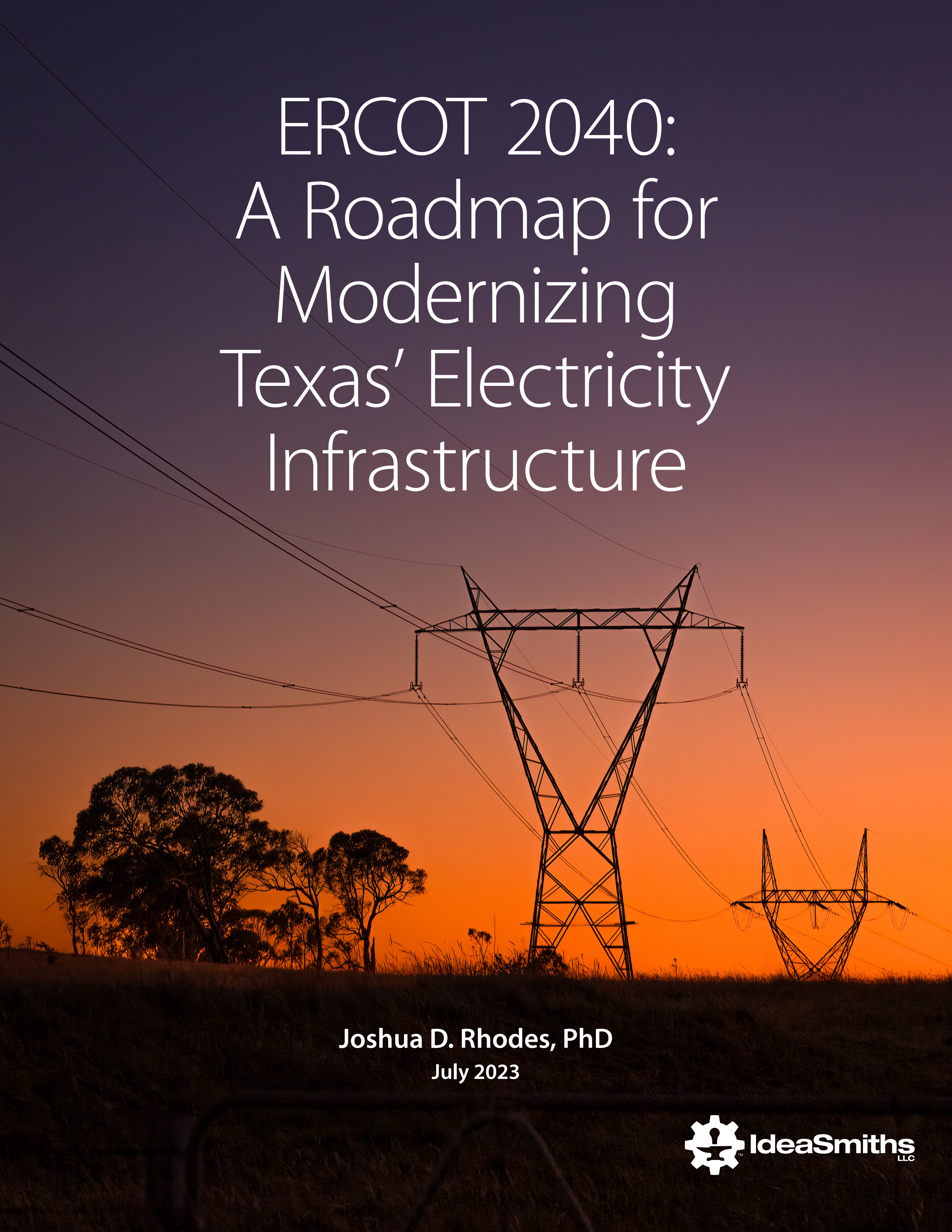
ERCOT 2040: A Roadmap for Modernizing Texas' Electricity Infrastructure



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Executive Summary

This study modeled the ERCOT electricity grid to determine the most cost-effective generation mix of the future and the transmission system upgrades needed to deliver that power given growing electricity demand, fuel, and technology costs. The analysis was produced using a model built by IdeaSmiths, and based solely on economics -- it included no technology mandates, targets, or emissions taxes. While it did not address transmission congestion specifically, the modeling points to the need for new infrastructure to relieve congestion while deploying Texas's lowest-cost resources. The analysis found that:

- The least-cost pathway for the ERCOT grid deploys approximately 1,350 miles of new transmission capacity to move almost 40,000 MW of power, or about 5.2 million MW-miles of new transmission.
- Most 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 border areas, where load growth and congestion are high.
- The transmission upgrades are expected to result in over $1.1 billion dollars per year in production cost savings averaged over 15 years -- or about $16.7 billion between now and 2040, while costing about $9.4 billion to build. This net $7 billion in savings is likely understated given ERCOT's conservative production cost savings definition.[1]
- The model economically deploys about 130 GW of new capacity (wind, solar, natural gas, and energy storage), which, in turn, delivers about 213 million more MWh of energy to meet the growing demand of 12 million more Texans by 2040.
- The expanded renewable energy deployment supports about $18.9 billion in new local taxes and roughly $20.1 billion in new landowner payments over project lifetimes.
- The estimated transmission, solar, wind, and energy storage deployment would support roughly 40,700 (20-year, full time equivalent) jobs during the construction and operation phases of the technology deployment.
- The cost-optimal grid of 2040 is also cleaner and produces about 121 billion fewer lbs. of CO_2, 316 million fewer lbs. of SO_2, and 75 million fewer lbs. of NO_x, per year than the grid of 2022.
- The optimal grid of 2040 also consumes about 50 billion fewer gallons of water per year and withdraws 6.4 trillion fewer gallons of water per year than the grid of 2022.
- An analysis of a high demand growth scenario in Far West Texas, due to the electrification of oil and gas operations, suggests the need to deploy more energy infrastructure in that region including about 1,765 MW of new natural gas.

1 Such as reduced costs from energy losses, reduced costs during transmission and generation outages, reduced costs during extreme events and system contingencies, etc.

