ERCOT Interconnection

Long-Term Transmission Analysis 2012 – 2032 Final Report

DRAFT   Version 1.0

Electric Reliability Council of Texas, Inc.

Topic A and B Final Report

Volume 1

October 2013

Federal Acknowledgement and Disclaimer

This material is based upon work supported by the Department of Energy [National Energy Technology Laboratory] under Award Numbers DE-OE-0000340 and DE-OE-0000341.

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Executive Summary

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1 Introduction and Project Intent

The Electric Reliability Council of Texas, Inc. (ERCOT) received grant funding from the Department of Energy (DOE) as part of the American Recovery and Reinvestment Act (ARRA, 2009) in April 2010, to conduct interconnection-wide long-range transmission planning for the Texas Interconnection, also known as the ERCOT Region. Texas law requires ERCOT to conduct a review of generation and transmission needs in the ERCOT Region biennially[1] and as a Planning Authority, the North American Electric Reliability Corporation requires ERCOT to conduct a valid 10-year assessment that shows the transmission system can be operated reliably.[2] ERCOT had completed two long-range studies when they applied for the DOE grant. While sufficient for basic planning and to satisfy Texas law, these past efforts were targeted in scope. ERCOT recognized the potential advantages of enhancing its long-term planning, ultimately reaching a decision to apply for funding in September 2009.

ERCOT has used the funds obtained from the DOE to augment and enhance the existing long-range planning efforts for the ERCOT region. Approximately three-fourths of the grant funded analyses of the long-term needs of the ERCOT system and extended the technical knowledge and capabilities of ERCOT staff to provide these analyses. The remaining grant funding supported expansion of the existing ERCOT planning stakeholder process to include additional representatives of state regulatory agencies and legislative personnel, as well as representatives of non-governmental organizations interested in long-range planning and energy issues.

This report documents the process improvements, analytical tools, and planning results ERCOT derived from this grant-funded enhanced planning effort. In the body, ERCOT describes the enhancements made to ERCOT's long-term planning process, the technical results of the studies, and the conclusions ERCOT reached about the enhancements. The appendices contain several third-party reports and data resource compilations commissioned by ERCOT and funded by this grant. Those reports addressed fundamental resource and supply issues such as fuel supply, water impacts on electricity generation, and renewable resource data.

ERCOT commissioned Black and Veatch to prepare a report that addressed the robustness of the natural gas supply and infrastructure and its interdependence with electricity generation. The report examined the future supply and deliverability of natural gas necessary to serve the forecasted growth of natural gas generation through the next 20 years and leveraged a

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[1] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §39.904(k) (PURA).

[2] *Reliability Standards for the Bulk Electric Systems of North America*, TPL-001-0.1 R1.2, North American Electric Reliability Corporation (Jun. 10, 2013).

previous study on the natural gas supply system in Texas under severe weather or other disruptive events that Black and Veatch prepared for ERCOT. Another report by Black and Veatch studied the impacts of water availability on future generation operation and development in Texas. The water report leveraged a DOE-funded study by Sandia National Laboratories on the long-term drought effects on power generation to analyze the specific water challenges faced by electric generation in Texas. The Brattle Group prepared the final report in the appendices. That report examined ERCOT's long-term planning process and proposed additional criteria for evaluation of economic transmission upgrades. ERCOT also acquired updated and more granular resource data for wind and solar generation. The reports provided by the firms that prepared these analyses appear in Volume 2 of the report. Also, Appendix A contains a glossary of term and acronyms used in this report.

1.1 Project Intent

There were three primary goals of this three-year long-range planning effort:

1. To provide relevant and timely information on the long-term system needs in the ERCOT Region to inform nearer-term planning and policy decisions;
2. To expand ERCOT long-term planning capabilities by developing new tools and processes that can be used in this and future studies, including extension of the planning horizon, incorporation of operational reliability considerations and more detailed analysis of the economic viability of emerging technologies; and
3. To facilitate enhanced stakeholder involvement and input into the ERCOT long-range planning process in a manner that is consensus-seeking, sustainable, and consistent with the established ERCOT stakeholder framework.

The ultimate intent of this long-range transmission planning effort was to meet the system need for transmission capacity in a manner that is cost-effective and adaptable over the long term.

The need for transmission capacity is generally driven by future load patterns (customer demand) and the set of resources that are expected to serve these loads. It is the changes in future resources and future load patterns that will result in the need for changes in transmission topology.

Because the future is unknown, future system needs must be evaluated through scenario analysis – the development of potential future scenarios, each of which is considered possible, though not certain. Through a review of transmission needs across a range of possible future scenarios the relationships between changing market forces and changing system needs can be identified. Also, those transmission projects that provide robustness, i.e., are cost-effective and provide reliability under varying future scenarios, can be identified.

A well-vetted and repeatable long-range planning process provides ERCOT with the capability to:

- Review transmission technologies that may be part of long-term cost-effective solutions, even though they require higher up-front expenditures;
- Allow stakeholders and regulatory personnel to consider the appropriate planning horizon both for near-term and long-range planning; and
- Provide initial indications of the possibility of significant changes in system conditions resulting from changes in market conditions, capabilities of technology or market participants, and/or the costs or capabilities of generation technologies.

This capability will be fully robust only with informed participation by the full spectrum of stakeholder interests.

1.2 Department of Energy Grants

ERCOT proposed to DOE that it use its biennial long-range planning studies for the Texas Interconnect as the foundation for grant-funded enhancements. Compared to its previous studies, ERCOT envisioned a more comprehensive evaluation of the impacts of commodity markets, federal policy initiatives, technological developments, and other uncertainties on the ERCOT system. The expanded studies would evaluate potential outcomes through scenario analysis designed to capture the possible impacts of future uncertainty, analyze future operational needs (most notably from the integration of high levels of intermittent resources), and to develop a framework for reviewing the suitability of the underlying goals of transmission planning for the ERCOT region. In addition to the value of the long-term planning results, ERCOT hoped to use these studies to evaluate the role and effectiveness of long-range transmission planning in a regulated, open-access transmission system that serves a competitive generation market and to identify improvements to its long-term planning. This project was designed to add perspective, depth, and granularity to established planning processes.

The DOE announced grant awards to ERCOT in December 2009. The total funding provided by the DOE to ERCOT is $3.5 million. ERCOT would use the first grant, referred to as Topic A, to enhance and extend its long-term modeling as described in its proposal. The second grant, referred to as Topic B, would enhance the engagement of stakeholders and interested market participants in the long-term planning process. While funded separately, ERCOT considered these tasks inseparable to achieve the comprehensive planning effort it envisioned. Accordingly, the report will not distinguish between activities performed for either Topic A or B.

ERCOT proposed to develop, in conjunction with stakeholders, a representation of the Texas Interconnection that could be used for 15 to 20-year planning. ERCOT would use this system model to study several planning scenarios with a variety of stakeholder-identified and developed inputs on topics such as weather, electric load growth, generation technologies, economic and financial factors, as well as public policies. With careful selection of scenarios and input variables, ERCOT could study and evaluate a range of many possible futures with its associated generation development and transmission needs. The selection of scenarios designed specifically to foster the development of new and emerging resource technologies could reveal the operational reliability needs of the system with high levels of variable generation and identify transmission solutions needed to support those newer technologies. ERCOT's near-term planning studies do not explore those types of possible emerging futures.

ERCOT desired to expand its existing planning capabilities and models to study system needs up to 20 years in the future. To perform the longer studies, ERCOT anticipated the need to develop a new methodology to represent the existing transmission grid more simply to reduce time spent evaluating load-serving reliability projects, but at the same time maintain sufficient system granularity to allow evaluation of the need for and cost-effectiveness of high-voltage long lead-time projects.

Because of the variable character of their output, the integration of larger quantities of renewable generation requires evaluations not historically performed by ERCOT in its long-term plans. Developing improved analysis tools and techniques for the integration of renewable generation was necessary to evaluate system reliability needs with high levels of variable generation and other new technologies. ERCOT recognized its need for such tools in an enhanced long-term plan and used grant funding to secure them. ERCOT expected to develop a methodology that would allow identification of sets of technologies that, in combination, can integrate variable generation and still provide sufficient resources to maintain system reliability.

Two of ERCOT's previously stated goals as part of the project intent involved communication to and from relevant stakeholders regarding long-range planning. ERCOT also received funding from the DOE to enhance the dialogue between ERCOT and policymakers, representatives of state regulatory agencies, and non-governmental organizations regarding the long-term power needs of the ERCOT system. ERCOT expected the increased stakeholder participation to guide the transmission planning studies for the Texas Interconnection, and to facilitate the distribution of the planning results to meet the information needs of policymakers in Texas.

To achieve those goals, ERCOT proposed to develop a new forum for all stakeholders, with enhanced participation from policy-makers and non-governmental organizations. ERCOT proposed to leverage its existing stakeholder process with its already developed tools for communication and notice to support this new group. These stakeholders' participation would:

- Inform, guide, and review the analysis of interconnection-wide transmission needs;

- Help develop a list of scenarios for consideration in long-term transmission planning studies;
- Help identify and characterize future technologies to be included in planning scenarios to account fully for the uncertainty resulting from technological innovation; and
- Ensure that information needs of policy-makers are appropriately addressed in the scenario analysis and planning.

ERCOT expected the combination of the improved planning tools and greater participation by stakeholders to yield an improved foundation for policy decisions and more refined studies upon which near-term planning decisions could be based.

2 Conclusions, Recommendations and Durable Enhancements

The DOE funding allowed ERCOT to develop tools and processes that made four general improvements to its long-term planning process. ERCOT extended its existing stakeholder structures and practices to the long-term planning process thereby providing a familiar mechanism to involve stakeholders in another ERCOT activity. Both ERCOT's generation planning and transmission planning process benefited from the acquisition or development of new analysis tools that facilitated more-detailed examination further in the future. ERCOT also acquired a unique tool that facilitates the study of reliable integration of greater amounts of intermittent generation, which ERCOT's analysis suggests might expand significantly. ERCOT also supplemented the general electricity market knowledge with better data about wind, solar, water, and natural gas resources. Finally, ERCOT had the process it used for screening economic transmission projects in this long-term study reviewed and received several recommendations to improve its evaluation of the societal benefits associated with specific transmission projects.

Expanded stakeholder integration into the long-term planning process yielded several benefits for the Texas Interconnect and did so by leveraging well-developed ERCOT processes familiar to ERCOT stakeholders. Now that ERCOT has cultivated relationships with a broader group of stakeholders, the effort required to sustain such involvement is greatly reduced. ERCOT has engaged all the traditional segments of the industry participating at ERCOT: generation, transmission, load serving/distribution entities, retail electric providers, and regulators and significant newcomers: those representing alternative generation technologies, demand side aggregation, environmental interests, water resource interests, transportation, and a robust set of other potentially affected stakeholders. Stakeholder involvement supplemented key issue development to form broadly designed scenarios and provides a channel for meaningful criticism of modeled results. With the Long-Term Study Task Force now set up and stakeholders participating in an email list and regular meetings, ERCOT and stakeholders can engage each other, as needed. Because ERCOT has already established the organizational infrastructure, additional stakeholders can join the existing group as they express an interest in ERCOT's long-term planning or as ERCOT identifies and recruits other stakeholders with an interest in the issues implicated by long-term planning. Section 4 contains more discussion about the stakeholder process and its evolution during this study. Also, other discussions throughout this report will identify specific instances when stakeholder involvement shaped the study.

ERCOT made several process enhancements to its long-term planning process as part of this study and many of those enhancements will endure beyond this study. First, consistent with

DOE's desire for a longer look at resource and transmission planning, ERCOT increased the study horizon of it long-term study to 20 years. As study horizons lengthen, uncertainty associated with underlying study's assumptions increases. The remedy for this increased uncertainty was to study divergent scenarios with varying sensitivities on key study input assumptions (e.g. fuel prices, future resource incentives, load growth, etc.) Accordingly, ERCOT used a diverse set of scenarios to evaluate the possible impact of the uncertainty on planning outcomes. While the evaluation of the various scenarios will not reveal the future, it will provide insights into common needs and solutions or identify key indicators that signal whether a scenario will become more or less likely. This 10-year extension beyond ERCOT's traditional planning horizon provided valuable insight into possible future system needs and operations of the transmission system. From this extension, ERCOT gleaned several valuable insights such as, the probable need for major import upgrades into major urban areas and circumstances that could justify the construction of 500-kV transmission to move power from remote regions to major urban load centers. Many of those conclusions could not have been reached in a 10-year study or without scenario analysis.

As analytical enhancements, ERCOT acquired or developed numerous tools to model resource expansion and retirement in a competitive market and then to identify reliable and cost-effective transmission plans to deliver that electricity to customers. Coupled with a database of costs and operating characteristics of various resource technologies developed in cooperation with stakeholders, ERCOT designed its resource expansion process with the underlying assumption that individual investors, after evaluating market conditions, will base their investment decisions on the expected market return of investments in their portfolio. The purpose was to capture, as closely as possible, the market conditions experienced by a specific resource and to add resources that appeared to be economically viable, in other words, resources that would provide adequate return on investment. The modeling of economic entry and exit from the generation fleet became more important in the longer-term studies because of the uncertainty inherent in each scenario and the changing relative generation prices of the different resource technologies over the years.

With these tools, ERCOT modeled the various generation technologies and non-generation options to meeting load. Under the various scenarios developed in cooperation with the stakeholders, ERCOT studied likely resource development. These resource expansion studies provided ERCOT with insights to possible future resource mixes and market or policy conditions that favor the development of certain technologies over others.

Perhaps the most notable resource expansion conclusion from these scenario results was their similarity: natural gas and renewable generation dominated the expansion mix for all of the sensitivities. In scenarios that resulted in low market prices and renewable generation received no incentives, most or all of the expansion units were fueled by natural gas. In scenarios with higher market prices (because of increased fuel costs, emissions allowance prices, etc.) ERCOT observed significant renewable generation additions. As modeled, the capital costs for pulverized coal, integrated gasification combined-cycle, and nuclear units were too high for them to be competitive under the future scenarios evaluated.

The notable renewable generation growth occurred because these future renewable generation units competed based on energy revenue in many hours against existing generation sources, including many natural-gas-fired combined-cycle units. As they have little or no variable costs to operate, the total cost of energy from renewable units resulted only from the capital investment costs. In scenarios in which the variable cost of energy from combined-cycle units exceeded the “all in” energy cost of renewable generation (i.e., inclusive of capital costs), renewable units were competitive with over half of the energy sources in the existing ERCOT fleet.

Another consistent result from the scenario analysis was declining reserve margins over time. Several reasons contributed to this result. ERCOT’s modeling of weather-normalized load and wind patterns and no forced outages of generation led to fewer hours during which the market experienced scarcity of generation resources than what would be expected in reality. In the resource expansion analysis methodology developed for this study, higher prices during scarcity hours provided the primary source of revenue to recover the capital costs of expansion thermal units. The reduced frequency of scarcity hours resulted in lower returns on new thermal units, which would underestimate the entry of new resources.

Building on each scenario’s resource expansion plans and the transmission system as designed in ERCOT’s six-year, near-term transmission plan, ERCOT used its transmission planning tools and new techniques to identify and resolve transmission issues that developed during the 20-year planning horizon. With its portfolio of planning tools, ERCOT identified transmission needs that resulted from each scenario’s load and resource expansion. Less granular tools allowed ERCOT to examine different cases more quickly. More granular models helped ERCOT site the expansion generation appropriately. Ultimately, ERCOT developed multi-year transmission plans for the various scenarios it studied. The network simplification process it developed helped ERCOT test possible transmission solutions more quickly and with comparable accuracy. ERCOT developed confidence in its methodology and believes that it forms a solid foundation upon which ERCOT can undertake future long-term transmission studies.

From the results of its transmission analysis, ERCOT gained several important insights about the possible transmission needs during the next 20 years:

- The Houston region will need at least one additional import path within the next ten years.
- The Dallas-Fort Worth (DFW) area will need additional import lines or several upgrades. However, the lines that require upgrades varied by scenario and depended primarily on the location of future generation development. The only finding consistent across scenarios for the DFW region was the need for expanded connections between the 345-kV and 138-kV systems.
- The retirement of legacy gas-fired resources in urban areas because of future market conditions or changing regulatory requirements would lead to an accelerated need for both expanded import capacity and dynamic reactive resources within the DFW and Houston regions.
- Higher-voltage transmission solutions, such as 500-kV transmission lines, become cost effective in scenarios with significant increases in renewable generation, high natural gas prices, and/or increased water costs associated with a continued drought.

The variability of wind and solar resources when combined with the load change the system experiences moment-to-moment is called net load. With intermittent resources on the system, load-following resources must follow the changes in net load, rather than changes in load. Further, because the output from intermittent resources can change in the opposite direction as load, in certain circumstances net load changes can be much larger than the load changes alone. ERCOT anticipates continued expansion of intermittent generation with corresponding net load increases. Historically, ERCOT's transmission planning has focused on the identification and location of new or retiring resources and the development of transmission upgrades to address thermal, voltage stability, or economic needs. As the net load grows, planning must consider satisfying net load changes as well as peak load considerations. For this report, ERCOT extended its planning analysis to consider hourly and intra-hourly operations.

ERCOT acquired the KERMIT tool to evaluate whether it could operate the grid reliably with the expansion resources identified in several scenarios or if these resource expansions must be reevaluated within the constraints of any identified operational limits. ERCOT used the KERMIT model to study the possible need for increased ancillary services under circumstances with greater amounts of intermittent generation integrated into the transmission system and also to validate whether the mix of generation resources in a scenario expansion plan could meet operational reliability criteria for following net load.

The adequacy of ancillary services is the most challenging during those hours with intermittent resources serving a high percentage of load. These hours will have less conventional generation online capable to respond to net-load changes and to support system frequency. In the two cases ERCOT modeled, net-load ramps increased with higher proportions of interconnected wind and KERMIT calculated a need for more resources capable of responding to power changes very quickly. For a case with 20 GW of wind generation, roughly double the amount currently installed, the system needed an additional 800 MW of capacity capable of deployment in the zero-to-five minute range to achieve comparable balancing to current frequency maintenance performance standards. This need for the same zero-to-five minute product increased to 1,300 MW for the case with 50 GW of wind installed. While this need can be addressed by increasing procurement of existing ancillary service products, new technologies in the future may allow ERCOT to address this need differently, e.g. by introducing new ancillary service products.

Despite having roughly twice as much wind generation as currently installed, ERCOT observed net-load characteristics similar to those it currently experiences with high intermittent-resource contribution during early hours of spring and fall days. However, in the 50 GW study, even peak hours in the summer showed increased share of load served by intermittent generation and elevated net-load variability.

Assessing both the system ancillary service needs and the resultant shift in resource economics will help ERCOT understand the type and size of technologies required to maintain system balancing capability and how system balancing (regulation service) revenues change the resource value proposition. Because of its ability to examine such granular intervals on the transmission system, KERMIT may become a tool ERCOT uses regularly outside its long-term planning process. ERCOT envisions using KERMIT to help identify cost-effective changes to ancillary service procurement practices, as intermittent resource integration in ERCOT continues. In future studies, ERCOT will be able to use the results of the KERMIT model to reflect the increased cost of ancillary services in scenarios with increased penetration of intermittent generation. More discussion about the KERMIT studies appears in Section 9.2.5.

In addition to its own analysis, ERCOT commissioned four resource studies valuable in preparation of this report and that will provide valuable, public datasets useful for several years in the ERCOT market. Developers, transmission planners, ERCOT and others interested in a good understanding of the wind and solar resource in Texas will have access to very detailed wind and solar resource and generation output data. ERCOT has posted these studies on its website so stakeholders can access and use these data for their own analyses. The ERCOT market can also rely on a natural gas supply and delivery assessment to understand the robustness of a key fuel. Current economics and environmental policies favor natural gas and renewable generation to meet future resource expansion needs, a view supported in the results of this study. The natural gas study concluded that increases in natural gas production in Texas will more than offset production declines in conventional onshore and offshore supplies. Additionally, sufficient natural gas infrastructure exists to serve ERCOT's growing need for electricity. Especially valuable to ERCOT and the market is the water availability study. Water shortages and lack of water availability for power plants can lead to plant outages or reduced utilization that can cause reliability problems especially during periods of peak demand. Efficient use of water is also important to maximize the resource and to extend the potential for generation through those droughts. As the current drought continues in Texas, the electric industry can use the information in the water report to help shape any policy or investment decisions that may be faced in coming years. The water report concluded that there do appear to be sufficient water resources in Texas to allow building of additional thermal units. However, the water requirements of specific technologies and their cooling systems should be considered when siting new generation units. Fortunately, most generators in the ERCOT region do appear to have contingency plans in place to mitigate short-term, severe drought such as what occurred in 2011. Copies of these studies appear in the appendices of this report.

Some improvements to ERCOT's planning process may not occur until later. Near the end of the project, ERCOT commissioned a third-party review of the economic analysis of transmission alternatives used in its long-term planning process. While identifying areas for improvement, generally, the report concluded that ERCOT modeling of the economic value of transmission projects works well. The process is well designed and documented and ERCOT's staff has appropriate skills and experience. The report concluded that ERCOT's modeling techniques are best-in-class with respect to siting expansion generation and handling reliability upgrades to the transmission system in a consistent manner across scenarios. The report did recommend areas for improvement. Recommended organizational improvements include the consolidation of long-term and near-term planning teams and the use of a common planning model for long-term and near-term plans. On its modeling practices, the report suggested ERCOT should improve its backcasting to strengthen its model validation and develop the simulation of uncertainties within scenarios, such as weather or forced-outages. The report included a key recommendation to improve ERCOT's evaluation of economic transmission projects. The report recommended that ERCOT consider the net-present value of costs and benefits for the first several years of a project rather than ERCOT's current practice of considering only the first year benefits and costs. Additionally, the report recommended that ERCOT consider a broader range of benefits. A more detailed discussion of these and other recommendations appears in Section 9.6. A copy of the complete evaluation for the ERCOT long-term planning process appears in Volume 2.

While ERCOT cannot know the ultimate impact that the report's recommendations will have on the planning and evaluation of transmission options, ERCOT now has strong reasons to reexamine its current evaluation process. The current evaluation process may miss economic upgrades because the evaluation criterion used does not capture the costs and benefits correctly. ERCOT will evaluate whether the net present value approach provides a better long-term assessment of a potential project.

Overall, ERCOT's long-term examination of transmission and resource needs for the Texas Interconnect was far more robust and revealing than past studies. The tools and resources ERCOT procured with funds supplied by the DOE permitted a more comprehensive examination of the future needs of the ERCOT system. The opportunity to perform a longer-term study with a variety of generation, resource, and load scenarios was timely. As the Texas Interconnect faces declining reserve margins, studying various resource expansion plans provides the stakeholders visibility into possible market futures. In the following sections, ERCOT discusses more thoroughly how it engaged the stakeholders in the planning process, performed its resource expansion and transmission analyses, and reached meaningful conclusions from the results.

3 Interconnection Background and ERCOT Planning Process

The Texas Interconnection, as suggested by the name, resides entirely within the State of Texas. The smallest of the three interconnections in the United States, it encompasses approximately 75% of the land area of Texas, and approximately 85% of the customer demand. The Electric Reliability Council of Texas, Inc. (ERCOT) is a not-for-profit organization, regulated by the Public Utility Commission of Texas and under the oversight of the Texas Legislature, which is responsible for overseeing the reliable transmission of electricity over the entire Texas Interconnection. As the independent system operator for the Texas Interconnection, ERCOT is also responsible for facilitating the wholesale and retail electricity markets. The ERCOT Board of Directors, by Texas law, is composed of five independent Board members, eight members that represent different segments of the market stakeholder community, and three ex officio members.

The ERCOT grid consists of approximately 40,500 miles of 69-kilovolt (kV), 138-kV and 345-kV transmission circuits. The peak load of 68,305 megawatts (MW) in ERCOT was recorded on August 3, 2011. There are currently approximately 550 generation units on the ERCOT system, providing approximately 74,000 MW of on-peak generation capacity.

As shown in Figure 1, capacity additions since 2000 have been mostly provided by natural gas fired resources with significant wind generation added more recently. Annual additions have ranged from 200 MW to roughly 8,000 MW and vary between only natural gas resources in a few years (2000, 2002, and 2004) to natural gas, coal, and wind resources. A limited amount of bulk solar generation has been added in recent years.

There are limited ties between ERCOT and the surrounding interconnections. Two asynchronous ties provide approximately 820 MW of intertie capacity between the Texas and the Eastern Interconnection and three asynchronous ties provide approximately 300 MW of intertie capacity with the transmission system in Mexico. There are approximately 2,900 MW of generation capacity that can switch their output between the Texas Interconnection and the Eastern Interconnection.

