployed to better connect the West and Central parts of the state, as well as shoring up connections to South Texas, where load growth and congestion are high.
- The transmission upgrades are expected to cost about $4 billion between now and 2035[1].
- These transmission upgrades would result in about $6.7 billion in production costs savings between now and 2035.
- Along with the evolving transmission grid, the model deploys about 92 GW of additional wind, solar, energy storage, and natural gas capacity by 2035, which, in turn, deliver about 203 million more MWh of energy to meet growing demand.
- The expanded renewable energy deployment support about $11.1 billion in new local taxes and roughly $13.2 billion in new landowner payments (over their lifetime).
- We estimate that the level of transmission, solar, and wind deployment would support roughly 25,300 (20-year, full time equivalent) jobs during the construction and operation phases of the technology deployment.
- The optimal grid of 2035 is cleaner and produces about 83 billion fewer lbs. of $CO_2$, 434 million fewer lbs. of $SO_2$, and 84 million fewer lbs. of $NO_x$, per year.
- The optimal grid of 2035 also consumes 25 billion less gallons of water per year and withdrawals 3.2 trillion fewer gallons of water per year than the grid of 2018.

[1] Based on CREZ line construction costs.

## Introduction

Texas is an energy state. Texas not only leads the nation in oil and gas extraction and use, but Texas also consumes almost twice as much electricity as the next-highest state [1]. While overall electricity growth in the US has been relatively flat, Texas is expected to see considerable growth in the electricity sector. The Electric Reliability Council of Texas (ERCOT), the grid that serves roughly 90% of Texas, expects electricity consumption to increase over 25% from now to 2033 [2]. This load growth, coupled with the natural retirement of power plants as they age, will require new capacity to be built to meet the growth in demand.

While natural gas and coal have generated the bulk of Texas electricity for the past decade, technology costs changes have introduced new sources of energy into the mix. Falling costs have led to rapid growth in wind, solar, and storage. There is also a strong social demand for clean energy sources from consumers of all types, particularly corporates, as evidenced by the large number of corporate renewable power purchase agreements executed in Texas over the past six years.

The purpose of this study was to model the future growth of the ERCOT grid to 2035 and estimate the least-cost solution to meet supply and demand. In particular, this analysis sought to assess where the existing transmission network should be upgraded in the near-term to deliver the least-cost optimal mix of future generation for the ERCOT grid.

## Methodology

The following is a brief description of the model and methodology description used for the analysis in this report. A more detailed description of each can be found in

Appendix A.

## The model

This analysis modeled the ERCOT grid by utilizing a customized version of the SWITCH 2.0 open-source capacity expansion model [3]. A capacity expansion model is an optimization program that makes decisions about the operation, retirement, and construction of power plants, transmission lines, and other electric grid assets. It accomplishes this on both short (grid operations) and long (system planning) timescales. On the short time scale, the model dispatches the power plant fleet so that electricity generation and electricity demand are balanced for each hour of the simulation. On the long-time scale, the model builds new power plant and transmission capacity to 1) provide enough power plants so that electricity generation and demand can be balanced in future years, and 2) enable the composition of the power plant fleet to evolve in ways that minimize the total system cost.

## ERCOT-specific data

The baseline year for the grid optimization analysis was 2018. Baseline year data include both spatial load and renewable generation profiles from the same year, which is important because the same meteorological conditions that drive renewable generation also impact load. All data, including the existing power plant fleet, used in this analysis are based on public ERCOT reports. Future fuel price and technology costs are based on the National Renewable Energy Laboratory's NREL Annual Technology Baseline (ATB) and the US Energy Information Administration's (EIA) Annual Energy Outlook.

## Transmission

This analysis was not intended to provide site specific information at the power line level, but to instead highlight the general regions of the ERCOT grid that will need upgrading as demand grows. Figure 1 shows the 16 zone ERCOT model and transmission network used in this analysis. These types of reduced-order transmission models are commonly used in these types of analyses to keep the problem tractable [4]. The transmission limits between each of the connected zones were calculated based on physical infrastructure, historical power flows, and Generic Transmission Constraints [5].

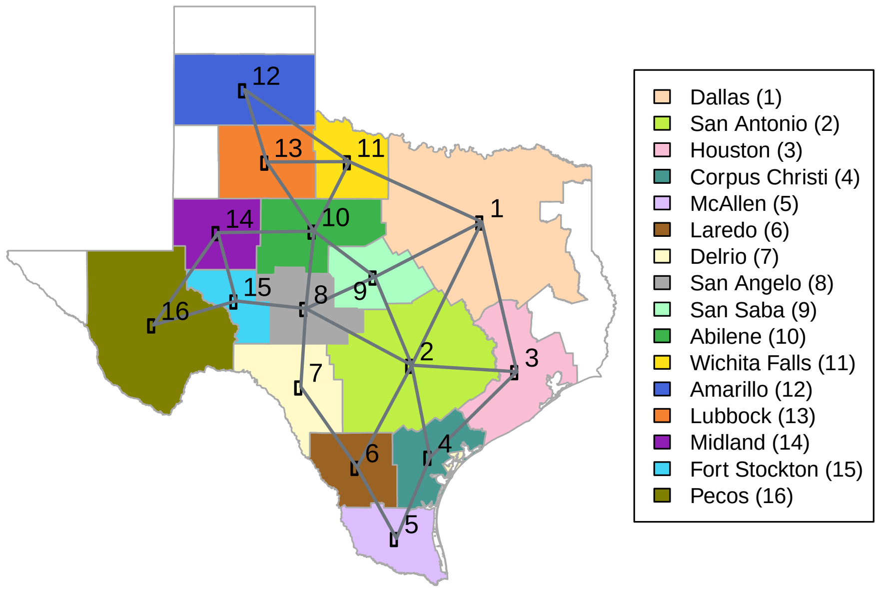


*Figure 1: The 16-zone ERCOT model and transmission network used in this analysis.*

## Time horizon

The focus of this analysis was to utilize a least-cost optimization methodology to estimate the sequence in which different parts of the ERCOT transmission network would be upgraded over current capacity. The time horizon of the most recent ERCOT Long-Term System Assessment (LTSA) [2] was approximated, while modeling the evolution of the ERCOT grid out to the year 2035 in 5-year increments (2025, 2030, 2035) given future technology and fuel costs.

## The process

The model was fed the ERCOT-specific data, the transmission network, and the time horizon to allow the model to determine the power architecture that will minimize system costs overtime. To accomplish this task, the model simulated the dispatch and retirement of existing power plants, as well as the construction of new generation and transmission capacity to meet future demand growth. The model will not build transmission unless the new infrastructure reduces overall system costs. For example, new transmission could create an opportunity to build newer, more affordable generation resources or allow existing resources to be dispatched in a way that reduces system costs enough to offset the additional capital investment requirements for the new infrastructure.

This analysis did not include any goals or targets for any particular type of technology, such as a Renewable Portfolio Standard, or a tax on any type of pollutant, such as $CO_2$. The analysis also did not include any subsidies, such as the Production Tax Credit that will have fully expired over the timeframe of this analysis[2].

[2] The analysis did include the at 10% Investment Tax Credit (ITC) for solar because, while the ITC is scheduled to step down over time, under current tax code, it stays at 10% for utility-scale solar indefinitely. The most recent potential extension of the federal tax credits as of December 2020 are not considered in this analysis.