Introduction

Texas is *the* 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]. Texas has long been the leader in wind power and is expected to be number one in utility-scale solar by the end of 2023, surpassing California. 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' electric load, expects electricity consumption to increase over 30% in the next decade [2]. This load growth, coupled with the natural retirement of power plants as they age, will require new generating capacity to be built to meet the growth in demand.

While thermal power plants have generated the bulk of Texas electricity for the past decade, technology changes have introduced new sources of energy into the mix. Falling costs have led to a rapid growth in low-cost energy like wind, solar, and storage, and lower fuel costs have prompted a large change from coal to natural gas. There is also a strong social demand for clean and affordable energy sources from consumers of all types, particularly corporations, 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 2040 and estimate the most cost-optimal solution to meet supply and demand. In particular, this analysis sought to assess to what extent the existing transmission network should be upgraded in the near future to deliver the most cost-optimal mix of future generation for a changing ERCOT grid.

Methodology

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

The model

For this analysis, IdeaSmiths modeled the ERCOT grid by utilizing a customized version of the GenX open-source capacity expansion model [3]. A capacity expansion model is an optimization program that optimizes 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 which simulates normal grid management without interruptions in service. On the long-term 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 2020 and the first simulation year was 2025. Results show actual information for 2022 and future simulated values thereafter. 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 [2] [4]. 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 [5]. The transmission limits between each of the connected zones were calculated based on physical infrastructure, historical power flows, and Generic Transmission Constraints [6].

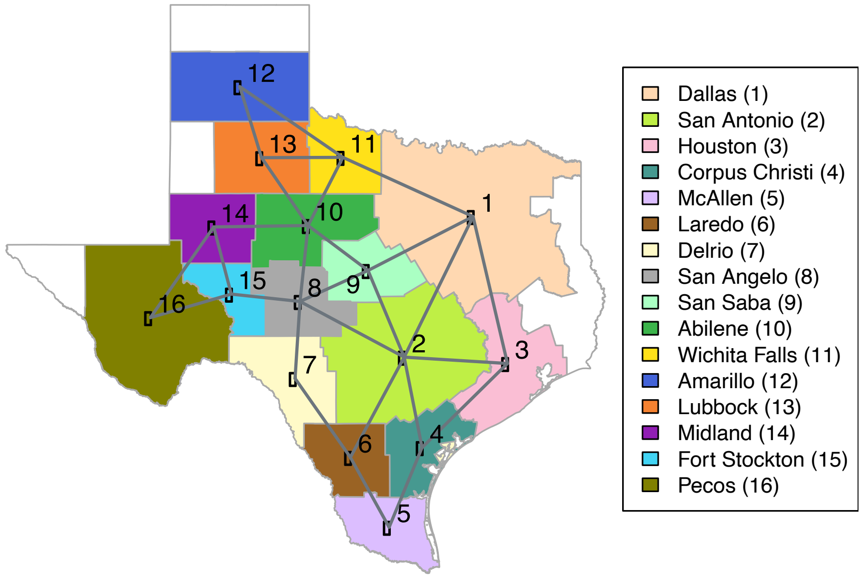

Figure 1: The 16-zone ERCOT model and transmission network used in this analysis.

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 2040 in 5-year increments (2025, 2030, 2035, 2040) given future technology and fuel costs. While the 2022 LTSA projected values to 2032, these projections were extended to 2040, assuming similar trends continued.

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 was technology-neutral in that it 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 did include the production tax credit (PTC) for both wind and solar given their recent extension via federal legislation.[2]

Scenarios modeled

Table 1 shows a summary of the scenarios modeled in this analysis. Base scenario assumptions refer to the assumptions given in the Methodology section and Appendix A as well as how the assumptions for the high-cost transmission scenario (S2) and the High West Texas load growth (S3) scenarios differ from the Base scenario (S1).

Scenario	Scenario Assumptions
(S1) Base	Base scenario assumptions
(S2) High-cost transmission	Base scenario assumptions + 2X transmission costs
(S3) High West Texas load growth	Base scenario assumptions + 3X growth in Far West Texas

Table 1: Table showing the scenarios considered in this analysis.

2 Given the tax credits history of extensions, we assumed that this level of tax credit continued throughout the period of 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 2022 and 2040.

Generation capacity

ERCOT's overall energy consumption and peak demand are expected to grow significantly between 2022 and 2040, 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 for the Base scenario (S1). Total generation capacity in ERCOT grows from about 120 GW in 2022 to about 250 GW in 2040.

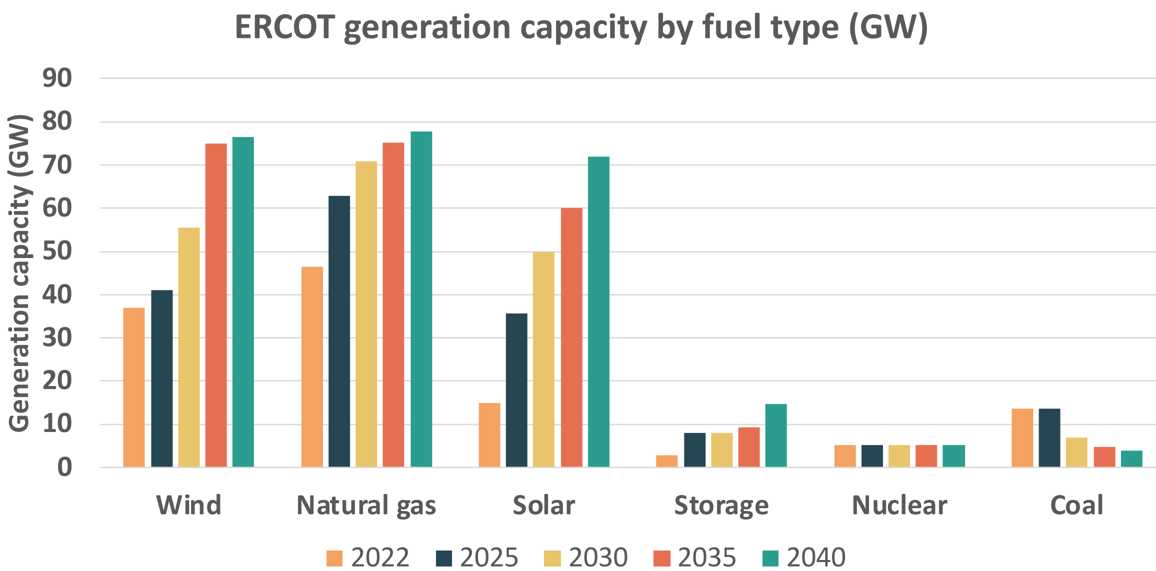

Figure 2: Actual 2022 and expected future ERCOT utility-scale generation capacity changes by major fuel type (GW) for the Base scenario (S1).

