ERCOT System Planning

2014 Long-Term System Assessment for the ERCOT Region

December 2014

Executive Summary

Section 39.904(k)[1] of the Public Utility Regulatory Act requires that the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas, Inc. (ERCOT) study the need for increased transmission and generation capacity throughout the state of Texas and report on these needs to the Legislature. A report documenting this study must be filed with the legislature each even-numbered year.

By definition, within ERCOT the bulk transmission network consists of the 69-kilovolt (kV), 138-kV, and 345-kV transmission lines and associated equipment. In planning for both the additions and upgrades to this infrastructure, ERCOT conducts a variety of forward-looking reviews to ensure continued system reliability.

ERCOT's planning process is undertaken over several time horizons to identify and approve new transmission investments required in the near-term to maintain system reliability and efficiency, and to evaluate upgrades that may be required in the long-term under different future scenarios. The near-term needs are assessed in the six-year planning horizon as studied in the Regional Transmission Plan (RTP). This Long-Term System Assessment (LTSA) evaluates the potential needs of ERCOT's extra-high voltage (345-kV) system in the ten to fifteen year planning horizon.

The primary venue for the introduction of system upgrades is the Regional Planning Group, which is made up of representatives of the transmission service providers and other market participants. Its role is to provide review of the development of near-term (six-year) transmission plans to address evolving system needs and near-term inadequacies in the system.

In contrast, the LTSA does not provide specific recommendations for transmission projects. Rather, it is used to guide the six-year planning process in two ways. First, the LTSA provides a longer term view of system reliability needs. Whereas in the six-year planning horizon a small transmission improvement may appear to be sufficient, the LTSA planning horizon may reveal

[1]Section 39.904(k) of the Public Utility Regulatory Act states that the commission and the independent organization certified for ERCOT shall study the need for increased transmission and generation capacity throughout this state and report to the legislature the results of the study and any recommendations for legislation. The report must be filed with the legislature not later than December 31 of each even-numbered year.

that a larger project will be required. A larger project may also be more cost-effective than multiple smaller projects—each being recommended in consecutive RTPs.

Second, the LTSA can identify system needs that require solutions that will take longer than six years to implement. In such cases, it is desirable to incorporate these projects into the six-year evaluation process as early as possible.

ERCOT studies diverse scenarios in their long-term transmission planning process due to the inherent uncertainty of planning the system beyond the next six years. The goal of using scenarios in the LTSA is to identify upgrades that are robust across a range of scenarios or might be more economic than the upgrades that would be determined considering only near-term needs. Based on stakeholder-driven scenario-development workshops, ERCOT identified ten different scenarios that were considered for the 2014 LTSA. Using the assumptions and guidelines set in the scenario descriptions, ERCOT prepared six different 50th-percentile hourly load forecasts. Planning for transmission ten and fifteen years in the future required ERCOT to make assumptions on additional generation that would come online. ERCOT conducted generation expansion analysis for nine of the ten scenarios using the guidelines set in the scenario descriptions. ERCOT and stakeholders, using the results from generation expansion analysis findings, shortlisted four of the ten scenarios, namely, Current Trends, High Economic Growth, Global Recession and Stringent Environmental for transmission planning analysis. ERCOT prepared reliability cases using the 90th-percentile summer peak load forecast. Additional generation was modeled in the reliability cases based on the generation siting methodology.

Most of the needs for system improvements to the extra-high voltage system noted in this analysis were located in and around the Dallas/Fort Worth region. ERCOT identified six major transmission upgrades that were required for three scenarios, namely, Current Trends, Stringent Environmental and High Economic Growth. The West Roanoke and Fort Worth projects were designed to provide additional transmission sources to meet the growing needs of Tarrant County. The Rockhill and Nevada projects were designed to provide additional support for the counties of Rockwall and Collin located immediately northeast of Dallas. The West Denton area project, which was recently reviewed by the Regional Planning Group (RPG), was seen as helpful in resolving longer-term needs of the Denton area under the High Economic Growth and Stringent Environmental scenarios. In addition to the Dallas/Fort Worth area

projects, two new paths were added in the South weather zone. In the Stringent Environmental and High Economic Growth scenarios, the Hamilton to Lobo project was conceptualized to provide an additional path to transfer solar generation from west Texas to the load centers in the south, whereas, in the High Economic Growth scenario, the La Palma to Loma Alta project was proposed to serve the Brownsville area Liquefied Natural Gas (LNG) terminal addition.

In the near-term planning horizon ERCOT is actively studying the needs of the transmission system due to the recently experienced oil and gas exploration and production related load growth. While most of the system needs are expected to be addressed in this near-term horizon, all of the scenarios in this LTSA evaluated the long-term needs of the system under varying future conditions for this industry. Some specific oil and gas sector related scenarios include High Natural Gas Prices, Low Global Oil Prices, and High LNG Exports.

Continued economic development in the oil and gas sector is expected to fuel a need for further transmission expansion to support the LNG terminals that may potentially be built as seen in the High Economic Growth scenario. The High Economic Growth scenario saw the largest increase in system load. This scenario also assumed the addition of two LNG terminals in the Corpus Christi and Brownsville areas. These block load additions combined with the system-wide load growth resulted in eleven 345-kV transmission upgrades with six of them needed by 2024.

In the Stringent Environmental scenario, generation closer to the load centers was replaced by a large amount of solar and wind generation located in the West Texas and Panhandle areas. The impact of this generation migration was seen in the 2029 model where sixteen 345-kV transmission upgrades were needed as opposed to only five needed in 2024.

The Current Trends scenario, which assumed that current growth trends continue in the foreseeable future, saw fewer upgrades than the High Economic Growth or Stringent Environmental scenarios. This scenario required eight 345-kV transmission upgrades, three of which were needed by 2024. The Global Recession scenario, which had the least amount load growth, required only four transmission upgrades in 2029.

In addition to the reliability analysis, ERCOT conducted production-cost simulation for years 2024 and 2029 for the four scenarios selected for transmission analysis. The analysis identified a few transmission elements/interfaces which showed consistent, heavy congestion across all the scenarios and years. The most noteworthy elements were the Panhandle interface and the 345-kV lines from Kendall to Highway 46, Zenith to TH Wharton, Big Brown to Jewett, Morgan

Creek SES to Tonkawa Switch and some 345/138-kV autotransformers such as those at Kendall and Hutto substations.

ERCOT evaluated twenty potential projects to relieve these and other congested elements. ERCOT also evaluated the pre-defined transmission upgrades modeled in the Panhandle Study[2] that ERCOT completed in April 2014. Projects developed for the Panhandle Study were chosen for economic testing because they have already passed tests for dynamic performance, and because their effects on the Panhandle export stability limit are known. Per the analysis, it can be concluded that while only stage 1 upgrades were economical in the High Economic Growth scenario, upgrades for all stages met the economic criteria in the Stringent Environmental scenario which saw a large growth in renewable additions (solar and wind) in the Panhandle area. Apart from these, ERCOT also identified Morgan Creek to Tonkawa 345-kV line in West Texas, Kendall to Cagnon 345-kV line in the South Central weather zone and South Texas Project to Hillje and South Texas Project to W. A. Parish 345-kV double-circuit line upgrades to be economical in the Stringent Environmental scenario by 2024.

2 http://www.ercot.com/content/news/presentations/2014/Panhandle%20Renewable%20Energy%20Zone%20Study%20Report.pdf

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1. Introduction

The Electric Reliability Council of Texas (ERCOT) is a membership-based 501(c)(4) nonprofit corporation, subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. In 1999, the Texas Legislature restructured the Texas electric market and assigned ERCOT the responsibilities of maintaining system reliability through both operations and planning activities, ensuring open access to transmission, processing retail switching to enable customer choice, and conducting wholesale market settlement for electricity production and delivery.

In fulfilling these responsibilities, ERCOT manages the flow of electric power to 24 million Texas customers – representing 85 percent of the state's electric load. ERCOT schedules power on an electric grid that connects 41,500 miles of transmission lines and more than 550 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for customers in competitive choice areas.

As part of its responsibility to adequately plan the transmission system, ERCOT must develop a biennial assessment of needed transmission infrastructure. Specifically, Section 39.904(k) of the Public Utility Regulatory Act (PURA) requires the Public Utility Commission of Texas (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 31st of each even-numbered year.

ERCOT develops two reports to meet this requirement:

- Annual Report on Constraints and Needs in the ERCOT Region – this report provides an assessment of the need for increased transmission and generation capacity for the next six years (2015 through 2020) and provides a summary of the ERCOT Regional Transmission Plan to meet those needs (provided under separate cover).
- Long Term System Assessment (LTSA) for the ERCOT Region – this report provides an analysis of the system needs in the tenth year and beyond. The longer-term view in this analysis is designed to guide near-term decisions.

Together, these reports provide an assessment of the needs of the ERCOT System through the next ten years and beyond.

2. Transmission Planning Overview

2.1 ERCOT Planning 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 Regional Transmission Plan, Regional Planning Group submissions and review, and ongoing long-range studies, which are documented in the Long-Term System Assessment. In addition to these activities, transmission service providers (TSPs) conduct analysis of local transmission needs outside of the ERCOT Planning Process.

ERCOT performs its planning function in coordination with TSPs, ERCOT market participants, and other interested parties. ERCOT primarily works with two market stakeholder committees in fulfilling its planning responsibilities:

- The Regional Planning Group (RPG) is responsible for reviewing and providing comments on new transmission projects in the ERCOT region. Per ERCOT Protocol section 3.11.3, participation in the RPG is required of all TSPs and is open to all market participants, consumers, other stakeholders, and PUCT Staff.
- The Planning Working Group (PLWG) reviews the Planning Guides to identify any needed improvements to planning criteria, processes and data provision requirements as well as to maintain alignment with North American Electric Reliability Corporation (NERC) Reliability Standards requirements and recommend appropriate Regional Standard Authorization Requests, Planning Guide Revision Requests, or Nodal Protocol Revision Requests as needed.

The LTSA process is based upon scenario analysis techniques to assess the potential needs of the ERCOT System up to 15 years into the future. Due to the high degree of uncertainty associated with the amount and location of loads and resources in the 15-year timeframe, the role of the LTSA is not to recommend the construction of specific system upgrades. Instead, the role of the LTSA is to evaluate the system upgrades that are indicated under each of a wide variety of scenarios in order to identify upgrades that are robust across a range of scenarios or might be more economic than the upgrades that would be determined considering only near-term needs in the RTP development. The LTSA process represents a planning simulation

laboratory, in which engineers can model futures that appear possible, unlikely, or even extreme in order to highlight fundamental connections between market and regulatory trends and likely system needs, and to assess the effectiveness and usefulness of new planning processes and techniques.

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

2.2 Enhancements to 2014 LTSA

In 2013, The Brattle Group (1) reviewed the process ERCOT used in the 2012 LTSA to assess economic transmission needs and (2) recommended improvements to ERCOT's "business case" for transmission investment in future studies. Subsequently, Brattle recommended in their 2013 report that ERCOT should improve the scenario-development process. Brattle further assisted in developing a new stakeholder-driven scenario-development process, which was employed for the 2014 LTSA.

The 2013 Brattle Report also recommended linking the near-term and long-term transmission planning processes. Such a linkage was expected to increase the consistency in modeling assumptions and results across the two planning horizons, avoid overlapping modeling efforts, and allow the effective use of results from long-term studies to inform near-term planning efforts. ERCOT re-organized its planning team such that the same group of planning engineers will focus on both the near-term (RTP) and longer-term (LTSA) planning assessments. The transmission analysis methodologies employed in the LTSA were also modified to be consistent with the RTP. Furthermore, ERCOT's near-term and long-term economic analysis used similar economic models with consistent input assumptions.

ERCOT also reviewed comments on its resource siting methodology employed in the preparation of the 2012 LTSA. The siting methodology was improved based on the stakeholder feedback to utilize potential sites identified in the generation interconnection process. The new generation siting methodology is attached with the report in the Appendix A.

3. Future Scenario Development

3.1 2014 LTSA Scenario-Development Process

3.1.1 Background

The 2014 LTSA enhanced its scenario-development process based on Brattle recommendations. The enhanced scenario-based planning approach provided a structured way for participants/stakeholders to identify the most critical trends, drivers, and uncertainties over a ten to fifteen-year period. A fundamental aspect of this approach was the understanding that there is a difference between scenarios and sensitivities. Sensitivity analyses are usually conducted to understand how adjusting a single variable from a base set of assumptions may impact results and outcomes. However, scenario-based planning considers sufficiently different, yet plausible futures and is best used to evaluate whether a transmission project is worth pursuing across multiple future states. An overview of the scenario development process follows in section 3.1.2. The complete Brattle report describing the process can be found in the Appendix B of this report.

3.1.2 Process

The scenario-development process was organized in four major segments as follows,

- Industry expert presentations describing industry trends, drivers, and uncertainties impacting the electric sector were organized for the scenario-development workshops. All interested stakeholders were urged to participate in this workshop. A list of presenters and topics discussed in this workshop is available in Appendix C.
- With the expert presentations as a background, the stakeholders and ERCOT staff, with the assistance of Brattle, developed a list of key drivers and potential scenarios that were important to the future of ERCOT's transmission system. The candidate scenarios naturally followed the discussion of key drivers.
- The scenarios were defined by the outcome of either a single key driver or a set of interrelated key drivers. ERCOT stakeholders identified which drivers could alone create distinctly different scenarios in the future that should be considered in the planning process.
- Stakeholders worked in teams to develop comprehensive descriptions of each scenario. Each team comprised a mix of members representing generation, transmission, ERCOT

staff, and other stakeholders. Teams were encouraged to provide detailed future possibilities on various variables such as economic growth, environmental regulations/policy, alternative generation, oil and gas prices, transmission regulations/policy, resource adequacy, end-use/new markets, and weather/water. Each scenario was then summarized with a high level narrative describing the future state and its implications for ERCOT.

3.2 Drivers Considered for Scenario Development

3.2.1 Industry Expert Presentations

ERCOT organized scenario-development workshops with the help of Brattle. A broad set of experts were invited to educate ERCOT and its stakeholders on various topics. These topics were developed based on the issues identified by stakeholders as the most critical for the future of the ERCOT transmission system.

3.2.2 Key Drivers

Following the presentations on the industry trends, drivers, and uncertainties, the stakeholders developed a list of key drivers to consider in the 2014 LTSA, such as world oil prices; domestic gas prices; changes in the population of Texas; future weather conditions; the cost of generation capacity, including solar, wind, and cogeneration; different transmission policy and resource adequacy decisions; and environmental regulations, such as Mercury and Air Toxic Standards (MATS), Cross-State Air Pollution Rule (CSAPR), and Greenhouse Gas (GHG) standards.

A brief description of the key drivers identified by stakeholders is documented in Table 3.1.

Table 3.1: 2014 LTSA Key Drivers Developed by ERCOT Stakeholders

Key Drivers	Description
Economic Conditions	U.S. and Texas economy; regional and state-wide population, oil & gas, and industrial growth; Liquefied Natural Gas (LNG) export terminals; urban/suburban shifts; financial market conditions; and business environment
Environmental Regulations and Energy Policy	Environmental regulations, including air emissions standards (e.g., ozone, MATS, CSAPR), GHG regulations, water regulations (e.g., 316(b)), and nuclear safety standards; energy policies including renewable standards and incentives (incl. taxes/financing), mandated fuel mix, solar mandate, and nuclear re-licensing
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
Natural 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 on global supply and demand balance and spread of horizontal drilling technologies. Oil and gas prices will affect drilling locations within Texas.
Transmission Regulation and Policies	New policies around transmission build-out, interconnections to neighboring regions, and cost recovery
Generation Resource Adequacy Standards	Economically determined versus mandated reserve margins and flexible resource requirements
End-Use/New Markets	End-use technologies; efficiency standards, and incentives; demand-response; changes in consumer choices; DG growth; increase interest in microgrids
Weather and Water Conditions	May affect load growth, environmental regulations and policies, technology mix, average summer temperatures, frequency of extreme weather events, and water costs

3.3 Stakeholder-Developed Scenarios for 2014 LTSA

Table 3.2 shows the scenarios identified for transmission analysis and their initial descriptions as agreed upon by stakeholders to develop for the 2014 LTSA.

Table 3.2: 2014 LTSA Scenarios Developed by Stakeholders

Candidate Scenarios	Description
Current Trends	Trajectory of what we know today (e.g., LNG export terminals and West Texas growth, prolonged high oil prices)
Global Recession	Significant reduction in economic activities in the U.S. and abroad
High Economic Growth	Significant population and economic growth from all sectors of the economy (affecting residential, commercial, and industrial load)
High Efficiency/High DG/Changing Load Shape	Reduced *net* demand growth due to increase in distributed solar, cogeneration and higher building and efficiency standards
High Natural Gas Prices	High domestic gas prices
Stringent Environmental Regulation/Solar Mandate	On top of current regulations, the Environmental Protection Agency (EPA) also regulates GHG emissions. Federal or higher Texas renewable standards. More stringent water regulations. Texas legislative mandate on utility-scale and distributed solar development.
High LNG Exports	Significant additional construction of liquefied natural gas (LNG) terminals (beyond Current Trends)
High System Resiliency	Severe climate and system events leading to more stringent reliability and system planning standards
Water Stress	Low water availability
Low Global Oil Prices	Sustained low oil prices

The following section provides a brief description of each scenario.

3.3.1 Current Trends

The recent population and economic growth in Texas continues in the near future, fueled largely by the continued growth of the oil and gas sector and the relatively robust Texas economy compared to the rest of the U.S. World oil prices continue to stay high enough to keep increasing oil production in the short-term, keeping domestic natural gas prices relatively low. With low gas prices, several LNG export terminals are built between 2014 and 2024. The production tax credit (PTC) available to new wind generation expires. Capital costs for solar continue to decline at a slower rate than recent history. No required reserve margin is set for ERCOT. Additionally, the environmental regulations continue to be moderate, with no explicit federal carbon tax or required national cap and trade.

Implications to Load assumptions

Load continues to grow at a steady rate of about 1.5% as seen in recent years. The scenario calls for load growth focused on the I-35 corridor with the bulk of the industrial growth in Houston, Midland/Odessa and Valley areas of Texas. ERCOT assumed that LNG terminals with

permits to export to countries without free trade agreements with the U.S. would get established.

Implications to Generation Assumptions

The scenario calls for gradually increasing but overall low natural gas prices. No drastic changes are seen in the environmental regulations. The PTC is set to expire prior to 2018, and the MATS and regulations on cooling-water intake (Section 316(b) of the EPA's Clean Water Act) are implemented by 2016. The scenario also sees the trend of increasing capital costs for new resources matching the rate of GDP growth; with the sole exception of solar PV, which is experiences declining costs.

3.3.2 Global Recession

The global financial crisis of 2007-2008 has impacted the economic fortunes of many countries including the United States. What started as a housing-bubble-burst in United States, soon metamorphosed into global economic downturn. During this time frame, the U.S. alone saw a dramatic decrease in its GDP. The Global Recession scenario was designed to capture the low end of the spectrum and represent a future in which a recession-like-economy occurs for several years. Although, Texas fared relatively better during these troubled times, the stakeholders felt this would be an important scenario to study in the LTSA.

Under this scenario, low energy prices were expected to threaten the Texas economy. Load growth is limited due to the decline in oil and gas activity and shifts back to being in the urban centers. The decline is further highlighted by the decrease in GDP and in-migration into the affected areas. No LNG terminals are established in this scenario.

Implications to Load Assumptions

In this scenario the net population growth in Texas is expected to slow down to about 1%. No industrial growth, in addition to the in-migration slowdown, is expected to result in little or no GDP growth or net load growth. Reduced drilling activity is expected to slow down the load growth currently seen in the oil and gas-producing counties of west and southern Texas.

Implications to Generation Assumptions

This scenario uses a lower natural gas price forecast that further results in increased development of natural gas firing plants and retirement of coal plants due to low energy margins. The scenario also requires that the current subsidies to the renewables are continued.

3.3.3 High Economic Growth

Over the past year, Texas added jobs in all of the 11 major industry sectors, including professional and business services, trade, transportation and utilities, leisure and hospitality, education and health services, construction, mining and logging, government, financial activities, information, and manufacturing. Pre-recession Texas employment peaked at 10,638,100 in August 2008, a level that was surpassed in November 2011, and by July 2014 Texas added an additional 892,800 jobs. The U.S. recovered all recession-hit jobs by May 2014 and by July 2014 added an additional 639,000 jobs. Texas and the nation returned to economic growth in 2010, 2011, and 2012. In 2013, Texas real gross domestic product grew by 3.7 percent, compared with 1.8 percent for the U.S.

The High Economic Growth scenario reflects an optimism of the economy such that a large portion of the Texas economy is operating at a high level mostly driven by the oil and gas sector and continued job growth in related upstream and downstream industries.

Implications to Load Assumptions

Per the scenario, High GDP results in high population growth of about 2.5% per year. Industrial and commercial growth continues to flourish under a pro-business environment, with a lot of the growth focused in urban areas. The scenario also expects a higher number of LNG terminals to be constructed.

Implications to Generation Assumptions

This scenario also included a required capacity reserve margin of 13.75% and a slightly higher natural gas price than in the Current Trends scenario. Additionally, in this scenario, renewables are highly economic and growth occurs due to slightly higher natural gas prices.

3.3.4 High Efficiency/High DG/Changing Load Shape

The number of residential and commercial customers who have installed solar generating panels at their homes and businesses has increased in recent years. Motivated by environmental concerns and a desire to reduce their electric bills, these customers have spurred

a dramatic increase in the amount of distributed generation (DG) in the United States. Advances in solar photovoltaic (PV) technology, combined with decreasing capital costs and construction subsidies, have further sparked the construction of new capacity.

The High EE/DG scenario was designed to capture the scenario where there is a significant addition in energy efficiency and distributed generation installations. In many ways, this scenario is similar to the Current Trends scenario except for the inclusion of additional amounts of energy efficiency, demand response and distributed generation (EE/DG). In this scenario increased stringency in building codes and investment in building retrofits in addition to higher installation of distributed generation, such as solar PV, results in a lower net load growth. Additionally, the scenario also calls for more attractive demand response programs/pricing.

Implications to Load Assumptions

Lower net load growth is expected in this scenario due to increased energy efficiency standards and DG installation.

Implications to Generation Assumptions

Higher natural gas prices are expected in this scenario, which, in addition to the decreasing cost of solar, may result in addition of larger amounts of renewable generation. Additionally, an increased amount of demand response will be modeled in the economic analysis of this scenario.

3.3.5 High Natural Gas Prices

The current boom in the development of natural gas fired plants can be largely attributed to the low natural gas price. The stakeholders agreed that the long term impacts of higher natural gas on the ERCOT System be studied in the 2014 LTSA. The High Natural Gas Price scenario was expected to have natural gas prices that were higher than Current Trends. This natural gas pricing along with no impediments to LNG exports were expected to increase gas exploration in western Texas as well as growth of LNG export terminals across the coast.

Implications to Load Assumption

No impediments to LNG exports were expected in the scenario, resulting in load growth in both gas producing counties as well as counties with downstream facilities such as LNG terminals. Higher gas prices were also expected to cause a slowdown in non-oil/gas industrial development, thus balancing out the load growth seen in this scenario.

Implication to Generation Assumption

Higher gas prices were expected to fuel further development of renewable generation in the state.

3.3.6 Stringent Environmental Regulation/Solar Mandate

In June 2014, EPA proposed a plan to cut carbon pollution from power plants. In this action, the EPA is proposing emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. This rule, as proposed, would continue progress already underway to reduce carbon dioxide emissions from existing fossil fuel-fired power plants in the United States. The discussions following up to the proposal of the Clean Power Plan were being closely monitored by the ERCOT stakeholder community. Stakeholders agreed that this would be an important scenario to consider for the 2014 LTSA.

The Stringent Environmental Regulation scenario is designed to showcase a future where such aggressive actions on mitigating environmental impacts in the energy sector have occurred. Many of the environmental policies being discussed today, including GHG, CSAPR, MATS, etc. are implemented in this scenario as well as a continuation of subsidies for renewable generation types. The renewable subsidies such as the PTC and the investment tax credit (ITC) are renewed. These incentives, along with lower solar, wind, and storage costs, continue to support large additions of renewables across Texas.

Implications to Load Assumptions

Stringent building codes, energy efficiency requirements, and distributed generation development result in moderate load growth. This scenario also calls for reduced oil and gas activities, which further results in demand reduction in the Far West weather zone.

Implications to Generation Assumptions

While the cost of natural gas remains fairly similar to current trends, the continuation of renewable subsidies such as the PTC and the investment tax credit (ITC), along with lower solar, wind, and storage costs continue to support large additions of renewables across Texas. This scenario also requires addition of two new DC tie connections to the east and west.

Additionally, aggressive environmental regulations are expected to drive older coal and natural gas fired generators to retire.

3.3.7 High LNG Exports

Due to the recent advances in the natural gas activities in the shale formation, including three major fields in Texas, the United States has been producing more natural gas. This increase has resulted in surplus natural gas supplies with corresponding low prices. Producers are aiming to export this excess natural gas supply as LNG. As of September 30, 2014, at least 40 LNG export terminals have been proposed across the United States, of which at least 9 facilities are proposed on the ERCOT region of the Texas coast.[3] Those 40 facilities represent over 40 billion cubic feet per day (Bcf/d) of potential LNG capacity with over 13 Bcf/d in the ERCOT region. Most of these companies are facing long waits for the Energy Department's review, as a result only one of the proposed projects in the ERCOT region has received all the necessary approvals.

This scenario was designed to prepare a case where all the impediments to the approval of these facilities are removed resulting in a rise in LNG terminal development. Without any experience with LNG liquefaction facilities on the electric grid, ERCOT prepared estimates of the amount of LNG capacity constructed and its associated load. For this scenario, ERCOT, in consultation with the stakeholders, assumed that developers in the ERCOT region will construct 9.6 Bcf/d of the capacity currently holding or seeking DOE approval.

The research presented in the stakeholder meetings suggested a significant amount of new load being added to the grid. For instance, the only fully approved project in ERCOT, sited in Freeport, Texas, is expected to require in the excess of 700 MW of grid-supplied power to support its operation. ERCOT patterned its other LNG load requirements after those for the Freeport facility. Of note, the Freeport facility represents a higher net load addition than customary for LNG facilities. The facility will use large electric motors to drive the significant compression needs of the liquefaction process. This equipment choice results in higher electrical load requirement than a facility with the same LNG capacity, but instead uses the more typical natural gas driven compressors. Because ERCOT is conducting a long-term planning study, ERCOT chose to assume any LNG facility would have similar load characteristics to the Freeport LNG facility. ERCOT assumed 400 MW per Bcf/d of LNG capacity. ERCOT also assumed that, like

[3] http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-proposed.pdf

the Freeport LNG facility, grid-supplied power would serve the total load of any LNG facility. This scenario is also characterized by a healthy global and U.S. economy driving the global demand for natural gas higher.

Impact to Load Assumptions

This scenario is expected to see increased load growth in the natural gas producing counties due to the increased need driven by the LNG export demand. Furthermore large block loads will be expected to be added in the Corpus Christi and Brownsville areas, in addition to the LNG load already included in the Freeport area under the Current Trends scenario.

Impact to Generation Assumptions

The cost of domestic natural gas in this scenario is expected to remain unchanged thus having little or no effect on the generation build as compared to current trends.

3.3.8 High System Resiliency

While the majority of power failures from national grids last only a few hours, some blackouts can last days or even weeks, completely shutting down production at companies and critical infrastructures such as telecommunication networks, financial services, water supplies, and hospitals. The August 14, 2003 blackout in the Northeast United States started shortly after 4 PM EDT and resulted in the loss of 61,800 MW of electric load that served more than 50 million people. Anderson Economic Group (AEG) estimates the likely total cost to be between $4.5 and $8.2 billion with a mid-point of $6.4 billion. This includes $4.2 billion in lost income to workers and investors, $15 to $100 million in extra costs to government agencies (e.g., due to overtime and emergency service costs), $1 to $2 billion in costs to the affected utilities, and between $380 and $940 million in costs associated with lost or spoiled commodities.[4]

The concept of this scenario was to build a system that was highly reliable, so the system could support major power transfers within ERCOT during potential "black swan" events such as extreme weather events or large storms. In this scenario, it is assumed that the value of resilience and system flexibility is broadly recognized by stakeholders and regulators and hence the community is more willing to invest in infrastructure to ensure greater resiliency. This

[4] Anderson, Patrick L. and Ilhan K, Geckil, "Northeast Blackout Likely to Reduce US Earnings by $6.4 Billion," AEG Working Paper 2003-2, August 19, 2003 (http://www.andersoneconomicgroup.com/Portals/0/upload/Doc544.pdf).

scenario also called for a robust and diverse mix of generation which may require an increased reserve margin requirement.