## Results

The following discussion provides an overview of the primary results associated with generation capacity, energy production, transmission buildout, expected costs, and estimated tax, landowner payment, water, emissions, and jobs implications if the ERCOT grid were to follow a least-cost path between 2018 and 2035.

### Generation capacity

ERCOT's overall energy consumption and peak demand are expected to grow between 2018 and 2035, based on the ERCOT LTSA assumptions. Figure 2 shows the model results for the expected capacity changes by fuel type as the grid evolves to meet future demand. Total generation capacity in ERCOT grows from about 96 GW in 2018 to about 173 GW in 2035.

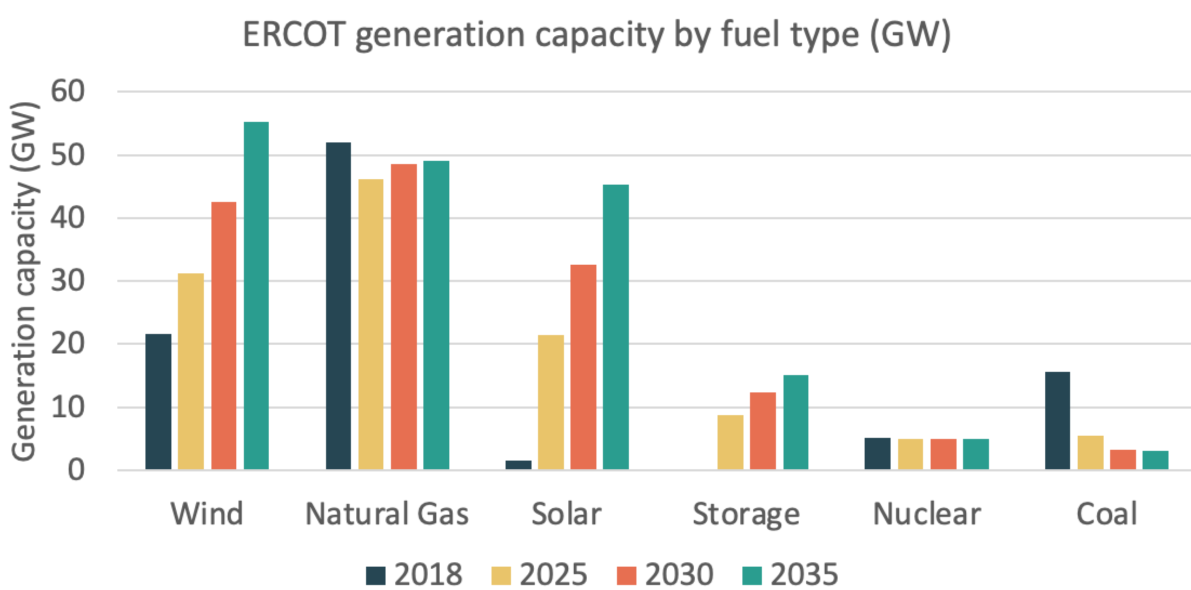


*Figure 2: Actual 2018 and expected future ERCOT utility-scale generation capacity changes by major fuel type (GW).*

The results indicate that the optimal pathway includes continued growth for both wind and solar, increasing to roughly 55 GW and 45 GW by 2035, respectfully. This growth represents a roughly 150% and 2,800% increase over the 2018 installed capacity for wind and solar, respectively. Energy storage is also expected to grow significantly to roughly 15 GW in the same time period. Natural gas is expected to grow slightly from 46 GW in 2025 to about 49 GW by 2035, after retiring some older, less efficient power plants prior to 2025. All current nuclear capacity is expected to stay online, but a large amount of coal retires with only about 3 GW left at the end of the modeling time period.

Figure 3 shows the same data as Figure 2, but broken down as a percentage of total capacity for each fuel type. As wind and solar continue to grow, so does their percentage of total generation capacity. In fact, we find that, are expected to constitute over 50% of the total generation capacity in ERCOT by 2030.

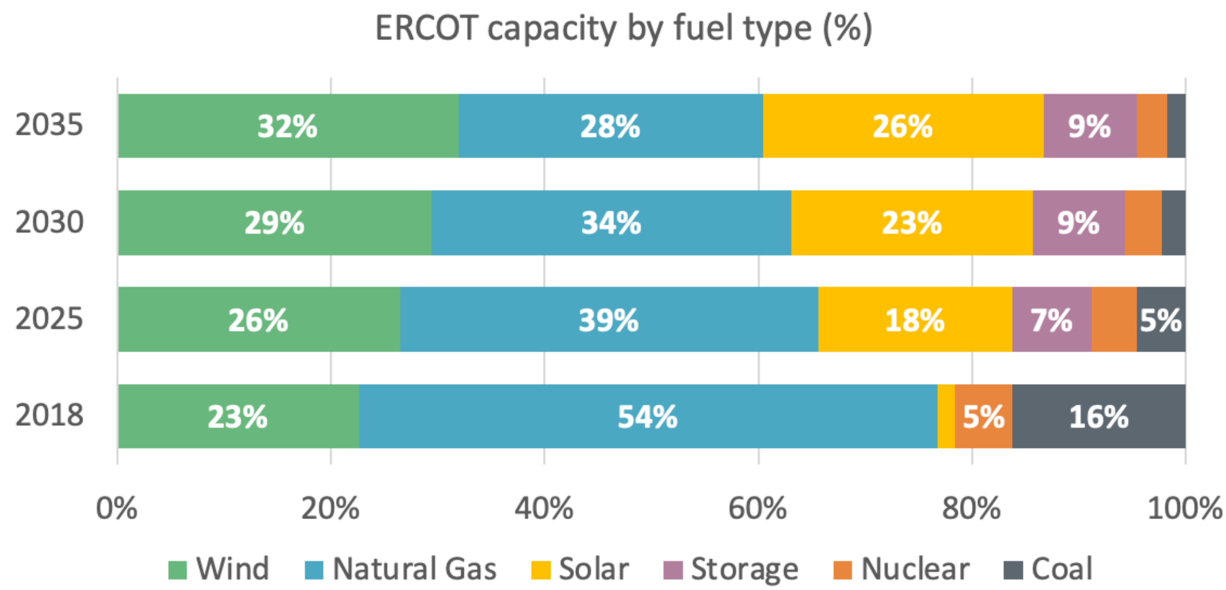


*Figure 3: Actual 2018 and expected future ERCOT capacity changes as a percentage of total capacity.*

## Energy generation

Figure 4 shows the change in energy generation over time. Energy demand is scheduled to grow from about 374 TWh in 2018 to about 578 TWh in 2035. Natural gas is expected to quickly increase output to account for coal retirements in ERCOT[3] while wind and solar quickly grow as they are built.