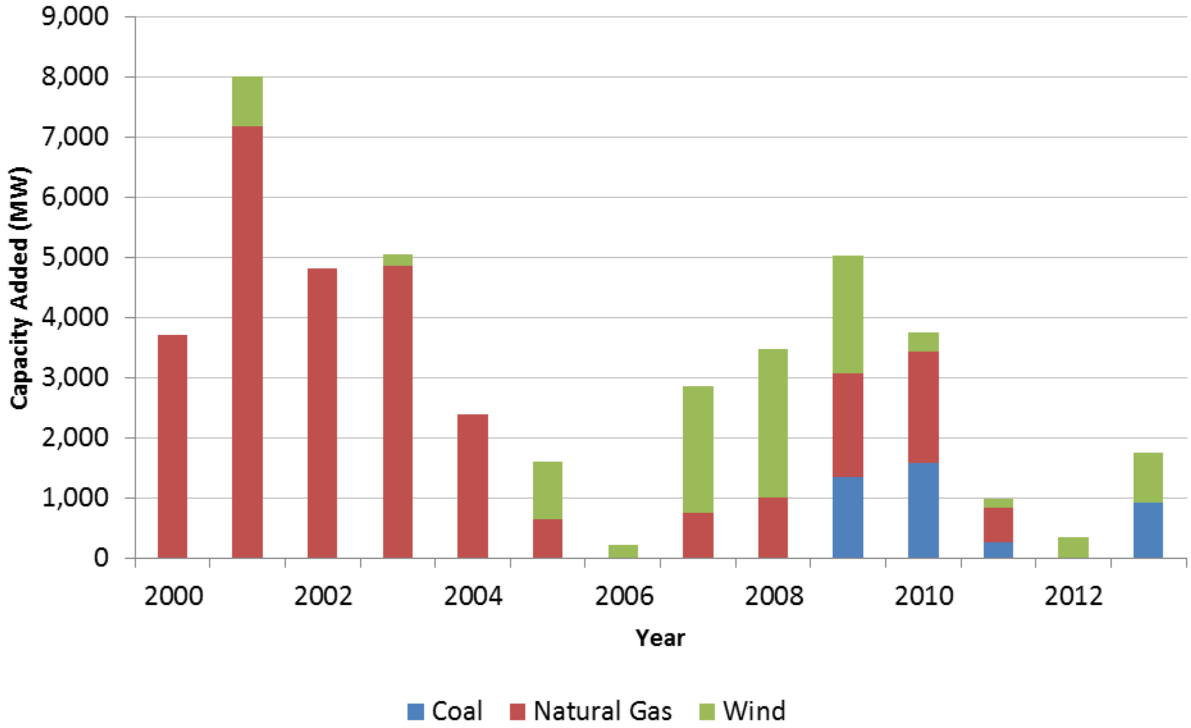

Figure 1 — ERCOT Historical Capacity Additions

The ERCOT system has a significant amount of natural gas generation. Because of the relative spot price of this fuel, natural gas generation sets the marginal wholesale cost of electricity in most settlement periods. ERCOT reports approximately 44,400 MW of natural gas generation; 18,200 MW of coal generation; and 5,100 MW of nuclear generation on the system.[3] Approximately 10,000 MW of wind generation capacity currently operates in the ERCOT system as do smaller amounts of hydro, solar and biomass generation. Energy efficiency programs, as required in Texas law,[4] provide 392 MW.[5] Market mechanics also include loads as capacity resources capable of meeting certain ancillary service requirements. These resources include Controllable Load Resources (formerly called Loads acting as Resource or LaaRs) that provide roughly 1,000 MW of capacity and are deployed when an Energy Emergency Alert is implemented.

3.1 ERCOT Market

Texas began its transition to the current market design in 1995 when changes to Texas law recognized new, competitive participants in the Texas wholesale market, exempt wholesale

[3] *Report on the Capacity, Demand, and Reserves in the ERCOT Region*, ERCOT (Dec. 2012) (*2012 CDR Update*).

[4] PURA § 39.905.

[5] *2012 CDR Update*.

generators and power marketers, and required open access to the electric transmission network for those independent wholesale suppliers. Those non-utility wholesale market participants could offer market-based prices for electricity in ERCOT. The following year, ERCOT was designated the Independent System Operator (ISO) to ensure impartial, third-party oversight to electric grid access. On September 11, 1996, ERCOT reorganized into a not-for-profit ISO.

A more significant change to the market occurred in 1999 when a change in Texas law directed the Public Utility Commission of Texas (PUCT) to oversee the restructuring of the Texas electricity industry to provide retail choice to most Texans. A key element of the new market was the separation of utilities into wholesale generation suppliers, open-access electricity delivery firms, and retail electric providers that market electricity to customers. This business separation formed the foundation for differing pricing and oversight regimes. Within broad limits, generators and retailers price their products in response to market forces. The electricity delivery firms remained rate regulated and provide their monopoly transmission and distribution services in a manner largely unchanged by the 1999 market restructuring except that they transmit electricity from any electricity supplier to a retail electric customer served by any retailer. Other than electricity delivery and power restoration, the regulated delivery utility has limited direct contact with retail customers. The installation of smart meters with remote meter reading capabilities has largely eliminated meter reading, another activity that historically provided the regulated delivery utilities an opportunity for customer interaction.

ERCOT accepted a central role in the restructured market and continues those responsibilities today. On the wholesale side, ERCOT acts as the grid operator for a single control-area transmission system. ERCOT ensures non-discriminatory access to the transmission and distribution systems, ensures a reliable and adequate electrical network, facilitates retail registration, customer switching, and other retail transactions, and provides accurate accounting and settlement for production and delivery among buyers and sellers in the market. Additionally, ERCOT administers the Texas Renewable Energy Credit program for the PUCT.

As a complement to deregulating pricing on competitive electricity services, the Texas Legislature also repealed the law that set out the PUCT's role and authority in resource planning. The Legislature intended for competitive forces to drive the addition and retirement of generation from the market. However, this change in generation planning did not eliminate the need for planning upgrades and expansion of the regulated delivery system. In the restructured market, ERCOT's reliability obligations and general oversight for the transmission system formed a natural foundation for system-wide transmission planning in coordination with the transmission service providers.

Another facet of the statutory changes made in 1999 was the establishment of a goal for renewable energy. The statutory mandate along with lower capital costs for wind generation equipment, federal tax incentives, and the low barriers to market entry in Texas resulted in substantial wind generation development in the ERCOT market. With more than 10,400 MW installed Texas became the state with the most wind generation capacity in the United States and has an installed capacity smaller than only five countries.[6] On May 2, 2013, a record 9,674 MW of wind generation served the ERCOT load, which was nearly 28% of the ERCOT load at the time. In 2012, wind generation provided 9.2% of ERCOT's energy.

This expansion of wind generation has highlighted that in a restructured market in which generation development occurs apart from transmission planning and development, transmission planning can lag behind new generation. Before the restructuring of the Texas market occurred, a utility that built generation remote from its load also designed and constructed transmission to move that power. Today, generation development can occur more quickly than the transmission system can keep up.

In the competitive retail market, ERCOT serves as the registration agent for the retail transactions, a role unique among the ISOs and Regional Transmission Operators (RTOs) in the United States. Many retail transactions, such as switching retailers or reporting customer meter data clear through ERCOT. In this way, ERCOT provides a common interface for retailers to conduct business with customers across the open-access areas of the ERCOT region. Individual retailers do not need to develop different transaction interfaces with each electric delivery company, which facilitates conducting business across the entire ERCOT region. The common interface also benefits the delivery companies because they principally transact with ERCOT.

Another characteristic of the ERCOT market is the pervasive deployment of smart meters in the retail choice areas. As of January 31, 2013, over 6.3 million advanced meters were installed with fewer than half a million remaining to be installed.[7] These meters are measuring customers' consumption every 15 minutes and ERCOT is settling those customers on their actual load, not a statistical representative load shape.

Since the retail choice market opened, ERCOT has worked with the PUCT and market stakeholders to improve the market efficiency and operations. Many of these changes have been evolutionary as better business practices are identified or new functionalities are developed and incorporated into market rules and commercial systems. Some market changes have modified fundamental characteristics of the competitive market design and resulted in significant changes to the market rules, commercial systems, and the manner competitive suppliers interact with and serve customers. After recognizing economic inefficiencies inherent

[6] *Global Wind Statistics 2012*, Global Wind Energy Council (Feb. 11, 2013).

[7] *AMS Install Numbers Update to RMS*, Presentation to ERCOT Retail Market Subcommittee (Feb. 20, 2013).

in the initial wholesale market design, the PUCT engaged the market stakeholders and ERCOT to remove or reduce those inefficiencies. In September 2003 the Commission ordered ERCOT to develop a new wholesale market design to improve market and operating efficiencies by using more rapid and detailed pricing and scheduling.[8]

The PUCT's initial wholesale market design priced electricity in a few large geographic zones and transmission limitation among the zones priced congestion on the grid. Several limitations existed with the zonal model including insufficient price transparency and indirect assignment of local congestion. A system with numerous pricing locations and central dispatch control over each generating unit was designed to improve the price transparency and improve the assignment of congestion costs. The Texas nodal market launched in December 2010, producing electricity prices at thousands of locations on the electric grid, also called nodes (an electrical bus where a resource's measured output is settled by ERCOT) across the ERCOT region. The nodal market improved price signals with more granular pricing, improved transmission efficiencies by dispatching at the resource level, and assigned local congestion costs directly where settlement prices are based on locational marginal costs. Since its implementation, the ERCOT market has enjoyed the efficiency benefits it expected and the market participants and stakeholders have continued to make improvements in pricing efficiency, congestion operations, congestion management and hedging, generation commitment, ancillary services, and other areas of grid operations and market economics.

3.2 ERCOT Planning Process

ERCOT has an established planning process that has resulted in significant on-going investment in new transmission infrastructure. The Regional Planning Group (RPG) is an open stakeholder forum consisting of a broad range of market participants that provides input and review of ERCOT planning activities with respect to transmission. The RPG meets regularly to vet and discuss transmission optimization, development, and study. Publicly available ERCOT planning guides and protocols govern the RPG process.[9]

The ERCOT Board of Directors provides oversight to the independent transmission project analyses conducted by the ERCOT planning staff. The Board determines the standards of review, the relative priority of transmission enhancement, reviews the criticality of certain projects, and endorses specific projects for implementation. The ultimate decision on the need for, and routing of, specific transmission projects is made by the PUCT, which gives great weight to the endorsement of the ERCOT Board in assessing the need for a new transmission project.

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[8] *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, Project No. 26376, Public Utility Commission of Texas (Sep. 23, 2003).

[9] See ERCOT website. http://www.ercot.com/mktrules/guides/planning/.

This planning process, alongside the efforts of transmission service providers that perform the actual construction, has resulted in a $7.4 billion investment for over 9,500 miles of new and improved transmission circuits since 1999.[10] Currently, almost 6,900 miles of additional transmission circuits are planned. These transmission improvements include those resulting from the designation of Competitive Renewable Energy Zones (CREZ) in West Texas and the Panhandle account for approximately 2,300 miles of new 345-kV circuits designed to connect areas of high wind generation potential with load centers in east Texas. These circuits are scheduled to be completed by the end of 2013, just over 8 years since the Texas statute authorized the PUCT to identify and designate CREZ and approve the development of a transmission plan to serve these regions.[11]

The process of planning a reliable and efficient transmission system for the ERCOT region consists of several complementary activities and studies. The ERCOT administered system planning activities include near-term studies, including the Regional Transmission Plan, Regional Planning Group submissions and review, generation interconnection studies, and ongoing long-range studies, documented in the Long-Term System Assessment (LTSA). In addition to these activities, transmission and distribution service providers (TDSPs) conduct analyses of localized transmission needs outside of the ERCOT Planning Process.

ERCOT performs its planning function in coordination with TDSPs, ERCOT market participants, and other interested parties. ERCOT works with two primary market stakeholder groups in fulfilling its planning responsibilities:

- The Regional Planning Group reviews and provides comments on new transmission projects in the ERCOT region.
- The Planning Working Group reviews the processes and criteria used by ERCOT and by transmission service providers in planning improvements to the ERCOT transmission system.

For the purposes of improving its long-term planning processes, ERCOT created the Long-Term Study Task Force in 2010, as a subgroup of the Regional Planning Group. This task force has a primary focus on long-range planning activities and assessments.

ERCOT's planning studies are enabled through the development and maintenance of computer model representations of the ERCOT grid topology. ERCOT works with owners of transmission, generation, and other resources to ensure that the models accurately represent the existing and expected future capability of the thousands of elements that collectively compose the grid. All planned system improvements, including local load-serving projects developed by TDSPs

[10] *Striking a Reliable Balance - 2012 State of the Grid Report*, ERCOT, p. 13 (Jan. 2013).

[11] PURA § 39.904.

outside the ERCOT planning process, are maintained in these system models so that resulting analyses accurately represent future system needs. Improvements within the last two years to the ERCOT model development process have increased the consistency of model databases used to conduct real-time system and market operations, near-term outage management, and near-term and long-range system planning.

Development of the annual Regional Transmission Plan is the primary component of the ERCOT near-term planning process. As part of this assessment of region-wide reliability and economic transmission needs, ERCOT works with the TDSPs and the RPG to plan improvements to meet system needs for the next six years. The resulting planned improvements address requirements included in the North American Electric Reliability Corporation (NERC) Reliability Standards and the ERCOT Market Protocols, Operating Guides, and Planning Guides. By evaluating system needs in a holistic fashion, that is, by comparing sets of projects that meet all system needs and incorporating and evaluating the longer-term results from the LTSA, ERCOT is able to increase the cost-effectiveness of future system improvements.

Although the goal of the Regional Transmission Plan process is to review all grid improvement projects in concert, in practice it has not been possible for all necessary system improvements to be reviewed on the same timeline. As system conditions in portions of the grid change (for example, recent significant load growth in the oil and gas producing regions of ERCOT), it is often necessary to review regional improvements outside of the Regional Transmission Plan process. The RPG review process is designed to provide an avenue for the endorsement of these types of projects outside the annual Regional Transmission Plan process.

Following the submittal of a proposed project by any RPG participant or market stakeholder, the RPG review process follows an increasingly rigorous evaluation of the need for the project and its cost-effectiveness, based upon project cost and the requirements for regulatory review. Projects that require an amendment to a TDSP's Certificate of Convenience and Necessity or that are expected to cost more than $50 million receive independent review by ERCOT. This independent review will often include an evaluation of project alternatives that achieve the system performance goals of the original project. ERCOT considers several factors when it evaluates a RPG proposal and its alternatives. Those factors include the project's capital cost and expected system operation cost, subject to consideration of the expected long-term system needs in the area and the relative operational impacts of the alternatives. Considered together, ERCOT recommends the project with the lowest expected total cost over the life of the project. ERCOT's LTSA is the long-term study that identifies those long-term needs and operational considerations to frame the near-term planning activities.

The role of the LTSA is not to recommend the construction of specific system upgrades because of the high degree of uncertainty associated with the size and location of loads and resources in the long-term timeframe. Instead, the role of the LTSA is to evaluate the system upgrades that are indicated under each of a wide variety of scenarios to identify upgrades that are robust across a range of scenarios or might be more economical than the upgrades that would be determined considering only near-term needs in the Regional Transmission Plan development. The LTSA process represents a planning simulation laboratory, in which analysts can model futures that appear possible, unlikely, or even extreme 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 shorter-term study horizons through scenario-based assessment of divergent future outcomes. As future study assumptions become more certain, the Regional Transmission Plan 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.

Although not part of the RPG review process, generator interconnection studies are another regular transmission review in the ERCOT region. Ultimately, before a generation resource is ready to connect to the electric grid, the generator interconnection process identifies connection and delivery projects associated with the integration of new resources as they are developed in the ERCOT region. The generation interconnection process is designed to ensure that new generation resources are connected to the existing grid in a reliable manner with sufficient local transmission capacity; neither the interconnection process nor the transmission policy in Texas assures a new generator full transmission capacity to all load centers. Those types of regional improvements are assessed through the Regional Transmission Plan and individual RPG project reviews discussed earlier. Collectively, these transmission review activities create a robust planning process to ensure the reliability and efficiency of the ERCOT transmission system for the foreseeable future.

3.3 ERCOT Planning Reports

The Regional Transmission Plan report and the Long-Term System Assessment (LTSA) document the input assumptions, methodology, and results of these two planning efforts. The Regional Transmission Plan report addresses region-wide reliability and economic transmission needs and includes the recommendation of specific planned improvements to meet those needs for the upcoming six years. When system simulations indicate a deficiency in meeting documented planning criteria, a corrective action plan, which typically includes a planned transmission improvement project, is developed.

In contrast, the LTSA does not provide actionable recommendations for specific transmission system improvements. Rather, the LTSA provides general guidance to near-term planning. The LTSA provides an evaluation of the benefits of system upgrades under each of a wide variety of scenarios and in this way identifies upgrades that are robust across a range of scenarios or might be more economic than would be determined if only the near-term needs (as in the Regional Transmission Plan development) were considered. The LTSA describes future scenarios that provide a likely boundary for future market conditions and an independent assessment of expected future resources and transmission needs in each future scenario.

The LTSA analysis is based on projections of certain factors that drive decisions on generation investment and system needs, such as the price of natural gas, technology incentives, and environmental regulations. These projections are incorporated in an analysis of likely resource expansions (both type and location), which in turn is used to assess system transmission needs.

3.4 Improving the Long-Term Planning Process

Planning for long-range transmission system needs in a deregulated energy market requires a methodology that assesses both commonality and the uniqueness of a wide range of future outcomes. In many instances, particular scenarios create future outcomes that bear little resemblance to any current or near-term study case. For example, 20 years ago, the preparation of an ERCOT future case with more than 10 GW of wind generation would have been considered extreme by many stakeholders, even though this is the resource portfolio serving the ERCOT region today. As it is impossible to know today which of the many possible futures will develop, long-range planning is used as a tool to influence near-term infrastructure improvement decisions through an understanding of commonalities of future system needs across a range of future possibilities. With the increased pace of change in system conditions, long-range planning is increasingly important to ensure adequate lead-time for the development of projects necessary to maintain system reliability.

The time horizon for actionable transmission planning in the ERCOT system is currently six years. For the past six years, every even-numbered year, ERCOT has conducted the LTSA, a 10-year study of system needs. However, this analysis has been limited in scope because of a lack of models, databases, and planning processes specifically designed to support the assessment of long-range system needs. In 2010, ERCOT received grant funding from the Department of Energy (DOE) through the American Recovery and Reinvestment Act (ARRA) to address this need for better long-range planning tools and processes. These funds have been used in a variety of ways to improve long-range planning.

Grant funding was used to develop a tool that simplifies the existing near-term ERCOT planning transmission topology database so as to highlight the need for large, inter-regional system upgrades while automatically resolving the need for smaller, local load-serving projects. This tool allowed ERCOT to extend the long-range planning horizon beyond 10 years by reducing the computational requirements on the models and permitting the study to focus on the most relevant upgrades. ERCOT's most recent LTSA included an assessment of the potential impacts of up to 20-years of load growth and resource development on the transmission system.

ERCOT used the DOE grant funding to evaluate new software packages, specifically PROMOD IV and the PROMOD Analysis Tool, which together provide more capability than ERCOT's existing tools to quantify the market viability of future resource additions. This increased capability is discussed in a later section about new tools. ERCOT used these tools, as well as new processes (developed by grant-funded staff) to assess system needs better over a longer study horizon. ERCOT worked closely with an expanded group of stakeholders to establish several scenarios, based upon underlying market and regulatory assumptions, to develop likely future resource additions based upon each resource technology's market competitiveness. As described in a later section, ERCOT used these future resource portfolios to evaluate future transmission needs for each scenario.

Grant funding was used to procure additional databases needed to assess the potential impact of variable generation on the ERCOT system. Specifically, ERCOT procured wind generation and solar generation hourly output time series that are chronologically consistent with the 15 years of weather information used by ERCOT to develop load forecasts. Time-synchronized wind, solar, and weather datasets allow ERCOT and other researchers to develop more detailed assessments of the impacts of high levels of variable generation penetration and the benefits of additional technologies in maintaining system reliability.

ERCOT also used the DOE grant funding to explore the effects of an increased amount of variable generation on the ability of a generation fleet to maintain system frequency. KERMIT, a model developed by DNV KEMA that simulates system operations at a multi-second granularity, was used to simulate the existing ERCOT fleet. KERMIT was used in scenarios with increased variable generation to evaluate incremental balancing needs and to update relative resource economics. These updates permitted ERCOT to refine the long-term generation expansion process described in this report to represent overall system needs more holistically.

The continuing drought in Texas has highlighted the need for further analysis of water usage by electrical generating facilities and the potential impacts that long-term, sustained drought conditions may have on system reliability. DOE grant funding supported a detailed analysis of the impacts of an extended drought on the ERCOT system. ERCOT retained Black and Veatch to adapt work completed by Sandia National Laboratories for all of the western United States into a Texas-specific long-term drought scenario with several sensitivities.

ERCOT also used DOE grant funding to support a project facilitator responsible for increasing stakeholder involvement in and overall awareness of the role of long-range planning in the ERCOT region. The facilitator increased the involvement of experts and organizations not traditionally engaged in transmission planning, thereby improving access to additional industry knowledge from stakeholders with knowledge of the ERCOT system. ERCOT also engaged the Demand-Side Working Group and the Emerging Technology Working Group to build appropriate representations of varying technologies within long-term system assessments.

DOE grant funding supported an evaluation of the economic transmission expansion evaluation criteria used in the ERCOT planning process, and the appropriateness of these criteria for use in long-range planning. The grant funding also supported an analysis of the interconnectedness of natural gas and electric grid infrastructure. Continuing on previous analysis of the adequacy of natural gas pipeline capacity in ERCOT, a follow-on study evaluated how much natural gas pipeline expansion would be necessary to support future scenarios with high levels of new natural gas-fired generation.

In summary, DOE grant funding allowed ERCOT to improve significantly the long-range planning process for the Texas Interconnection. New toolsets and new processes were developed, and new databases acquired that allowed ERCOT, in conjunction with key stakeholders through an enhanced regional planning process, to understand future transmission needs better and to quantify the benefits of transmission expansion. More extensive discussions of these tools and studies appear in later sections of this report.

4 Enhanced Stakeholder Participation

Historically, stakeholders have played a significant role in ERCOT operations and planning. ERCOT began as an organization formed by and for the joint benefit and coordination of utilities in the Texas Interconnection. ERCOT's stakeholders, at that time all utilities, controlled it completely. ERCOT's role has evolved and its constituency has broadened considerably concurrently with policy and structural changes to the electricity market. Today, ERCOT stands independently from any particular stakeholder group or market interest. That independence neither implies isolation from the various ERCOT market interests nor does it ignore the value provided by hearing from divergent interests. In fact, ERCOT has developed an inclusive process for stakeholder input and dialogue that informs both ERCOT and the market it manages.

ERCOT, its staff, its various technical groups, the wholesale and retail electric market, and the broadest possible planning and reliability functions, rely heavily on stakeholder involvement and support. Through an integrated, hierarchical, and formalized structure, the Technical Advisory Committee, which comprises stakeholders from the various market interests, and its numerous and varied subcommittees and task forces provide significant support to the ERCOT Board of Directors. Their review and consideration of each proposed protocol and operating guide change, including cost-benefit analysis, ensures that the deliberations of the Board of Directors are informed by the broadest possible diversity of viewpoints.

Through this process-driven effort, stakeholder knowledge-base and technical review contributes to the continuing development and improvement of the ERCOT market, including, in the instant case, transmission planning.

Within the ERCOT region, transmission planning has traditionally been undertaken through the efforts of the Regional Planning Group. While ERCOT holds a central role in regional grid planning, it relies heavily on transmission providers' planning knowledge and insight into their own system and the area they serve. Also, by involving each transmission provider in the regional planning process, the region benefits from the accumulated experience of possible solutions tried in individual service areas. This group, populated largely (though not exclusively) by transmission engineers, has been charged with both proposing and evaluating transmission-level enhancements to the electric grid.

4.1 Stakeholder Involvement in Transmission Planning

While robust participation in the RPG and other ERCOT stakeholder groups by various directly impacted market interests is the norm, Texas regulatory agencies (excepting PUCT staff), the legislative community, and non-governmental organizations with potential interests have largely been absent from day to day deliberations.

ERCOT believes that two factors have played a direct role in this lack of participation: resource limitations associated with the time commitment required to participate, and a general lack of awareness regarding opportunities for input.

It is in this context that, over the course of the last three years, ERCOT has sought to increase participation relative to its long-range planning efforts. The operative assumption has been that participation by a broader stakeholder community would both enhance the breadth of considered information and create a collaborative atmosphere in which a broad range of stakeholders would develop greater understanding of the ERCOT transmission planning process. Among the ways ERCOT worked toward enhancing two-way communication with stakeholders included direct interviews with stakeholder participants, production of a project-specific newsletter, and direct and active solicitation of new participants.

In developing its processes for input, ERCOT presented stakeholders with opportunities to provide feedback on technical assumptions vis-à-vis costs, new technologies, and changing market conditions. Stakeholder involvement also supplemented key issue development in broadly setting scenarios for evaluation. Although ERCOT anticipated that it would identify the types of assumptions required to model these scenarios and that stakeholders would create the vast majority of needed detail data, in the absence of direct feedback (in certain instances) ERCOT developed some of this detail for affirmative response rather than wholesale adoption.

DOE Grant funding allowed ERCOT to foster participation and involve stakeholders that were previously unavailable or unengaged. For example, ERCOT recognized that certain stakeholders required both outreach and education to enable their meaningful participation. Additionally, ERCOT sought to tailor its existing stakeholder participation process to the collaborative and interactive needs of the long-term planning process.

To achieve the goals of the grant, ERCOT staff established a new stakeholder group, the Long-Term Study Task Force (LTSTF), the meetings of which focused on the analysis and studies described in this report. In ERCOT's view, this group would: (1) provide input into the planning process on scenarios and assumptions and (2) provide insights about the information learned in the planning process. This group enabled and supported participation by any stakeholder or individual interested in long-term planning issues. ERCOT created a public email list (LongTermStudy@lists.ercot.com) to provide information to interested stakeholders regarding upcoming meetings, project status, and other issues. All members of the existing Regional Planning Group mailing list automatically became subscribers to the Long-Term Study list. Other stakeholders or interested individuals could sign up for this list by accessing the ERCOT mailing lists on the ERCOT website.

