2022 Long-Term System Assessment for the ERCOT Region

December 2022

Executive Summary

Section 39.904(k) of the Public Utility Regulatory Act (PURA) requires that the Public Utility Commission of Texas (PUCT) and Electric Reliability Council of Texas, Inc. (ERCOT) study the need for increased transmission and generation capacity and report such needs to the Texas Legislature. A report documenting this study must be filed with the Legislature by December 31 of each even-numbered year.

By definition, the bulk transmission network within ERCOT consists of the 60-kilovolt (kV) and higher transmission lines and associated equipment. In planning for both additions and upgrades to this infrastructure, ERCOT conducts a variety of forward-looking reviews to help ensure continued system reliability and efficiency.

ERCOT's planning process covers several time horizons to identify and endorse new transmission investments. The near-term needs are assessed in the six-year planning horizon through the development of the Regional Transmission Plan (RTP). The Long-Term System Assessment (LTSA) provides an evaluation of the potential needs of ERCOT's extra-high voltage (345-kV) system in the 10- to 15-year planning horizon.

The LTSA guides the six-year planning process by providing a longer-term view of system reliability and economic needs. While a small transmission improvement may appear to be sufficient in the six-year planning horizon, the longer LTSA planning horizon may reveal that a more extensive project could be required. A larger project may also be more cost-effective than multiple smaller projects - each being recommended in successive RTPs.

ERCOT studies different scenarios in its long-term planning process to account for the inherent uncertainty of planning the system beyond six years. The goal of using scenarios in the LTSA is to identify upgrades that are robust across a range of scenarios or more economical than the upgrades that would be determined if considering only near-term needs.

At the time of this analysis, ERCOT's economic criteria for project evaluation was pending. As a result, potential economically driven transmission improvements were not evaluated in the 2022 LTSA.

The following set of future scenarios was developed considering stakeholder feedback received via survey and at Regional Planning Group (RPG) meetings:

- Current Trends
- Expanded System Outlook
- Demand Side Evolution

The 2022 LTSA also included a sensitivity for the Demand Side Evolution scenario with a few modified assumptions based on stakeholder feedback.

Using the assumptions and guidelines in the scenario descriptions, ERCOT prepared different demand forecasts.

Planning for transmission 10 and 15 years into the future requires ERCOT to make assumptions regarding what types of new resources can be developed. ERCOT conducted capacity-expansion and retirement analysis[1] for the three future scenarios using the guidelines in the scenario descriptions. ERCOT also conducted transmission congestion analysis for the Current Trends scenario.

Based on the results of the 2022 LTSA, ERCOT identified the following key findings:

- Significant growth of inverter-based resources (IBR) and more advanced natural gas generation with higher efficiencies than today's conventional generation technology was observed across all three scenarios.
- Growth in renewable resources and electric vehicle adoption led to a shift in scarcity hours to later in the day, similar to previous LTSAs, and also a gradual shift in scarcity hours from primarily in the summer season to the winter season.
- Annual capacity factors for conventional generators were significantly higher in the Demand Side Evolution scenario compared with the Current Trends and Expanded System Outlook scenarios.
- Transmission challenges were identified for both the export from the renewable resource-rich region and the import into the demand centers.

In all three scenarios, a mix of IBR and natural gas generation was added to the system to serve the growing demand and replace retired capacity. Wind and natural gas generation additions represented the two largest resource capacity changes on the system for the three scenarios. As seen in Figure 1 below, total wind generation capacity additions ranged from 13,700 MW to 27,100 MW in the three scenarios. Total natural gas generation capacity additions ranged from 19,968 MW to 30,324 MW across the scenarios. Conversely, close to 20,000 MW of existing coal and natural gas generation capacity was retired by 2037 in all scenarios. The capacity-expansion and retirement analysis also accelerated some fixed age retirements based on economics, and the timing of specific unit retirements prior to 2037 were different across the scenarios.

[1] This analysis was conducted using the Aurora forecasting model, licensed by Energy Exemplar.

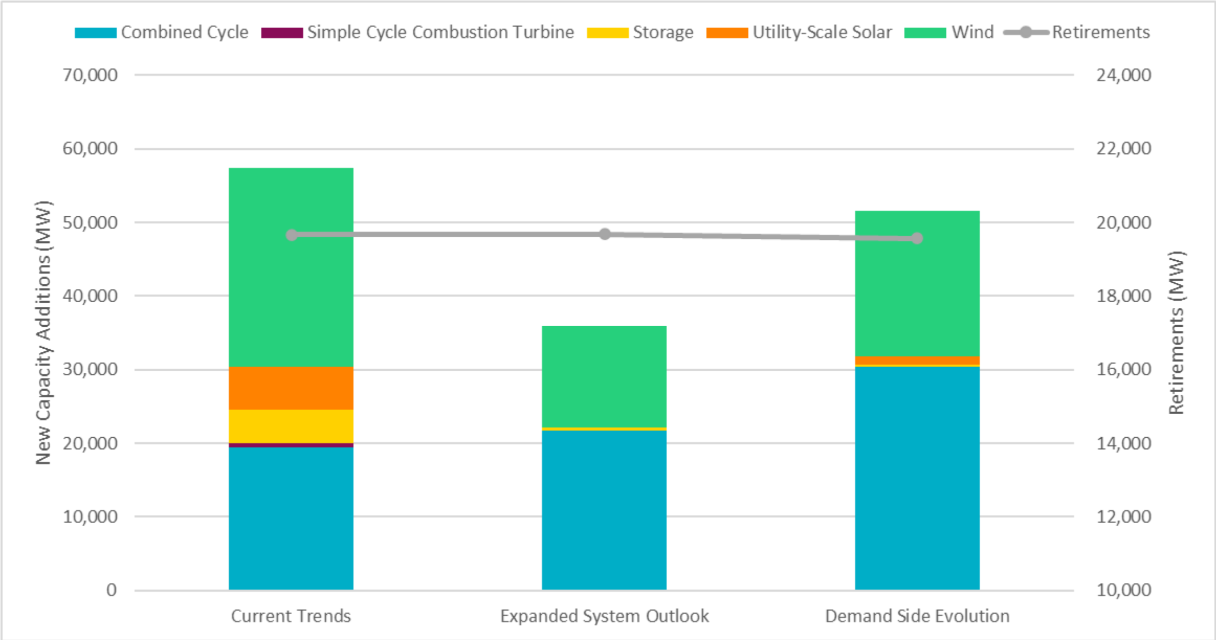

Figure 1: New Capacity Additions Across All Scenarios

Retired coal and natural gas generation was replaced by solar, wind, and new natural gas generation, and battery energy storage. The share of demand served by wind and solar generation increased in each of the three scenarios studied. These results indicate the possibility that there may be hours when demand could theoretically be served entirely by wind and solar resources. Thermal and stability constraints on the transmission system, as well as operational considerations such as ramping limitations and maintaining a minimum level of system inertia, will need to be assessed further to ensure reliability under high renewable penetration.

The study results also showed a shift in scarcity hours to later in the day in the Current Trends and Expanded System Outlook scenarios, similar to findings from previous LTSAs, while the Demand Side Evolution scenario did not have any scarcity hours. The gradual shift of scarcity hours from primarily in the summer season to the winter season was also observed in the 2022 LTSA. While scarcity hours in 2027 mostly happened in summer, more than half of the scarcity hours in 2032, and almost all scarcity hours in 2037, occurred in winter. The shift of the scarcity hours was driven primarily by an assumed increase in electric vehicle adoption rates and the amount of new solar generation in the resource mix. As renewable penetration on the ERCOT system continues to increase, possible system conditions during high net load hours (customer demand minus aggregate wind and solar output) need to be included in planning studies.

The Demand Side Evolution scenario observed significantly higher annual capacity factors for the conventional generators compared with the Current Trends and Expanded System Outlook scenarios. The scenario incorporated 16 GW of price responsive Large Flexible Load (LFL)[2] based on stakeholder feedback from an informal survey in early 2022. The LFL was expected to remain flat and only ramp

[2] LFLs are currently defined as Loads at least 20 MW in size directly connected to Generation Resources, or standalone Loads at least 75 MW in size, that plan to reach the maximum size within two years. The vast majority of LFLs (both in operation and undergoing interconnection study) are bitcoin mining facilities. https://www.ercot.com/services/comm/mkt_notices/detail?id=fc84b65f-72fe-4704-9974-b52974cdb81e

down when the market price exceeded the assumed strike price. In addition, more aggressive Electrical vehicle (EV) adoption together with managed EV charging were assumed in the scenario. The concept of managed EV charging was to mitigate the potential load impact of EV charging with the assumption that EV charging would happen during renewable-abundant hours when non-EV load was not high, which resulted in more charging activities in late-evening and early-morning hours. To serve the LFL throughout the day and EV charging load during the late evening and early morning hours, the annual capacity factors for the conventional generators increased significantly compared with the Current Trends and Expanded System Outlook scenarios. The capacity factor increase was most significant for natural gas generation, especially combustion turbine generation, due to their operational flexibility and availability to meet the load during the hours with lower renewable output.

Similar to findings from the 2020 LTSA[3], significant congestion was observed on the West Texas export interface, which measures the export of the renewable generation out of the resource-rich region in the west part of the system. Significant congestion was also observed on the paths into demand centers such as Dallas-Fort Worth and Houston. The areas with the most congestion during 2037 are shown in Figure 2 below.

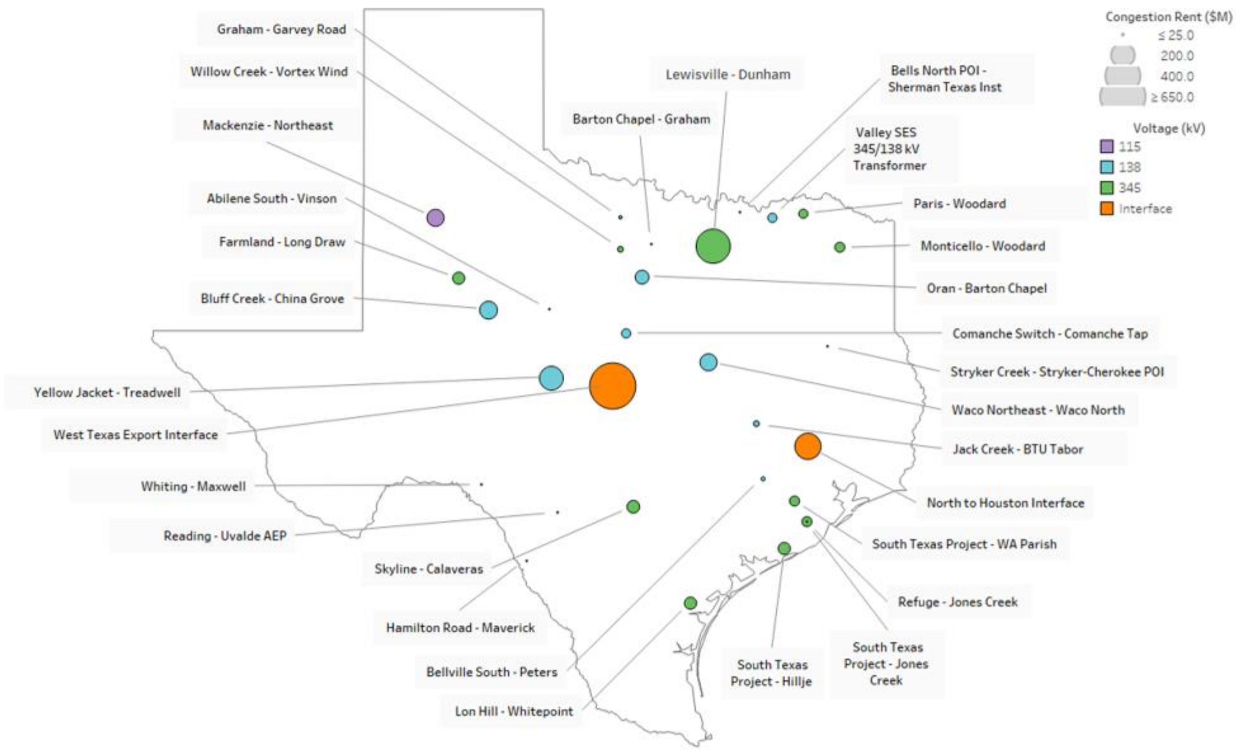

Figure 2: Top Congestion Areas for the Current Trends Scenario in 2037

[3] https://www.ercot.com/files/docs/2020/12/23/2020_LTSA_Report.zip

Chapter 1. Introduction

ERCOT manages the flow of electric power to more than 26 million Texas customers—representing about 90 percent of the state's electric demand. ERCOT schedules power on an electric grid that connects more than 52,700 miles of transmission lines and more than 1030 generation units.

As part of its responsibility to adequately plan the transmission system, ERCOT must develop a biennial assessment of needed transmission infrastructure. PURA § 39.904(k) requires the PUCT and ERCOT to study the need for increased transmission and generation capacity throughout the state of Texas and report to the Legislature the results of the study and any recommendations for legislation. The report must be filed with the Legislature no later than December 31 of each even-numbered year. ERCOT has developed this 2022 Long-Term System Assessment (LTSA) in satisfaction of that requirement.

This LTSA includes analysis of system needs for the long-term, 10- to 15-year planning horizon and is designed to guide near-term transmission planning decisions. Given the long-term nature of the LTSA study horizon, the findings and observations from the LTSA are based on analysis of multiple scenarios. Such scenarios are developed by collaboration among ERCOT and stakeholders and are based on projections of certain key assumptions. The LTSA projections - specifically: demand, generation, and transmission expansion plans - are outcomes of these scenario-specific studies. These projections should not be considered ERCOT's official forecasts for the long-term horizon.

The findings and observations from the LTSA are intended to provide information for ERCOT stakeholders and policymakers to consider in their decision-making, and are based upon complex analysis of multiple possible, but not necessarily probable, futures. Key limitations of the 2022 LTSA analysis should also be considered by interested parties, including the following:

- Hourly simulations used for economic analysis in both capacity-expansion and transmission expansion studies may not fully capture the intra-hour revenue and potential benefits of resources. Conducting intra-hour simulations was not feasible for the 2022 LTSA.
- The hourly wind and solar generation profiles used in the capacity-expansion analysis do not fully capture all of the considerations used by developers when selecting generation sites.
- While the scenarios selected are meant to investigate the boundaries of potential futures, they do not represent the entirety of possible future outcomes. Future conditions may deviate from those studied in the 2022 LTSA.
- The Demand Side Evolution scenario included in the 2022 LTSA analysis may not be fully representative of increasingly complex and evolving customer behavior. As such, it should be considered a starting point for evaluating the increased adoption of demand-side technologies, increased flexibility of certain types of demand, and their significant impact on the ERCOT system.

Chapter 2. LTSA Process

The process of planning a reliable and efficient transmission system for the ERCOT region is composed of several complementary activities and studies. The ERCOT-administered system planning activities comprise near-term studies, including the RTP and Regional Planning Group (RPG) projects, and ongoing, long-range studies, which are documented in the LTSA. In addition to these activities, transmission service providers (TSPs) conduct analyses of local transmission needs. Those TSP analyses are supplemental to the ERCOT planning process.

The LTSA guides the near-term planning horizon (RTP) through scenario-based assessment of divergent future outcomes. As future study assumptions become more certain, the RTP supports actionable plans to meet near-term economic- and reliability-driven system needs. In support of stakeholder-identified or ERCOT-assessed projects, the RPG review process leads to the endorsement of individual projects that maintain reliability or increase system efficiency. Collectively, these activities create a robust planning process to ensure the reliability and efficiency of the ERCOT transmission system for the foreseeable future.

The LTSA is a composite study made up of various processes and analyses such as scenario development, demand forecasting, capacity-expansion and retirement analysis, and transmission expansion analysis. ERCOT uses a scenario-based approach to perform the LTSA. The purpose of the scenario-based approach is to provide a structured format for stakeholders and ERCOT to identify the most critical trends, drivers, and uncertainties over a ten- to fifteen-year period. Scenarios developed in collaboration with stakeholders provided high-level guidelines for preparing cases to be used in the LTSA. The scenario descriptions were converted to modeling assumptions using available reference data. In addition, for each scenario, a scenario-specific demand forecast was created using inputs from the scenario descriptions.

The demand forecast and other scenario-specific generation input assumptions such as capital costs, operations and maintenance costs, emission costs, etc. were used to create each capacity-expansion and retirement plan. These plans describe the total amount of generation additions by technology. The plans also identify any retirements required as a result of the scenario assumptions. The generation additions were later added to transmission study models using the generation siting process as documented in the generation siting methodology.[4] The LTSA culminated in a transmission expansion analysis which involved evaluating the potential needs for the ERCOT grid under different demand and generation assumptions as developed during the demand-forecasting and capacity-expansion and retirement-planning stages. Figure 3 below provides a simplified depiction of the LTSA process. A detailed description of analyses and studies that went into the LTSA can be found in Appendix I.

[4] The LTSA Generation Siting Methodology is described in Appendix II.

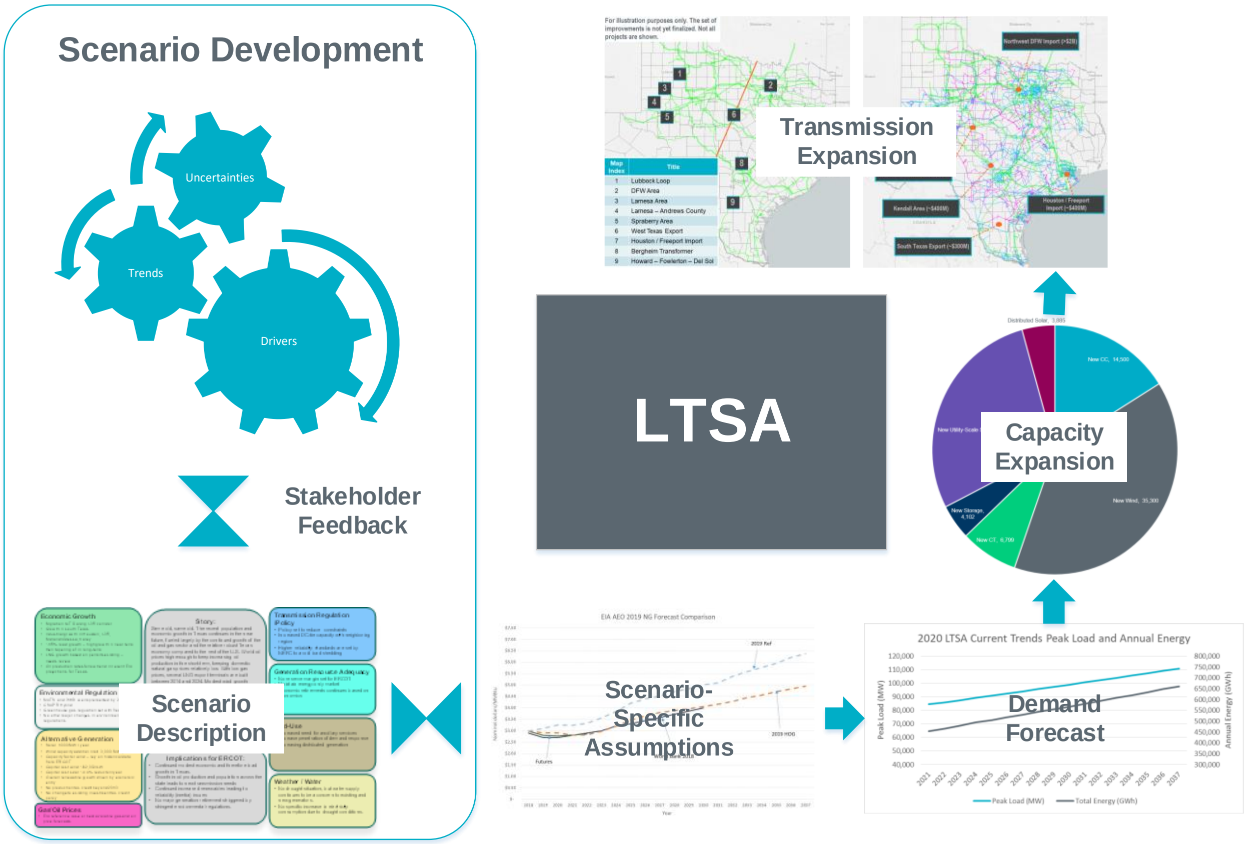

Figure 3: 2022 Long-Term System Assessment Process

Three scenarios were included in the 2022 LTSA. Table 1 provides a summary of each scenario.

Table 1: Scenarios Developed for the 2022 LTSA

Scenario	Description
Current Trends	The Current Trends scenario was designed to study a future trajectory consistent with what is known and knowable today (e.g., demand growth, economic trends, fuel prices, etc.). Similar to the 2020 LTSA, electric vehicle adoption assumptions were included in the demand forecast.
Expanded System Outlook	The Expanded System Outlook scenario included additional resources from the interconnection process, i.e., all the resources included in the December 2021 Capacity, Demand and Reserves (CDR) report. This scenario is designed to help overcome challenges with under-selection of some resource types (i.e., batteries and solar) and potential better correlation with the Generator Interconnection Status (GIS) report and CDR report in terms of both resource mix and siting.
Demand Side Evolution	The Demand Side Evolution scenario was developed to study the impacts of the integration of large amounts of LFL, high rooftop solar adoption, high EV adoption, and managed EV charging. A sensitivity analysis was also performed by imposing buildout limitations on advanced natural gas generators and utilizing tiered strike prices for the LFLs' price responses.