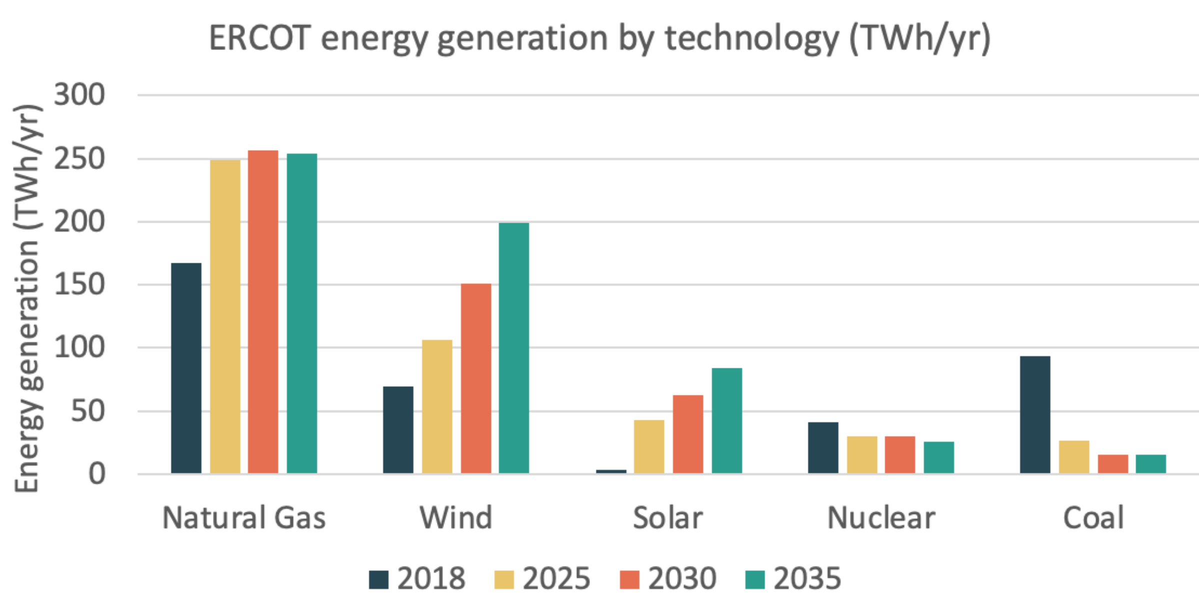


*Figure 4: Actual 2018 and expected future ERCOT energy generation by fuel type (TWh/yr). Other technologies, such as biomass left off as they do not contribute in a major way.*

[3] Historic annual average capacity factors for natural gas combined cycle plants in Texas are often less than 50% [35] and are thus estimated to have the ability to generate more energy.

Figure 5 shows the same data as Figure 4, but as a percentage of total generation by fuel type. The model estimates that electricity generation from wind and solar will continue to grow and constitute nearly half of total energy generation by 2035. It is worth noting that wind and solar dominate growth in future capacity installations in ERCOT in a least-cost scenario, as shown in Figure 2 and Figure 3; however, natural gas remains a large contributor to energy generation as shown in Figure 4 and Figure 5.

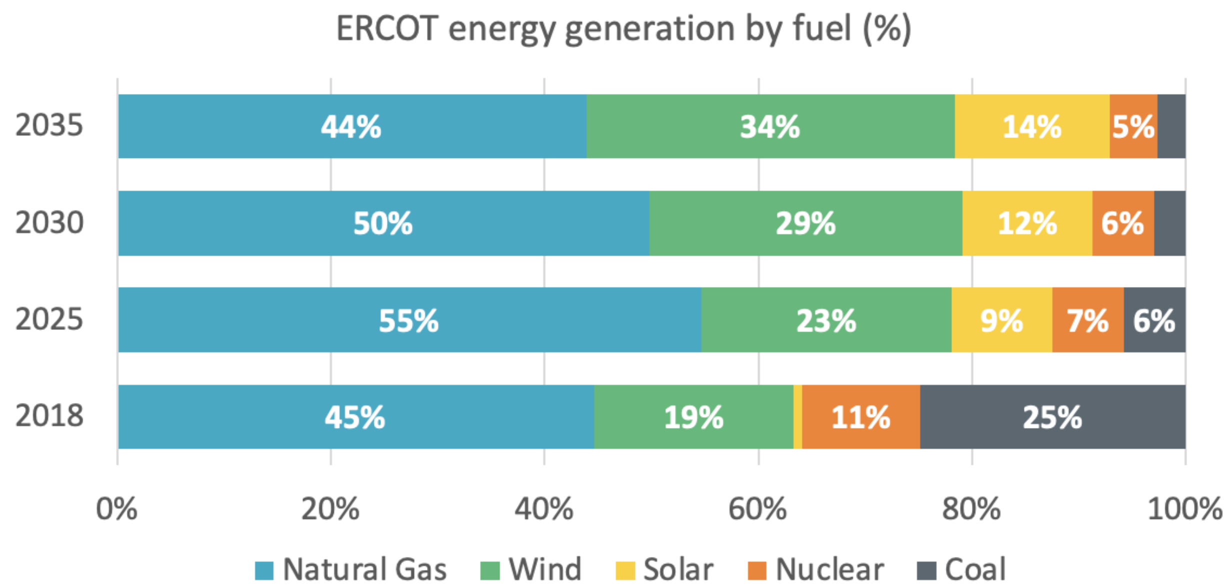


*Figure 5: Actual 2018 and expected future ERCOT energy generation as a percentage of total generation.*

## Transmission buildout

One of the primary goals of this analysis was to assess the locations in the ERCOT grid that, if upgraded, would allow for the least-cost expansion of the grid to meet future demand for electricity. In order to support this least-cost optimal future deployment of generation resources, the model also built new transmission to better connect the various regions of the ERCOT grid. **The model will not build transmission unless the new or upgraded lines further enables it to build new resources or dispatch existing resources in a way that reduces the overall cost, inclusive of the additional capital investment.** Figure 6 identifies the transmission connections that the modeling suggests to upgrade, shown in bold red.

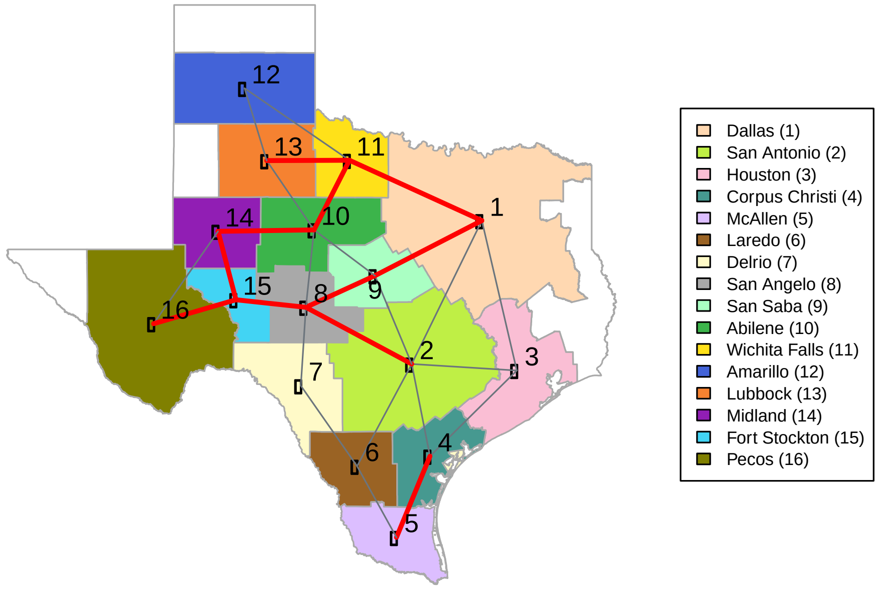


*Figure 6: Transmission upgrades necessary to host the optimal generation resource build out. Existing lines in gray, upgraded lines in bold red.*

Figure 7 shows the transmission capacity additions (in MW) between each regions that were highlighted in red in Figure 6. The model showed a strong preference for better connecting the more western regions of the ERCOT grid to the central regions, as well as fortifying the grid connecting the most southern region in ERCOT. These results are consistent with the increase in congestion that can be seen between these regions. The largest buildout was from the Fort Stockton region (#15) to the San Angelo region (#8) with the model suggesting to build almost 8,500 MW of transmission. The model strengthens connections between west Texas and the Dallas (#1) and San Antonio regions (#2) (moving from west to east). These results include adding over 11,000 MW of transmission roughly across the West Texas Generic Transmission Constraint [6] (as show in lines 1 <-> 11, 8 <-> 15) with about 40% of the additional capacity deployed immediately. These early transmission capacity deployments allow the model to build the lowest cost solar in West Texas and move it further to markets on the existing network. In next time period, the model focuses on deeper connections to central Texas and better connecting the Panhandle region.