The results indicate that the optimal pathway includes continued growth for wind, solar, natural gas, and energy storage. By 2040, the optimal ERCOT grid has about 76 GW of wind, 78 GW of natural gas, 72 GW of solar, and 15 GW of energy storage. It is worth noting that some projections of energy storage costs are falling much faster than others and thus energy storage might grow faster than shown here.[3] All current nuclear capacity is expected to stay online, but a large amount of coal retires with only about 3.7 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, solar, and natural gas capacity grow, the results indicate that each of them would optimally constitute about 30% of total overall capacity in ERCOT by 2040.

3 The February 2023 ERCOT interconnection queue has over 90 GW of battery storage projects and some are even being deployed at thermal assets.

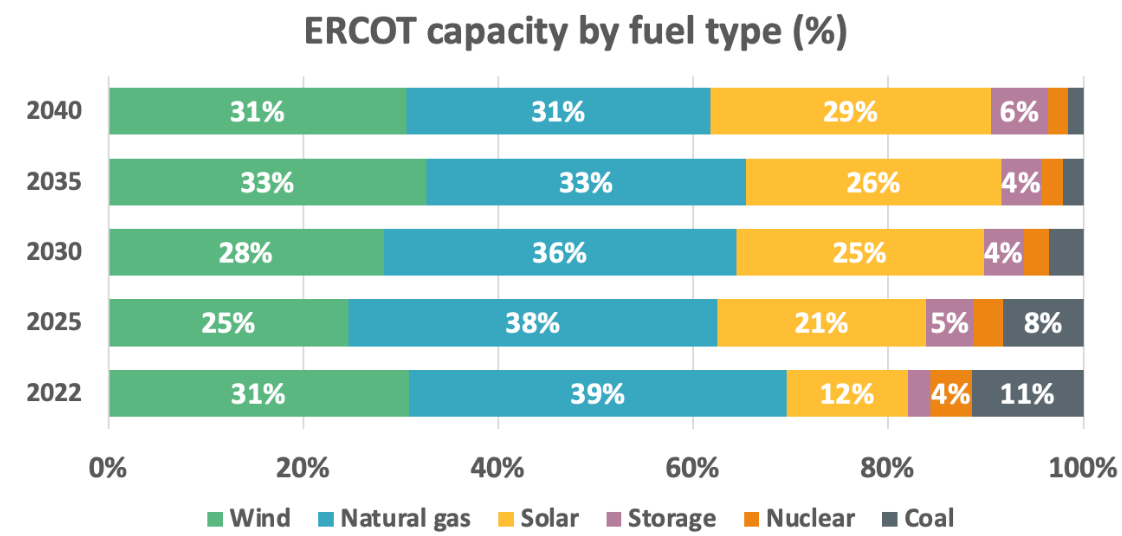

Figure** 3: Actual 2022 and expected future ERCOT capacity changes as a percentage of total capacity **for the Base scenario (S1).

Energy generation

Figure 4 shows the change in energy generation over time. Energy demand is scheduled to grow from about 428 TWh in 2022 to about 623 TWh in 2040. Natural gas generation remains relatively constant throughout the analysis period with some declines in the 2030s before rebounding in 2040. Both wind and solar see large growth over the next couple decades, nuclear holds steady, and coal generation declines as its capacity is retired.

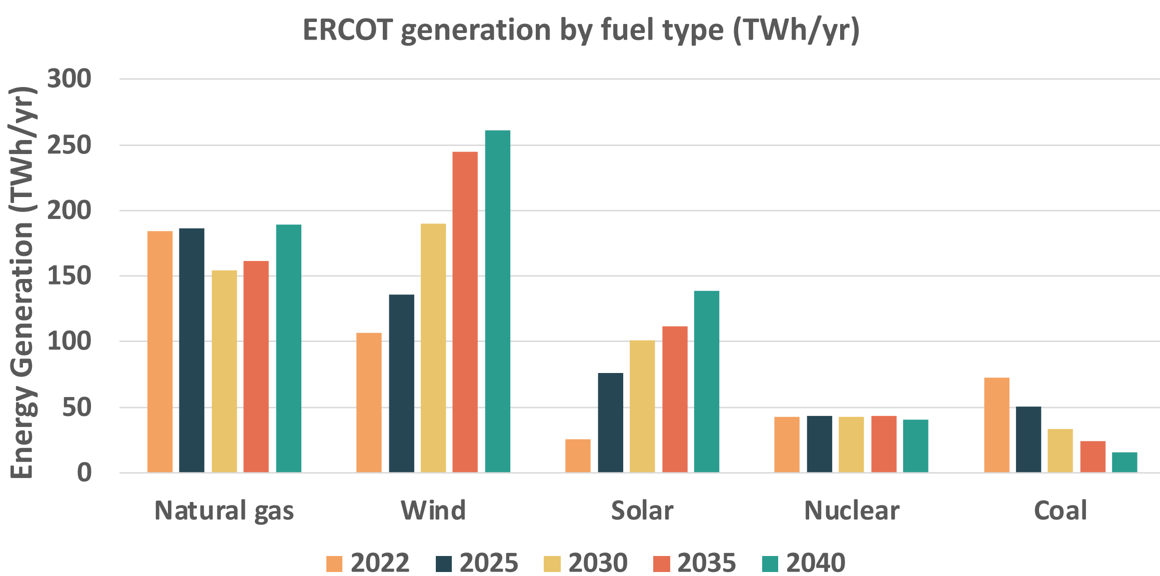

Figure 4: Actual 2022 and expected future ERCOT energy generation by fuel type (TWh/yr). Other technologies, such as biomass left off as they do not contribute in a major way for the Base scenario (S1).