Chapter 3. Key Findings

The 2022 LTSA includes a study of three different scenarios. Key findings from the study include:

1. Significant growth of inverter-based resources (IBR) and more advanced natural gas generation with higher efficiencies than today's conventional generation technology was observed across all three scenarios.
2. Growth in renewable resources and electric vehicle adoption led to a shift in scarcity hours to later in the day, similar to previous LTSAs, and also a gradual shift of scarcity hours from primarily in the summer season to the winter season.
3. Annual capacity factors for conventional generators were significantly higher in the Demand Side Evolution scenario and sensitivity compared with the Current Trends and Expanded System Outlook scenarios.
4. Transmission challenges were identified for both the export from the renewable resource-rich region and the import into the demand centers.

Key Finding 1: Significant growth of inverter-based resources (IBR) and advanced natural gas generation with higher efficiencies than today's conventional generation technology was observed across all three scenarios.

The capacity-expansion analysis found that retired coal and natural gas generation was replaced by wind, solar, battery energy storage, and more advanced high-efficiency natural gas generation technologies. The total installed capacities of IBR and more efficient natural gas generation increased in all scenarios. These findings are generally consistent with the results from the 2020 LTSA, but less new capacity was added in the 2022 LTSA.

The primary reason that less new capacity was added in the 2022 LTSA compared with the 2020 LTSA was the lower demand forecast. The peak demand forecast for 2035 was close to 95 GW in 2022 LTSA, which was about 11.6 GW or 11% lower compared to the 2020 LTSA. The 2022 LTSA used the ERCOT 2021 Long-Term load forecast, which was the most up to date forecast at the time of the analysis. The decrease in load forecast was influenced by pandemic-related assumptions that may no longer be applicable. The secondary reason is that the assumed distributed solar growth is higher than the 2020 LTSA. The assumed distributed solar installed capacity was close to 6,000 MW for 2035 in the 2022 LTSA Current Trends scenario while it was around 4,000 MW in the 2020 LTSA Current Trends scenario. Therefore, less new capacity was needed to serve the forecasted demand in the 2022 LTSA.

Capacity Additions

Total capacity added by the capacity-expansion analysis was 57,425 MW in the Current Trends scenario and varied from 35,906 MW in the Expanded System Outlook scenario to 95,701 MW in the Demand Side Evolution sensitivity. Utility-scale solar capacity additions ranged from 0 MW to 18,900 MW across the scenarios. The amount of distributed solar generation added in each scenario was a model input rather than a result of economic analysis. The assumed distributed solar adoption for Current Trends and Expanded System outlook scenarios was the same and it grew from 3,400 MW in 2023 to 5,900 MW in 2037. For Demand Side Evolution scenario and its sensitivity, the distributed solar was assumed to be 5,900 MW in 2023 and increase to 7,400 MW in 2037.

New IBR and more advanced high-efficiency natural gas generators comprised the majority of capacity additions in all scenarios to meet the demand growth and replace the unit retirements. Since the assumed capital cost of wind generation was low enough, such that the investment could be recovered by energy prices, the model added significant amount of wind in the resource mix among all the scenarios. However, not all scenarios added solar generators in the resource mix. The Demand Side Evolution sensitivity had the highest solar addition of 18,900 MW among all the scenarios. The Expanded System Outlook scenario, which had more than 33 GW installed solar capacity in the starting resource mix, did not add any additional solar capacity. Though wind and solar resources have different diurnal generation patterns, and they can complement each other to serve demand throughout the day, the relatively low average capacity factor of solar and the shift of peak net load to night hours may potentially limit the buildout of solar in certain scenarios depending on the future economics and penetration of energy storage technologies. The model added the highest combined cycle capacity in the Demand Side Evolution scenario, since this scenario included 16 GW of LFL and a significant amount of electric vehicle charging at night, which biased the model to select resources that were available at night. In the Demand Side Evolution sensitivity, the gas capacity addition was restricted to one combined cycle per year and 800 MW of simple cycle for each year. This sensitivity showed the highest amount of solar, wind and battery additions. Figure 4 shows the amount of capacity added by technology in each scenario and sensitivity.

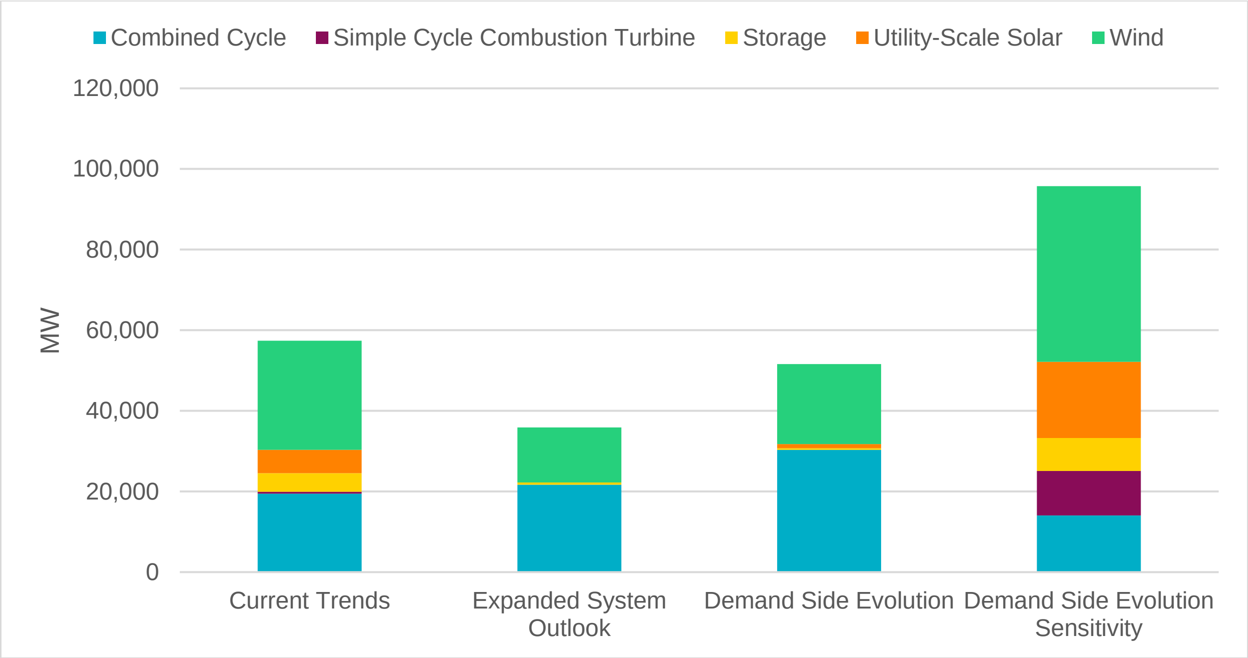

Figure 4: New Capacity Additions by Scenario by 2037

Generation Retirements

The retirement process for the 2022 LTSA had two distinct parts, similar to the 2020 LTSA. First, a group of fixed-age retirements was determined for use in all scenarios. These fixed-age retirements were determined by the age of an existing unit. Natural gas units were retired after 60 years of operation, and coal units were retired after 45 years of service. The second part of the retirement process considered economics as the criterion for retirement. Based on economic simulations, if a unit's fixed and variable costs were greater than the unit's total revenue, the unit was retired in the next model year studied. By 2037, the total fixed-age retirements were 8,116 MW of coal and 11,449 MW of natural gas. The list of affected units and dates of retirement are provided in Appendix III. The fixed-age retirements for coal were lower than the 2020 LTSA because some of the coal retirements happened before the end of 2022. The capacity-expansion and retirement analyses also accelerated some of the fixed age retirements based on economics, and the timing of specific unit retirements prior to 2037 were different across the scenarios.

The capacity-expansion model retired an additional 105 MW capacity based on economics. Comparatively, in the 2020 LTSA, the model did not retire any additional capacity based on economics, but accelerated some fixed age retirements.

Changing Resource Mix

The share of demand served by coal-fired generation declined throughout the 15 years in each of the three scenarios as well as the sensitivity for the Demand Side Evolution scenario, due to coal generation retirements and demand growth over the study period. Retired coal and natural gas generation was replaced by solar, wind, new natural gas generation, and battery energy storage. The share of IBR increased in all scenarios, driven by the expanded IBR capacity in the final resource mix.

The Expanded System Outlook scenario showed that the starting resource mix alone affected the capacity-expansion results and final resource mix with all the other assumptions remained the same as the Current Trends scenario. With 33,146 MW of utility-scale solar already in the starting resource mix, the Expanded System Outlook scenario did not have any solar additions in capacity expansion compared with 5,800 MW solar addition in the Current Trends scenario. In addition, with 39,877 MW of wind in the starting resource mix, the Expanded System Outlook scenario added 13,700 MW of wind in capacity expansion compared with 27,100 MW wind addition in the Current Trends scenario. The final resource mix in the Expanded System Outlook scenario had 10 GW more solar and approximately 11 GW less wind than the Current Trends scenario. Although the Expanded System Outlook scenario was designed to help overcome challenges with under-selection of some resource types (i.e., batteries and solar), the final battery capacity was comparable between the Current Trends scenario and the Expanded System Outlook scenario. The Expanded System Outlook scenario had close to 4,600 MW batteries in the starting resource mix, which was around 2,500 MW higher than the starting resource mix for the Current Trends scenario. The capacity expansion in the Expanded System Outlook scenario added less than 600 MW of batteries and brought the total battery capacity to slightly over 5,000 MW in the final resource fix. The total battery capacity in the Current Trends scenario final resource mix was approximately 6,600 MW.

Wind and natural gas are the primary resource types used to serve ERCOT demand in all the scenarios and sensitivity. In the Current Trends scenario and the Demand Side Evolution sensitivity, wind generation replaced natural gas generation to become the primary technology by 2037. Figure 5 shows the percent of total energy generated by fuel type in 2037 for all scenarios.

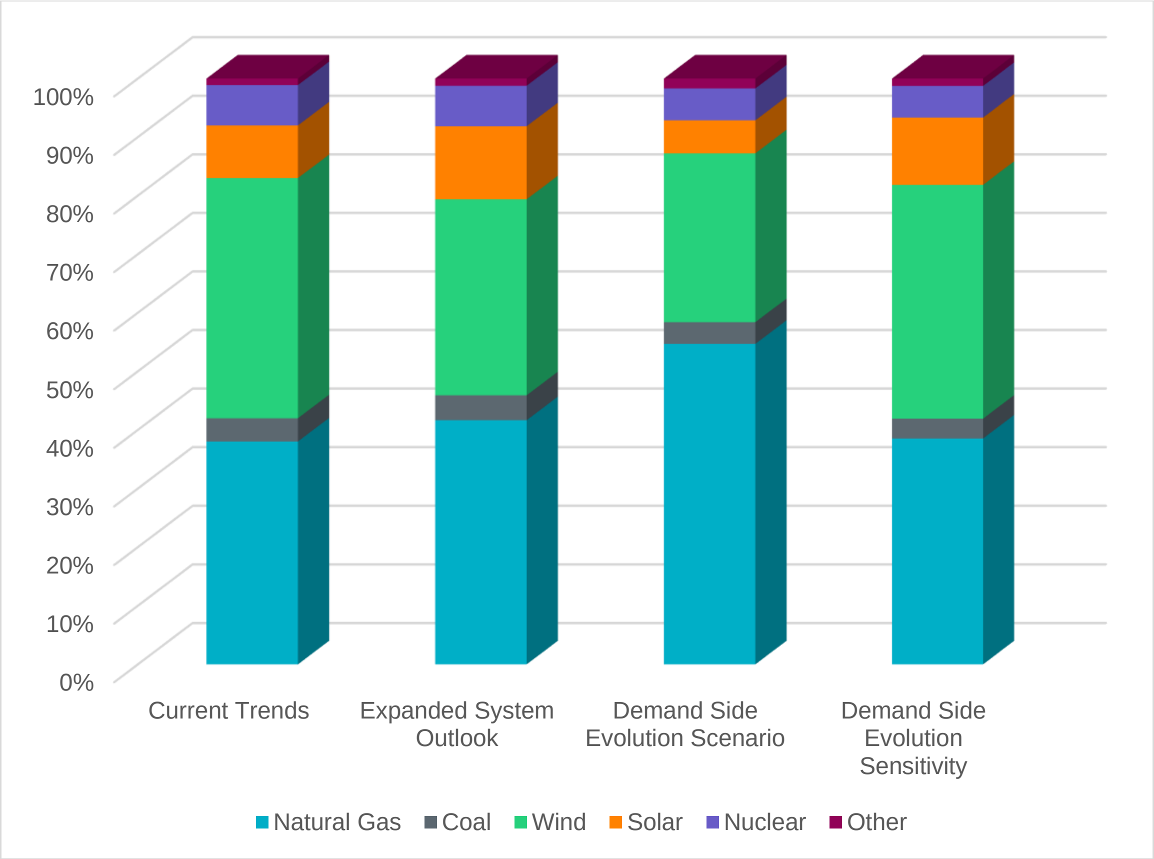

Figure 5: Generation by Fuel Type for 2037

Figure 6 below provides a comparison of historical renewable penetration[5] experienced in 2021 to that seen in the Current Trends scenario. It is expected that the number of hours during which the majority of demand could be served by intermittent renewable resources will increase as more wind and solar capacity is integrated into the ERCOT system. Given the amount of renewable generation added in these scenarios, it appears that there may be hours when all ERCOT demand could theoretically be served by wind and solar resources. However, thermal and stability constraints on the transmission system and unit commitment limitations caused the grid simulation software to curtail available wind and solar output. In addition, operational considerations, such as ramping limitations and maintaining a minimum level of system inertia, would need to be assessed further to ensure reliability under high renewable penetration conditions.

[5] Renewable penetration is defined as the total amount of demand at any given time that is being served by solar and wind generation.

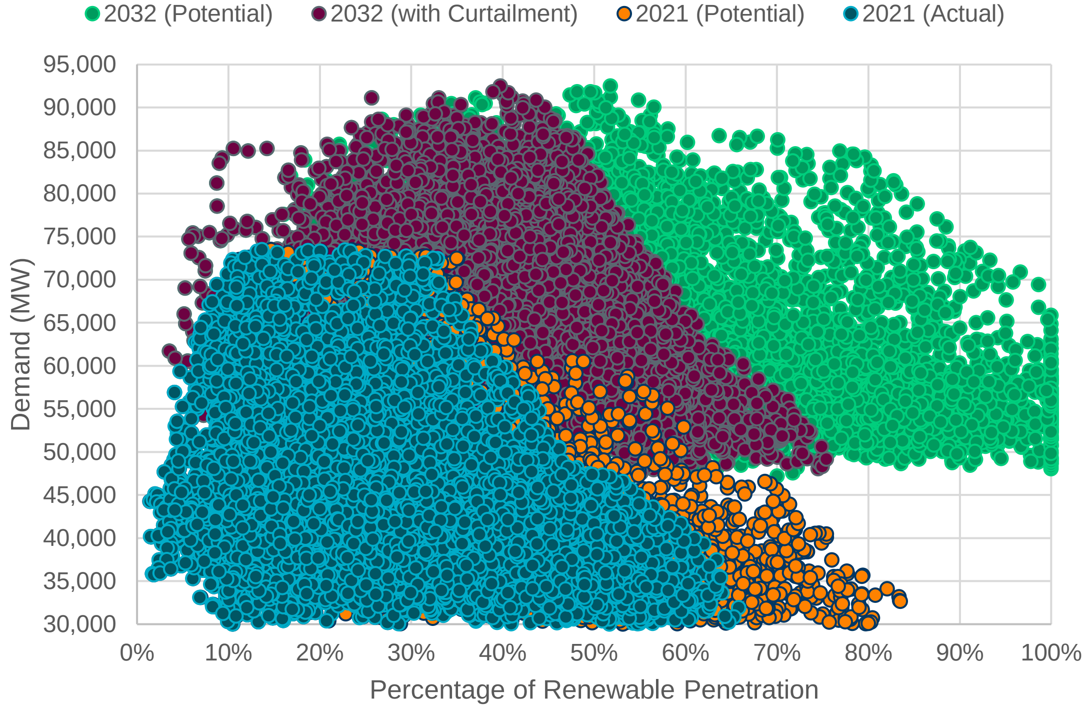

Figure 6: Renewable Penetration Trends

Key Finding 2: Growth in renewable resources and electric vehicle adoption leads to a shift in scarcity hours to later in the day, similar to previous LTSAs, and also a gradual shift of scarcity hours from primarily in the summer season to the winter season.

Scarcity hours shifted to later in the day in the Current Trends and Expanded System Outlook scenarios, similar to previous LTSAs, while the Demand Side Evolution scenario and sensitivity did not observe any scarcity hours. The Current Trends scenario saw scarcity hours from 7 pm to 1 am, and the Expanded System Outlook scenario saw scarcity hours from 7 pm to 12 am by 2037.

The gradual shift of scarcity hours from primarily in the summer season to the winter season was also observed in the 2022 LTSA. While scarcity hours in 2027 mostly happened in summer, more than half of the scarcity hours in 2032 and almost all scarcity hours in 2037 occurred in winter.

Factors[6] influencing the shift in scarcity hours include:

- Increased adoption of electric vehicles could result in a significant shift in hourly demand profiles. This observation was also noted in the previous LTSAs.
- The drop in solar production experienced in late evening hours can result in a high ramping rate for net load.[7] High net load ramping conditions will likely become more frequent and severe as solar penetration increases.
- The loss of solar production in late evening hours coupled with limited wind generation output could lead to stressed system condition.
- The peak net load hour happened in the winter season for all scenarios and sensitivity in 2037 due to the drop in both solar and wind production in late evening hours.

As renewable penetration on the ERCOT system continues to increase, possible system conditions outside of summer peak, including peak net load conditions, need to be included in planning studies.

Peak Day Load Shape

One potential challenge identified in the study is the need for additional generation resources to offset the drop in solar production in late evening hours of the summer and morning and late evening hours of winter seasons. With the amount of solar resource capacities noted in the scenarios in this study, the loss of solar output in the late evening while air conditioning demand remains high could lead to extreme system ramping conditions, or possibly insufficient generation to serve demand (especially on days when there is little to no wind generation output). On some days the model simulation output indicated limited amounts of unserved energy. Below, Figure 7 shows this potential result for a summer peak evening in 2037 from the Current Trends scenario. The dashed lines are plotted on the secondary vertical axis while the solid lines are plotted on the primary vertical axis.

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[6] Please note the additional outages caused by winter storm Uri were not considered in this LTSA study, and average forced outage rates based on normal historical weather conditions were used in the study.

[7] Customer demand minus aggregate wind and solar output. Net load is representative of the portion of demand not served by wind or solar generation.

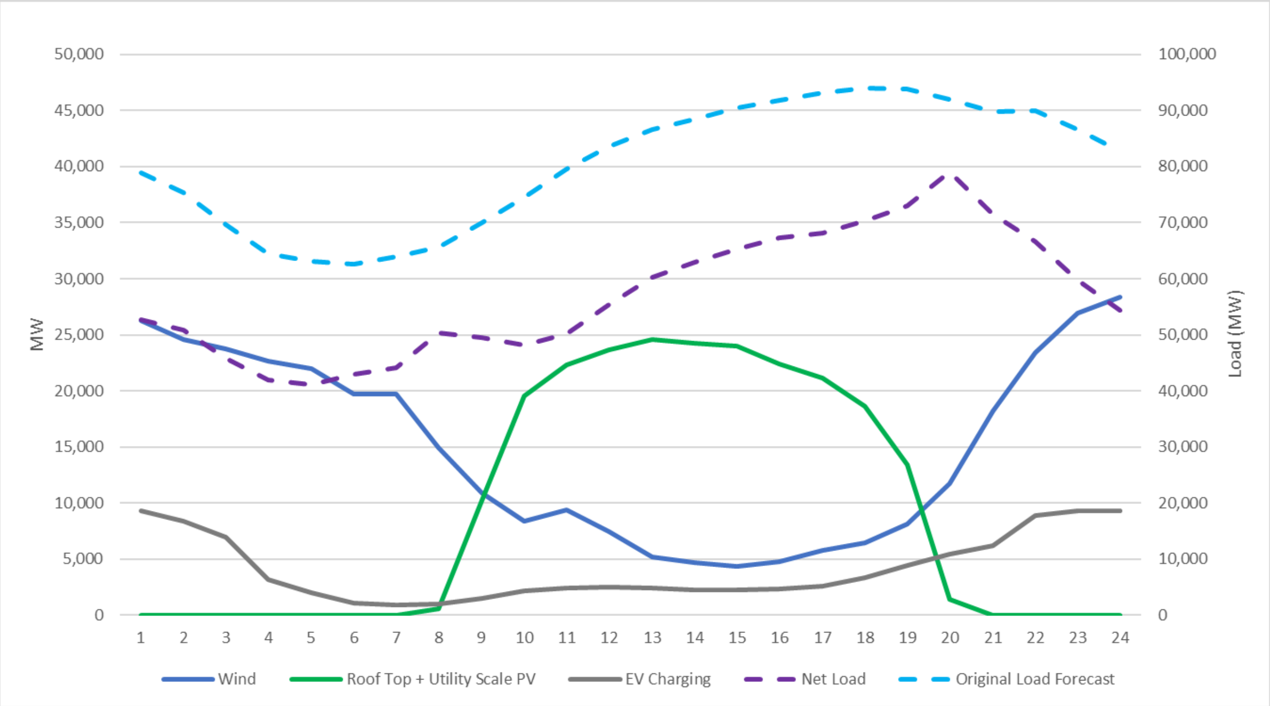

Figure 7: Summer Peak Net Load Challenge on a Hot Summer Day in 2037

In 2037, peak net load happened in the winter season when the solar production was gone, and the wind output also greatly dropped. Figure 8 shows this potential result for a winter peak evening in 2037 from the Current Trends scenario.