3.3.9 Water Stress

In 2011, Texas had its worst single-year drought on record, an event that was widely publicized in the news media and was a concern for many water users, including power generators. The average rainfall across the state that year was 14.89 inches, the lowest on record and 0.1 inch below the previous record set in 1917. In addition, the 12-month period between October 2010 and September 2011 was the driest 12-month period ever recorded with an average rainfall of 11.18 inches across the state.

Initial review of survey data provided by the generators and the actual historical generation output from 2011 have shown that most generators are prepared or have contingency plans for moderate or even short duration severe droughts such as the conditions experienced in 2011. The more complex issue for generators in Texas appears to be a multi-year drought, such as the drought that occurred in Texas between 1950 and 1957. While the 1950 – 1957 drought was not as severe on an individual year basis as 2011, it is still the period of record for extended drought across most of the state.

The Water Stress scenario was designed to capture the impact of such an extended water-stressed future. In this scenario the stakeholders expected that the rate of population growth will decline moderately due to the sustained drought conditions. This scenario also sees the potential of rising prices for water and electricity and a slight increase in the natural gas price.

Implications to Load Assumption

In this scenario, prolonged water stressed conditions result in decline in agricultural productivity as well as oil and gas development. These conditions are expected to result in limited growth in the rural areas.

Implication to Generation Assumption

Lack of water available for generating facilities will require installation of expensive dry cooling technologies; this change, in addition to the continued renewal of PTC and ITC is expected to fuel the growth of renewables. This scenario also calls for increased DC tie connections to the east and west. Additionally, this scenario required a capacity reserve margin mandate to be in effect.

3.3.10 Low Global Oil Prices

The Low Global Oil Prices scenario was designed to capture the impact of increased oil supply or drop in global oil demand on Texas. Under this scenario, Texas sees a decline in oil and gas production that further causes natural gas price to go higher. Texas economy is also expected to decline causing reduction in overall electricity demand. Higher natural gas prices result in more renewable development.

Implication to Load Assumptions

In this scenario the Texas economy is expected to decline, resulting in decline of electricity demand. The electricity demand is also expected to shift to non-oil sectors. Overall, there is expected to be less load growth in the current oil plays, while the search for natural gas is expected to gain momentum.

Implication to Generation Assumptions

This scenario expects the price of natural gas to be high enough to encourage development of more renewables.

4. Load Forecasting

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

For this long-term plan, ERCOT developed scenario-based forecasts for the region. ERCOT based these forecasts on a set of neural network models that provide the hourly load in the region as a function of certain economic and weather variables. Vendors under contract with ERCOT provided the data used as input variables to the energy, demand, and premise forecast models. County-level economic and demographic data were obtained on a monthly basis from Moody's Economy.com. Twelve years of weather data were provided by Telvent for 20 weather stations in ERCOT.

Six different forecasts were created to support the scenarios included in this study. The forecast scenarios are:

1) Current Trends,
2) High Economic Growth,
3) High Energy Efficiency And Distributed Generation,
4) High Natural Gas,
5) Stringent Environmental, and
6) Global Recession.

These forecasts used different values for a set of input variables that were consistent with the scenario-specific assumptions.

Table 4.1: Load forecasts used for different scenarios

Forecasted Scenarios	Scenarios that Used Same Forecast	Selected for Transmission Analysis
Current Trends	Current Trends, High System Resiliency	Yes
High Economic Growth	High Economic Growth, High LNG Exports	Yes
Stringent Environmental	Stringent Environmental	Yes
Global Recession	Global Recession, Low Global Oil Prices, Water Stress	Yes
High Energy Efficiency And Distributed Generation	High Energy Efficiency And Distributed Generation	No
High Natural Gas	High Natural Gas	No

The Current Trends forecast, which served as the load forecast for the Current Trend scenario, showed 1.3% average peak load growth through 2029, when it reached a system peak of 82 GW. For the High Economic Growth scenario, forecast peak demand grew at a 1.8% annual average. Peak demand in the High Economic Growth forecast reached 88 GW in 2029, roughly 6 GW higher than the Current Trends forecast. With the differences between these two forecasts, ERCOT could study how higher-than-normal load growth could accelerate the need for transmission upgrades. On the other hand, the High Energy Efficiency and Distributed Generation forecast provided a slower peak demand growth scenario for the study. The High Energy Efficiency and Distributed generation forecast reached 76 GW in 2029, which represents a 0.8% annual average compound rate of growth. As indicated by Figure 4.1 and 4.2, these forecasts represented very different possible load futures for the ERCOT region. Figure 4.2 shows ERCOT 50th percentile peak load across all the forecasted scenarios.

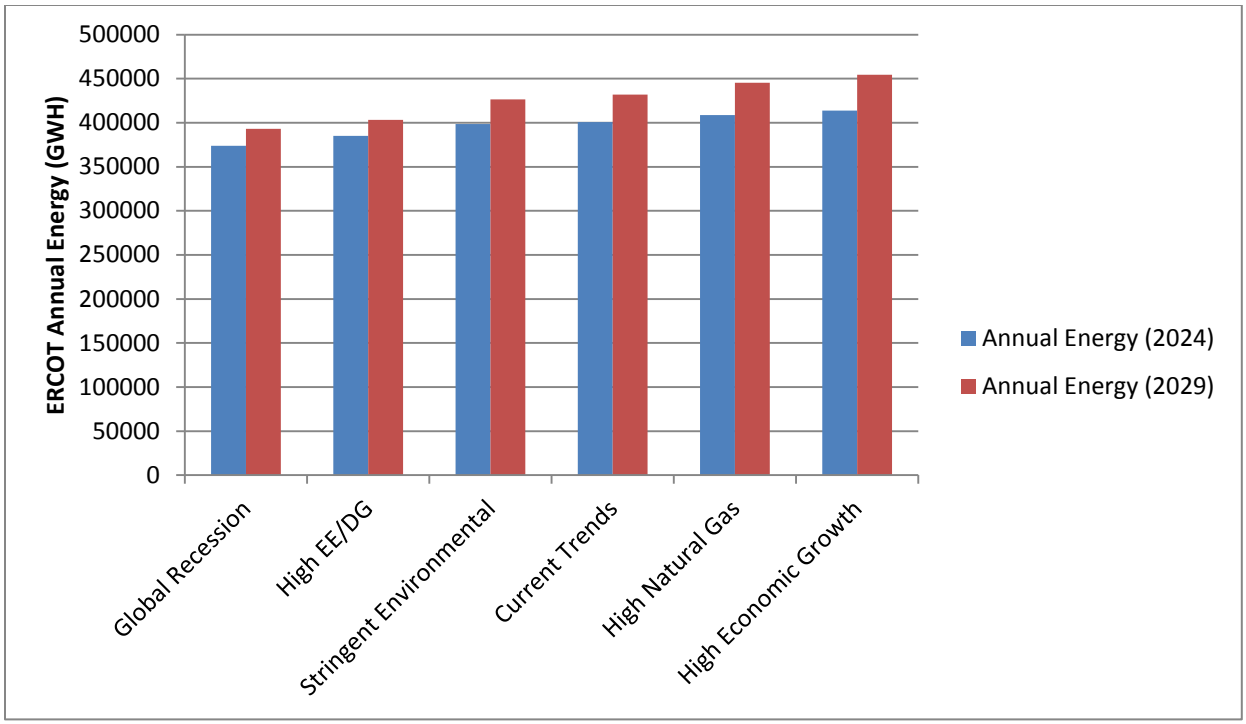

Figure 4.1: Chart showing ERCOT annual energy across all scenarios for 2024 and 2029 expressed in GWH

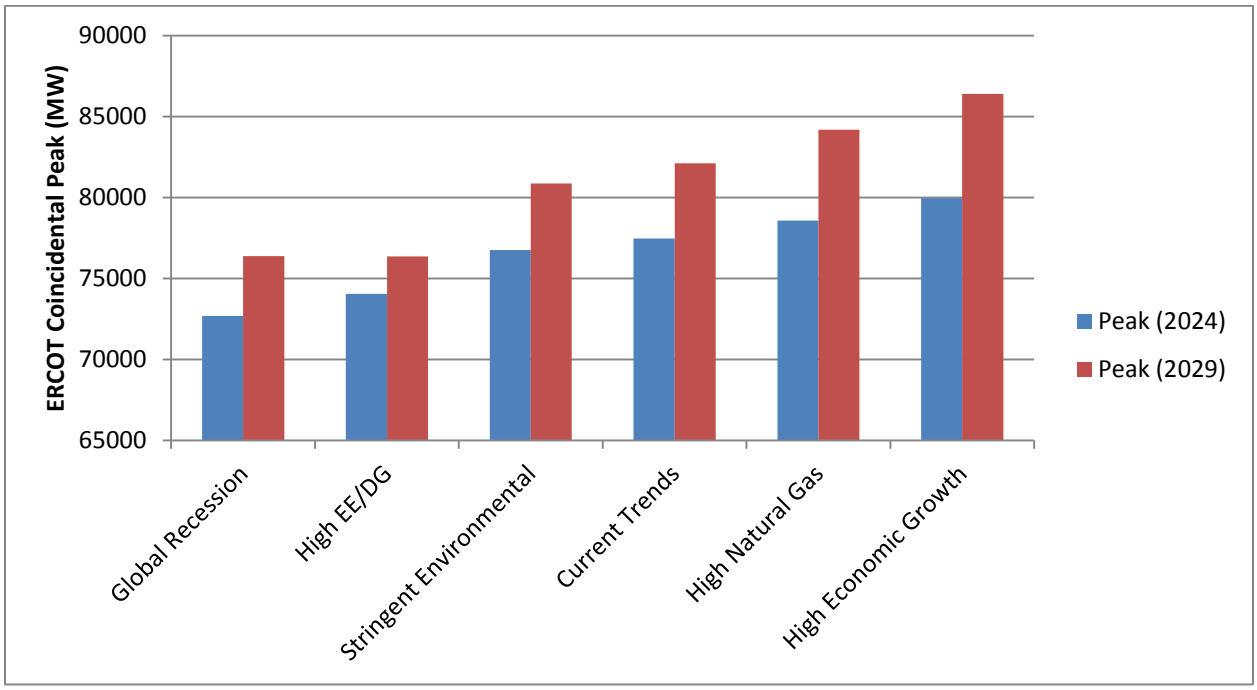

Figure 4.2: Chart showing ERCOT peak load across all scenarios for 2024 and 2029 expressed in MW

4.1 Forecast Development

The load forecasts combined econometric input, scenario-specific assumptions, and neural network models to describe the hourly load in the region. Factors considered included certain economic measures (e.g., nonfarm payroll employment, housing stock, population) and weather variables (e.g., heating and cooling degree days). A county-level forecast of economic and demographic data was obtained from Moody's. Twelve years of historical weather data (e.g., hourly dry bulb temperature, wind speed, and cloud cover) were provided by Telvent/DTN for 20 weather stations in ERCOT. Detailed documentation on ERCOT's Long-Term Load Forecast can be found on the Long-term load forecast page on the ERCOT website[5].

4.1.1 Load Modeling

ERCOT consists of eight distinct weather zones, as shown in Figure 4.3. Weather zones[6] represent a geographic region within which all areas have similar climatological characteristics. To reflect the unique weather and load characteristics of each weather zone, separate load forecasting models were developed for each of the weather zones. The ERCOT forecast is the sum of all of the weather zone forecasts.

4.1.2 Modeling Framework

These scenario-specific forecasts used neural network models that combine weather, customer premise data (including number of premises and average annual usage per premise), and calendar variables to capture and project the long-term trends extracted from the historical load data. As underpinning for these forecasts, ERCOT developed two sets of models: daily energy models and premise count models.

Premises were separated into three different customer classes for modeling purposes: residential, business, and industrial. The premise count models consider changes in population, housing stock, and non-farm employment.

ERCOT developed daily energy models for each of the eight weather zones. These neural network models estimated the relationship between daily energy and several parameters. Thirty neural network models were developed for each weather zone. An average of the thirty models

[5] http://www.ercot.com/gridinfo/load/forecast/index.html

[6] See ERCOT Nodal Protocols, Section 2.

was used as the final daily energy forecast model. The models were developed by using historical data from 2009 to 2013.

ERCOT considered the time of year (month and season), day type, non-holiday day of week, holidays, numerous weather variables, number of daylight minutes, and a premise weighting factor for each of the eight ERCOT weather zones. The weather variables include cooling degree days (CDDs) and heating degree days (HDDs) for various timeframes such as morning, afternoon, evening, and night. The cooling degree day and heating degree day parameters are calculated by using 65 degrees Fahrenheit as the base. The weighted premise variable was calculated by multiplying the number of premises times their average annual usage for all three premise types and then summing the values.

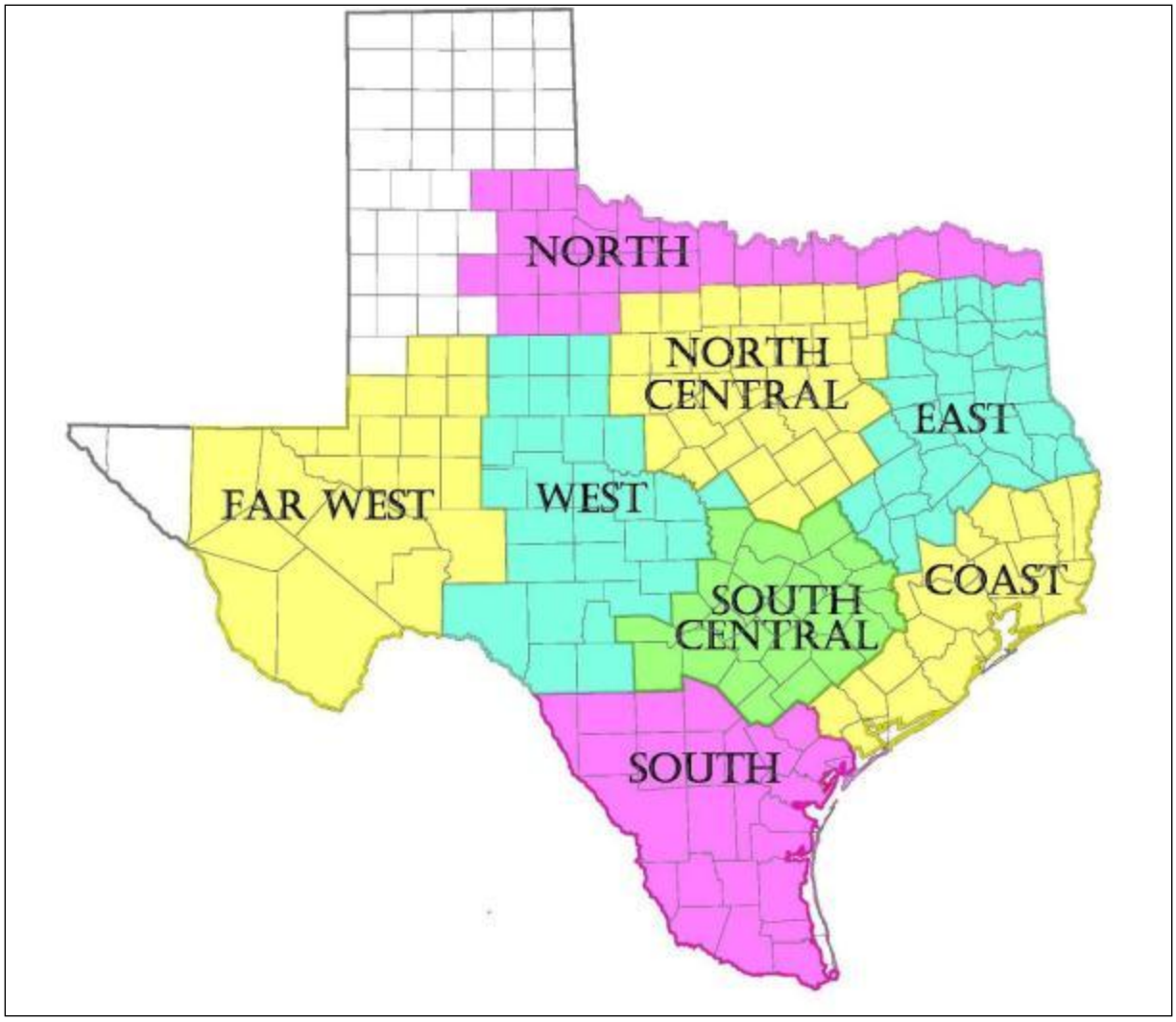

Figure 4.3: ERCOT Weather Zones

4.1.3 Hourly Forecast Scenarios

To convert the daily forecast into hourly loads, ERCOT distributed the total daily load across the hours of each day in a pattern that represents customers' historical load. Historical hourly allocation factors were calculated for each weather zone for each day by using the actual hourly energy divided by the total energy for that particular day. For example, the historical hourly allocation factor for the North Central weather zone on August 8, 2002 @ 5 pm was equal to the actual energy for the North Central weather zone on August 8, 2002 @ 5 pm divided by the total energy for the North Central weather zone for that day (August 8, 2002). The actual hourly allocation factors from all days in 2002 are copied into the same day for each of the forecasted years (2014–2024). Coupling the 2002 actual hourly allocation factors with the daily

energy forecast based on 2002's weather for each weather zone results in a forecast for 2014–2024 assuming 2002's weather. This coupling preserves actual customer behavior particularly at the time of ERCOT's summer peak. This process was repeated for each of the historical years (2002–2013). At the completion of this step, each weather zone had allocation factors for each historical year (2002–2013) covering the time period of 2014 – 2024. Because 12 historical years were used (2002–2013), there will be 12 different sets of hourly allocation factors for each weather zone. Each set of hourly allocation factors covers a complete year. By applying the hourly allocation factors to the daily energy forecast values ERCOT creates the hourly forecast scenarios.

Normal Weather (50th-percentile) Forecast

The 2014 LTSA generation expansion and transmission economic analysis use the normal weather (50th-percentile) hourly load forecast. The process for creating the normal weather (50th-percentile) forecast begins with the 12 hourly forecast scenarios for each weather zone. Each of these 12 hourly forecast scenarios, which cover the time period of 2014–2024, are separated into individual calendar year forecasts. Each individual calendar year forecast is ordered from the highest load to the lowest load. Then for each ordered load an average is calculated. For example, to determine the normal weather (50th-percentile) forecasted peak value for calendar year 2017, the average of the highest forecasted load for each of the 12 historical weather years for calendar year 2017 is calculated. The second highest load for calendar year 2017, is determined by averaging the second highest forecasted load for each of the 12 historical weather years for calendar year 2017 and average them. This process, which is commonly known as Rank and Average methodology, was repeated for all hours in the calendar year 2017. At the conclusion of this step, the normal weather (50th-percentile) forecast was completed for each ordered load.

A key input in any load projection is the forecasted weather. A normal (typical) weather hourly profile is used. Normal weather means what is expected on a 50% probability basis; i.e., that the forecast for the monthly energy or peak demand has a 50% probability of being under or over the actual energy or peak. This is also known as the 50th-percentile forecast.

ERCOT's analysis included 12 years of weather data (2002–2013). The methodology that ERCOT selected to create the "normal" weather year is commonly referred to as the Rank and Sort methodology. A forecast is created using each of the 12 years of historical weather data.

The resultant hourly forecast is ordered from the largest value to the smallest value. The normal forecast is then calculated by calculating the average of each ordered hourly value.

Ninetieth-Percentile Forecast

The 2014 LTSA transmission reliability analysis uses the 90th-percentile summer peak load forecast. The process for creating the 90th-percentile weather uses a similar methodology as used to develop the 50th-percentile forecast. Except, instead of taking the average for each ordered load, ERCOT calculated the 90th-percentile load values from the ordered loads.

Premise Forecast

Another key input is the forecast of the number of premises in each customer class. Premise forecasts are developed by using historical premise count data and various economic variables such as non-farm employment, housing stock, and population. ERCOT extracted the historical premise data from its settlement databases. The current condition of the United States economy and its future direction is an element of great uncertainty. Thus far, the recent economic downturn has not affected Texas to the same extent as the rest of the United States. This has led to Texas having somewhat stronger economic growth than most of the rest of the nation. Since May of 2010, there has been 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. Premise forecast models were also developed for each weather zone. As required for each scenario, ERCOT adjusted premise counts to reflect different anticipated load growth. The premises were separated into three different groups for modeling purposes:

1. Residential (including street lighting),
2. Business or small commercial, and
3. Industrial (premises that are required by protocol to have an interval data recorder meter).[7]

Residential Premise Forecast

To determine projected residential premise counts, ERCOT uses historical and projected residential housing stock and population values to create a scaling index. The forecasted

[7] See ERCOT Nodal Protocols, Section 18.6.1.

indexed value was converted to a forecasted premise value for use in the neural network models.

For the North and West weather zones, ERCOT modeled residential-premise growth based on a five-year average premise growth rate instead of the residential premise index model. ERCOT chose this approach to overcome difficulties in developing a statistical model for weather zones that have historically low premise growth rates (less than 1.0%).

Business Premise Forecast

For the business premise counts, ERCOT uses a similar indexing methodology, except it also considers changes in non-farm employment values to develop the index. Like the residential model, the forecasted indexed value was converted to a forecasted premise count for use in the neural network models.

The growth in the business-premise in the Far West zone is linear over the historical timeframe instead of being subject to economic variations as the other weather zones. As a result ERCOT modeled the Far West weather zone premise forecast using a five-year average business-premise growth rate instead of the business premise index model.

Industrial Premise Forecast

Industrial premise forecast was based on a 5-year average premise growth rate instead of an industrial premise index model. In addition, ERCOT meets with Transmission Service Providers (TSPs) to gather information on the expected growth of industrial premises in their service territories. ERCOT uses this information to adjust the forecasted industrial premises as necessary.

Average Use Per Premise

An average use per premise forecast was created for each weather zone. The average use per premise was based on normal or typical weather for a contiguous 12-month time frame. Historical data from 2009 – 2013 was analyzed to determine a representative time period with normal weather. The time period from 8/1/2012 – 7/31/2013 was selected to represent typical weather. ERCOT develops a weighted premise index for each weather zone by multiplying each premise class' premise count forecast by the class' average use per premise, then summing the results.

Forecast Calendar

The last step was to take the ordered loads from the normal weather (50th-percentile) forecast for each weather zone for each calendar year and associate them with a representative calendar. This process involves assigning the peak load into the representative calendar's peak hour, assigning the second highest load into the representative calendar's second highest load hour, and so on until all hours have been assigned.

4.2 Forecast Scenarios

4.2.1 Current Trends Forecast

The Current Trends forecast was the base (50th-percentile) forecast used for the analysis. The Current Trends scenario assumed that the Freeport LNG terminals have come online thus adding 235 MW by summer of 2018 and 706 MW by summer of 2019. Additionally, 431 MW of energy efficiency and 255 MW of load management were added based on ERCOT's February 2014 CDR report. These values were held constant for the entire study period. No incremental load forecast adjustments were performed for roof-top solar.

4.2.2 High Natural Gas Forecast

The High Natural Gas forecast was very similar to the Current Trends forecast. It included the Freeport LNG, energy efficiency, and load management adjustments as seen in the Current Trends forecast. No incremental load forecast adjustments were performed for roof-top solar. The only difference in this scenario when compared to the Current Trends forecast is a modest increase of 0.2% in the forecasted load values for the Coast and North Central weather zones. This escalation in load is intended to reflect an increase in energy consumption that would be expected in this scenario.

4.2.3 High Economic Growth Forecast

The High Economic Growth forecast was based on the assumption that in addition to the Freeport LNG site modeled in Current Trends, two large LNG terminals will be located in the Corpus Christi and Brownsville areas of the South weather zone. This development added another 784 MW in 2018 and 1,568 MW by 2019. The energy efficiency, load management and roof-top solar assumptions were similar to the ones used in the Current Trends forecast. Load values for the Coast, North Central, and South Central weather zones were increased by 1.5% which was intended to reflect an increase in energy consumption that would be expected in this scenario.

4.2.4 High Energy Efficiency (EE) & Distributed Generation (DG) Forecast

In the High EE/DG forecast the energy efficiency values from ERCOT's February 2014 CDR report were increased by 20% per year while the load management values were increased by 3.3% per year. These changes resulted in the energy efficiency summer peak value increasing from 431 MW in 2014 to 6,648 MW in 2029. Similarly, the load management impact on the summer peak increased from 255 MW in 2014 to 415 MW in 2029. Incremental load forecast adjustments were performed for roof-top solar with addition of 1,057 MW of new PV installations. This scenario has the same 0.2% increase in the forecasted load for the Coast and North Central weather zones as seen in the High Natural Gas scenario.

4.2.5 The Stringent Environmental Scenario Forecast

Using ERCOT's February 2014 CDR as a reference, the Stringent Environmental forecast assumed a 3.3% increase in the energy efficiency and load management. These changes resulted in the energy efficiency summer peak value increasing from 431 MW in 2014 to 702 MW in 2029. Similarly, the load management impact on the summer peak increased from 255 MW in 2014 to 415 MW in 2029. Incremental load forecast adjustments were performed for roof-top solar as 2,400 MW were added through 2029. Additionally, load values in the Far West weather zone were decreased by 1.0% to reflect a decrease in energy consumption resulting from a reduction in oil and gas activity as expected in this scenario.

4.2.6 The Global Recession Scenario Forecast

In the Global Recession scenario, the demand levels for all weather zones were reduced by 5% in 2021, which was the assumed year for a global recession. The recovery from the recession is expected to occur at a slower growth rate than for the Current Trends forecast. The Freeport LNG terminal is projected to be in service before the global recession hits and therefore was included in this scenario.

4.3 Load Forecast Distribution

As described in Section 4.1, ERCOT's load forecasts were developed by weather zone. However, county-level load growth within a weather zone is expected to vary between scenarios. For example, expert presentations conducted during the first scenario-development workshop indicated that under current (or better) economic conditions, higher growth rates are expected along the Interstate 35 corridor than in other areas of Texas, specifically in the so-called "ring counties" (suburban counties surrounding major cities).

In order to reflect scenario-specific assumptions it was necessary to adjust the distribution of load within weather zones. This adjustment was accomplished through the development of scenario-specific load distribution factors that allowed weather zone load forecasts to be distributed down to individual buses.

ERCOT's load forecasts include losses, which were removed prior to adjusting load because the software packages used for both reliability and economic analyses account for losses separately from load. In addition, the load forecasts do not include self-served load. The self-served loads were left unchanged from the reliability and economic base cases while the load forecasts minus losses were distributed to all other loads in the cases on a by-weather-zone basis. Ninetieth-percentile summer peak load forecasts, shown in Figure 4.4, were used for reliability analysis and 50th-percentile hourly load forecasts, shown in Figure 4.2, were used for economic analysis.

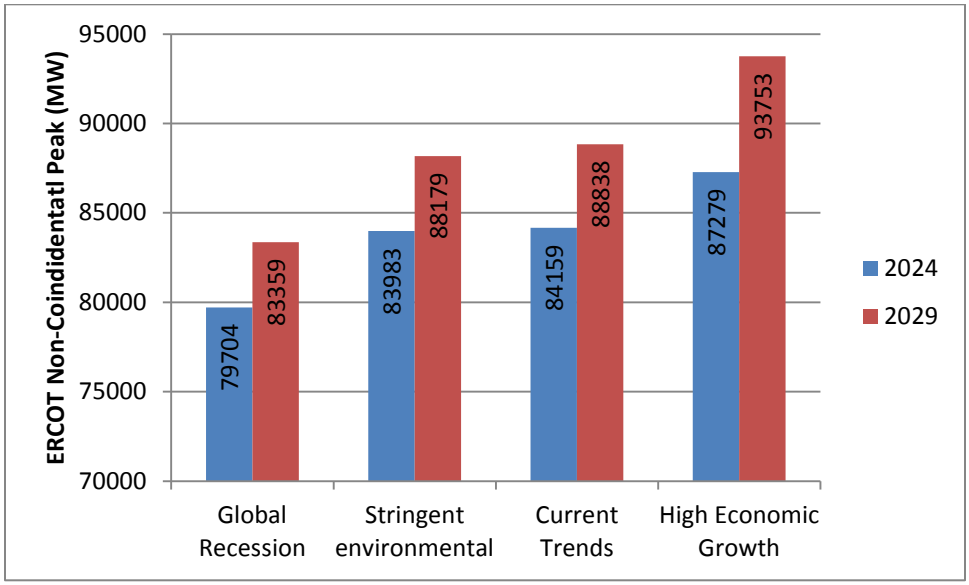

Figure 4.4: Chart showing ERCOT non-coincidental 90th percentile peak loads for years 2024 and 2029

5. Resource Expansion Analysis

5.1 Resource Expansion Input and Assumptions

Market participants created a Current Trends scenario as the first scenario to provide a reference point for the selection of other future scenarios and to evaluate the effectiveness of the tools used for this study. The Current Trends scenario is based on the assumption that current policies and regulations will remain in place and that no new mandates will be introduced.