The LTSTF convened initially on a monthly basis, meeting numerous times since the start of the grant funding in April 2010. The LTSTF met for the first time on April 29, 2010. Prior to this meeting, an overview of the long-term study was presented at the ERCOT Board of Directors meeting on March 23, 2010, and at the ERCOT Regional Planning Group meeting on April 16, 2010. The first meeting of the LTSTF included an overview of the proposal accepted by the Department of Energy, and an open discussion with stakeholders regarding what issues should be included in the study and what stakeholders could gain from the analyses.

ERCOT and the stakeholders used the meetings held throughout 2010 to identify and understand issues that could have significant impact on future electricity markets, demand, and resources. Experts from industry, academia, and regulatory agencies provided insights into the following issues: load forecasting, water demand projections, customer demand response programs, emerging smart grid technologies, geothermal generation potential, and environmental policies and impacts. In addition, the LTSTF began discussions on development of future scenarios at the meeting held on June 18, 2010. At that meeting, stakeholders developed an influence diagram for the fundamental drivers of this project,[12] and reviewed results from issue boards that had been made available at the previous meeting. The transmission planning topics considered by the stakeholders included electricity demand; regulatory policies; commercial, economic, and technology considerations for generation; smart grid; operational reliability; disruptive factors; and numerous subtopics within these categories.

After further discussions regarding scenario development at the July 23, 2010 meeting, ERCOT and the stakeholders established a Scenario Development Working Group to focus on finalizing an initial set of scenarios for analysis. This working group met three times via WebEx in August and September 2010. At these meetings, ERCOT asked stakeholders to propose potential scenarios or specific issues to study and to review possible scenarios proposed by ERCOT. Because of limited participation, the sub-group disbanded and relinquished its work to its parent taskforce, the LTSTF.

Scenario development became the primary focus of the LTSTF at the first meeting in 2011, held on January 10. At this meeting participants discussed an initial business-as-usual scenario, based on the assumption that there would be no changes in current market conditions. The stakeholders proposed to use the latest fuel forecasts from the Energy Information Agency as assumptions in this scenario.[13] ERCOT used this scenario to show the implementation of the resource expansion analysis process performed on the PROMOD IV and MarketPower software packages. The meetings on January 10 and March 1 also included discussions of the

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[12] Available at http://www.ercot.com/calendar/2010/06/20100618-LTS. {{check link}}

[13] *Annual Energy Outlook*, Energy Information Administration (Jun 2010 and Jun 2011). (*AEO 2010* and *AEO 2011*, respectively)

appropriate alternate scenarios desired for study, such that stakeholders would have sufficient information regarding the resource expansion tools.

LTSTF meetings also included discussions regarding other tools and processes being developed as part of the long-range planning process. These processes included the transmission simplification process, the evaluation of economic return of potential future resources, a proposed generation siting methodology, and the results of initial evaluations of the need for new transmission capacity following 20 years of load growth in ERCOT.

The types of organizations and groups shown in Table 1 participated in stakeholder meetings. Appendix B lists specific stakeholders that participated in the long-term process and meetings.

Table 1 — Stakeholder Participants in Long-Term Study Meetings

Participating Stakeholder Segments		
Independent Power Producers	Transmission Providers	Municipal/Cooperative Utilities
Power Marketers	Government/Regulators	Consultants
Research and Development	Industry Groups	Concern Groups
Landowner Groups	Other Organizations and Firms	

ERCOT hosted the LTSTF meetings at its facility, located near the Austin-Bergstrom Airport. Teleconference services for meetings of the LTSTF facilitated participation by individuals who could not travel to the Austin area. After the meetings, ERCOT posted meeting notes and attendee lists for the LTSTF meetings on its public web site. ERCOT also notified stakeholders that funds were available as part of the DOE grant for interested parties to travel to Austin to participate in these Planning meetings.

ERCOT conducted over two dozen noticed public meetings with stakeholders directly addressing the long-term study issues through the Regional Planning Group and the Long-Term Study Working Group. Additionally, ERCOT staff gave presentations and updates at numerous other stakeholder meetings as part of its outreach effort. Table 2 shows the opportunities for stakeholder involvement throughout the life of the long-term study. ERCOT also created several newsletters that it distributed to individuals enrolled on the LTSTF email distribution list. In those newsletters ERCOT educated stakeholders about the planning process; explained its planning methodologies used to create load forecasts, generation expansion plans, and transmission plans; reported to stakeholders the status of the long-term study; alerted them about times and places of upcoming meetings; and invited greater stakeholder participation. ERCOT used the newsletter as another communication method to keep stakeholders informed about various aspects of the long-term study.

Table 2 — Long-Term Study Timeline for DOE Grant

Milestone	Kick-off Meetings	Draft Interim Report due to DOE	Interim Report due to DOE	LTSA for Texas Legislature	Draft Final Report	Final Report due to DOE
Timeline	April 2010	June 2011	August 2011	December 2012	May 2013	July 2013
Work Product	Initial Development Business as Usual Case & Modeling		Alternative Scenario Development & Modeling		Final work product	
Stakeholder Process	Monthly introductory meetings		Quarterly LTS meetings with interim workgroup meetings			

Figure 2 shows a matrix of open, public meetings and communications between ERCOT and interested stakeholders.

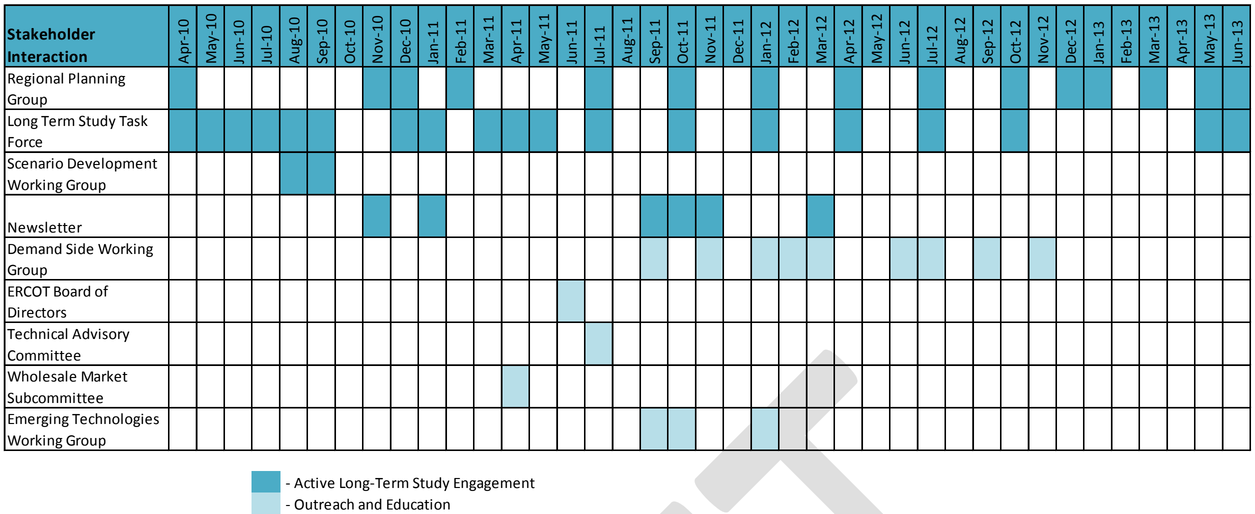

Figure 2 — Periodic Stakeholder Interactions

4.2 Outreach to Texas Agencies, Non-governmental Organizations, and Other Stakeholders

To enhance participation from representatives of Texas regulatory agencies, ERCOT staff met individually with representatives of the following agencies:

- Office of the Texas Comptroller of Public Accounts
- Texas Department of Transportation
- Railroad Commission of Texas
- Texas State Energy Conservation Office
- Texas Commission on Environmental Quality
- Texas Office of Public Utility Council
- Texas Water Development Board
- Texas Parks and Wildlife Department

ERCOT staff used these meetings to describe the purpose of the long-term study, to begin a dialogue regarding how the long-term study could benefit regulatory agencies, and to determine the ways in which the agency staff could contribute to the long-term study effort. For example, ERCOT staff met with the Texas Commission on Environmental Quality (TCEQ) so the economic and siting models developed for the study would properly reflect the applicable air quality limits and other considerations.

ERCOT also met with representatives of several non-governmental organizations, including Public Citizen, Environment Texas, Sierra Club and the Environmental Defense Fund, to discuss the goals of the long-term study process. ERCOT held additional meetings with representatives of Transmission Service Providers to discuss the transmission analysis process and potential system upgrades. In an effort to increase general awareness of the project, ERCOT delivered presentations regarding the long-term study to the ERCOT Board of Directors, the Regional Planning Group, and the Wholesale Market Subcommittee. ERCOT also participated in two National Association of Regulatory Utility Commissioners meetings that focused on the interconnection-wide studies being conducted through ARRA grant funding from DOE.

Although participation in the LTSTF meetings by state agency personnel was substantial, participation by other segments of the stakeholder community lagged expectations. Limited stakeholder participation possibly resulted in a lack of diverse views being expressed during stakeholder meetings, which hampered ERCOT efforts to solicit market participant opinions. ERCOT considered this stakeholder participation especially important during scenario development, when specific assumptions regarding market conditions and the cost and availability of generation and demand-side resources were determined.

4.3 Mining the Existing Stakeholder Groups

A fully represented stakeholder community would include all the traditional segments of the industry participating at ERCOT: generation, transmission, load serving/distribution entities, retail electric providers, and regulators. However, complete stakeholder representation should also include newcomers: those representing alternative generation technologies, demand side aggregation, environmental interests, water resource interests, transportation, and a robust set of other potentially affected stakeholders. In September 2011, ERCOT staff explained the long-term study to the Emerging Technologies Working Group and the Demand Side Working Group. This outreach allowed ERCOT staff to improve stakeholder awareness of the long-term planning process and to recruit stakeholder participation in the effort. For instance, because of its outreach to the Demand-Side Working Group, ERCOT gained better insight into the cost and finance structure of the demand response industry and a better understanding of demand response programs in other states.

In 2013, ERCOT retained the Brattle Group to assess how ERCOT identifies transmission projects with net economic benefits and to identify opportunities to improve the ERCOT modeling process and evaluation methodologies. As part of their evaluation, Brattle interviewed stakeholders to gather relevant insights from a cross section of the of the planning process constituency. From these interviews Brattle identified the value stakeholders place in ERCOT's planning process and ways ERCOT can improve its interactions with stakeholders to facilitate participation and improve the quality of shared insights. Brattle's complete report contains their specific observations and recommendations related to stakeholder feedback and participation; that report appears in Volume 2 of this report.

In ERCOT's judgment, increased stakeholder participation added real value to the planning process. Interaction with the stakeholders yielded diverse perspectives and allowed ERCOT to leverage the expertise of market participants in the development of its long-term plan.

Collaboration in the future will only further improve the planning process and will highlight the importance of adequate stakeholder reviews and input. In subsequent sections, this report documents the specific roles the stakeholders played in this long-term study.

4.4 Interaction with Historically Active Stakeholders

ERCOT now has a framework for stakeholder participation in the long-term planning process. Outreach to new stakeholders can continue as new market interests seek engagement in the process or as ERCOT identifies previously unengaged stakeholders and informs them of the opportunity to participate in the planning process. By relying on the education and interaction processes developed for this study, ERCOT can develop assumptions and scenarios more quickly and focus on incremental improvements to its stakeholder process for long-term planning. This expected efficiency stems from ERCOT's and the stakeholders' familiarity with the now developed process.

5 Planning Scenario Development

In an effort to provide relevant information on the long-term system needs for the ERCOT region, a process for evaluating various potential futures was developed. This process included developing scenarios to include multiple assumptions that would simulate the ERCOT market and model the potential economic viability of various technologies over a long-term horizon. Because part of the intent of this study was to develop new processes to enhance long-term planning capabilities in ERCOT, scenario analysis was used for the first time. The scenario development process was the first stage in engaging ERCOT stakeholders in this study.

The interplay of future energy trends is complex. The combination of numerous diverse market forces, changes in natural resource availability, development of new energy sources, and regulatory changes at the local, state, and federal levels make it impossible to predict how the electric system will change over the next 10 or 20 years. As such, in analyzing future system needs, it is necessary to create a variety of potential future scenarios that include assumptions around energy prices, consumption and supply, the advancement and penetration rate of emerging technologies, and the size and cost of energy resources, especially in the longer term. To the extent that these scenarios capture most or all of the range of potential future outcomes, or in other words, define a boundary within which the future is likely to occur, then the resulting analysis of transmission needs likely leads to relevant insights. While the results of this scenario analysis are not definitive statements of what will happen, the results do allow a better understanding of the relationships between market changes and system needs.

ERCOT began the scenario development process by reviewing recently published studies by the Energy Information Administration (EIA),[14] the International Energy Agency,[15] and private corporations such as Shell[16] and ExxonMobil.[17] The studies published by these organizations each accounted for a variety of current and future policies and market trends. These studies included considerations of emission regulations, economic growth and demand for energy, demand for commodities, and development of emerging technologies.

ERCOT also reviewed historical data from EIA and the British Petroleum (BP) Statistical Review of World Energy 2010 to develop an understanding of national and global historical trends and relationships[18]. This evaluation included the review of historical production and consumption

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[14] *AEO 2010, AEO 2011, AEO 2012*.

[15] *World Energy Outlook*, International Energy Agency (Nov. 2010).

[16] *Shell Global Scenarios to 2025*, Shell International BV (Mar. 2008).

[17] *Outlook for Energy - A View to 2030*, ExxonMobil (Dec. 2009).

[18] *BP Statistical Review of World Energy*, BP p.l.c. (Jun. 2010).

of energy commodities (crude oil, natural gas, and coal) by country, commodity prices, and economic indicators such as GDP, employment growth rates, and population growth rates. An understanding of historical events and associated economic indicator values helps to provide a comprehension for suggesting values to use when forecasting into the future. It is important to have an idea of potential implications of assumption values to maintain internal consistency and keep the assumptions within the boundaries of the particular scenario's theme.

ERCOT considered several policy effects on expected generation, generation type, and load as part of this study. These policies included various emission regulations, the federal renewable production tax credit (PTC), demand response mandates, renewable portfolio standards (RPS), energy efficiency mandates, and water usage costs under drought conditions.

After performing background research, ERCOT staff presented various ideas to stakeholders for consideration as part of developing scenarios. There were multiple iterations of scenarios that included scenario themes, various possible assumptions, stakeholder concern over internal consistency between assumptions within each scenario, and ranges of assumption values. Following an extensive number of meetings with stakeholders through the Long-Term Study Task Force and review of numerous comments, ERCOT developed 11 scenarios for the long-term study.

5.1 Scenario Descriptions

In an effort to facilitate enhanced stakeholder involvement in the ERCOT long-term planning process, the Scenario Development Working Group was established under the direction of the LTSTF as part of the Regional Planning Group. It was the intent of the Scenario Development Working Group to create internally consistent scenarios with variables driving the largest market impact in the ERCOT region. These variables included fuel costs, resource capital costs, generation market economics, emission regulations, technology mandates, impacts of drought, economic growth, and various public policies. Using these variables, ERCOT and the Scenario Development Working Group created the following scenarios: Business as Usual with five variations, Environmental with one variation, and Drought with two variations.

The scenarios developed for analysis resulted in a range of generation expansion portfolios that were not predetermined as part of the scenario definition. The resulting generation resources ranged from low renewable generation and higher amounts of fossil-fueled resources to scenarios with significant energy provided by renewable generation, which is discussed more completely in the generation expansion results section. The specific assumptions and inputs used in each scenario are described in the following sections.

Table 3 — Business as Usual Scenario Descriptions

	Business as Usual (BAU)					
	All Technologies	**Updated Wind Shapes**	**All Tech w/ PTC**	**All Tech w/ Retirements (NG units >50 yrs)**	**All Tech w/ Increased DC Tie Capacity**	**All Tech w/ High NG Price**
Moody's Employment	Base	Base	Base	Base	Base	Base
Weather Shape	Normal	Normal	Normal	Normal	Normal	Normal
Fuel Prices ($/MMBtu)						
Natural Gas	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref plus $5
Coal PRB	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref
Coal Lignite	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref
PTC	NO	NO	YES	NO	NO	YES
Emission Costs ($/ton)						
Seasonal NO_X	$0	$0	$0	$0	$0	$0
Annual NO_X	$0	$0	$0	$0	$0	$0
SO_2	$0	$0	$0	$0	$0	$0
CO_2	$0	$0	$0	$0	$0	$0
Retirement	Economic	Economic	Economic	NG at 50 years	Economic	Economic
Demand Response (MW potential)	**0**	**2,700**	**2,700**	**2,700**	**2,700**	**2,700**
Residential	0	1,100	1,100	1,100	1,100	1,100
Commercial	0	1,100	1,100	1,100	1,100	1,100
Industrial	0	500	500	500	500	500
Note		Added: Utility Solar PV, Geothermal, Biomass, Landfill Gas, Demand Response, Batteries, CAES, Gravity Power, and Internal Combustion Engines		Assumed all natural gas fired units were retired at 50 years of age. This resulted in approx. 13,000 MW of retirements. These units were steam gas units and two combined cycles.		

5.1.1 Business as Usual

The members of the Scenario Development Working Group requested that the analysis begin with a scenario that would allow for straightforward implementation of understood policies and assumptions so as to build an understanding of the capabilities of the tools and processes for this long-term study effort. A Business as Usual (BAU) scenario was developed to simulate current policies and market trends into the future. This scenario started with the development of the generation resource database described in Section 7.2. Cost information relied upon the EIA Annual Energy Outlook 2011 Reference Case, which included fuel forecasts, capital costs, and unit operating costs.[19] ERCOT escalated all cost information annually by the average rate of inflation over 20 years found in the EIA Annual Energy Outlook 2011.[20] That annual rate was 1.84%. The load forecast described in the load forecast development section used Moody's Base economic growth data with a normalized weather year. For the BAU scenario, ERCOT did not alter existing policies or regulations. When ERCOT and the stakeholders developed this base scenario, the PTC was set to expire in December of 2012. Accordingly, ERCOT assumed in this scenario the PTC would not continue beyond 2012. Other scenarios address the possible impacts of Congress extending the PTC. To understand fully the capabilities of the tools used in this study, ERCOT staff evaluated conventional thermal technologies and wind. At that time, wind generation was the only renewable resource that ERCOT had sufficient operational and cost data to fully model. ERCOT used this scenario to vet their new processes. The results were not especially meaningful, even as a base case, so they are not included or discussed further in this report. ERCOT presented a more complete discussion about this scenario in its interim report to the Department of Energy.[21]

5.1.2 Business as Usual with All Technologies

As the study progressed, ERCOT gained additional information regarding other renewable resources. This knowledge led to the development of the BAU with an expanded set of resource technologies, referred to as the BAU All Tech. The additional technologies included were solar, geothermal, compressed air energy storage (CAES), pumped storage Gravity Power, and some demand response programs. The solar technology evaluated in the generation expansion process was utility scale photovoltaic (PV). All other assumptions in the BAU All Tech scenario were congruent with the original BAU scenario. Table 3 contains a matrix of the key assumptions in the six BAU scenarios and variations studied by ERCOT for this report.

5.1.3 Business as Usual with Retirement of Natural Gas Fired Units Aged 50 Years and Older

Prompted by observed idling and retirement of some older gas-fired units, stakeholders expressed concern about the effect that additional unit retirements would have on the needs of the transmission system. To assess these impacts, ERCOT developed a version of the BAU All Tech with the retirement of natural-gas-fired units after 50 years of service. ERCOT chose a fifty-year life span because it exceeded the expected life of most natural gas steam generators when they were constructed.

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[19] *AEO 2010, AEO 2011, AEO 2012*, pp. 115-155. (Annual data were downloaded from www.eia.doe.gov.)

[20] *Ibid*., p. 58. (Annual data were downloaded from www.eia.doe.gov.)

[21] *ERCOT Interconnection – Long-Term Transmission Analysis 2010-2030 Interim Report*, ERCOT (Aug. 2011).

Supporting this concern was a recent report developed by ERCOT that indicated the implementation of new cooling water intake structure requirements could lead to the retirement of almost 10,000 MW of older gas-fired steam units in ERCOT.[22] As many of these legacy 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 after discussions ERCOT staff had with TCEQ. At the same time, the proximity of these legacy units to load centers means that they are relied upon to support system reliability during peak load conditions. As a result, the retirement of these units would likely increase the need for transmission system improvements significantly.

The possible retirement of coal-fired generation was not included in this BAU alternative because most coal-fired generation sites in ERCOT are not located in or around major load centers and thus represent prime locations for future brown-field generation. The potential loss of any coal-fired facilities would not be expected to have a significant impact on transmission needs because of probable generation replacement at that location. In this scenario ERCOT estimated approximately 13,000 MW of existing gas-fired generation retirements by 2032. The list of affected units and dates of retirement are provided in Appendix C.

While determining the retirement of generation on the basis of its age captured the obsolescence experienced by older generation plants, in the ERCOT market, the competitiveness of a plant informs owners whether or not to retire a unit, not its age. In response to stakeholder suggestions, ERCOT staff developed an economic retirement model for use in subsequent scenarios. The economic retirement model better matched the commercial decision each generator makes as its plant becomes less competitive in the ERCOT market. A more complete discussion about how the model works appears in the generation expansion methodology section of this report.

Also for this and all subsequent scenarios, ERCOT updated the capital cost forecast for utility-scale solar PV systems to reflect lower construction costs.

5.1.4 Business as Usual with Updated Wind Shapes

In May 2012, ERCOT procured new hourly wind generation patterns based on actual weather data from the previous 15 years. These updated wind patterns included new hourly wind output patterns for 130 hypothetical future wind generation units distributed throughout Texas, and were developed using power generation curves consistent with the most recent generation of wind turbine technologies. More discussion about the wind technologies appears

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[22] Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System-Revision 1, ERCOT (Jun. 2011).

in Appendix D. Each profile represents the historical wind speeds in its respective county. For existing generation, the output profiles reflected the installed technology. For expansion generation, the output reflected the latest technology with its improved operating characteristics. ERCOT incorporated these new wind profiles in this and all subsequent scenarios.

5.1.5 Business as Usual with Renewable Production Tax Credit Extension

Congress passed the Federal renewable generation Production Tax Credit (PTC) in 1992 to help spur additional economic growth in the industry. Because Congress has extended the tax credit several times, ERCOT developed a scenario in which the PTC remained in place through the entire 20-year planning horizon. The PTC is a tax credit available to various renewable energy projects (landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, hydrokinetic power, anaerobic digestion, small hydroelectric, tidal energy, wave energy, and ocean thermal) for the first 10 years of operations. This tax credit, which is earned on energy produced, began with an initial value of $0.015/kWh and has increased over time up to the current value of $0.022/kWh. Wind, geothermal, and closed-loop biomass technologies can receive a $0.022/kWh credit. Other eligible technologies can receive $0.011/kWh for their energy production. For the purpose of this study another tax incentive, the Business Energy Investment Tax Credit (ITC), was not evaluated because the final year of the ITC coincided with the first year of the expansion plan. In this study, ERCOT assumed the PTC would continue to increase at the rate of inflation (1.84% was used in this study).

5.1.6 Business as Usual with High Natural Gas Prices

A high natural gas price scenario was developed to assess the impact of increasing the price of this commodity on scenario results. In past years, the volatility of natural gas prices had a direct impact on the change of generation resources in the ERCOT region. In this scenario, ERCOT increased the base case price of natural gas by $5.00/MMBtu for all years, and assumed the PTC continued beyond 2012.

5.1.7 Business as Usual with Increased Asynchronous Tie Capacity

As projects to move power between electrical interconnects, like the intertie proposed by Tres Amigas, LLC and Pattern Energy Group's Southern Cross proposal, progressed further along in their developmental stages, ERCOT stakeholders requested a scenario reflecting additional asynchronous tie capacity between ERCOT and other regions.

The scenario was initially to be based on the BAU with updated wind shapes. However, after ERCOT staff analyzed the amount of curtailed wind in that scenario, it determined that there would not be significant inexpensive power, especially curtailed wind generation, available to flow on the additional DC Tie lines to make this scenario distinct. As a result, ERCOT staff chose the "Business as Usual with PTC" scenario, which had a larger amount of nameplate capacity of wind technology found to be economic, as the basis for this scenario. To that scenario, ERCOT added three additional DC ties. The tie to the east (SERC region) had a transfer capability of 3,000 MW, the tie to the west (WECC or SPP) had a capability of 2,000 MW and the tie to CFE (Mexico) had a capability of 1,000 MW for a total additional transfer capability of 6,000 MW to and from ERCOT.

5.1.8 Environmental

ERCOT stakeholders also expressed concern about the impact that new regulations from the U.S. Environmental Protection Agency (EPA) could have on generation in the ERCOT region. The environmental scenario accounts for several proposed regulations, including the proposed Cross-State Air Pollution Rule (CSAPR), 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 those using integrated gasification combined-cycle (IGCC) technology. To achieve these policy objectives, ERCOT reflected the proposed regulations and emission rates in existing regional markets to develop emission costs and limits to include in its production cost models. A high natural gas price was also included in this scenario, reflecting increased demand for natural gas because natural gas generation technologies produce fewer emissions of carbon dioxide, sulfur dioxide, and nitrogen oxides relative to coal plants. Because of concern over the environment, the Federal renewable PTC is assumed to continue in this scenario as well.

5.1.9 Environmental with DR/EE

As environmental regulations force generator owners to decide between incurring the cost of installing emission technology or retiring their power plants, the risk to resource adequacy increases. To reflect this resource adequacy concern, this scenario specifies that 10,000 MW of capacity be supplied by demand response programs by 2032 and that 15% of total energy in 2025 is met by energy efficiency programs. This scenario also included the imposed emission costs, continuation of the renewable PTC, and high natural gas prices used in the original environmental scenario.

