A Case Study of Transmission Limits on Renewables Growth in Texas

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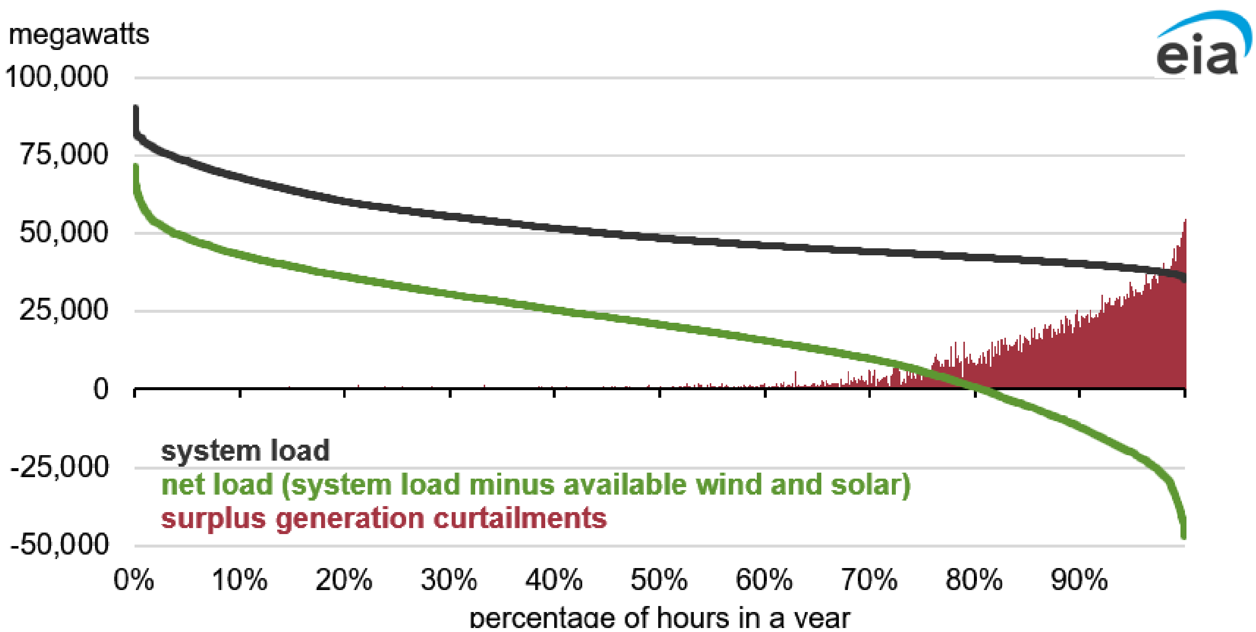
1. Executive Summary

This paper explores the interplay between projected renewable energy additions onto the electricity grid in Texas operated by the Electric Reliability Council of Texas (ERCOT) and the region's existing electrical transmission network.

Without expanding ERCOT's electrical transmission network and storage capacity, congestion and curtailments will rise. Curtailments are due to both inadequate transmission capacity and surplus generation during high availability periods of variable renewable generation. This analysis indicates the amount of variable renewable capacity in ERCOT that we projected would be online by 2035 in our 2023 *Annual Energy Outlook* (AEO) could significantly reduce net load – the difference between the electricity demand and available renewable generation at a specific point in time. We also found the amount of time in which available renewable generation exceeds electricity demand could increase significantly if Texas adds the amount of renewable generation projected in the AEO by 2035: 19% of hours had negative net load and associated curtailment of renewable generation (Figure 1).

Transmission system upgrades could reduce some curtailments that arise from transmission capacity limitations. But curtailments resulting from surplus generation cannot be mitigated by transmission system upgrades and storage. With the addition of variable renewable generating capacity, we project system energy prices to fall relative to current prices, with a significant increase in the number of hours where system energy is priced at $0 per megawatthour (MWh). Identifying the source of renewable curtailments is key to developing a long-term plan that seeks to maximize the value of renewable assets.

Figure 1. Projected shift in 2035 ERCOT net load and curtailments due to greater renewables capacity



Data source: U.S. Energy Information Administration, model simulation of the Electric Reliability Council of Texas (ERCOT) power market

1. Introduction

Changing economics and a series of policies aimed at shifting the electric power sector to cleaner sources of energy point to a large increase in renewable generation throughout the United States, but certain constraints could curb that growth. Strong projected growth in renewable energy in the Electric Reliability Council of Texas (ERCOT) over the next decade could be constrained by transmission capacity. ERCOT currently has the most renewable generation in the country due to significant wind resources and focused investment in the electric transmission system.[1] While continued growth is likely in a wide range of scenarios projected in our Annual Energy Outlook (AEO) 2023 and by other organizations, there are several uncertainties associated with those projections. The most prominent include:

- Pricing levels sufficient to incentivize additional new generating capacity
- Changes in government policy
- Adequacy of transmission capacity

In this analysis, we build upon assumptions from the AEO2023 and use a model with more detailed geographic and temporal granularity to analyze how transmission limits could affect future generation patterns in ERCOT given projected solar and wind capacity additions. The AEO only models transmission limits between regions[2] ("inter-regional"), rather than within regions ("intra-regional"), which are not as relevant to the isolated ERCOT region. For this analysis, we added renewable capacity in ERCOT approximately equivalent to the AEO2023 Reference case levels in 2035 to the UPLAN production cost model and evaluated their impact on the market operating under current ERCOT intra-regional transmission constraints.

2. Issues Overview

The AEO2023 projects that combined U.S. solar and wind capacity will increase two-and-a-half times current levels by 2035, after growing 500% between 2010 and 2022. Much of the strong growth in wind and solar nationwide is concentrated in Texas. In 2022, ERCOT wind generation represented 24% of total U.S. wind generation, and ERCOT solar generation represented 15% of total U.S. solar generation. U.S. wind and solar generation grew from 2% of total U.S. generation in 2010 to 14% in 2022. In 2022, the combined share of wind and solar generation in ERCOT was 30%, twice the renewable generation share in the United States (Figure 2).

High quality wind resources in Texas's western and Panhandle regions are key in driving renewables growth in ERCOT. In addition, these areas have thinly-populated, undeveloped land, which has enabled construction of large wind projects and leveraged significant economies of scale. Coinciding with faster growth in the early 2000s, wind power generation steadily increased to meet rising electricity demand.

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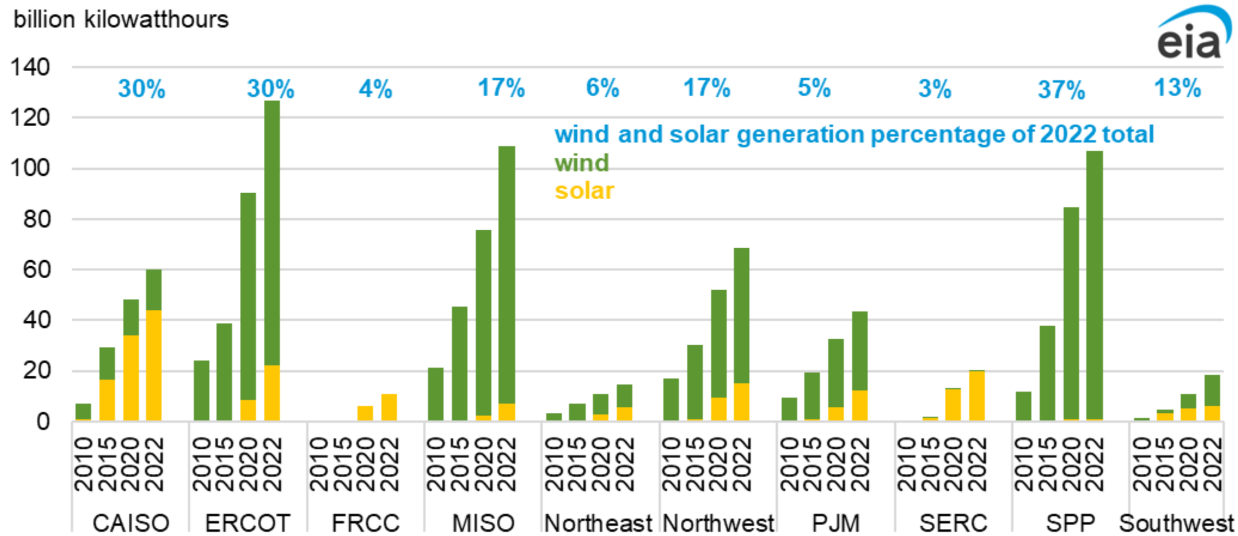
[1] All generation values referenced in this document represent net generation, which is the amount of gross generation less the electrical energy consumed at the generation station(s) for station service or auxiliaries.