Trends in capital costs for new technologies are expected to increase at the same rate as GDP; solar photovoltaics (PV) are the exception with costs that are projected to decline throughout the study period. Commodity prices for natural gas and coal were obtained from the EIA AEO 2014 Early Release Reference Case. The reference case can be found in the Appendix D. Natural gas prices were further adjusted to reflect an additional forecast produced by the consulting firm Wood Mackenzie. Other characteristics of this scenario include small amounts of LNG block load, no major changes to environmental regulations, and a modest increase in the penetration of demand response.

The technologies included for generation expansion were current and advanced combined-cycle and combustion turbine technologies, solar, geothermal, compressed air energy storage (CAES), biomass, coal, coal with carbon capture and sequestration (CCS), integrated gasification combined cycle (IGCC), IGCC w/ CCS , nuclear, and some demand response (DR) programs. The solar technology evaluated in the generation expansion process was utility scale PV with single-axis tracking technology.

Additionally, the continuation of the PTC and the ITC was included in several of the scenarios. The PTC is a tax credit of approximately $23/megawatt-hour (MWh; in 2014 dollars) that can be applied to some renewable energy projects for the first 10 years of operation. This tax credit expired at the end of 2013, but can be extended by an act of Congress. The ITC is a 30% tax credit on total investment applied to qualifying units that start construction before the end of 2016. After 2016 the credit is reduced to 10%.

As many older units are located in or near major load centers (many of which are non-attainment zones under the National Ambient Air Quality Standards) redevelopment of these sites with new generation was considered unlikely. The proximity of these legacy units to load

centers means that they are relied upon to support system reliability during peak load conditions.

The retirement process for this LTSA had two distinct parts. First, a group of fixed retirements were determined for use in all scenarios. These fixed retirements were determined by the age of an existing facility. Wind units were retired after 25 years of operation, steam gas units were retired after 50 years of operation, and coal units were retired after 55 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.

The total fixed retirements by capacity type, as described above by age, were 1,208 MW of coal, 6,399 MW of steam gas, and 1,182 MW of wind. The list of affected units and dates of retirement are provided in Appendix E.

In 2011, ERCOT procured hourly wind generator output profiles based on actual weather data from the previous 15 years. This dataset includes new hourly wind output patterns for 130 hypothetical future wind generation units and were developed using power generation curves consistent with the most recent wind turbine technologies. The 130 profiles were distributed throughout Texas. Each profile is representative of the historical wind output in a specific county. These new wind profiles were incorporated in all scenarios.

In March 2013, ERCOT procured new hourly solar generation patterns based on actual weather data for the previous 15 years. These patterns contained profiles for 254 Texas counties for four different types of solar technologies, single-axis tracking, fixed tilt, solar thermal, and residential. ERCOT selected the single-axis tracking and residential profiles for inclusion in this LTSA.

ERCOT stakeholders were also interested to understand the impact that new regulations from the Environmental Protection Agency (EPA) would have on generation in the ERCOT region. The Stringent Environmental scenario generally accounts for several proposed regulations, including the proposed Cross-State Air Pollution Rule, the Mercury and Air Toxics Standard, and possible greenhouse gas regulation, by imposing emissions costs for sulfur dioxide, nitrogen oxides, and carbon dioxide on generating units and by limiting construction of new coal units to integrated gasification combined-cycle units (IGCC).

The effects of water-stressed conditions are assessed in the final scenario evaluated as part of this LTSA. The preliminary results of the analysis of the Low Global Oil Prices scenario, conducted per the guidelines from scenario descriptions, were very similar to those from Global Recession. However, in the interest of performing robust analysis on scenarios deemed more critical by stakeholders, ERCOT chose to not complete the formal analysis for this scenario.

5.2 Resource Expansion Methodology

Determining the likely set of resource expansion units for each scenario requires a multi-step process. For this LTSA, the resource expansion analysis was conducted using Uplan, an hourly economic-dispatch model.

The Uplan Merchant module was used to determine the timing, location and capacity of new entrants (generating units) likely to participate in the competitive electric energy market and those that may be economically retired. A major aspect of the merchant decision process is capital cost recovery. Using the specified capital costs, recovery period, inflation rate and cost of capital, the model calculates an amount that is paid in equal installments over the capital recovery period. This payment is calculated into an annualized rate that is added to fixed costs. The calculated result is the hurdle rate. The inflation rate ensures that units that are added in the future have their capital costs appropriately adjusted for inflation providing consistency with the other specified costs. Second, the module determines the sizes and locations where reserve margin (RM) units are most likely to be added to the system over a given time horizon. This part of the Merchant module was only used in the High Economic Growth, High System Resilience, and Water Stress scenarios.

The last module used in this analysis was Uplan's Network Power Model (NPM). NPM performs hourly chronological security constrained unit commitment and economic dispatch. The results of the NPM module, which includes locational marginal prices, emissions, generation energy mix, and unserved energy are used to determine if the generation expansion process provides for an economic and reliable system.

To determine the impact of increasing proportions of wind, solar, storage, and demand-response resources, ERCOT studied the ability of hypothetical resource expansion plans to maintain frequency with timely load/resource deployment. The adequacy of system frequency response is a second-to-second metric-driven by technology-specific response and availability

characteristics. Analyzing the ability of a resource mix to comply with current balancing metrics requires an equally granular second-by-second time series simulation of events. The graphic below shows two days in March from the 2029 Stringent Environmental scenario. Figure 5.1.1 shows the amount of time that intermittent resources are meeting a portion of the ERCOT load (shaded area) along with hourly solar and wind generation for two days in March studied in the 2029 Stringent Environmental scenario. The highlighted hour, hour 19 on the 9th shows a load/generation ramp of nearly 12,770 MW.

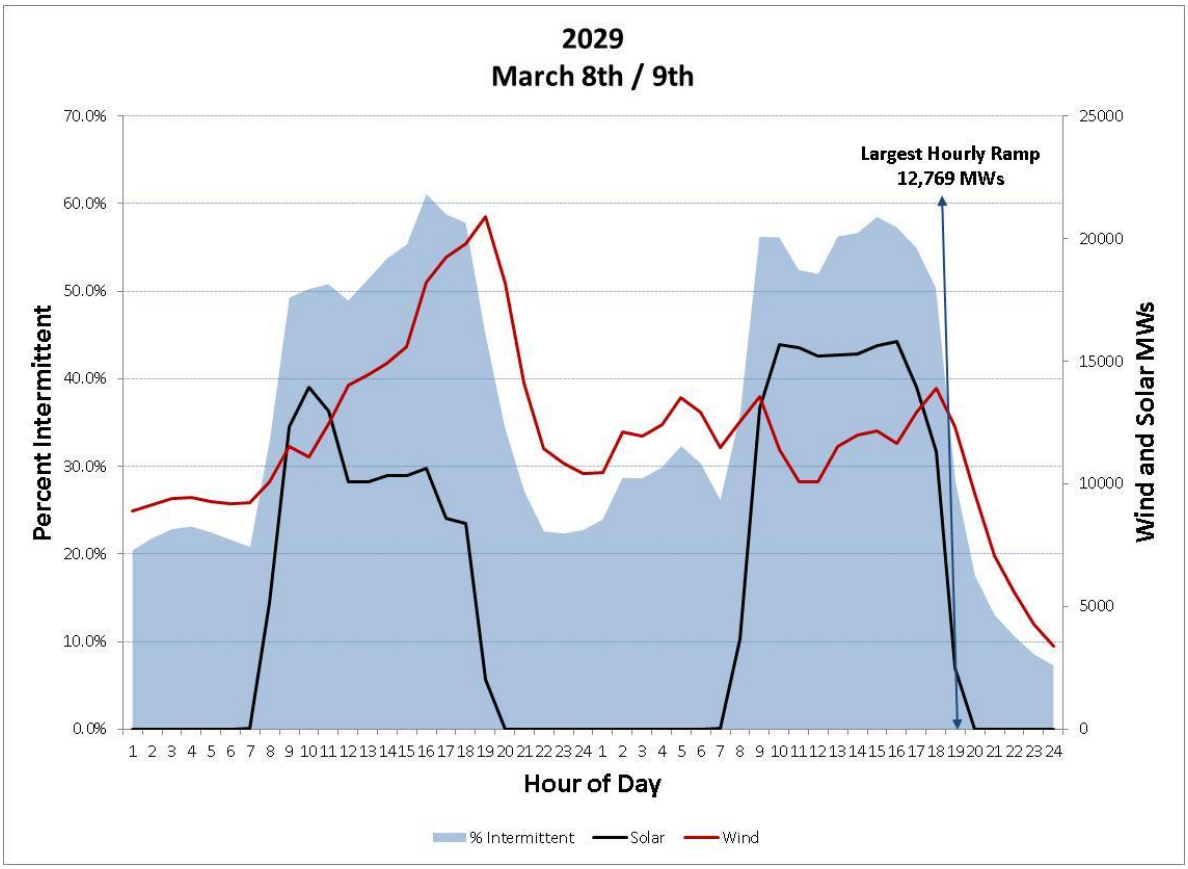

Figure 5.1: Graph showing percent intermittency for 2 days in March from the 2029 Stringent Environmental scenario

5.3 Resource Expansion Results

ERCOT staff performed the generation expansion process for nine scenarios. In general the scenario results indicate that natural gas will remain the primary fuel used to meet ERCOT load, however wind and solar resources will continue to developed. The amount of energy being met

by coal generation declines in most scenarios from roughly 34% to about 25% of load by 2029 and approximately 50% of the coal fleet is retired in the Stringent Environmental scenario.

Figure 5.2 shows the percent of energy generated by fuel type in 2029 for all modeled scenarios. Figure 5.3 shows the reserve margins for years 2024 and 2029 for all scenarios per the generation expansion results. The reserve margin calculation multiplied wind capacity times 8.7% and solar capacity times 100% except for the scenarios that required a 13.75% margin. In those scenarios (High Economic Growth, High System Resilience and Water Stress) solar capacity was multiplied by 70%.

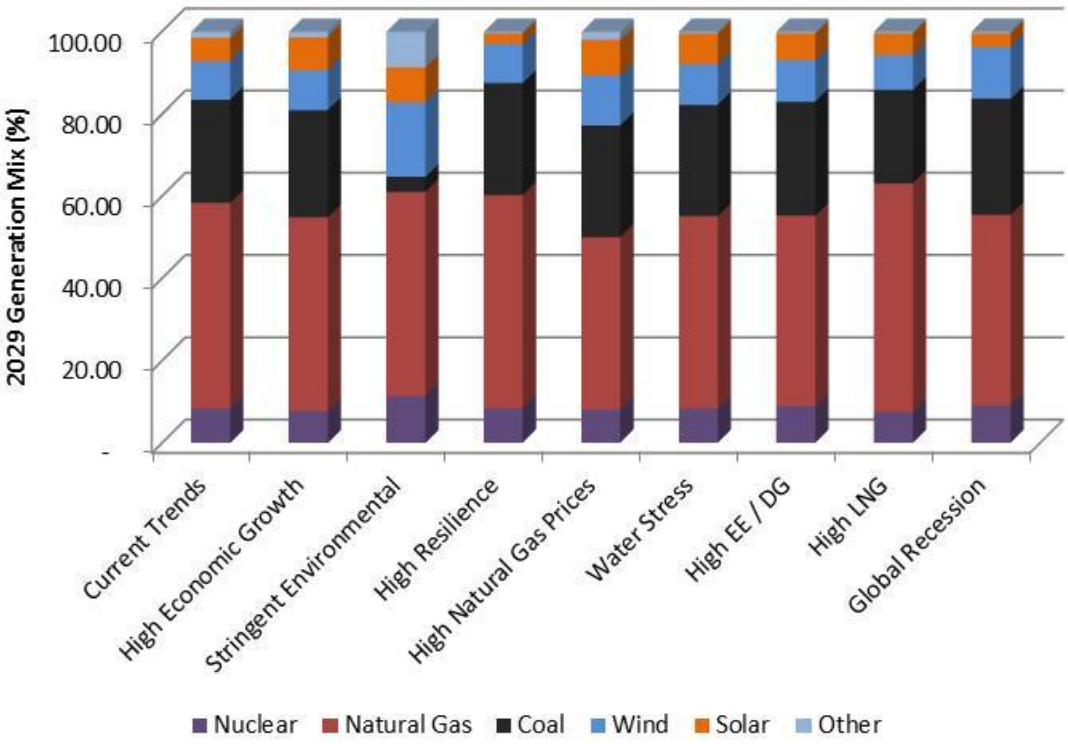

Figure 5.2: Generation mix in year 2029 (%)

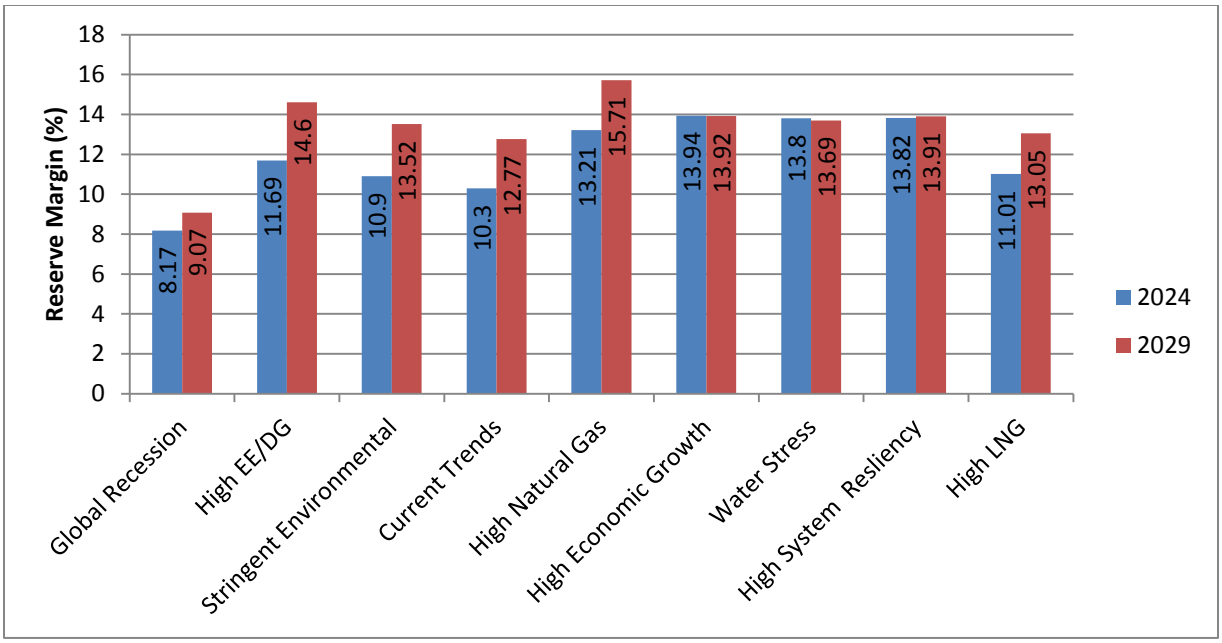

Figure 5.3: Reserve margin observed across studied scenarios for years 2024 and 2029.

A brief description of the generation expansion results for each of the scenarios evaluated in this LTSA follows. Specific details for each scenario are provided in Appendix F.

5.3.1 Current Trends

This scenario is designed to simulate today's market conditions, extended 15 years into the future. The results indicate that natural gas fired generation will remain the predominant resource for the foreseeable future. In this scenario 5,450 MW of combined-cycle plants and 5,810 MW of combustion turbines were built. Additionally 10,100 MW of solar PV generation were built as a result of the declining capital cost for new solar. Solar generation's greater output during the hours that typically have higher LMP prices likely contributes to this expansion as well. The scenario is also marked by a slight reduction in future generation reserve margins (12.8% in 2029) and a minor increase in the number of scarcity-priced hours (detailed annual results are attached in Appendix F).

5.3.2 Global Recession

This scenario is generally marked by a slow-down in all areas of the U.S. and Texas economies. The lowest peak demand occurred in this scenario with a value of 81,600 MW. This is significantly lower than the Current Trends and High LNG Export scenarios, which experienced 87,300 MW and 94,700 MW, respectively.

The Global Recession scenario included total new capacity of 14,125 MW built while 8,842 MW of existing generation retired. The new unit additions consisted of 6,450 MW of combustion turbines, 5,400 MW of solar and 2,265 MW of wind generation. The retirements were mainly older gas-steam driven facilities, which are the most expensive units on the system to run, with operations limited to peak system hours. As a result of the retirement of these units and the overall lowering of LMPs, the system reserve margin declined, and the number of scarcity hours (hours when the market price is set by the System Wide Offer Cap) increased. Because these retired units were run infrequently while they were still in operation, much of their capacity was replaced in the resource expansion process by gas-fired combustion turbines.

Also, because these system peak hours typically occurred during early to late afternoon hours (when there is high energy output from the sun), solar PV units were often economic. With the overall lower LMP prices reducing the revenue potential of new and existing resources, the reserve margin in this scenario was the lowest of all scenarios analyzed at 9% with a corresponding increase in scarcity hours.

5.3.3 High Economic Growth

The High Economic Growth scenario reflects an optimistic outlook concerning the Texan economy. The scenario assumes that a large portion of its economic productivity is driven by the oil and gas sector and related upstream and downstream industries. This scenario also included a required capacity reserve margin of 13.75% and a slightly higher natural gas price than in the Current Trends scenario.

Due to the inclusion of higher natural gas prices, LMPs were higher than those in the Current Trends scenario. Higher LMPs, in general, help the development of new generation, but it can also hurt those resources that burn natural gas. The added renewable generation in this scenario results in lower market prices in many hours and lowers the revenue potential for all intermediate and base-load units (including the combined-cycle units).

The generation expansion results show that fewer natural gas resources are economic, and solar resources, because of their daytime operating profile, are very economic.

As mentioned above, this scenario included a reserve margin requirement at or above 13.75%. Because of the reserve margin requirement, the model constructed 16,539 MW of additional combustion turbine units. This additional capacity resulted in a 13.92% reserve margin in 2029 with very few scarcity hours. Final expansion results for this scenario are shown in Appendix F.

5.3.4 High Energy Efficiency & Distributed Generation

The High EE / DG scenario is similar to the Current Trends scenario except for the inclusion of additional amounts of energy efficiency, demand response, and distributed generation (EE/DG). This scenario added 9,617 MW of EE/DG compared to the 1,865 MW of EE/DG added in the Current Trends scenario. Also included in this scenario were 1,057 MW of new residential PV by 2029. Also having an impact on the scenario was a higher natural gas price forecast. The resulting generation expansion added 2,000 MW of combined cycles and 4,330 MW of combustion turbines. Added to that were 11,100 MW of solar PV and 100 MW of new wind.

The higher natural gas prices lead to increased dispatch costs for all natural gas units in the model and decreased the economic viability of new natural gas resources. Increased natural gas prices and an increase in the amount of solar generation during on-peak hours also reduced the hours of operation of older, less-efficient natural gas units. These market conditions likely aided in the development of over 11,000 MW of solar PV units.

The resulting reserve margin in this scenario in 2029 was 13.97% with a correspondingly small number of scarcity hours.

5.3.5 High Natural Gas Price

The High Natural Gas Price scenario utilizes a forecast that is $3.50/MMBtu higher than the Current Trends scenario. This higher natural gas price would increase gas exploration in western Texas, however it may also reduce downstream industrial growth. The stakeholders assumed the net effect of these impacts would be a slightly higher load growth.

The generation expansion differences between this scenario and the Current Trends scenario reflect the higher natural gas price forecast. The results still show an increase in new natural gas generating units (4,950 MW of combined cycles and 3,560 MW of combustion turbines); the higher resulting electricity prices allow greater additions of more economic resources. The resulting reserve margin in this scenario is 15.71% for 2029. However, compared to the Current Trends scenario, renewable generation supplies the bulk of new capacity (16,500 MW of solar PV and 3,894 MW wind). Additionally, 840 MW of steam gas retired and roughly 800 MW of new demand response entered the market.

As mentioned earlier, a higher natural gas price would lead to an increased dispatch cost for all existing gas units and new natural gas capacity. A high natural gas price would also increase

on-peak LMPs, which averaged just over $90 in 2029. In turn, the higher LMPs would increase the economic viability of wind and solar capacity.

5.3.6 Stringent Environmental

This scenario depicts a future where aggressive action to mitigate environmental impacts in the energy sector has occurred. Many of the environmental policies being discussed today, GHG, CSAPR, MATS, etc., are implemented in this scenario as well as a continuation of subsidies for renewable generating types. The combination of expected high natural gas prices, continuation of the PTC and ITC, and increased emission costs (SO_2, NO_X, and CO_2) in this scenario resulted in a large amount of renewable resources being built. While some natural gas generation continues to be built the vast majority of new generation was from solar and wind, 16,500 MW and 13,291 MW, respectively. When combined with the existing renewable generation fleet, this scenario results in addition of over 40,000 MW of intermittent resources on the ERCOT system. Additionally, 480 MW of geothermal, 240 MW of biomass, as well as 2,200 MW of new nuclear resources were added to the generation mix in this scenario.

Conversely, over 20,000 MW of existing ERCOT resources retire from service. This capacity includes most of ERCOT's steam gas units and roughly half of the coal fleet. The capacity factor on the remaining coal units in 2029 is reduced to 35%, which is slightly lower than today's average of 40%. The resulting reserve margin in this scenario for 2029 was 13.52%.

5.3.7 High LNG Exports

The High LNG Exports scenario is characterized by a healthy global economy that is driving a high demand for natural gas. In Texas, environmental regulations and other policies conducive to growth of oil and gas production and LNG exports are developed. Currently there are nine proposed LNG facilities in ERCOT totaling over 13 Bcf/d of production. Without judging the individual merits of each proposed facility, ERCOT assumed a total of 9.6 Bcf/d of LNG capacity would be constructed in Freeport, Corpus Christi, and Brownsville.

Total peak load for this scenario is the highest of all scenarios with the addition of the 3,840 MW of flat load for the LNG production facilities.

With continued growth in the oil and gas industry, natural gas prices remain relatively consistent with the price in the Current Trends scenario. The resulting generation expansion contains large amounts of new natural gas units, consisting of 16,500 MW of combined-cycle

units and 3,710 MW of combustion turbines, as well as 10,700 of solar PV. The resulting reserve margin in this scenario is 13.1% in 2029.

5.3.8 High System Resilience

The concept of this scenario was to build a transmission system that was highly reliable, perhaps overbuilt, so the system could support major power transfers within ERCOT during potential "black swan" events such as a northeast type blackout or large storms. Additions to the database for this scenario included two new DC ties to the east and west totaling 1,500 MW each, a required capacity reserve margin, and the addition of 2,500 MW of new demand response.

With these criteria, the capacity expansion process results in small amounts of economic expansion capacity being built. Only 4,260 MW of new gas generation was built and 4,700 MW of new solar. Adding the DC ties and expanding the demand response program, kept the average LMP relatively low. Because of the small amount of economic generation added, reliability additions were just over 15,000 MW. This development further suppressed LMPs which averaged only $55.20 in 2029. As might be expected, the reserve margin in 2029 was 13.91% and there were no scarcity hours.

5.3.9 Water Stress

This scenario is characterized by increased DC-tie connections to the east and west, requirements that all new expansion generating resources be dry cooled or use no water, and a required capacity reserve margin. No combined-cycle units were built because of the increased cost of dry cooling for those facilities. Capacity constructed included 1,060 MW of economic combustion turbines, 13,700 MW of solar, and 670 MW of new wind. Additionally because of the reserve margin requirement 7,230 MW of reliability combustion turbines were built. The end result was a 13.7% reserve margin and, as expected, only minor amounts of unserved energy.

5.4 Utility Scale Solar Expansion

The generation expansion results for many of the LTSA scenarios point to the possibility that a large amount of utility-scale solar resources could be built in the future. The capital costs for new solar continue to decline at a fairly consistent and rapid rate. The capital costs used for the expansion solar units in the LTSA analysis were based on a combination of solar developer supplied costs and information provided by the Brattle Group.

Recent reports provided by the Solar Energy Industries Association (SEIA),[8] Citi Group,[9] Lazard,[10] and the National Renewable Energy Laboratory (NREL)[11] indicate that the capital costs for new solar installations may decline faster in the early years of the study period (2018-2021) and throughout the entire study period (2018-2029) in the LTSA analysis than indicated by the original solar capital cost projections that were initially used in the LTSA analysis discussed above. Therefore, it is likely that had these adjusted lower solar capital costs been used in the initial LTSA analysis, more solar capacity would likely have been built in the early years of the generation expansion process, 2018 thru 2021. Sensitivity runs conducted on the Current Trends scenario for 2018 indicated that at a capital cost of $1,850/kWac solar capacity would have been built.

As stated above, recent reports indicate that utility-scale solar capital costs currently range between $1,600 to $1,920 per kilowatts of direct current power (kWdc), with Citi Group projecting costs at $930-$650/kWdc by 2020. Figure 5.4 illustrates the potential amount of utility-scale solar generation resource capacity that would be built at lower solar capital costs per kilowatts of alternating current power (kWac).

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[8] Greentech Media, Inc and Solar Industries Association. *U.S. Solar Market Insight Report.* Q1 2014. Confidential Report. (SEIA provided ERCOT with the Q2 U.S. SMI report that showed that utility-scale solar capital costs range between $1.60 and $2.05 per watt-dc for fixed tilt systems.

[9] Citi Research, *Launching on the Global Power Sector: The Sun Will Shine but Look Further Downstream.* February 6, 2013. Confidential Report.

[10] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 8.0*, September 2014. *Available at* http://www.lazard.com/pdf/levelized%20cost%20of%20energy%20-%20version%208.0.pdf.

[11] NREL, Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2013 Edition, available at: http://emp.lbl.gov/sites/all/files/presentation.pdf.

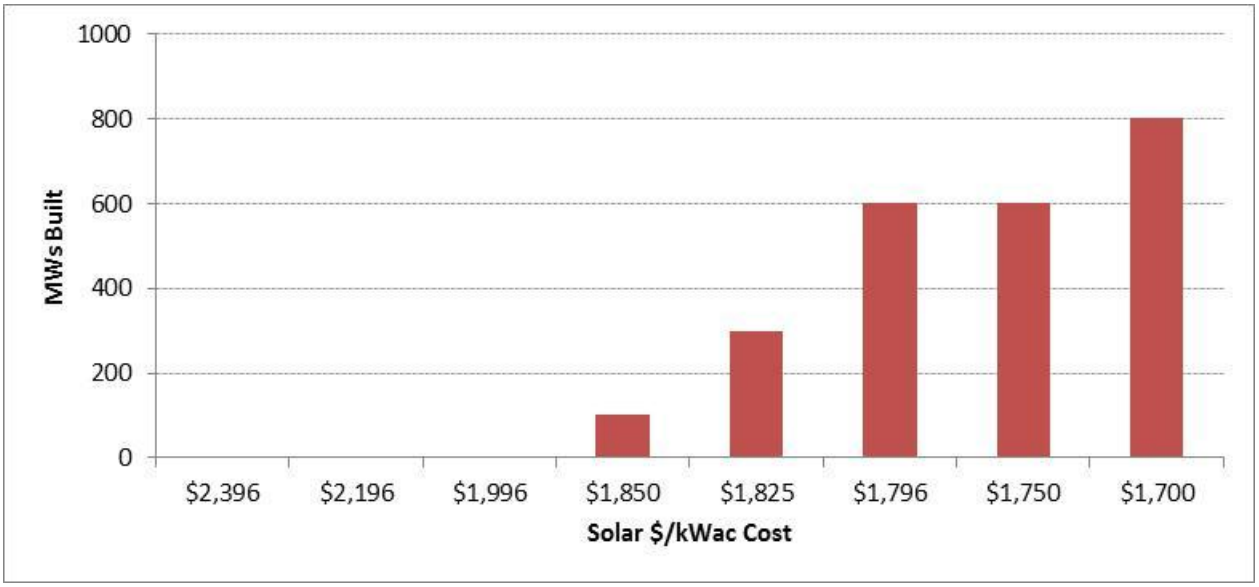

Figure 5.4: Sensitivity on Solar Capital costs for 2018

If current trends in the decline of solar capital costs continue, the installed cost for new solar projects may be in the $1,850/kWac range by 2018. Figure 5.5 shows the amount (incremental) solar and wind generation added by 2029 for all the studied scenarios.