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 about 60% of total energy generation by 2040.

It is worth noting that while wind and solar see the highest percentage growth between 2022 and 2040 in ERCOT in a least-cost scenario, as shown in Figure 2 and Figure 3, natural gas also grows during that time and remains a large contributor to energy generation as shown in Figure 4 and Figure 5.

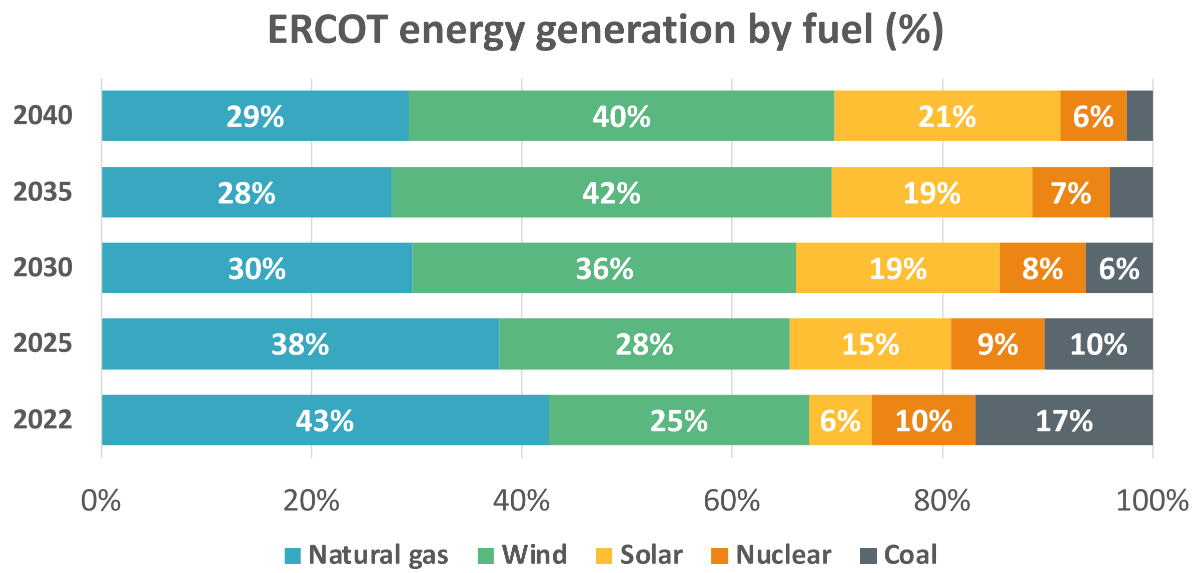

Figure 5: Actual 2022 and expected future ERCOT energy generation as a percentage of total generation for the Base scenario (S1).

In general, the model appears to approach about 40% of capacity[4] and 40% of energy[5] generation coming from coal, natural gas, and nuclear and the other 60% from utility-scale wind and solar by 2040. The model does this while also maintaining ERCOT's historical economically efficient 13.75% reserve margin target and matching supply and demand in all hours.

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 while maintaining reliability to meet future demand for electricity. To support this most 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 enables it to build new technology-neutral resources or dispatch existing resources in a way that reduces overall cost, inclusive of the additional capital investment.** Figure 6 identifies the transmission connections that the modeling suggests upgrading, shown in bold red.

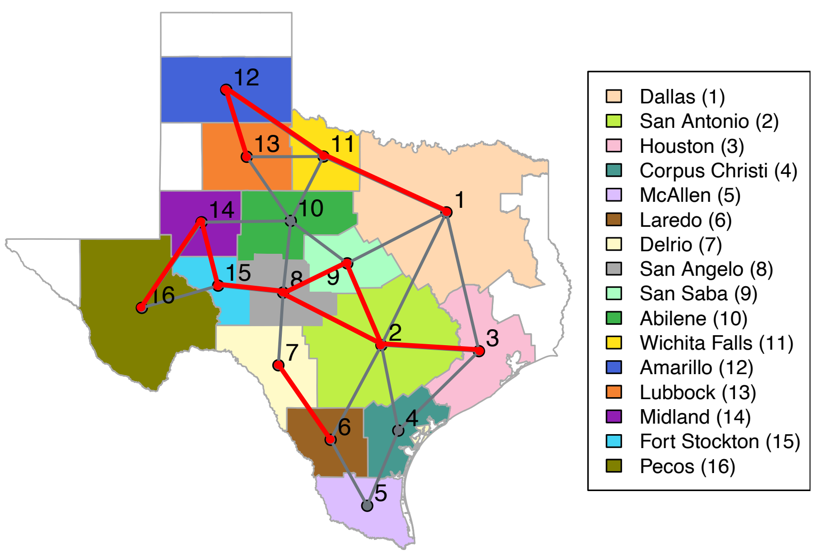

Figure 6: Transmission upgrades necessary to host the optimal generation resource build out for the Base scenario (S1). Existing lines in gray, upgraded lines in bold red.

4 Natural gas, coal, nuclear, and energy storage.

5 Natural gas, coal, and nuclear.

Figure 7 shows the transmission capacity additions (in MW) between each of the regions that were highlighted in red in Figure 6. These expansions are likely a mix of greenfield and an expansion of existing transmission lines. The model showed a strong preference for better connecting the more western regions of the ERCOT grid to the central and eastern regions, as well as fortifying the grid around Laredo. These results are consistent with the increase in congestion that can be seen today between these regions. The largest buildout was from the Wichita Falls region (11) to the Dallas region (1) with the model suggesting to build almost 12,500 MW of additional transmission between those regions. The model strengthens connections between west Texas and San Antonio (2) and Houston (3) regions (moving from west to east). These results include adding almost 25,000 MW of transmission roughly across the West Texas Generic Transmission Constraint [7] with about 25% 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 the next investment period, the model focuses on deeper connections to central Texas and better connecting to the Houston (3) region. The latter investment periods continue to reinforce those trends.