[2] U.S. Energy Information Administration, Electricity Market Module of the National Energy Modeling System: Model Documentation 2022 Sep. 2022. pg. 6

Figure 2. Growth in regional wind and solar generation, 2010–2022

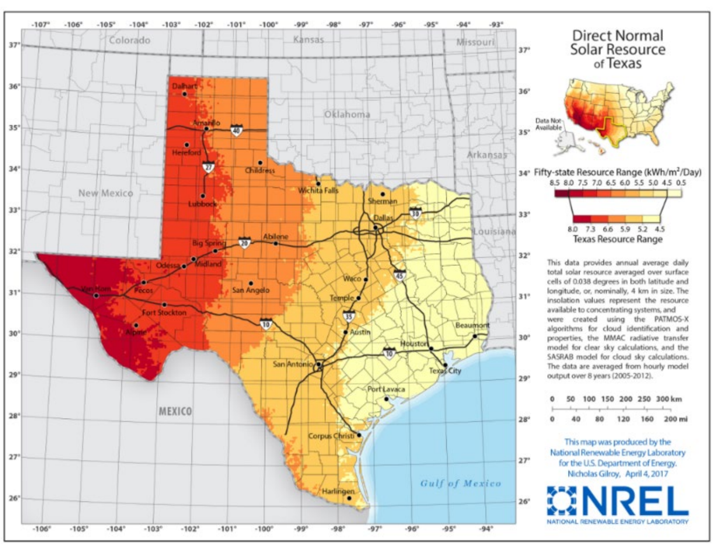


Data source: U.S. Energy Information Administration, Form EIA-923 database

In 2005, the Texas Legislature proposed the Texas Competitive Renewable Energy Zone (CREZ) initiative to promote the development of renewable energy, mainly wind power, and to increase overall transmission capacity.[3] Wind generation in ERCOT has grown at an average annual rate of 14% since the CREZ project was completed in 2014.

The power market in ERCOT is undergoing a solar investment boom, although solar currently represents a relatively small share of the region's total generation (5% in 2022). Solar electric generating capacity additions over the past two years exceeded all competing alternatives, representing 46% of all additions from 2020 to 2022. That compares to 37% for wind, 10% for battery storage, and 7% for natural gas. Based on announced future projects, Texas will lead the nation in solar power growth over the next few years, surpassing California's expected solar capacity by 2024.

Figure 3. Solar photovoltaic resources in Texas



Source: National Renewable Energy Laboratory

Like its abundance of available wind, western Texas has some of the highest-rated solar resources in the country

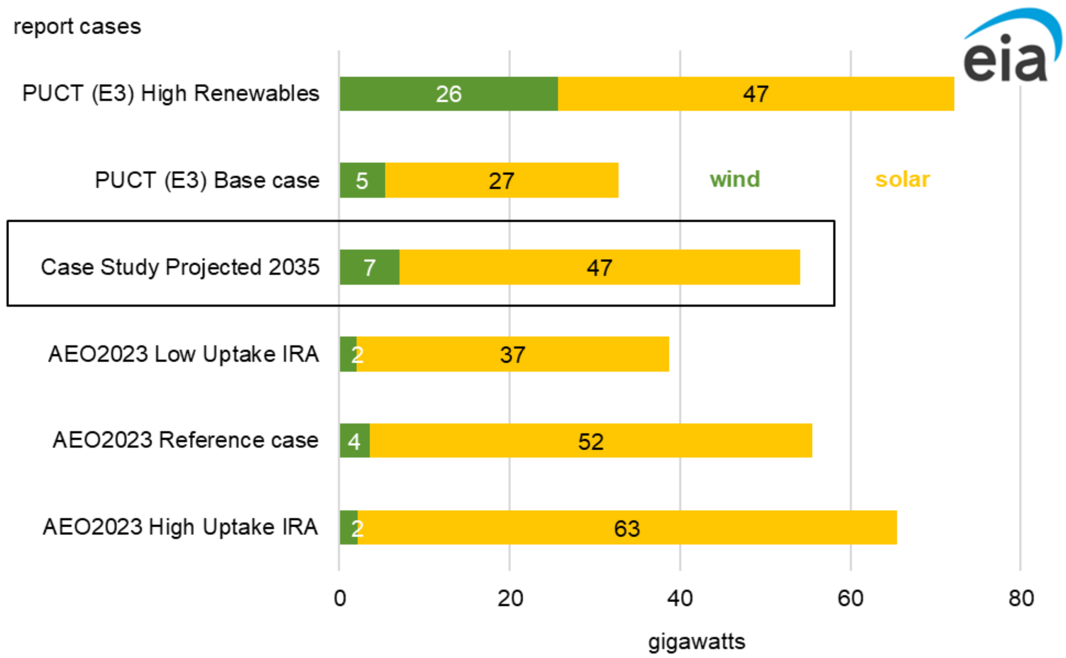
[3] Baker Institute Center for Energy Studies, "Texas CREZ Lines: How Stakeholders Shape Major Energy Infrastructure Projects," Nov. 2017; and ERCOT, "The Competitive Renewable Energy Zones Process," Aug. 2014

(Figure 3) and is the location for a large share of the state's planned solar capacity. In addition, the complementary relationship between solar and wind in ERCOT plays a role because solar generation is greater in the middle of the day, when there is typically less wind generation. While failure to add new transmission capacity could potentially limit overall renewables growth, the use of existing transmission lines creates opportunities for intra-day shifting between sources in west Texas: transmission lines that already handle the large amount of wind power in the area will be available during midday to deliver power from the new solar capacity additions.

Projected renewables growth in ERCOT

We compared our analysis of renewables deployment under conditions where transmission is constrained with several scenarios from recent studies. Those studies also anticipate variable renewable capacity additions in ERCOT over the next decade despite significant variance in the distribution between solar and wind additions. In a November 2022 study supporting the Public Utility Commission of Texas's (PUCT) proposed market reforms, PUCT projected total variable renewable capacity additions in its Base Case scenario to be 33 gigawatts (GW) by 2035. The vast majority of those additions are from solar installations, based on screening criteria the PUCT applied to projects in the ERCOT interconnection queue (IQ).

Figure 4. Alternative projections for variable renewable capacity additions by 2035



Data source: Public Utility Commission of Texas (PUCT), "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System," November 2022, p. 67; U.S. Energy Information Administration, *Annual Energy Outlook* (AEO) 2023

Note: 1) UPLAN's *Projected 2035 likely IQ adds* refers to projects in ERCOT's *Generator Interconnection Status* report that had an Interconnection Agreement completed, Full Interconnection Study completed, and a Security Screening completed. More information is available in the Methodology section and in Figure 7 below. 2) Totals may not equal sum of components because of independent rounding.

Alternatively, the PUCT report's High Renewables Case envisions nearly double the amount of total capacity additions at 72 GW, although with a higher expected share of wind additions at one-third of the total (Figure 4). The PUCT study attributes the stronger potential growth of variable renewables to several factors. Those factors include government policy, such as the Inflation Reduction Act (IRA); lower renewables costs; and increased consumer preference.

Our AEO2023 projects a similar range of variable renewable capacity additions for the ERCOT region when compared with the PUCT cases, depending on the assumed impact of the IRA. Although not all provisions of the IRA have been implemented, the AEO2023 Reference case represents our current understanding of the law, and we project total variable renewable capacity additions in ERCOT to be 56 GW by 2035 (with detailed assumptions behind modeling of the IRA are addressed in the AEO2023 release appendix). By contrast, 65 GW of total renewables capacity are added in AEO2023's High Uptake IRA side case and 39 GW are added in the Low Uptake side case, mostly with solar additions like the PUCT results.[4]

Although both the AEO and PUCT use scenarios to address a range of uncertainties confronting variable renewable capacity expansion, neither study includes scenarios specifically focused on the ability to expand transmission to accommodate renewables growth. Transmission adequacy has been a key factor in the integration of renewables throughout the country. The impact of transmission constraints is particularly critical in ERCOT, given both its rapid growth in electric load, as well as its almost complete isolation from the rest of the U.S. grid.

The AEO2023 and PUCT projections have similar ranges of expected additions. For this analysis, we are assuming total solar and wind capacity additions by 2035 for the ERCOT region that are similar to the AEO2023 Reference case. In this study, unlike the AEO, we indicate specifically where in ERCOT this new capacity will be built since we model transmission-level electricity flows within ERCOT.

To analyze the impact of high levels of renewable generating capacity, we must represent the transmission system at a highly detailed level, including where future capacity additions will interconnect with the grid. To model the location of this capacity, we selected likely future projects from ERCOT's *Generator Interconnection Status* (GIS) report. Each project in the GIS report indicates the specific bus (node) where it plans to link with ERCOT's transmission system. The projects we identified as most likely to come online total 54 GW of renewable capacity additions, similar to the AEO2023 Reference case variable renewables total, although with somewhat more wind additions (+3 GW) and fewer solar capacity additions (–5 GW.)