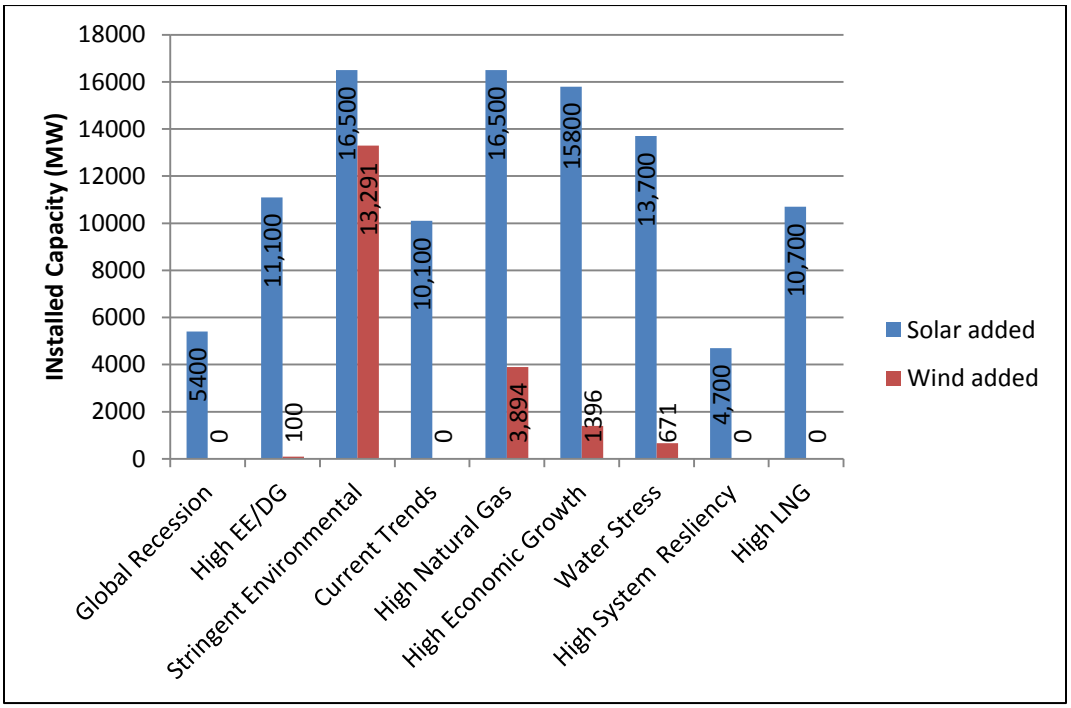

Figure 5.5: Amount of solar and wind generation added by 2029

6. Transmission Needs Analysis

Scenario-development workshops identified ten different scenarios with internally consistent planning assumptions as documented in Section 3 of this report. Load forecasting and generation expansion was performed on each of these scenarios using the guidelines and assumptions captured in the scenario-development process. Transmission expansion analysis followed for four of the ten scenarios. These four scenarios were selected by the stakeholders and ERCOT staff based on the combination of generation expansion analysis and load forecasting results, the likelihood of each of the scenarios coming to fruition, and their potential impacts on the transmission system. The following section explains the transmission analysis process applied in the 2014 LTSA.

6.1 Methodology

6.1.1 Base Case Creation

For each of the scenarios evaluated, the 2018 case from the 2013 RTP was the base case used for the transmission reliability analysis portion of this study. This case included the transmission upgrades that were recommended as a result of the reliability and economic analyses from the 2013 RTP.

The initial demand levels modeled in the base case represented the forecasted load for the 2018 summer peak. To prepare the LTSA cases, the loads in the models were increased up to 2024 and 2029 levels using a 90th-percentile, summer-peak load forecast by weather zone. This forecast was created to reflect the assumptions and guidelines from the scenario-development workshops.

Scenario-specific portfolios of incremental generation resources were added to the transmission base case to support anticipated load growth. As described in Section 5.2, these portfolios were created based upon an economic assessment of the viability of emerging or existing resource technologies given scenario-specific assumptions. The resources were modeled in the cases at the appropriate buses as outlined in the guidelines from the generation siting methodology. Similarly, the resource expansion results show the retirement of several existing generation units on the basis of operating age or economics. The transmission base cases were further updated based on the guidelines provided by the LTSA Scope document attached in Appendix G.

ERCOT used a 50th-percentile hourly load forecast to conduct the generation expansion analysis and evaluate hourly revenue impacts to identify the fuel type, unit size, and market entry timing of the added resources. The transmission reliability analysis was performed for summer peak conditions, per the guidelines set in the LTSA Scope document. Consistent with the RTP, ERCOT used a 90th-percentile load forecast to represent the critical weather conditions during the summer peak timeframe. Furthermore, the reliability cases used the non-coincidental peak load for all weather zones. As a result, the amount of incremental generation identified in the generation expansion process was not sufficient to meet the aggregate non-coincidental system load, loss, and reserve requirements. To address this imbalance, the cases were further divided into four study regions, and renewable resource dispatch and load levels outside each study region were adjusted to aid the analysis. ERCOT uses a similar approach to split and scale the cases when it conducts the RTP.

6.1.2 Reliability Analysis

ERCOT conducted reliability analysis on each of the scenario-appropriate base cases created for 2024 and 2029 to determine the potential transmission needs of the system. As an initial review, DC Security-Constrained Optimal Power Flow (SCOPF) run was utilized to identify any unresolvable constraints under relevant contingencies. All NERC Category B and some NERC Category C contingencies were studied. The NERC C contingencies that were included in the study are:

- the loss of double circuit lines that share towers for more than 0.5 miles,
- the loss of a generation resource followed by another contingency, and
- the loss of a 345/138-kV transformer followed by another contingency.

Contingencies at all voltage levels were evaluated while only monitoring the 345-kV network. First, ERCOT began with the premise that most of the 138-kV and 69-kV network upgrades would occur through the near-term planning process. Furthermore, because those upgrades would be identified in the near-term planning process, they would be missing from the LTSA start cases and would not need to be addressed in the LTSA reliability analysis. In the rare instance that large clusters of the 138-kV system were overloaded in the study and required a solution at the 345-kV level, they were included in this study. Limiting the system monitoring allowed ERCOT to concentrate principally on the 345-kV network and bulk transmission needs of the system.

Overloaded 345-kV elements requiring upgrades regardless of system dispatch were addressed and documented as reliability upgrades. In a later part of the study, reliability upgrades were compared to alternatives that resolved the same issues to identify lower cost options.

ERCOT worked with associated TSPs to develop potential long-term upgrades for the overloaded elements identified in the reliability analysis. The results of the reliability analysis are further discussed in section 6.2.

6.1.3 Economic Analysis

ERCOT used the final economic case for the year 2018 from the 2013 RTP as a starting point for the 2014 LTSA economic analysis for all scenarios. The cases were modified with the necessary generation fleet changes and load adjustments to represent the different scenarios and years included in the transmission analysis. After completing the analysis to determine upgrades necessary to maintain system reliability for each of the years and scenarios, ERCOT added the resulting projects to the corresponding economic start cases. ERCOT used the scenario-specific 50th-percentile hourly load forecast, in addition to the self-served load, to model the system demand for each transmission scenario. The resource profile, including the profile for DR, which was developed in the generation expansion planning process, was used to model the generation build for each scenario. A Panhandle export interface limit of 2669 MW[12] was enforced on the 345-kV double circuit interface defined between the Gray to Tesla, Tule Canyon to Tesla, Cottonwood to Edith Clarke, and Cottonwood to Dermott substations.

Each scenario that was evaluated for transmission reliability needs was also evaluated for economic project opportunities. As explained in the reliability analysis section, this economic analysis was also focused on resolving the congestion on the 345-kV network. The study began in areas of high congestion where conceptual projects were designed in an attempt to reduce system production costs sufficiently to offset each project's total cost to customers. ERCOT used the economic planning criteria from ERCOT Protocol section 3.11.2(5) to evaluate the studied projects.

Reliability-driven projects and economic alternatives or supplements were documented separately for consideration in subsequent shorter-term study horizons. Near-term planning

[12] http://www.ercot.com/content/meetings/rpg/keydocs/2014/0819/DATC_ERCOT_assessment_update_RPG_08192014.pdf

studies (e.g. the RTP) will reference long-term reliability constraints when proposing projects in the same geographical area.

Cost estimates for potential transmission projects used in this study do not reflect routing considerations, such as unknown obstacles, physical constraints, or public preferences. These routing obstacles can lead to significant project cost increases.

6.2 Study Results

6.2.1 Overview of reliability cases

The key factors that drive the need for transmission projects are the availability and location of generation resources, the magnitude and concentration of load growth, and the transmission network which connects the two. Appendix H includes maps depicting generator retirements for each of the scenarios studied. Similar maps were prepared to illustrate the geographical locations of the incoming resources for each of the scenarios (Appendix I). In order to understand the results of the transmission analysis and the resulting projects, it is important to understand the changes in the generation fleet and load growth that was modeled in the LTSA.

Figure 6.1 illustrates the change in generation availability across the four scenarios that were used for the transmission analysis. The warm colors in the map indicate the location and magnitude of generation megawatts that were added in a particular scenario, whereas the cool colors on the map show the loss of generation megawatts on the system. Two common themes that are consistent across all scenarios are the retirements in the Dallas—Fort Worth area and the addition of renewable resources in the West and Far West weather zones—though the magnitudes differ from case to case.

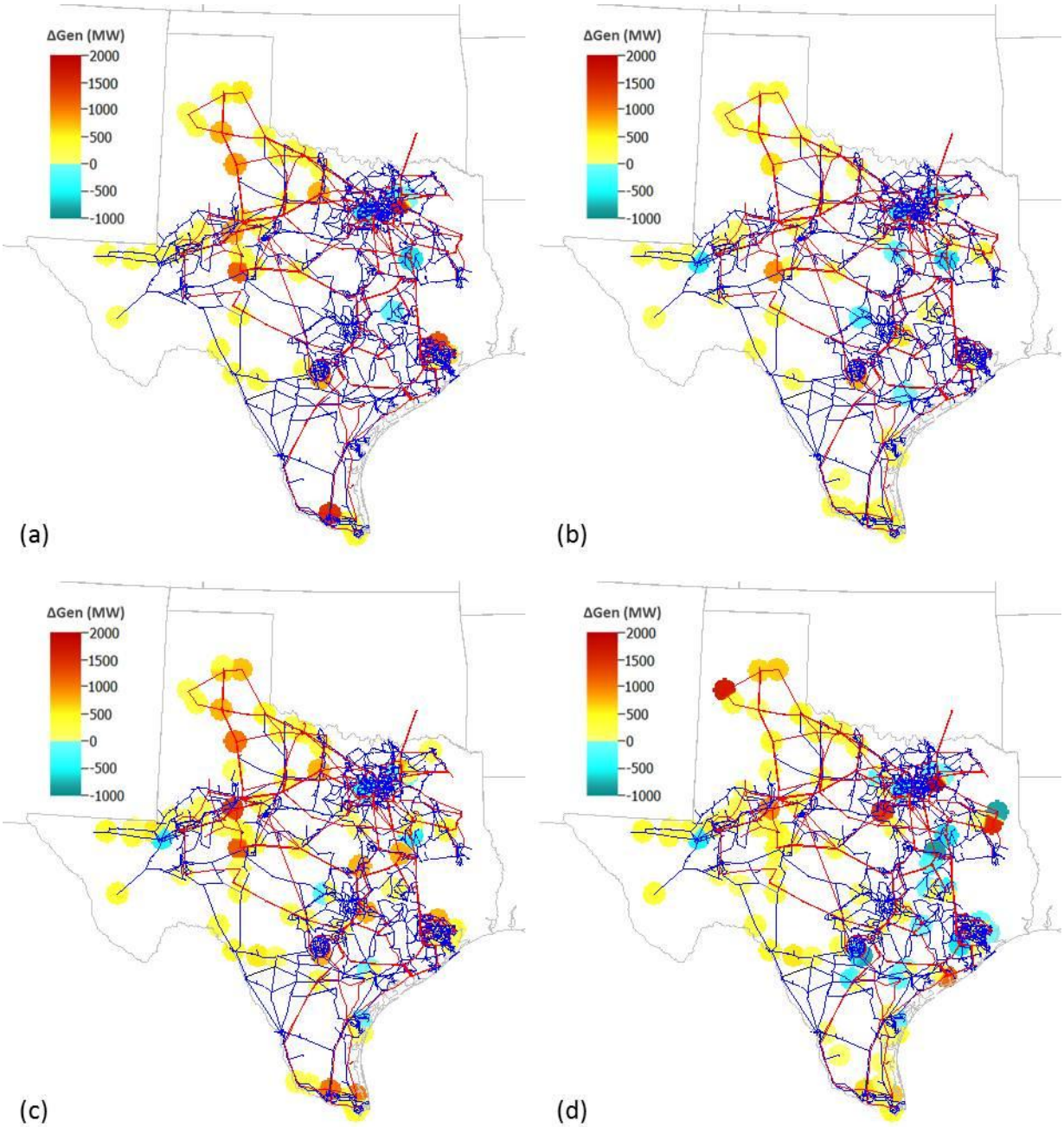

Figure 6.1: Change in availability of generation resources by 2029 in the (a) Current Trends, (b) Global Recession, (c) High Economic Growth, and (d) Stringent Environmental scenarios.

As the resources closer to the urban centers retire and new generation resources appear further away from the load pockets, the need for new or further reinforcement of existing inter-area transmission paths increases. This is particularly evident in the Stringent Environmental scenario, where fossil fuel generation closer to the load centers was replaced by renewable

sources which were limited to particular areas. The location of the new generation resources was 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 solar and wind resources are limited by the availability of the natural resources. Both the Stringent Environment and High Economic Growth scenarios experienced a large increase in renewable generation resources.

As the availability and location of the generation resources shift over time, so does the demand for the energy. Figure 6.2 illustrates the compound annual growth rate (CAGR) for the load in the ERCOT region for each of the four scenarios that were evaluated for transmission projects. The observable trend within all scenarios is the load growth along the I-35 corridor and the satellite counties surrounding the major cities in Texas, which represents the continuing urban sprawl. As expected, the Global Recession scenario experienced the most muted load growth across the entire region, while the High Economic Growth scenario experienced the highest. Additionally, not illustrated here, the High Economic Growth scenario also included the block addition of load in the Corpus Christi and Brownsville area to support the LNG exports. The key difference between the Current Trends and the Stringent Environmental Scenario is the reduction of electric demand to support the oil industry.

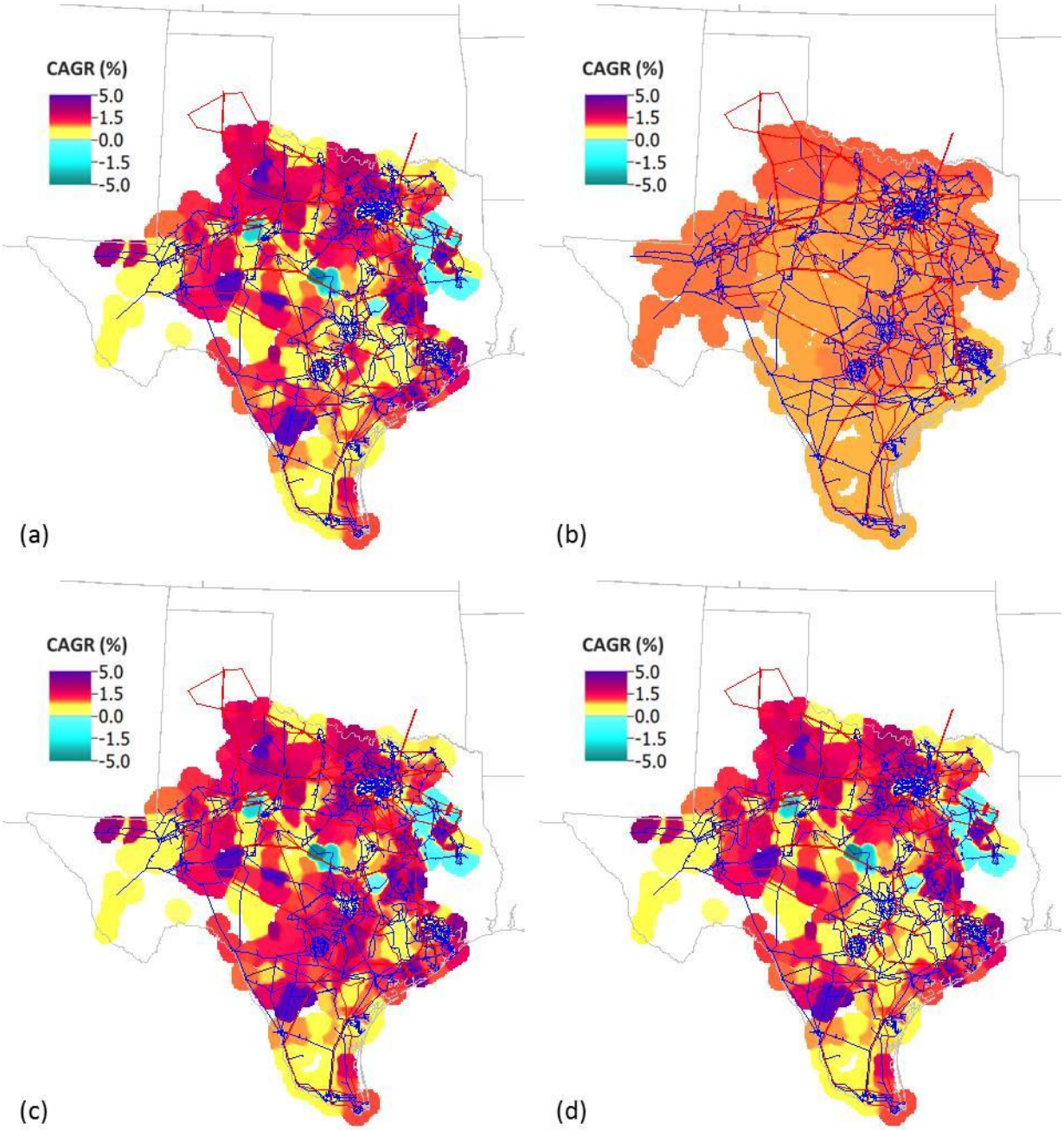

Figure 6.2: Compound Annual Growth Rate (CAGR) of the load in the (a) Current Trends, (b) Global Recession, (c) High Economic Growth, and (d) Stringent Environmental scenarios.

The compound effect of a changing generation fleet and differences in load growth across the different scenarios drove the need for different projects across the four scenarios. The High Economic Growth and Stringent Environmental scenarios demonstrated the largest need for transmission projects. Though the generation expansion for the High Economic Growth scenario enforced a reserve margin and resources were sited throughout the state, the high load growth

in the region was likely a key factor that required the transmission improvements. The load growth in the Stringent Environmental scenario was similar to the load growth in the Current Trends scenario but the high retirement rate and the addition of renewable resources in more remote locations was a contributing factor in the need for the transmission projects.

The Current Trends scenario generally needed a subset of the projects proposed in the High Economic Growth and Stringent Environmental scenarios, while the Global Recession scenario needed only a few minor transmission improvements. The Global Recession scenario assumed muted load growth past 2020 and resulted in the delayed need for infrastructure improvements to support the load in the region.

6.2.2 Results of reliability analysis

The DC SCOPF was used to dispatch the case and determine the transmission constraints that could not be resolved with a system redispatch. Contingency analysis identified the need to upgrade several 345-kV lines, while the transformer outage analysis identified a need to add 345/138-kV autotransformers across the ERCOT system. While significant, these upgrades are expected to be identified in due course of the RTP. As a result, this report includes a more detailed discussion of reliability projects that require significant topology changes or new rights-of-way. A more complete list of all 345-kV projects for each scenario and year studied is included in Appendix J. The significant projects are listed in Table 6.1 and their corresponding geographical locations are illustrated in Figure 6.3.

Table 6.1: Significant reliability projects identified in the 2014 LTSA

Index	Weather Zone	Project Name	Current Trends		Global Recession		High Economic Growth		Stringent Environmental	
			2024	2029	2024	2029	2024	2029	2024	2029
1	North Central	West Roanoke project								
2	North Central	Rockhill project								
3	North Central	Fort Worth project								
4	North Central	Nevada project								
5	West South	Hamilton - Lobo 345-kV line								
6	South	New 345-kV path from La Palma to Loma Alta								

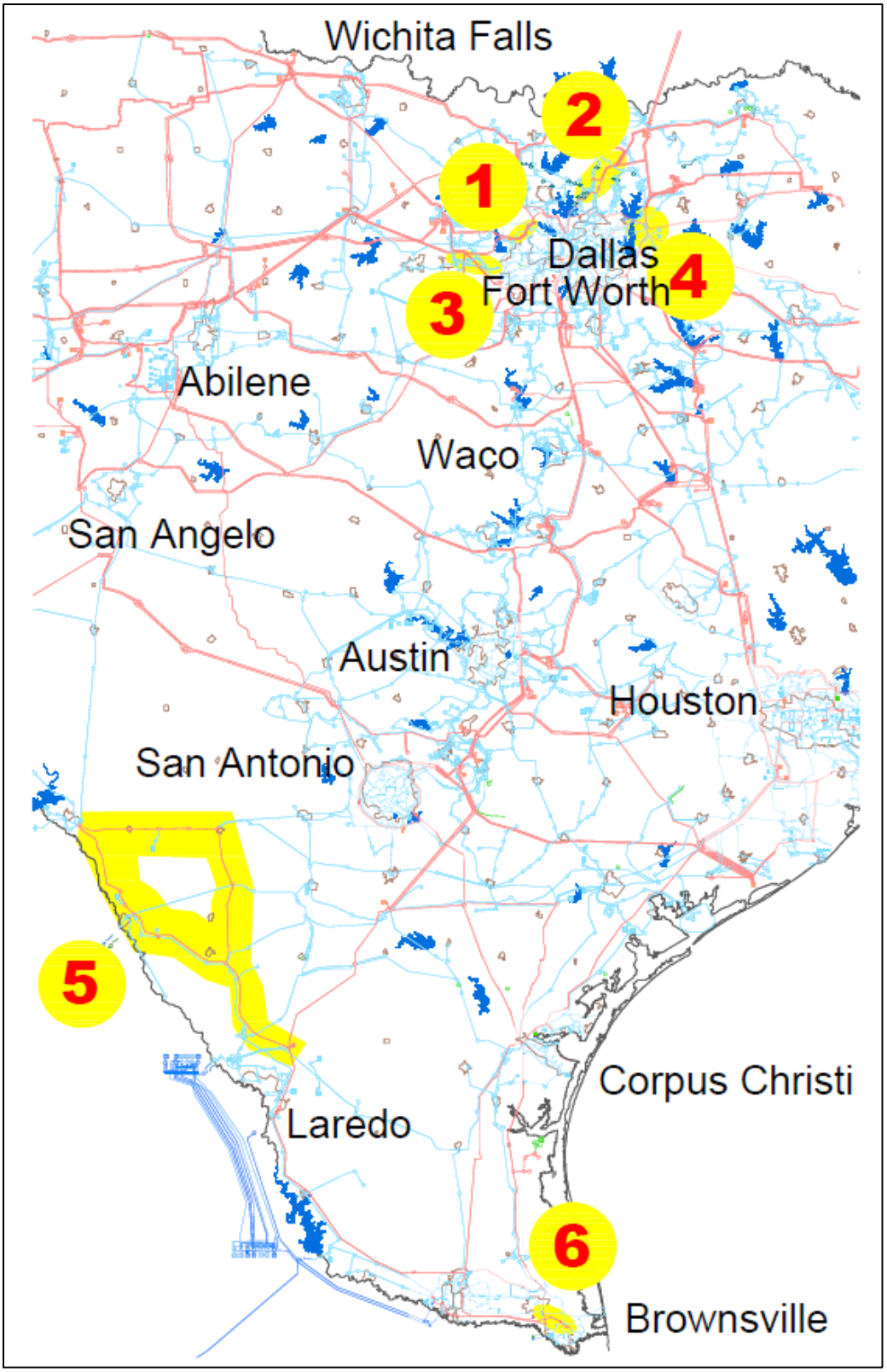

Figure 6.3: Significant reliability projects identified in 2014 LTSA

Dallas-Fort Worth Area Projects

Fueled by a robust economy, electricity demand in the Dallas/Fort Worth region is expected to continue to grow. Based on the load forecast prepared for the Current Trends scenario, the demand in Tarrant, Dallas, Denton, Collin and surrounding areas is expected to grow at a rate of 1.4%. As a result of this growth the 2014 LTSA reliability analysis identified a need to develop several 345-kV transmission projects by 2029. These projects are described in the following sections.

Fort Worth Area Project

Continued growth in Tarrant County has resulted in the overloads of several autotransformers in the area. Primarily, the Benbrook, Rocky Creek, Everman and Eagle Mountain 345/138-kV autotransformers are overloaded under N-1 contingency conditions. ERCOT observed these needs in 2029 under Current Trends, High Economic Growth and Stringent Environmental LTSA scenarios. The following project is designed to provide new support on the west side of Tarrant County.

The project includes a new 345/138-kV substation near the Hilltop – White Settlement Switch 69-kV line to tap the existing 345-kV double-circuit Parker to Benbrook transmission line. These additions are highlighted in yellow on the map in Figure 6.4. Two new 345/138-kV autotransformers rated at least 600 MVA will be added to this new substation. Additionally, the existing 69-kV transmission line between the Brazos-owned Hilltop substation, located in Parker County, and the Oncor-owned White Settlement Switch substation, located in Tarrant County, will be upgraded to a new 138-kV double-circuit transmission line rated at least 474 MVA.