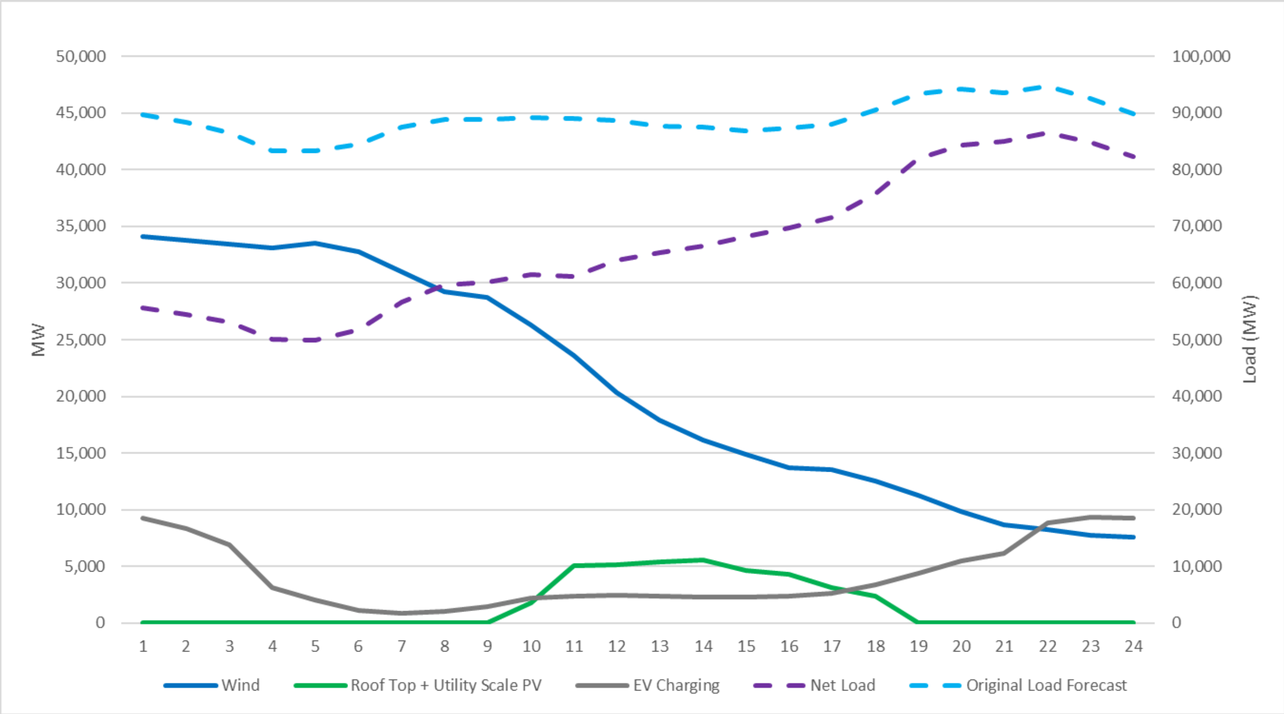

Figure 8: Winter Peak Net Load Challenge in 2037

Historically, the most stressed system conditions – from both resource-scarcity and transmission-security standpoints – have been during summer afternoons. In all three scenarios and the sensitivity, stressed system conditions were observed at other times of day and in the winter season. As wind and solar penetration on the ERCOT system continue to increase, transmission planning studies need to consider system conditions outside of summer peak demand hours, and specifically during high net load hours.

Peak Net Load

A comparison of net load and conventional demand from the Current Trends scenario in year 2037 is shown below in Figure 9. The net load curve is the part of ERCOT demand that will be served after intermittent renewable resources (i.e., wind and solar) are utilized. Please note that the wind and solar generation used in the net load calculation reflects curtailment. The peak load portion of the net load duration curve is steeper than the conventional load duration curve. The peak net load occurs in a relatively small number of hours, and, therefore, investors in conventional peaking generation capacity (e.g., combustion turbines) may not be able to recover investment costs to meet the peak net demand,[8] and other resources will be necessary to serve the peak net demand requirement. Such resources will require suitable availability and ramping capabilities.

[8] PUCT's market redesign initiatives may help to address this issue. For more information see PUCT websites: https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=52373&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending and https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=54335&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending.

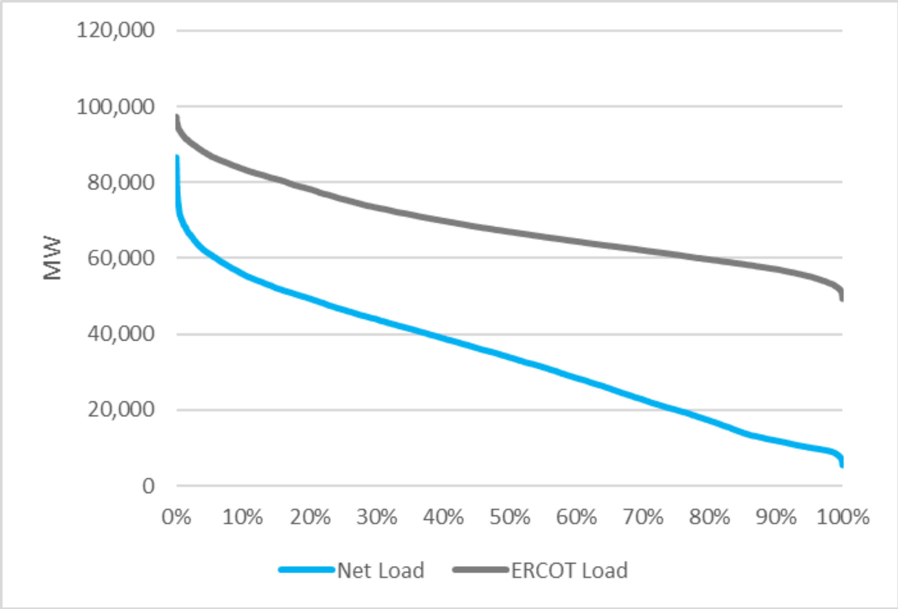

Figure 9: Load vs Net Load for Current Trends Scenario for 2037

Key Finding 3: Annual capacity factors for conventional generators were significantly higher in the Demand Side Evolution scenario compared with the Current Trends and Expanded System Outlook scenarios.

The Demand Side Evolution scenario and sensitivity included 16 GW of price responsive LFL based on an informal survey conducted in early 2022. The LFL was expected to remain flat and only ramp down when the market price exceeded the assumed strike price. In addition, more aggressive EV adoption across all vehicle categories from light duty vehicle, to buses, to heavy duty vehicle was assumed. Managed charging was also utilized to mitigate the potential impact of EV charging by assuming EV charging during renewable-abundant hours where non-EV load is not high, which resulted in more charging activities in late evening and early morning. The addition of the significant amount of the LFL and the managed EV charging presented the need for additional generation resources to offset the drop in solar production in late evening and early morning hours. It was observed that conventional generators had significantly higher annual capacity factors compared with the Current Trends and Expanded System Outlook scenarios to serve the LFL throughout the day and EV charging load during the late evening and early morning hours. The capacity factor increase was most significant for the natural gas generation, especially combustion turbine generation, due to their operational flexibility and availability to meet the load during the hours lower renewable output. The annual capacity factor comparison for 2037 among the different scenarios is shown in Table 2 below.

Table 2: Annual Capacity Factors for 2037

Resource Technology	Current Trends	Expanded System Outlook	Demand Side Evolution	Demand Side Evolution Sensitivity
Battery	7%	8%	9%	7%
Coal	69%	74%	83%	76%
Combined Cycle	46%	48%	71%	61%
Simple Cycle Turbine & Gas Steam	15%	15%	26%	21%
Solar	27%	26%	27%	28%
Wind	44%	43%	45%	44%

Large Flexible Loads

Industrial demand growth remains strong on the ERCOT system, driven in part by oil and gas activity in West Texas and increased demand in data centers and cryptocurrency mining facilities. The requests for the interconnection of LFLs surged in the past couple of years, and ERCOT continues to improve its processes to account for such hard-to-forecast, large-scale load additions with short interconnection timelines. In order to capture the impacts of the LFLs on the ERCOT system from the long-term planning horizon perspective, the Demand Side Evolution scenario was incorporated in the 2022 LTSA. ERCOT conducted an informal survey in early 2022 to obtain necessary information to determine the appropriate demand from LFLs to be included. Based on the survey results, 16 GW demand from LFLs was included in the Demand Side Evolution scenario. Based on historical data analysis, the strike price for the LFLs to ramp down in response to market price was set to $100/MWh.

The current LFL requests as of October 2022 can be found in Figure 10 below.[9]

[9] Operational – Projects that are currently in operation and projects that are approved to energize by ERCOT. This category also accounts for staged energization schedules.
Met Planning – Projects that have received approval of the required planning studies.
Deferred – Project MWs that were limited after ERCOT review or for which the project owner has provided an energization schedule.
In Study – Projects that have studies under review by ERCOT.
Planned – Projects that are tracked by ERCOT but that have not yet provided sufficient information to begin review.
https://www.ercot.com/files/docs/2022/10/24/LLI%20Queue%20Update%20-%202022-10-24.pdf

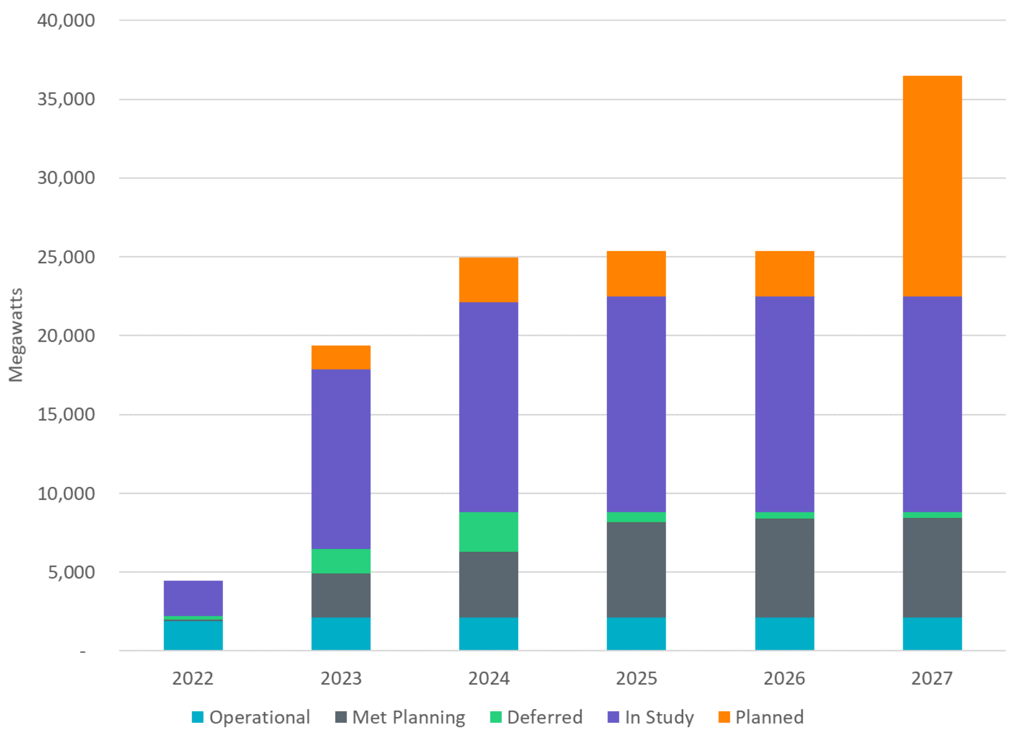

Figure 10: LFL Requests as of October 2022

After the completion of the Demand Side Evolution scenario, a Demand Side Evolution sensitivity was also conducted to incorporate stakeholder feedback. The strike price for the LFL was changed as follows.

- 60% of LFL (9,600 MW) at 100 $/MWh, this is an energy only curtailment for the standard mining equipment.
- 30% of LFL (4,800 MW) at 200 $/MWh, this is also an energy only curtailment targeted toward LFLs with more efficient/newer crypto mining equipment that can curtail at higher price.
- 10% of LFL (1,600 MW) at 1,000 $/MWh, this is for miners that are less price responsive to real time price swings.

In addition, a max buildout limit for both advanced combined cycle trains and combustion turbines was also employed, based on stakeholder feedback, in the Demand Side Evolution sensitivity.

Managed EV Charging

An aggressive EV adoption was assumed for the Demand Side Evolution scenario, as shown in Figure 11 below. The adoption levels of local heavy-duty vehicles and long-haul heavy-duty trucks are more than doubled compared with the Current Trends and Expanded System Outlook scenarios. To mitigate the potential negative consequences of the high-level EV adoption, managed EV charging was utilized to better align EV charging with high renewable and non-peak load hours.

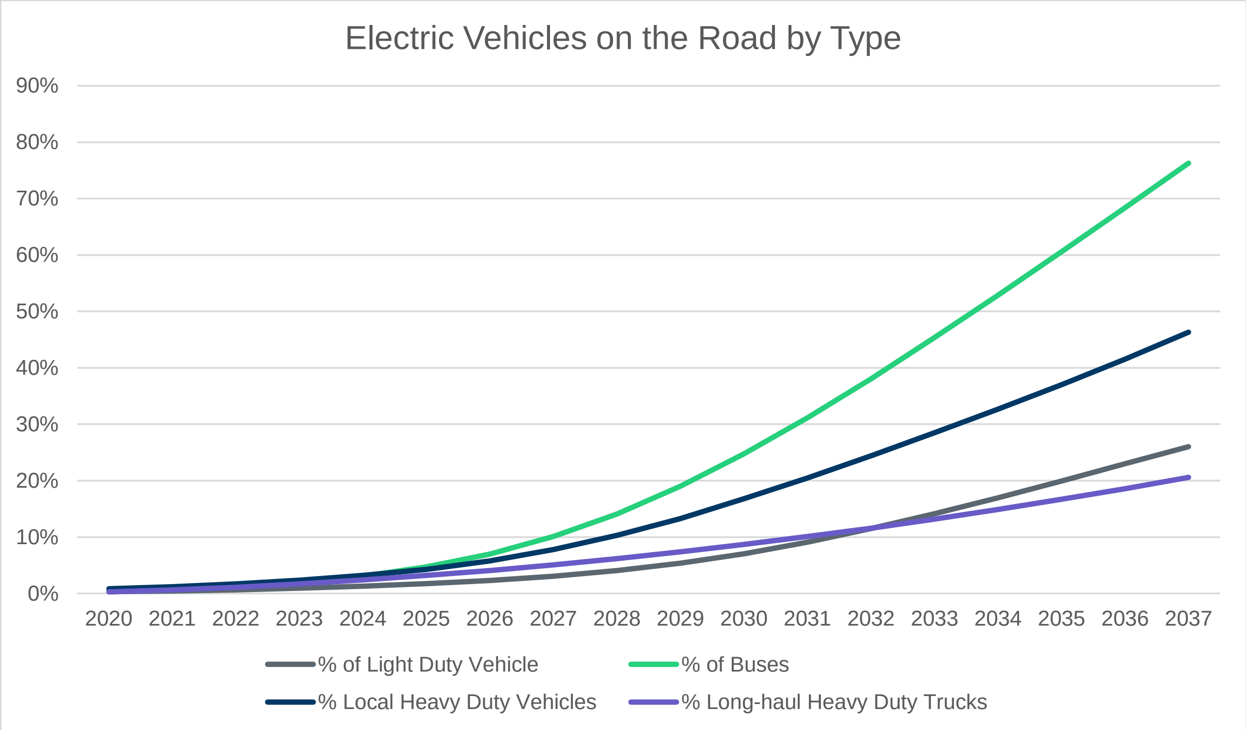

Figure 11: High Adoption of EV in Demand Side Evolution

With managed EV charging, EV charging energy demand was balanced throughout the day, with a focus on reducing energy usage during peak net load periods. EV managed charging profiles were developed for each season to capture seasonality of renewable generation and non-EV load. The concept is illustrated in Figure 12 and the detailed description can be found in Appendix IV.

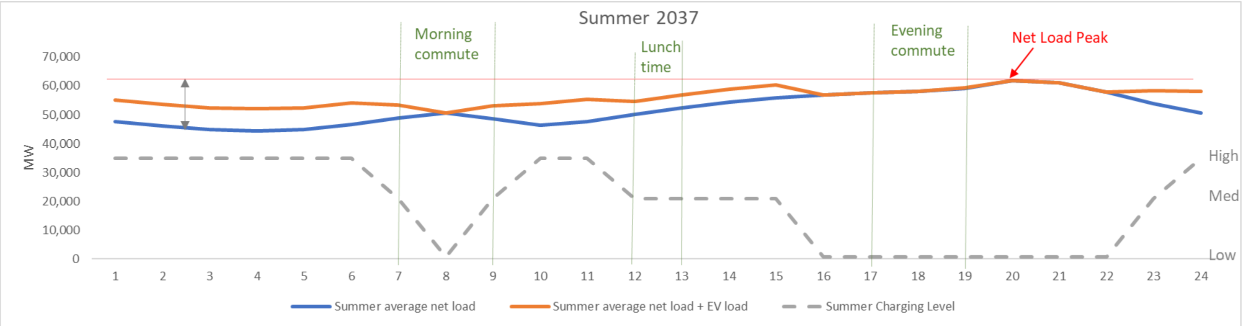

Figure 12: Illustration of EV Charging Load Management Method

Based on the approach documented in Appendix IV, EV charging profiles were developed for each season in each year. Figures 13 and 14 show the EV charging profiles for each season in 2037.

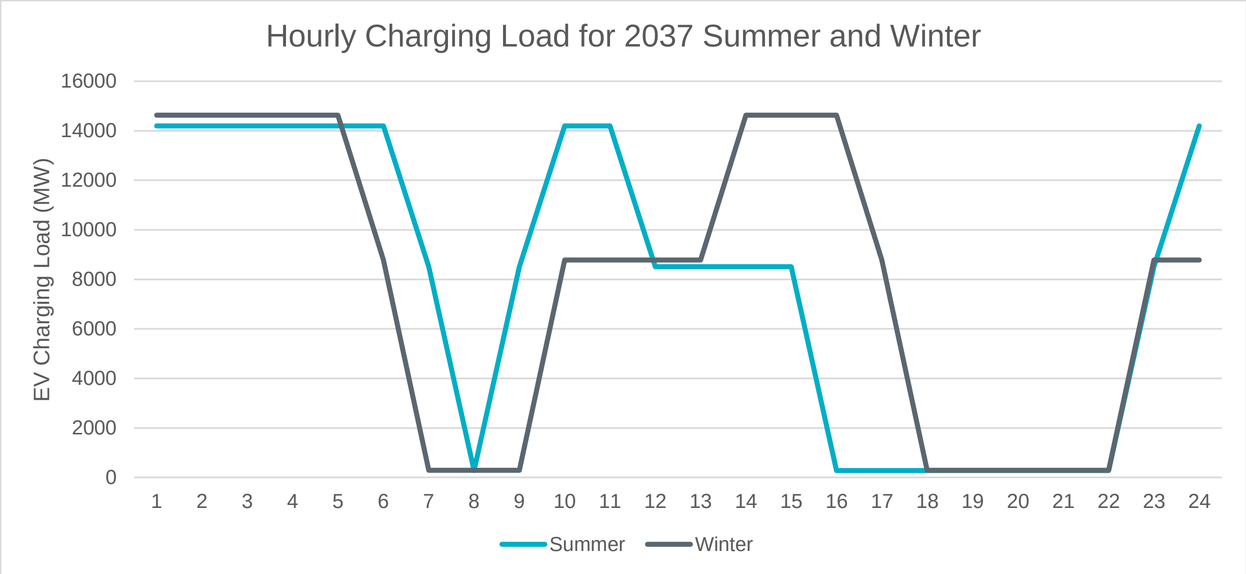

Figure 13: Summer and Winter Managed EV Charging

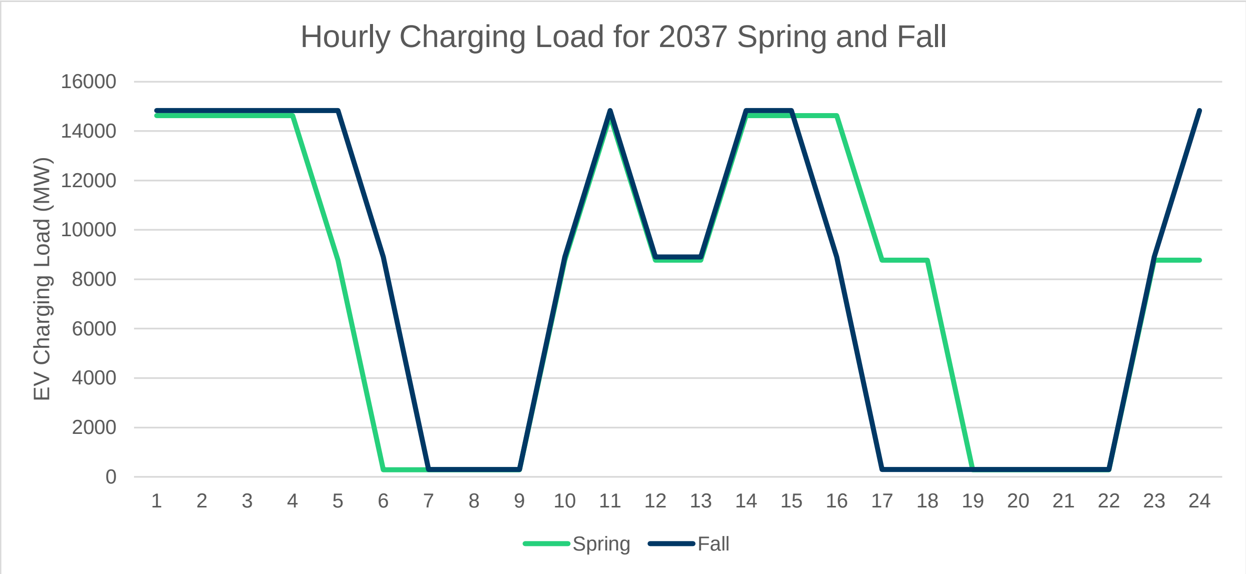

Figure 14: Spring and Fall Managed EV Charging

Key Finding 4: Transmission challenges were identified for both the export from the renewable resource-rich region and the import into the demand centers.