[4] U.S. Energy Information Administration, Annual Energy Outlook 2023, Issues in Focus: Inflation Reduction Act Cases in the AEO2023, March 2023

Key issues in modeling the impact of transmission limits on renewables growth in ERCOT

Analyzing the impact of variable renewables additions on ERCOT's power system requires addressing two fundamental issues:

- Properly accounting for transmission as a constraint
- Identifying the causes of potential curtailment of renewable generation

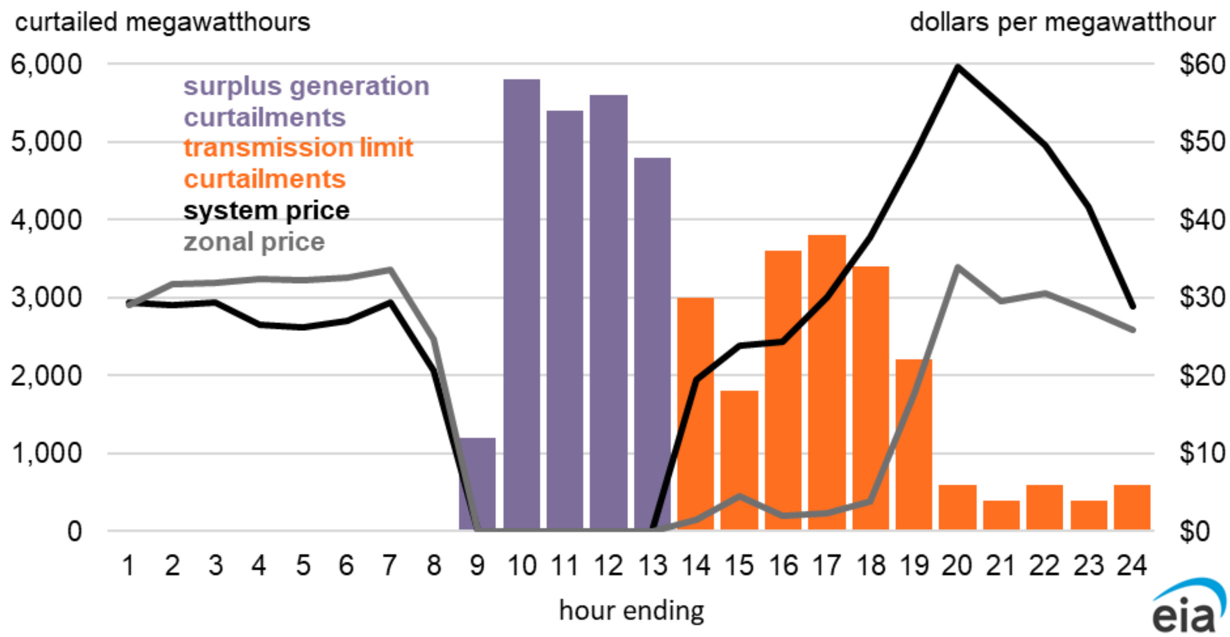
Instead of attempting to determine what the future grid would look like, this analysis focused on the impact of potential renewable additions connected to ERCOT's existing transmission grid. So, in this study we limited changes to the existing transmission grid. Since our goal was not to resolve network level congestion, we chose to eliminate localized issues arising from unlikely outcomes. In other words, we increased the transmission capacity on select branches just enough to:

- Accommodate expected peak load levels
- Allow new projects to inject full capacity into the grid at their designated node
- Allow batteries to fully charge and fully discharge into the grid at their designated node

These adjustments represent relatively small changes in ERCOT's transmission system. Of the 11,591 transmission lines modeled, we increased the transmission capacity on 84 of the lines, with an average capacity increase of 48%. Curtailment of renewable generation can occur in response to both transmission capacity flow limitations and an excess supply of generation. In this analysis, we attempted to differentiate between these two reasons for curtailed generation.

In cases when there are curtailments and the energy price in one of ERCOT's zones is less than the ERCOT-wide system energy price, the transmission system limits the flow of electricity from a zone with lower-cost resources to a zone with higher-cost resources. By contrast, when the zonal price is greater than or equal to the ERCOT-wide system energy price and there are curtailments, these curtailments are due to an excess supply of generation. The two types of curtailments are illustrated in Figure 5 on a typical summer day for one of eight ERCOT load zones, LZ_South, (green region, load zone map Figure 8). During the morning hours, from Hour 9 through Hour 13, the ERCOT-wide energy price and zonal energy price are both zero, signaling a market with surplus generation, and renewable curtailments occur. Beginning in Hour 14, the ERCOT-wide system price increases above the zonal price. Renewable curtailments continue but for a different reason. More renewable generation is available in LZ_South than can flow through the transmission system to higher demand regions of ERCOT. Because supply is greater than demand in LZ_South, prices fall relative to the rest of ERCOT. This lower price provides a market signal to reduce generation in LZ_South, but renewable curtailments occur if the lower price fails to trigger enough generation reductions. In this analysis, we distinguish the source of the renewable curtailments, transmission limits or surplus generation, by comparing the hourly zonal price to the ERCOT-wide hourly system price.

Figure 5. Two types of curtailments: surplus generation versus transmission capacity limits (projected 2035 scenario, LZ_South region, a June day in 2035)



Data source: U.S. Energy Information Administration, UPLAN model simulation of ERCOT power market

3. Methodology

For this analysis, we used the UPLAN production cost model, which is a network model that simulates energy and ancillary service procurement and congestion management. We set up the UPLAN model using a dataset of input assumptions that represents the ERCOT system's unique market rules and its transmission network consisting of thousands of nodes (or buses).

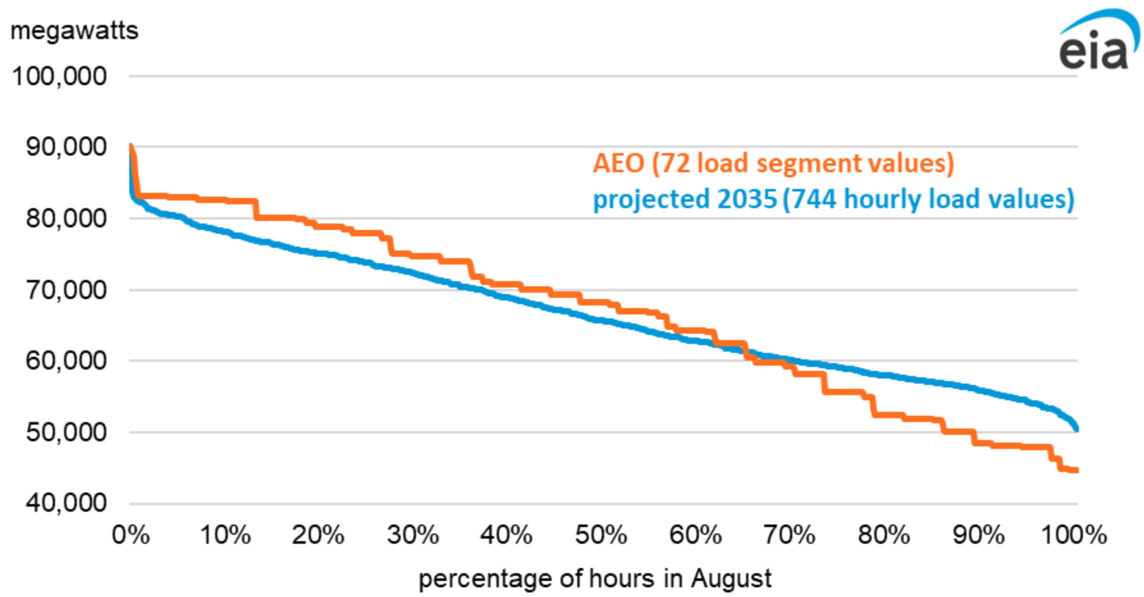
Before beginning our analysis, we calibrated the UPLAN model assumptions by simulating 2022 so that we could replicate ERCOT's historical generation mix for that year. We then set up a scenario for 2035 as the long-term target year for ERCOT generating capacity additions. We took several steps to adapt the 2035 electricity demand and supply projections from the AEO2023 into the nodal UPLAN model, for example:

- Demand: we applied AEO's load projections to ERCOT's long-term hourly load forecast in order to allocate AEO's ERCOT-wide system load to each of ERCOT's 8 weather zones
- Supply: we identified likely projects from the ERCOT GIS report as a basis for siting projected solar and wind capacity additions similar to the AEO's capacity projections

The AEO models electric load at an aggregated level, based on three representative day-types (weekday, weekend, and peak weekday) for each month, resulting in 72 load segments, instead of 744 hourly load values (for a 31-day month.)

To adapt the AEO2023 projected electricity demand for use in our hourly chronological analysis, we needed to scale the more detailed UPLAN model to match the monthly energy and the monthly peak loads.

Figure 6. *Annual Energy Outlook* versus UPLAN projected 2035 electric load: August 2035



Data Source: Electric Reliability Council of Texas, "2023 Long-Term Hourly Peak Demand and Energy Forecast," January 2023; U.S. Energy Information Administration, National Energy Modeling System (NEMS), Electricity Market Module (EMM)

To accomplish this objective, we took a series of steps. First, we calculated the monthly energy values for the year 2035 from the AEO2023 projections. Next, we divided the monthly energy values into hourly values because our analysis simulated every hour of the year. We relied on ERCOT's 2023 hourly load forecast for the year 2031 to allocate the monthly energy values into hourly values because 2031 was the most distant year in the ERCOT forecast that included a 365-day representation. This approach yielded monthly energy values that were almost exactly equivalent to the AEO monthly values and monthly peak values that precisely matched AEO projections. Figure 6 provides a comparison of the AEO projections and our hourly load forecast for August, sorted from highest load to lowest load. This comparison of load duration curves shows that the August peak hourly loads of the two forecasts match. Although the shapes of the load duration curves vary, the areas below the two lines are almost exactly equivalent. The main difference between these two forecasts is the number of unique loads. Our load forecast includes 744 unique loads, one for each hour in August (24 hours x 31 days) while the AEO2023 projections include 72 unique hours (3 day types x 24 hours= 72).