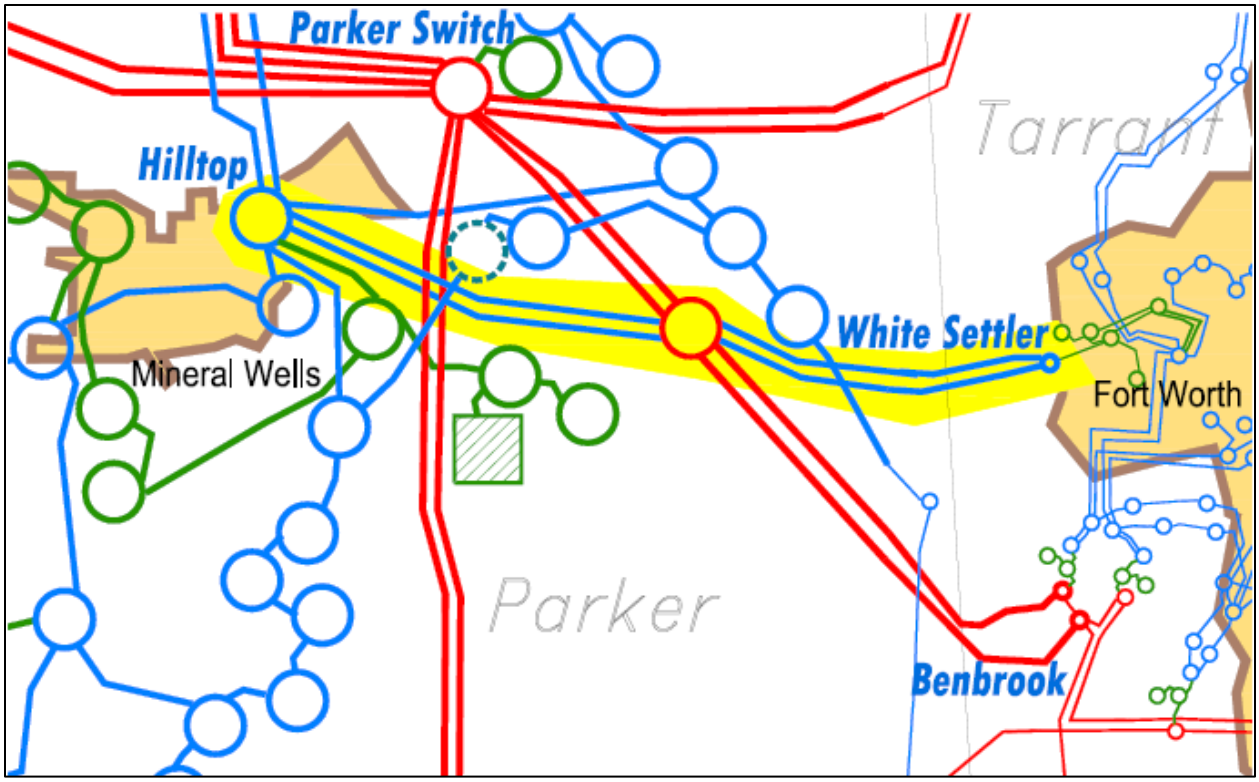

Figure 6.4: Fort Worth Area Project

West Roanoke Project

The Roanoke autotransformers are a primary receiving point of power flowing from Willow Creek and Parker Switch. The flow is directed along the Willow Creek – Hicks 345-kV double-circuit line and the Parker – Hicks 345-kV line, which ultimately directs the flow through the Roanoke autotransformers. The models show the existing Roanoke autotransformers, located in Denton County, will experience heavy loading in 2029 for the following scenarios: Current Trends, High Economic Growth and Stringent Environmental.

The proposed West Roanoke project will add a new 345-kV double-circuit line from Hicks to West Roanoke rated at least 2987 MVA. The project will also tap the existing West Denton to Roanoke 345-kV line and Lewisville Switch to Roanoke Switch 345-kV line with a new 345-kV bus located at the existing West Roanoke 138-kV substation.

In addition to the new 345-kV double-circuit line from Hicks to West Roanoke, two new 345/138-kV autotransformers at West Roanoke will be added as a new source at West Roanoke diverting the flow originating from the east (Willow Creek and Parker Switch) ultimately

lowering the megawatt loading on the Roanoke autotransformers. The Figure 6.3 shows the location of the new double circuit lines from Hicks to West Ronoake.

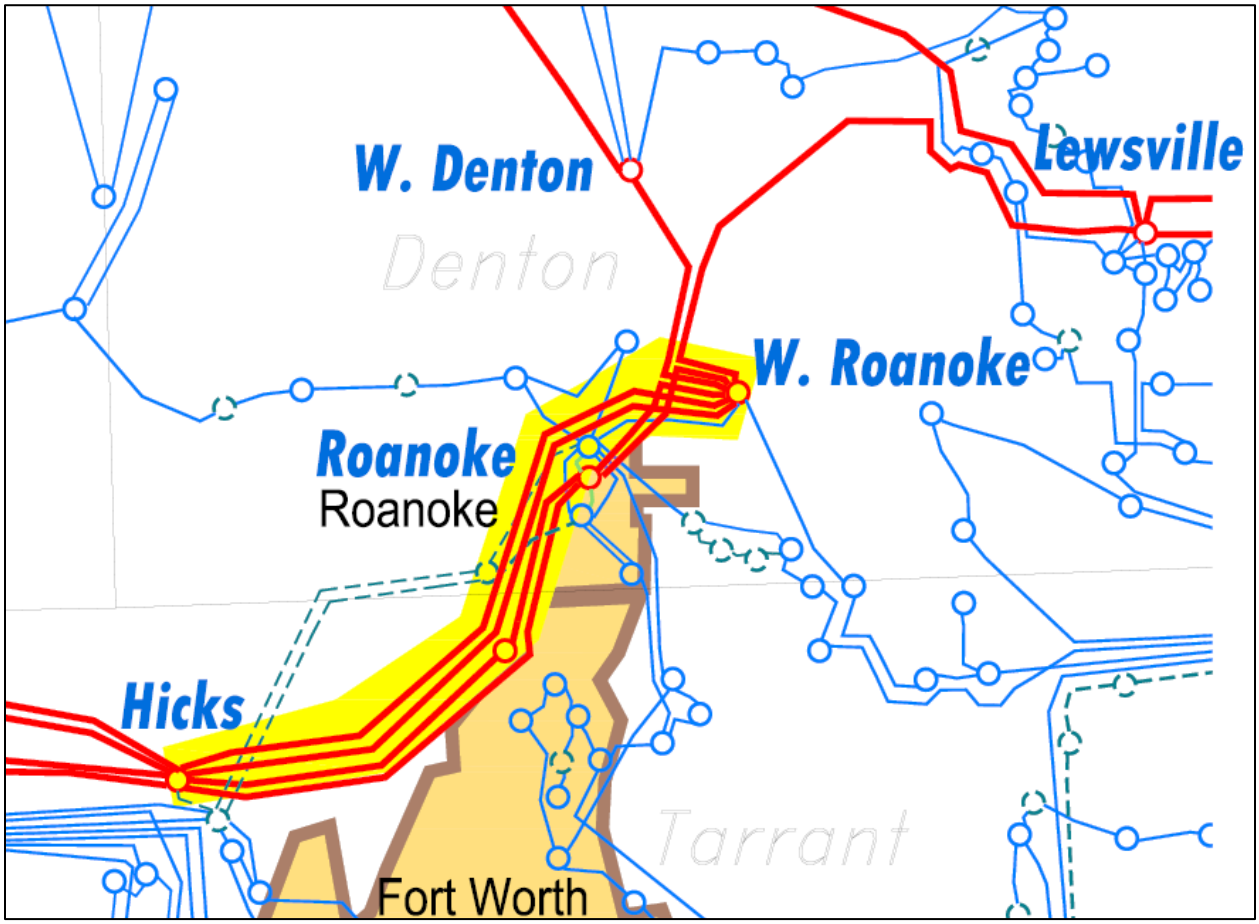

Figure 6.5: The West Roanoke Project

Rockhill Project

The existing 345-kV path between Anna Switch substation and Collins Switch substation serves as the main 345-kV path that directs over 1000 MW of flow onto the Collins Switch autotransformers for the various scenarios. As a result of this flow pattern, the existing Collin Switch autotransformers 1 and 2 experience heavy loading in the years 2024 and 2029 for the Current Trends and High Economic Growth LTSA scenarios under contingency conditions.

The project includes new 345-kV circuit rated at least 2987 MVA from the Anna Switch substation to the Rockhill substation. The existing Anna Switch to Collin Switch 345-kV path can be used to serve as right of way to accommodate the proposed 345-kV circuit between Anna Switch substation and Rockhill substation. This new path, highlighted in yellow in Figure 6.6,

will lower the loading on the Anna Switch – Collin Switch 345-kV circuit and divert flow from the Collin Switch autotransformers. In addition to the 345-kV line, two 345/138-kV autotransformers rated at least 600 MVA will be added at the Rockhill substation.

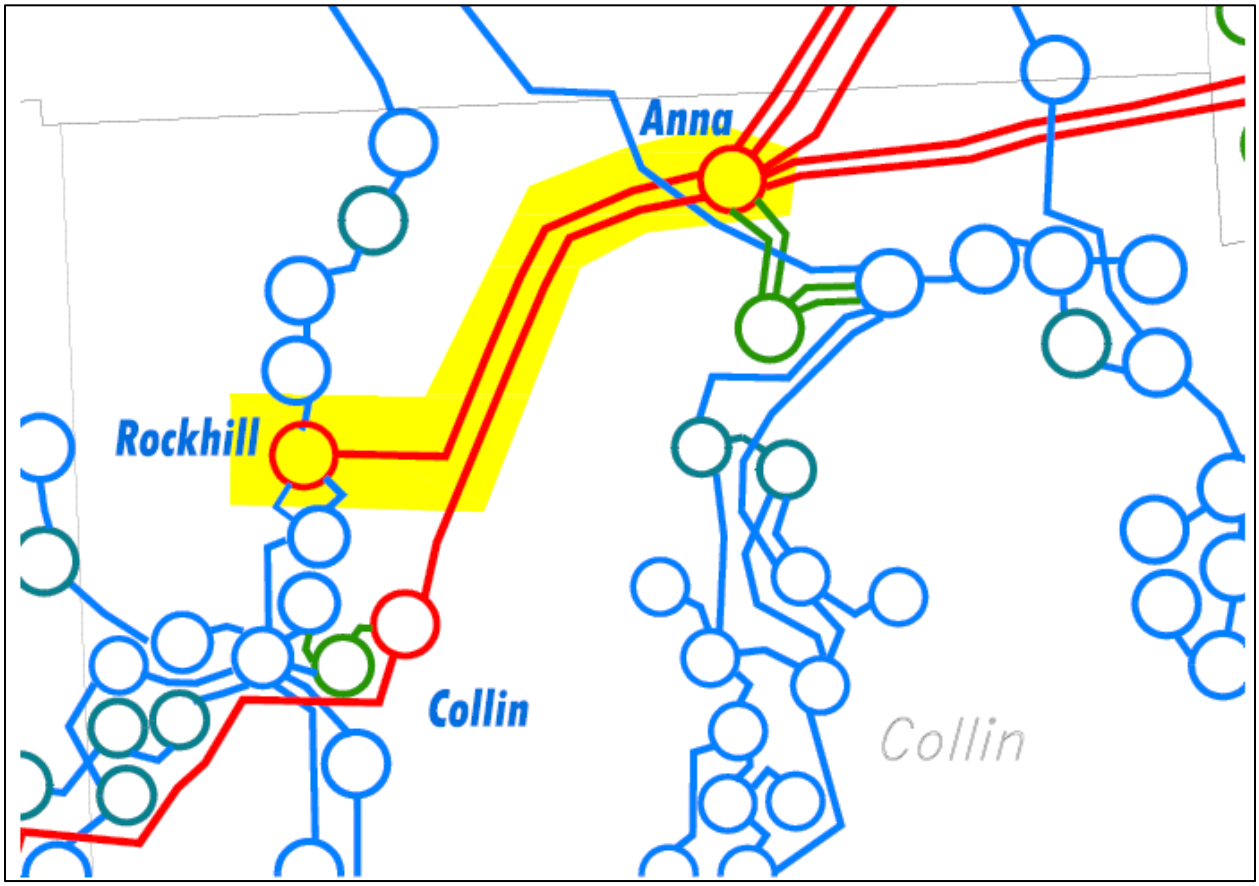

Figure 6.6: The Rockhill Project

Nevada Project

The Royse autotransformers experience heavy loading in 2029 for all transmission scenarios (Stringent Environmental, Current Trends, High Economic Growth, and Global Recession). Several 345-kV circuits from both the north and south transfer power into the Royse Switch autotransformers.

The proposed project will add a new 345-kV bus at Nevada substation and add a new 345-kV transmission path, rated at least 1420 MVA, from Royse to this new 345-kV bus located at the Nevada substation. This line will ultimately reduce loading on the Royse autotransformers and divert the flow in the southwest direction along the Royse-Rockwall 138-kV path. Additionally,

the project will also add two new 345/138-kV autotransformers rated at least 600 MVA each at Nevada.

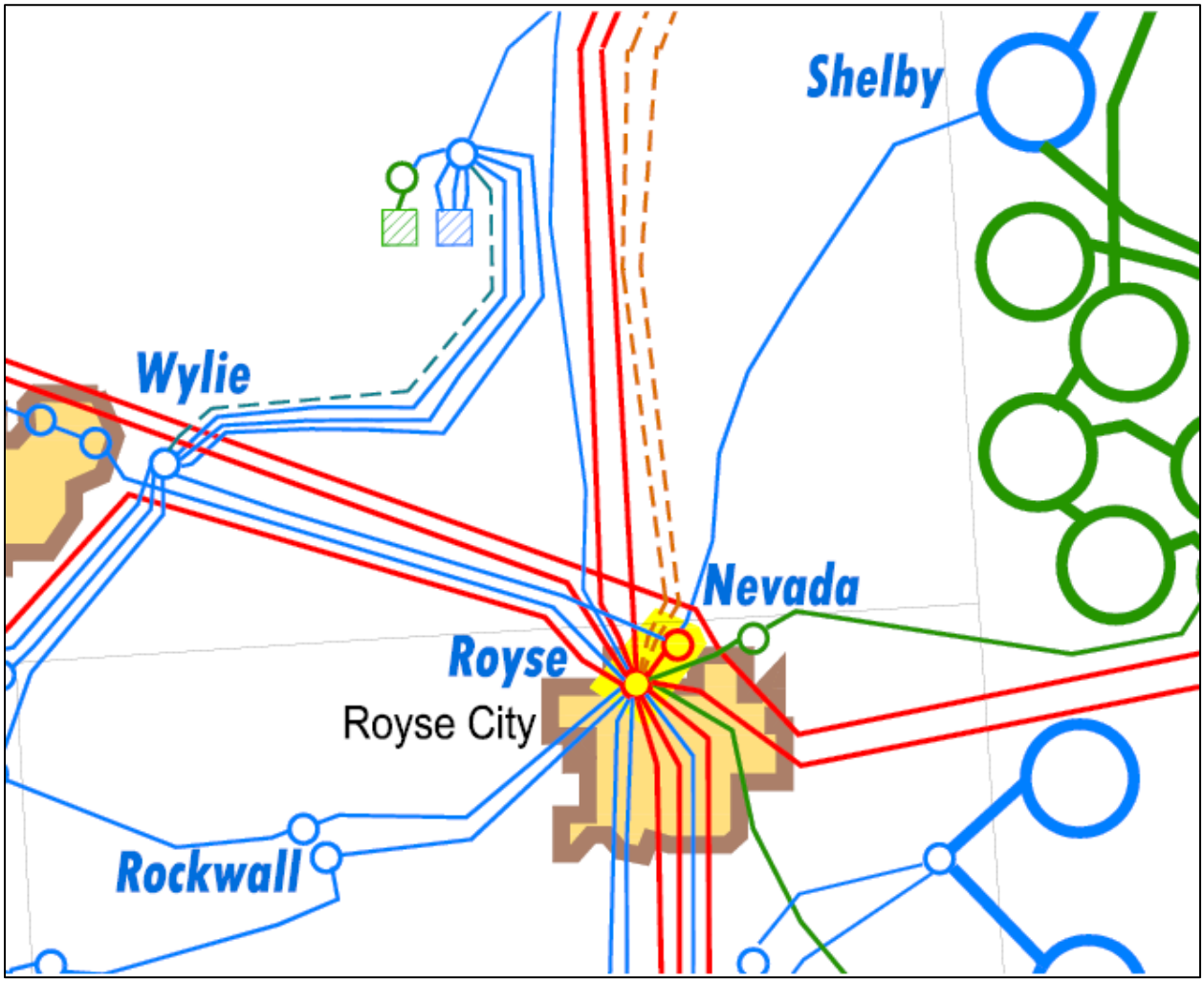

Figure 6.7: The Nevada Project

6.2.3 Impact of Solar Additions in West Texas

As discussed in Section 5, decline in cost of solar generation results in significant solar expansion across ERCOT by 2029. This continuing growth is observed, in varying levels, across all scenarios. For instance, the installed capacity of utility-scale solar generation in the Current Trends scenario for year 2029 is expected to be 10,100 MW. Similarly, the Stringent Environmental and High Economic Growth scenarios include an addition of 16,500 MW and 15,800 MW respectively. Even the Global Recession scenario, with modest load growth and low

natural gas prices, saw an addition of 5,400 MW of solar generation. It should be noted that roof top solar installations are not considered in this discussion.

System-Wide Impact

In Texas, which experiences its most critical system condition during the hot summer days, solar generation is expected to be co-incident with demand. The effect of including this 10 GW of solar is a net reduction in the total system load to be served by non-solar generation. Figure 6.8 shows hourly load on a peak summer day in the Current Trends scenario for year 2029. The y-axis shows the load in megawatts, with the blue line representing the load forecast prior to adjustments due to solar generation. The solar generation level is based on the solar profiles employed in the economic analysis of this scenario.

As seen below, the peak load served, 76,322 MW, drops to 67,884 MW peak net load after adjusting for solar generation. Additionally, the hour when the system experiences its net peak moves from the hour ending at 5:00 p.m. to the hours ending at 8:00 p.m. The transmission system may experience two different stressed conditions: the first at hour ending 5:00 p.m. (peak demand), and the second at 8:00 p.m. (peak demand less solar). Transmission planners may need to consider performing reliability analyses for both of these time periods rather than the traditional approach of studying a single peak hour.

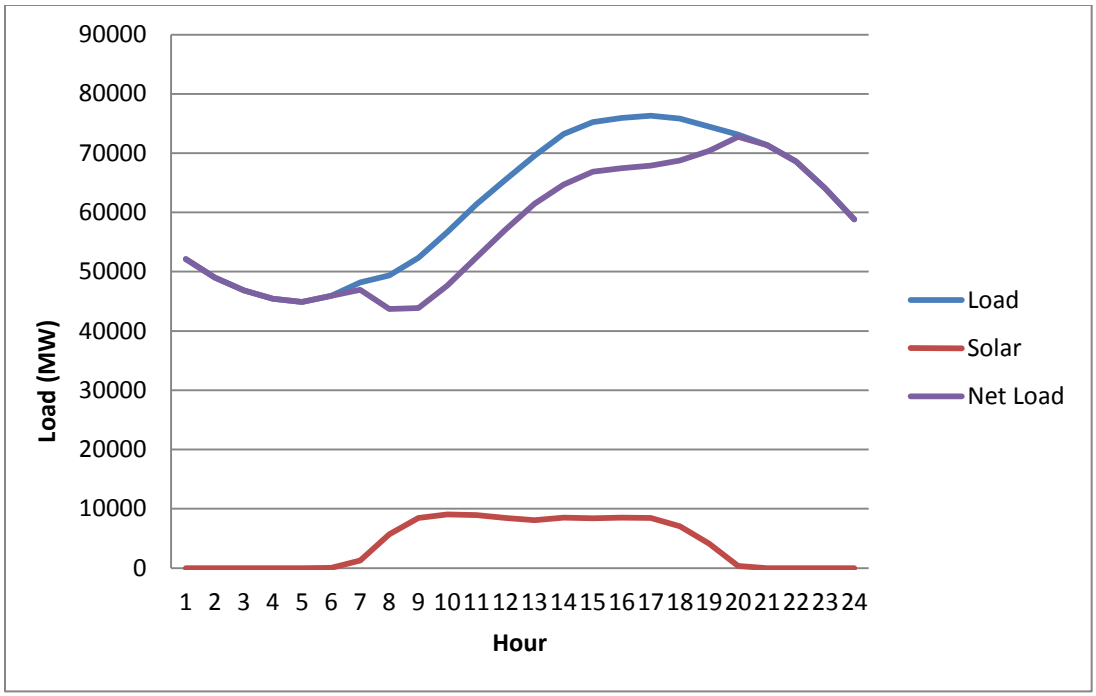

Figure 6.8: Impact of Solar generation on the 2029 summer hourly load

Regional Impact

During the scenario-development workshops the participating stakeholders designed the scenarios with certain assumptions as a starting point. One of the assumptions was that a CREZ-like transmission upgrade may be sanctioned to allow the additional transfer of large amounts of solar power from regions that have the best solar sites to the load centers. Using the solar curves from URS, the generation expansion analysis recommended the addition of most of this solar generation in the West and Far West weather zones. The generation expansion for the High Economic Growth and Stringent Environmental scenarios resulted in a significant increase of solar generation in the counties on the border of the West and South weather zones. The solar generation for each of the scenarios in Val Verde, Kinney, and Uvalde counties are shown in the table below.

Table 6.2: Solar generation in Val Verde, Kinney, and Uvalde counties

Scenario	Solar Generation (MW)
Current Trends	875
Global Recession	455
High Economic Growth	1,435
Stringent Environmental	1,435

Solar expansion in the Panhandle would occur alongside the wind generation already under development in the area. In 2014, ERCOT studied the needs of the Panhandle area and summarized its findings in the Panhandle study report.[13] The report identified the upgrades that would be needed in incremental stages as the amount of intermittent generation in the Panhandle exceeds certain thresholds. The first threshold of 2900 MW was exceeded in the Stringent Environmental for 2029. As a result, the addition of second 345-kV circuits from Alibates to Windmill, Windmill to Ogallala, and Ogallala to Tule Canyon recommended in the Panhandle study report were modeled in the Stringent Environmental cases for 2029.

Solar expansion in the Panhandle is in addition to wind generation under development in the area. In 2014, ERCOT studied the needs of the Panhandle area in the Panhandle study report. This report identified upgrades needed when the amount of intermittent generation in the Panhandle exceeded certain thresholds. The first threshold of 2900 MW was exceeded in the Stringent Environmental Regulation scenario for 2029. As a result, the addition of second 345-kV circuits from Alibates to Windmill, Windmill to Ogallala, and Ogallala to Tule Canyon recommended in the Panhandle study report were modeled in the Stringent Environmental Regulation cases for 2029.

Elsewhere in the system, in the Current Trends and Global Recession scenarios, simple upgrades of the existing 138-kV network will be sufficient to resolve pre-contingency and post-contingency overloads. However, in the High Economic Growth and Stringent Environmental scenarios, as shown in Figure 6.9, two parallel 345-kV paths are needed from the Hamilton substation in Val Verde County to the Lobo substation in Webb County. This project will convert the existing 138-kV lines from Hamilton Road to Escondido, Hamilton Road to Uvalde and Uvalde to Asherton (via West Batesville) to 345 kV. This project will also add a new 345-kV line

[13] http://www.ercot.com/content/news/presentations/2014/Panhandle%20Renewable%20Energy%20Zone%20Study%20Report.pdf

from Escondido to Lobo via West Conoco and Asherton. Additionally, new 345/138-kV autotransformers will be added at the new 345-kV substations at Hamilton Road in Val Verde County, Eagle Hydro Tap, Escondido, and West Conoco in Maverick County, Asherton in Dimmit County; Odlaw Switchyard in Kinney County; Uvalde AEP in Uvalde County; and West Batesville in Zavala County.

Figure 6.9: Hamilton to Lobo project

If the recent trends in the decline of utility-scale solar capital cost continue in the future, there may potentially be a need for further expansion of the transmission system into other areas that are suitable for solar resource operation.

6.2.4 Impact of LNG additions

As discussed in Section 3, the scenario-development workshop identified the potential for the addition of LNG terminals on the ERCOT system. Applications are pending at the DOE for several LNG export facilities along the Texas Gulf Coast, specifically Freeport, Corpus Christi and Brownsville. ERCOT assumed 721 MWs of block load at Freeport in all four scenarios studied. ERCOT assumed an additional 784 MWs were added in both Corpus Christi and the Brownsville area in the High Economic Growth scenario. For this analysis, the Brownsville area LNG terminal was served by the 345-kV Loma Alta substation and the Corpus Christi area LNG terminal was served by the 345-kV White Point substation.

The Jones Creek upgrade project, designed to support the Freeport LNG addition in the Coast weather zone, is currently undergoing ERCOT's independent review. This project was modeled in the 2014 LTSA for all scenarios and was deemed sufficient for both 2024 and 2029. ERCOT did not identify any upgrades to serve the LNG terminal in the Corpus Christi area.

In the Brownsville area, following the load addition, the 138-kV lines from La Palma to Rio Hondo and La Palma to Loma Alta are overloaded under the contingency loss of the South McAllen to Loma Alta 345-kV line. To alleviate the 138-kV overloads under this contingency loss, a single 345-kV path is needed to support the Loma Alta substation, thus relieving the 138-kV overloads.

This project, highlighted in yellow in Figure 6.10, will convert the existing 138-kV lines from La Palma to Los Fresno and Loma Alta to Los Fresnos to single-circuit 345-kV lines, thus closing the 345-kV loop in the Valley area in the Cameron County.

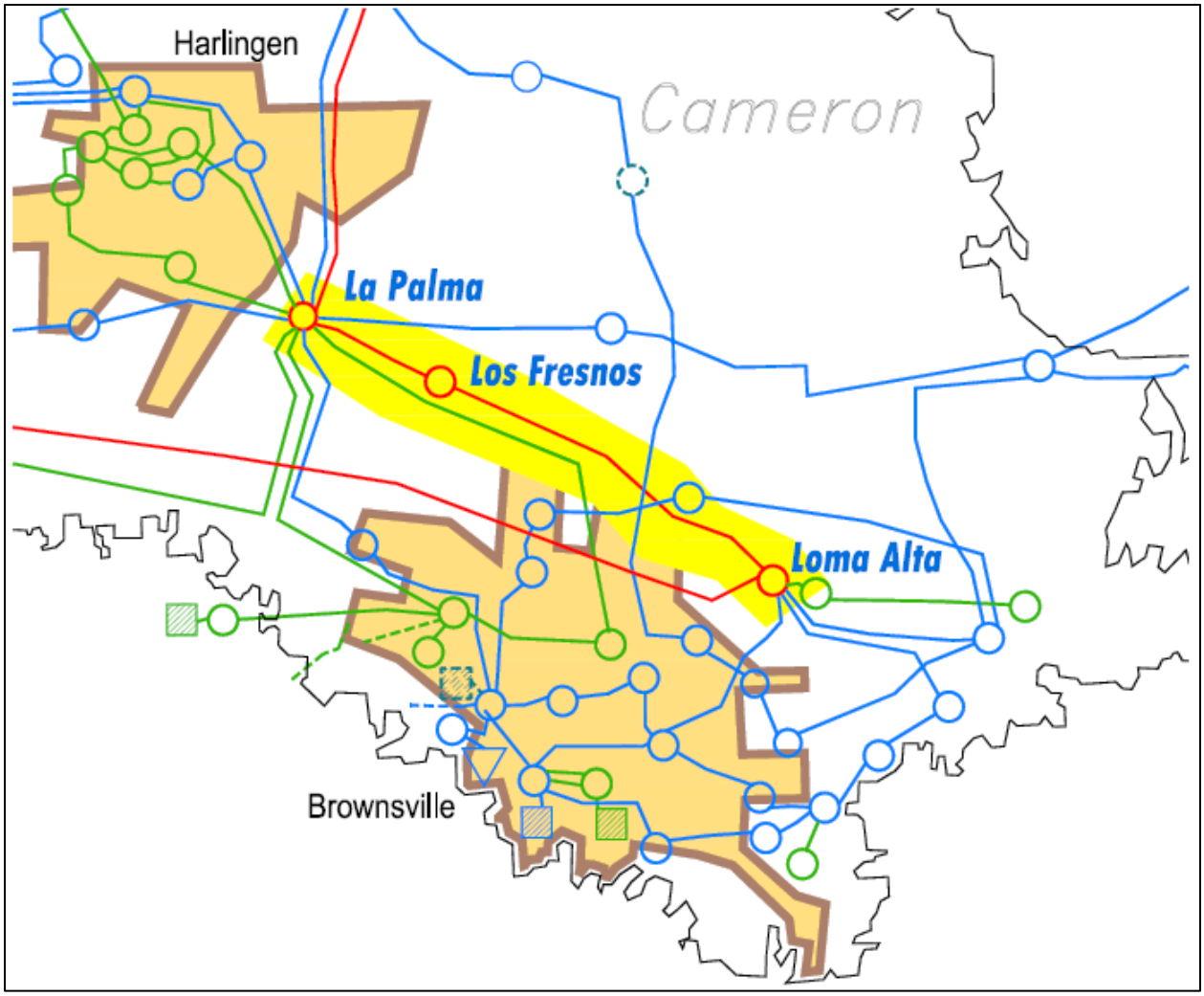

Figure 6.10: Brownsville area transmission upgrades for LNG terminal

6.2.5 The Valley Region

The Lower Rio Grande Valley (LRGV) area of ERCOT's South weather zone has been one of the fastest growing areas in the state. This area has seen an increased risk of rotating outages due to high power demand and transmission import limitations into the area. As of October 2014, in the LRGV there were two new sizeable natural gas plants in the final stages of the interconnection study process and one new natural gas plant that had a signed generation interconnection agreement (SGIA), although had not provided financial commitment.