Later, the model also suggests adding about 1,500 MW of additional transmission capacity in South Texas (line 4 <-> 5). Other regions also received some increases in capacity to better strengthen the West Texas infrastructure.

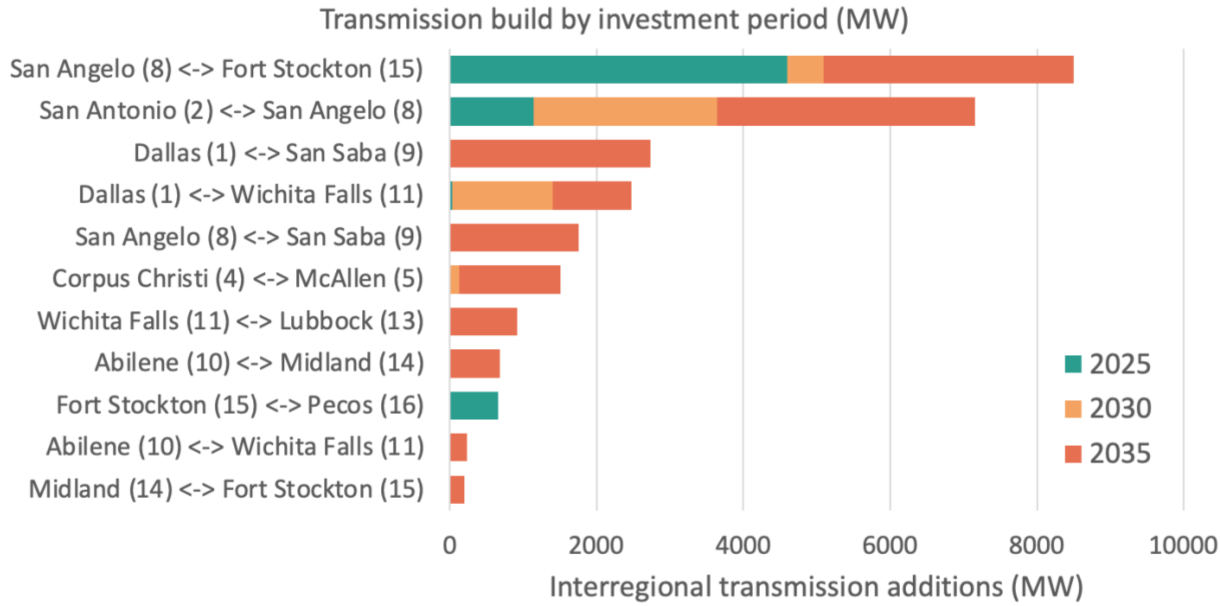


*Figure 7: Interregional transmission additions to support grid development by time period. Lines that were not explicitly upgraded are not shown here.*

In all, the model built about 1,700 miles of new transmission capacity with the ability to move almost 27,000 MW of power, or about 3.2 million MW-miles of capacity. The analysis estimates that this transmission buildout would cost roughly about $4.7B to build[4]. For reference, the CREZ lines included about 5.4 million MW-miles of transmission capacity and cost about $7B.

While not part of this modeling effort, congestion and short-term stability are also important to consider when planning for new transmission capacity. Thus, the results of this analysis are conservative in both the size and timing of the suggested transmission deployment. If these additional concerns were taken into account, it is likely that some of the transmission projects highlighted in this analysis would be larger and deployed earlier than indicated here.

## Production cost savings

The model is able to reduce production costs in ERCOT by either by building more efficient generation assets and/or building transmission to allow it to better dispatch the existing fleet.

To calculate these production costs savings[5], this analysis compared the optimal-system production costs with the production costs from a "high-cost" transmission case where the cost to build transmission was increased to roughly three times that of our assumed base case, or about $4,700/MW-mi. Higher transmission costs would force the model to try to build differently and reduce its transmission build. However, even with higher transmission costs, the model still had to build transmission to match growing supply and demand. The model still built about 529,000 MW-mi of transmission in the higher-cost case (vs. 3.2 million in the base case).

[4] Based on historical CREZ line costs, about $1,500/MW-mi.
[5] This model calculated production costs savings vs. energy savings. The latter which include the impacts of the marginal generator, but previous analyses have found these costs savings in ERCOT to be essentially the same [34].

In general, the higher-cost scenario built transmission in similar locations as the base case, but generally in lower quantities[6]. Using the base case transmission construction costs, the model built about $4B more transmission in the base case vs. the higher cost case.

However, energy production costs in the base case were lower than in the high-cost transmission case. Figure 8 shows the production costs savings, per year[7], between the high cost transmission case and the base case.

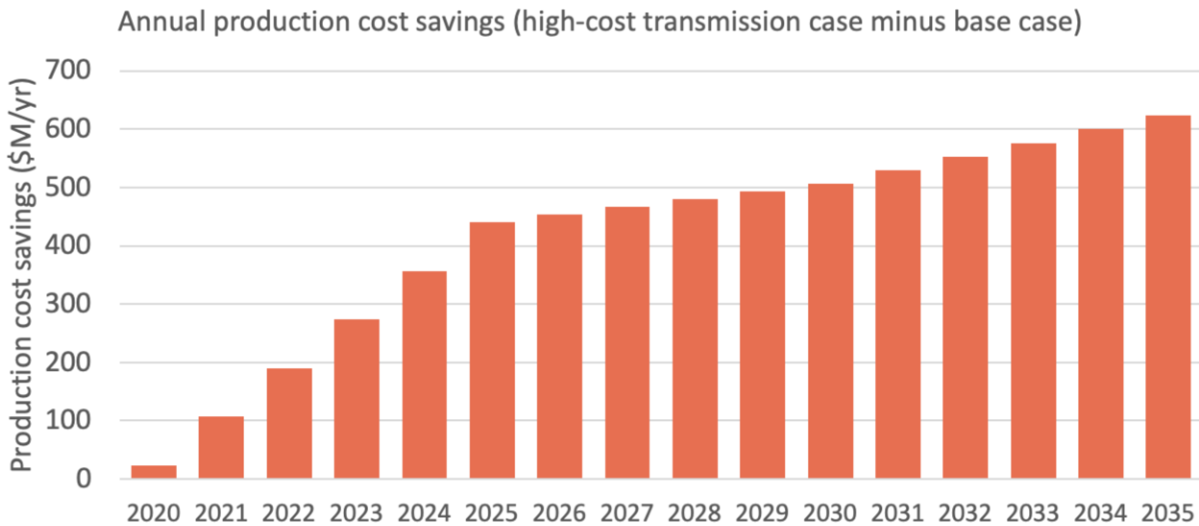


*Figure 8: Production cost savings from comparing market costs of the high-cost transmission case and the base case ($M).*

**Production cost savings increase rapidly as more, lower-cost technologies are deployed to meet future demand.** Average production costs savings over the 15-year modeled timeframe (transmission assets often live much longer) are roughly about $417M per year and total about $6.7B over the 15-year timeframe[8]. Thus, this analysis indicates a roughly 10-year breakeven period if all of the transmission suggested by this analysis was built.