To identify the location for future capacity additions within our model of the ERCOT transmission system, we analyzed the projects listed in the ERCOT *Generator Interconnection Status* (GIS) report. Although the inventory of planned projects in the GIS report has built up and multiyear project backlogs have developed, the interconnection approval process is a necessary step in managing how future generating capacity is interconnected with the transmission system. The approval process for projects seeking to interconnect into ERCOT's grid includes three major milestones:

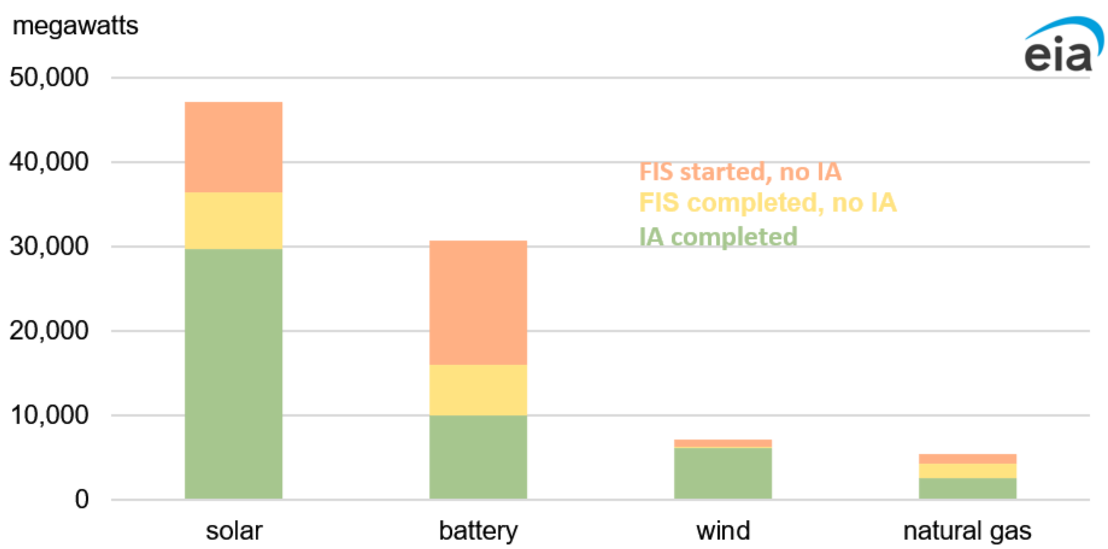
- Security screening (SS)
- Full interconnection study (FIS)
- Interconnection agreement (IA)

Completing a security screening is generally the first step in the process; the interconnection study and interconnection agreement can be carried out at the same time. The projects we identified as most likely to be completed were those that had completed a SS, along with:

- IA Completed
- FIS Completed, No IA
- FIS Started, No IA

Figure 7 shows, we found 54 GW of solar and wind that fell into one of these categories. We modeled these resources at the nodes specified in the GIS report. We assigned each wind and solar project a generation profile outlining its availability for every hour of the year. The profiles are specific to the county in which each project is located.[5]

Figure 7. Likely capacity additions according to ERCOT's *Generator Interconnection Status* report, by status

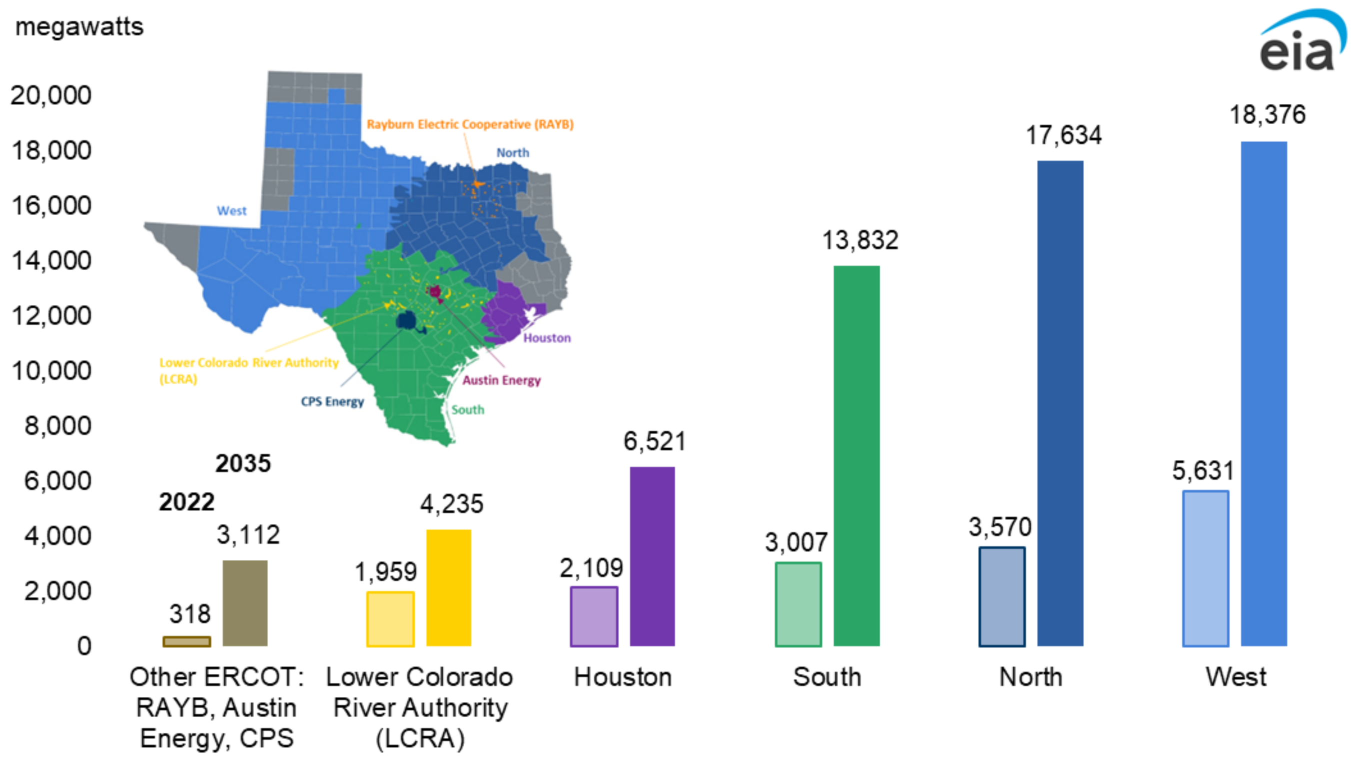


Data source: Electric Reliability Council of Texas (ERCOT), *Generator Interconnection Status* (GIS) report, March 2023

[5] The profiles were developed for ERCOT by UL Laboratories (formerly AWS Windpower.)

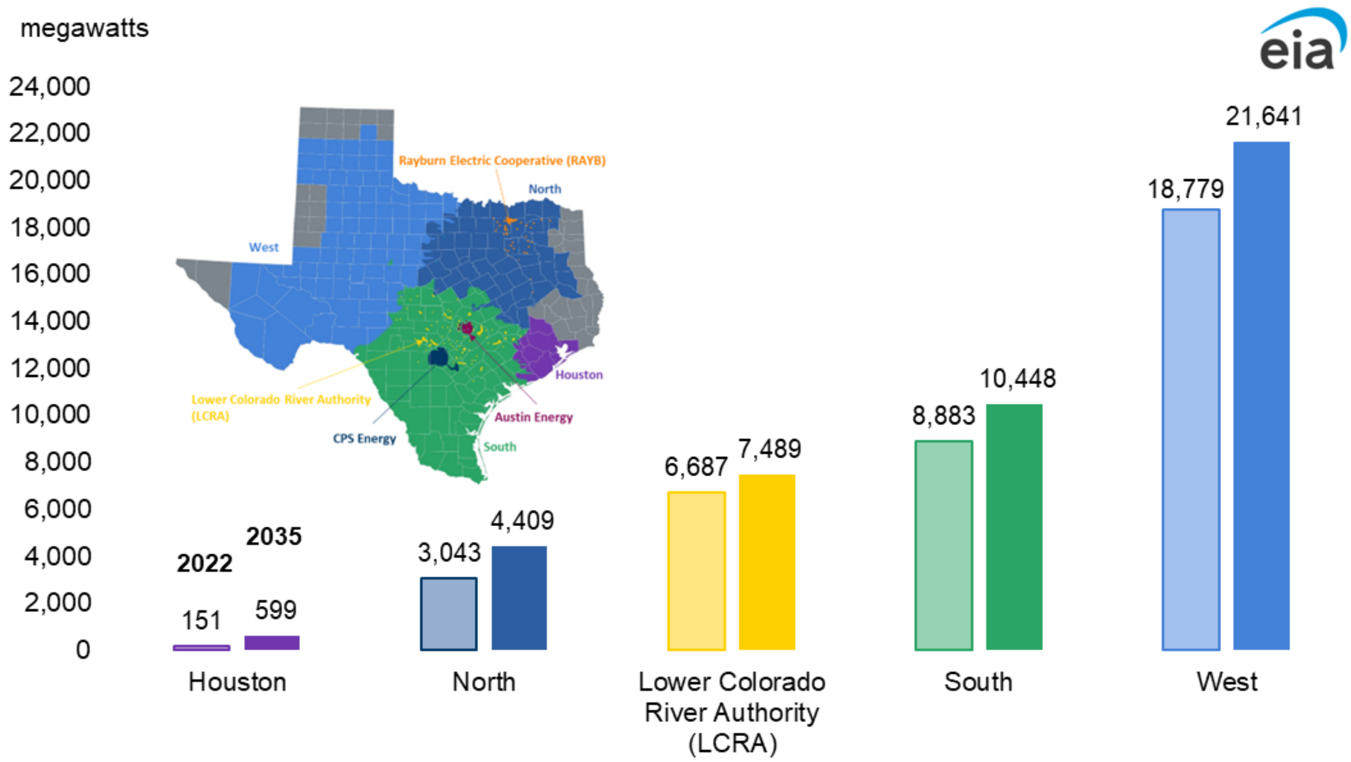
The significant amount of solar capacity that is expected to be added by 2035 is spread across Texas (Figure 8). The largest additions are in West Texas given its greater solar resource, more undeveloped land, and potential for surplus transmission capacity during those hours of the day when wind generation is reduced. In contrast, the relatively moderate increase in wind capacity is not concentrated in any one region and is likely to be built near existing wind projects.