Table 6.3.3 shows the amount of natural gas generation added by the generation expansion analysis in the Valley area across all scenarios.

Table 6.3: New natural gas generation added in the Valley by scenario

Scenario	Additional Generation Sited (MW)	
	By 2024	By 2029
Current Trends	1,650	2250
Global Recession	1,900	1900
High Economic Growth	2,879	2879
Stringent Environmental	2,670	2960

With these additional generation resources in place, ERCOT's studies across all scenarios did not show the need for additional transmission improvements. These studies assumed that the 'Cross Valley' project, which includes the new 345-kV line from North Edinburg to Loma Alta and the new 345-kV line from the Lobo station, near Laredo, to the North Edinburgh station, were in-service. If the assumed generation fails to come online, transmission needs in this area will have to be closely monitored.

6.2.6 Results of economic analysis

As described in Section 6.1.3, ERCOT conducted production cost simulations for years 2024 and 2029 for the four scenarios selected for transmission analysis. When applicable, pre-defined Special Protection Systems (SPSs) were modeled in the case to relieve congested portions of the network. After SPS modeling, when congestion persisted, transmission upgrades and additions were tested by comparing the production cost simulation results for models with and without the projects.

Table 6.4: Transmission facilities with heavy congestion across multiple scenarios

Scenario	Current Trends		Global Recession		High Economic Growth		Stringent Environmental	
Constrained element	**2024**	**2029**	**2024**	**2029**	**2024**	**2029**	**2024**	**2029**
Zenith - TH Wharton								
Kiamichi Energy Facility - Kiowa Switch								
Big Brown SES - Jewett								
Hutto Transformer								
Panhandle Interface			-					
Kendall - Highway 46								-
Kendall Transformer	-		-					
Bracken - Highway 46	-		-					-
Calaveras - Pawnee Switching Station							-	-
San Miguel Transformer							-	-
Richland Chambers - Big Brown SES	-			-	-			-
Austrop - Sandow Switch							-	-
Oklaunion - Riley							-	-
Gilleland Transformer	-	-	-					
Morgan Creek SES - Tonkawa Switch	-		-	-				

** Red = high congestion rent, Orange = medium congestion rent, Yellow = low congestion rent, White = no congestion rent*

The list of most congested elements across all scenarios and years is shown in Table 6.4. Appendix K shows a list of all constrained elements reviewed in the 2014 LTSA economic analysis. The table has color codes to depict the range of annual congestion rent (red=highest, yellow=least). As shown in the table, few transmission elements/interfaces show consistent,

heavy congestion across all the scenarios and years. Most notable examples are the Panhandle interface and the 345-kV lines from Kendall to Highway 46, Zenith to TH Wharton, Big Brown to Jewett, Morgan Creek SES to Tonkawa Switch and some 345/138-kV autotransformers such as those at Kendall and Hutto substations.

While it is evident that a lot of these areas of congestion were driven by generation siting, ERCOT evaluated economic projects to resolve these constraints. The economic benefits of each project were measured against the economic planning criteria per the ERCOT Protocol Section 3.11.2(5). The criteria states that if the annual production cost savings of a transmission project equals or exceeds the annual first-year revenue requirement for that project, then the project is economic from a societal perspective and will be recommended. In this study, it was assumed that the annual revenue requirement for the transmission project is approximately 16% of the total transmission project cost. The production cost savings and project costs were represented in 2024 dollars with a discount rate of 8%[14]. If a project does not meet the economic planning criteria the projected congestion will remain on the system. ERCOT tested twenty projects to relieve congestion identified in the economic analysis.

Table 6.5 shows the list of projects evaluated and the results of the evaluation per scenario. It should be noted that these projects were evaluated individually and their viability as a group of upgrades will need further study.

[14] Reference of discount rate:
www.puc.texas.gov/industry/electric/reports/31600/PUCT_CBA_Report_Final.pdf

Table 6.5: Economic projects evaluated in 2014 LTSA

Project Tested	Current Trends		Global Recession		High Economic Growth		Stringent Environmental	
	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year
Panhandle Upgrades - Stage 1	No	-	No	-	Yes	2029	Yes	2024
Panhandle Upgrades - Stage 2	No	-	No	-	No	-	Yes	2024
Panhandle Upgrades - Stage 3	-	-	-	-	No	-	Yes	2024
Panhandle Upgrades - Stage 4	-	-	-	-	-	-	Yes	2024
Graham SES - Garvey Rd and Bowman Switch - Jacksboro Switching Station 345-kV Line Upgrades	No	-	-	-	-	-	Yes	2024
Everman Switch - Courtland, Courtland - Cedar Hill Switch, and Everman Switch - Venus Switch 345-kV Line Upgrade	-	-	-	-	-	-	Yes	2029
Decordova - Comanche Peak 345-kV Line Upgrade	-	-	-	-	-	-	No	-
Big Brown - Jewett 345-kV Double Circuit Line Upgrade	-	-	-	-	-	-	No	-
Morgan Creek – Tonkawa Switch 345-kV Line Upgrade	-	-	-	-	No	-	Yes	2024
Kendall - Highway 46 345-kV Line Upgrade	Yes	2024	No	-	No	-	No	-

Project Tested	Current Trends		Global Recession		High Economic Growth		Stringent Environmental	
	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year
Kendall - Cagnon 345-kV Line Upgrade	-	-	-	-	-	-	Yes	2029
San Miguel 3rd 345/138-kV Auto Addition	Yes	2024	-	-	No	-	-	-
Fayetteville 2nd 345/138-kV Auto Addition	Yes	2024	No	-	No	-	No	-
La Palma 2nd 345/138-kV Auto Addition	-	-	-	-	No	-	Yes	2024
Rio Hondo - North Edinburg 345-kV Line Upgrade	-	-	-	-	-	-	No	-
Calaveras - Pawnee - Lon Hill 345-kV Line Upgrade	-	-	-	-	No	-	-	-
Zenith - TH Wharton Ckt 71 345-kV Line Terminal Equipment Upgrade	-	-	-	-	No	-	No	-
South Texas Project - Dow 345-kV Double-Circuit Line Rebuild	-	-	-	-	-	-	No	-
South Texas Project - Dow 345-kV Double-Circuit Line Reconductor	-	-	-	-	-	-	Yes	2024
South Texas Project - Hillje Ckt 1 345-kV Line Reconductor and South Texas Project - WA Parish 345-kV Line Rebuild	-	-	-	-	-	-	No	-

Project Tested	Current Trends		Global Recession		High Economic Growth		Stringent Environmental	
	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year	Economic Criteria Met?	In-service Year
South Texas Project - Hillje Ckt 1 and South Texas Project - WA Parish 345-kV Lines Reconductor	-	-	-	-	-	-	Yes	2029

Panhandle Interface Upgrades

As shown in Table 6.4, the Panhandle interface (defined in Section 6.2.3) is highly congested in the High Economic Growth and Stringent Environmental scenarios in 2024 and across all scenarios in 2029. To address this congestion, projects included in the Panhandle Transmission Upgrade Roadmap (see Table 6.6) developed for ERCOT's Panhandle study were tested.

Table 6.6: Panhandle Transmission Upgrade Roadmap – Detailed Project List

Stage	Panhandle Export Stability Limit (MW)	Upgrade Element
1	3500	• Add a second circuit on the existing Panhandle grid • 200 MVA synchronous condensers • 150 MVAr reactors
2	5200	• Add on new 345-kV double circuit (Ogallala – Long Draw) • 750 MVA synchronous condensers • 350 MVAr reactors
3	6175	• Add one new 345-kV double circuit (Gray – Riley, Windmill – Edith Clarke, or Windmill – Cottonwood – West Shackelford) • 350 MVA synchronous condensers • 300 MVAr reactors
4	7500	• Add one additional new 345-kV double circuit (Gray – Riley, Windmill – Edith Clarke, or Windmill – Cottonwood – West Shackelford) • 350 MVA synchronous condensers • 450 MVAr reactors

Projects developed for the Panhandle study were chosen for economic testing because they have already passed tests for dynamic performance and their effects on the Panhandle export

stability limit are known. Furthermore, because the 2014 LTSA uses DC analysis, only the line additions were modeled in the cases. The modeled Panhandle export stability limits included the effects of the synchronous condenser and reactor additions, but were enforced at 90% of the limit given in Table 6.6 to provide an operational margin.

Table 6.6 lists the Panhandle upgrades that meet the economic criteria from ERCOT Protocol Section 3.11.2(5) in different scenarios. It should be noted that upgrades that improve the Panhandle export stability limit are highly dependent on the location of intermittent generation interconnections and, therefore, there is no guarantee that the upgrades tested for the 2014 LTSA will be sufficient from either a dynamic or economic standpoint as conditions in the Panhandle evolve.

Table 6.7: Possibly Economic Panhandle Upgrades by Scenario

Scenario	Study Year	Stage
High Economic Growth	2029	1
Stringent Environmental	2024	4
Stringent Environmental	2029	4

The highest stage of Panhandle upgrades that met the economic criteria for both the High Economic Growth and Stringent Environmental scenarios are listed in Table 6.7. This is partly a result of the large amount of solar generation that was added in the Panhandle for these scenarios. In addition, the Stringent Environmental scenario had a new DC tie, as well as wind generation, sited in the Panhandle. Increasing the Panhandle export stability limit allows a large quantity of low-cost power to displace more expensive generation on the system, thus significantly reducing system-wide production costs.

In addition to the high congestion rent on the Panhandle interface itself, there were also high congestion rents on the Graham SES to Garvey Road and Bowman Switch to Jacksboro Switching Station 345-kV lines in some scenarios. These 345-kV lines form part of the path for power from the Panhandle to flow to the Dallas/Fort Worth metroplex and were upgraded for reliability reasons in the High Economic Growth and Stringent Environmental cases for 2029. A project to upgrade both lines met the economic criteria for the Stringent Environmental case for 2024. If a large amount of generation is sited in the Panhandle, it may be necessary to upgrade these, and other, lines that carry power from the Panhandle to major load centers.

7. Conclusion

ERCOT conducted an analysis of the needs of the bulk transmission system for the years 2024 and 2029. Using stakeholder-driven scenario-development workshops, a broad range of scenarios were developed to model sufficiently different, yet plausible futures. ERCOT prepared six different 50th-percentile hourly load forecasts using the assumptions and guidelines set in the scenario descriptions. Planning for transmission ten and fifteen years in the future required ERCOT to make assumptions on additional generation that would come online. ERCOT conducted generation expansion analysis for nine of the ten scenarios created during the scenario development workshops. ERCOT and external stakeholders used the results from the generation expansion analysis to shortlist four of the ten scenarios, namely, Current Trends, High Economic Growth, Global Recession and Stringent Environmental for transmission planning analysis.

Based on this analysis, ERCOT has reached the following conclusions:

- ERCOT identified six major transmission upgrades that were required for three scenarios, namely, Current Trends, Stringent Environmental and High Economic Growth.
- The West Roanoke and Fort Worth projects were added to provide additional transmission sources to meet the growing needs of Tarrant County. The Rockhill and Nevada projects were designed to provide additional support for the counties of Rockwall and Collin located immediately north east of Dallas. The West Denton area project, which was recently reviewed by the RPG, was seen as helpful in resolving longer-term needs of the Denton area under the High Economic Growth and Stringent Environmental scenarios.
- The scenario-development workshops identified the potential for the addition of LNG terminals on the ERCOT System. Applications are pending at the DOE for several LNG export facilities along the Texas Gulf Coast, specifically Freeport, Corpus Christi and Brownsville. The La Palma to Loma Alta project in the South weather zone was proposed to serve the Brownsville area LNG terminal addition.
- A decline in the cost of solar generation results in significant solar expansion across ERCOT by 2029. This continuing growth has been observed, in varying levels, across all scenarios. Much of this solar capacity was added in the remote location of west Texas, which has the best conditions for solar generation. The Hamilton to Lobo project was

designed to provide an additional path to transfer solar generation from west Texas to the load centers in the south. Furthermore, as increase in inclusion of large amounts of solar may result in rapid reduction in the net system load to be served by non-solar generation. As a result, the transmission system may experience two different stressed conditions—one at hour ending 5:00 p.m. (peak load) and the other at 8:00 p.m. (peak load less solar). Transmission planners may need to consider performing reliability analyses for both of these time periods rather than the traditional approach of studying a single peak hour.

- Few transmission elements/interfaces show consistent, heavy congestion across all the scenarios and years. The most notable examples are the Panhandle interface and the 345-kV lines from Kendall to Highway 46, Zenith to TH Wharton, Big Brown to Jewett, Morgan Creek SES to Tonkawa Switch and some 345/138-kV autotransformers such as those at the Kendall and Hutto substations. Transmission upgrades to relieve congestion for some of these constraints were found to be economic under the Current Trends and Stringent Environmental scenarios. ERCOT identified Morgan Creek to Tonkawa in west Texas, Kendall to Cagnon 345-kV in the South Central weather zone and South Texas Project to Hillje and South Texas Project to W. A. Parish 345-kV double circuit line upgrades to be economic in the Stringent Environmental scenario. Additional 345/138-kV autotransformers in Fayetteville, which is in the South Central weather zone, and La Palma, which is in the South weather zone, help relieve congestion in the Current Trends scenario.
- The Panhandle area congestion was addressed using the Panhandle Transmission Upgrade Roadmap developed from ERCOT's Panhandle Study. Projects developed for the Panhandle Study were chosen for economic testing because they have already passed tests for dynamic performance and their effects on the Panhandle export stability limit are known. There are Panhandle upgrades that met the economic criteria for both the High Economic Growth and Stringent Environmental scenarios. This is partly a result of the large amount of solar generation sited in the Panhandle for these scenarios. In addition, the Stringent Environmental scenario had a new DC tie, as well as wind generation, sited in the Panhandle. Increasing the Panhandle export stability limit allows a large quantity of low-cost power to displace more expensive generation on the system, thus significantly reducing system-wide production costs.

Appendices

Appendix A.

Generation Siting Methodology (Attached with the report)

Appendix B.

ERCOT LTSA Scenario Development Report (MIS Secure>Grid>Long-Term Planning>ERCOT 2014 Long-term planning assessment> ERCOT_LTSA_Scenario_Development-Brattle_Report.pdf)

Appendix C.

Table C.1: Presentations by Subject Matter Experts on Industry Trends, Drivers, and Uncertainties

Segment	Topic	Speakers
Texas Economic Growth	Economic Growth in Texas	• Eric Clennon, Texas Economic Development Office • Lloyd Potter, Texas State Demographer
Environmental Regulations	Potential Effects of Environmental Regulations on Existing Baseload Generation	• Metin Celebi, The Brattle Group
Water	Energy/Water Issues	• Michael Webber, Deputy Director, University of Texas, Austin, Energy Institute • Bridget Scanlon, University of Texas, Austin, Bureau of Economic Geology
Renewable Energy	Renewable Energy Potential and Economics	• Alan Comnes, SunPower Corporation representing Solar Energy Industries Association • Jeff Clark, The Wind Coalition • Julia Matevosyan, ERCOT • Ira Shavel, The Brattle Group
Oil and Gas	Natural Gas Supply and Market Prices	• Svetlana Ikonnikova, University of Texas, Austin, Bureau of Economic Geology • Gabe Harris, Wood Mackenzie
Oil and Gas	Electricity Usage by Oil & Gas Developers	• Toni Gordon, Pioneer
Transmission /Utility	Advances in transmission technologies	• Ken Donohoo, Oncor
Transmission /Utility	Load growth in Houston and Coastal Region related to LNG	• Bill Sumner, CenterPoint
Transmission /Utility	Load growth in the south-south central due to growth in Eagle Ford Shale	• Charles DeWitt, Lower Colorado River Authority

Appendix D.

EIA AEO 2014 Early Release Reference Case (http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf?bcsi_scan_88e3db366cfd5e80=0&bcsi_scan_filename=0383(2014).pdf)

Appendix E.

Table E.1 : Fixed unit retirements in the 2014 LTSA

Unit Name	Unit Size	Inst. Date	Retirement Date	type
BBRN 1 G	606	12/23/1971	12/23/2026	coal
BBRN 2 G	602	12/6/1972	1/1/2028	coal
CB 1	745	12/11/1970	12/11/2020	stgas
CB 2	749	3/15/1972	3/15/2022	stgas
CIELOG#1	99	12/24/2003	12/24/2028	wind
CIELOG#2	61	12/24/2003	12/24/2028	wind
DANSBY14	110	9/1/1978	9/1/2028	stgas
DAV #1	335	4/15/1974	4/15/2024	stgas
DLWRMTN1	34.32	5/27/1999	5/27/2024	wind
ENRON	82.5	6/1/2001	6/1/2026	wind
GIDEONG2	140	3/1/1968	3/1/2018	stgas
GIDEONG3	340	5/1/1972	5/1/2022	stgas
GRAM 2 G	390	6/5/1969	6/5/2019	stgas
HAND 4 G	435	1/1/1976	1/1/2026	stgas
HAND 5 G	435	1/1/1977	1/1/2027	stgas
INDMESA1	84	1/1/2002	1/1/2027	wind
INDMESA2	76.5	1/1/2002	1/1/2027	wind
KM-NEP	79.3	11/8/2001	11/8/2026	wind
KM-NWP	79.3	9/21/2001	9/21/2026	wind
KM-SEP	40.3	12/1/2001	12/1/2026	wind
KM-SWP	79.3	8/12/2001	8/12/2026	wind
LKHB 1 G	392	6/18/1970	6/18/2020	stgas
OLINGR2	107	5/1/1971	5/1/2021	stgas
OLINGR3	146	12/1/1975	12/1/2025	stgas
OWS1	420	1/1/1972	1/1/2022	stgas
OWS2	420	1/1/1974	1/1/2024	stgas
STEAM3	41	1/1/1978	1/1/2028	stgas
Sweetwater1	36.58	11/20/2003	11/20/2028	wind
SWMSWD1	74.2	6/1/1999	6/1/2024	wind
TRENTIPP	150	7/9/2001	7/9/2026	wind
TWPP_1	39.8	9/1/1995	9/1/2020	wind

VHB2	230	1/1/1968	1/1/2018	stgas
VHB3	412	1/1/1970	1/1/2020	stgas
WAP4	552	6/1/1968	6/1/2018	stgas
WDWDU1	82.5	7/31/2001	7/31/2026	wind
WDWRDU2	77.22	7/31/2001	7/31/2026	wind
WESTXWIN	6.6	5/1/1999	5/1/2024	wind

Appendix F.

Generation expansion summary

Table F.1: Generation expansion summary for Current Trends scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	650	3,600	1,200	-	-
CT Adds	MW	700	2,090	380	1,740	900
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	-	100	3,200	4,200	2,600
Wind Adds	MW	-	-	-	-	-
Annual Capacity Additions	MW	1,350	5,790	4,780	5,940	3,500
Cumulative Capacity Additions	MW	1,350	7,140	11,920	17,860	21,360
Retirements	MW	955	2,086	2,379	2,453	950
Residential Demand Response	MW	300	18	19	21	14
Industrial Demand Response	MW	1,200	73	78	83	58
Reserve Margin	%	9.95	10.10	10.30	11.90	12.77
Coincident Peak	MW	76,571	79,935	82,686	85,443	87,300
Average LMP	$/MWh	52.50	55.40	65.41	68.01	71.21
Natural Gas Price	$/mmbtu	5.02	5.07	5.93	6.03	6.35
Average Market Heat Rate	MMbtu/MWh	10.46	10.93	11.03	11.28	11.21
Natural Gas Generation	%	46.0	51.0	49.0	51.0	51.0
Coal Generation	%	31.0	27.0	28.0	26.0	25.0
Wind Generation	%	12.0	11.0	11.0	10.0	9.0
Solar Generation	%	-	-	2.0	4.0	6.0
Scarcity Hours	HRS	8.0	10.0	10.3	10.0	8.0
Unserved Energy	GWhs	4.5	10.8	11.9	10.9	8.3
SO2	Tons	312,930	272,616	304,280	272,207	266,469
CO2	(k) Tons	240,205	247,719	256,896	256,860	259,524
NOx	Tons	112,419	114,359	118,814	118,987	120,677

Table F.2: Generation expansion summary for Global Recession scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	-	-	-	-	-
CT Adds	MW	380	950	3,990	760	380
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	-	-		3,000	2,400
Wind Adds	MW	-	853	-	990	422
Annual Capacity Additions	MW	380	1,803	3,990	4,750	3,202
Cumulative Capacity Additions	MW	380	2,183	6,173	10,923	14,125
Retirements	MW	975	2,086	2,379	2,453	950
Residential Demand Response	MW	300	337	379	427	480
Industrial Demand Response	MW	1,200	1,349	1,518	1,708	1,921
Reserve Margin	%	7.95	8.67	8.17	8.23	9.07
Coincident Peak	MW	76,307	75,760	77,897	80,099	81,604
Average LMP	$/MWh	55.58	60.12	63.23	67.19	70.33
Natural Gas Price	$/mmbtu	4.27	4.37	5.20	6.00	6.63
Average Market Heat Rate	MMbtu/MWh	13.02	13.76	12.16	11.20	10.61
Natural Gas Generation	%	51.7	51.9	50.3	47.6	46.4
Coal Generation	%	25.6	24.9	27.1	27.9	28.2
Wind Generation	%	12.1	12.8	12.4	9.6	12.7
Solar Generation	%	-	-	-	1.9	3.3
Scarcity Hours	HRS	11.0	17.0	12.0	12.0	12.0
Unserved Energy	GWhs	13.2	18.2	20.2	24.5	19.8
SO2	Tons	230,606	230,491	265,478	279,012	285,814
CO2	(k) Tons	209,007	209,887	223,368	227,725	230,919
NOx	Tons	109,579	108,933	117,475	120,448	121,949

Table F.3: Generation expansion summary for High Economic Growth scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	1,300	800	400	-	-
CT Adds	MW	190	-	190	-	-
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	600	4,200	4,500	3,900	2,600
Wind Adds	MW	-	-	100	1,175	121
Reliability Adds	MW	4,147	4,222	3,230	3,040	1,900
Annual Capacity Additions	MW	6,237	9,222	8,420	8,115	4,621
Cumulative Capacity Additions	MW	6,237	15,459	23,879	31,994	36,615
Retirements	MW	-	-	-	-	-
Residential Demand Response	MW	300	18	19	21	14
Industrial Demand Response	MW	1,200	73	78	83	58
Reserve Margin	%	13.75	13.98	13.94	13.88	13.92
Coincident Peak	MW	78,133	83,071	86,747	90,551	93,176
Average LMP	$/MWh	50.11	53.37	63.70	67.80	73.05
Natural Gas Price	$/mmbtu	6.52	6.57	7.43	7.53	7.85
Average Market Heat Rate	MMbtu/MWh	7.69	8.12	8.57	9.00	9.31
Natural Gas Generation	%	43.5	45.6	45.8	46.8	48.1
Coal Generation	%	33.8	31.2	29.7	27.4	26.0
Wind Generation	%	11.9	10.8	10.3	10.2	9.8
Solar Generation	%	0.4	2.8	5.1	6.9	8.0
Scarcity Hours	HRS	-	-	2	3	3
Unserved Energy	GWhs	-	-	0.3	2.3	4.6
SO2	Tons	388,082	392,774	392,711	356,953	326,398
CO2	(k) Tons	236,104	249,096	255,942	258,156	262,170
NOx	Tons	126,985	133,607	137,619	138,437	140,451

Table F.4: Generation expansion summary for High Energy Efficiency and Distributed Generation scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	-	800	800	-	400
CT Adds	MW	-	3,160	190	-	980
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	-	1,400	4,200	3,600	1,900
Wind Adds	MW	-	-	-	-	100
Annual Capacity Additions	MW	-	5,360	5,190	3,600	3,380
Cumulative Capacity Additions	MW	-	5,360	10,550	14,150	17,530
Retirements	MW	-	-	-	-	-
Residential Demand Response	MW	300	337	379	427	480
Industrial Demand Response	MW	1,200	1,349	1,518	1,707	1,921
Reserve Margin	%	10.1	9.76	11.69	13.50	14.60
Coincident Peak	MW	75,232	77,819	79,274	79,891	81,567
Average LMP	$/MWh	59.90	66.91	74.34	76.89	79.73
Natural Gas Price	$/mmbtu	6.52	6.57	7.43	7.53	7.85
Average Market Heat Rate	MMbtu/MWh	9.19	10.18	10.01	10.21	10.16
Natural Gas Generation	%	42.5	45.6	44.3	45.1	46.4
Coal Generation	%	34.5	31.6	31.0	29.2	27.7
Wind Generation	%	12.2	11.6	11.3	10.4	10.1
Solar Generation	%	-	1.0	3.4	5.5	6.5
Scarcity Hours	HRS	6.0	10.0	8	7	5
Unserved Energy	GWhs	3.4	9.2	5.0	7.1	6.4
SO2	Tons	389,731	373,746	377,590	335,150	300,927
CO2	(k) Tons	231,190	234,751	236,033	232,092	233,437
NOx	Tons	125,311	126,642	127,305	124,712	124,786

Table F.5: Generation expansion summary for Natural Gas Price scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	650	-	2,600	400	1,300
CT Adds	MW	700	1,140	100	1,430	190
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	250	250	250	250	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	200	4,500	4,500	4,500	2,800
Wind Adds	MW	100	2,065	232	571	926
Annual Capacity Additions	MW	1,900	7,955	7,682	7,151	5,216
Cumulative Capacity Additions	MW	1,900	9,855	17,537	24,688	29,904
Retirements	MW	-	-	-	-	-
Residential Demand Response	MW	300	47	55	63	48
Industrial Demand Response	MW	1,200	189	219	253	191
Reserve Margin	%	10.51	11.04	13.21	14.32	15.71
Coincident Peak	MW	76,603	79,866	83,092	86,413	88,697
Average LMP	$/MWh	71.54	75.78	83.06	87.08	90.89
Natural Gas Price	$/mmbtu	2.00	2.00	2.00	2.00	2.00
Average Market Heat Rate	MMbtu/MWh	35.77	37.89	41.53	43.54	45.45
Natural Gas Generation	%	42.3	40.5	40.3	41.7	42.7
Coal Generation	%	34.7	32.8	31.4	29.0	27.2
Wind Generation	%	12.1	13.4	12.9	12.0	12.1
Solar Generation	%	0.2	2.9	5.3	7.5	8.7
Scarcity Hours	HRS	4	8	10	7	7
Unserved Energy	GWhs	2.3	6.9	8.1	9.2	11.7
SO2	Tons	395,927	394,626	398,444	359,957	325,148
CO2	(k) Tons	235,875	236,522	241,295	242,950	243,038
NOx	Tons	127,634	128,360	132,255	132,284	132,331

Table F.6: Generation expansion summary for Stringent Environmental scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	-	2,000	650	2,000	6,400
CT Adds	MW	-	-	190	-	-
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	1,100	1,100
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	120	120	120	120
Biomass adds	MW	-	-	80	80	80
Solar Adds	MW	-	4,500	4,500	4,500	3,000
Wind Adds	MW	2,627	4,337	5,614	413	300
Annual Capacity Additions	MW	2,627	10,957	11,154	8,213	11,000
Cumulative Capacity Additions	MW	2,627	13,584	24,738	32,951	43,951
Retirements	MW	-	-	-	-	-
Residential Demand Response	MW	300	318	337	358	373
Industrial Demand Response	MW	1,200	1,273	1,351	1,434	1,492
Reserve Margin	%	11.96	9.84	10.90	14.49	13.52
Coincident Peak	MW	76,557	79,931	82,692	85,457	87,321
Average LMP	$/MWh	69.39	84.78	106.59	100.97	109.67
Natural Gas Price	$/mmbtu	6.52	6.57	7.43	7.53	7.85
Average Market Heat Rate	MMbtu/MWh	10.64	12.90	14.35	13.41	13.97
Natural Gas Generation	%	51.6	54.9	54.1	54.5	56.7
Coal Generation	%	24.5	16.5	12.0	8.3	3.7
Wind Generation	%	13.8	16.5	19.9	18.7	18.2
Solar Generation	%	-	2.6	4.9	7.1	8.4
Scarcity Hours	HRS	-	2.0	8.0	1.0	2.0
Unserved Energy	GWhs	-	1.5	6.1	0.8	2.1
SO2	Tons	253,868	169,839	123,993	86,700	41,523
CO2	(k) Tons	206,849	184,529	166,290	153,662	132,129
NOx	Tons	106,910	92,600	80,318	74,607	69,006