5.1.10 Drought

In 2011, Texas experienced its worst single-year drought on record, which the news media publicized widely. Water availability in 2011 caused concern for many water users, including power generators. Through the ERCOT stakeholder process, many stakeholders expressed their concerns, which culminated in the development of drought scenarios for this long-term study effort. To include the impact of long-term drought conditions on likely resource development this scenario evaluated the impacts of increased water costs for new generation and unit capacity derations to existing thermal generating units.

ERCOT also worked with the Western Electric Coordinating Council (WECC), Sandia National Laboratories (Sandia), and Argonne National Laboratory to study the effects of long-term drought on power generation facilities throughout the western United States. This study was based on an analysis of surface hydrology, streamflow modeling, and reservoir storage. Groundwater, wastewater, and brackish groundwater costs were also included in this analysis.

Initial review of survey data provided by the generators and the actual unit history 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. Single-year droughts do not appear to significantly affect generation capacity because of storage buffers against short-term droughts. 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. Multi-year droughts affect generation capacity because of limited water supply availability and the temperature effects on power plant cooling. 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.

To complete an assessment of the potential impacts of a multi-year drought, ERCOT contracted with Black and Veatch (B&V) to review and extend the Sandia results. B&V reviewed current water costs by ERCOT-designated weather zone by water-usage type, including agricultural, raw water, treated water and wastewater. Water cost information from municipalities and water authorities was also reviewed. B&V also examined the need for additional infrastructure should new sources of water be required, and historical weather patterns by ERCOT weather zone.

To include the impact of future drought conditions on likely resource development, B&V developed water cost adders for each technology to reflect the additional costs of an extended drought. B&V designed these adders so ERCOT could include the additional costs into PROMOD IV and thereby consider those costs in resource expansion modeling and production cost calculations. As an example, water-cost adders for combined-cycle units across the weather zone regions are provided in Table 4.

Table 4 — Water Cost Adder by Weather Zone for Combined Cycle Units

Weather Zone	$/MWh
COAST	$0.22
EAST	$0.24
NORTH CENTRAL	$0.36
SOUTH CENTRAL	$0.38
NORTH	$0.44
SOUTH	$0.48
WEST	$0.63
FAR WEST	$0.76

By reviewing water supply availability data and reviewing annual and monthly rainfall patterns, reservoir/lake levels and withdrawals, and surface water temperatures, B&V developed assumed capacity deratings to existing thermal generation units in the event of a long-term drought. Figure 3 shows an example of the cumulative capacity derations of existing ERCOT resources over the last three years of an extended drought.

With this information ERCOT staff developed three scenarios to include into the long-term study to analyze the effects of a multi-year drought. For these scenarios load forecasts were developed by using Moody's Base economic assumptions to which the 2011 ERCOT load shape was applied.

The three drought scenarios were developed around the BAU All Tech scenario. All three of the drought scenarios contained the following two changes: First, capacity reductions for all existing thermal generation units were applied during the period of the drought, 2019 through 2025, attributed to a lack of water at existing plant sites and an increase in water intake/discharge temperatures. Second, development costs for new thermal generating expansion units were increased to reflect higher costs to acquire sufficient water for operation. Despite incurring water costs, ERCOT assumed any expansion units would use the best available technology so that water intake/discharge temperatures would not impact the maximum output for the unit. Existing units were not subjected to water usage costs because ERCOT assumed long-term water contracts already existed.

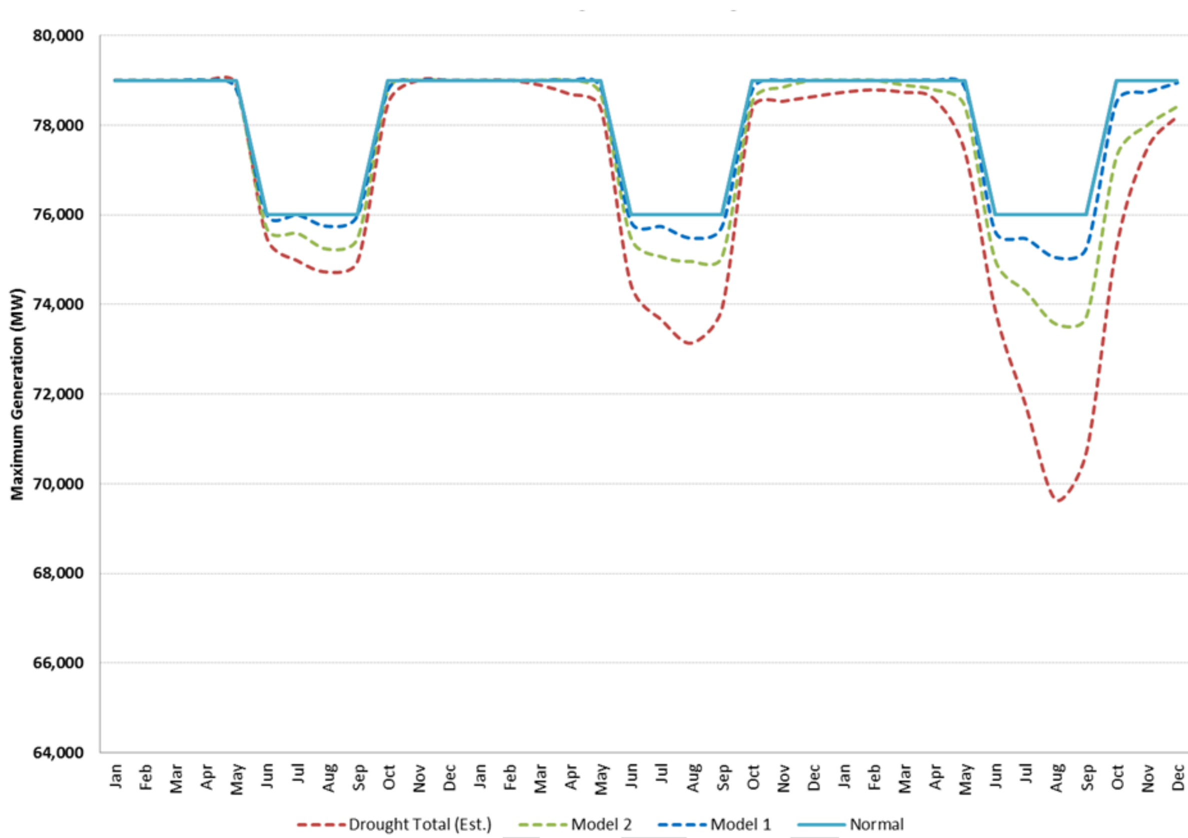

Figure 3 — Example Multi-Year Drought Capacity Deration

The second drought scenario differed from the first by reducing the baseline natural gas price forecast by $2/MMBtu for all years. ERCOT developed this scenario to emulate the weather and market conditions Texas experienced in 2011, harsh drought, high temperatures, and relatively low natural gas prices. The third scenario started with the assumptions in the first drought scenario and included the extension of the wind production tax credit and placed emission costs on all fossil-fueled thermal units. The first three columns of Table 5 allow display the assumptions in the three drought scenarios.

Table 5 — Weather and Environmental Scenario Descriptions

	Drought			Environmental	
	Water Impacts	**Water Impacts w/ Low NG Price**	**Water Impacts w/ PTC & Emission Costs**	**Base**	**Base with DR/EE Mandates**
Moody's Employment	Base	Base	Base	Base	Base
Weather Shape	2011 Summer	2011 Summer	2011 Summer	Normal	Normal
Fuel Prices ($/MMBtu)					
Natural Gas	EIA Ref	EIA Ref Minus $2	EIA Ref	EIA Ref plus $5	EIA Ref plus $5
Coal PRB	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref
Coal Lignite	EIA Ref	EIA Ref	EIA Ref	EIA Ref	EIA Ref
Continuation of PTC	NO	NO	YES	YES	YES
Emission Costs ($/ton)					
Seasonal NO_X	$0	$0	$600	$600	$600
Annual NO_X	$0	$0	$1,500	$1,500	$1,500
SO_2	$0	$0	$700	$700	$700
CO_2	$0	$0	$25	$50	$50
Retirement Methodology	Economic	Economic	Economic	Economic	Economic
Demand Response (MW potential)	**5,200**	**5,200**	**5,200**	**7,400**	**10,700**
Residential	1,100	1,100	1,100	2,200	4,400
Commercial	1,100	1,100	1,100	2,200	3,300
Industrial	3,000	3,000	3,000	3,000	3,000
Notes	Drought conditions modeled: water usage cost for new units or dry-cooling technology capital costs; unit derations in summer months for 2019-2025	Drought conditions modeled: water usage cost for new units or dry-cooling technology capital costs; unit derations in summer months for 2019-2025	Drought conditions modeled: water usage cost for new units or dry-cooling technology capital costs; unit derations in summer months for 2019-2025	Policies modeled: CSAPR, MATS/NESHAPS with compliance by 2015. Additionally, no new pulverized coal; IGCC technology only.	Included: DR Mandate for 10,000 MWs by 2032 and 25% of total energy met by energy efficiency by 2025.

6 Load Forecast Development

Key to any long-term transmission plan is the forecast of electricity load. The changes in electricity consumption contribute to future transmission needs as do new generation technologies, generator obsolescence, and economic, commercial, and policy factors. Transmission planning studies the reliable movement of electricity from generation to consuming load locations, therefore planners need to know what resources can provide electricity but also they must know 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 so transmission planners can study load, generation, and transmission needs for those various futures.

For this long-term plan, ERCOT developed three forecasts for the region. ERCOT based these forecasts on a set of econometric 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 and demand forecast models. Economic and demographic data, including a county-level forecast, were obtained on a monthly basis from Moody's Economy.com. Fifteen years of weather data were provided by Telvent for 20 weather stations in ERCOT.

Three different forecasts were created to support the study scenarios:

- Business as Usual (BAU),
- Drought, and
- Energy Efficiency Mandate.

The majority of the planning scenarios relied on the business as usual load forecast. The BAU forecast served as the base forecast for the ERCOT region. It did not include any significant changes for energy efficiency, demand response, distributed generation, and plug-in electric vehicles over the levels that were observed during the historical time period (2002–2011) and used "normal" weather forecasts.

The three scenarios intended to study the long-term impacts of extreme weather, especially low precipitation, relied on the load forecast adjusted for the higher-temperatures and other weather conditions associated with drought. The drought forecast assumed that a prolonged drought will be experienced over the study period. This forecast was based on using the harsh weather from 2011 for each year of the study period.

The energy efficiency mandate peak-load forecast reflected an ambitious goal to reduce electricity consumption by introducing greater efficiency into the market. Such goals affect the amount of electricity consumed directly. The Energy Efficiency Mandate forecast was based on the DOE's Energy Information Administration's (EIA) "Best Available Demand Technology" case from its 2012 Annual Energy Outlook.[23] This case was selected because it was the only case in the EIA's Annual Energy Outlook (2012) to achieve the scenario's assumption that 15% of load be met by energy efficiency by 2025. From a load impact perspective, this forecast reflected the greatest load reduction contained in the EIA's Annual Energy Outlook. As an example, this case assumed LED technology would be used for residential lighting. It also included a large reduction in technology costs and improvement of building standards. Like the business as usual forecast, the energy efficiency load forecast reflected a normal weather forecast. Only the energy efficiency and demand response scenario used this low-load forecast.

The summer peak demands for the three forecasts are shown in Figure 4. The business as usual forecast, which served as the base case load forecast for the business as usual scenarios, showed 2.0% average peak load growth through 2032 when it reached a system peak of 97 GW. For the drought scenario forecast peak demand grew at a 1.9% annual average. Peak demand in the drought forecast reached 107.5 GW in 2032, roughly 10 GW higher than the business as usual forecast. By 2026, the higher load forecast for the drought scenarios exceeded the 2032 peak load for the business as usual forecast. With the differences between these forecasts provided ERCOT could study how higher than normal load growth could accelerate the need for transmission upgrades. On the other hand, the energy efficiency mandate forecast, with its aggressive demand reduction inputs, exhibited only a few years of growth before flattening out after 2018. For the 20-year forecast period, this forecast showed only 0.4% annual growth in peak demand. The assumed efficiency measures held the forecasted 2032 system peak demand, 72.2 GW, to an amount below the 2013 peak demand for the drought scenario forecast. These forecasts represented very different possible load futures for the ERCOT region. Figure 5 shows the average annual growth rates for the three load forecast scenarios compared to the actual load growth ERCOT experienced between 2002 and 2012.

[23] *AEO 2011*.

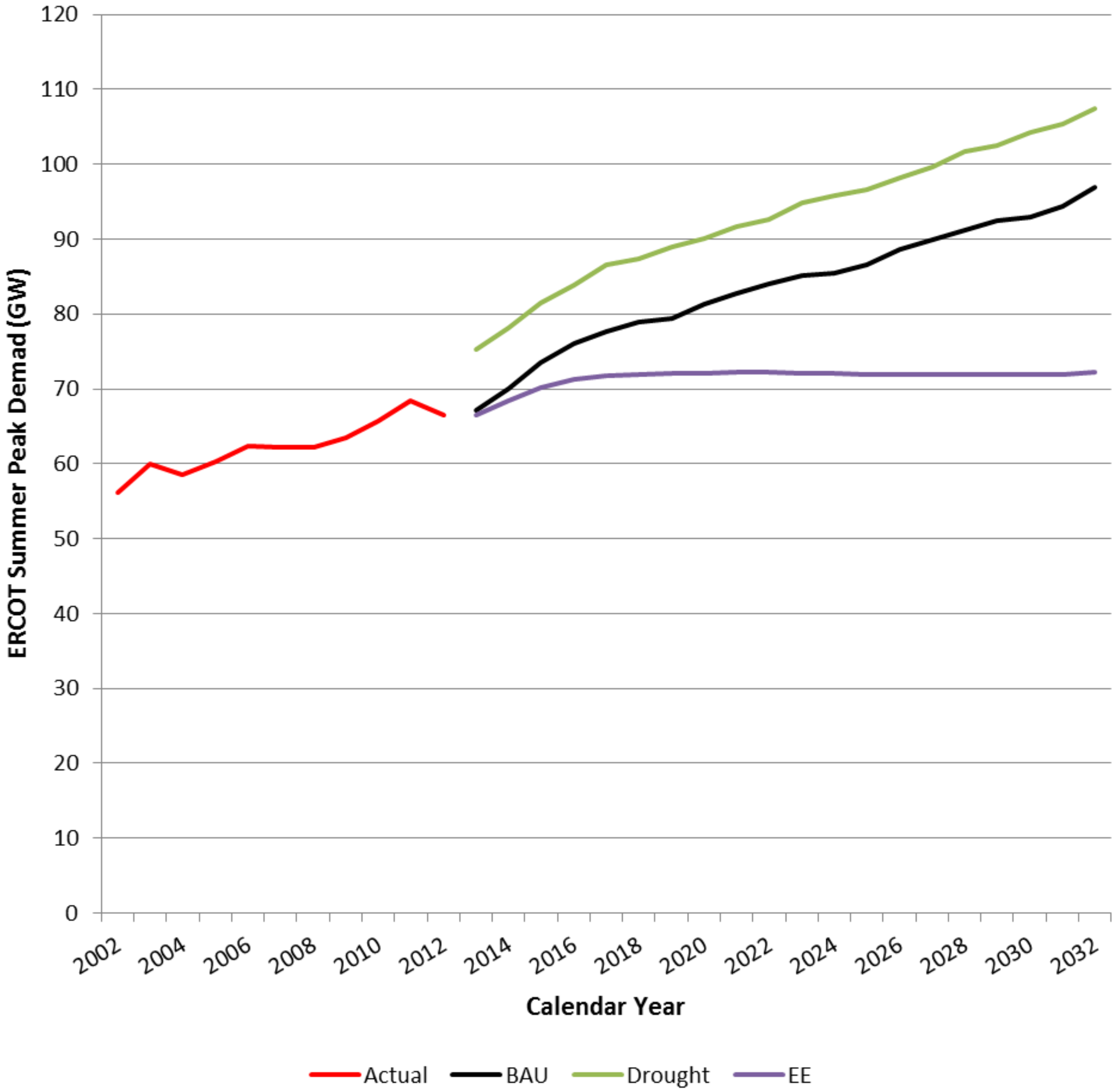

Figure 4 — ERCOT Summer Peak Demand Forecast

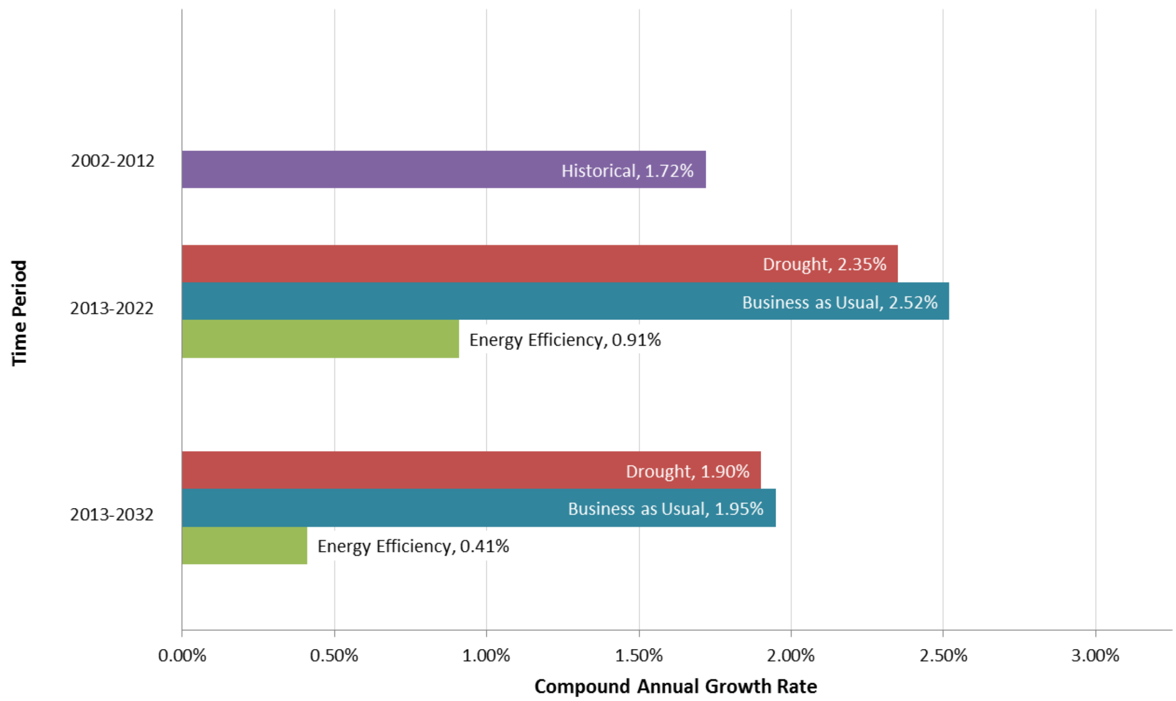

Figure 5 — Comparison of Load Growth Rates

6.1 Forecast Development

The load forecasts were produced using a set of econometric and neural network models that combine weather, economic, and calendar variables to capture and project the long-term trends extracted from historical load data. The long-term trend in monthly energy was modeled separately for each of the eight weather zones in ERCOT. The models incorporated economic, demographic, and weather data to develop the monthly energy forecast.

After the calculation of the monthly energy forecast, the development of the hourly load forecast required the allocation of that monthly energy to each hour in the month. A total of 864 neural network models were developed to produce hourly energy allocations for the twelve months. ERCOT validated the models by backcasting the hourly load allocations against several years of historical hourly load. Model validation was conducted by using historical monthly energy in the modeling networks to backcast the hourly loads for each day in the historical load database.

A key input of both energy models is the forecasted weather. A normal (typical) weather hourly profile is used in both models. 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 50/50 forecast.

ERCOT's analysis included 15 years of weather data (1997–2011). The methodology that ERCOT selected to create the "normal" weather year ranks monthly weather data based on temperature extremes (hot temperatures in the summer and cold temperatures in the winter) and on the average temperature for each weather zone. The "normal" weather month is determined by selecting the historical month which is closest to the median, based on extreme and average temperatures. The next step is to time-align the date of the monthly maximum or minimum temperature. This is necessary because different historical years of weather data (for each weather zone) can be used for a particular month, which results in understating ERCOT's coincident peak demand.

Another key input of both energy models is the forecast of non-farm employment. The current condition of the United States economy and its future direction is an element of great uncertainty. Texas thus far has not been affected to the same extent as the United States as a whole by the current economic downturn. 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.

The ERCOT stakeholders participated in the identification of factors to consider and assumptions to form the basis of the load forecasts. From the comments made by stakeholders at the Long-Term Planning Working Group meetings, stakeholders realized that population growth is a direct driver of energy use. Additionally, stakeholders expressed interest in the factors that cause load growth, such as Texas attracting business to move here and whether the historical drivers of Texas growth will also drive future growth. Conversely, the stakeholders discussed factors that reduce electric load growth such as energy efficiency programs, building envelope standards, unanticipated technology changes, load-reduction opportunities identified from smart meters, and load being at least partially served by self-generation. Generally, the stakeholders recognized the uncertainty inherent in a long-term electricity load forecast and the numerous factors that contribute to that uncertainty.

7 Generation Expansion Methodology and Process

7.1 Resource Expansion Tools

In forecasting the transmission needs of the ERCOT system, an analysis of likely generation resource additions and retirements follows the development of the load forecast. Because historically peak load has increased over time, new resources will need to be developed to serve the future increase in load and maintain system reliability. This section describes the tools acquired and developed to conduct resource expansion analysis for the long-term study.

ERCOT modeled the resource expansion process to develop resource portfolio outcomes consistent with the deregulated energy market in the region. To mimic the commercial decisions of generation developers and investors, ERCOT assumed that market conditions and expected market return would drive firms' investment decisions. The resource expansion process was designed to lead to a reasonable resource expansion, consistent with the current ERCOT market design, projected load requirements, and grid operating constraints. The generation expansion process captures, as closely as possible, the market conditions that are apparent to a specific generating resource and to add resources that appear economically viable because they will provide adequate return on investment.

ERCOT designed its process to capture and evaluate the sequential, interval-by-interval interactions of traditional thermal generation, intermittent generation and other resources in a competitive market. To model the relative values of the intermittent resource technologies, ERCOT believed its modeling must have at least hourly granularity. Further, ERCOT considered the use of a sequential interval model as the best way to capture the operational and financial merits of the various resource technologies. Most importantly, ERCOT believed that its approach would produce more representative financial results than a duration curve model. A sequential model would more accurately represent the financial and operational characteristics of the various technologies within a given interval, which would result in a resource expansion plan that better reflected the market entry decisions developers must make.

To identify tools that allowed ERCOT to conduct this analysis, ERCOT staff issued an RFP in 2010 for production-cost modeling software to be used to analyze expected market prices and operating revenue of new resources. ERCOT staff attended presentations delivered by multiple vendors and completed the competitive bidding process by selecting PROMOD IV and Market Power from Ventyx. To complement this suite of software tools, ERCOT developed a pro-forma financial analysis tool and an economic retirement analysis tool to measure the financial return on investment of expansion and existing resources.

PROMOD IV models hourly dispatch of the electricity grid and provides unit-specific operation and production cost values given user-defined inputs (e.g. load, transmission constraints, fuel costs, etc.). The program performs a security-constrained unit commitment and economic dispatch that is co-optimized with operating reserve requirements. It also provides the capability to conduct multi-year, detailed generating unit cost and revenue analysis, asset profitability assessments, locational marginal price calculations, congestion revenue right valuations, transmission analysis, and reliability studies. PROMOD IV also provides information on the dynamics of the marketplace through its ability to calculate and assess the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. Additionally, PROMOD IV simulates the effects of intermittent energy scheduled from wind and solar generation on transmission congestion and forecasts the amount of energy that would be curtailed given transmission and operational constraints. Ultimately, PROMOD IV calculates the hourly revenue and hourly costs of each resource; annual output of revenue and costs can be used to assess the market returns of each resource.

Market Power is a long-term generation expansion modeling platform that performs a quick economic analysis based on user-defined input assumptions. The model relies on a database of existing resources and determines any additional capacity needed to service a user-defined reserve margin and load forecast. Market Power determines the annual economic viability of a generation project, based on expected operating levels, market revenues and operating costs to determine when and what type of new prototype units would be added to the resource mix.

By considering the marginal costs of the generating resources in the market, the simulation in Market Power creates market-based expansion plans by using various input assumptions. Both existing units and generating units considered for possible expansion, called “prototypes,” have generic operational characteristics specific to the resource technology categories built for this study. Table 6 and Table 7 show the operating characteristics of the existing generation resources and the expansion generation resources, respectively. These resource categories can be found in Appendix C. In addition to operational characteristics, the prototype units also have capital cost and investment assumptions.

ERCOT developed a pro-forma financial spreadsheet tool to assess the economic viability of expansion units in the generation expansion process. The pro-forma financial spreadsheet provided an external analysis to compare the PROMOD IV operational results and the expansion build-out suggested by Market Power. The pro-forma tool accounts for items such as corporate taxes, project financing structure, and the renewable PTC, which cannot be modeled in Market Power. The pro-forma spreadsheet, developed with the same financing assumptions for all technologies (debt/equity ratio, cost of debt, cost of equity, etc.), used the revenues and operating costs from the PROMOD IV output, along with technology-specific capital costs and fixed costs to measure the financial viability of proposed expansion resources.