Comparable to findings from the 2020 LTSA, ERCOT identified the significant congestions on the West Texas Export interface and the import paths to demand centers such as Dallas-Fort Worth and Houston. This congestion pattern is driven by both a changing resource mix and trends in customer demand growth with consequent challenges for both power transfer across the system and customer delivery. Large industrial load additions are occurring, and are projected to continue occurring, in both rural and urban areas. The time of use and flexibility of customer demand are also shifting as new technologies are adopted.

Figure 8 shows the top constraints observed in 2032 for the Current Trends scenario. Figure 16 shows the same in 2037. The sizes of the bubbles indicate the relative amount of congestion rent experienced by each transmission element.

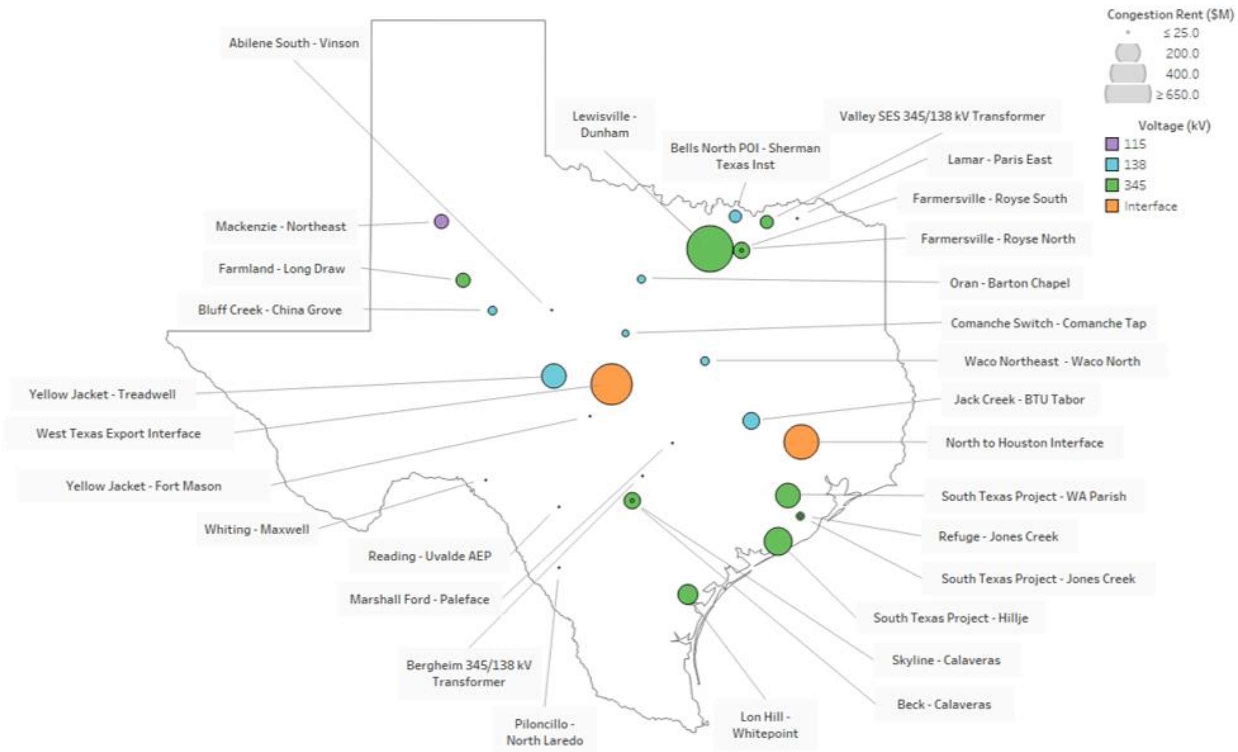

Figure 8: Top Constraints for the Current Trends Scenario (2032)

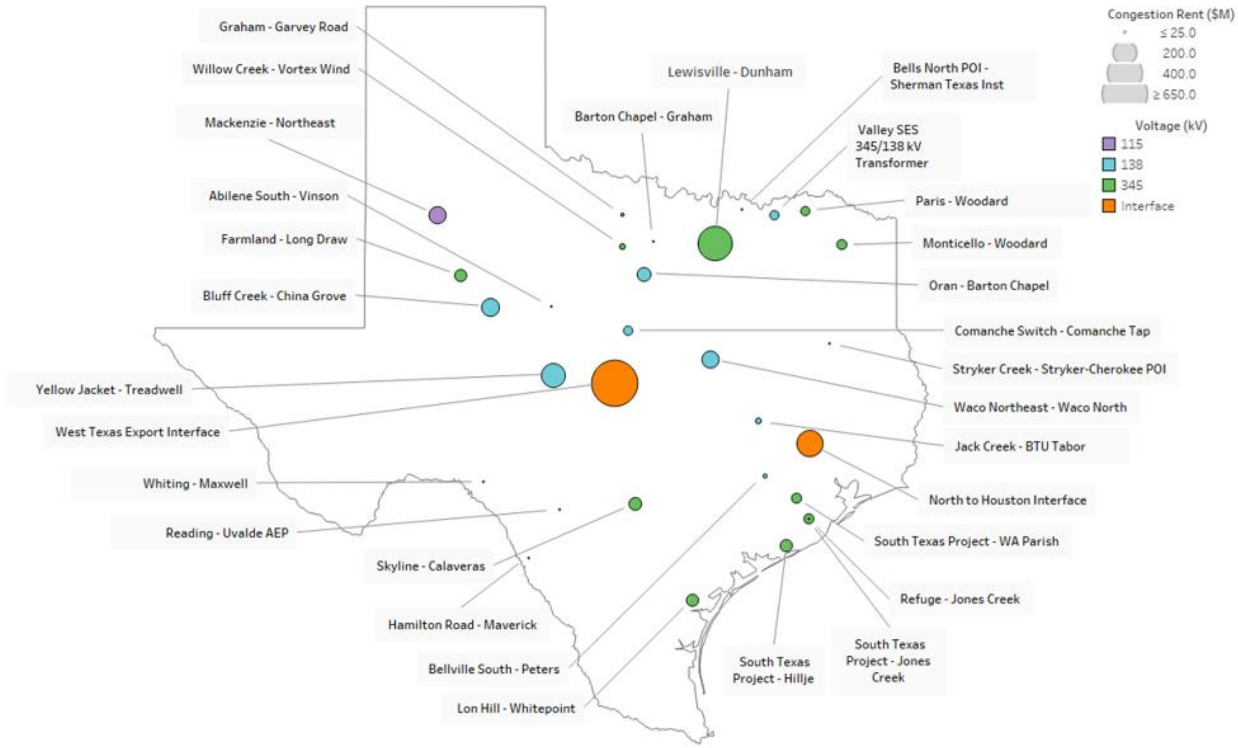

Figure 9: Top Constraints for the Current Trends Scenario (2037)

The Dallas-Fort Worth area was highly congested in the Current Trends scenario, driven by both generation additions to the northwest of the area and load growth within the area. This observation is consistent with both the findings of the 2020 LTSA and near-term needs identified by the 2022 RTP.

The import paths into Houston, including the North to Houston interface and the 345-kV transmission lines from South Texas Project to WA Parish and Hillje, were also highly congested. The congestion was driven by the conventional generation retirement and load growth in Houston and the renewable generation additions in both the south and northwest areas of the system.

The West Texas export interface also experienced high congestion in the Current Trends scenario. The congestion rent for the West Texas export interface was close to $1 billion in 2037 due to the significant renewables added by the capacity-expansion model in north and West Texas.

At the time of the analysis, ERCOT's economic criteria for project evaluation was pending.[10] As a result, potential economically driven transmission improvements were not evaluated in the 2022 LTSA.

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[10] The Commission recently adopted rule amendments establishing these criteria. *See* PUC rulemaking Project No. 53403, *Review of Chapter §25.101 Certification Criteria*, Order Adopting Amendments to 16 TAC 25.101 as Approved at the November 30, 2022 Open Meeting (Dec. 7, 2022);
available at: https://interchange.puc.texas.gov/Documents/53403_86_1256975.PDF.

Appendices

Appendix I: LTSA Process

LTSA Scenario Development

The 2022 LTSA scenario development process focused on stakeholder feedback received via survey and during Regional Planning Group (RPG) meetings. The scenario-based planning approach provided a structured way for stakeholders to identify the most critical trends, drivers, and uncertainties for the upcoming ten- to fifteen-year period. Scenario-based planning considered different, yet plausible futures and was used to evaluate transmission plans across multiple futures. Some of the noteworthy drivers considered in the LTSA can be seen in Table 3 below.

Table 3: Key Drivers Considered in the 2022 LTSA

Drivers	Brief Description
Economic Conditions	The US and Texas economy; regional and state-wide population; oil & gas, and industrial growth; LNG export terminals; urban/suburban shifts; financial market conditions; and the business environment.
Environmental Regulations and Energy Policies	Environmental regulations including air emissions standards (e.g., ozone, MATS, CSAPR), GHG regulations, water regulations (e.g., 316b), and nuclear safety standards; energy policies include renewable standards and incentives (incl. taxes/financing), mandated fuel mix, solar mandate, and nuclear relicensing.
Alternative Generation Resources	Capital cost trends for renewables (solar and wind), technological improvements affecting wind-capacity factors, caps on annual capacity additions, storage costs, other distributed generation (DG) costs, and financing methods.
Gas and Oil Prices	Gas prices are a function of total gas production, well productivity, LNG exports, industrial gas demand growth, and oil prices. Oil prices are dependent in part on global supply and demand and the proliferation of horizontal drilling technologies. Oil and gas prices will affect drilling locations within Texas.
Government Regulations/Policy/Mandates	New policies around resource adequacy, transmission buildout, interconnections to neighboring regions, and cost recovery.
Technology	Improvements in technologies resulting in more efficient turbines or higher capacity factor intermittent resources.
End-Use/New Markets	End-use technologies, efficiency standards and incentives, demand response, changes in consumer choices, DG growth, and increased interest in microgrids.
Weather and Water Conditions	Weather and water conditions may affect demand growth, environmental regulations and policies, technology mix, average summer temperatures, the frequency of extreme weather events, and water costs.

Stakeholder feedback on important drivers and potential scenarios was solicited via an online survey in March 2021. The survey also collected stakeholder feedback on the scenarios in the 2020 LTSA to assist the scenario development for the 2022 LTSA. A broad range of stakeholder perspectives – including those representing municipally owned utilities, electric cooperatives, investor-owned utilities, generators, retail electric providers, consumers, and other interest groups – were included in survey responses.

A summary of the survey results is illustrated in Figures 17 and 18 using boxplots. The lower and upper edges of the boxes represent the first and third quartiles of the rankings for each item, respectively, while the blue bar inside of the boxes represent the median rank. The dots represent the average ranking, and the ends of the line segments represent the minimum and maximum ranks for each item. In both figures, a ranking of one indicates highest impact or most useful.

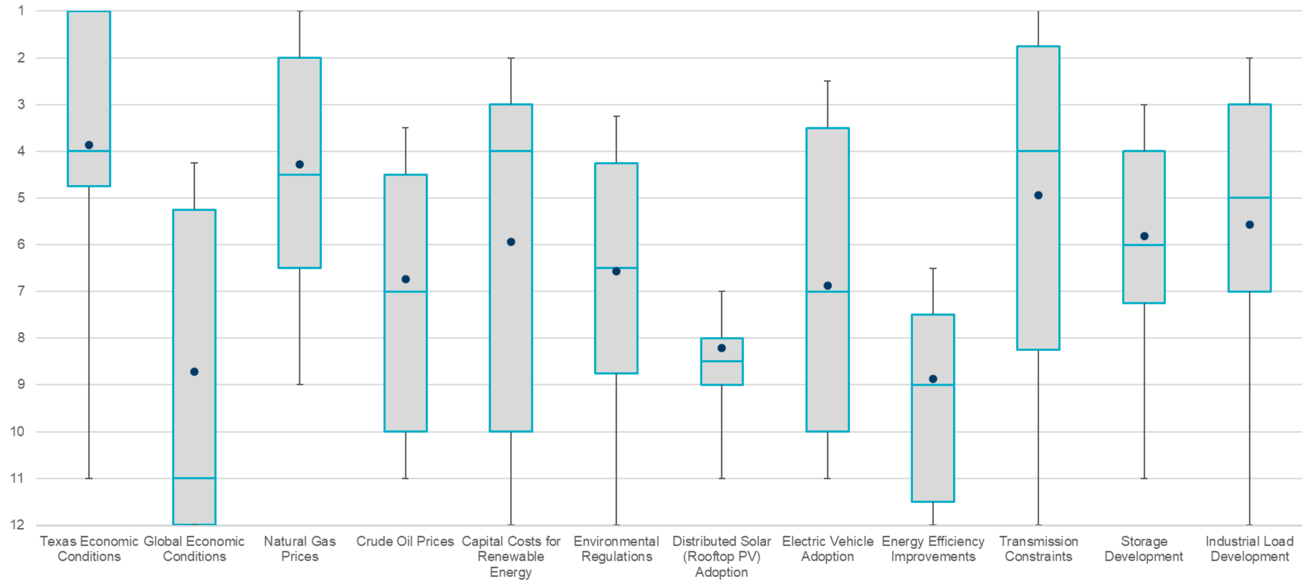

Figure 17. Key Driver Rankings from the 2022 LTSA Stakeholder Survey

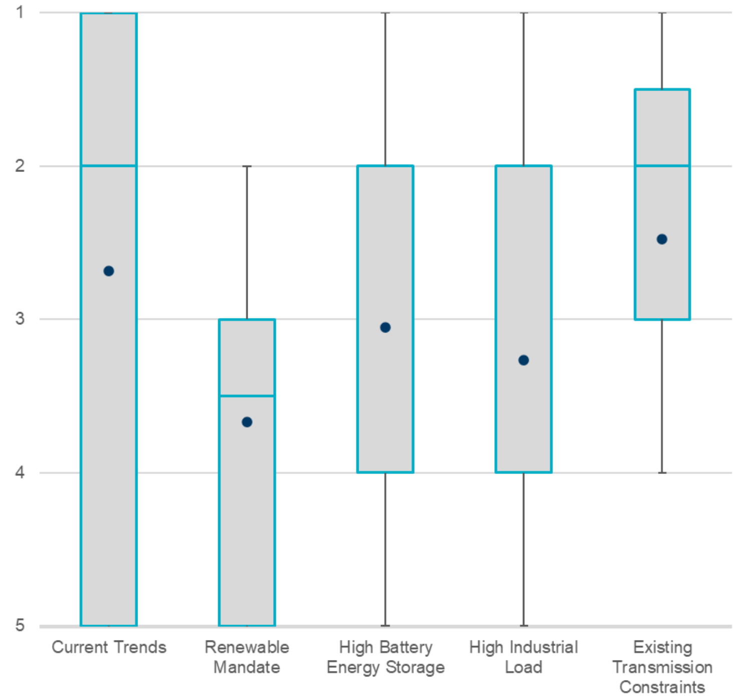

Figure 18. Ranking of 2020 LTSA Scenarios

ERCOT considered stakeholder feedback received from the online survey and during RPG meetings to develop a proposal for additional scenarios. The scenario proposal and draft assumptions for proposed scenarios were presented to stakeholders at the October 2021 RPG meeting. Further stakeholder feedback received, following the scenario proposal, led to the final development of the scenarios considered for the 2022 LTSA. Table 4 summarizes the unique elements of each scenario.

Table 4: Scenarios Studied in the 2022 LTSA

Scenario	Description
Current Trends	The Current Trend scenario describes the trajectory of what we know today (e.g., demand growth, economic trends, fuel prices, etc.). Similar to the 2020 LTSA, EV adoption was included in the assumptions for the Current Trends scenario in the 2022 LTSA.
Expanded System Outlook	The Expanded System Outlook scenario included additional resources from the interconnection process, i.e., all the resources included in the December 2021 CDR report. This scenario is designed to help overcome challenges with under-selection of some resource types (i.e., batteries and solar) and potential better correlation with the GIS and CDR reports in terms of both resource mix and siting.
Demand Side Evolution	The Demand Side Evolution scenario was developed to study the impacts of the integration of large amounts of LFL, high rooftop solar adoption, high EV adoption and managed EV charging. A sensitivity analysis was also performed by imposing buildout limitations on advanced natural gas generators and utilize tiered strike prices for LFLs' price responses.

The final input assumptions used in creating the 2022 LTSA study are documented in Table 5 below.

Table 5: 2022 LTSA Input Assumptions

	Demand				Generation			
Scenario	**Demand and Energy Forecast**	**Electric Vehicle Assumptions**	**Additional Large Flexible Load Assumptions**	**Distributed Solar Assumptions**	**Renewable Incentives (ITC/PTC)**	**Carbon Pricing**	**Renewable Annual Capacity Addition Limit**	**Natural Gas Prices**
Current Trends	ERCOT 2021 Long-Term Demand and Energy Forecast based on the 2013 weather year	Approximately 3.6 million cars and pickup trucks by 2037	No additional demand beyond that included in the ERCOT Long-Term Demand and Energy Forecast	5.9 GW by 2037 To be updated	Current schedule for retirement	None	Wind: 3,000 MW Solar: 4000 MW	2021 AEO Reference Case
Expanded System Outlook	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends	Extended through 2035	Same as Current Trends	Same as Current Trends	Same as Current Trends
Demand Side Evolution	Same as Current Trends	Approximately 5.2 million cars and pickup trucks by 2037	16 GW of Large Flexible Load	7.4 GW by 2037	Same as Current Trends	Same as Current Trends	Same as Current Trends	Same as Current Trends

Demand Forecasting

One key component to any long-term transmission plan is an appropriate forecast of electric demand. Changes in electricity consumption contribute to future transmission needs, as do new generation technologies, generator obsolescence, and economic, commercial, and policy factors. Transmission plans study the reliable movement of electricity from generation sources to consumer demand locations; therefore, planners need to know which resources can provide electricity as well as how much electricity will be required and where. The uncertainty in many of these factors can be significant; as such, demand forecasters often prepare several forecasts that reflect different possible futures and circumstances so transmission planners can study demand, generation, and transmission needs for those various futures and conditions.

The demand forecast was created for the years between 2023 and 2037 to support the scenarios included in this study.

The demand forecast combined econometric and scenario-specific assumptions as inputs into forecast models to describe the hourly demand in the region. Factors considered included certain economic measures (e.g., nonfarm payroll employment, housing stock, population, number of premises) and weather variables (e.g., heating and cooling degree days, temperature, cloud cover, dew point, and wind speed). Detailed documentation on ERCOT's Long-Term Hourly Peak Demand and Energy Forecast can be found on the long-term load forecast page on the ERCOT website.[11]

ERCOT consists of eight distinct weather zones. Each of these weather zones represents a geographic region within which all areas have similar climatological trends and characteristics. The ERCOT forecast is the sum of all the weather zone forecasts. A map of the ERCOT weather zones is shown in Figure 19 below.

[11] http://www.ercot.com/gridinfo/load/forecast

Figure19: ERCOT Weather Zones

The forecast used models that combine weather, economic data, and calendar variables to capture and project the long-term trends extracted from the historical demand data. The models were developed using historical data from 2016 through summer 2021.

Premises were separated into three different customer classes for modeling purposes: residential, business, and industrial. The premises count models considered changes in population, housing stock, and non-farm employment. An autoregressive model (AR1) was used for all premises models.