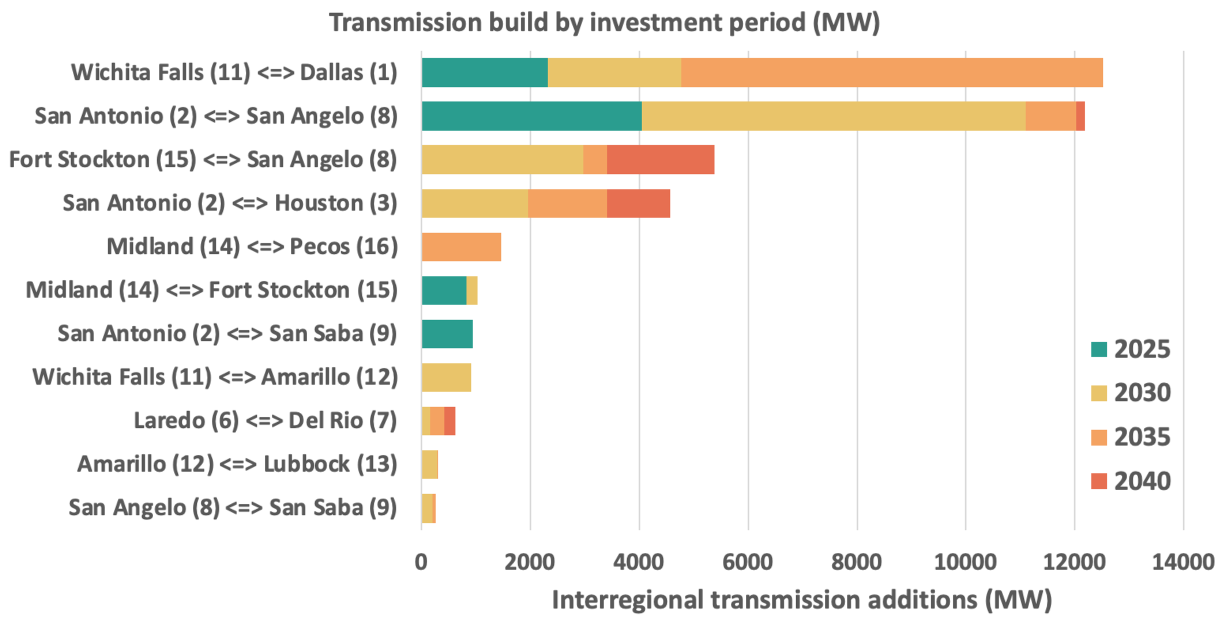

Figure 7: Interregional transmission additions to support grid development by time-period for the Base scenario (S1). Lines that were not explicitly upgraded are not shown here.

In all, the model built about 1,350 miles of new transmission capacity with the ability to move almost 40,000 MW of power, or about 5.2 million MW-miles[6] of capacity. The analysis estimates that this transmission buildout would cost roughly about $9.4B to build[7].

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 considered, it is likely that some of the transmission expansions highlighted in this analysis would be larger, deployed earlier, and deliver greater savings than indicated here.

Production cost savings

The model is able to reduce production costs in ERCOT 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[8], this analysis compared the optimal-system Base scenario (S1) production costs with the production costs from the high-cost transmission scenario (S2) where the cost to build transmission was increased to roughly twice that of the assumed base scenario, or about $3,600/MW-mi. Higher transmis-

6 MW-miles is simply the the added capacity of the line, in MW, times the length of the line, in miles.

7 Based on historical CREZ line costs, about $1,800/MW-mi.

8 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 [42].

sion 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 1.5 million MW-mi of transmission in the higher-cost S2 scenario (vs. 5.2 million in the Base scenario S1). In general, the higher-cost scenario (S2) built transmission in mostly similar locations as the Base scenario (S1), but in lower quantities. Using the Base scenario (S1) transmission construction costs, the model built about $6.6 billion more transmission in the Base scenario (S1) vs. the high-cost transmission scenario (S2).

However, energy production costs in Base S1 scenario were lower than in the High-cost S2 scenario. Figure 8 shows the production costs savings, per year[9], between the High-cost transmission scenario (S2) and the Base scenario (S1).

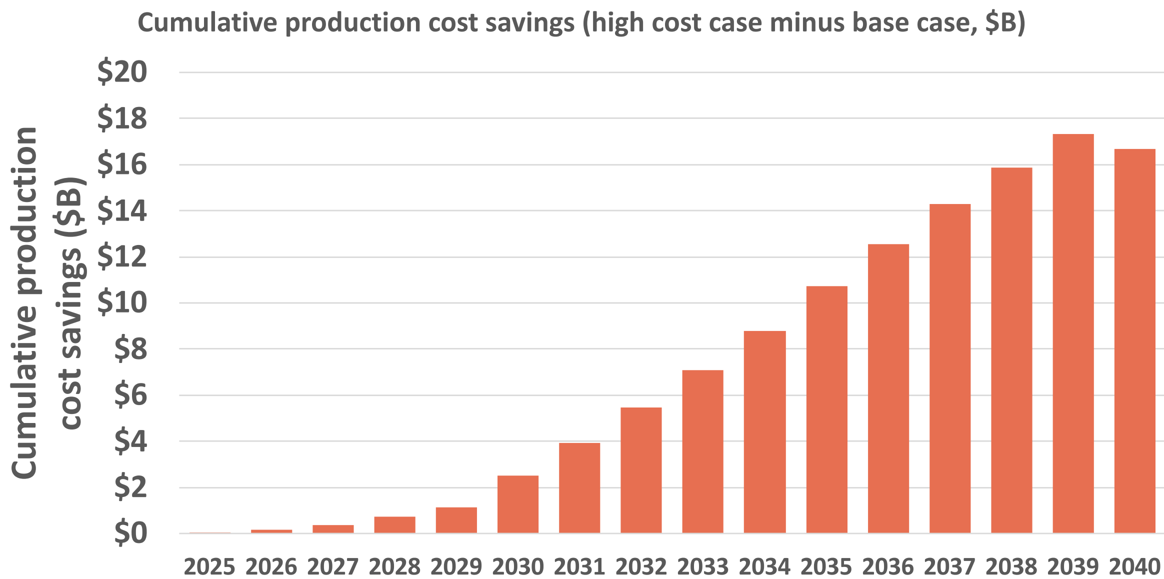

Figure 8: Cumulative production cost savings in billions of dollars from comparing market costs of the High-cost transmission scenario (S2) and the Base scenario (S1).