## Local tax and landowner payment implications

Renewable energy projects, especially in Texas, are almost exclusively built on private lands. These projects typically make both landowner and local county and school tax payments over their lifetime. A recent report indicates that existing renewable energy projects in Texas will pay billions in taxes and landowner payments [7] with the potential to create multigenerational income that supports family farms and ranches.

[6] Except in the South Texas region McAllen (5) to Corpus Christi (4) where it built the full size line, even in the high-cost transmission case.
[7] The years between the model run years are linear interpolations.
[8] These estimates of savings are likely conservative in that there are almost assuredly to be continued savings beyond the modeling time horizon and transmission projects often have multiplier effects beyond the immediate reduction in energy production costs.

The results of this analysis indicate that the amount of wind and solar will continue to grow if the grid is able to support that growth, resulting in increased local tax and landowner payments. Figure 9 shows the estimated amount of new local taxes and landowner payments (over the individual project's lifetimes) in each model region based on the base case scenario for future construction of electricity infrastructure in ERCOT.

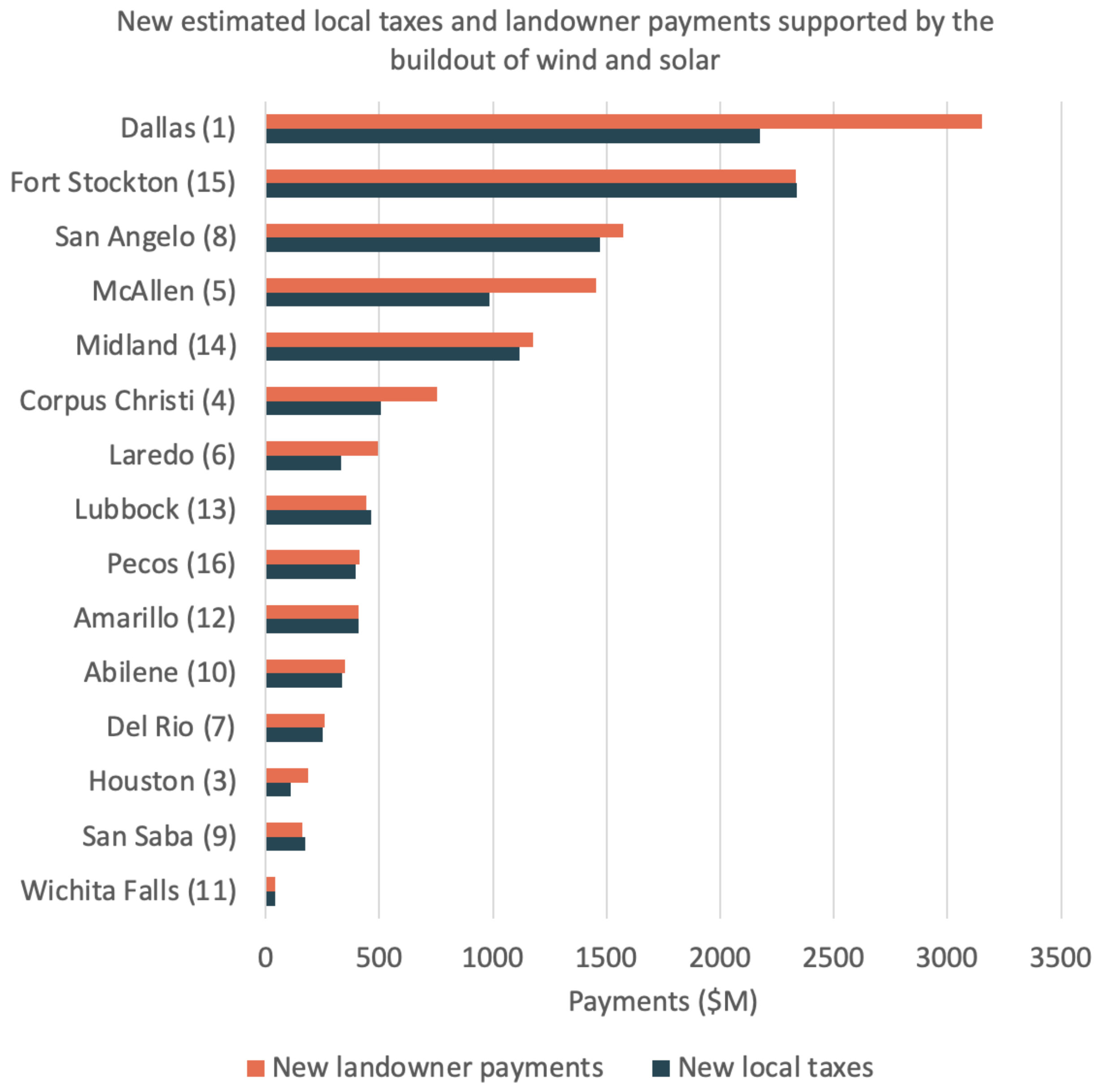


*Figure 9: Estimated local taxes and landowner payments supported by the continued deployment of wind and solar in Texas over their lifetimes ($M).*

This analysis indicates the level of wind and solar deployment would result in roughly $11.1 billion in new local taxes and roughly $13.2 billion in new landowner payments over their lifetime, with the majority of the payments being made to areas of Texas that are more rural[9].

### Emissions, water, and job impacts

While not the main focus of this analysis, the level of deployment of wind, solar, and storage, along with coal retirements also has an impact on the emissions and water usage of the power sector. Using average numbers for ERCOT power plant types [8], we estimate that the ERCOT power sector in 2035, compared to 2018 actual values, results in about 83 billion fewer lbs. of $CO_2$, 434 million fewer lbs. of $SO_2$, 84 million fewer lbs. of $NO_x$ – all of which increase air quality and reduce mortality and morbidity for Texans. The ERCOT grid mix that is projected based on this analysis would also reduce water withdrawals by 3.2 trillion gallons per year and reduce water consumption by 25 billion gallons per year, all while delivering about 203 million more MWh of electricity.

The deployment of transmission and the expected build out of wind and solar presented in this analysis is also estimated to support roughly 25,300 (20-year, full time equivalent) jobs during the construction and operation phases of the technology deployment [9].

## Conclusions

This analysis built and utilized a capacity expansion model of the ERCOT power grid to assess how the electricity infrastructure would evolve over a least-cost optimal path, given future projections of demand, fuel, and technology costs. The model results are based solely on identifying the most economically competitive solutions, without accounting for technology mandates, targets, subsidies, or emissions taxes.