Figure 8. Solar: 2022 existing ERCOT capacity versus projected 2035 capacity additions, by region



Data source: U.S. Energy Information Administration, Form EIA-860M database; Electric Reliability Council of Texas (ERCOT), *Generator Interconnection Status* (GIS) report, March 2023

Figure 9. Wind: 2022 existing ERCOT capacity versus projected 2035 capacity additions, by region



Data source: U.S. Energy Information Administration, Form EIA-860M database; Electric Reliability Council of Texas (ERCOT), *Generator Interconnection Status* (GIS) report, March 2023

To further support consistency with AEO2023, we needed to implement AEO projected capacity additions, retirements, and fuel-conversions for coal generating capacity. We also needed to use AEO-projected delivered cost of coal and natural gas to electric generators (see AEO2023 Reference Case results).

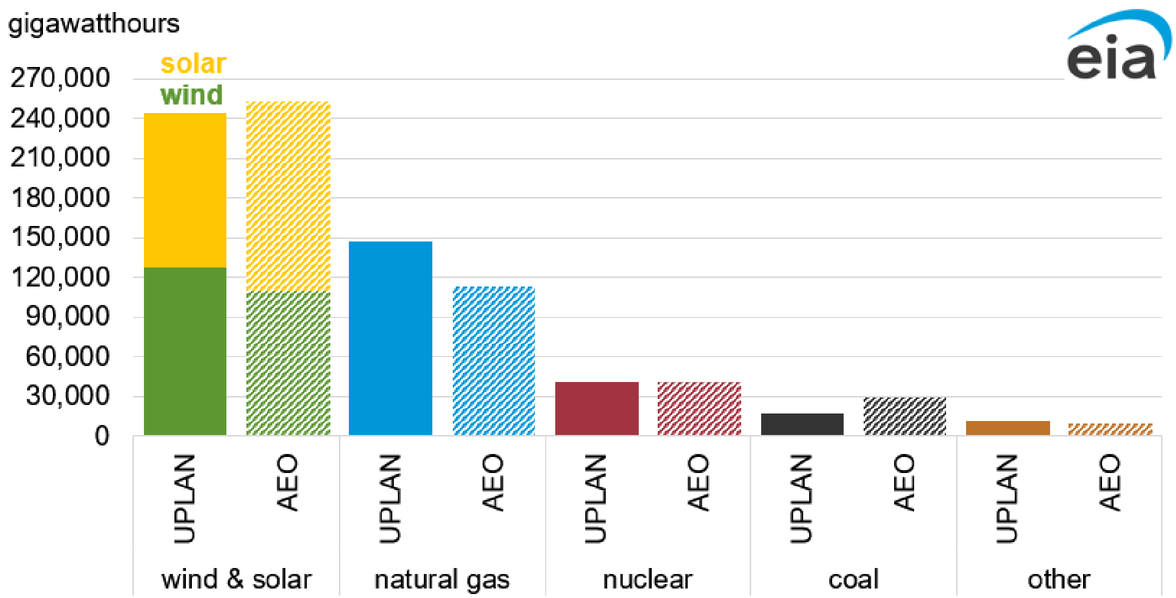
4. Findings

We found that increased variable renewable capacity in 2035 significantly reduced net load to the extent that 19% of the hours of net load are negative (Figure 1), resulting in curtailments due to surplus generation.

While total AEO and UPLAN variable renewable capacity additions are very close, total wind and solar generation, after accounting for curtailed energy, is 9,000 GWh higher in AEO than in UPLAN. The difference in total renewable generation is largely due to different modeling approaches. UPLAN is a production costing model that simulates the flow of electricity across transmission lines from generators to end-users. When available generation is more than what can flow across the transmission lines, some of that generation (in our case from solar and wind) must be curtailed. So these curtailments are quantified in UPLAN.

On the other hand, AEO's modeling approach does not explicitly model the ERCOT transmission grid, so curtailments due to insufficient transmission capacity are not captured. AEO only includes curtailments that occur when renewable resources are curtailed to maintain balance between ERCOT's electricity supply and ERCOT's electricity demand. Since the UPLAN modeling approach captures both types of curtailments, (due to surplus generation and transmission-limits), UPLAN projects less renewable generation than AEO in 2035 even though UPLAN and AEO assume about the same amount of planned renewable capacity in 2035.

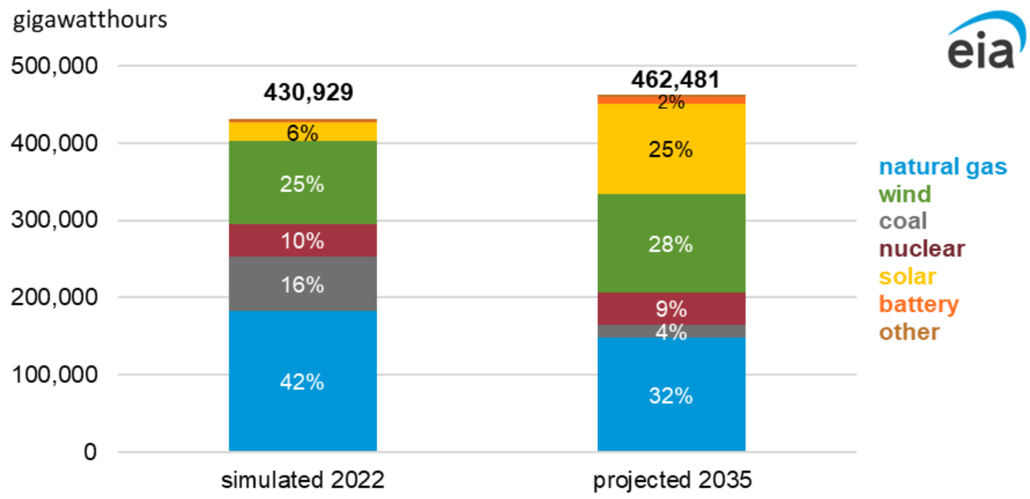
Figure 10. Projected 2035 ERCOT generation by fuel, UPLAN versus AEO2023 Reference case



Data source: U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas (ERCOT) power market; U.S. Energy Information Administration, *Annual Energy Outlook* (AEO) 2023

Total generation in ERCOT rises to 462,500 GWH in 2035, an increase of 7.3% from 2022 (Figure 11). Of that total, combined solar and wind generation rises to 244,000 GWH, or 53% of total generation, compared with a 31% share in 2022. As a result, natural gas generation falls by 60,000 GWH, representing a decline to a 29% share of total generation, compared with 45% in 2022 (Figure 12). The decline in natural gas generation is most pronounced during the daylight hours when solar resources are available. The share of generation from coal falls from 17% in 2022 to 4% in 2035, primarily as a result of the retirement of half of the current fleet's capacity.

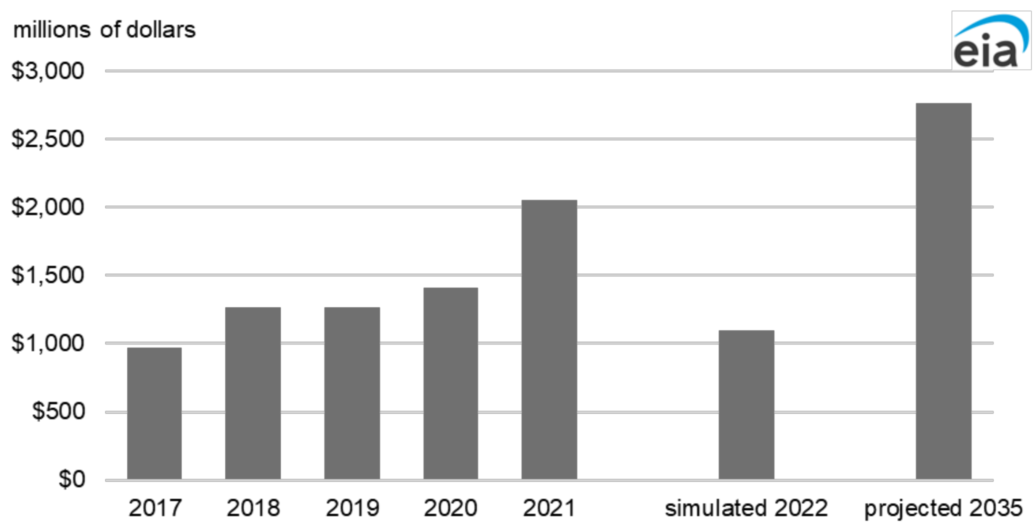
Figure 11. Summary of results: generation by energy source, simulated 2022 versus projected 2035



Data source: U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas (ERCOT) power market

Most of the generators in ERCOT rely on the ERCOT electrical transmission system to transport electricity to the demand areas. Periodically, the transmission capacity limits the flow of generation from lower-cost resource areas, and higher-cost resources are then dispatched. The cost of not having enough transmission capacity to move electricity from the lower-cost resource areas to the demand areas is represented by the system's congestion cost. Congestion costs in ERCOT's real-time market have ranged from $1.26 billion in 2019 to $2.1 billion in 2021, (Figure 12). Winter Storm Uri contributed to the jump in 2021's congestion costs. Our analysis indicates that congestion costs may top $2.8 billion in 2035 given our assumptions for load growth, new resources, and minimal transmission upgrades.