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 $1.1B per year and total about $16.7B between 2025 and 2040.[10] Thus, this analysis indicates a roughly 10-year breakeven (~2034) if all the transmission suggested by this analysis was built.[11] Note that this estimate would grow with a more expansive definition of production cost savings that was more in line with other ISO regions.[12]

Local tax and landowner payment implications

Renewable energy and energy storage 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 [8] with the potential to create multigenerational income that supports family farms and ranches.

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 scenario (S1) for future construction of electricity infrastructure in ERCOT.

9 The years between the model run years are linear interpolations.

10 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.

11 Using the difference in transmission builds from the high-cost (S2) to the Base (S1).

12 Such as reduced costs from energy losses, reduced costs during transmission and generation outages, reduced costs during extreme events and system contingencies, etc.

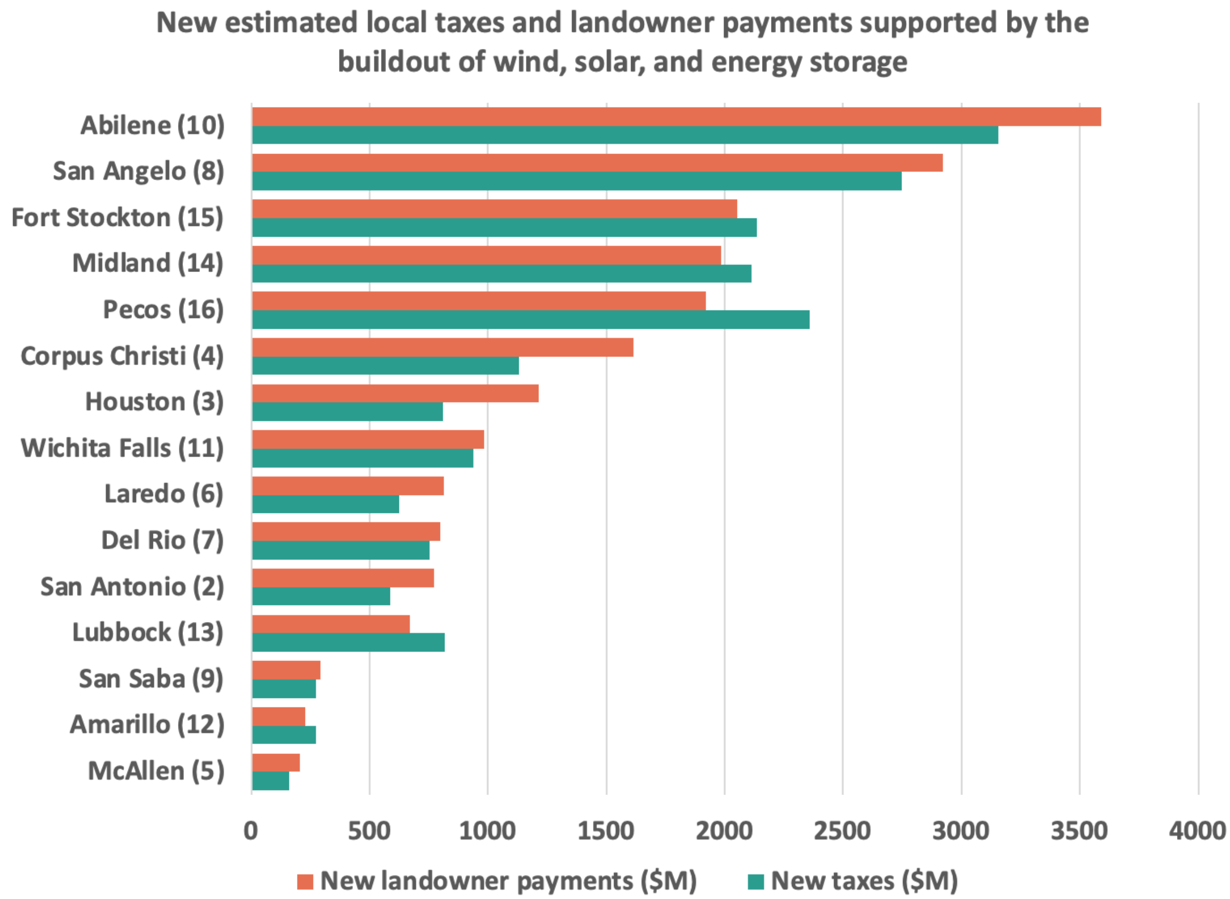

Figure 9: Estimated local taxes and landowner payments supported by the continued deployment of wind and solar in Texas over their lifetimes ($M) for the Base scenario (S1).

This analysis indicates that the economically optimal level of wind and solar deployment would result in roughly $18.9 billion in new local taxes and roughly $20.1 billion in new landowner payments over their lifetime, with most of the payments being made to areas of Texas that are more rural[13], but all Texans benefit from the production costs savings mentioned above.

Emissions, water, and job impacts

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 [9], we estimate that the ERCOT power sector in 2040, compared to 2022 actual values, results in about 121 billion fewer lbs. of CO_2, 316 million fewer lbs. of SO_2, 75 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, compared to today, would also reduce water withdrawals by 6.4 trillion gallons per year and reduce water consumption by 50 billion gallons per year, all while delivering about 213 million more MWhs of electricity.

The deployment of transmission and the expected build out of wind, solar, and energy storage capacity presented in this analysis is also estimated to support roughly 41,700 (20-year, full time equivalent) jobs during the construction and operation phases of the technology deployment [10].