From a single year of PROMOD IV revenues, the pro-forma analysis tool forecasted future-year revenues based on a fixed escalation rate, consistent with the escalation rate inherent to the natural gas price forecast. As natural gas is the marginal fuel in most hours in the ERCOT market, this assumption is reasonable for scenarios that result in a unit economic dispatch similar to current market conditions.

The pro-forma analysis tool assumed a resource investment financing of 55% debt to 45% equity, with an 8% cost of debt and a 15% cost of equity. ERCOT developed these financial factors in consultation with the stakeholders. The economic life of the plant varied according to the technology; that information appears in Table 7. The pro-forma financial spreadsheet used the revenue stream, production costs, and the financing assumptions to calculate a net present value (NPV) of each project. Economically viable projects yielded positive net present values.

The generation expansion process included one final tool designed to perform economic retirement analysis. Every three years, this tool evaluated existing units' and previously built new units' profitability in the simulated market by using a polynomial equation with a weighting mechanism that took into account the three metrics of unit profitability, age, and efficiency. From this equation ERCOT calculated a unit's total retirement value. While not the only factor considered in the retirement evaluation process, units with higher calculated retirement values had a greater likelihood for economic retirement than units with lower retirement values.

Each metric was broken into five or six ranking groups with lower ranking values assigned to more favorable characteristics, such as better efficiency or younger plant age. The higher the unit's total retirement value, the higher probability of that unit being retired. If the individual unit's retirement value exceeded the mean retirement value of all units by over two standard deviations for two consecutive evaluations, ERCOT considered that unit no longer economic in the simulated market.

To utilize the strengths and efficiencies of each of these tools, ERCOT developed a general process for evaluating potential resource expansion that combined model output from PROMOD IV and Market Power, which were then evaluated through the pro forma and retirement analysis tools. Although PROMOD IV can evaluate transmission constraints in its analysis, ERCOT used it for the resource expansion analysis without considering these constraints; i.e., as though all resources had full deliverability to load. This approach provided results that indicated the overall market viability of different resource options, rather than market opportunities in specific areas or even specific buses of the ERCOT system. In addition, given the market design of the ERCOT system (wherein resources can site anywhere and all transmission upgrades are paid for by load customers), it is consistent with the likely market outcomes to begin this long-term analysis without constraining generation based on potentially short-term localized market conditions.

In the ERCOT region, transmission is typically built to connect competitively developed generation to load. If transmission were taken into account, it would be difficult to perform a 20-year generation expansion plan without evaluating and upgrading the transmission system concurrently. To avoid that complication, ERCOT assumed that the transmission system would receive the necessary upgrades to move power from existing and expansion resources to load reliably and no transmission constraints limited the generation expansion process. Separating these steps allowed ERCOT to complete the resource expansion plan more quickly first with the more time-consuming transmission expansion plan following. This approach also permitted ERCOT to be more selective when identifying the scenarios for which it would develop long-term transmission plans, which is discussed further in Section 9.

7.2 Resource Expansion Database

To focus on long-term regional system needs, and to allow stakeholder access to all modeling data, ERCOT staff created a generation database with representative, generic characteristics for all units in the ERCOT system, based on the unit data available in the Capacity, Demand, and Reserves Report (CDR). Table 6 contains a list of the technology categories developed for the unit generation database. All existing units were assigned to one of these generic unit categories.

Table 6 — Existing Units' Generic Characteristics

Technology	Heat Rate	Min Capacity	Min up time	Min down time	Variable O&M	Fixed O&M	Start Cost	NOx	SO2	CO2
	Btu/MWh	%	hrs	hrs	2011$/MWh	2011$/kW-yr	2011$	lbs/MWh		
Gas Steam Reheat	12,000	38.41	8	8	8.00	13.25	2,500	0.11	0.0006	118
Gas Steam Non-Reheat	13,000	43.13	8	8	5.00	20.50	2,500	0.11	0.0006	118
Supercritical Gas Steam	11,000	28.52	8	8	6.50	15.75	2,500	0.11	0.0006	118
Combustion Turbines (LM6000)	9,500	36.58	1	1	8.00	8.25	2,000	0.11	0.0006	118
Combustion Turbines ("E" Class)	11,500	25.03	1	1	4.00	5.00	1,000	0.11	0.0006	118
Older Combustion Turbines	14,500	25	1	1	5.00	11.00	-	0.11	0.0006	118
Combustion Turbines (LMS 100)	9,200	25	1	1	13.00	10.25	10,000	0.11	0.0006	118
Nuclear	10,000	N/A	168	24	4.00	73.00	-	N/A	N/A	N/A
Coal	9,800	47.44	24	12	5.00	25.50	5,000	0.13	0.8400	218
Combined Cycle (LM6000)	8,000	36.58	4	8	5.00	12.00	5,000	0.11	0.0006	118
Combined Cycle ("E" Class)	8,500	24	4	4	3.00	13.50	3,000	0.11	0.0006	118
Combined Cycle ("F" Class)	7,200	32.2	6	4	3.00	13.25	10,000	0.11	0.0006	118
Combined Cycle ("G&H" Class)	6,700	62.5	6	8	2.90	12.00	15,000	0.11	0.0006	118
Biomass	13,000	25	8	6	9.50	13.25	2,500	N/A	N/A	N/A
Diesel (Internal Combustion Engines)	9,800	20	1	1	3.50	11.50	500	0.018	0.0006	119
Wind	N/A	N/A	N/A	N/A	-	29.25	N/A	N/A	N/A	N/A

ERCOT developed the operational characteristics of each category by using a combination of information sources, including the Energy Information Administration (EIA), Generating Availability Data System (GADS), Continuous Emissions Monitoring System (CEMS), Environmental Protection Agency (EPA), software vendor supplied data, and industry research.

ERCOT worked with knowledgeable stakeholders in the planning groups and the Demand-side Working Group and the Emerging Technologies Working Groups to select emerging technologies to include in future scenarios and to evaluate the potential impact of these new technologies on the ERCOT system. The technologies chosen for evaluation in the generation expansion process were derived from EIA's Annual Energy Outlook 2011, preview released November 2010, and industry research of various technologies currently in the market place or in the research and development phase. Overall, ERCOT staff initially reviewed more than 30 technologies. Ultimately, ERCOT included numerous technologies in its evaluation, including conventional thermal and emerging resource types. Appendix D contains summaries of some of the technologies evaluated for this analysis.

ERCOT utilized EIA's Annual Energy Outlook 2011 as well as various other public sources for the operational characteristics, capital costs, operating and maintenance costs, and fuel price forecasts for these additional technologies. From these sources ERCOT developed profiles to include in the resource database for the additional prototype units. Appendix E contains a compilation of the operating characteristics of the different generation technologies. The fuel price forecasts for these technologies appears in Appendix F

Table 7 — Expansion Units' Generating Characteristics

Technology	Capacity	Heat Rate	Min Capacity	Min up time	Min down time	Variable O&M	Fixed O&M	Start Cost	NOx	SO2	CO2	Economic Life
	MW	Btu/kWh	MW	hrs	hrs	2011$/MWh	2011$/kW-yr	$	lbs/MWh			yrs
Conventional CC (F type)	500	7,200	200	6	8	2.65		10,000	0.03	0.0006	119	20
Advanced CC (H/G type)	650	6,700	250	6	8	2.90	14.62	15,000	0.03	0.0006	119	20
Conventional CT (F type)	170	10,500	130	2	3	8.00	6.98	7,500	0.01	0.0006	119	20
Advanced CT (LMS100)	100	9,200	70	2	3	13.00	6.70	10,000	0.01	0.0006	119	20
Supercritical Coal	750	9,000	250	24	12	3.95	29.67	5,000	0.06	0.06	220	30
Supercritical Coal W/ CCS	625	11,950	250	24	12	7.35	63.21	7,000	0.06	0.06	11	30
IGCC	625	9,000	250	24	12	6.00	5.00	5,000	0.03	0.0006	119	30
IGCC W/ CCS	539	10,700	250	24	12	7.00	69.30	7,000	0.03	0.0006	6	30
Nuclear	1,150	10,300	600	168	48	4.00	88.75	-	N/A	N/A	N/A	40
On shore Wind	100	-	-	-	-	-	28.07	-	N/A	N/A	N/A	20
Geothermal	50	11,000	20	8	8	10.00	84.27	-	N/A	N/A	N/A	20
Biomass	40	13,000	15	8	8	9.50	100.50	2,500	N/A	N/A	N/A	20
Solar PV	500	-	-	-	-	-	16.70	-	N/A	N/A	N/A	20

Capital cost estimates for the various technologies were also taken from EIA's Annual Energy Outlook 2011. New and developing technologies often experience declining capital costs in their early years. To create a forecast of prices that account for technological advancement, economies of scale, and information learning, ERCOT staff used estimates from a study conducted by Pace Global for Austin Energy in July 2009.[24] The estimates created represented early, middle, and late time periods, defined as 2009-2015, 2016-2022, and 2023-2030,

[24] *Assumptions and Market Drivers Document for Focused Integrated Resource Planning Analysis: ERCOT-Prepared for: Austin Energy*, Pace Global (Jul. 2009).

respectively. ERCOT staff applied the price trends, in percent changes, to the EIA values of all technologies to develop a forecast of capital cost assumptions. The full forecast of capital costs can be found in Appendix G.

After including the additional technologies in the analysis, ERCOT staff acquired updated cost and operational information for wind and solar technologies from stakeholders. In April 2012, ERCOT began using reduced capital cost forecasts for wind and solar PV because of economies of scale and technological advancement relating to the increase in development of these technologies in the ERCOT region. Figure 6 shows the adjustment of capital cost forecast to both wind and utility-scale solar PV technologies used in this study.

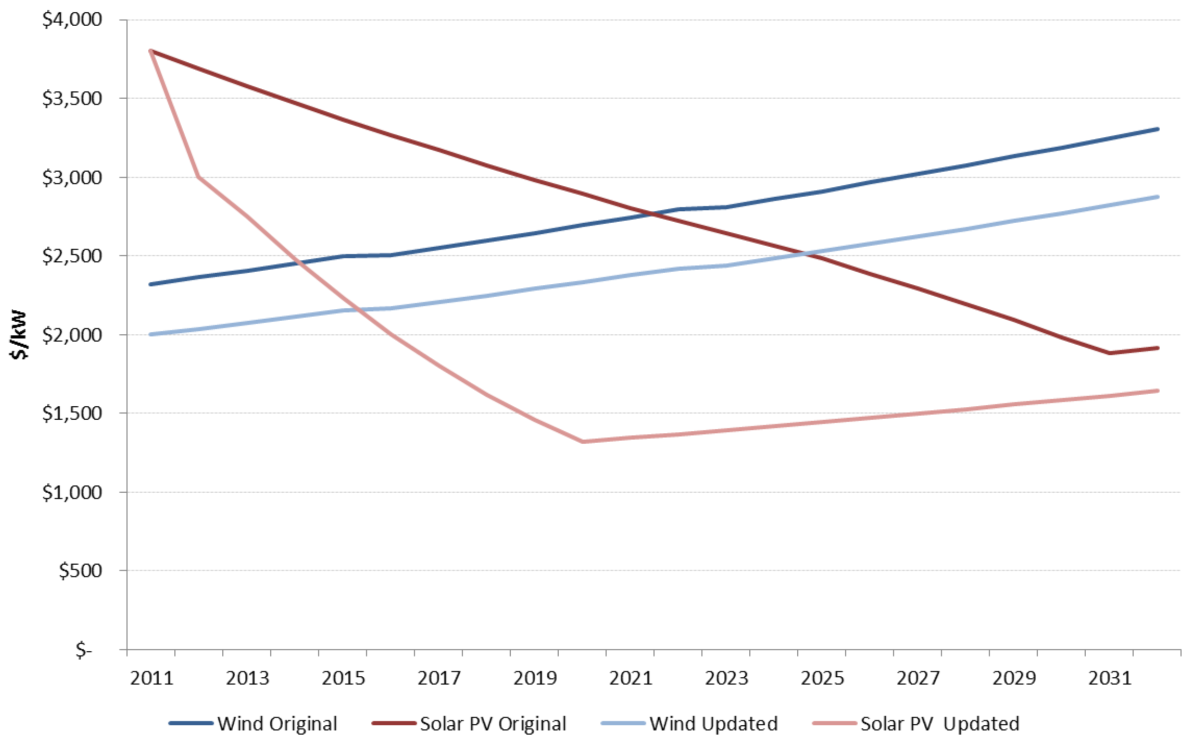

Figure 6 — Original and Updated Wind and Solar Capital Cost Forecasts

7.2.1 Intermittent Resource Data/Modeling

In an effort to enhance its planning capabilities, ERCOT obtained specific wind and solar hourly profiles to understand better the economic viability and operational reliability issues that occur with these technologies. In January 2012, ERCOT engaged AWS Truepower through a competitive selection process to provide 15 years of wind power data for existing, planned, and hypothetical sites in Texas. These data were based on high-resolution simulations of historical climate covering the period 1997 through 2011. An explanation of the methodology AWS Truepower used to develop these hourly profiles can be found in Volume 2 of this report.

ERCOT can now conduct more accurate analyses of wind integration impacts by using the updated data for existing units and 130 unique hourly forecasts for hypothetical wind units.

Historically, ERCOT had not needed detailed solar output profiles for planning because the economics did not favor utility-scale solar generation development. The declining capital costs of solar technologies have made possible the development of solar generation within the long-term planning horizon. In December 2012, ERCOT contracted with URS to develop hourly solar output profiles from potential solar installations of varying sizes, technologies, and geographical locations throughout Texas. URS provided ERCOT with 20 years of estimated hourly energy output for four different solar technologies (CSP, PV Fixed Tilt, PV Single-Axis Tracking, and Residential) derived by using data from 34 different weather stations.

Figure 7 shows the capacity factor differences among different locations across Texas. Notice the higher capacity factors for Lubbock and Dallas when compared to Austin or Houston. The updated solar data reflected the higher quality of solar resources available in western or northern Texas and supported ERCOT's choice to rely on location-specific information for evaluating the relative economics of different areas when siting expansion resources.

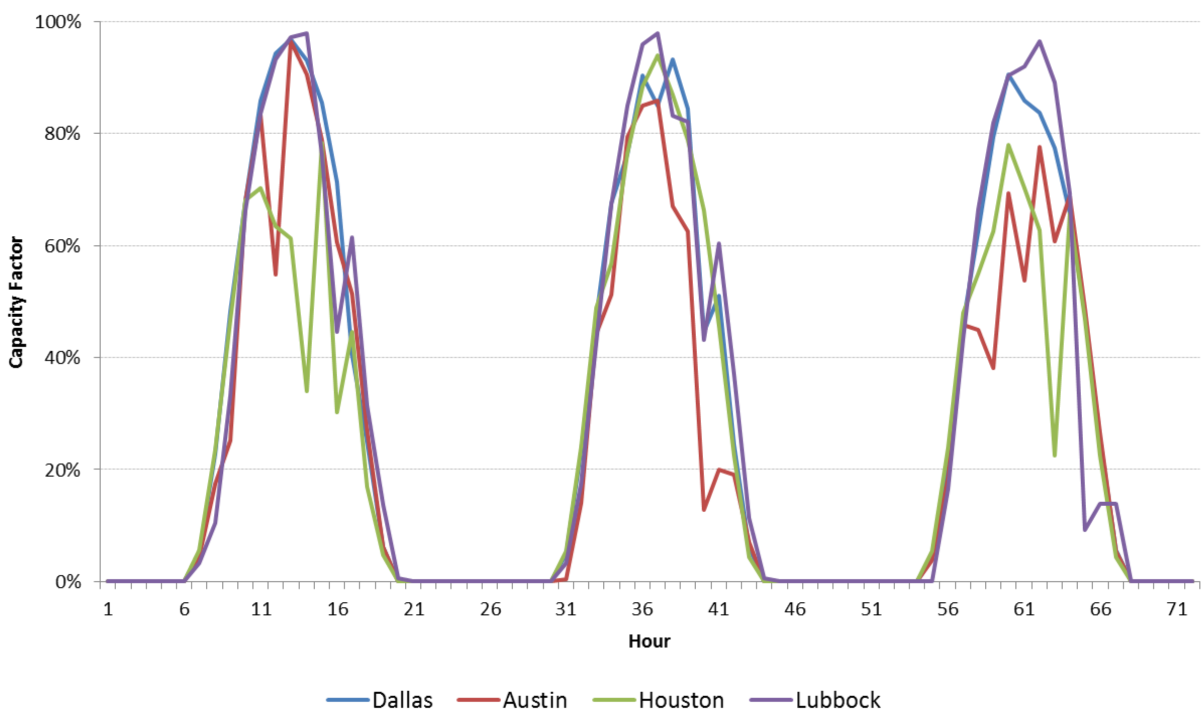

Figure 7 — Solar PV Capacity Factor Comparison across Texas for a 72-hour Period in August of Hourly Output

7.3 Resource Expansion Process

The generation expansion process involves an iterative approach using results from PROMOD IV, Market Power, and the pro-forma financial and economic retirement analysis tools. Initially, ERCOT started its resource expansion plan in 2014 to align with the assumed three-year construction period typical of many technologies. After completing the first scenario, ERCOT pushed the starting year back to 2016 to provide an easier transition between the generation expansion process and the transmission planning process, which has a longer lead-time. The 2016 start year also created a build year in 2022 that aligned with the 2012 LTSA study end year. A more detailed explanation of these steps follows. Figure 8 depicts the process in a flow chart example.

The iterative process began by running PROMOD IV in three-year increments, beginning in 2014 for the first scenario and 2016 for all subsequent scenarios. After PROMOD IV runs, ERCOT tested the revenues received by the existing units in the economic retirement analysis tool to determine their future market viability. The process for using this tool included a multi-year look at the value of a generating unit before it could be retired. If a generating unit met the retirement criteria described in Section 7.1 in 2016, it was placed on a risk assessment list. ERCOT would only retire a unit if it appeared on the risk assessment list for two consecutive analysis years. A unit could not be retired in the first study year, 2016.

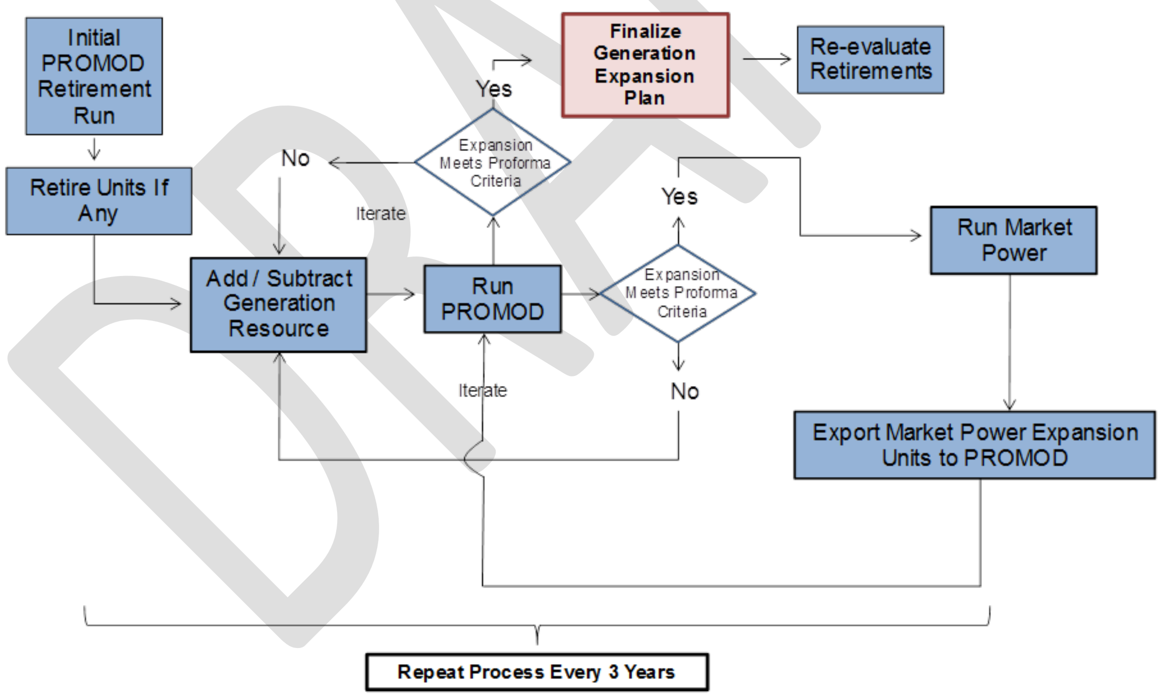

Figure 8 — Generation Expansion Process Flow Chart

From a second PROMOD IV run, ERCOT evaluated the energy-limited resource revenues in the pro-forma analysis tool to determine their economic viability in the market as measured by financial metrics developed by ERCOT in consultation with the stakeholders. If the resulting PROMOD IV revenue forecast generated a revenue stream over the life of the project that created a positive NPV and an internal rate of return (IRR) at or above 16%, then the energy limited resource remained in the expansion plan. Otherwise, ERCOT removed the unit from the expansion plan. If the resource remained in the expansion plan, then ERCOT executed PROMOD IV with a second increment of energy-limited resources. ERCOT repeated this process until the last additional energy-limited resource selected by PROMOD IV did not meet the IRR threshold. Figure 9 below, cut out from the full process graphic above, illustrates this first iterative step.

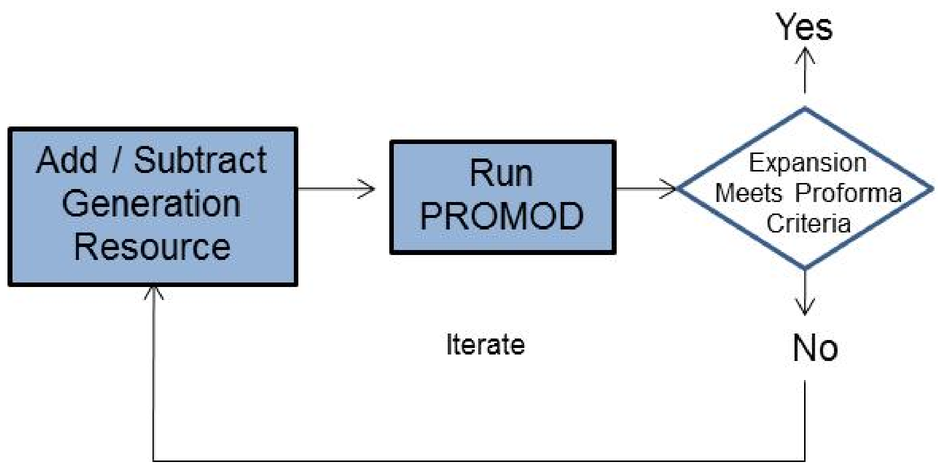

Figure 9 — Initial Energy-Limited Resource Iterative Process

After finalizing the amount of energy-limited resources in 2016, ERCOT ran Market Power from 2016 to 2032 to determine the initial conventional thermal expansion plan for 2016. ERCOT exported the resulting Market Power expansion plan to PROMOD IV, which was re-run for 2016 with the Market Power prototype units constructed in 2016, including any energy-limited resources found to be economically viable in the previous step. ERCOT tested the resulting revenue for the prototype expansion units in the pro-forma analysis tool in the same manner and against the same threshold as it did for the energy-limited resources. In an iterative process, ERCOT ran PROMOD IV and the pro-forma analysis tool to determine the best combination of energy-limited resources and conventional thermal generation from the Market Power build out. Figure 10 below, cut from the full process graphic above illustrates this final iterative step.

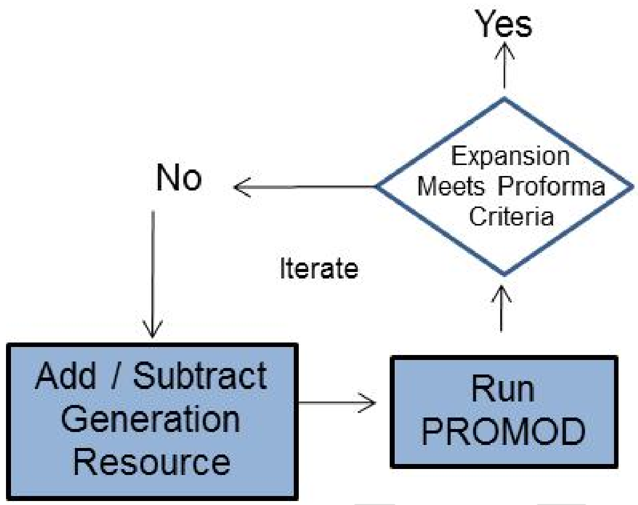

Figure 10 — Final Resource Expansion Iterative Process

Ultimately, ERCOT determined the best combination of units through a two-step decision making process. In the first step, ERCOT made sure all units in the expansion plan met the IRR threshold of 16%. In the second step, ERCOT selected the expansion plan with the lowest system production cost if more than one plan met the IRR threshold. For this second step, ERCOT compared the resulting total system production cost of the various expansion plans to select the least-cost alternative.

As soon as ERCOT finalized the expansion plan (with both energy-limited resources and conventional thermal generation) for 2016, the process repeated for 2019.

ERCOT repeated this process for a total of six simulation years: 2016, 2019, 2022, 2025, 2028, and 2032. After ERCOT finalized the full generation expansion plan (accumulation of the interim years' expansion plans), ERCOT sited the units at specific buses using the generation siting process. Section 9.1.2 of the report contains a detailed description of the siting process.