Table F.7: Generation expansion summary for High Liquefied Natural Gas Export scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	2,600	7,200	3,200	1,450	1,850
CT Adds	MW	760	1,700	190	1,060	-
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	-	-	3,700	4,200	2,800
Wind Adds	MW	-	-	-	-	-
Annual Capacity Additions	MW	3,360	8,900	7,090	6,710	4,650
Cumulative Capacity Additions	MW	3,360	12,260	19,350	26,060	30,710
Retirements	MW	-	-	-	-	-
Residential Demand Response	MW	300	18	19	21	14
Industrial Demand Response	MW	1,200	73	78	83	58
Reserve Margin	%	9.51	9.85	11.01	11.98	13.05
Coincident Peak	MW	78,721	84,639	88,315	92,119	94,744
Average LMP	$/MWh	53.50	57.10	63.59	67.54	69.16
Natural Gas Price	$/mmbtu	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)
Average Market Heat Rate	MMbtu/MWh	(35.67)	(38.07)	(42.39)	(45.02)	(46.11)
Natural Gas Generation	%	47.2	48.3	52.9	54.9	55.5
Coal Generation	%	30.6	29.1	26.3	23.8	22.9
Wind Generation	%	11.8	12.0	10.0	8.9	8.5
Solar Generation	%	0.0	0.0	2.0	4.0	5.3
Scarcity Hours	HRS	8	11	8	11	7
Unserved Energy	GWhs	7.1	12.9	8.7	10.0	6.7
SO2	Tons	316,107	273,429	314,332	278,560	269,049
CO2	(k) Tons	230,087	220,369	256,336	258,153	262,069
NOx	Tons	124,100	119,118	142,814	144,306	147,069

Table F.8: Generation expansion summary for High System Resiliency scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	-	1,600	-	-	-
CT Adds	MW	-	2,660	-	-	-
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	-	-	2,500	1,800	400
Wind Adds	MW	-	-	-	-	-
Reliability Adds	MW	1,710	3,990	3,420	3,420	2,470
Annual Capacity Additions	MW	1,710	8,250	5,920	5,220	2,870
Cumulative Capacity Additions	MW	1,710	9,960	15,880	21,100	23,970
Retirements	MW	-	-	-	-	-
Residential Demand Response	MW	300	47	55	63	48
Industrial Demand Response	MW	1,200	189	219	253	191
Reserve Margin	%	13.80	13.80	13.82	13.79	13.91
Coincident Peak	MW	79,571	82,936	85,686	88,443	90,300
Average LMP	$/MWh	38.43	42.31	47.72	51.23	55.20
Natural Gas Price	$/mmbtu	5.02	5.07	5.93	6.03	6.35
Average Market Heat Rate	MMbtu/MWh	7.66	8.35	8.05	8.50	8.69
Natural Gas Generation	%	46.1	49.8	48.3	50.6	51.9
Coal Generation	%	31.1	28.7	29.6	27.8	27.3
Wind Generation	%	12.1	11.4	10.9	9.8	9.4
Solar Generation	%	0.0	0.0	1.5	2.5	2.7
Scarcity Hours	HRS	-	-	-	-	-
Unserved Energy	GWhs	-	-	-	-	-
SO2	Tons	315,785	301,067	340,338	312,889	304,938
CO2	(k) Tons	225,041	233,102	244,327	248,058	254,251
NOx	Tons	119,110	124,851	130,037	131,855	134,802

Table F.9: Generation expansion summary for Water Stress scenario

Description	Units	2018	2021	2024	2027	2029
CC Adds	MW	-	-	-	-	-
CT Adds	MW	-	760	300	-	-
Coal Adds	MW	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-
Solar Adds	MW	-	3,200	4,400	3,500	2,600
Wind Adds	MW	-	-	399	-	272
Reliability Adds	MW	1,550	3,500	850	1,140	190
Annual Capacity Additions	MW	1,550	7,460	5,949	4,640	3,062
Cumulative Capacity Additions	MW	1,550	9,010	14,959	19,599	22,661
Retirements	MW	-	-	-	-	-
Residential Demand Response	MW	300	318	337	358	373
Industrial Demand Response	MW	1,200	1,273	1,351	1,434	1,492
Reserve Margin	%	13.62	13.36	13.81	13.70	13.69
Coincident Peak	MW	76,557	79,931	82,693	85,457	87,322
Average LMP	$/MWh	47.58	52.14	57.27	72.73	77.82
Natural Gas Price	$/mmbtu	6.52	6.57	7.43	7.53	7.85
Average Market Heat Rate	MMbtu/MWh	7.30	7.94	7.71	9.66	9.91
Natural Gas Generation	%	46.3	48.3	47.2	48.9	49.6
Coal Generation	%	32.3	29.6	28.8	26.8	25.6
Wind Generation	%	11.3	10.7	10.6	9.6	9.4
Solar Generation	%	-	1.9	4.2	5.9	7.1
Scarcity Hours	HRS	-	2.0	-	4.0	7
Unserved Energy	GWhs	-	0.04	-	3.8	9.0
SO2	Tons	392,932	379,956	384,213	345,663	311,049
CO2	(k) Tons	233,829	238,339	243,316	245,872	247,597
NOx	Tons	125,808	127,781	130,469	131,884	132,695

Appendix G.

LTSA Scope Document (Attached with the report)

Appendix H.

Gen Siting Summary-Texas geographic showing retirement by technology

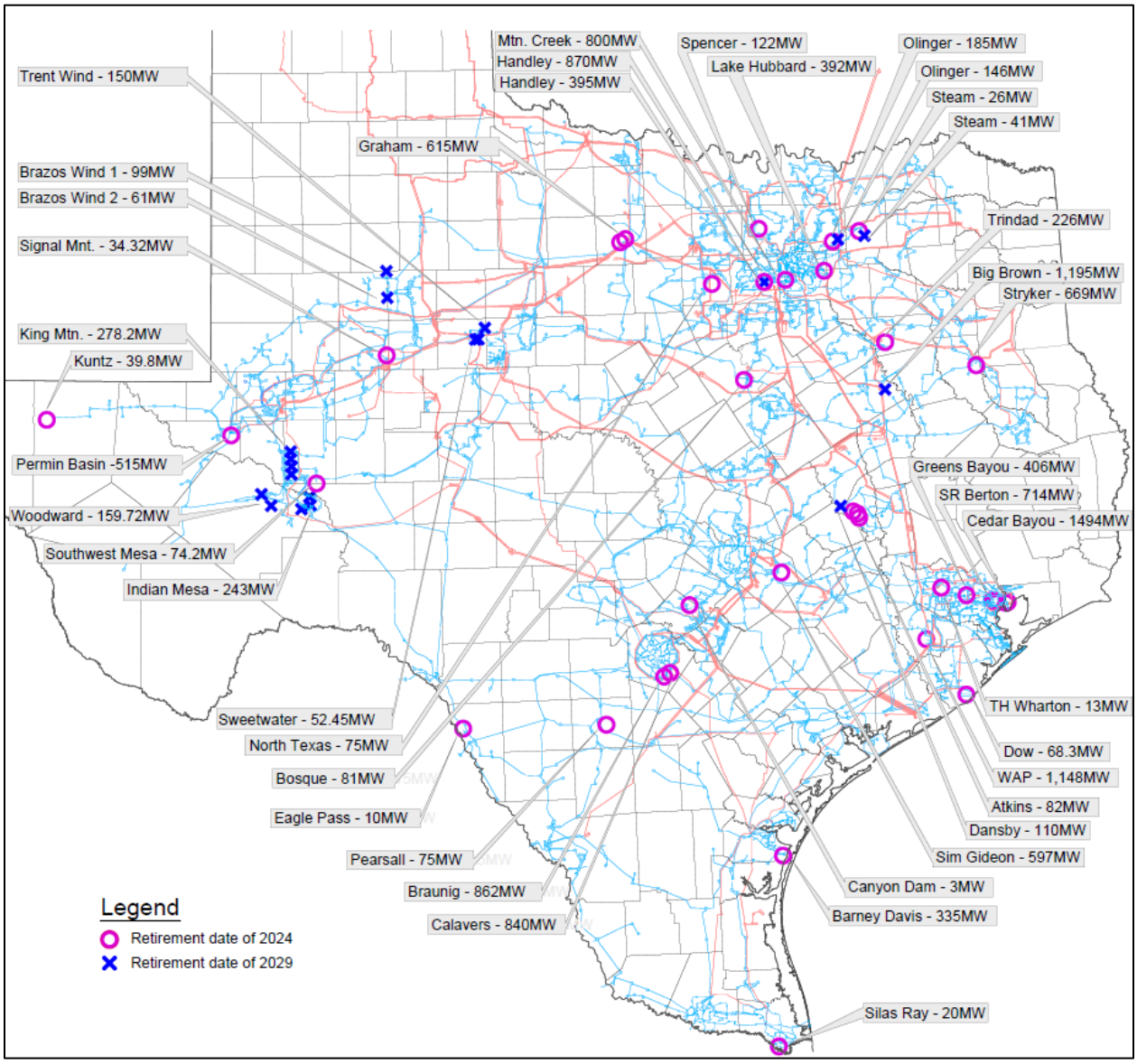

Figure H.1: Retirements for 2029 Current Trends scenario

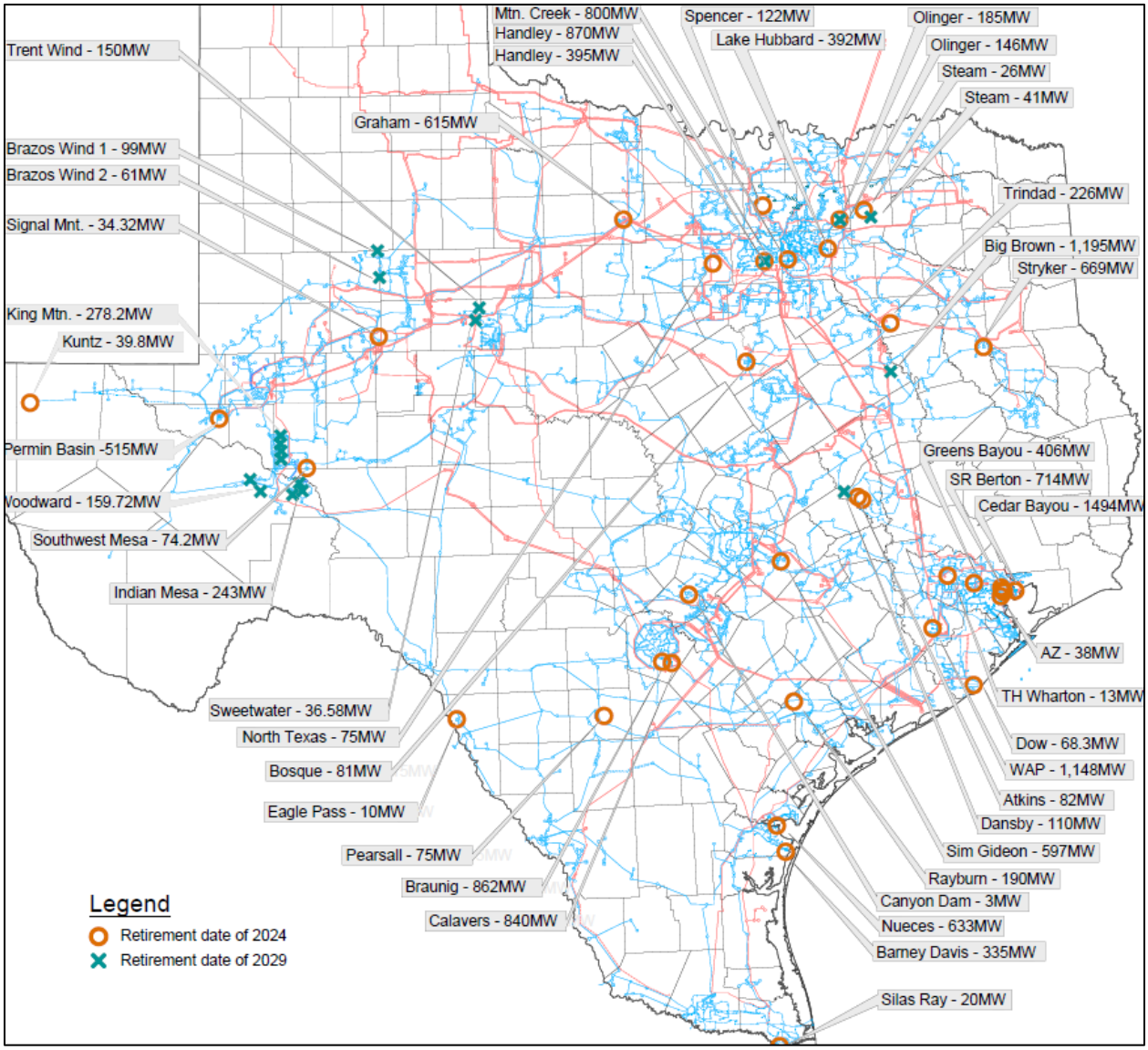

Figure H.2: Retirements for 2029 High Economic Growth scenario

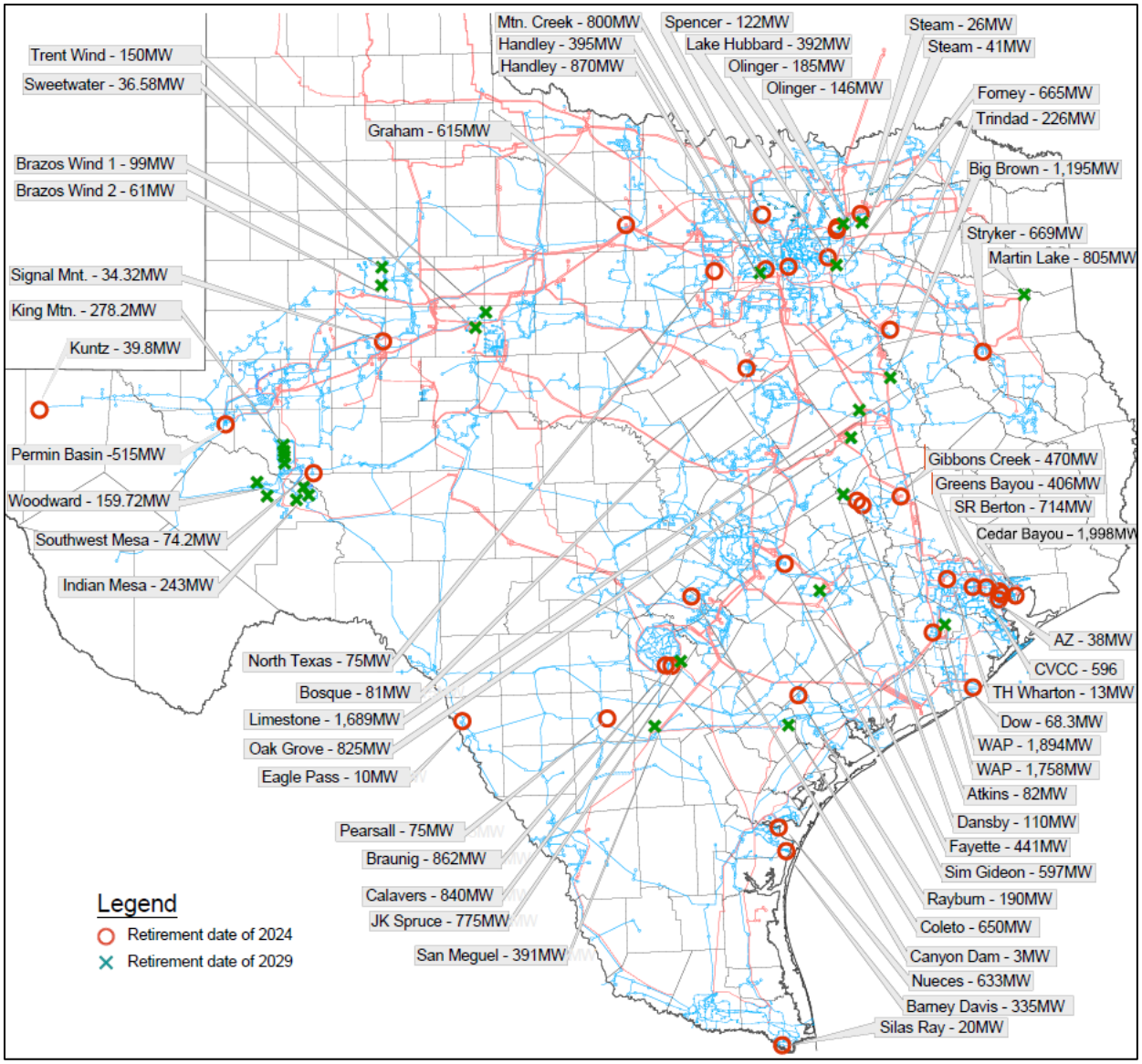

Figure H.3: Retirements for 2029 Stringent Environmental scenario

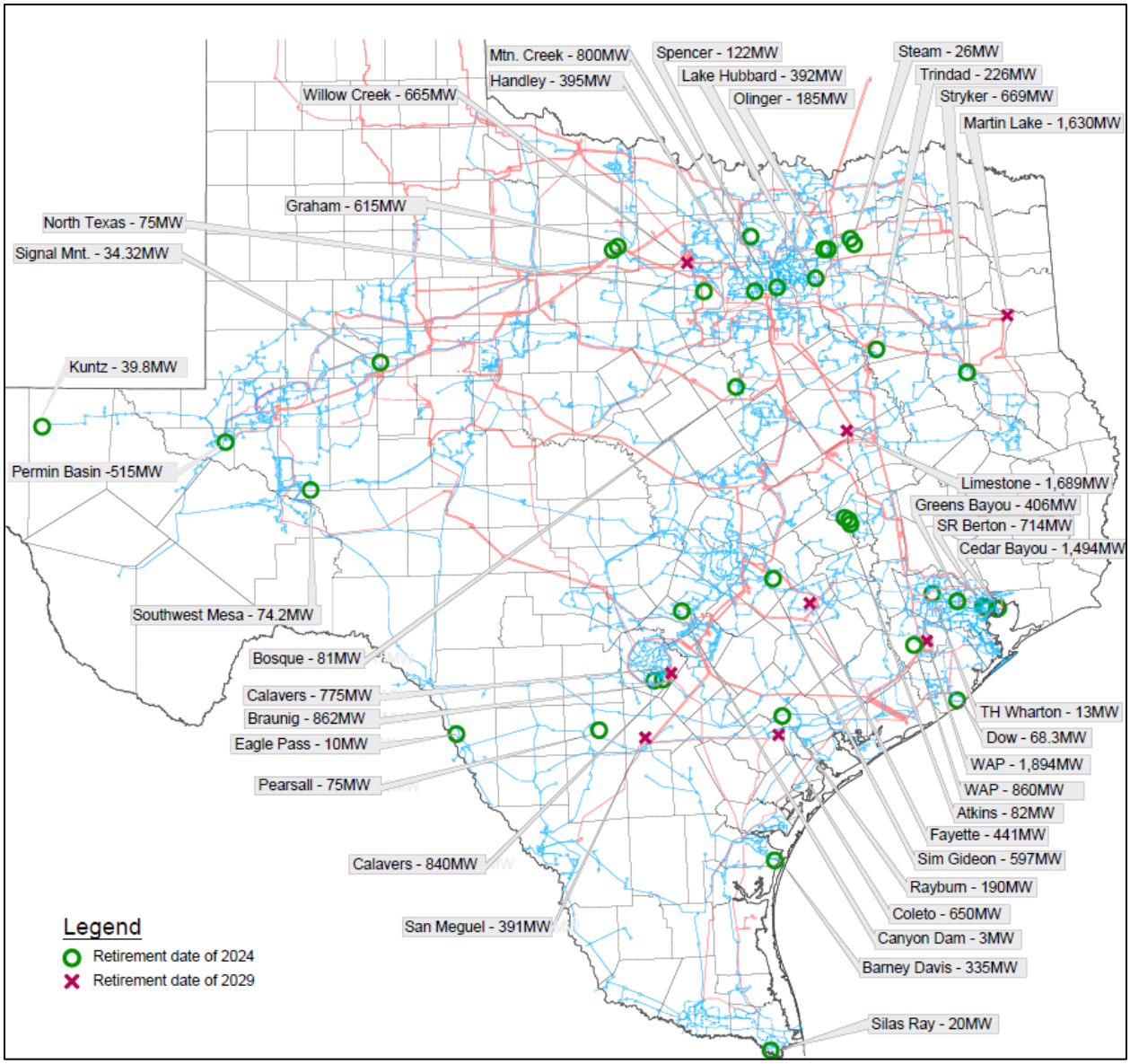

Figure H.4: Retirements for 2029 Global Recession scenario

Appendix I.