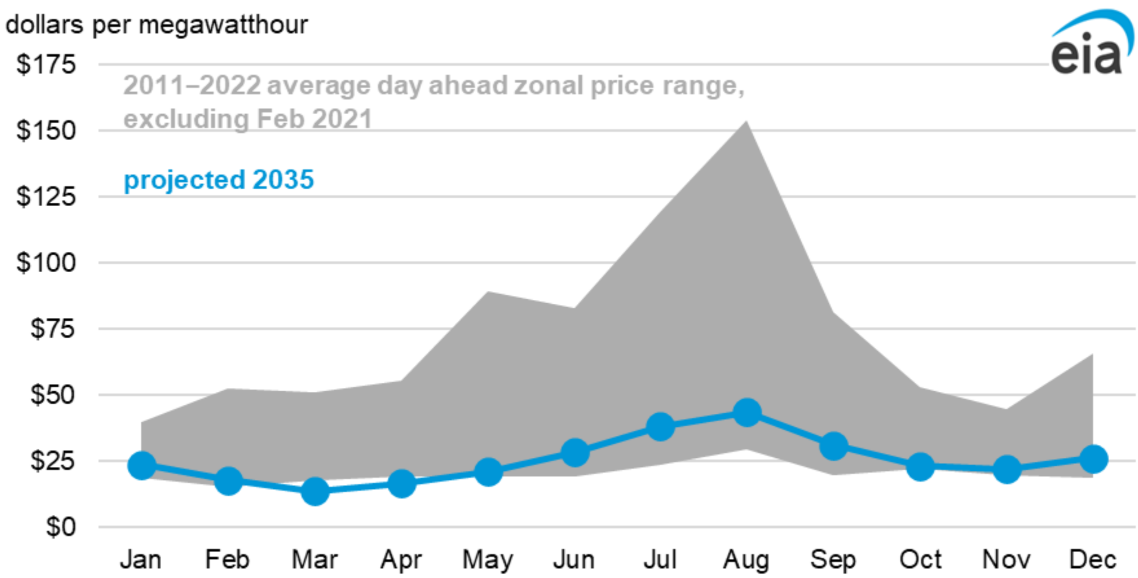
Figure 12. Annual congestion cost, reported 2017–2021 and projected 2035



Data source: Potomac Economics, "2019 State of the Market Report for the ERCOT Electricity Market," May 2020, "2021 State of the Market Report for the ERCOT Electricity Markets", May 2022 and U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas (ERCOT) power market

Our analysis indicates that when wind and solar resources comprise a larger share of the resource mix, energy prices fall, even without government subsidies. This outcome occurs because fuel costs generally make up a significant component of energy prices, and wind and solar resources have no fuel costs. Figure 13 shows how our projection of average monthly prices for 2035—the blue line—rests either below or in the lower section of the historical range of prices from 2011 to 2022—the gray area.

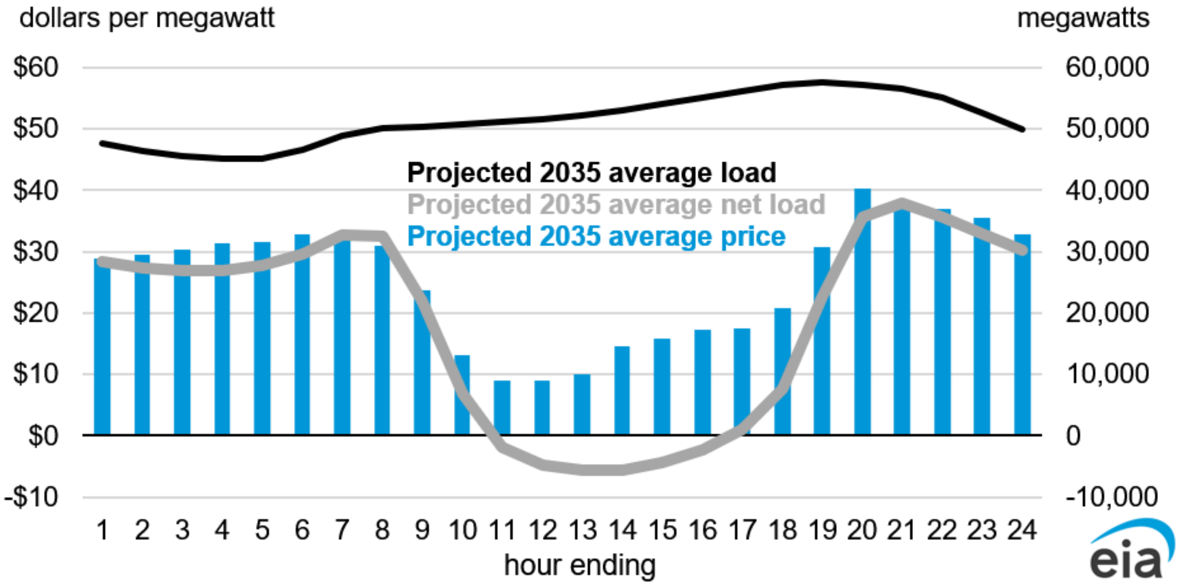
Figure 13. ERCOT actual day ahead average hub price versus projected 2035 price



Data source: ERCOT historical DAM load zone and hub prices, 2011-2022, 4 zone average (LZ_HOUSTON, LZ_NORTH, LZ_SOUTH and LZ_WEST) and U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas (ERCOT) power market, 4 zone average (LZ_HOUSTON, LZ_NORTH, LZ_SOUTH and LZ_WEST)

The 2035 daily energy price pattern moves less with the system-wide load and more with net load, which is the system-wide load less available wind and solar generation. Figure 14 depicts average system load, system net load, and prices for each hour. Although the ERCOT system load shows a steady increase in demand from Hour 7 to Hour 19, the net load dives downward beginning in Hour 9, falls below zero in the afternoon, and then quickly rises and peaks at Hour 21. Hourly prices also decline during the late morning and early afternoon hours and rise as the net load increases.

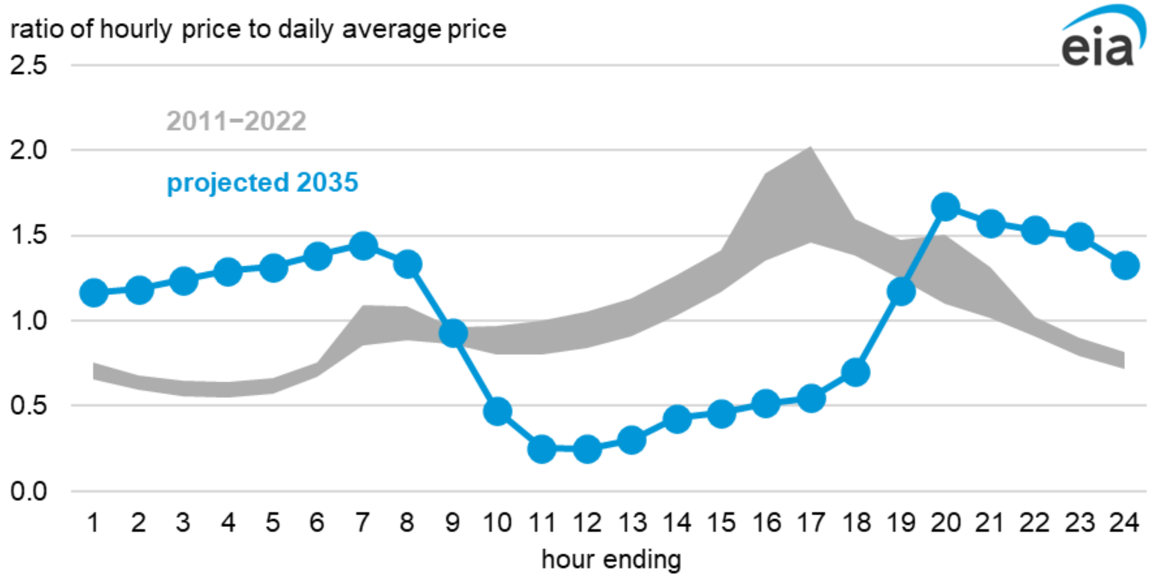
Figure 14. Projected ERCOT 2035 system load, system net load and energy daily price profile



Data source: U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas (ERCOT) power market

The daily energy pattern in 2035 differs from recent price patterns. Figure 15 compares daily price patterns. The relationship between the hourly price and daily price, across each hour, is plotted for historical years and 2035. All values greater than one indicate an hourly price that is greater than the average daily price, and values less than one indicate an hourly price that is less than the average daily price. A comparison of the profiles indicates a shift in the peak price hour, from Hour 17 to Hour 20, when net demand is higher. In addition, the price dip that occurs between the morning peak and evening peak is deeper and wider in 2035 than in recent years. Another significant change occurs in the low-priced time periods. Historical prices have low prices during the current off-peak hours, Hours 1–6 and Hours 23–24. In 2035, prices during these hours are expected to be higher than the midday prices.

Figure 15. Normalized daily ERCOT system energy price profile, 2011–2022 and projected 2035



Data source: ERCOT historical DAM load zone and hub prices, 2011–2022, 4 zone average (LZ_HOUSTON, LZ_NORTH, LZ_SOUTH and LZ_WEST) U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas (ERCOT) power market;

Figure 16 shows the percentage of hours during which energy prices are $0/MWh or lower by month and hour for the simulated 2022 case and the projected 2035 case. In our simulated 2022 case, hours with $0/MWh or lower prices occur no more than 18% of the hours. In 2035, however, many hours have $0/MWh or lower prices exceeding 18%. In fact, during the peak solar generation, Hours 11 through 13, in March, when electricity demand is also typically low, energy prices were $0/MWh or lower for more than 90% of the hours.