8 Generation Expansion Results

ERCOT observed varied results among the generation expansion plans for the different scenarios. The different scenario assumptions resulted in expansion plans with different mixes of generation technologies. In many instances, the results were intuitive. A scenario with a higher natural gas price forecast would produce a resource expansion plan with less natural gas generation. The converse also held true with low natural gas price forecasts resulting in greater natural gas generation development vis-à-vis the other scenarios. Correspondingly, the average clearing price for electricity noticeably increased and decreased with gas price forecast changes.

The sections that follow include discussions about specific observations reached from the various expansion studies. The results provide some general conclusions useful in long-term planning. First, no scenarios included coal or nuclear generation in the expansion plan. These traditional base-load generation technologies were not economic under the assumptions studied. In the later years of the study, several scenarios included geothermal and solar generation, possibly foreshadowing the addition of new technologies to the ERCOT region at locations suited to exploit their respective primary energy sources. On the other hand, another renewable generation resource, biomass, did not appear in any expansion plans.

Natural gas and wind generation dominated the expansion plans. The various scenarios produced very different mixes of these technologies, even differences between the natural gas technologies. A common characteristic of the dominant expansion technologies is the relatively short lead time for their construction. From a planning perspective, the development of these generation types will only become certain a few years before commercial operation. Even in the latter years of ERCOT's near-term plan, the addition of these generation technologies may not be known with certainty. Table 8 shows the generation expansion build out for all scenarios in 2032, the final year of the study.

Table 8 — 2032 Scenario Results Summary

Description	Units	BAU All Technologies	BAU Retirements	BAU Updated Wind Shapes	BAU High NG Price	Environ-mental	Drought	Drought Low NG Price	Drought Emissions & PTC	Environ-mental EE & DR	BAU w/ PTC	BAU Increased DC Tie Capacity
Total CC Adds	MW	13,200	8,500	3,600	-	-	3,600	4,400	10,400	-	-	8,400
Total CT Adds	MW	7,400	19,800	7,140	400	2,890	13,090	15,295	170	-	-	680
Total Geothermal Adds	MW	-	-	-	3,600	3,600	3,600	1,700	3,600	3,600	3,600	-
Total Wind** Adds	MW	-	1,500	16,855	35,975	70,464	13,031	5,550	68,128	51,211	23,365	28,546
Total Solar** Adds	MW	-	10,000	10,000	13,000	18,000	11,000	9,000	7,500	-	11,000	7,500
Total Demand Response Adds	MW	2,700	2,700	-	-	2,000	1,000	2,000	0	10,700	3,500	2,500
Total Retirements	MW	-	13,765	-	4,892	21,241	-	-	8,635	12,752	1,344	13,004
2032 Peak Demand	MW	100,744	100,744	100,744	100,744	100,744	108,981	108,981	108,981	76,851	100,744	100,744
2032 Planning Reserve Margin	%	1.33	(1.00)	(4.35)	(11.00)	(19.86)	(1.75)	(0.09)	(13.60)	12.10	(12.10)	(14.66)
Administrative Units	MW	-	14,790	17,850	23,990	32,500	16,490	15,300	29,410	5,270	26,690	27,540
Average LMP	$/MWh	94.11	90.89	87.99	95.24	101.85	88.05	75.31	86.76	85.02	86.17	83.49
Scarcity Hours	hrs	21	24	37	30	14	27	36	9	-	25	18
Percent Change in Emissions (2016-2032)												
SO_2	%	1.1	0.5	0.4	-3.6	-90.0	0.9	75.0	80.5	-10.6	1.6	2.6
CO_2	%	26.3	24.6	3.5	-1.8	-39.1	-1.4	22.0	-6.5	-14.4	7.6	10.4
NO_X	%	14.4	5.0	-0.9	-2.3	-49.3	-1.8	19.0	1.6	-12.3	6.6	2.4

**The wind and solar additions are listed in nameplate capacity.

Scenario studies also help identify the variables or assumption with the most significant impact on the possible outcomes. In these studies, ERCOT determined that the main drivers affecting resource selection and development were the price of natural gas, continuation of the PTC, and emission costs. These factors principally impacted the overall cost of energy or the relative cost of energy between traditional thermal generation technologies and renewable generation technologies. See Appendix H for scenario-specific resource expansion results for each three-year planning interval. Appendix I provides a comparison overview of the market price impacts across the scenarios by comparing the price duration curves. This comparison shows the relative market prices of the different scenarios including the relative amount of time prices are higher, likely during scarcity intervals, and times low-cost intermittent resources set the market price.

8.1 Generation Capacity Reserve Margin

The generation resource capacities listed in Table 8 reflect 100% capacity values. However, the reserve margin calculations included only 8.7% of the wind generation capacity and 50% of the solar generation capacity to reflect the effective capacity contribution to meet peak electrical demand.

In addition to modeling the types and quantities of generation resource investment that market economics will encourage, the resource expansion studies also examined the resulting planning reserve margin to serve the forecast load. Generation must be sufficient to match load on the electric grid at all times. To assure it maintains that balance, ERCOT operates with excess generation in reserve to replace generation unexpectedly becoming unavailable or because of errors in forecasting weather, load, or renewable generation output. For long-term studies the amount of generation reserves is measured at the time of greatest load, or system peak. This surplus generation, called the planning reserve margin, indicates whether the system has sufficient reserves during the time of greatest usage. ERCOT calculates the planning reserve margin as the net of total capacity for the peak load season, less firm peak load for the peak load season, divided by the firm peak load for the peak load season (expressed as a percentage).

In the ERCOT region, market rules do not require market participants to develop resources to satisfy that planning reserve margin; rather, generation expansion occurs in response to competitive decisions made by individual resource developers. A developer that determines the market conditions favor additional generation will construct that generation expecting to capture sufficient revenues to make that investment profitable. The ERCOT market depends on the necessary financial signals providing incentives sufficient for enough resource development to meet the target planning reserve margin.

Many of the most profitable periods for generation resources occur during intervals when system resources are insufficient or barely sufficient to satisfy current load. During these periods, the ERCOT market generally experiences higher prices and possible shortages or scarcity of electricity. In market like ERCOT's with competitive entry and exit of resources, the opportunities to earn profits dominates a developer's decision about whether or not to construct generation to serve load.

When the market experiences lower planning reserve margins and more shortage hours at higher prices, developers see opportunities for greater profits. Eventually, those expected future profits during shortage can be great enough to encourage resource entry. Upon entry of new resources, the planning reserve margin increases, the number of shortage hours falls and the opportunity to earn those profits diminishes. The planning reserve margin reflects the amount of surplus generation relative to the peak system load the competitive developers will construct in excess of expected load and may not satisfy a target reserve margin that was identified for reliability purposes unless the financial incentives are great enough to attract sufficient resource development. In these scenarios, the scarcity hours determined by ERCOT was reasonably consistent across the scenarios with an annual high of only 37 hours and a low of zero, as shown in Table 8.

Many of the scenarios resulted in generation expansion plans with extremely low reserve margins. In fact, for most scenarios the reserve margins by 2032 were negative. A negative reserve margin implies insufficient resources to meet peak demand, let alone the surplus generation needed to provide the desired cushion. However, for calculating the reserve margin in ERCOT, the nameplate capacity contribution from intermittent generation resources such as wind and solar are administratively set. When determining the capacity available to meet load, ERCOT adjusts the nameplate capacity of intermittent generation resources to reflect the statistically likely capacity that will be available to meet the maximum load. ERCOT refers to that adjusted capacity as the resource's Effective Load Carrying Capability (ELCC). The ELCC represents an associated capacity that can be relied on during peak load hours. Currently, ERCOT uses an ELCC value of 8.7% for wind resources when calculating the planning reserve margin. Because of the limited amount of solar generation installed in the ERCOT region, ERCOT does not have a calculated ELCC value for solar technologies. For this study, ERCOT chose a 50% ELCC for utility scale solar PV based on analysis performed on data provided by the National Renewable Energy Laboratory.[25]

While the intermittent resources built in each scenario do not receive their full capacity rating when calculating the scenarios' planning reserve margins, the energy produced from these resources exceeded their ELCC value during many hours. This disparity between the calculated capacity values and energy produced can produce the effect of negative planning reserve margins with very low to zero emergency energy hours. Typically, low reserve margins are associated with a high number of emergency energy hours. These results imply that the ELCC values for wind and solar resources may be too low and need to be updated or evaluated based on technology used and/or geographic location. In addition, as previously mentioned in Section 5.1.4, energy produced from a wind turbine located in the CREZ West Central zone would have a different shape than wind energy produced in the CREZ Panhandle zones or even in Texas coastal counties. When ERCOT determined the 8.7% ELCC currently used, wind generation development had occurred only in West Texas. Coastal and Panhandle wind development occurred later.

In a recent study completed for ERCOT, updated ELCC factors were proposed that reflect the historical performance along the Texas coast and in non-coastal regions, predominantly, West Texas. Although not approved for use in ERCOT studies, the revised ELCC factors are 32.9% for coastal wind resources and 14.2% for all non-coastal regions. Were the proposed ELCCs used to calculate the reserve margins in the scenarios, the result would be higher.

8.2 Implications of Drought

The resource additions in the three drought scenarios were significant, which would be consistent with the higher load forecasts developed for use in those scenarios. In both the original drought scenario and the scenario with low natural gas prices, ERCOT observed the diverse resource expansion among all the scenarios. By 2032, these scenarios' resource plans included natural gas, wind, solar, geothermal, and demand response additions. The low natural gas price scenario favored more natural gas development and less renewable generation. Also, in neither scenario did ERCOT model any economic generation retirements.

[25] *Users Manual for TMY3 Data Sets*. National Renewable Energy Laboratory (May 2008).

While the Drought with PTC and Emissions Costs scenario also produced significant resource additions, the mix of added resources differed notably from the two other drought scenarios. While the overall natural gas expansion was slightly lower, almost all the natural gas generation added was combined cycle with nearly no combustion turbine additions. The technology benefiting the most from the assumptions in the final drought scenario was wind. In that scenario, the economic advantages of emission costs on thermal generation and continuation of the PTC favored the addition of almost 70 GW of wind generation by 2032.

The increased water costs shown previously in Table 4 reflect the location-dependent aspect of the simulated drought. After implementing these costs ERCOT staff tested various water costs to determine the breakeven point at which dry cooling technology would become economical to install on a combined cycle generator. By altering the water cost input value in PROMOD IV, ERCOT found that a combined-cycle generator not utilizing dry cooling technology would need to pay approximately $2.50/MWh before the capital cost investment for installing dry cooling technology became economical. If that threshold were converted to a cost per gallon, the combined cycle plant would need to face a price of nearly $0.01 per gallon, a price comparable to higher residential potable water rates.

8.3 Fuel Price Impacts

Typically a natural gas-fired resource is the marginal unit providing electricity to the grid, therefore as their fuel costs increase so do their dispatch costs and the electricity clearing prices within the model. Figure 11 shows the dispatch costs for five different thermal generation technologies across three different scenarios. The three scenarios were chosen to illustrate how fuel price forecasts and emission costs affect the dispatch costs of certain technologies. The dispatch costs directly impact the locational marginal price (LMP) calculation. Assuming a natural gas-fired unit is on the margin, an increase in dispatch costs, whether caused by a fuel price increase or an emission cost adder, will cause any generation unit not fueled by natural gas and having a lower dispatch cost to receive greater revenue in the model if they are providing energy during those hours. Increased revenue directly relates to increased economic viability for that lower-cost resource. This additional revenue benefit is most pronounced for wind, solar, and geothermal technologies because they do not have fuel costs to offset.

Across the scenarios, higher natural gas prices generally translated to no combined cycle expansion, limited or no combustion turbine expansion, and higher average electricity prices. The three scenarios that included the high-natural gas price forecast assumption produced three of the four scenarios with the largest increases in wind generation, which is consistent with the relative dispatch cost advantage those technologies have, as discussed above.

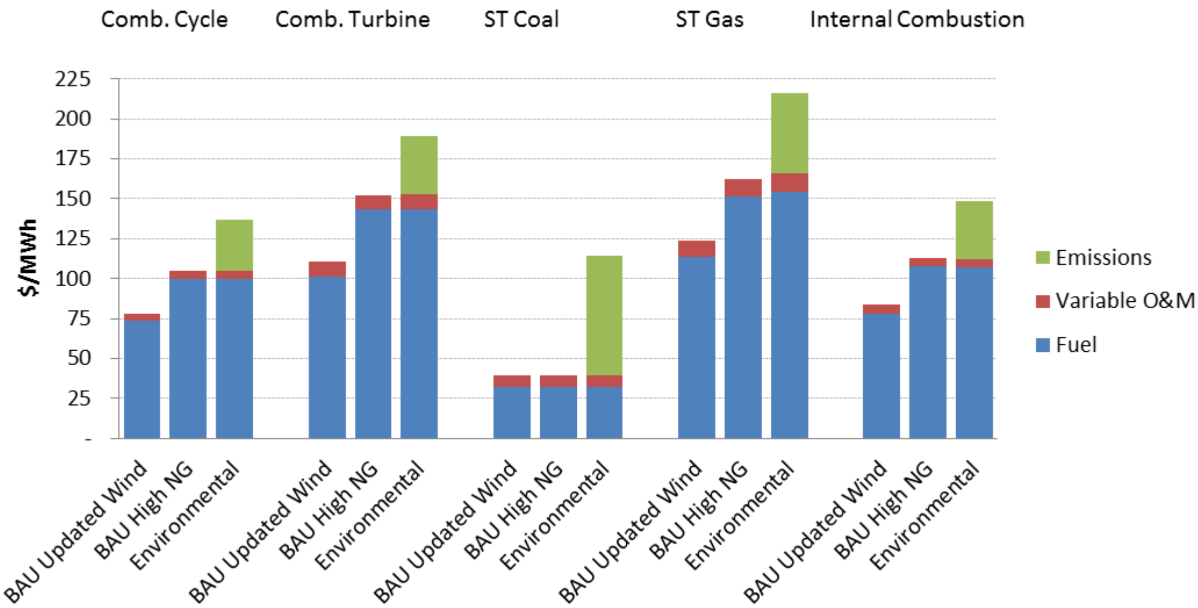

Figure 11 — 2032 Total Dispatch Cost

8.4 Intermittent Resource Dynamics

The forecasted decline in capital costs of solar technologies, noted in Section 7, resulted in utility-scale solar PV technology becoming largely economically viable in almost all scenarios by 2022.

Table 9 — Cumulative Solar Installed Capacity

Cumulative Solar Builds	2016	2019	2022	2025	2028	2032
BAU all Tech	-	-	-	-	-	-
BAU w/ Retirements	-	-	2,000	5,000	7,000	10,000
BAU Updated Wind Shapes	-	1,500	4,500	6,500	7,500	10,000
BAU w/ PTC	-	1,000	4,500	6,500	6,500	11,000
BAU High NG Price	-	-	6,000	8,000	10,000	13,000
BAU w/ Increased DC-Tie Capacity	-	-	2,500	3,500	4,000	7,500
Drought	-	2,500	4,500	6,500	8,500	11,000
Drought w/ Low NG Price	-	-	2,500	5,000	7,000	9,000
Drought w/ Emission Costs & PTC	-	2,000	3,500	3,500	7,500	7,500
Environmental	-	-	15,500	16,000	16,500	18,000
Environmental EE & DR	-	-	-	-	-	-

Despite the declining capital costs, Table 9 shows two scenarios that did not have any solar capacity built. The first such scenario was the BAU with All Tech. ERCOT completed this scenario prior to implementing reduced capital costs for solar technologies in its models and the original capital costs never reached a breakeven point with the assumed solar profiles used in this study. The second scenario that did not have any solar capacity built was the Environmental EE & DR scenario. This scenario included a reduced load forecast that reflected the assumption of 25% of total energy provided by demand response by 2025. This aggressive policy assumption led to a load forecast with minimal growth during peak hours. Additionally this scenario was the only scenario to have a positive planning reserve margin and zero scarcity hours.

Many scenarios studied resulted in high volumes of installed nameplate capacity for intermittent resources. Other than the two scenarios mentioned previously, BAU with All Tech and Environmental EE & DR, the remaining scenarios showed solar capacity investment by 2032 of 7,500 MW or more. One scenario, the Environmental scenario, showed 18,000 MW. The quantity of wind generation installed by 2032 varied significantly across the scenarios with as little as 1,500 MW installed in the BAU retirements scenario to over 70,000 MW installed with the aid of a PTC and emission fees in the environmental case. Two scenarios yielded interesting wind investment results. The drought scenario built around the high-load forecast, a PTC, emission fees, and dry cooling on all combined-cycle plants favored over 68,000 MW of wind generation investment. However the drought scenario, built around the same high-load forecast, but without the PTC or emission fees and with low natural gas prices supported only 5,500 MW of wind. Appendix J contains comparisons of wind resource expansion and natural gas prices among several scenarios. In the appendix, the figures show the cumulative expansion of wind resources for each three-year study interval.

8.5 Implications of Policy Changes

Including the assumption that the PTC will continue beyond 2013 appeared to have a larger impact on the economic viability of wind than the updated wind patterns in the simulated markets created for the scenario analysis of this study. The PTC provides a tax credit to renewable resources based on the amount of annual energy produced, effectively lowering the cost of electricity from any technology eligible for the PTC. It can be seen in the scenarios that included the continuation of the PTC that the amount of installed nameplate wind capacity was significantly higher compared to the scenarios that did not include the continuation of the PTC as an assumption.

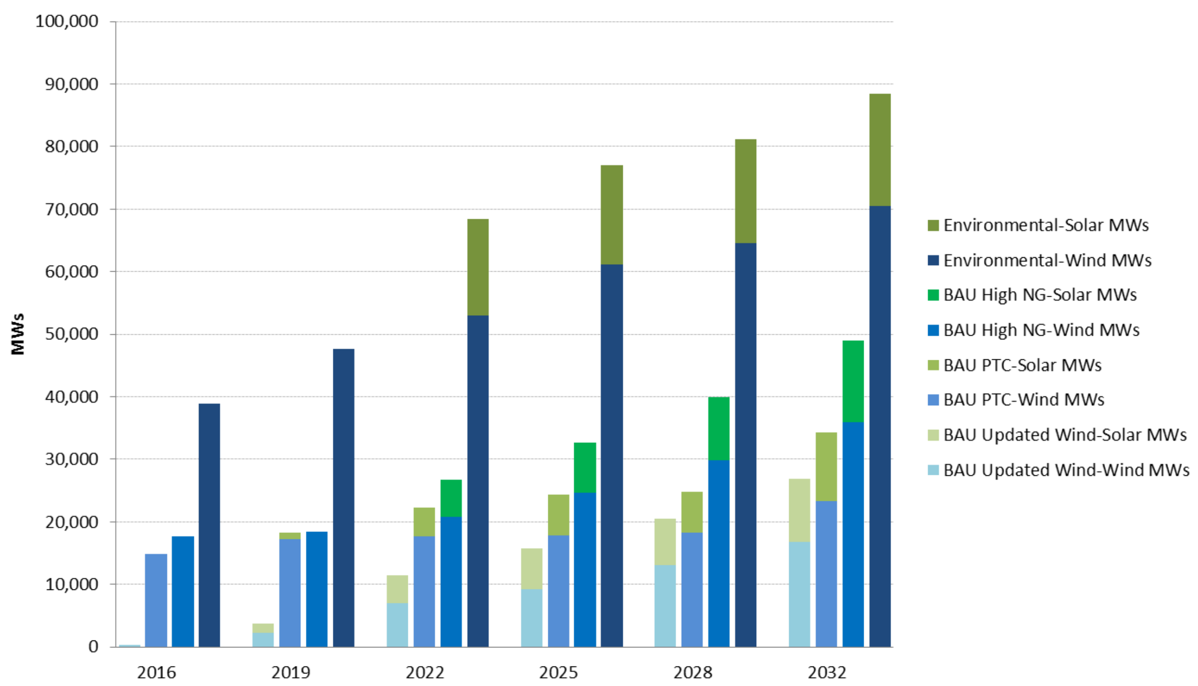

Figure 12 — Wind and Solar Capacity Installations

Applying emission costs had a similar effect on LMPs as did increasing the natural gas price, discussed in Section 8.3. ERCOT included emission costs as a variable operation cost included in the dispatch cost of any unit that emits nitrogen oxides, sulfur dioxide, or carbon dioxide. Figure 11 shows the impact emission costs have on the dispatch cost of various technologies in the generation database. By applying the specific emission cost adders to the generation technologies, ERCOT changed the relative dispatch costs of the generation resources and increased the LMPs. Accordingly, any unit that had no emissions or had lower emission rates benefited from the relative change of dispatch costs and the increase in LMPs. This advantage can be seen in the two environmental scenarios in which large amounts wind, solar, and geothermal capacity were built, technologies not subject to the emission cost adders. Figure 12 compares the solar and wind capacity additions through the 20-year studies. The amount of solar and wind resources added in the environmental scenario greatly exceeds the other scenarios to which it is compared.

9 Transmission Analysis

Effective long-term transmission planning designed to serve changing system needs for a deregulated energy market requires careful consideration of a full spectrum of possible outcomes. A number of assumptions drive each potential outcome. For example, variations of study assumptions on load, natural gas prices, and continuation of current incentives for renewable generation may produce differing portfolios of economically viable resources. Each scenario, a collection of themed assumptions, identifies probable resource expansion portfolios. These resource portfolios may be complemented by similar or differing transmission system improvements. In its long-term plans, ERCOT identifies similar and differing transmission system needs for each hypothetical resource expansion portfolio. Upgrades that support reliable and efficient transmission operations across scenarios can inform shorter-term study horizons of expected system needs. Similarly, unique outcomes that support differing transmission expansion needs for specific outcomes can inform shorter-term study horizons as the assumptions that drive upgrades in each scenario become more certain. For this extended long-term study, ERCOT identified and studied potential reliability and economic plans that can be used to identify and test solutions for near-term needs in future studies. Developing a 20-year plan was a major effort to formulate and refine processes for improving long-term analyses and planning. Some processes evolved during the study and those differences have made comparisons across scenarios more challenging.

After completing the resource expansion for each scenario, as described in the preceding section, ERCOT had to place the resources at specific nodes on the electric grid and determine the transmission upgrades needed for those resources and the corresponding scenario load. To represent deregulated resource development more closely, ERCOT distributed the portfolio of resources based upon simulated wholesale electric prices throughout the ERCOT region. Presumably, resource developers would seek out high-price locations in regions where existing infrastructure or other site characteristics (e.g. fuel availability, cooling sources, wind/renewable output profiles, etc.) could support each resource technology. Finally, ERCOT would design transmission system improvements to satisfy each unique scenario's resource build and load assumptions. Several of the scenarios yielded similar resource expansion and load results therefore ERCOT chose to select a single scenario to represent the transmission plan for scenarios with similar generation plans. The quantity of wind generation added and the corresponding transmission needed to move that remote energy to load notably distinguished the scenarios from each other. Figure 13 shows the scenarios for which ERCOT prepared complete transmission analyses.

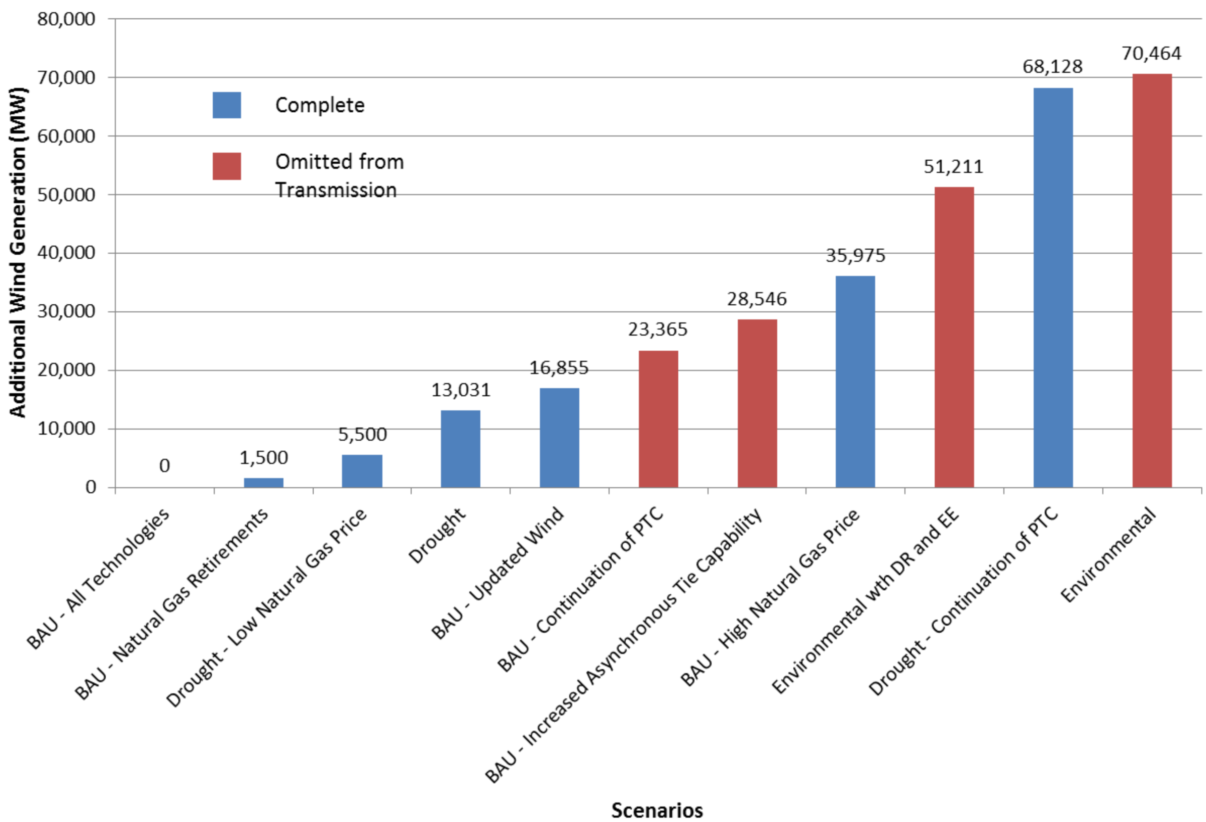

Figure 13 — Scenarios Selected for Transmission Analysis

A long-term plan provides meaningful insight for stakeholders, system planners, and policy makers. Least-regrets solutions that satisfy a spectrum of yet-to-be determined resource builds provide timely information about staged expansion plans. Accordingly, this report identifies both scenario-specific transmission system needs and projects that are common across scenarios.