The results indicate that upgrading the existing grid by about 3.2 million MW-miles of new transmission capacity in critical energy pathways would result in lower overall production costs that would more than offset the cost of the new transmission capacity over the modeled time horizon. As demand grows in ERCOT, the model retires some older, less efficient power plants, but also builds about 92 GW of additional wind, solar, energy storage, and natural gas capacity, which, in turn, deliver about 203 million more MWh of energy to meet growing demand, all while reducing emissions and using less water. Technologies have evolved rapidly, and with them, costs have declined. This analysis indicates that, for the ERCOT grid to continuously deliver some of the lowest cost power to consumers, the bulk transmission system will need to aggressively expand.

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[9] These estimates are likely conservative as taxes and landowner payments are likely to be higher in the future, but we used present day values for our estimates.

## Acknowledgements
This work was funded by the Advanced Power Alliance[10].

## About Us
IdeaSmiths LLC[11] was founded in 2013 to provide clients with access to professional analysis and development of energy systems and technologies. Our team focuses on energy system modeling and assessment of emerging innovations, and has provided support to investors, legal firms, and Fortune 500 companies trying to better understand opportunities in the energy marketplace.

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# Appendix A

## 1. General Model Summary: Capacity Expansion Modeling in Switch

The analysis for this project is completed using the capacity expansion model called, “SWITCH” [3].

A capacity expansion model is an optimization program that makes decisions about the operation and construction of power plants, transmission lines, and other electric grid assets. It accomplishes this at two different time scales:

- Short Time Scale: the model dispatches the power plant fleet so that electricity generation and electricity demand are balanced for each hour of the simulation.
- Long Time Scale: the model builds new power plant capacity to 1) provide enough power plants so that electricity generation and demand can be balanced in future years, and 2) enable the composition of the power plant fleet to evolve in ways that minimize the total system cost.

The model solves for the Short and Long Time Scales simultaneously to meet the modeling objective. The objective for this model is to minimize the net present value of all investment and operation costs. Thus, the model will

- dispatch power plants in the Short Time Scale so that the least expensive power plants are turned on first, to balance the hourly generation and demand at the lowest possible cost, and
- build new power plants if the upfront investment cost of constructing those power plants will reduce the total net present value by reducing the cost of the Short Time Scale power plant operation during future time periods.

This objective is subject to a number of constraints and input variables. For example, power plant operational characteristics, fuel prices, power plant construction costs, renewable energy generation profiles, transmission capacity, and many other variables described in the following sections constrain the model’s solution.

“Switch” is a unique grid planning model that is built using capacity expansion modeling theory. Switch is developed and maintained by Professor Matthias Fripp at the University of Hawaii, and has been in development since 2012. It is an open source model built on the Python programming language. For more details about the model, its validation, calibration, and equations, see [3].

## 2. Time Series

Because a capacity expansion model operates at both Short and Long Time Scales, it must use simplified time series so that the model is tractable and can be solved. For example, a capacity expansion model that solves a 2020-2050 scenario will <u>not</u> solve for all 8,760 hours of all 30 analysis years. Instead it will use a few representative days for each year, and a few representative years for the whole 30-year time scope.

In this model, we use 9 representative days and 4 representative years.

### 2.1. Representative Days

This model uses 9, 24-hour periods to represent the annual electricity market. Those 24-hour periods include:

- Annual Peak: we use the 24-hour profile of the day with the greatest instance of hourly system demand. The Annual Peak time series is scaled up to represent 3 of 365 days for each model year.
- Annual Net Peak: we use the 24-hour profiles of the two days with the greatest instance of hourly net system demand—i.e. demand minus renewables output. Each of the two Annual Net Peak time series is scaled up to represent 3 of 365 days for each model year.
- Seasonal and Monthly Averages: the electricity demand for each of these 6 profiles equals the average electricity demand of all of the days in that season/month. For example, hour 1 of the March/April profile is equal to the average demand of the first hour of the day for all 61 days in the March/April data. The model uses average profiles for the following seasons and months:
  - July – represents a high-demand summer profile. Scaled up to represent 30 of 365 days for each model year.
  - June/August – represents the bulk of summer energy needs. Scaled up to represent 59 of 365 days for each model year.
  - January – represents a high-demand winter profile. Scaled up to represent 30 of 365 days for each model year.
  - February/November/December – represents the bulk of winter energy needs. Scaled up to represent 89 of 365 days for each model year.
  - March/April – represents spring energy needs. Scaled up to represent 59 of 365 days for each model year.
  - May/September/October – represents summer shoulder season energy needs. Scaled up to represent 89 of 365 days for each model year.

When compared to a complete, 8,760-hour demand profile, the 9 representative days outlined above have 5% greater annual energy consumption. Figure 10 below compares the 8,760 and 9-representative-day time series using a duration curve—where the demand for each hour of the year is sorted in decreasing order. The peak demand of the 5-representative-day curve is 98.5% of the peak of the 8,760 hour curve. When compared to the 8,760-hour series, the 9-representative-day series has higher demand for the lowest-demand hours of the year but is otherwise very similar.

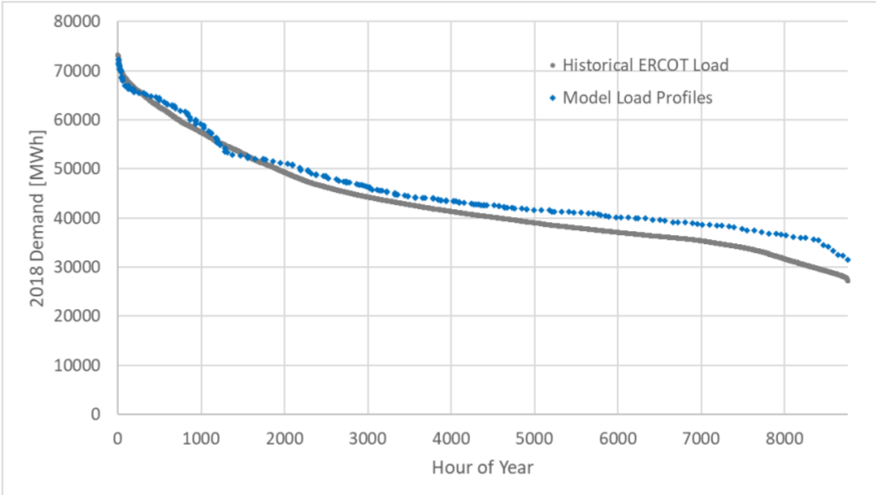


*Figure 10: Duration curve of 8,760-hour time series (Historical ERCOT Load) and the 5-representative-day time series used in this model.*

### 2.2. Representative Years

The model simulates these 9 representative days a total of four times each. Each of the four time periods represents a 5-year span: 2020-2025, 2025-2030, 2030-2035, and 2035-2040.

For each of these 5-year time periods, we average the input values across those years. For example, the natural gas price for the 2020-2025 time period equals the average of the 2020, 2021, 2022, 2023, and 2024 forecasted natural gas prices.

## 3. Generator Data

Our model represents each individual power plant in the ERCOT system. To parameterize each of these power plants, we compile data from a variety of sources as outlined below.

### 3.1. ERCOT Capacity Demand and Reserve Report, 2018 [10]

Twice a year, ERCOT releases a report that includes some data for all of the operating generators in the ERCOT market. We use this report to gather data on each existing generator's:

- capacity,
- construction year, and
- county.