The long-term trend in hourly energy was modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable, hourly energy, and the following:

- Month,
- Season,
- Day Type (day of the week, holiday),

Weather Variables:

- Temperature,
- Temperature Squared,
- Temperature Cubed,
- Dew Point,
- Cloud Cover,

- Wind Speed,
- Cooling Degree Days (base 65),
- Heating Degree Days (base 65),
- Lag Cooling Degree Days (1,2, or 3 previous days),
- Lag Heating Degree Days (1,2, or 3 previous days), and
- Lag Temperature (1, 2, and 3, 24, 48, or 72 previous hours)

Interactions:

- Hour and Day of Week,
- Hour and Temperature,
- Hour and Dew Point,
- Temperature and Dew Point,
- Hour and Temperature and Dew Point.
- Number of premises[12], and
- Non-Farm Employment/Housing Stock/Population

All the variables listed above are used to identify the best candidates for inclusion in the forecast model and to provide details on the types of variables that were evaluated in the creation of the model. Not every variable listed above was included in each model. Unique models were created for each weather zone to account for the different demand characteristics for each area.

Another key input is the forecast for the number of premises in each customer class. Premises forecasts are developed using historical premise count data and various economic variables, such as non-farm employment, housing stock, and population. ERCOT extracted the historical premises data from its internal settlement databases. Since May of 2010, there has been a reasonably close agreement between actual non-farm employment in Texas and Moody's base economic forecast. Given this trend, ERCOT used the Moody's base economic forecast of non-farm employment in these forecasts. Separate premises forecast models were developed for each weather zone. The premises were separated into three different groups for modeling purposes: residential (including street lighting), business or small commercial, and industrial (premises that are required by Protocol to have an interval data recorder meter).

- Residential Premises Forecast: Residential premises counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (residential premises) and the following:
  - Housing Stock and
  - Population.
- Business Premises Forecast: Business premises counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (business premises) and the following:
  - Housing Stock,
  - Population, and
  - Non-Farm employment.

[12] Used in Coast, East, North Central, South, and South Central weather zones.

- Industrial Premises Forecast: Industrial premises counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (industrial premises), and the
  - Housing Stock,
  - Population, and
  - Non-Farm employment.

The 2022 LTSA capacity-expansion, retirement, and transmission economic analyses used an 8,760-hour demand forecast. This base demand forecast before adjustments for all scenarios was based on the 2013 weather year. The Current Trends and Expanded System Outlook scenarios used the base forecast plus the projected EV charging load. The Demand Side Evolution scenario and sensitivity used the base forecast plus higher projected EV charging load and an additional 16 GW of LFL.

ERCOT's demand forecasts include losses, which were removed before adjusting demand because the software packages used for both reliability and economic analyses account for losses separately from the demand. Furthermore, scenario-specific demand adjustments were also applied based on the input assumptions.

For instance, distributed solar was assumed to be concentrated in the urban demand centers and was modeled based on residential (distributed solar) generation profiles. The assumed distributed solar adoption for the Current Trends and Expanded System outlook scenarios was the same and it grew from 3,400 MW in 2023 to 5,900 MW in 2037. For the Demand Side Evolution scenario and its sensitivity, the distributed solar was assumed to be 5,900 MW in 2023 and increase to 7,400 MW in 2037

EV-charging patterns for cars, short-haul trucks, buses, and long-haul trucks were used to model the effect of EV adoption. Details for EV-charging patterns can be found in Appendix IV of this report.

Also, the demand forecasts did not include self-served load. The self-served loads were left unchanged from the base cases used for transmission expansion while the demand forecasts (net of losses) were distributed to all other loads in the cases on a by-weather-zone basis.

Capacity-Expansion and Retirement Analysis

Capacity-expansion analysis is used to estimate the types and amount of new generation resources to be added, and the existing generation resources to be retired for every scenario. To provide a reference point for the selection of other future scenarios, a Current Trends scenario is developed as the first scenario. The primary input assumptions for all scenarios were the capital cost, new technology types, incentives, and wind and solar locations and profiles. The long-term capacity-expansion and retirement concept is depicted in Figure .

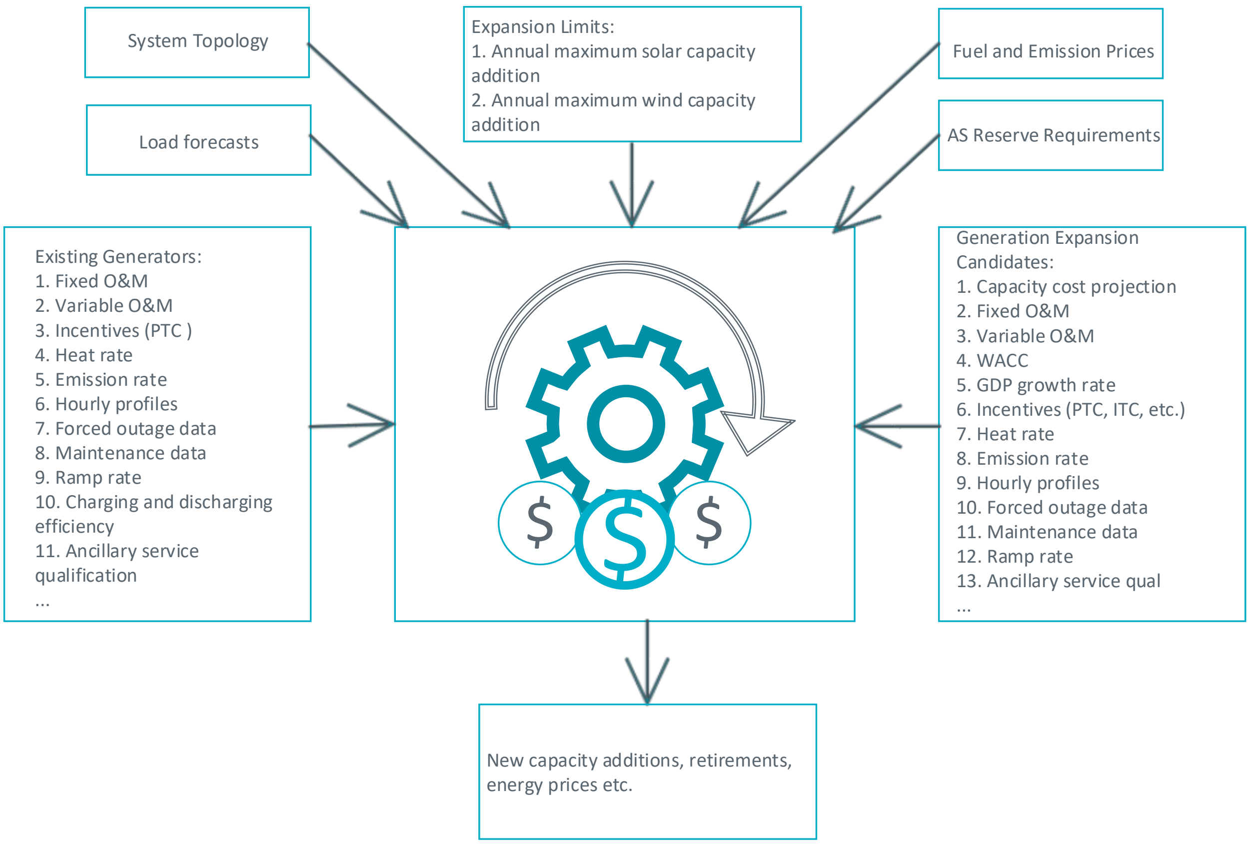

Figure 20: Long-Term Capacity-Expansion and Retirement Concept

Trends in capital costs for new expansion technologies generally increased at an assumed GDP growth rate in this analysis except for the wind, utility-scale solar, and battery energy storage technologies which were forecasted to decline rapidly through the early part of the study period. Commodity prices for gas were set as the EIA AEO 2021 Reference Case.

The technologies included for capacity expansion in this LTSA were current and advanced gas-fired combined cycles and combustion turbines, solar, geothermal, compressed air energy storage (CAES), Lithium-ion battery energy storage, biomass, coal, coal with carbon capture and sequestration (CCS), Integrated Gasification Combined Cycle (IGCC), IGCC with CCS, and nuclear. The solar technology evaluated in the capacity-expansion process was utility-scale, solar single-axis, tracking.

Additionally, the 2017 extensions[13] of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) were included in all three scenarios for renewable generation.

In 2020, ERCOT procured hourly wind-generation profiles based on actual weather data for the previous 40 years (1980-2019). These wind profiles include hourly wind output patterns for 148 hypothetical future wind generation units and were developed using a power conversion model reflecting current and near-future wind turbine technologies. The 148 profiles were distributed throughout Texas. Each profile is representative of the historical wind output in a specific county if there is an existing wind farm in the county. These wind profiles were incorporated in all scenarios.

In 2020, ERCOT also procured new hourly solar-generation profiles based on actual weather data for the previous 40 years. These patterns contained profiles representative of the west and panhandle Texas counties for two different types of solar technologies: single-axis and dual-axis tracking. Four distributed solar profiles have been developed for four urban demand centers including Dallas-Fort Worth, Austin, Houston, San Antonio, and rural areas. ERCOT selected single-axis tracking and residential profiles for inclusion in this LTSA.

A significant aspect of the expansion-decision process is capital-cost recovery. Using the specified capital costs, recovery period, inflation rate, and cost of capital, the capacity-expansion optimization model calculated a repayment that was paid in equal installments over the capital-recovery period. The inflation rate ensures that units that were added in the future have their capital costs appropriately adjusted for inflation, providing consistency with the other specified costs. In addition, the modeled ancillary service prices were much lower than historical ancillary service prices. Average ancillary service prices based on the past three years (2018-2020) were used in the decision-making process of new capacity additions and existing generator retirements. A summary of this analysis can be found in Appendix IV.

The amount of renewable generation included in the scenarios is partially a result of the use of an hourly system dispatch model to develop the capacity-expansion plan. This type of model does not simulate intra-hour balancing reserve deployment and the need for commitment of additional resources to limit the impact of variable generation forecasting error consistent with increased levels of renewable generation integration. Separate analysis needs to be conducted to determine the need for additional system flexibility to integrate levels of renewable resources seen in this analysis.

[13] The Renewable Electricity Production Tax Credit: In Brief (fas.org)

Transmission Expansion Analysis

Transmission expansion analysis in the LTSA involves evaluating the potential needs for the ERCOT grid under different demand and generation assumptions as developed during the demand-forecasting and capacity-expansion and retirement-planning stages. Transmission-expansion analysis was conducted for the Current Trends scenario. The Transmission expansion analysis was focused on analyzing congestion on ERCOT's 345-kV and 138-kV network.

ERCOT used the UPLAN NPM model to perform transmission-expansion analysis. ERCOT used the start case for the year 2027 from the 2022 RTP economic analysis as a starting point for the Current Trends scenario. This case was first updated to incorporate status changes for existing and planned generation, which occurred before the start of this study, as well as status changes to near-term transmission projects.

For each scenario and each study year, the case was then modified with the scenario-specific generation fleet changes and demand adjustments, which resulted from the inputs from the scenario development. ERCOT used the resource profile, including generation retirements, generation additions, and profiles for demand response, as developed by capacity-expansion and retirement analysis, to model capacity additions for each scenario and study year. The locations of new resources were determined based on the limitations of the technology; certain technologies such as combustion turbines are more flexible and can be built in many areas across the state, whereas the availability of the natural resources limits solar- and wind-resource locations. Figure 21 shows the results of generation siting in the Current Trends scenario, considered for transmission-expansion analysis. The resources were modeled in the cases at the appropriate buses as outlined in the guidelines from the resource siting methodology provided as Appendix II. Similarly, generating units were retired consistent with the resource-expansion results. Detailed information for generation retirements is included in Appendix III.

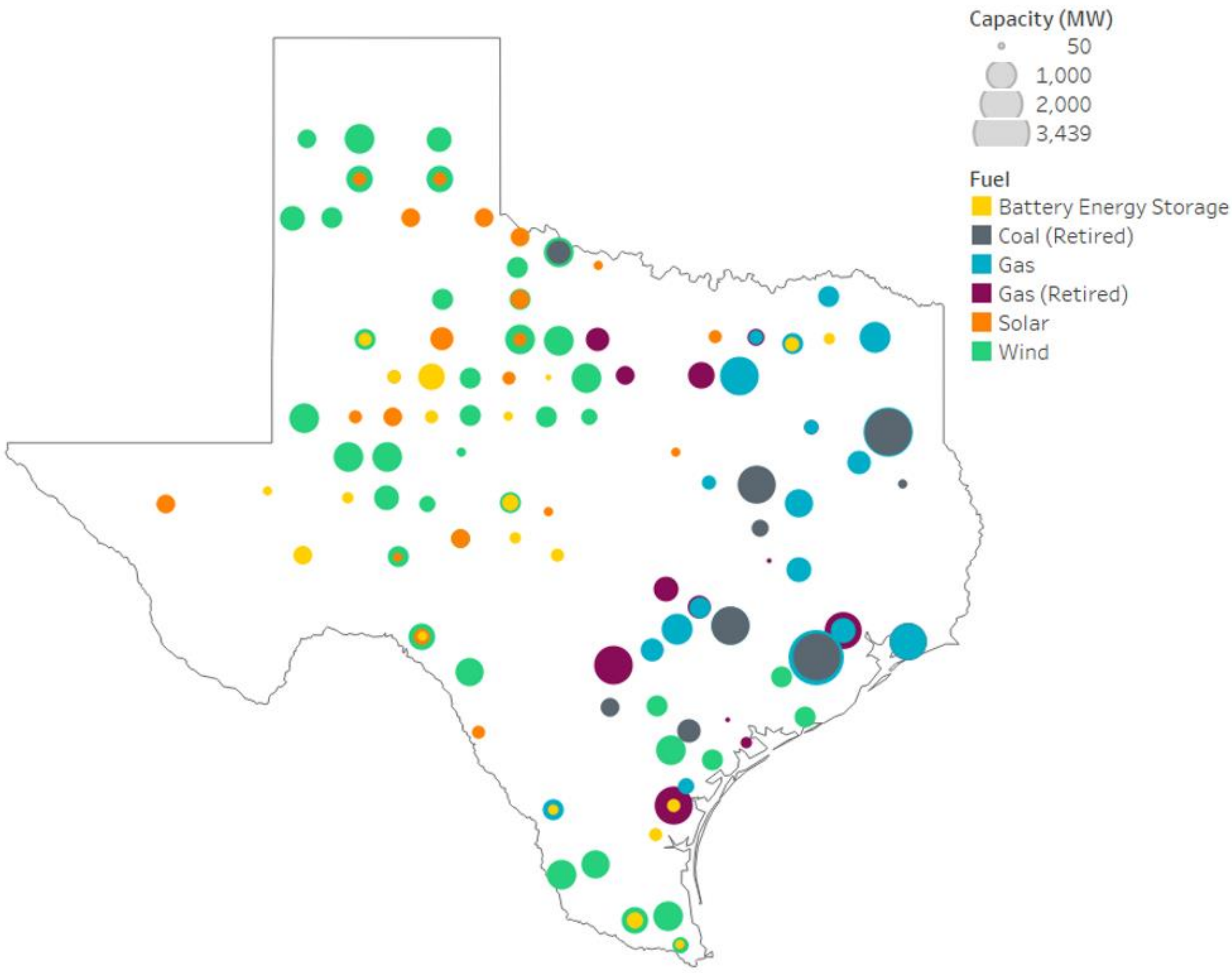

Figure 21: Generation Additions and Retirements in the Current Trends Scenario (2037)

ERCOT analyzed each of the scenario-appropriate base cases created for 2032 and 2037 for the congestion patterns of the system. ERCOT studied NERC TPL-001-5.1 Planning Events P0, P1, and P7, which included the loss of a generator, a transmission circuit, or a transformer. ERCOT's P7 planning events also included the loss of double circuit lines that share towers for more than half a mile. In addition to the above contingencies, ERCOT included generator maintenance outages in this evaluation.

ERCOT evaluated the contingencies at all voltage levels, but mainly focused on violations and congestion on the network connected at 100-kV and above, as the needs to resolve violations and congestion on the 69-kV network were assumed to be addressed through the RTP process and/or other near-term planning processes. To reveal the potential violations and congestion on the 345-kV network, ERCOT added transmission upgrades due to identified local needs to facilitate generation addition and demand growth in the corresponding start cases and did not monitor the 69-kV transmission elements.

ERCOT evaluated the reliability and congestion needs of the system for the Current Trends scenario. At the time of the analysis, ERCOT's economic criteria for project evaluation was pending. As a result, potential transmission projects to alleviate observed congestions in the system were not evaluated. A summary of this analysis can be found in Appendix IV below.

Appendix II: Resource Siting Methodology

The Long-Term System Assessment Resource Siting Methodology is included in a separate document attached with the report.

Appendix III: Fixed-Age Generation Retirements

Unit Name	Unit ID	Fuel	summer Capacity	In Service	Retirement Date
MARTIN LAKE 2	MLSES_UNIT2	Coal	805	1978	12/31/2023
W A PARISH 6	WAP_WAP_G6	Coal	663	1978	12/31/2023
HANDLEY 3	HLSES_UNIT3	Gas	395	1963	12/31/2023
FAYETTE POWER PROJECT 1	FPPYD1_FPP_G1	Coal	604	1979	12/31/2024
MARTIN LAKE 3	MLSES_UNIT3	Coal	805	1979	12/31/2024
COLETO CREEK	COLETO_COLETOG1	Coal	655	1980	12/31/2025
FAYETTE POWER PROJECT 2	FPPYD1_FPP_G2	Coal	599	1980	12/31/2025
W A PARISH 7	WAP_WAP_G7	Coal	577	1980	12/31/2025
SIM GIDEON 1	GIDEON_GIDEONG1	Gas	130	1965	12/31/2025
STRYKER CREEK 2	SCSES_UNIT2	Gas	502	1965	12/31/2025
TRINIDAD 6	TRSES_UNIT6	Gas	235	1965	12/31/2025
POWERLANE PLANT 1	STEAM1a_STEAM_1	Gas	18	1966	12/31/2026
V H BRAUNIG 1	BRAUNIG_VHB1	Gas	217	1966	12/31/2026
SAN MIGUEL 1	SANMIGL_G1	Coal	391	1982	12/31/2027
W A PARISH 8	WAP_WAP_G8	Coal	610	1982	12/31/2027
T H WHARTON G1	THW_THWGT_1	Gas	14	1967	12/31/2027
W A PARISH T1	WAP_WAPGT_1	Gas	13	1967	12/31/2027
MOUNTAIN CREEK 8	MCSES_UNIT8	Gas	568	1967	12/31/2027
POWERLANE PLANT 2	STEAM_STEAM_2	Gas	24	1967	12/31/2027
RAY OLINGER 1	OLINGR_OLING_1	Gas	78	1967	12/31/2027
R W MILLER 1	MIL_MILLERG1	Gas	70	1968	12/31/2028
SIM GIDEON 2	GIDEON_GIDEONG2	Gas	135	1968	12/31/2028
V H BRAUNIG 2	BRAUNIG_VHB2	Gas	230	1968	12/31/2028
W A PARISH 4	WAP_WAP_G4	Gas	527	1968	12/31/2028
GRAHAM 2	GRSES_UNIT2	Gas	390	1969	12/31/2029
LIMESTONE 1	LEG_LEG_G1	Coal	824	1985	12/31/2030
CEDAR BAYOU 1	CBY_CBY_G1	Gas	745	1970	12/31/2030
LAKE HUBBARD 1	LHSES_UNIT1	Gas	392	1970	12/31/2030
V H BRAUNIG 3	BRAUNIG_VHB3	Gas	412	1970	12/31/2030
LIMESTONE 2	LEG_LEG_G2	Coal	836	1986	12/31/2031
RAY OLINGER 2	OLINGR_OLING_2	Gas	107	1971	12/31/2031
NUECES BAY STG 7	NUECES_B_NUECESG7	Gas	567	1972	12/31/2032
CEDAR BAYOU 2	CBY_CBY_G2	Gas	749	1972	12/31/2032
O W SOMMERS 1	CALAVERS_OWS1	Gas	420	1972	12/31/2032
R W MILLER 2	MIL_MILLERG2	Gas	118	1972	12/31/2032
SIM GIDEON 3	GIDEON_GIDEONG3	Gas	336	1972	12/31/2032
NUECES BAY STG 7_DB	NUECES_B_NUECESG7_DB	Gas	66	1972	12/31/2032
FAYETTE POWER PROJECT 3	FPPYD2_FPP_G3	Coal	437	1988	12/31/2033
ATKINS 7	ATKINS_ATKINSG7	Gas	18	1973	12/31/2033
LAKE HUBBARD 2	LHSES_UNIT2A	Gas	523	1973	12/31/2033
T H WHARTON STG 3	THW_THWST_3	Gas	326	1974	12/31/2034
T H WHARTON STG 4	THW_THWST_4	Gas	326	1974	12/31/2034
B M DAVIS 1	B_DAVIS_B_DAVIG1	Gas	300	1974	12/31/2034
O W SOMMERS 2	CALAVERS_OWS2	Gas	410	1974	12/31/2034
TWIN OAKS 1	TNP_ONE_TNP_O_1	Coal	155	1990	12/31/2035
T H WHARTON 51	THW_THWGT51	Gas	56	1975	12/31/2035
T H WHARTON 52	THW_THWGT52	Gas	56	1975	12/31/2035
T H WHARTON 53	THW_THWGT53	Gas	56	1975	12/31/2035
T H WHARTON 54	THW_THWGT54	Gas	56	1975	12/31/2035
T H WHARTON 55	THW_THWGT55	Gas	56	1975	12/31/2035
T H WHARTON 56	THW_THWGT56	Gas	56	1975	12/31/2035
R W MILLER 3	MIL_MILLERG3	Gas	208	1975	12/31/2035
RAY OLINGER 3	OLINGR_OLING_3	Gas	146	1975	12/31/2035
B M DAVIS STG 2	B_DAVIS_B_DAVIG2	Gas	615	1976	12/31/2036
TWIN OAKS 2	TNP_ONE_TNP_O_2	Coal	155	1991	12/31/2036
GREENS BAYOU 73	GBY_GBYGT73	Gas	56	1976	12/31/2036
GREENS BAYOU 74	GBY_GBYGT74	Gas	56	1976	12/31/2036
GREENS BAYOU 81	GBY_GBYGT81	Gas	56	1976	12/31/2036
GREENS BAYOU 82	GBY_GBYGT82	Gas	50	1976	12/31/2036
GREENS BAYOU 83	GBY_GBYGT83	Gas	56	1976	12/31/2036
GREENS BAYOU 84	GBY_GBYGT84	Gas	56	1976	12/31/2036
HANDLEY 4	HLSES_UNIT4	Gas	435	1976	12/31/2036
B M DAVIS STG 2_DB	B_DAVIS_B_DAVIG2_DB	Gas	18	1976	12/31/2036
J K SPRUCE 1	CALAVERS_JKS1	Coal	560	1992	12/31/2037
HANDLEY 5	HLSES_UNIT5	Gas	435	1977	12/31/2037

Appendix IV: Scenario Results Summary

Demand Forecasts

The load forecasts for the Current Trends and Expanded System Outlook scenarios were the same. The load forecasts were developed by applying the following three adjustments to the long-term load forecast based on 2013 weather year released in January 2021: (1) the Private Use Network (PUN) load was added on the top of the long-term load forecast; (2) the distributed solar was treated as a negative load modifier; and (3) the EV-charging load was also included. The resulted summer peak demand and annual energy forecasts are shown in Figure 22.