ERCOT and the stakeholders used the 2016 transmission system topology, the final year of the 2011 Regional Transmission Plan, as the starting basis for this Long Term Study. Accordingly, the Long-Term Study is inclusive only of transmission projects, resource additions, and resource retirements that were known at the time of the development of that plan. Transmission upgrades and resource additions added to develop cases for 2022 and 2032 result from scenario-specific assumptions of network topology and loading. Specific developer's proposed expansion plans beyond this study year were not considered.

ERCOT considers the projects presented in this report to be conceptual. Economic and reliability merits of each project are supported exclusively by scenario-specific system loading, topology, and resource mix. ERCOT did not consider all aspects of each project when examining its feasibility. Routing issues were not a consideration in project development and although a significant amount of coordination and review was provided by TDSPs, some listed projects may not be feasible given physical limitations of existing equipment or infrastructure or outage scheduling. Needed upgrades ultimately determined to be infeasible for these or other reasons should be considered as surrogates for new transmission. ERCOT is grateful to the TDSPs that participated in this study, especially for their support with ideas of potential projects, their knowledge of future system limitations, and review of proposed solutions.

9.1 Methodology and Process

ERCOT and the stakeholders developed a repeatable process to perform transmission system assessments based upon load forecasts and resource expansion scenarios developed in support of this long term study. Each scenario assessment identified reliability transmission upgrades and economic alternatives to support reliable and efficient system operations. Because the development of a complete transmission plan required significant resources, ERCOT only developed a transmission plan for a scenario that presented a sufficiently different resource mix and system loading, when compared to previously studied scenarios in this assessment. As mentioned earlier in this section, ERCOT considered a scenario sufficiently similar to another scenario when it had similarly sited expansion resources and comparable system loading and would, therefore, likely produce a similar transmission plan to the one already developed. To complete a longer, more comprehensive assessment of probable outcomes and complementary transmission network upgrades, ERCOT built a process around new and existing tools and practices.

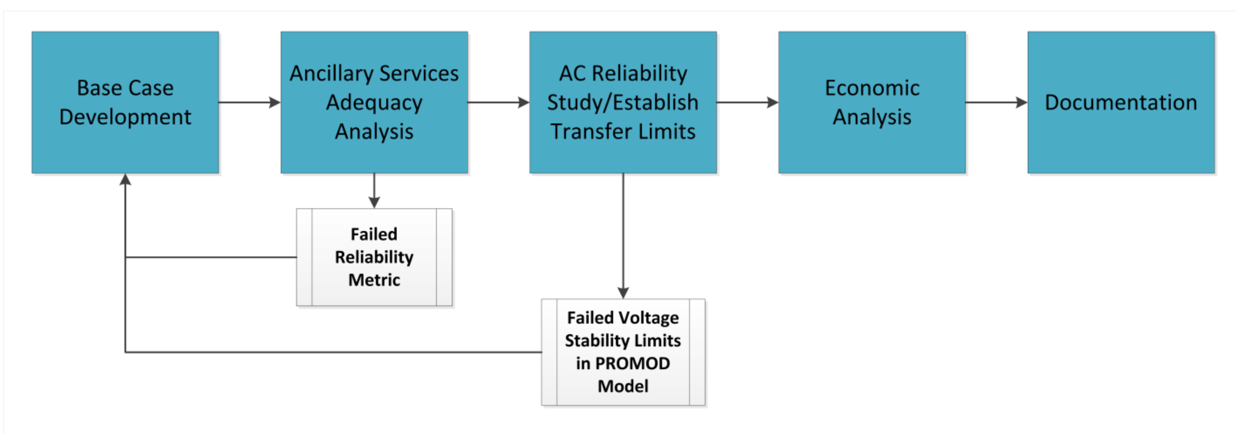

Figure 14 — Transmission Analysis Process Flow Diagram

To represent the deliverability constraints of the transmission system, each study began with the development of a base case, as shown in Figure 14. ERCOT derived each base case from the latest year of the most recent Regional Transmission Plan, as developed by ERCOT and the Regional Planning Group.

Absent a complementary increase in resource availability, aggregated demand growth over a 20-year period would greatly exceed the capacity provided by the current and anticipated resource base represented in the Regional Transmission Plan. Similarly, absent transmission expansion that would typically occur over subsequent six-year study horizons, existing transmission facilities would be inadequate to provide reliable service. To minimize the base-case development process cycle time, but maintain sufficient granularity for long-term studies, ERCOT developed an automated tool to create a simplified equivalent representation of the ERCOT system. This simplification process simulated the transmission upgrades typically identified in near-term plans and constructed to address local needs while maintaining focus on issues relevant to a long-term study horizon.

ERCOT located sites for resource expansion in a two-step process. First, resource expansion sites were identified based on a county-by-county assessment of the feasibility of operating a specific resource technology within that county. Thereafter, ERCOT modeled the expansion resources at the electrical bus with the highest marginal cost, as simulated in a 2016 representation of the ERCOT system

This new, potential future network may differ greatly from the existing ERCOT system, particularly where new resources have differing locations and operational qualities than the existing resource base. Drastic changes in the resource base and transmission network may introduce new transmission circuit overloads and binding constraints within the base case. Poorly defined constraints and/or system overloads can produce erroneous results. Similar to contingency definition for mid-term study horizons, the study engineer will consider known and anticipated constraints when preparing a production cost model. The base case development of contingencies for long-term study begins with the contingency data from the Regional Transmission Plan, to which are added future binding constraints based upon scenario-specific base cases. This process is facilitated by the PROMOD Analysis Tool, further described in Section 9.2. Once new binding constraints are identified, the study engineer must resolve any overloads that exist in the model. In PROMOD, an overload occurs when there is any violation of a transmission element's thermal limit that cannot be resolved by a dispatch change for at least one hour of a simulated year. All identified upgrades were tabulated and reviewed with the incumbent transmission providers. The updated base case provided a reliable system simulation useable for further analysis.

Direct-current representations of alternating current power systems are routinely utilized in production cost simulations. These simulations provide adequate approximations of system operations in an expedient fashion. Unfortunately, if steady-state voltage limitations are more constraining than thermal limitations, then a DC representation will not recognize this limit unless the study engineer explicitly models the constraint.

Typically, thermal limitations in a transmission system are more binding than voltage stability limitations. Notable exceptions in ERCOT include the existing stability constraint from West Texas to North Texas, which will be eliminated with completion of the CREZ projects, and the stability constraint from North Texas to Houston. Both constraints represent pre- or post-contingent steady-state voltage limitations that correspond to the maximum transfer levels that occur in a secure dispatch. If a scenario-specific portfolio modeled new resources outside of a major ERCOT load pocket and/or fewer resources internal to a major load pocket, then ERCOT performed a separate AC analysis to determine new steady-state stability import limits into each major load pocket. These updated AC interface limits were imposed upon DC production cost simulations such that the simulation would respect the user-defined steady-state import limitations into the region of interest.

Finally, the completed representation of a thermal- and steady-state reliable system is useable for comparative analysis of alternatives to reliability-driven solution sets. Before developing economic alternatives, ERCOT hosted meetings with TDSPs to determine:

- The reasonableness of system dispatch, overloads, and other observations,
- The feasibility of assumed reliability upgrades, and
- Previously studied economic alternatives.

Thereafter, ERCOT worked closely with TDSPs to determine scenario-specific and common transmission system needs observed in each production cost simulation. Each scenario analysis considered the economic viability of various transmission expansion initiatives. Economic transmission expansion considered the ability of a project to offset a reliability need and/or return production cost savings to load commensurate with its expense. The results of both reliability assessments and economic alternatives were disseminated via ERCOT's secure Planning and Operations Website to all market participants qualified to access specific engineering details of detailed transmission system information. Results were also presented publicly at LTSTF meetings. Summaries of both reliability-driven needs and economic alternatives are summarized in the Transmission Results Section of this report. Complete scenario-specific results are presented in Appendix K through Appendix Q.

9.1.1 Network Simplification

Transmission databases developed by ERCOT and the transmission system providers incorporate the network elements operated above 60-kV, including all 69-kV, 138-kV and 345-kV elements. Much of the 69-kV system and some of the 138-kV system were designed for load-serving purposes rather than for moving bulk power. When these network databases are used for long-range planning, increased loads typically result in many of the load-serving circuits becoming overloaded in the models. Hundreds or even thousands of network elements can be included in network violations reports if 20 years of load growth are modeled on near-term planning topologies.

In reality, the TDSPs will continue to upgrade their systems over time, constructing new substations, and building new circuits to ensure the reliability of electric service to their customers. But for long-range planning purposes, it is extremely time-consuming for transmission planners to adjust the model input to reflect the likely upgrades on the lower-voltage circuits. In previous 10-year planning studies, it has taken several weeks for ERCOT engineers to review all of the circuit overloads and determine which should be studied as part of the long-range planning study and which overloads can be disregarded for long-term planning consideration. In the past, the time spent on this effort greatly reduced the time ERCOT planners had to dedicate to the long-range planning efforts. For a 20-year study such as this, the effort would be even greater.

To facilitate this and future long-range planning efforts, ERCOT has developed a mostly automated process to simplify the network topology. The Network Simplification Tool simplifies power flow transmission models for the purpose of improving analysis visibility and computational efficiency. This tool removes the 69-kV network, removes radial and inline buses, and increases the ratings of short 138-kV transmission lines. This tool is useful in improving visibility of long-term system needs by reducing the time spent identifying and resolving more routine system upgrades that are best handled in near-term planning.

By simplifying parts of the network that tend to contribute to short-term issues (such as the 69-kV system), larger, more important issues on the bulk-carrying 138 and 345-kV networks become easier to observe. This tool may also be useful in computationally intensive studies such as loss of load probability, where a simplified network can decrease run-times and allow more scenarios to be run.

Because simplification reduces model detail, the loss of granularity must be weighed against the benefit of increased visibility and computational efficiency to the transmission planner. As a result, it is important that results from analyses performed on the simplified case occasionally be checked against the full case.

The simplification process eliminated time-intensive steps that produced little value for long-term planning horizons. While constraints on the 69-kV system can accrue significant congestion rents, most remediating projects would be designed and applied in shorter-term study horizons. Removal of the 69-kV system ratings eliminated time-consuming analysis without significant impact on the 345-kV or 138-kV systems. Thereafter, the simplification criteria removed radial 138-kV buses. Long 138-kV radial circuits serve remote load, rather than contributing to bulk system transfers. ERCOT moved loads on radial lines to the upstream 138-kV networked bus. As a further simplification, if a sectionalized 138-kV line had load modeled on in-line buses, the simplification code moved these loads to the remote ends of the line. Removing sectionalized lines preserved networked transmission system flows while eliminating system detail unnecessary for long-range planning. A diagram of this removal of in-line buses appears in Figure 15.

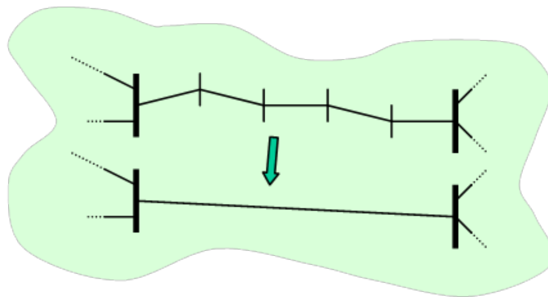

Figure 15 — Equivalence of Sectionalized 138-kV Line

If the elimination of in-line buses created additional 138-kV radial buses, then a second pass removed those radial lines and replaced them with a load at a networked 138-kV bus. The simplification process also applied "automatic upgrades" to short 138-kV lines with low ratings. These automatic upgrades replicated upgrades of overloaded facilities that would typically be observed and addressed in short-term study horizons. For this report, the simplification program was set to increase capacity ratings on short lines with low capacity ratings according to the criteria shown in Table 10.

Table 10 – Short-line 138-kV Upgrade Criteria

	Criteria		Upgrade To
	Length	Rating	
Rural Lines	< 30 miles	0-150 MVA	300 MVA
	< 20 miles	150-440 MVA	455 MVA
Urban Lines	< 2.5 miles	0-800 MVA	808 MVA

To reflect these changes to the network, ERCOT updated the contingency file to include newly created contingencies and to eliminate those contingencies that no longer applied. The resultant network topology is relevant for both expeditious and accurate long-range planning.

Over the course of the DOE study, it became increasingly evident that the time-intensive development of a 20-year base case threatened the timely completion of a full spectrum of scenarios. Twenty years of resource expansion and load growth, when applied to the current system configuration, required 10 to 20 iterations of reliability upgrades.

ERCOT opted to optimize study cycle time by strategically enforcing system ratings for differing study horizons. For 10-year assessments, ERCOT utilized the system simplification tool to upgrade facilities automatically that would be out-of-scope or traditionally resolved in shorter study horizons. Further, ratings on the 69-kV system were not enforced for 10-year assessments because ERCOT assumed those issues would be resolved in shorter-term study horizons. For 20-year assessments for a few scenarios, ERCOT explored the option of enforcing transfer limits on only the 345-kV system. This relaxation of transfer limits reduced reliability upgrade iterations from 20 passes, to less than five. Despite this tremendous gain in study speed,

- Production costs were roughly congruent,
- Reliability and economic opportunities were apparent and comparable to previous process results, and
- Inter-regional system needs were equally or more apparent.

9.1.2 Resource Siting Process

A generation siting process was developed to provide a consistent approach for siting that can be applied to the various scenarios evaluated as part of this study effort. Similar to the generation expansion process, the siting process is not intended to produce the optimal locations for new resources; rather it is designed to mimic the ERCOT market, in which independent developers site their units based on a variety of factors.

The various factors that were used to evaluate potential siting locations for specific technologies were:

- Natural gas pipeline density
- Railroad density
- Urban population density
- Environmental constraints
- Wind conditions
- Solar thermal conditions
- Surface water availability
- Solar photovoltaic (PV) conditions
- EPA Non-attainment areas

ERCOT applied detailed criteria to all counties to identify regions on the ERCOT system that could support individual or multiple resource technologies. Appendix R contains a detailed explanation of the siting process used in this analysis. At a bus level, 345-kV buses within a county capable of supporting a resource were selected in order of locational marginal price, with the highest-priced buses selected first. ERCOT determined the locational marginal prices based upon production cost simulations in a year sufficiently preceding the desired in-service date to allow hypothetical time for resource construction. Figures showing scenario-specific siting results are presented in Appendix K through Appendix Q.

9.1.3 Urban Area Reliability Analysis

Because ERCOT had not previously conducted any 20-year planning efforts, no studies existed to provide insights into the level of new transmission capacity that would likely be required in the urban centers following 20 years of load growth. Planners used the reliability planning effort described in the next few sections to develop an understanding of likely system needs in urban areas. Population growth forecasts indicate that populations in Texas would become more concentrated in the urban centers in future years, which will likely lead to a significant growth in the need for urban transmission capacity.

Beyond addressing load growth, the retirement of generation resources embedded in urban centers will further exacerbate the need to import electricity into those major load areas. Given the ERCOT market design, generation owners can retire resources they cannot continue to operate economically. Further, air quality and water access limitations can make development of new urban generation challenging.

The ERCOT Load Forecasting group provided a weather zone forecast disaggregated at a bus level, proportionate to the loading on each bus in each case. With expected loads in 2032 applied to each simulation, the system required additional generation to serve load. For each of the urban areas studied, additional generation capacity outside of that region was included in the model database. ERCOT evaluated multiple dispatches to ensure that information from this analysis would be relevant to a range of potential resource expansion scenarios. When a metropolitan area depended heavily upon electricity imports, ERCOT Staff performed an AC transfer analysis to identify constraints more binding than thermal line constraints. ERCOT evaluated all cases by using PSS/E, PowerWorld, and VSAT. These study results were posted on the ERCOT website so that they could be reviewed by stakeholders and the TDSP representatives.

As described in the following sections, ERCOT evaluated voltage collapse, low-voltage conditions, thermal overloading, and angular stability issues under the following conditions, where appropriate:

- Base case conditions
- N-1 contingency (loss of one transmission element)
- G-1 contingency (loss of one generation unit)
- Various system loading levels (scenario specific)
- G-N: Clusters of generator outages/retirements

9.2 Tools for Transmission Planning Analysis

ERCOT used grant funding to evaluate new software packages which provided more capability than ERCOT's existing tools to quantify the market viability of future resource additions. ERCOT used these tools, as well as new processes (developed by grant-funded staff) to better assess system needs over a longer study horizon.

9.2.1 PROMOD IV/PROMOD Analysis Tool

ERCOT utilized PROMOD IV to perform DC production-cost simulations for the 10 and 20-year planning horizon. This tool imported results from PSS/E steady-state transmission and resource models and performed a security-constrained unit commitment analysis for a user-defined time period (ranging from hours to years.) Each production cost simulation included user-defined assumptions of generation economics and transmission constraints. ERCOT used the PROMOD Analysis Tool in conjunction with PROMOD to define contingencies relevant to the desired year of study. Collectively, the two platforms helped ERCOT develop base case representations of future years to identify reliability-driven, system improvements and optional projects designed to improve overall system economic efficiency.

9.2.2 PowerWorld Simulator 17

PowerWorld Simulator performs sophisticated AC steady-state power system analytics and DC representations of security constrained optimal power flows. ERCOT utilized the graphical user interface of PowerWorld to illustrate both system overloads and highly congested transmission system elements. PowerWorld was utilized extensively to explore graphical results from PROMOD production cost simulations. PowerWorld was also used in the preparation of many of the graphics in this long-term study.

9.2.3 PSS/E

Siemens/PTI's PSS/E program is an industry-standard tool for AC power system analysis. PSS/E also interfaces with multiple programming languages to carry out user-defined model updates. For example, ERCOT utilized PSS/E and Python code to carry out the automated activities associated with the Network Simplification Tool utilized in this long-term study. Additionally, ERCOT used PSS/E to perform base case preparation, validation, and updates for production cost simulations.

9.2.4 Voltage Security Assessment Tool (VSAT)

VSAT is an automated steady-state analysis tool designed for voltage security assessment. ERCOT utilized VSAT to identify steady-state pre- and post-contingency stability limits for increasing amounts of imported power into major ERCOT load centers so ERCOT could represent those pre- and post-contingent import limitations in DC production cost models. This tool was particularly effective where system topology changes created future scenarios in which steady-state voltage stability constraints were more binding than thermal constraints.

9.2.5 KERMIT

ERCOT explored the effect of increasing intermittent generation on the ability of a resource portfolio to maintain system frequency. Previous studies verified the adequacy of ERCOT's existing ancillary service products and procurement to maintain system frequency for up to 15 GW of total interconnected wind generation.[26] Economic expansion results suggested by multiple scenarios in this study yielded an increase in intermittent generation that greatly exceeds previously studied ancillary service assessments. To facilitate this study, ERCOT issued a request for proposals to procure a model capable of identifying ancillary service needs on a scenario-by-scenario basis.

To determine the impact of increasing proportions of wind, solar, storage, or demand-response resources, ERCOT elected to study the ability of hypothetical resource expansion scenarios 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. Accordingly, ERCOT procured a tool with the following capabilities:

- Intra-hour time series simulation with net-load changes of one-second resolution.
- Adequate representation of emerging or expanding non-traditional resources, including, but not limited to, wind, solar, and storage technologies.
- Adequate representation of the existing ERCOT system, including existing resources, system load, and historic and forecasted variable generation availability patterns.

ERCOT selected DNV KEMA's KERMIT platform, a MatLab Simulink-based time-series simulation. KERMIT models existing technologies, including traditional thermal generation and existing wind turbines. Emerging and expanding technologies, including solar, demand response, and storage resources can be modeled in user-defined proportions to assess the ability of the combined fleet to meet reliability metrics, including NERC's Control Performance Standard 1 (CPS1) and disturbance control standards (DCS).

DNV KEMA calibrated the KERMIT tool with a representation of the ERCOT system, using recent operational events. This calibration verified that KERMIT time-series simulations are consistent with real-time results. Figure 16 demonstrates the similarities between actual and simulated system events and corresponding system response. After demonstrating the accuracy of the model against operational data, ERCOT and DNV KEMA replicated Long Term Study scenario models within the KERMIT platform.

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[26] *Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements*, Prepared by General Electric for ERCOT (Mar. 28, 2008). (*GE Ancillary Services Study*)

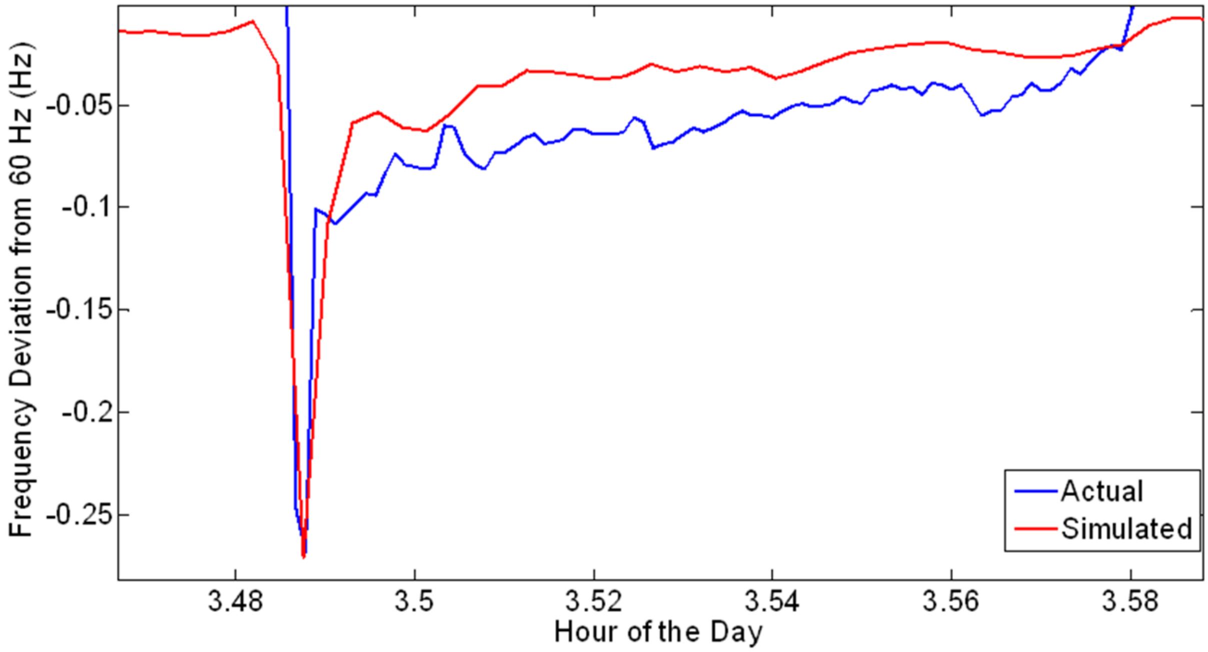


Figure 16 — Actual versus KERMIT-simulated Frequency Performance

With the calibrated model, ERCOT and DNV KEMA utilized the KERMIT tool to simulate potential future outcomes and complimentary portfolios of ancillary services. As illustrated in this DNV KEMA diagram shown in Figure 17, KERMIT possesses the ability to consider all types of resources and system assumptions to perform a balancing simulation with second-by-second granularity.

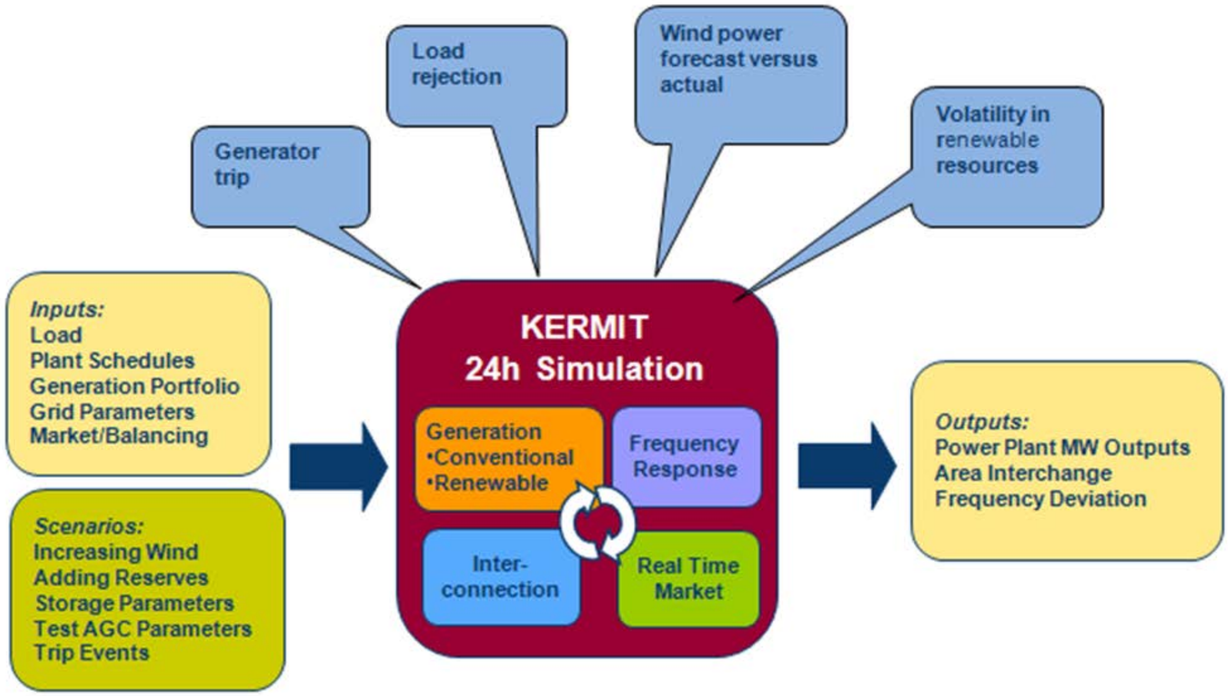


Figure 17 — KERMIT Inputs, Process, and Outputs[27]

9.3 Regional Analysis

ERCOT used these tools to study the various scenarios and developed transmission plans for those representative loads and resource expansion plans. ERCOT focused primarily on two major types of transmission needs: improving the import paths into major urban regions and moving remote power to those urban centers.