### 3.2. Emissions & Generation Resource Integrated Database (eGRID), 2018 [11]

eGRID is maintained by the EPA and contains information about the existing U.S. power plant fleet. We use it to gather data on each ERCOT generator's:

- fuel type, and
- technology type.

### 3.3. Annual Technology Baseline (ATB), 2019 [12]

The ATB is published annually by NREL and contains a set of assumptions and futures to inform electric sector analyses in the U.S. The data provides operational and cost characteristics for different types of generators projected from 2018-2050. We use it to gather data for each generator's:

- scheduled outage rates,
- forced outage rates, and
- fixed operation and maintenance cost.

We also use the ATB to provide the following data for characterizing new generators:

- capital cost of construction,
- fixed operation and maintenance cost,
- heat rate, and
- roundtrip efficiency for battery charge/discharge cycles.

### 3.4. Garrison Dissertation, 2014 [8]

In addition to the sources above, which are used broadly for modeling the U.S. power sector across many different regions, we also refer to the dissertation of Dr. Jared Garrison, which contains data compiled specifically for modeling the ERCOT region. Those data include the following.

#### 3.4.1. Heat Rates

Heat rates for existing generators are calculated by diving each generator's monthly fuel consumption by its monthly electricity generation. These data come from the US EIA 923 database. We average these monthly heat rates over multiple years to approximate each generator's full load heat rate.

#### 3.4.2. Startup Costs

Startup costs for existing and new generators are based on data from the Power Plant Cycling Costs report. This report lists startup cost for cold, warm, and hot startups. For the ERCOT power plants, the startup costs for each generator type were selected based on whether that generator type tends to startup from warm or cold conditions.

#### 3.4.3. Min Up and Down Time, Min Output, and Variable Operation & Maintenance Costs

These characteristics come from the assumptions that ERCOT uses for the capacity expansion model used to create the ERCOT Long Term System Assessment report. Based on conversations with different stakeholders, Garrison updated some of these original data for a few of the generator types.

### 3.5. Coal Retirements

Based on age, the majority of coal plants are expected to retire in Texas by 2035, we force coal retirements for any coal plants that have been operating for 43 years or longer. This requirement has the following impact on overall coal capacity:

- 2018: 13.1 GW
- 2020-2025: 11.5 GW
- 2025-2030: 5.5 GW
- 2030-2035: 3.3 GW

- 2035-2040: 3.0 GW

## 4. Wind and Solar

### 4.1. Profiles

We use hourly wind and solar generation profiles for hundreds of sites around ERCOT. These generation profiles were developed by AWS TruePower for ERCOT and are available for public download [13].

The hourly profiles are simulated using historical weather data. A generation profile is created for each existing wind and solar site in ERCOT along with many potential sites where wind and solar capacity have not yet been installed.

For developing future wind capacity, we let the model expand the capacity of simulated sites (modeled at a hub height of 90m) and existing sites with hub heights of 80m or greater. For existing sites with hub heights below 80m, we use their profiles to represent existing wind generation resources available for dispatch, but do not let the model expand their capacity. For counties without existing or simulated wind generation, we average the profiles of sites with similar wind resources in neighboring counties.

For developing future solar capacity, we let the model expand the capacity of the simulated sites. Texas solar resources [14] generally improve as one travels west. We observe this trend in the capacity factors of the simulated solar sites, but not consistently in the capacity factors of the existing solar sites. Thus, we use the profiles of existing sites to represent existing solar capacity resources available for dispatch, but do not let the model expand their capacity.

### 4.2. Site Limits for Wind and Solar Capacity

Since wind and solar plants require a significant amount of real estate, we limit the amount of wind and solar development that the model can build in each Texas county.

For solar, we assume single-axis tracking arrays built at a density of 30 MW/km$^2$ (77.7 MW/mi$^2$). [15]

For wind, we use the appendix data from [16] to divide the total Texas wind capacity by the total developed land area of that wind capacity to get a density of 7.14 MW/mi$^2$.

We then multiply these development densities by the square mileage of land in each county that is available for development[12]. The result is the maximum amount (MW) of wind and solar capacity that could be built in the developable land in each county.

The wind limit is, on average, 6.5 GW per county. But that capacity can only be realized if all of the county's available land area has suitable wind resources. However, in most counties, the

[12] Personal communication with the University of Texas at Austin Bureau of Economic Geology.

wind resource quality varies across the county's geography. To account for this, we use data from [17] to estimate the amount of land in each county that has wind resources with wind speeds of 7.0-7.5, 7.5-8.0, and 8.0+ m/s. We use those estimates to cap the amount of capacity that each wind site may develop, depending on its capacity factor.

The solar limit is, on average, 70.4 GW per county. In practice, this solar limit never constrains the model. Thus, we assume that, because of its density, solar development has little impact on wind development—i.e., if a county builds many GW of solar capacity, this requires a relatively small amount of land and we assume that it does not meaningfully diminish the county's wind capacity limit.

### 4.3. Annual Limits for Wind and Solar Capacity Growth

Wind and solar development are also limited by materials supply chains, manufacturing capabilities, and construction capabilities. To capture this, we impose an annual limit on how much wind and solar can be built in the model.

For both wind and solar, we establish a baseline limit on GW/year that can be installed. Then, assuming that these limitations will increase with GDP, we scale the installation limits up according to the forecasted Texas GDP growth through 2050 [18].

For the baseline wind limit, we take data on annual wind development in Texas from 2009-2019 [19] [20]. We take the average of these numbers—1.45 GW/year—as the baseline for the wind development limit.

We assumed the same deployment rate for utility-scale solar.

### 4.4. Land Lease Rates for Wind and Solar

The fixed operating cost of each wind and solar site varies depending on which county it is built in. To accomplish this, we first compile a lease rates for rangeland, native pasture, and hunting leases in 33 Texas regions [21]. Then we normalize those lease rates, multiply them by wind and solar lease costs from [7], and assign them to the counties contained in each region. Note that wind land lease costs vary from 1,100 to 24,500 $/MW-year with an average of 8,960 and solar land lease costs vary from 630 to 14,400 $/MW-year with an average of 8,960.

We then use these land costs to adjust the fixed operation and maintenance costs from section 3.3 by:

- for wind sites: subtracting the average wind land lease cost from the wind FOM. Then adding back the county-specific wind land lease cost.
- for solar sites: because the ATB does not include solar land lease costs in its solar FOM, we simply add the county-specific solar land lease cost to the ATB FOM.

### 4.5. Tax Credits

We give solar an investment tax credit of 10% by reducing its overnight capital costs by 10%.

## 5. Transmission

As electricity travels from region to region it incurs losses and must not exceed the capacity of the transmission lines. The model can increase the capacity of the existing transmission lines by paying the capital cost to build new lines.

### 5.1. Losses

We assume losses of 1% per 100 miles of transmission. This aligns with the assumption used by the National Renewable Energy Laboratory's ReEDS model [22]—a capacity expansion model of the continental United States.

### 5.2. Regions and Capacities

The model comprises 16 regions with transmission capacity between many of the regions' borders. The regions and transmission locations were determined using geographic transmission data from the Department of Homeland Security [23].

Existing transmission capacities were determined by running the historical 2018 hourly load and generation in a power flow model [24].