Up until 2010, ERCOT had set daily operating limits for wind generation due to the structure of its power market and transmission protocols. The advent of ERCOT's nodal market reduced the share of annual wind generation that was curtailed from 17% in 2009 to just 1% annually between 2013 and 2015. However, as wind capacity has continued increasing since then, the amount curtailed has risen to a 5% share in 2022. We project wind curtailments in 2035 to return to near historic levels (Figure 17).

Figure 16. Projected percentage of zero price hours in ERCOT, 2022 and 2035

Simulated 2022 (percentage of hours when prices are $0/MWh or lower)

Month	Hour																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	2	1	0	0	0	0	0	0
Feb	3	3	4	4	4	0	0	0	1	1	3	3	5	13	15	16	13	10	2	0	1	0	0	1
Mar	1	2	5	2	1	4	2	1	0	3	2	4	4	6	6	6	6	2	1	0	0	0	0	0
Apr	8	18	12	17	11	8	3	3	4	4	3	5	4	3	2	1	3	1	1	0	0	0	3	3
May	3	7	6	10	7	5	3	6	10	5	8	1	2	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	3	13	13	7	7	3	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	10	10	13	6	3	0	0	0	0	1	1	1	1	1	0	1	0	1	0	0	0	0	0	0
Nov	0	1	3	1	1	3	1	1	0	1	1	1	1	1	4	3	1	1	0	0	0	0	0	0
Dec	4	1	1	1	0	0	0	0	0	0	1	1	6	9	9	10	8	5	0	3	3	3	3	3

Projected 2035 (percentage of hours when prices are $0/MWh or lower)

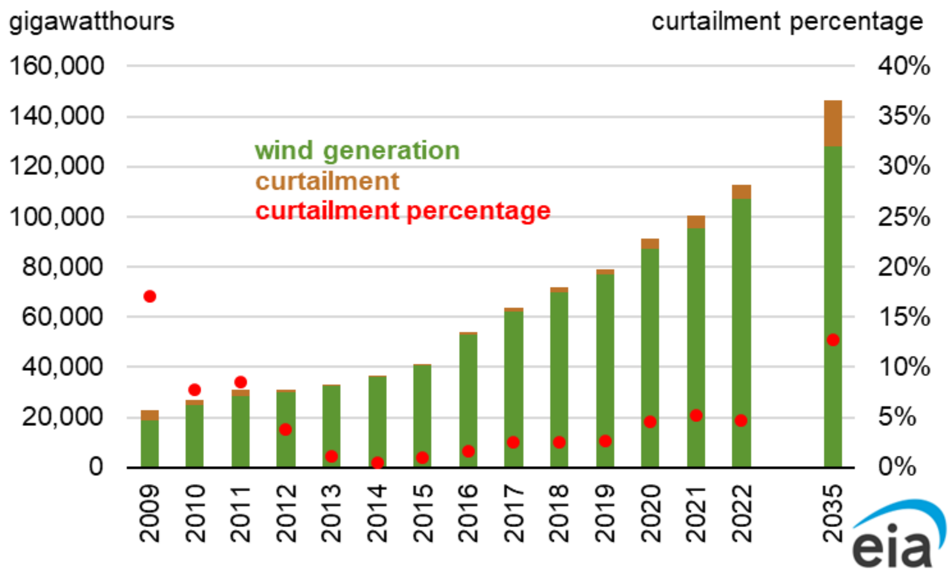
Month	Hour																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	3	6	3	0	0	0	0	0	0	3	47	49	36	35	44	37	31	7	1	0	0	0	0	3
Feb	7	9	5	4	4	0	0	0	3	38	71	79	86	90	90	81	77	63	4	0	0	0	0	4
Mar	11	17	16	16	10	8	3	0	22	60	92	90	93	87	85	83	89	90	44	0	6	6	15	13
Apr	8	3	7	3	10	4	1	3	43	72	93	74	73	60	63	59	58	59	50	1	0	0	1	3
May	0	0	0	0	0	0	0	0	35	73	78	79	74	74	60	61	57	47	19	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	19	61	57	30	18	10	8	8	7	6	3	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	15	13	11	3	2	1	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	28	31	11	1	1	0	1	0	0	0	0	0	0	0	1
Sep	0	0	0	0	0	0	0	0	0	17	19	16	7	11	16	19	14	2	0	0	0	0	0	0
Oct	0	0	0	1	0	0	0	0	0	52	52	55	44	35	33	20	33	15	0	0	0	0	0	0
Nov	0	3	8	8	7	3	0	0	1	24	56	62	56	49	40	37	18	4	0	0	0	0	0	1
Dec	0	0	0	0	0	0	0	0	0	6	33	64	41	31	36	30	21	0	0	0	0	0	0	0

Data source: U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas (ERCOT) power market

Note: The curtailment percentage provides an indication of how much more renewable energy could have been produced. The curtailment percentage is the amount of renewable energy that was curtailed divided by the total amount of renewable energy that could have been delivered to the grid had there been no curtailments.
MWh=megawatthour

The large-scale deployment of solar PV is a more recent development in Texas, but capacity is growing rapidly. In the mid-2010s, less than 2% of ERCOT's solar generation was curtailed. By 2022, that share had reached 9%. As a result of the major growth in solar generation through 2035, we project curtailments to rise to 19%, exceeding wind curtailment levels (Figure 18).

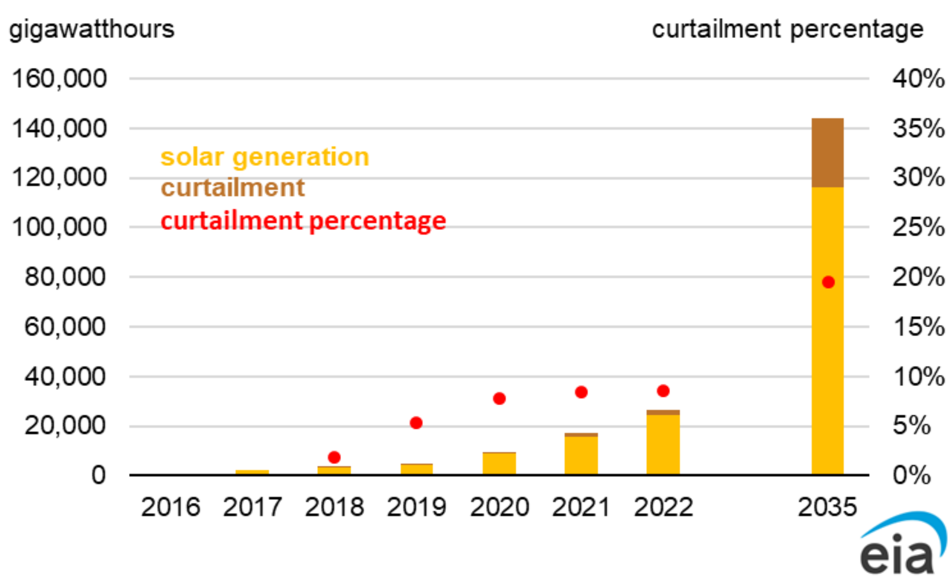
Figure 17. Historical 2009–2022 and projected 2035 wind generation and curtailment



Data source: Potomac Economics, “2019 and 2022 State of the Market Report for the ERCOT Electricity Market,” May 2020 & May 2023; U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas power market

Note: The curtailment percentage provides an indication of how much more renewable energy could have been produced. The curtailment percentage is the amount of renewable energy that was curtailed divided by the total amount of renewable energy that could have been delivered to the grid had there been no curtailments.

Figure 18. Historical 2016–2022 and projected 2035 solar generation and curtailment

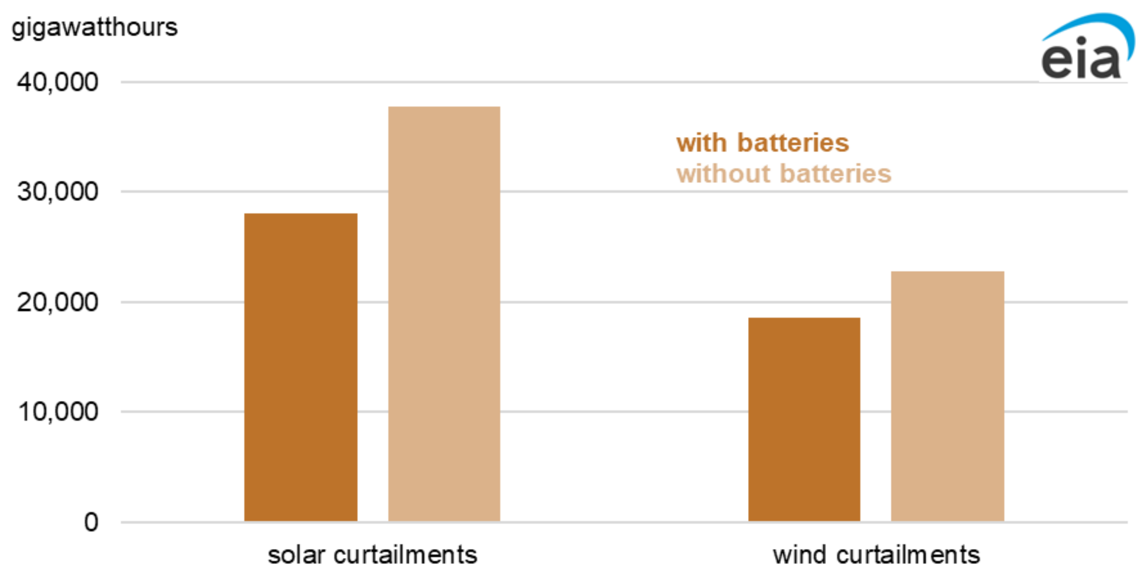


Data source: Potomac Economics, “2022 State of the Market Report for the ERCOT Electricity Market,” May 2023; U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas power market

Our projected 2035 portfolio included 30 GW of 4-hour duration batteries. These batteries provide both ancillary services and energy to the grid. After discharging, batteries need to recharge using generation from other resources. Because the energy required to charge a battery is greater than the energy a battery can discharge, batteries need to be able to charge when electricity prices are low and discharge when electricity prices are high in order for batteries to recover their costs. Batteries can also generate revenue through providing ancillary services and resource adequacy capacity.