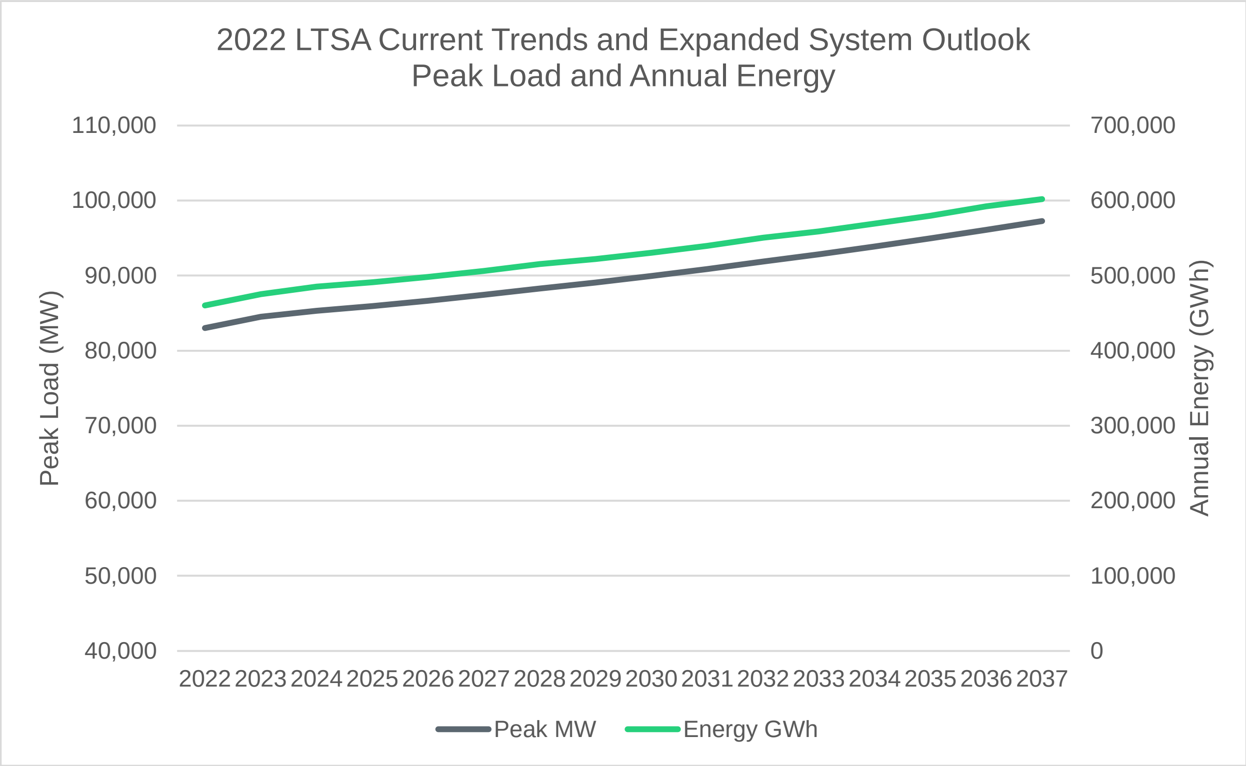

Figure 22: Energy and Peak Demand for Current Trends and Expanded System Outlook Scenarios

A high EV adoption and an aggressive distributed solar projection were used for the Demand Side Evolution scenario and sensitivity case. The biggest change in the load forecast was the inclusion of 16 GW of LFLs. Therefore, the load forecasts are much higher than the Current Trends and Expanded System Outlook scenarios. The summer peak demand and annual energy forecast for the Demand Side Evolution scenario and sensitivity are depicted in Figure 23.

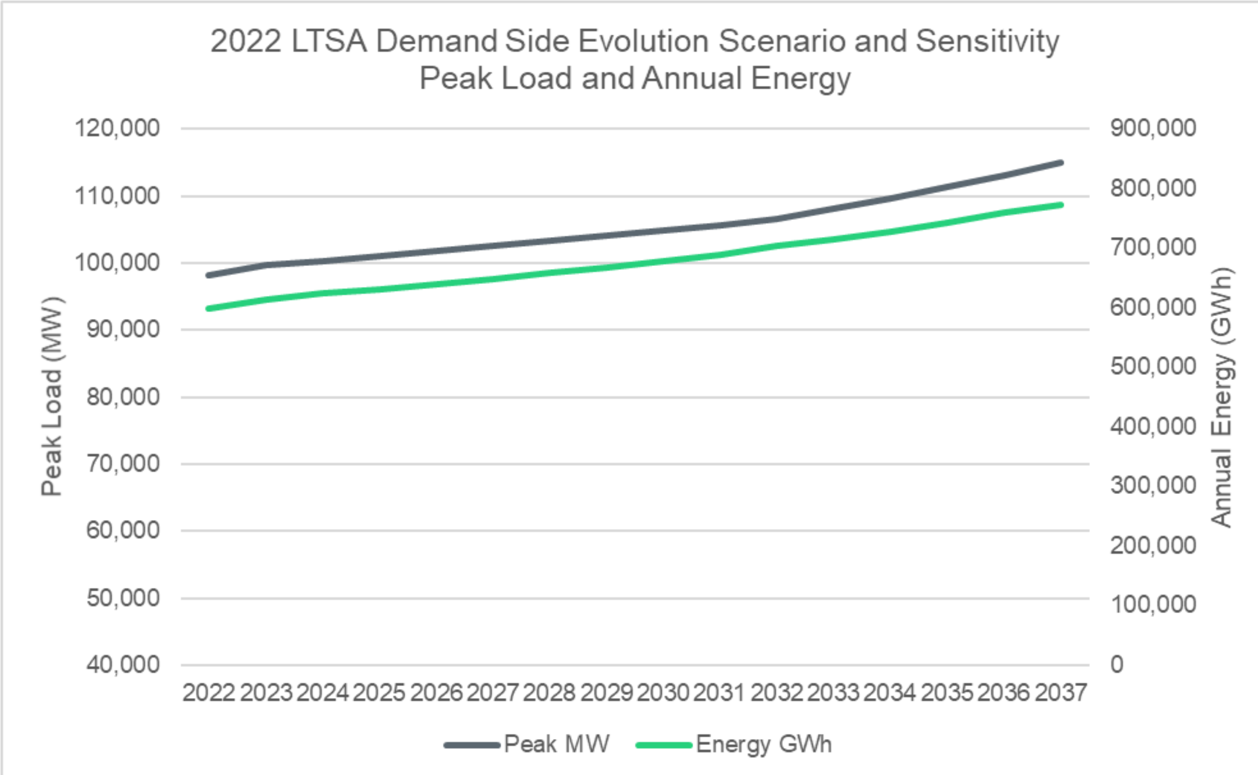

Figure 23: Energy and Peak Demand for Demand Side Evolution Scenario and Sensitivity

Current Trends Scenario

The Current Trends scenario was designed to simulate current market conditions extended 15 years into the future. The Current Trends scenario included an EV assumption and the moderate distributed solar projection[14] presented at the May 2021 SAWG meeting as outlined below.

EV adoption by type, based on adjusted Bloomberg New Energy Finance (BNEF) 2020 projection,[15] was included in this scenario as shown in Figure 24. Transportation electrification was assumed to start slowly but grow exponentially as wider availability of desirable models and cost reductions in battery technology are realized. The light-duty vehicles category includes both cars and pickup trucks, but different adoption rates were used for them. Assumed EV growth was determined by adjusting the BNEF projection (time-shifting curve to match actual sales from 2015 through 2020). The three categories of EVs identified in the 2020 LTSA were expanded to 4 categories in the 2022 LTSA by separating buses and short haul trucks given the availability of the buses' charging patterns/metrics. Miles driven by trucks were also estimated since growth projections, which were not available in time for the 2020 LTSA, exist now. Electric load was based on miles-driven data for trucks and buses from Texas Department of Transportation (TXDOT) and Texas Education Agency (TEA) data.

[14] https://www.ercot.com/files/docs/2021/05/18/SAWG__Meeting_5-18-2021_Updated_Rooftop_Solar_Growth_Projectionsv3.pptx

[15] https://about.bnef.com/new-energy-outlook-2020/

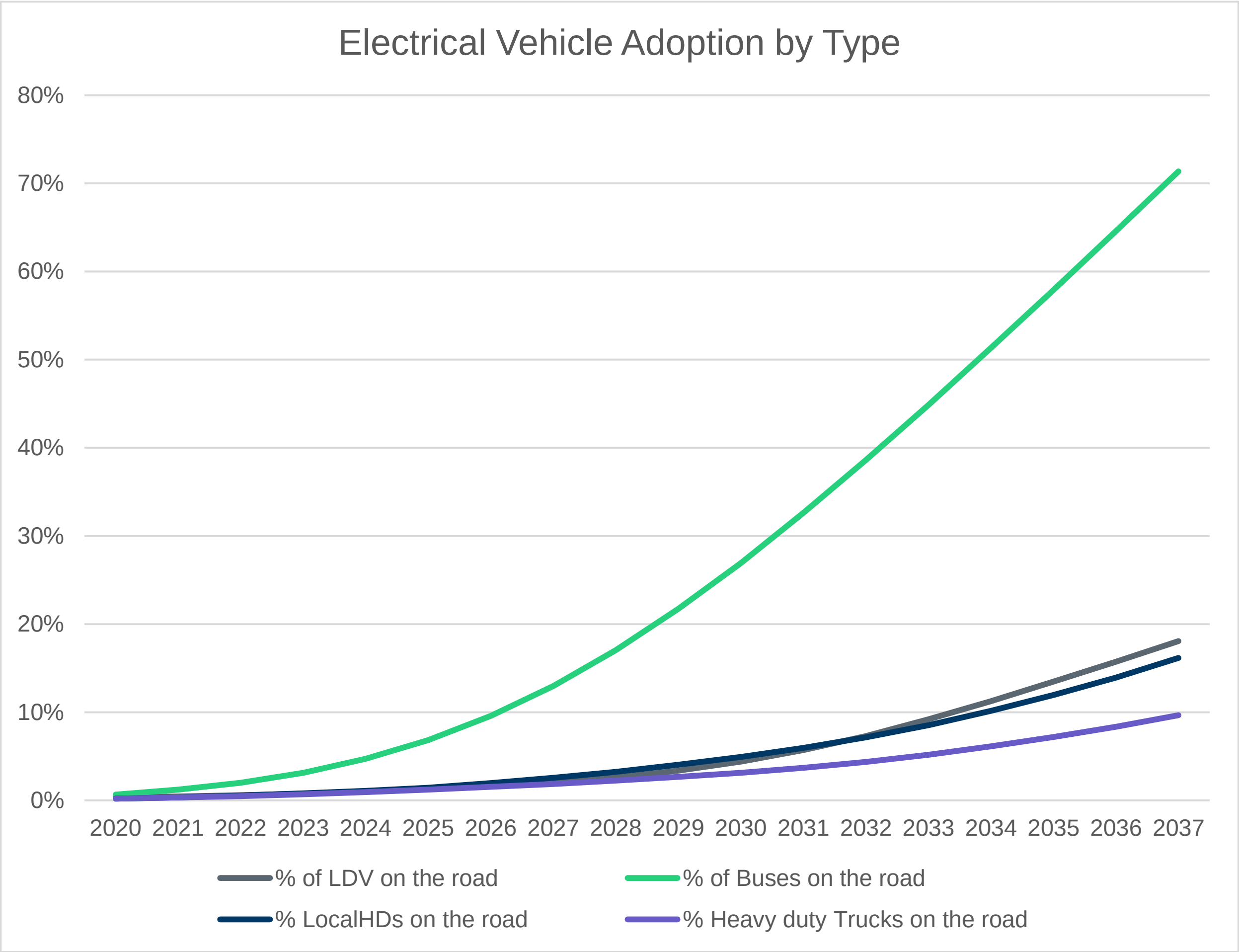

Figure 24: Adoption of EV in the Current Trends Scenario

For 2037, the peak charging demand for all EVs was estimated to be over 9,300 MW at midnight. Approximately 1,500 to 2,600 MW of charging demand was expected during hours ending between 9 am and 5 pm. In this scenario, peak electric vehicle demand was assumed to occur at approximately 11 pm. Below, Figure 25 shows the hourly charging pattern by type.

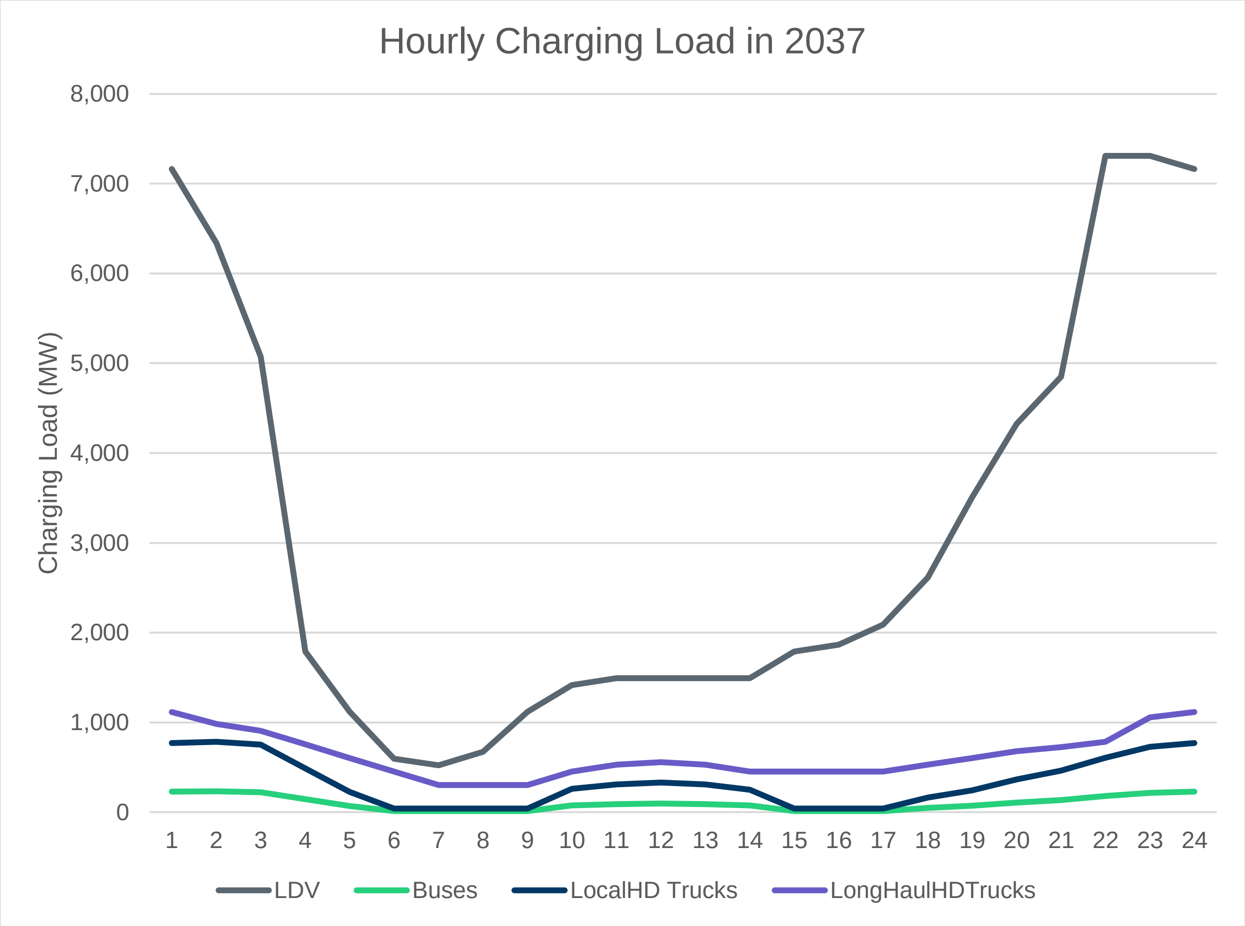

Figure 25: Estimated Total Charging Demand of EVs in 2037

Distributed solar adoption was assumed to follow a moderate growth sigmoid (or S-curve) pattern. The maximum distributed solar potential in urban and rural areas was estimated by Underwriters Laboratories (UL) in a screening analysis.[16] The market saturation rate was assumed to be 20%; fast growth was assumed to start in 2021; and the takeover time was assumed to be seven years. Figure 26 shows assumed distributed solar adoption by year. The distributed solar peaked at close to 5,920 MW.

[16]https://www.ercot.com/files/docs/2020/07/31/ERCOT_SolarPVProfiles_1980-2019.zip

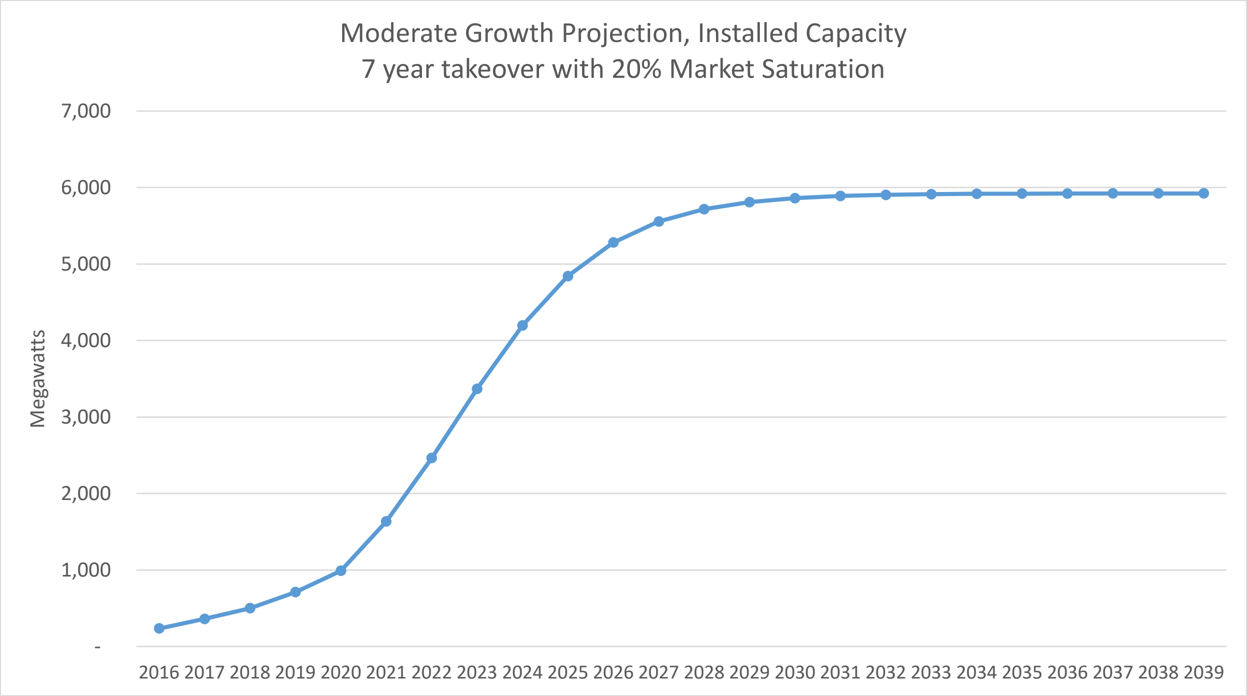

Figure 26: Distributed Solar Adoption by Year

The generation retirement process for the Current Trends scenario had two distinct parts. First, a group of fixed-age retirements were determined for use in all scenarios. These fixed-age retirements were determined by the age of an existing unit. Natural gas units were retired after 60 years of operation, and coal units were retired after 45 years of service. The second part of the generation retirement process considered economics as the criterion for retirement. Based on economic simulations, if a unit's fixed and variable costs were greater than the unit's total revenue the unit was retired by the model. Total resources retired by 2037 were 19,670 MW. The retirements for different technology types are shown in Table 6.