- Hourly Load: see section 7.1 and 7.2.
- Hourly Thermal Generation: comes from aggregating CEMS data to the county level, and the aggregating those county-level generation profiles up to the transmission-region level
- Hourly Wind and Solar Generation: see section 4.1
- Nuclear Generation: we assume constant nuclear generation at 95% of total capacity to match the annual nuclear generation capacity factors.
- Existing transmission: we connect regions with transmission lines if they have existing transmission connections already. And we add multiple lines between regions when there are multiple 345-kV lines that connect those regions in the existing transmission grid. For example, we connect the 1Dallas—10WichitaFalls regions with (3) 345-kV lines based on their existing transmission connections, but connect the 15FortStockton—16Pecos regions with (1) 345kV line.

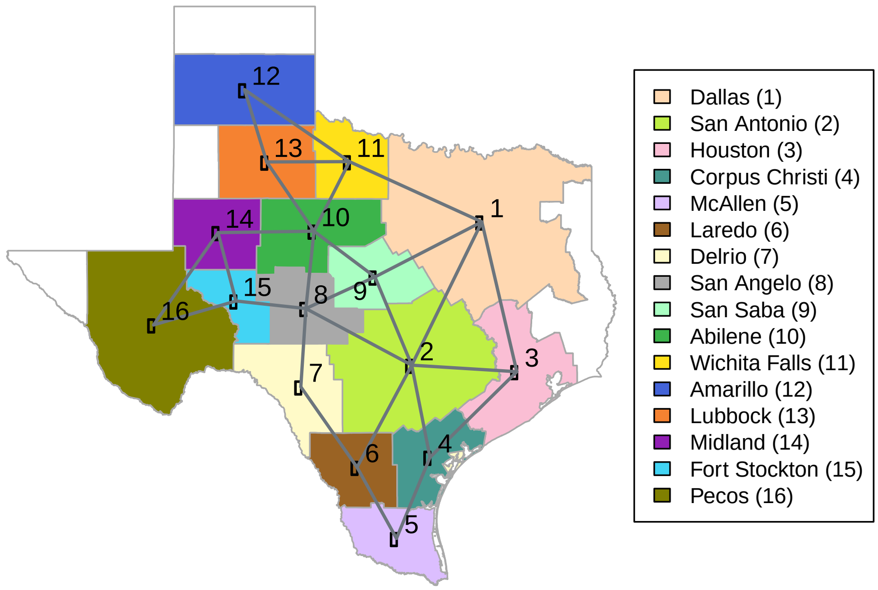


*Figure 11: The 16-zone ERCOT model and transmission network used in this analysis.*

### 5.3. Construction Cost

Transmission construction costs are based on data from the Competitive Renewable Energy Zones (CREZ) project—a large-scale transmission construction project carried out in ERCOT from 2008-2013. We use a transmission construction cost of 1500 \$/MW-mile (932 \$/MW-km) as described in [4].

## 6. Fuel Prices

Fuel price data come from the EIA's 2020 Annual Energy Outlook (AEO) [25]. This report contains future projections out to 2050 of energy consumption, emissions, and fuel prices. We use the

- forecasted AEO coal prices for our model's subbituminous coal prices,
- forecasted AEO coal prices plus 0.72 \$/mmBtu for our model's lignite coal prices, and
- forecasted AEO natural gas prices for our model's natural gas prices.

The lignite prices are increased by 0.72 \$/mmBtu so that the average of the forecasted 2020-2030 prices equal the average of the historical 2015-2020 Texas lignite prices [26].

## 7. Load

### 7.1. Load Data

We use 2018 hourly load data provided by ERCOT [27]. This load data is separated out for each ERCOT's 8 weather regions.

### 7.2. Scaling Load Data by Region

We scale this 8-region ERCOT data to our 15-region transmission model in two steps.

First, we distributed the ERCOT load down to the county level by assuming that county population is directly related to energy consumption. This is, if Region 1 has a demand of 12,000 MWh in a specific hour, and County 1—one of a number of counties in Region 1—has 15% of the population of Region 1, then we assume that County 1 also represents 15% of that hourly demand—or 1,800 MWh. The result is an hourly 2018 load profile for each Texas county.

Second, we aggregate these county-level load profiles up the regional level using the region boundaries in our model. The result is an hourly 2018 load profile for each of our 15 transmission regions.

### 7.3. Load Growth

We assume that load increases at a rate of 1.8% annually. This load growth rate was determined by calibrating the model's future loads against the energy forecasts in Figure 2 of the 2020 ERCOT System Planning Forecast [28].

We implement this load growth assumption by starting with our baseline hourly 2018 load profiles for each region and multiplying every hourly demand datum by 101.8% for each year after 2018.

### 7.4. Electric Vehicles

We include electric vehicle energy demand using the following steps.

First, we use a 24-hour profile from the LTSA that forecasts ERCOT electric vehicle charging behavior in 2033. We assume that electric vehicles will charge according to this 24-hour pattern for each day of the year.

Second, we scale the profile up and down for different model years. We assume that the charging pattern scales linearly, where the electric vehicle load in 2015 equals zero. Under this assumption, the electric vehicle load in 2015 is zero, in 2024 is 50% of the 2033 ERCOT profile, in 2042 is 150% of the 2033 ERCOT profile, etc.

Third, we distribute the total electric vehicle charging profile amongst the 15 transmission regions. We take the 2018 population for each of the transmission regions and divide by the total Texas population to calculate that region's load fraction. Then we multiply each region's load fraction by the total EV charging profile for each year to produce each region's hourly EV profile for each year.

Finally, we add the EV charging profile to each region's hourly load profile.

### 7.5. Distributed Solar

We simulate distributed solar generation for each region and subtract it from that region's hourly load. That is, the model does not treat distributed solar as power plant that can be dispatched, but as a distributed resource that reduces the amount of load that the model's power plants must provide.

First, we create hourly 2018 solar generation profiles for the largest city in each region using the NREL System Advisor Model (SAM) [29]. The SAM model uses historical weather and solar insolation data to calculate the hourly electricity generation of a photovoltaic panel depending on that panel's orientation, tilt, efficiency, and other parameters. We use the default SAM settings for the solar panel—180 degree azimuth, 20 degree tilt, 96% inverter efficiency, and 14.08% system losses. The result is a normalized, hourly 2018 solar generation profile for each of the 15 transmission regions.

Second, we scale these solar profiles up to match the forecasted capacities of distributed solar in each region. We calculate the forecasted solar capacities in two steps:

> Step 1: we forecast the total amount of distributed solar in all of ERCOT. We use 5 GW of distributed solar for 2033, based on Table I.1 of the ERCOT 2018 Long Term System Assessment (LTSA) [2]. As for electric vehicles, we assume that the distributed solar profile scales linearly, where the distributed solar in 2015 equals zero. Under this assumption, the distributed solar in 2015 is zero, in 2024 is 2.5GW (50% of the 2033 ERCOT profile), in 2042 is 7.5GW (150% of the 2033 ERCOT profile), etc.
>
> Step 2: we spread the distributed solar capacity amongst the 16 transmission regions. As for electric vehicles, we take the 2018 population for each of the transmission regions and divide by the total Texas population to calculate that region's fraction. Then we multiply each region's fraction by the total distributed solar capacity for each year to produce each region's distributed solar capacity for each year.

## 8. Financial

The Switch model uses an interest rate and discount rate for various financial calculations. We assume a discount rate equal to a weighted average cost of capital (WACC) of 7.17% and an interest rate of 6.01%. These align with the assumptions of the NREL ATB [12].