In addition, the greater the price difference between the time of discharge and the time of charging, the greater the net income for batteries. Since electricity prices are typically lower when there are renewable curtailments, battery charging often takes place during the same hours as renewable curtailments. In fact, our analysis showed that 80% of the battery charging took place during hours of renewable curtailments. In addition, had batteries not been part of the portfolio, 34%, solar curtailments would have increased from 19% to 26% or 28,112 GWh to 37,799 GWh, while wind curtailments would have increased from 13% to 16% or 18,566 GWh to 22,845 GWh (Figure 19).

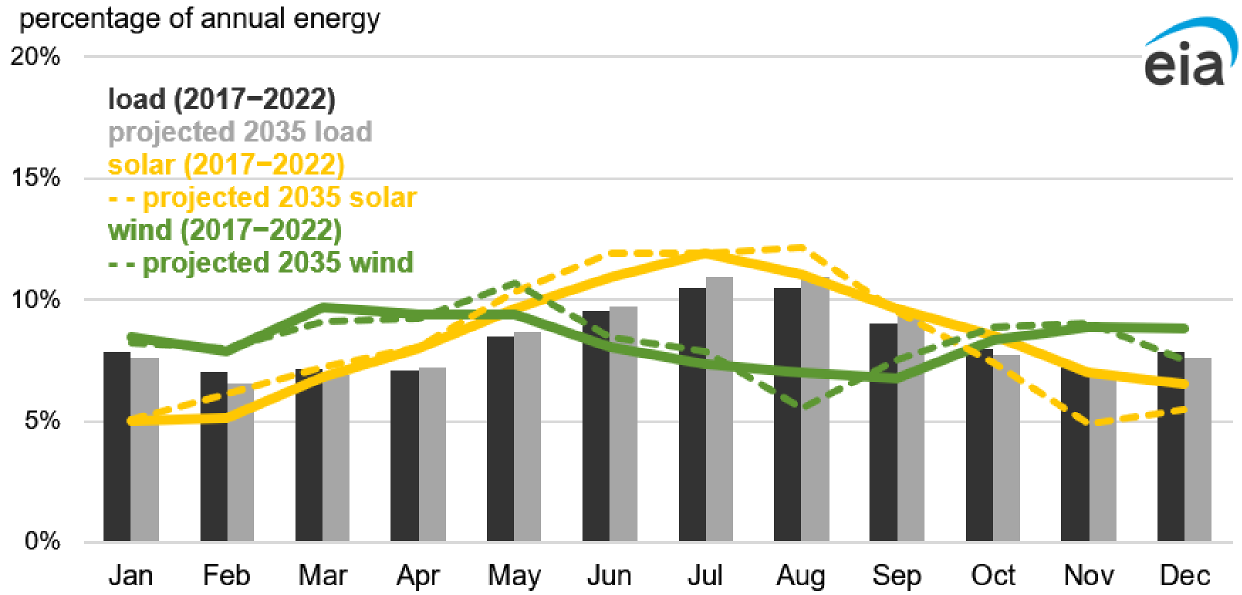
Figure 19. Projected 2035 wind and solar curtailments with and without battery storage included in our case study



Data source: U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas power market

Solar generation follows a pattern that is similar to load in that it is highest in the summer months, unlike wind generation, which dips during the summer (Figure 20). These patterns still exist in 2035 and provide insight into the pattern of wind and solar curtailments.

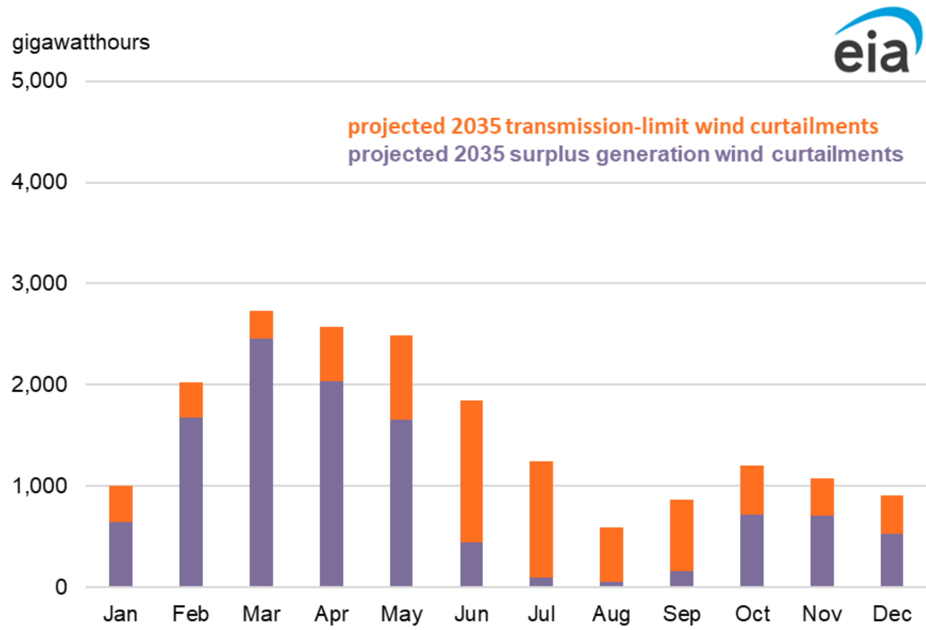
Figure 20. Historical 2017–2022 and projected 2035 share of load and solar and wind generation in ERCOT by month



Data source: ERCOT Fuel Mix Report, 2017–2022 and ERCOT Hourly Load Data Archives, 2017–2022

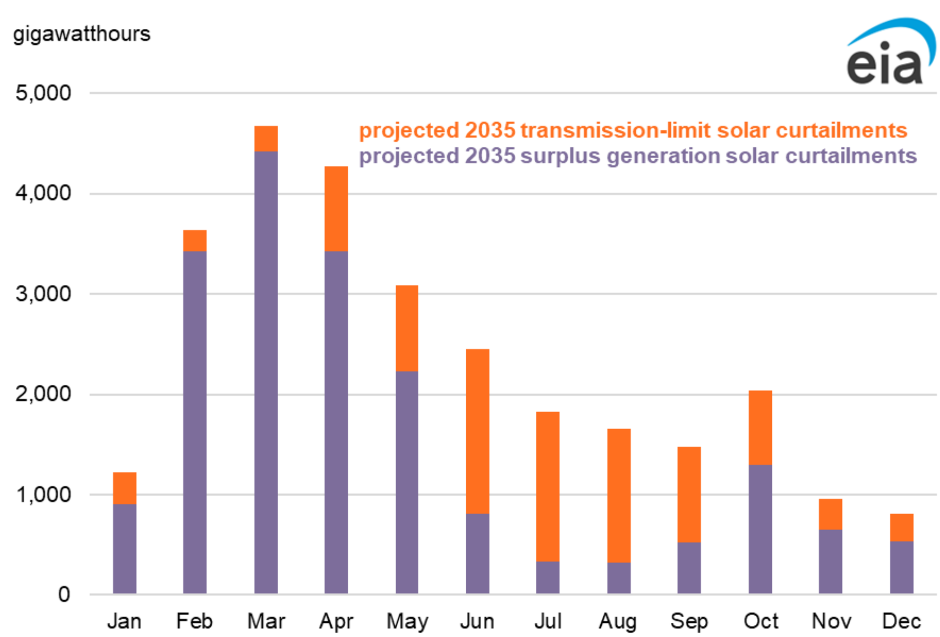
Monthly ERCOT energy demand is typically lowest from February through April, which is also the time of year when wind generation is relatively high and solar generation is starting to pick up. This imbalance results in the most wind curtailments (Figure 21) and solar curtailments (Figure22). ERCOT energy demand increases in the summer months and curtailments decrease, even while solar generation is increasing. The causes of curtailments follow a similar pattern. From February through April, when energy demand is lower than in other months, most of the curtailments are due to surplus generation. In the summer, when energy demand is higher, the transmission system cannot carry all of the available wind and solar generation, thus transmission system limitations cause most of the summer curtailments.

Figure 21. Projected 2035 wind curtailments: transmission-limit versus surplus generation



Data source: U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas power market

Figure 22. Projected 2035 solar curtailments: transmission-limit versus surplus generation



Data source: U.S. Energy Information Administration, UPLAN model simulation of the Electric Reliability Council of Texas power market

In this analysis we have quantified the contribution to renewable generation curtailments from two sources: surplus generation and transmission capacity limits. Understanding the source of the renewable curtailments is key to developing a long-term plan that not only includes renewable capacity, but one that seeks to maximize the value of renewable assets to the grid by investing in curtailment mitigation to support load-shifting programs or assets, ranging from "time-of-use" pricing to utility scale batteries.