The Current Trends scenario resulted in additions of 19,494 MW of combined cycle, 474 MW of simple cycle combustion turbine, 5,800 MW of utility-scale solar, 27,100 MW of wind, and 4,557 MW of battery energy storage. Fixed-aged retirements totaling 4,140 MW were accelerated based on economic analysis. Table 6 shows the starting capacity mix, retirements, and capacity-expansion additions for the Current Trends scenario for the 15-year study period.

Table 6: Capacity-Expansion Results for the Current Trends Scenario

	2022LTSA - Current Trends (MW)					
	Operational Resources	Planned Resources	Total Starting Capacity Mix	Retirements	Capacity Expansion	Total Resources
Battery	235	1,807	2,042	-	4,557	6,598
Combined Cycle	37,478	86	37,564	1,918	19,494	55,139
CT & IC	12,616	860	13,476	711	474	13,239
Gas Steam	11,620	60	11,680	8,819	-	2,861
Solar	4,095	13,332	17,427	-	5,800	23,227
Wind	25,203	11,821	37,024	-	27,100	64,124
Coal	12,151	-	12,151	8,116	-	4,034
Hydro	536	-	536	-	-	536
Nuclear	5,153	-	5,153	-	-	5,153
Other	920	-	920	105	-	815
Total	110,006	27,965	137,972	19,670	57,425	175,726

A summary of the capacity-expansion results for the Current Trends scenario is shown in Table 7 below. In this scenario the reserve margin varied between 10% to 20% from 2023 to 2037. For 2027, 2032, and 2037 the number of scarcity hours were 12, 23, and 11 hours respectively. For the same study years, during the summer season the unserved energy occurred between 3 pm to 8 pm, and during winter the unserved energy is between 6 pm and 1 am. The 15-year comparison of capacity additions for different technology types between the 2020 LTSA and the 2022 LTSA is shown in Figure 27, found below Table 7. Compared to the 2020 LTSA, the 2022 Current Trends scenario resulted in more combined cycle and battery energy storage capacity, but less solar, wind and combustion turbine capacity.

Table 7: Summary of the Results for Current Trends Scenario

Description	Units	2023	2027	2032	2037	Total
CC Adds	MW	-	-	2,166	17,328	19,494
CT Adds	MW	-	-	474	-	474
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
Storage Adds	MW	-	800	3,180	577	4,557
Solar Adds	MW	-	-	5,800	-	5,800
Wind Adds	MW	600	9,300	13,100	4,100	27,100
Annual Capacity Additions	MW	600	10,100	24,720	22,005	
Cumulative Capacity Additions	MW	600	10,700	35,420	57,425	
Retirements	MW	-	7,123	5,447	7,099	
Cumulative Retirements	MW	-	7,123	12,571	19,670	
Reserve Margin	%	20	10	11	16	
Coincident Peak	MW	84,499	87,430	91,891	97,279	
Peak Net Load (1)	MW	69,651	71,840	76,458	86,558	
Minimum Net load (1)	MW	9,491	8,065	4,592	5,497	
Annual Energy	GWhs	475,132	506,060	550,505	601,975	
Average LMP	$/MWh	25.44	49.26	68.85	47.45	
Natural Gas Price	$/MMbtu	3.10	3.44	4.39	5.04	
Average Market Heat Rate	MMbtu/MWh	8.20	14.34	15.70	9.41	
Natural Gas Generation	%	43.14	40.35	35.03	38.03	
Coal Generation	%	9.36	6.85	4.91	3.97	
Wind Generation	%	28.80	35.16	41.49	41.00	
Solar Generation	%	8.41	8.00	9.80	8.99	
Scarcity Hours	HRS	-	12	23	11	
Unserved Energy	GWhs	-	21.77	71.64	37.63	

(1) Hourly Net Load = Hourly Load Forecast – Hourly Wind Output – Hourly Solar Output

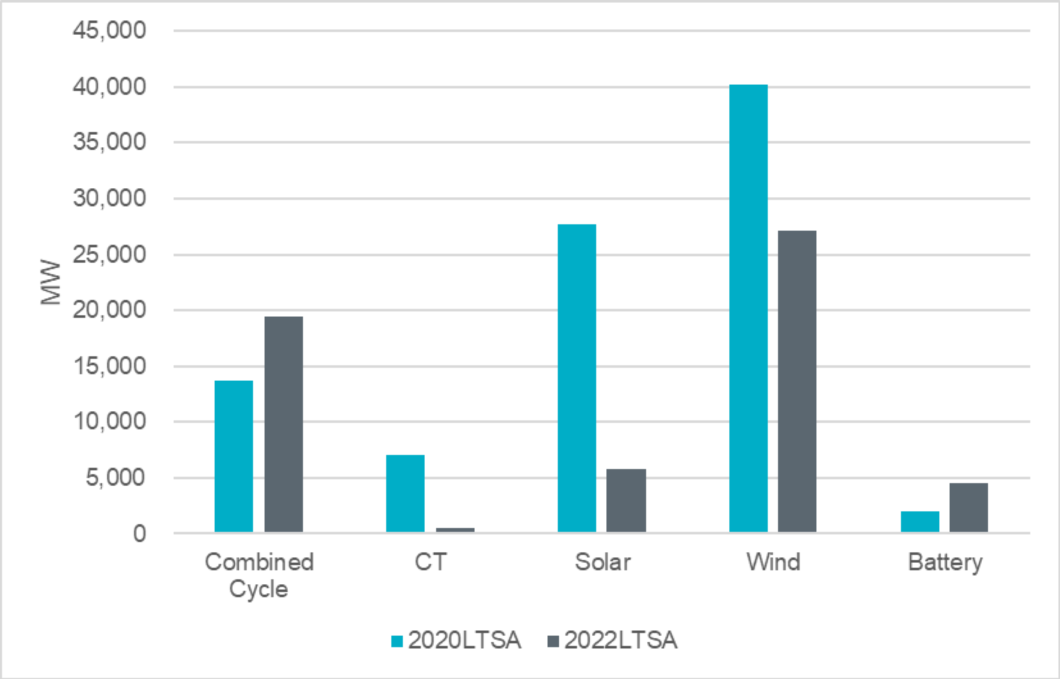

Figure 27: 15-Year capacity expansion comparison of the 2020 versus 2022 LTSA Current Trends Scenario

As described in Appendix I, ERCOT used the UPLAN NPM model to perform transmission expansion analysis. Any recently approved RPG projects and local 138-kV upgrades and additions were included in the start cases. Figure 2828 and 29 show a map of Texas with the top congested elements connected at levels 100-kV and higher for the 2032 and 2037 study years, respectively. The size of each bubble indicates the amount of annual congestion rent. At the time of the analysis, ERCOT's economic criteria for project evaluation was pending. As a result, potential economically driven transmission improvements were not evaluated in the 2022 LTSA.

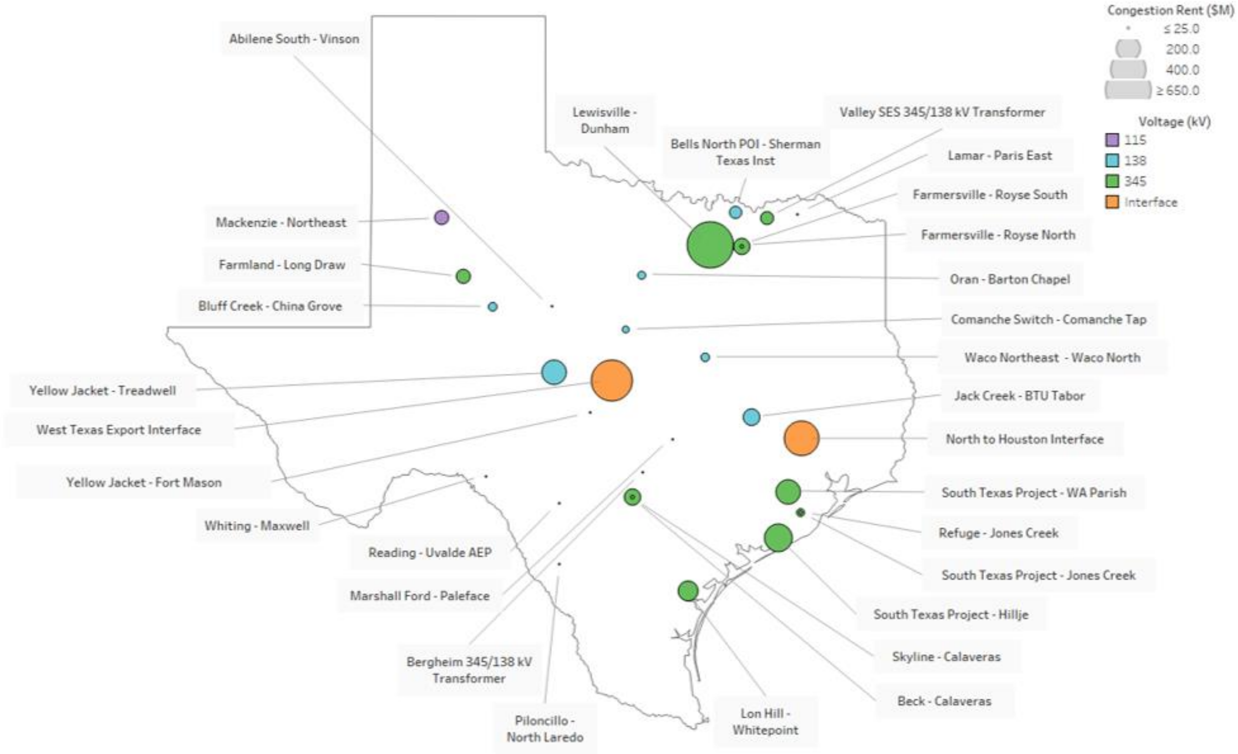

Figure 28: Top Constraints for the Current Trends Scenario (2032)

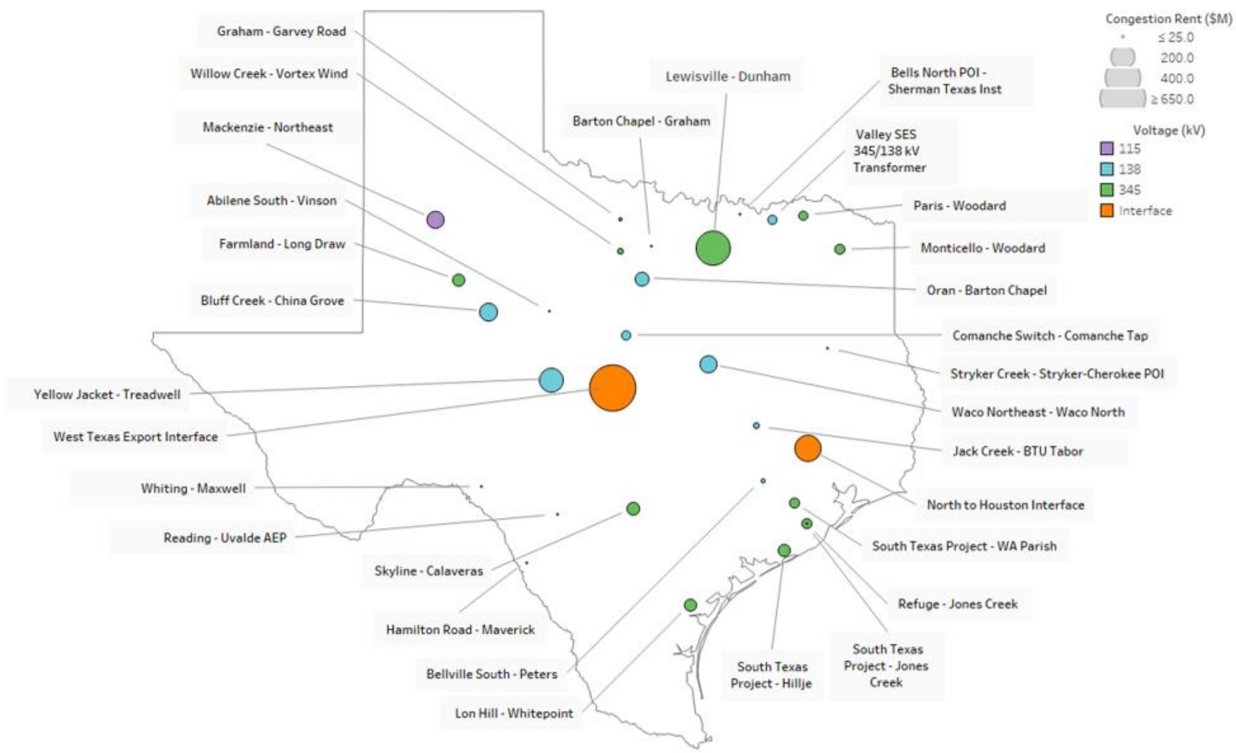

Figure 1029: Top Constraints for Current Trends Scenario (2037)

Expanded System Outlook

The Current Trends scenario included planned resources meeting the requirements of Planning Guide Section 6.9(1) as of March 31, 2021 in the starting capacity mix used for capacity-expansion and retirement analysis. The Expanded System Outlook scenario was designed to help overcome challenges with under-selection of some resource types (i.e., batteries and solar). The capacity-expansion results for the Current Trends scenario showed less new battery energy storage, solar, and wind capacities than what was reflected in the December 2021 Capacity, Demand and Reserve (CDR) report.[17] In this scenario, additional planned resources from the December 2021 CDR were included to evaluate the impact on capacity-expansion results.

Table 8 shows the starting capacity mix comparison between the Current Trends and the Expanded System Outlook scenarios. In the Expanded System Outlook scenario, an additional 2,523 MW of battery energy storage, 663 MW of gas, 15,719 MW of solar and 2,853 MW of wind were included compared with the Current Trends scenario. This resulted in 159,730 MW of starting capacity resources as an input to the model compared to 137,972 MW in the Current Trends scenario. Please note Table 8 does not reflect the fixed and planned unit retirements.

Table 8: Starting capacity mix comparison between the Current Trends and the Expanded System Outlook scenarios

	2022LTSA - Current Trends (MW)			Expanded System Outlook (MW)	
	Operational Resources	Planned Resources	Total Starting Capacity Mix	Resources incremental to CT1	Total Starting Capacity Mix
Battery	235	1,807	2,042	2,523	4,565
Combined Cycle	37,478	86	37,564	-	37,564
CT & IC	12,616	860	13,476	663	14,139
Gas Steam	11,620	60	11,680	-	11,680
Solar	4,095	13,332	17,427	15,719	33,146
Wind	25,203	11,821	37,024	2,853	39,877
Coal	12,151	-	12,151	-	12,151
Hydro	536	-	536	-	536
Nuclear	5,153	-	5,153	-	5,153
Other	920	-	920	-	920
Total	110,006	27,965	137,972	21,759	159,730

Table 9 shows the starting capacity mix, the retirements by 2037, and the capacity-expansion additions by 2037 for the Expanded System Outlook scenario. In this scenario 546 MW of battery energy storage, 21,660 MW of combined cycles, and 13,700 MW of wind expansion capacity were added by the model to meet the load growth and replace the retirements. The total fixed and economic retirements were 19,683 MW. This resulted in total resources of 175,953 MW by 2037 for this scenario.

[17] https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.xlsx

Table 9: Starting Capacity Mix, Retirements, and Capacity-Expansion Results for the Expanded System Outlook Scenario

	Expanded System Outlook (MW)			
	Total Starting Capacity Mix	Retirements	Capacity Expansion	Total Resources
Battery	4,565	-	546	5,111
Combined Cycle	37,564	1,918	21,660	57,305
CT & IC	14,139	711	-	13,427
Gas Steam	11,680	8,819	-	2,861
Solar	33,146	-	-	33,146
Wind	39,877	13	13,700	53,564
Coal	12,151	8,116	-	4,034
Hydro	536	-	-	536
Nuclear	5,153	-	-	5,153
Other	920	105	-	815
Total	159,730	19,683	35,906	175,953

Table 10 shows the summary of the results for the Expanded System Outlook scenario. In this scenario the reserve margin varied between 22% to 30% from 2023 to 2037. For 2027, 2032, and 2037 the number of scarcity hours were 1, 10, and 7 hours respectively. For the same study years, during the summer season, the unserved energy occurred at 8 pm, and, during winter the unserved energy is between 7 pm and 12 am midnight.

Table 10: Summary of the Results for the Expanded System Outlook Scenario

Description	Units	2023	2027	2032	2037	Total
CC Adds	MW	-	-	7,581	14,079	21,660
CT Adds	MW	-	-	-	-	-
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
Storage Adds	MW	-	156	-	390	546
Solar Adds	MW	-	-	-	-	-
Wind Adds	MW	-	3,400	7,900	2,400	13,700
Annual Capacity Additions	MW	-	3,556	15,481	16,869	
Cumulative Capacity Additions	MW	-	3,556	19,037	35,906	
Retirements	MW	13	8,198	5,563	5,909	
Cumulative Retirements	MW	13	8,210	13,773	19,682	
Reserve Margin	%	30	23	22	24	
Coincident Peak	MW	84,499	87,430	91,891	97,279	
Peak Net Load (1)	MW	68,922	72,218	76,898	87,089	
Minimum Net load (1)	MW	7,764	6,719	6,213	6,282	
Annual Energy	GWhs	475,132	506,060	550,505	601,975	
Average LMP	$/MWh	23.85	29.84	49.24	46.09	
Natural Gas Price	$/MMbtu	3.10	3.44	4.39	5.04	
Average Market Heat Rate	MMbtu/MWh	7.69	8.69	11.23	9.14	
Natural Gas Generation	%	38.98	37.97	37.71	41.66	
Coal Generation	%	8.30	6.62	5.21	4.25	
Wind Generation	%	29.55	31.14	34.69	33.47	
Solar Generation	%	12.94	14.71	13.55	12.47	
Scarcity Hours	HRS	-	1	10	7	
Unserved Energy	GWhs	-	2.26	27.63	19.38	

(1) Hourly Net Load = Hourly Load Forecast – Hourly Wind Output – Hourly Solar Output

Demand Side Evolution

This scenario was developed to evaluate an increased adoption of demand-side technologies, as well as studying the impact of flexibility of certain types of demand on system needs. The key input assumptions that differed from the Current Trends scenario are shown below:

- High distributed solar adoption
- High EV adoption
- Managed EV charging
- Addition of 16 GW of LFL based on an informal survey that was conducted in early 2022.
- LFL was allowed to be curtailed at market price of 100 $/MWh or above.

Distributed solar adoption was assumed to follow an aggressive growth S-curve pattern. The maximum distributed solar potential in urban and rural areas was estimated by UL in a screening analysis.[18] The market saturation rate was assumed to be 25%; fast growth was assumed to start in 2021; and the takeover time was assumed to be four years. Figure 30 shows assumed distributed solar adoption by

[18] https://www.ercot.com/files/docs/2020/07/31/ERCOT_SolarPVProfiles_1980-2019.zip

year and compared with the S-curve projection for the Current Trends scenario. The aggressive distributed solar peaked at close to 7,380 MW.