High West Texas load growth (S3) scenario

This analysis also considered a separate scenario of much higher load growth in the Far West Texas due to the electrification of oil and gas operations in the Delaware and Midland basins [11]. S3 is equivalent to the Base scenario (S1) except that the load growth of zones Pecos (16), Fort Stockton (15), and Midland (14) saw accelerated growth due to these projections. For example, these three regions are estimated to start consuming about 40 TWh total in 2025. In the Base scenario (S1), these regions increase their consumption by about 30% to 52 TWh by 2040, but in the High West Texas (S3) growth scenario, these regions grow

13 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.

by almost 85% to about 73 TWh which is conservative compared to other estimates.[14]

In comparison to S1, the S3 scenario deployed similar amounts of interregional transmission capacity. While beyond the scope of this analysis, it is estimated that significant amounts of sub-transmission and distribution infrastructure will be necessary within these regions to serve these oil and gas loads. The levels of load expected in these regions rival that of major metropolitan areas around the state, but differ in that they are spread over very large areas whereas cities are much more concentrated.[15]

However, there were marked differences between the optimal generation capacity strategies of these regions. In particular, these regions saw the deployment of about 1,765 MW of new natural gas, about 1,000 MW of additional wind, and about 175 MW more solar capacity than in S1. In general, the increased baseload in the area saw the model deploy more and more firm resources in the region.

Conclusions

The analysis built and utilized a capacity expansion model of the ERCOT power grid to assess how the electricity infrastructure would evolve over a cost optimal path to 2040, 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, or emissions taxes.

The results of the modeling indicate that Texas can reduce wholesale energy costs and provide energy to a growing population while maintaining grid reliability, conserving water, and improving air quality. Upgrading the existing grid by adding about 1,350 miles of new or upgraded high-voltage transmission lines (~5.2 million MW-miles) along 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 quickly in ERCOT, the model builds about 130 GW of additional wind, solar, natural gas, and energy storage capacity, which, in turn, deliver about 213 million more MWh of energy, all while reducing emissions and using less water than the ERCOT grid used in 2022. Technologies have evolved rapidly, and with them, costs have declined.

This analysis indicates that, for the ERCOT grid to continue to deliver some of the lowest cost power to consumers, the bulk transmission system will need to aggressively modernize and expand to better bridge the western and eastern parts of the state.

Acknowledgements

This work was funded by Advanced Energy United.[16]

About Us

IdeaSmiths LLC[17] 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.

14 Note that the High West Texas growth scenario modeled for this analysis is only about half of the projected growth in the S&P report for this region.

15 Rural COOPs often talk about how many miles per meter they must run whereas city-based utilities discuss meters per mile.

16 https://advancedenergyunited.org/about

17 https://www.ideasmiths.net/

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Appendix A

1. General Model Summary: Capacity Expansion Modeling in GenX

The analysis for this project is completed using the capacity expansion model called, "GenX" [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.

"GenX" is a unique grid planning model that is built using capacity expansion modeling theory. GenX is developed and maintained by Professor Jesse Jenkins at Princeton University. It is an open source model built on the Julia 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 not 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 11, 48-hour periods to represent the annual electricity market. These representative periods are created automatically in the GenX model using a Time Domain Reduction module that creates the following periods:

- 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 1 of 365 days for each model year.
- Annual Minimum Renewable Output: we use the 24-hour profiles of the two days with the lowest amount of wind generation and the lowest amount of solar generation. Each of these time series is scaled up to represent 1 of 365 days for each model year.
- Representative Days: the remaining 24-hour periods are created using a k-means clustering method to create a set of representative days. The clustering algorithm identifies days with similar load profiles, total load, wind profiles, and solar profiles. It aggregates days with similar profiles into a single 24-hours profile, and then weights that representative profile according to how many annual days it should represent, based on how many of the historical load curves are included in each cluster.

When compared to a complete, 8,760-hour demand profile, the 11 representative days outlined above have 1% greater annual energy consumption. Figure 10 below compares the 8,760 and 11-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 100% of the peak of the 8,760 hour curve. When compared to the 8,760-hour series, the 11-representative-day series has higher demand for the highest-demand hours of the year but is otherwise very similar.

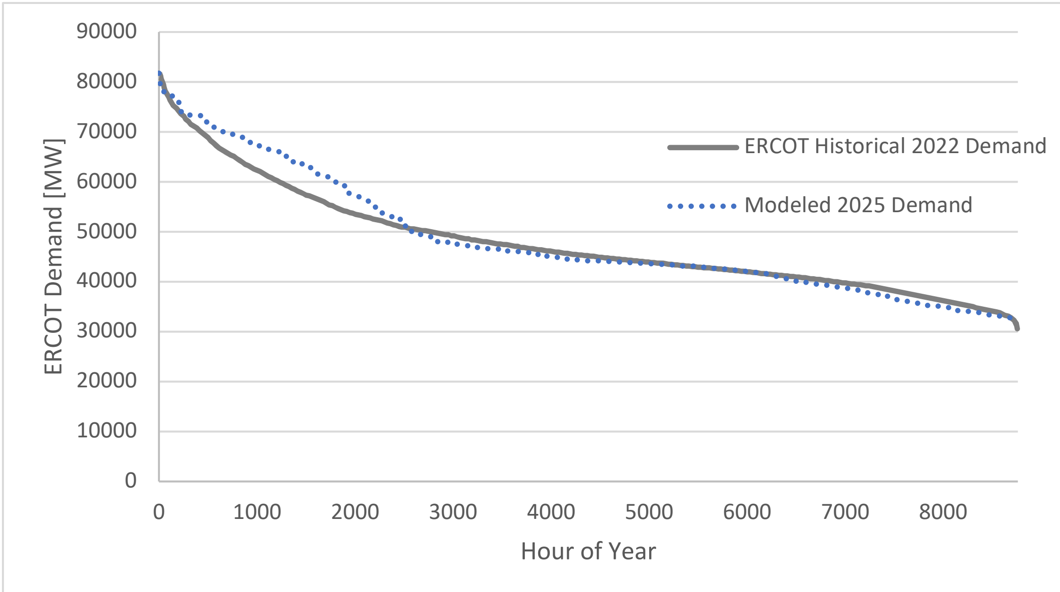

Figure 10: Duration curve of 8,760-hour Historical ERCOT Load and the representative time series used in this model.