Gen Siting Summary-Texas geographic showing addition by technology

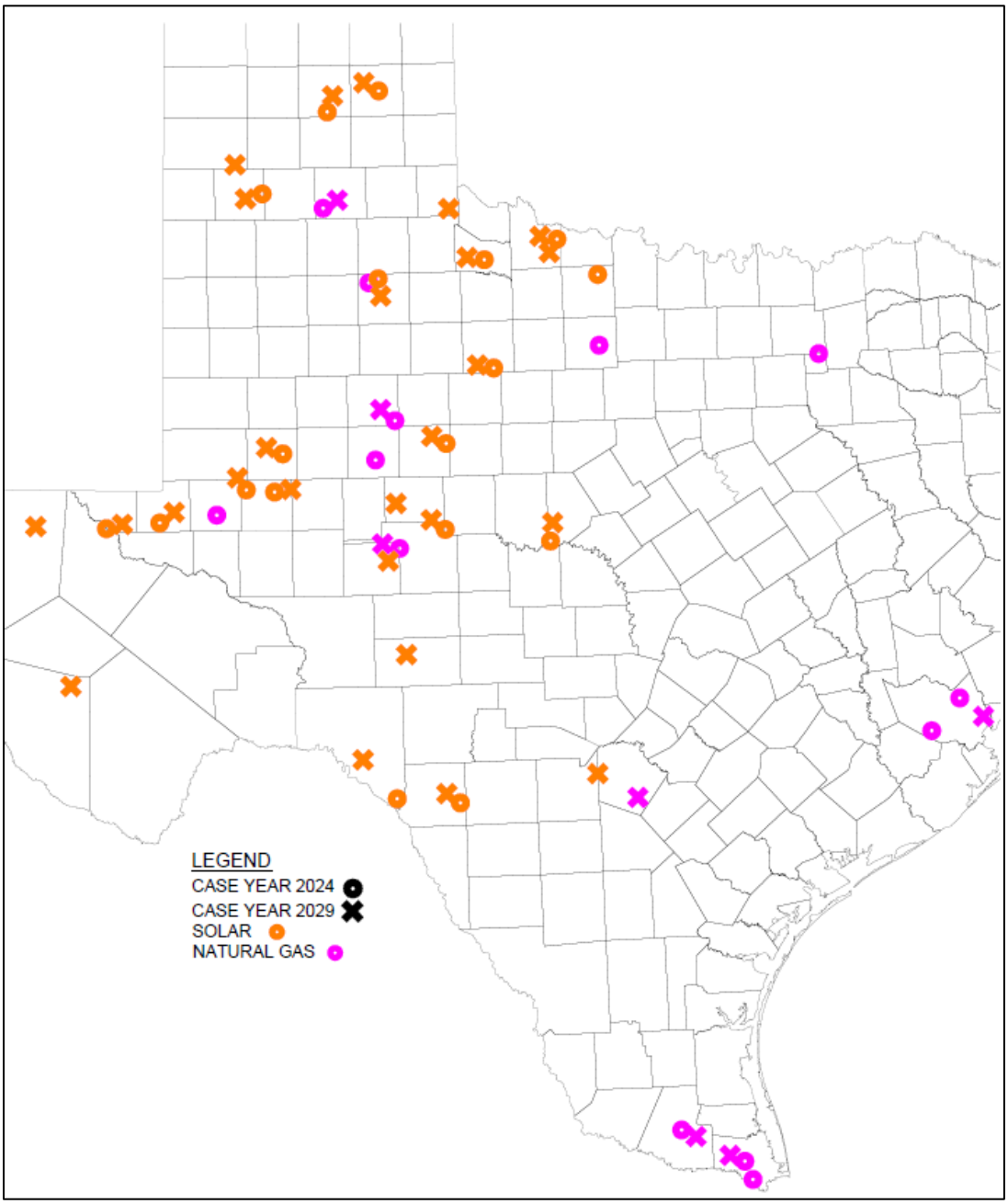

Figure I.1: 2014 LTSA Current Trends generation additions by fuel type

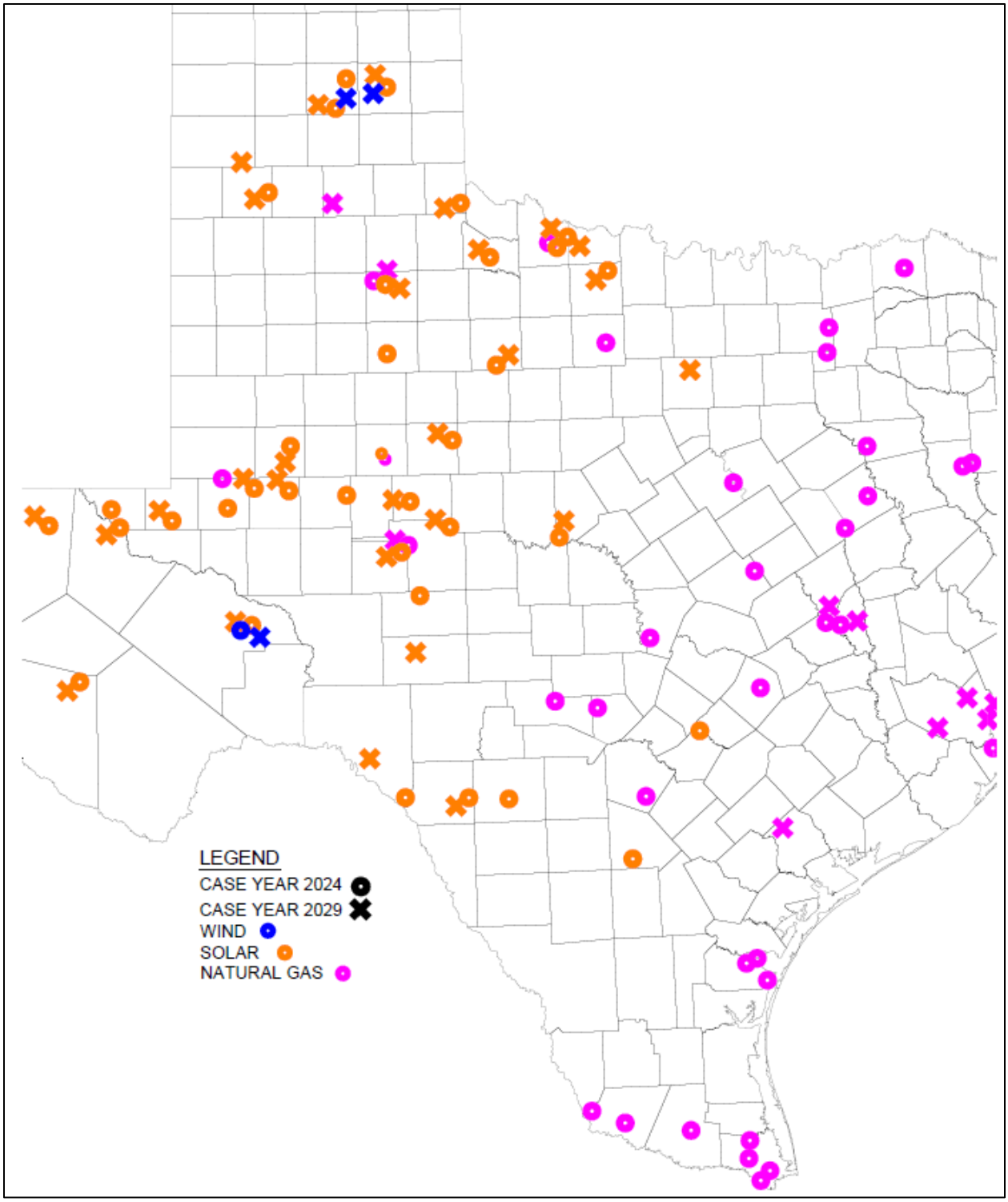

Figure I.2: 2014 LTSA High Economic Growth generation additions by fuel type

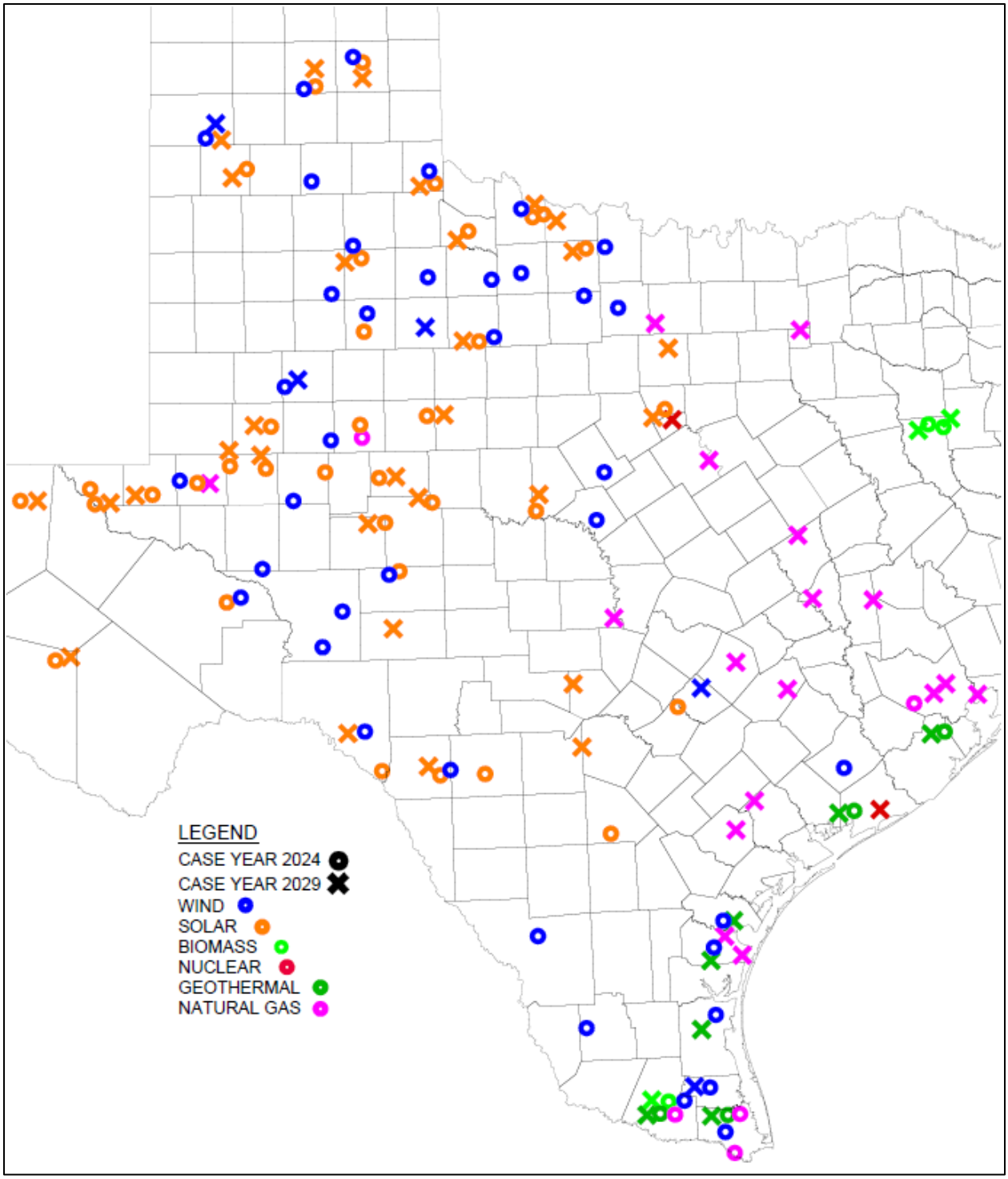

Figure I.3: 2014 LTSA Stringent Environmental generation additions by fuel type

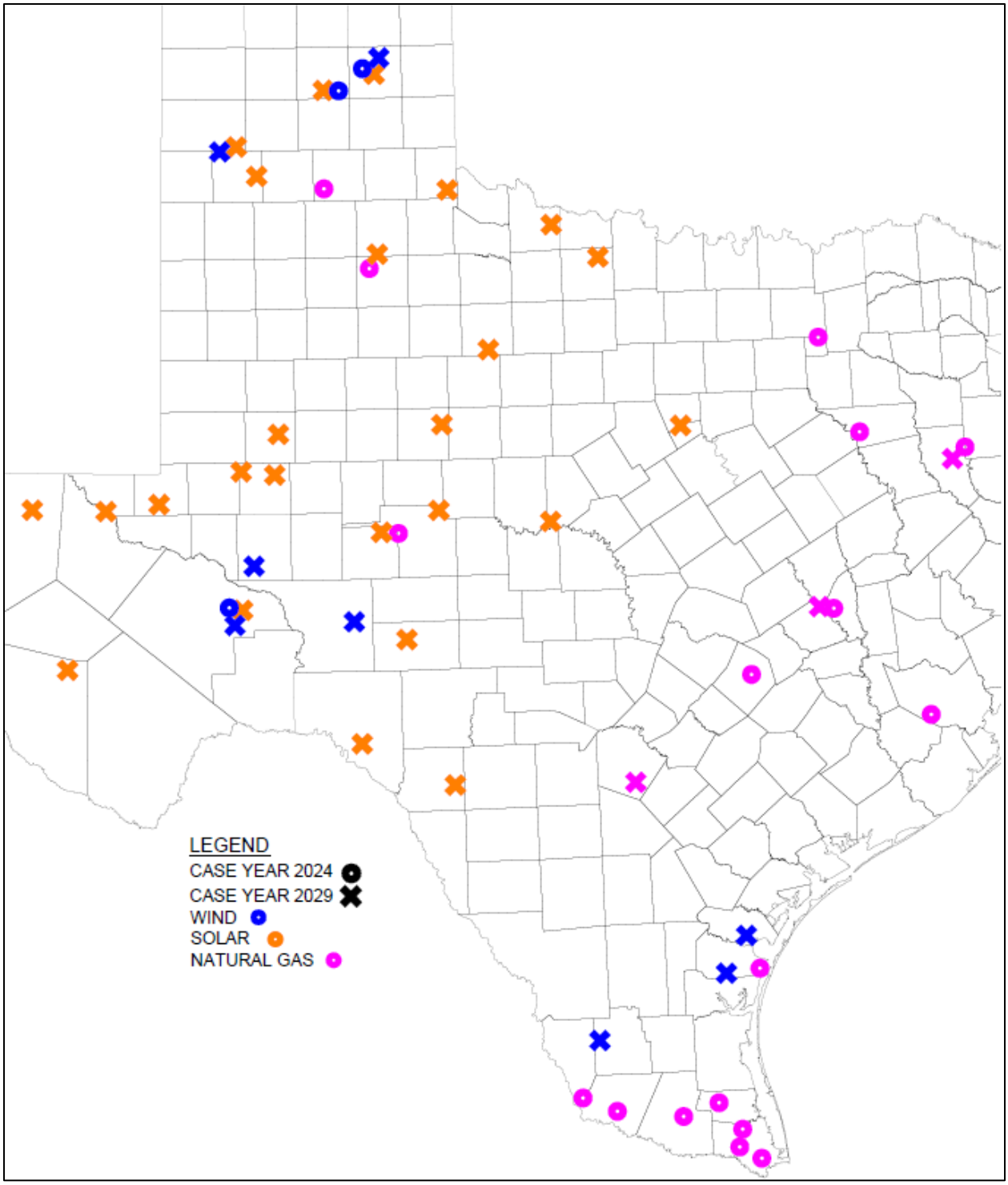

Figure I.4: 2014 LTSA Global Recession generation additions by fuel type

Appendix J.

Table J.1: Reliability projects identified in 2014 LTSA by year and scenario

Index	Weather Zone	Project name	Current Trends		High Economic Growth		Stringent Environ-mental		Global Recession	
			2024	2029	2024	2024	2029	2029	2024	2029
1	North Central	West Roanoke project		X	X		X	X	X	X
2	North Central	Rockhill project	X	X	X			X	X	X
3	North Central	Fort Worth source project		X			X	X		X
4	North Central	Nevada project	X	X				X		X
5	South	Hamilton - Lobo 345-kV line			X			X	X	X
6	South	New 345-kV path from La Palma (8317) to Loma Alta (5966)			X			X		
7	North Central	Hicks 345/138-kV autotransformer #2 addition	X	X	X		X	X	X	X
8	North Central	Valley SES - Anna Switch 345-kV line upgrade		X	X			X		X
9	North Central	Everman Switch #2 and #3 345/138-kV autotransformer upgrade		X			X	X		X
10	North Central	Everman Switch - Kenndale 345-kV line upgrade	X	X	X			X	X	
11	North Central	West Denton Project		X				X		X
12	North Central	Venus Switch - Britton Road 345-kV line upgrade		X				X		
13	North Central	Bowman - Jacksboro 345-kV line upgrade						X		X
14	North Central	Graham - Garvey Road 345-kV line upgrade						X		X
15	East	a. Loop Martin Lake (3100) - Stryker Creek (3109) into Mt Enterprise (3116) b. Loop Mt Enterprise (3116) - Trinidad (3124) into Stryker Creek (3109) c. Upgrade Mt Enterprise							X	X

		(3116) - Stryker Creek (3109) 1072-MVA 345-kV line to 1792 MVA d. Upgrade Mt Enterprise (3116) - Stryker Creek (3109) 1631-MVA 345-kV line to 1792 MVA								
16	Coast	Loop North Belt - Jordan 345-kV Line into King (additional autotransformer at Jordan may be needed)						X		X
17	North Central	Century - Kenndale 345-kV line upgrade		X						
18	North Central	Paris Switch - Monticello SES 345-kV line upgrade						X		
19	North Central	Farmersville Switch - Royse 345kV double circuit line upgrade			X	X				
20	North Central	Lavon - Royse Switch 345-kV line upgrade								X
21	North Central	Ben Davis - Royse Switch 345-kV line upgrade								X
22	North Central	Tri Corner - Tyler Grande 345-kV line upgrade							X	
23	North Central	Forney Switch - Elkton 345-kV line upgrade							X	
24	North Central	Webb - Britton Road 345-kV line upgrade					X			
25	North Central	Lake Creek SES - Temple Switch 345-kV line upgrade					X			
26	North Central	Allenn Switch #2 345/138-kV autotransformer upgrade						X		
27	North Central	Venus - Sam Switch 345-kV double circuit line upgrade					X			
28	North Central	Wolf Hollow - Rocky Creek 345-kV line upgrade								X
29	East	Upgrade Richland (3133, 3134) to Big Brown (3380) 345-kV lines from 1072 to 1792 MVA								X
30	Coast	Upgrade South Texas Project (5915) - Dow (42500) and South Texas Project (5915) - Jones Creek (42400) - Dow (42500) 345-kV lines								X
31	South Central	Kendall - Bracken 345-kV line upgrade								X
32	Coast	Upgrade Singleton - Zenith 345-kV lines								X

Appendix K.

Table K.1: Annual congestion rents across constrained elements in different scenarios.

Map Index	Constrained Element	Current Trends		Global Recession		High Economic Growth		Stringent Environmental	
		2024	2029	2024	2029	2024	2029	2024	2029
1	Zenith – T.H. Wharton								
2	Kiamichi Energy Facility - Kiowa Switch								
3	Big Brown Ses – Jewett								
4	Panhandle Interface								
5	Kendall - Highway 46								
6	Kendall Auto								
7	Bracken - Highway 46								
8	Calaveras - Pawnee Switching Station								
9	San Miguel Auto								
10	Richland Chambers - Big Brown Ses								
11	Morgan Creek Ses - Tonkawa Switch								
12	Pawnee Switching Station - Lon Hill								
13	Graham Ses - Garvey Road Switch								
14	Fayetteville Auto								
15	South Texas Project - Dow Chemical								
16	La Palma Auto								
17	South Texas Project - Jones Creek								
18	Bowman Switch - Jacksboro Switching								
19	Everman Switch - Courtland								

20	Rio Hondo - North Edinburg				
21	Benbrook Auto				
22	Whitepoint Auto				
23	South Texas Project - Hillje				
24	Cagnon - Kendall				
25	Kendall - Edison				
26	Stryker Creek Ses - Trinidad Ses				
27	Decordova Ses - Comanche Peak Ses				
28	Ogallala - Tule Canyon				
29	Stryker Creek Auto				

*Note: Red and yellow highlights represent highest and lowest congestion rents.

Appendix L.

Geographic representation of congestion map across Texas

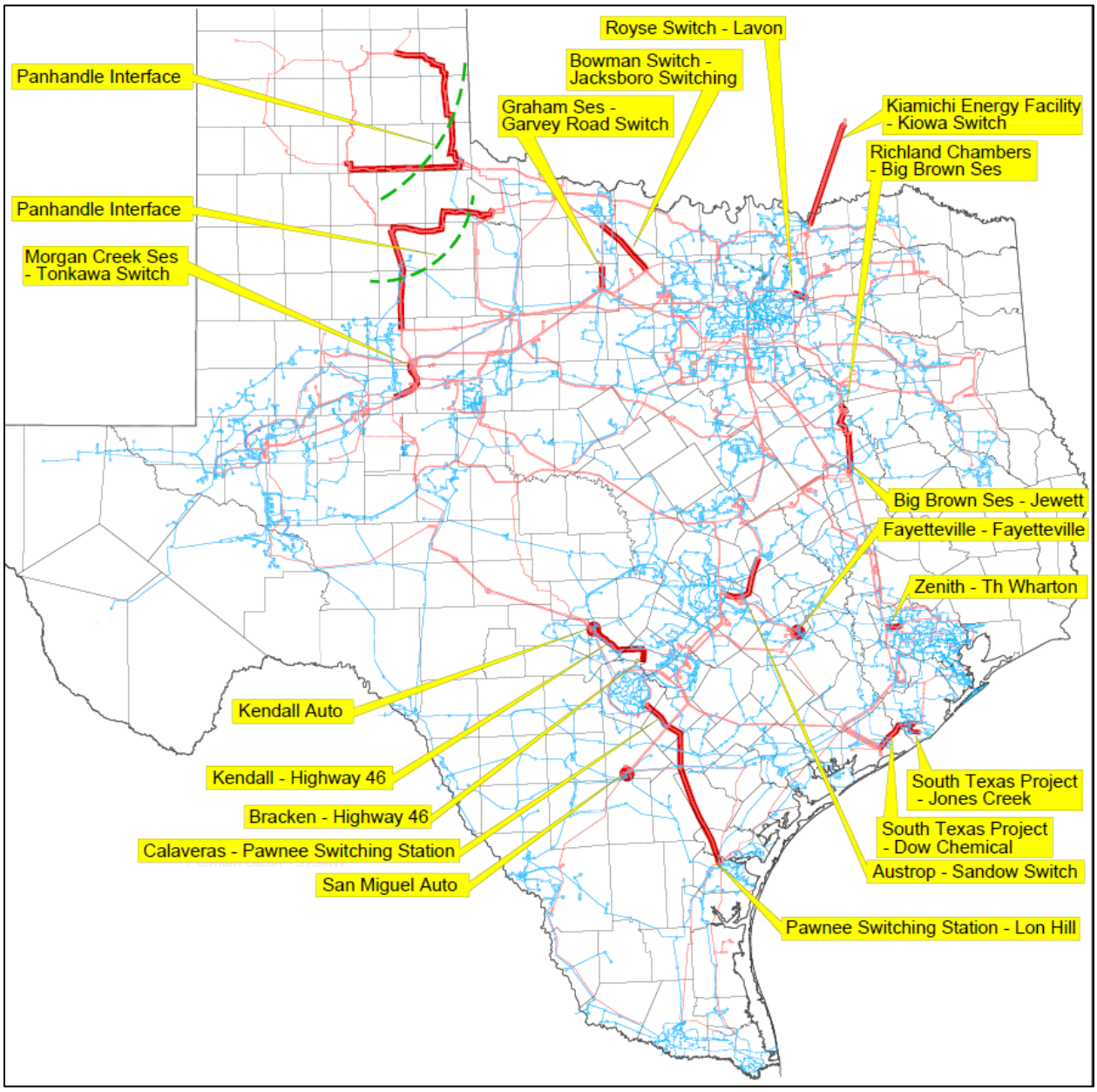

Figure L.1: Projected constraints in the Current Trends scenario

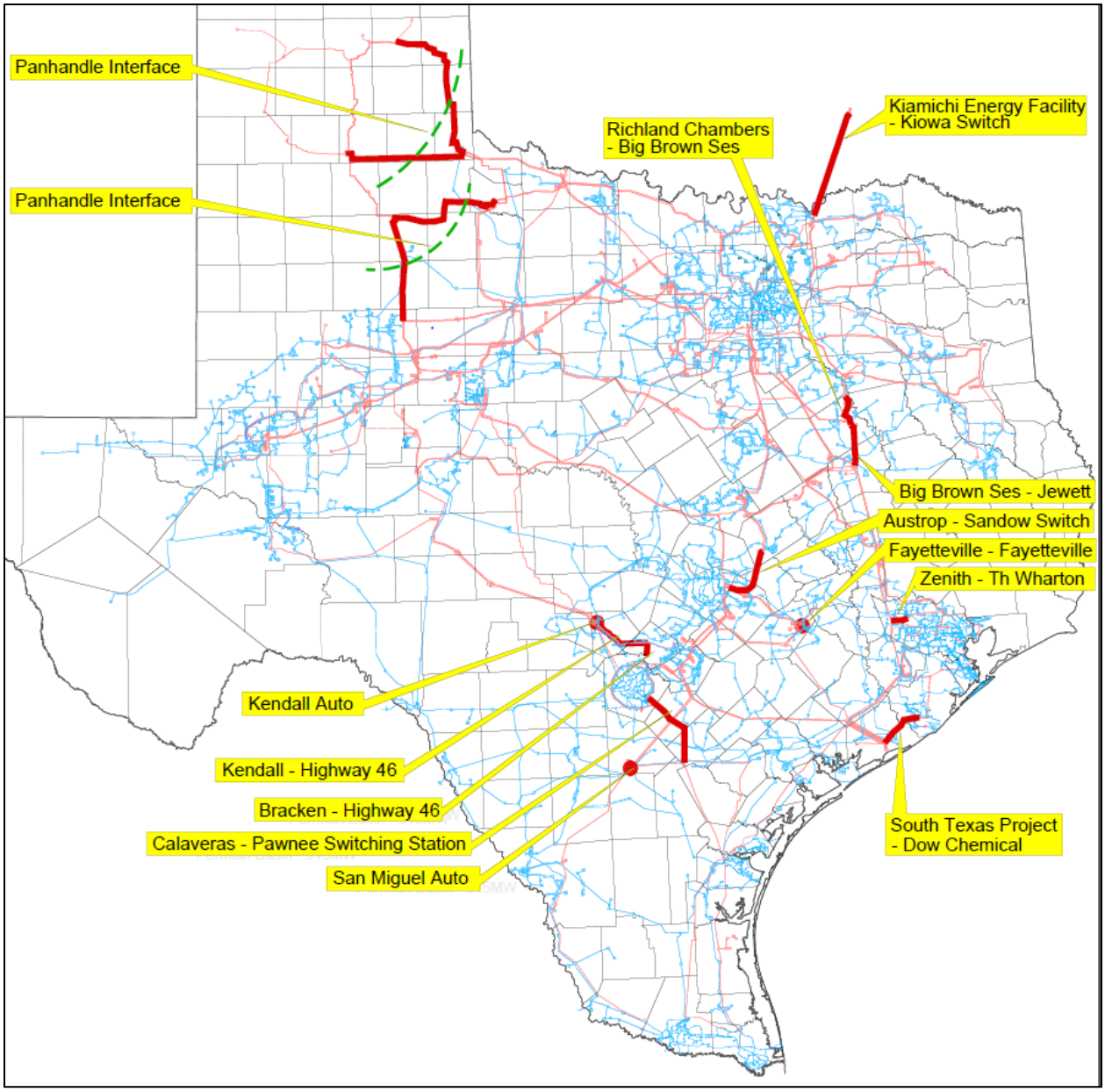

Figure L.2: Projected constraints in the Global Recession scenario

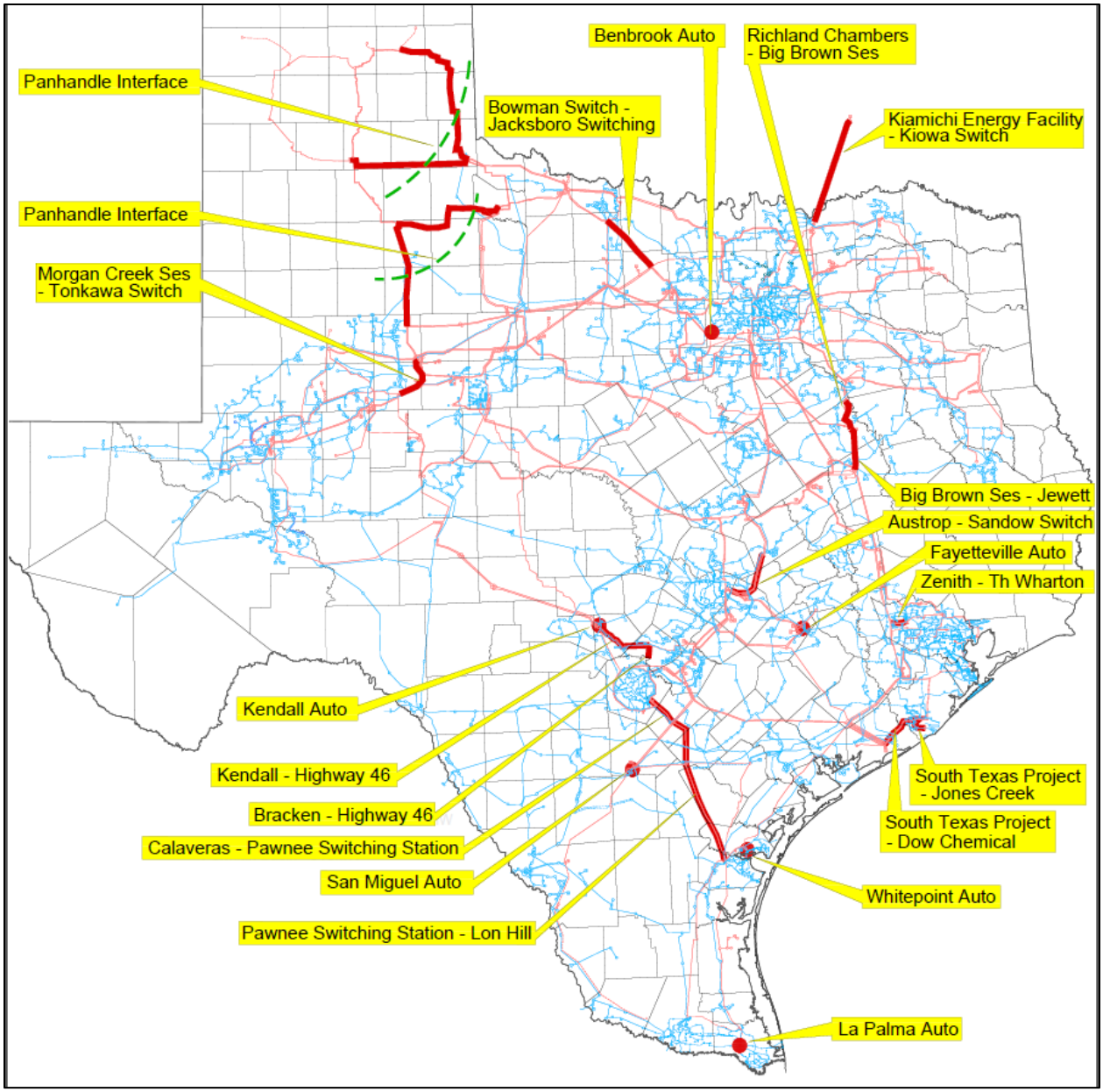

Figure L.3: Projected constraints in the High Economic Growth scenario

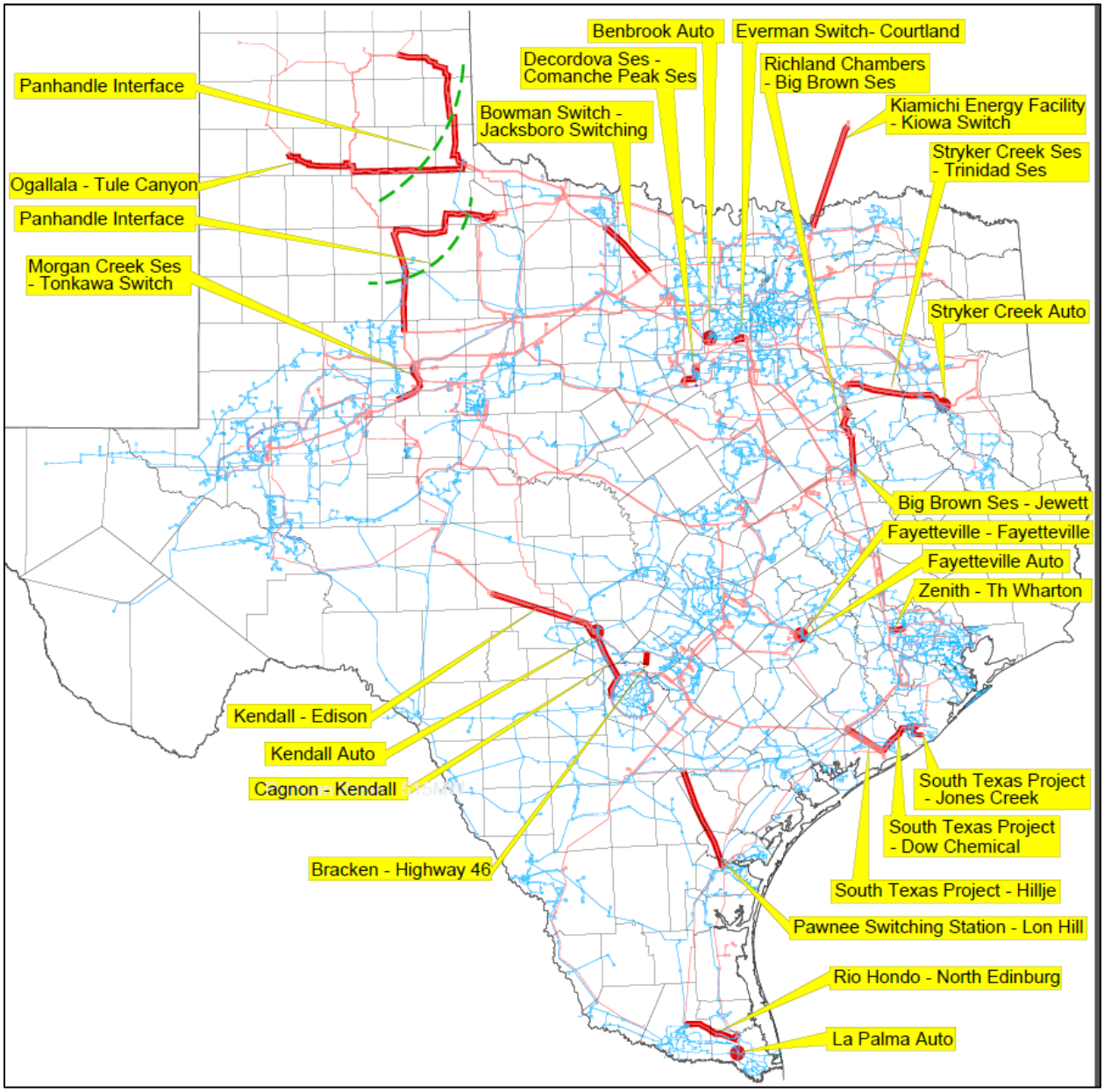

Figure L.4: Projected constraints in the Stringent Environmental scenario