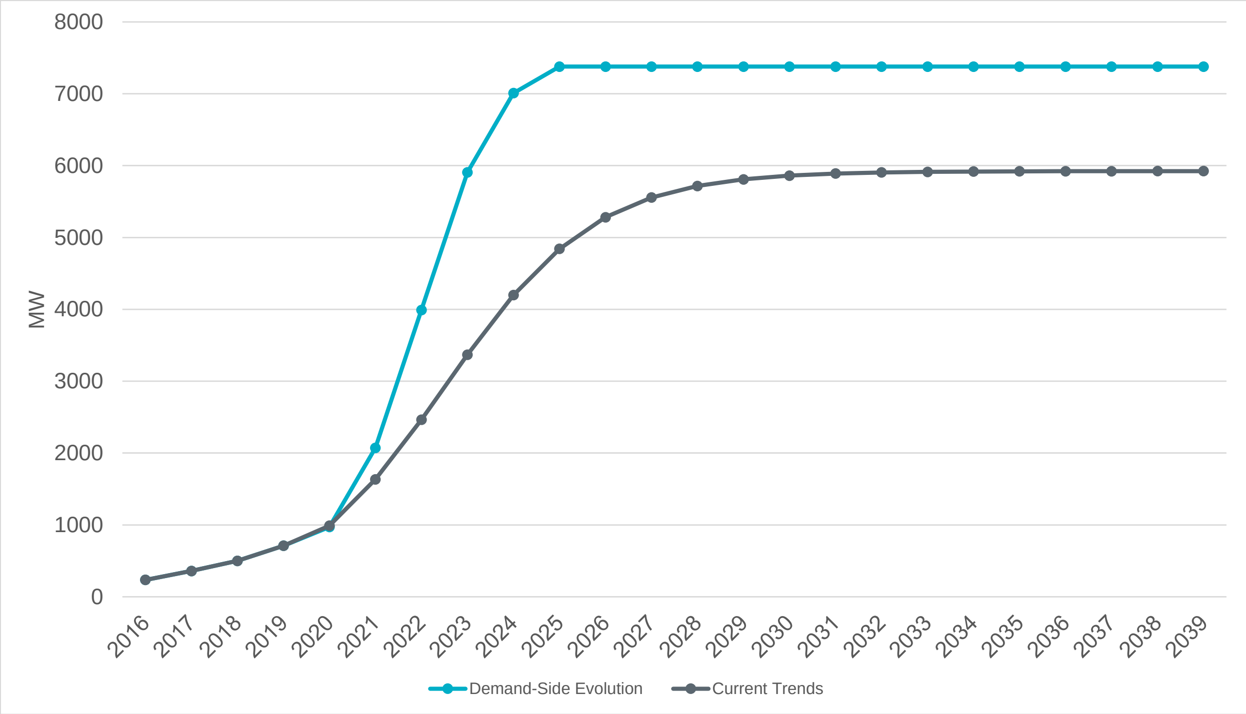

Figure 30: S-Curve for Aggressive Growth Projection of Distributed Solar

An aggressive EV adoption was assumed for the Demand Side Evolution scenario as shown in Figure 31. The adoption levels of local heavy-duty vehicles and long-haul heavy-duty trucks were more than doubled. To mitigate the potential negative consequences of the high-level EV adoption, EV charging load should be wisely distributed across hours in a day.

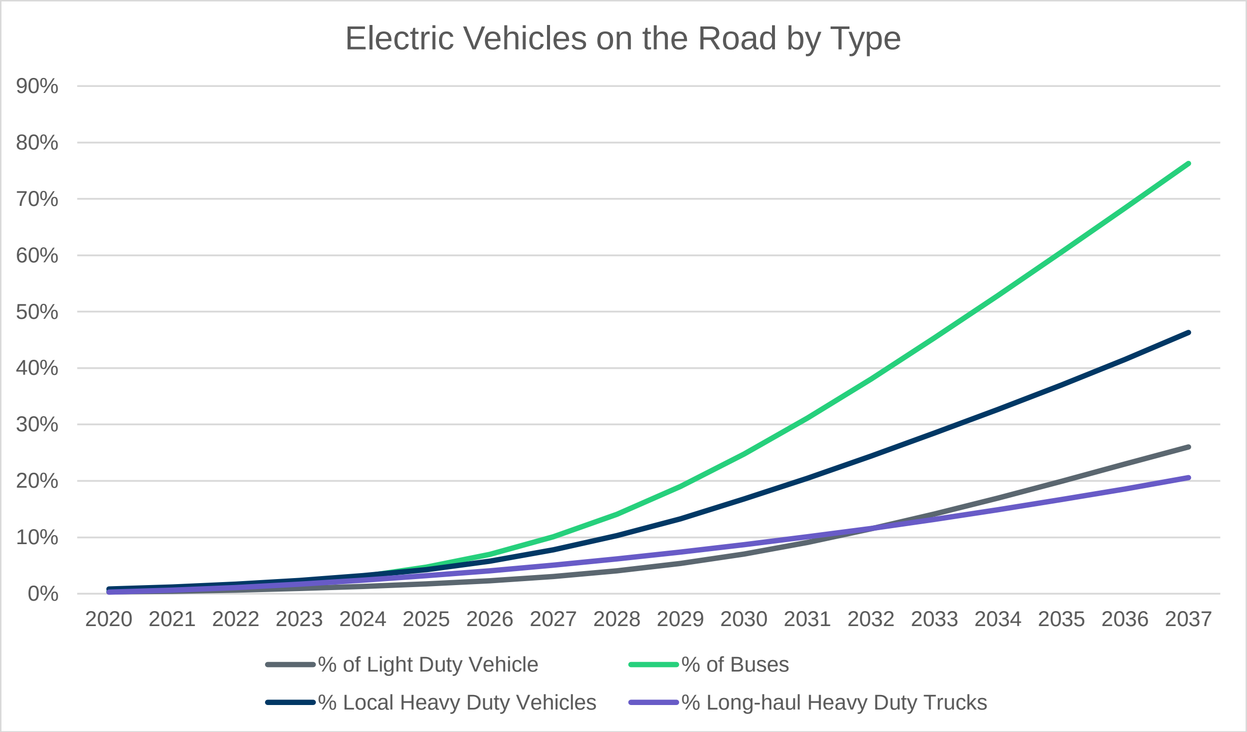

Figure 31: High Adoption of EV in the Demand Side Evolution Scenario

Impacts of EV adoption is heavily dependent on charging patterns. In this scenario, EV charging energy demand was balanced throughout the day, with a focus on reducing energy usage during peak net load periods. EV managed charging profiles were developed for each season to capture seasonality of renewable generation and non-EV load. To simplify the problem, three charging load levels were assumed (high, medium, and low). There were two steps to determine EV charging load for each hour. First, hourly average net load for each season was calculated since net load reflects both renewable generation output and non-EV load level; then, based on the gap between the peak net load and hourly average net load, EV charging level was determined with the consideration of driving needs as shown in Figure 32. EV charging load was high when the gap was big and driving needs are low, for example, hour ending 1:00-6:00, 10:00-11:00 and 24:00 in summer. EV charging load was medium when the gap or driving needs were medium, for example, though the gap is big in hour ending 7:00 and 9:00 but morning commute starts and ends in these two hours, respectively, so EV charging load was medium for these hours. For hour ending 12:00-15:00 and 23:00, the gap was medium, there were also substantial driving needs during lunch hours, so EV charging load was also medium for these hours. For hours ending 8:00 and 16:00-22:00, the gap in hour ending 8:00 was high, but it is the peak hour for morning commutes, so vehicles are not available for charging and charging load should be low; for the other hours, the gap was small so charging load was low. Based on this approach, EV charging profiles were developed for each season in each year. Figures 33 and 34 show the EV charging profiles for each season in 2037.

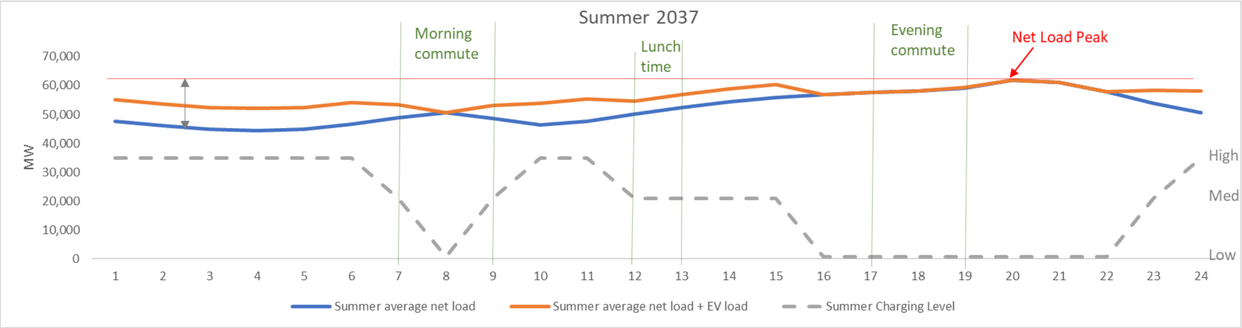

Figure 32: Illustration of EV Charging Load Management Method

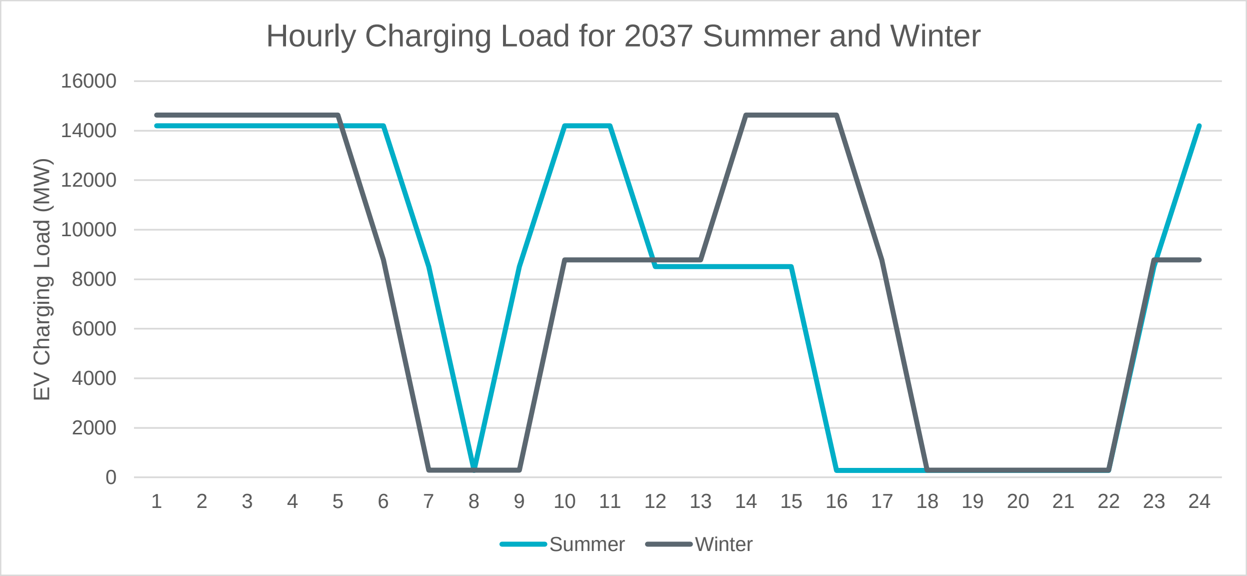

Figure 33: Summer and Winter Managed EV Charging

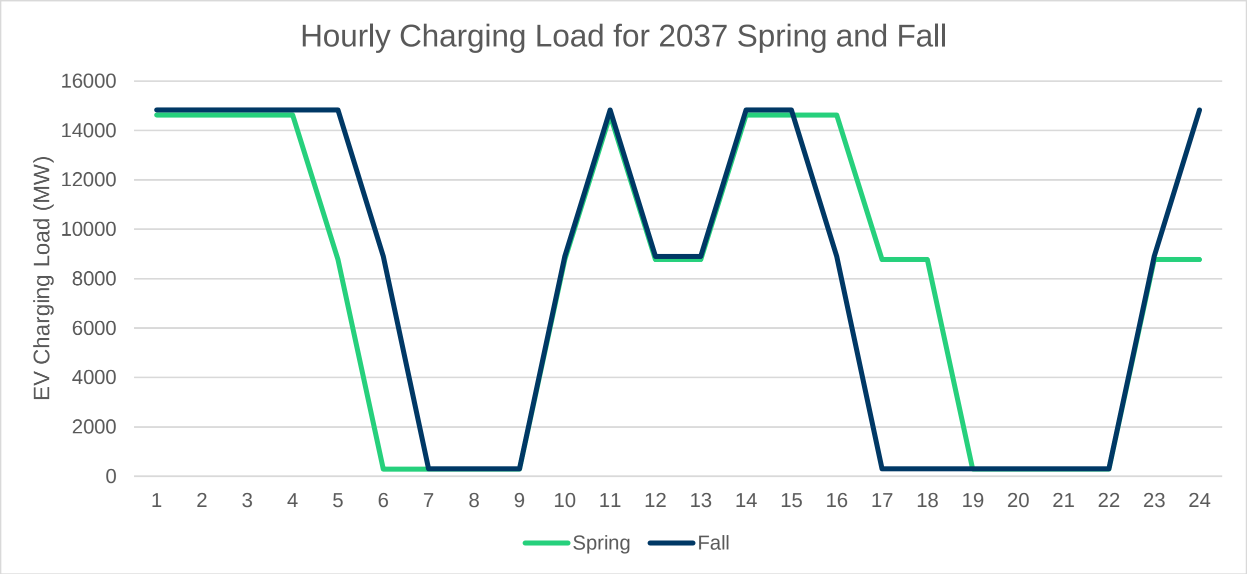

Figure 34: Spring and Fall Managed EV Charging

The operational and planned resources for the Demand Side Evolution scenario were the same as the Current Trends scenario so the total starting capacity mix was the same for the two scenarios. This scenario included 16 GW of LFL based on an informal survey that was put out in early 2022. The 16 GW LFL was allowed to be curtailed at market price of 100 $/MWh or above. Table 11 shows the starting capacity mix, retirements, and the expansion capacity additions for the Demand Side Evolution scenario. In this scenario, 370 MW of battery energy storage, 30,324 MW of combined cycles, 1,100 MW of solar, and 19,800 MW of wind expansion capacity were added by the model. The total expansion capacity addition was 51,594 MW. The total fixed and economic retirements were 19,565 MW. This resulted in total resources of 170,001 MW by 2037 for this scenario. The significant increase in the combined cycle addition was to meet the managed EV charging load for an aggressive EV adoption and the 16 GW LFL.

Table 11: Starting Capacity Mix, Retirements, and Capacity-Expansion Results for Demand Side Evolution Scenario

	Demand Side Evolution (MW)					
	Operational Resources	Planned Resources	Total Starting Capacity Mix	Retirements	Capacity Expansion	Total Resources
Battery	235	1,807	2,042	-	370	2,411
Combined Cycle	37,478	86	37,564	1,918	30,324	65,969
CT & IC	12,616	860	13,476	711	-	12,765
Gas Steam	11,620	60	11,680	8,819	-	2,861
Solar	4,095	13,332	17,427	-	1,100	18,527
Wind	25,203	11,821	37,024	-	19,800	56,824
Coal	12,151	-	12,151	8,116	-	4,034
Hydro	536	-	536	-	-	536
Nuclear	5,153	-	5,153	-	-	5,153
Other	920	-	920	-	-	920
Total	110,006	27,965	137,972	19,565	51,594	170,001

Table 12 shows the summary of the results for the Demand Side Evolution scenario. In this scenario the reserve margin varied between 16% to 18% from 2023 to 2037. This scenario didn’t show any scarcity hours due to the flexibility provided by the LFL. The LFL was curtailed at 100 $/MWh. The curtailment hours are show in Table 12 and they ranged from 514 to 927 hours from 2023 to 2037.

Table 12: Summary of the Expansion Results for the Demand Side Evolution Scenario

Description	Units	2023	2027	2032	2037	Total
CC Adds	MW	-	6,498	9,747	14,079	30,324
CT Adds	MW	-	-	-	-	-
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
Storage Adds	MW	-	200	170	-	370
Solar Adds	MW	1,100	-	-	-	1,100
Wind Adds	MW	3,000	11,000	5,400	400	19,800
Annual Capacity Additions	MW	4,100	17,698	15,317	14,479	
Cumulative Capacity Additions	MW	4,100	21,798	37,115	51,594	
Retirements	MW	-	6,596	5,975	6,994	
Cumulative Retirements	MW	-	6,596	12,571	19,565	
Reserve Margin	%	18	18	18	16	
Coincident Peak	MW	99,633	102,588	106,576	114,881	
Peak Net Load (1)	MW	84,515	86,286	90,872	101,215	
Minimum Net load (1)	MW	9,553	8,559	9,293	9,333	
Annual Energy	GWhs	612,664	647,526	703,485	772,811	
Average LMP	$/MWh	34.65	36.65	43.20	48.46	
Natural Gas Price	$/MMbtu	3.10	3.44	4.39	5.04	
Average Market Heat Rate	MMbtu/MWh	11.17	10.67	9.85	9.61	
Natural Gas Generation	%	48.88	48.07	50.05	54.69	
Coal Generation	%	11.08	6.28	4.72	3.70	
Wind Generation	%	24.26	30.69	31.46	28.84	
Solar Generation	%	6.99	6.71	6.21	5.64	
Scarcity Hours	Hours	-	-	-	-	
Unserved Energy	GWhs	-	-	-	-	
Large Flexible Load Curtailment	Hours	514	589	652	927	

(1) Hourly Net Load = Hourly Load Forecast – Hourly Wind Output – Hourly Solar Output

Demand Side Evolution Sensitivity

Based on stakeholder feedback, the Demand Side Evolution sensitivity case was run with the following assumption changes to the Demand Side Evolution scenario:

- The combined cycle build was limited to one per year with the buildout starting in 2025.
- The simple cycle combustion turbine build was limited to 800 MW per year.
- The large flexible load curtailment was split into three categories.
  - 60% of the LFL (9,600 MW) could be curtailed at 100 $/MWh; this is an energy only curtailment for the standard mining equipment.
  - 30% of the LFL (4,800 MW) could be curtailed at 200 $/MWh; this is also an energy only targeted toward LFLs with more efficient/newer crypto mining equipment that can curtail at higher price.
  - 10% of the LFL (1,600 MW) could be curtailed at 1,000 $/MWh; this is for miners that are less price responsive to market price.

Table 13 shows the starting capacity mix, retirements, and the capacity-expansion comparison of the two Demand Side Evolution cases. The starting capacity mix between the two cases were identical. The retirements were almost the same except that the Demand Side Evolution sensitivity had an additional 105 MW of economic retirement. The Demand Side Evolution sensitivity showed significantly higher capacity addition compared to any other scenario because of the limitation on combined cycle build. This case added 8,176 MW of battery, 14,079 MW of combined cycles, 11,046 MW of simple cycle combustion turbine, 18,900 MW of solar, and 43,500 MW of wind. The total final resource was 214,002 MW which was higher than any other scenario.

Table 13: 15-Year Total Resources (Plus Capacity Expansion) Comparison of Demand Side Evolution Scenarios

				Demand Side Evolution (MW)			Demand Side Evolution Sensitivity (MW)		
	Operational Resources	Planned Resources	Total Starting Capacity Mix	Retirements	Capacity Expansion	Total Resources	Retirements	Capacity Expansion	Total Resources
Battery	235	1,807	2,042	-	370	2,411	-	8,176	10,217
Combined Cycle	37,478	86	37,564	1,918	30,324	65,969	1,918	14,079	49,724
CT & IC	12,616	860	13,476	711	-	12,765	711	11,046	23,811
Gas Steam	11,620	60	11,680	8,819	-	2,861	8,819	-	2,861
Solar	4,095	13,332	17,427	-	1,100	18,527	-	18,900	36,327
Wind	25,203	11,821	37,024	-	19,800	56,824	-	43,500	80,524
Coal	12,151	-	12,151	8,116	-	4,034	8,116	-	4,034
Hydro	536	-	536	-	-	536	-	-	536
Nuclear	5,153	-	5,153	-	-	5,153	-	-	5,153
Other	920	-	920	-	-	920	105	-	815
Total	110,006	27,965	137,972	19,565	51,594	170,001	19,670	95,701	214,002

Table 14 shows the summary of the results for the Demand Side Evolution sensitivity. In this scenario the reserve margin varied between 21% to 32% from 2023 to 2037. This scenario didn't show any scarcity hours due to the flexibility provided by the large flexible load. The curtailment hours of large flexible load ranged from 100 to 248 hours from 2023 to 2037. This sensitivity showed lower curtailment hours because 40% of LFLs had higher curtailing prices than the Demand Side Evolution scenario and on average the LMP was 5 $/MWh lower than the Demand Side Evolution scenario. The lower LMP was due to lower combined cycles and higher renewables buildout in this sensitivity.

Table 14: Summary of Expansion Results for Demand Side Evolution Scenario Sensitivity

Description	Units	2023	2027	2032	2037	Total
CC Adds	MW	-	3,249	5,415	5,415	14,079
CT Adds	MW	-	3,156	3,945	3,945	11,046
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
Storage Adds	MW	2,400	1,800	-	3,976	8,176
Solar Adds	MW	4,000	10,500	2,900	1,500	18,900
Wind Adds	MW	3,000	12,000	15,000	13,500	43,500
Annual Capacity Additions	MW	9,400	30,705	27,260	28,336	
Cumulative Capacity Additions	MW	9,400	40,105	67,365	95,701	
Retirements	MW	-	6,310	6,366	6,994	
Cumulative Retirements	MW	-	6,310	12,676	19,670	
Reserve Margin	%	21	29	32	28	
Coincident Peak	MW	99,633	102,588	106,576	114,881	
Peak Net Load (1)	MW	84,124	85,663	89,697	99,666	
Minimum Net load (1)	MW	7,732	5,954	4,996	1,552	
Annual Energy	GWhs	612,664	647,526	703,485	772,811	
Average LMP	$/MWh	31.43	31.55	36.50	42.08	
Natural Gas Price	$/MMbtu	3.10	3.44	4.39	5.04	
Average Market Heat Rate	MMbtu/MWh	10.14	9.18	8.32	8.35	
Natural Gas Generation	%	48.18	42.97	39.37	38.53	
Coal Generation	%	10.98	6.31	4.40	3.39	
Wind Generation	%	24.17	30.84	36.96	39.92	
Solar Generation	%	8.19	12.05	12.12	11.49	
Scarcity Hours	Hours	-	-	-	-	
Unserved Energy	GWhs	-	-	-	-	
Large Flexible Load Curtailment	Hours	189	109	100	248	

(1) Hourly Net Load = Hourly Load Forecast – Hourly Wind Output – Hourly Solar Output