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.

3. Generator Data

Our model represents the power plant fleet in ERCOT by aggregating different types of generators. Generators are aggregated by clustering them according to 1) the model region where they are located and 2) their operating cost.

To parameterize and cluster the power plant data, we use PowerGenome [12]. PowerGenome is a python-based tool that compiles open-source, publicly-available data from a variety of sources, clusters the data, and outputs the data into a form that can be ingested into the GenX model.

3.1. EIA 860, 2022 [13]

EIA 860 is a database of information collected by the EIA. It is automatically queried in PowerGenome and used to build the model's existing power plant fleet, including each generator's:

- capacity,
- construction year,
- county,
- fuel type, and
- technology type

3.2. Annual Technology Baseline (ATB), 2022 [14]

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:

- fixed operation and maintenance cost.
- capital cost of construction,
- fixed operation and maintenance cost,
- heat rate,
- roundtrip efficiency for batteries,
- and other data useful for dispatch modeling such as minimum down time, minimum load, ramp rate, etc.

3.3. Coal Retirements

Based on age, the majority of coal plants are expected to retire in Texas by 2040, we allow coal to retire that has been operating for 50 years or longer. This has the following impact on overall coal capacity:

- 2020-2025: 13.6 GW
- 2025-2030: 6.9 GW
- 2030-2035: 4.7 GW
- 2035-2040: 4.3 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 [15].

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 [16] 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). [17]

For wind, we use the appendix data from [18] 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.[18] 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 wind resource quality varies across the county's geography. To account for this, we use data from [19] 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. Minimum Wind and Solar Buildout

Short term wind, solar, and battery development are difficult to model in a long-term capacity expansion model like GenX. To compensate, we require the model to build a minimum amount of these technologies during the first capacity expansion period [2020-2025]. These requirements are based on the January 2023 ERCOT CDR report [20].

Technology	Required Capacity in 2025 [GW]
Solar	35.0
Wind	41.0
Battery	8.0

Table 2: Required solar, wind, and battery capacity that must be built during the first model period.

18 Personal communication with the University of Texas at Austin Bureau of Economic Geology.

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 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 [22], 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

Given the extension of tax credits from the passage of the Inflation Reduction Act, we estimate that both wind and solar projects in Texas would opt for the production tax credit (PTC) over the investment tax credit (ITC) and each resource's variable costs were reduced by the PTC amount of $8.67/MWh based on a $26/MWh PTC for 10 years stretched over the assumed 30-year lifespan of the asset.

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 [23]—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 [24].

Existing transmission capacities were determined by running the historical 2020 hourly load and generation in a power flow model [25].

- 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.

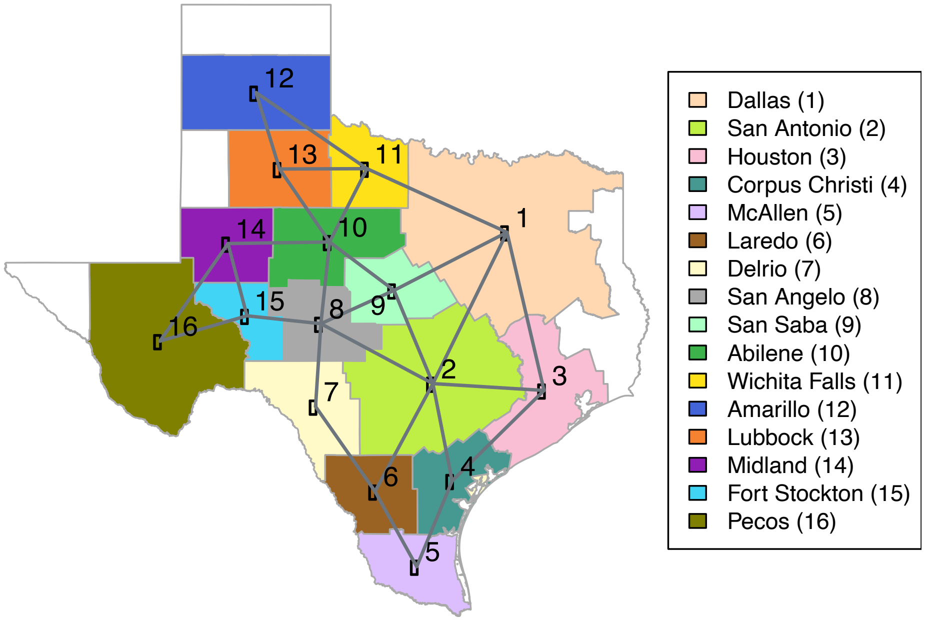

Figure 11: The 16-zone ERCOT model and transmission network used in this analysis.

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 1800 $/MW-mile as described in [5] including inflation.

6. Fuel Prices

Fuel price data come from the EIA's 2022 Annual Energy Outlook (AEO) [26]. This report contains future projections out to 2050 of energy consumption, emissions, and fuel prices.

7. Load

7.1. Load Data

We 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 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 load profile for each of our 15 transmission regions.

The far west region of Pecos (zone 16) in our model was apportioned differently based on a recent HIS Markit and S&P report on the evolution of demand in the Delaware and Midland basins [11].

7.3. Load Growth

We assume that load increases at a rate of about 2.1% annually. This load growth rate was determined by calibrating the model's future loads against the energy forecasts in the 2022 ERCOT Long Term Load Forecast [4]. While 2.1% is the expected long-term average, higher rates of growth have been seen in the past few years. If growth were higher, it is likely that transmission needs would grow faster.

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 16 transmission regions. We take the 2022 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) [28]. 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 using the forecast in the ERCOT 2022 Long Term System Assessment (LTSA) [2]. In this forecast, distributed solar is 1.0 GW in 2020, 5.0 GW in 2025, and 6.0 GW in 2030+.

Step 2: we spread the distributed solar capacity amongst the 16 transmission regions. As for electric vehicles, we take the 2022 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 GenX model uses a WACC for various financial calculations. We assume a WACC of 5% for power plant investments and a WACC of 4.0% for transmission investments.