9.3.1 Import Needs into Major Load Zones/Retirement of Urban Resources

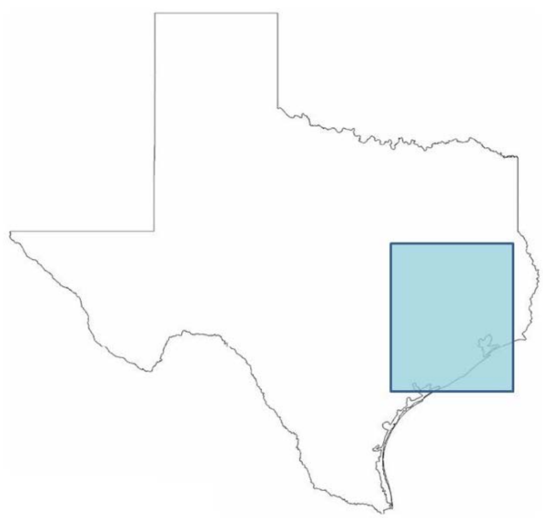
The existing urban load centers in ERCOT rely on legacy generation resources located within the area and transmission system imports from outside of the region to serve their demand. Many generation units within the load centers were built 30 to 50 years ago. These resources are nearing the end of their useful life and are less efficient and consequently more expensive to operate than newer generation. The legacy generation was built at a time when generation and transmission alternatives were considered collectively. Additionally, rapid urbanization has surrounded many of the legacy resources with residential, commercial, and industrial development. With increasing urban density and today's environmental regulations typically it is not as feasible to site generation within a major load center. This siting difficulty is expected

[27] *Kermit Software Implementation Update*, DNV KEMA Presentation to the ERCOT Regional Planning Group and Long Term Study Task Force, (Oct. 2012).

to put an increasing demand on transmission system import paths into major load centers in the future.

ERCOT determined AC stability import limitations into the major load zones so it could ensure that the models did not violate steady-state voltage stability limits as urban areas became increasingly dependent upon imported power. These import constraints, when modeled in a production cost simulation, often represented the most congested elements on the system. The economic opportunity for import expansion is more pronounced in scenarios with higher load growth and/or greater economic retirement of urban-sited units. The following sections address region specific import needs, with emphasis on Houston, Dallas/Fort Worth, Austin, and San Antonio. It is noteworthy that slight sensitivities modeled in certain scenarios, such as higher load growth, urban resource retirement, or higher natural gas price, drastically accelerated the timeline for reliability-driven expanded imports paths into all major ERCOT load areas.

9.3.2 Imports into the Houston Metropolitan Region



ERCOT observed the need for expanded import paths into the Houston metropolitan region in every scenario studied in the context of this report. In most scenarios, existing import paths into Houston were overloaded (i.e., import capacity was exceeded within the 10-year initial planning horizon). The 20-year studies illustrated a more pronounced need for expanded import capacity to maintain reliability. In the most severe instance, the Drought Scenario with PTC, every 345-kV import path into the Houston region was overloaded and needed upgrades or additional new import lines by 2032 to maintain reliable operations. Most upgrades were needed within the 10-year horizon, as illustrated in Table 11.

Table 11 – Reliability Upgrades to Existing Houston Import Paths

Existing Import Lines	BAU - All Technologies (2022)	BAU - NG Retirements (2022)	BAU - Updated Wind (2022)	Drought (2022)	Drought - Low NG Prices (2022)	Drought - PTC (2022)	BAU - High NG Prices (2022)
Singleton to Tomball		Upgraded	Upgraded	Upgraded	Upgraded	Upgraded	Upgraded
Roans Prairie to Kuykendahl		Upgraded				Upgraded	
Singleton to Zenith		Upgraded		Upgraded		Upgraded	
South Texas to Dow		Upgraded				Upgraded	
South Texas to W.A. Parish	Upgraded	Upgraded			Upgraded	Upgraded	
Hillje to W.A. Parish							

To model reliable operations Houston ERCOT needed additional new or upgraded 345-kV import lines into Houston. The Houston region depends greatly upon imported power, most notably from the north; though significant imports occur from the south. The eastern side of Houston borders the neighboring Eastern Interconnection with no synchronous ties to ERCOT. The Houston region's current dependence upon existing import lines would make scheduling the outages needed during an upgrade of an existing major import pathway extremely difficult. As such, the upgrades shown in Table 11 can be viewed as surrogate projects for increased import capacity. Projects selected in the RTP would be much more likely to involve construction requiring new right-of-way.

Every scenario studied in this long-term study required the upgrade of at least one existing import path within the 10-year study horizon, as shown in Table 11. The scenario in which natural gas plants retired when they reached 50-years old and the harshest drought scenario required upgrades to almost every import line. Figure 18 show the upgraded transmission paths and new lines ERCOT determined it needed to maintain reliable operations in the Drought with Emissions Costs and PTC scenario.

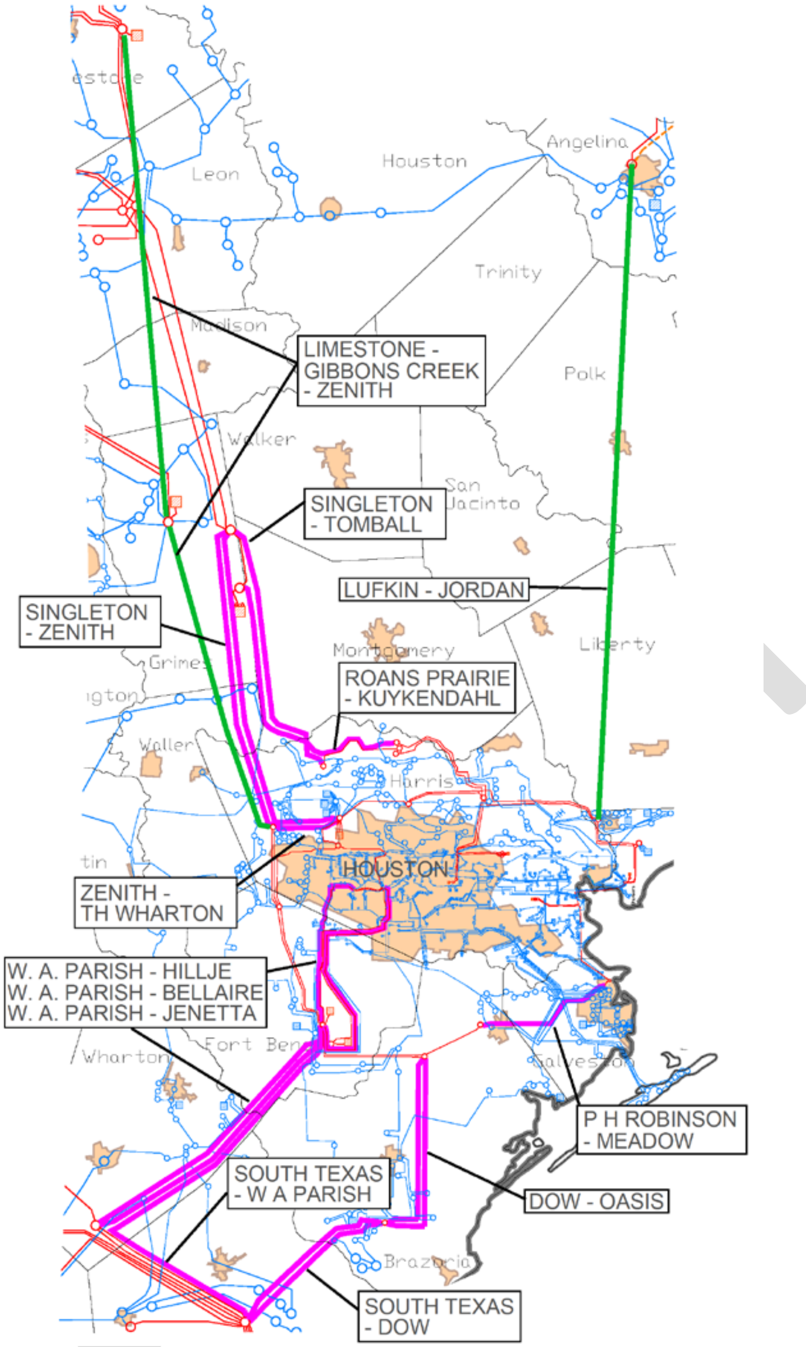


Figure 18 — New and Upgraded Reliability Import Paths into Houston - Drought Scenario

Increased loads and/or retirement of existing gas-fired resources within the Houston load region accelerated the need and magnitude of new import capacity required for reliability. Conversely, the development of new resources within the Houston region or lower than anticipated load growth could delay the need of new imports paths into Houston. However, new resource development is considered unlikely, given that:

- Harris County/Houston currently does not meet applicable air quality standards, thereby limiting resource expansion.
- Houston loads have, historically, grown at rates higher than that of the rest of ERCOT and that comparatively higher growth is anticipated to continue.
- New resource development is challenging in increasingly urban areas.
- Because of the city's large load, new resource development within the Houston region would have to exceed 500 MW to delay the need for an import upgrade into Houston by one year (as determined in the modeling of demand response in the Business as Usual-All Technologies with Demand Response scenario).
- Any new resource development that does occur may be offset by the retirement of existing resources because of environmental and siting constraints, which would limit the net effect.

The above constraints typically apply to and restrict large-scale, centralized thermal resource development. Expansive development of distributed resources, including demand response, does have the potential to delay the need for a new Houston import path. In the Business as Usual with Updated Wind and Demand Response Scenario the development of demand response sufficiently reduced demand within the Houston region to delay the import need by one year. However, demand response development of this magnitude would be a significant departure from the current level of load participation. These resources would also need to be appropriately located within the Houston region to provide the anticipated benefit. Further studies would be required to qualify, quantify, and demonstrate availability of sufficient demand response to offset any transmission system needs.

In light of the criticality of existing Houston imports, and the pronounced need for expanded capacity, ERCOT identified and prioritized options for new and expanded lines into Houston, by scenario. These solutions may be useable in the likely event that upgrades of existing imports paths are difficult or impractical to perform because of the duration and outage requirements associated with such upgrades. As such, the identified reliability upgrades to those import paths should be viewed as surrogates for the new import paths that ERCOT identified.

The 345-kV lines that carry imported power from the north into Houston, specifically Singleton to Zenith lines, Roans Prairie to Kuykendahl, and Singleton to Tomball were consistently either overloaded or heavily congested. Imports into Houston from around the South Texas Project/Dow Chemical area (southwest of Houston) were also consistently overloaded in each scenario.

Additionally, voltage stability limits were exceeded in all of the studied scenarios. In the BAU with Retirements scenario, in which legacy natural-gas fired units were retired upon their 50th

anniversary of commercial operations, voltage collapse was imminent for certain single contingencies before 2022.

ERCOT considered multiple solutions to ease the Houston import constraint. Passive solutions, such as increased dynamic and static reactive support, were studied to the extent that such solutions were operationally achievable. Power factor assumptions, load distribution assumptions, and dynamic/static reactive resources may alter the timing of the need for new or expanded import paths. These solutions were particularly effective where stability limits were more constraining than the thermal limitations of the region and neighboring strong sources were far away. However, in certain scenarios, the reactive power consumption associated with heavily loaded, long lines exceeded what was generally acceptable as an operable level of static or dynamic reactive support. ERCOT worked closely with TDSPs to establish reasonable approximations of maximum achievable reactive support before investigating new transmission line solutions.

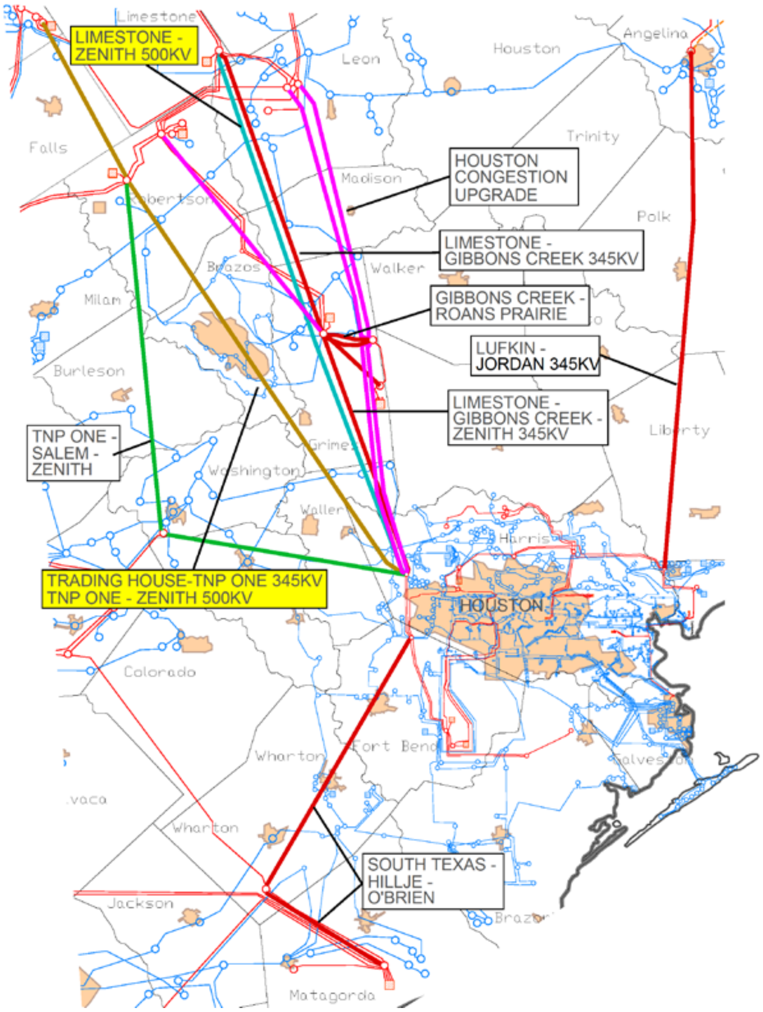


Figure 19 — Potential Import Paths into Houston Tested for Economic Expansion

Consistent with ERCOT's Long-Term Planning Process, ERCOT also evaluated opportunities to improve the economic efficiency of the system. Figure 19 shows the various import path additions ERCOT studied to identify projects that could be justified economically. Beyond just the projects ERCOT identified to establish maintain reliable operations for each scenario, Table 12 shows the additional projects ERCOT determined were economic for the Houston region. ERCOT evaluated those projects with significant congestion rents according to ERCOT's economic planning criteria. Multiple projects in several scenarios maintained reliability and returned production cost savings commensurate with the economic planning criteria as defined in the ERCOT Protocols.[28] Notably, several Houston import projects were economic between 2022 and 2032 in several scenarios, including the natural-gas-fired unit retirements scenario and the high natural gas price scenario. In both of those scenarios, several options

[28] *ERCOT Nodal Protocols*, Section 3.11.2.

demonstrated cost-effectiveness when included in system topologies within the 10-year study horizon.

Table 12 — Houston Economic Project Assessments

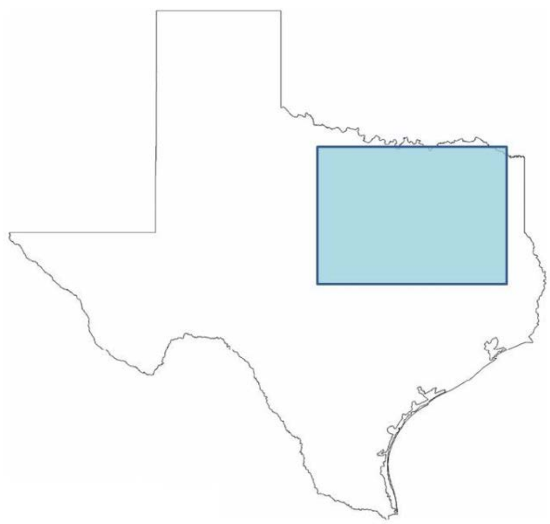
Tested Project in 2032	Voltage Category (kV)	New Line or Upgrade Existing Line?	Capital Cost (2032 $M)	Economic in Scenarios	Economic in How Many Scenarios?
Limestone to Gibbons Creek to Zenith	345	New	**477**	**BAU - 50-yr Retirements; BAU - Upgraded Wind Shapes; BAU - High NG Price**	**3**
Lufkin to Jordan	345	New	**535**	**BAU - 50-yr Retirements; Drought; BAU - High NG Price**	**3**
Limestone to Gibbons Creek 345-kV line	345	New	**218**	**Drought; Drought - Low NG Price**	**2**
Gibbon Creek to Roans 345-kV line	345	New	**36**	**Drought - Low NG Price**	**1**
South Texas to Hillje to O'Brien	345	New	**323**	**BAU - 50-yr Retirements**	**1**
TNP One to Salem to Zenith	345	New	**542**	**BAU - High NG Price**	**1**

No economic project tested was consistently needed across all scenarios within the 20-year horizon, because of the divergent assumptions of resource development. Nevertheless, multiple projects tested to improve imports into Houston achieved production cost savings commensurate with their expense to ratepayers. It is important to note that these projects were tested in conjunction with reliability-driven upgrades of existing 345-kV imports into Houston. As previously stated, if scheduling and performing the reliability upgrades of those existing corridors proves infeasible, then those reliability upgrades should be viewed as surrogates for a new pathway into Houston. Section 9.6 contains a more complete discussion about the economics associated with transmission outages.

From the various scenarios evaluated, ERCOT consistently and clearly reached the following conclusions. The Houston region will need upgraded or new import capacity sooner than 2022 absent a significant amount of generation development within the area. Additional dynamic reactive support may delay the need, though certain scenarios demonstrated that the level of reactive support needed to ensure reliability without expanded import capability may not be operationally achievable. For most scenarios ERCOT could not model reliable operations without expanded Houston import paths. In several scenarios over the 20-year study horizon, certain Houston import projects returned production cost savings in excess of their total cost to consumers. Ultimately, to achieve reliable operations, the Houston area would need those expanded import paths. Delaying the implementation of upgraded or new imports into

Houston may forgo economic benefits and increase dependence upon existing import lines as loads grow and legacy resources retire.

9.3.3 Dallas-Fort Worth Regions



The Dallas-Fort Worth region (DFW), unlike many other urban load pockets within ERCOT, does not have a well-defined boundary (from an electrical topology perspective). Characterized by two major cities with blurred borders and overlapping suburban growth, DFW's expanding import needs are unique. The DFW transmission needs identified by ERCOT differ notably among the scenarios. Scenarios that resulted in more wind development in West Texas required very different transmission upgrades than scenarios that resulted in more natural gas generation development south or east of DFW. The only finding consistent across scenarios for the Dallas-Fort Worth region was the need for expanded connections between the 345-kV system and the 138-kV system. Individual 345-kV lines were overloaded in multiple scenarios where limited connections serviced increasingly urban load growth and 345-kV connected resources.

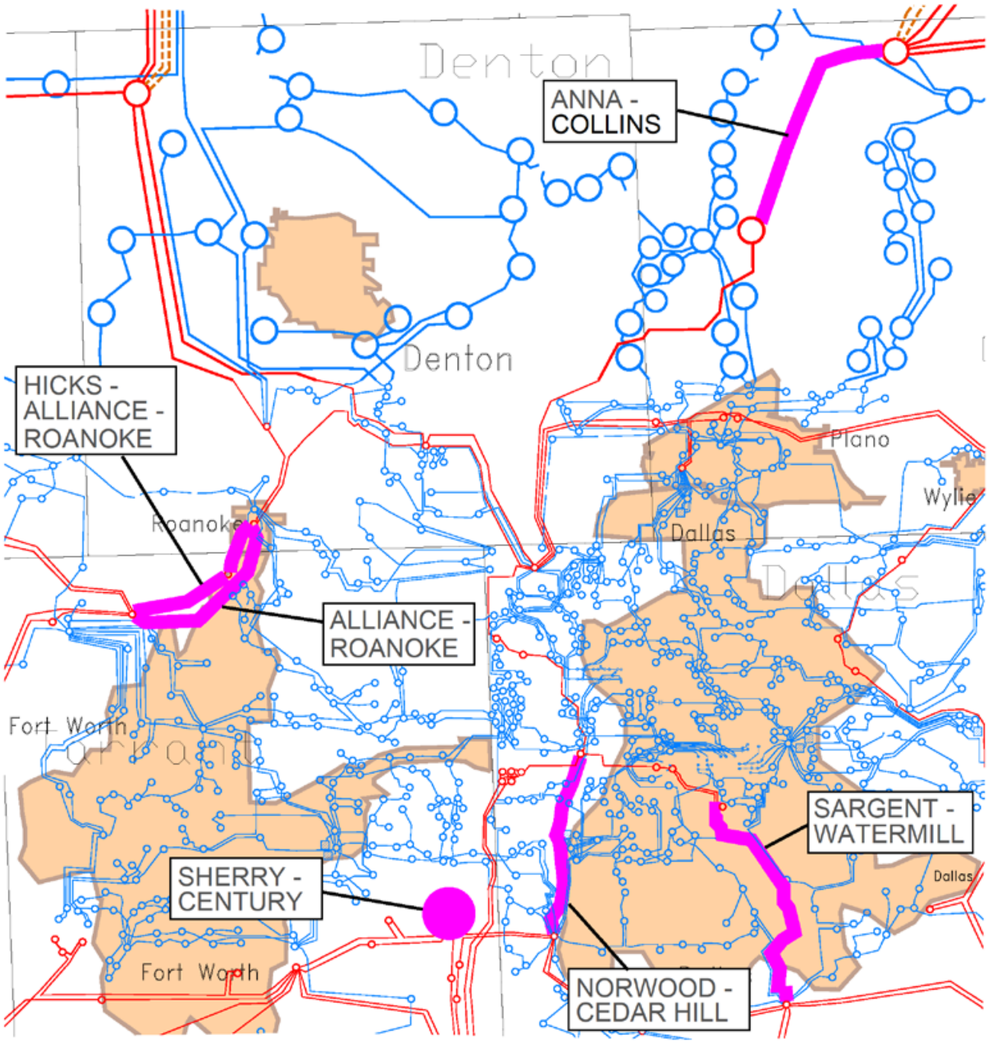


Figure 20 — DFW Lines Overloaded in Most Scenarios

In Figure 20, the highlighted line north of Dallas, the Anna Switch to Collins 345-kV line, was overloaded in every scenario. To alleviate this overload, ERCOT upgraded the Anna Switch to Collins 345-kV line. The other highlighted lines in Figure 20 were upgraded in most scenarios. For a complete description of reliability upgrades by scenario, see Appendix K through Appendix Q.

Historically DFW received a significant amount of its power from coal and natural gas units located east and southeast of Dallas and south of Fort Worth. The transmission import corridors that delivered the power from those plants were typically sized to accommodate those specific generators, which were built during a regulated, vertically integrated era of the electric utility industry. The resultant DFW transmission topology reflects the expectation that a specific amount of power would flow from those legacy plant locations to DFW along those transmission lines. As those plants approach the end of their economic lives, ERCOT must evaluate whether the transmission system will adequately support the generation that will possibly serve the DFW region in the future. Generation expansion or repowering at those existing plant locations could reduce the need for major transmission improvements. However, given the uncertainty inherent in planning transmission for a deregulated wholesale electric marketplace, ERCOT considered it prudent to evaluate the development of an extra-high voltage loop around the DFW region. This project investigated the benefits associated with a more flexible "highway" to DFW loads.

A loop provides new connection points for thermal generation, as well as contingency mitigation for the loss of any one connection to the loop. As anticipated, the conceptual project mitigated individual contingencies of lines connecting resources east and south of DFW. The proposed loop also provided enhanced connectivity for future, as yet unknown generating units. The resulting flexibility in the transmission system appeared to be most beneficial in scenarios in which future resource development likely occurs to the south and east of DFW, such as the Business as Usual with Updated Wind Patterns scenario, or any of the drought scenarios.

In contrast, scenarios modeling large increases in installed wind capacity in West Texas showed little need for expansive transmission projects in the south and eastern areas of DFW because less thermal generation was added in these areas. A fully-utilized CREZ system created a strong source for DFW and efficiently delivered power through new CREZ connections to DFW load.

From a stability perspective, most scenarios demonstrated that incremental import paths into Dallas would be required outside of the 10-year study horizon assuming expected load growth and no generation retirements. In several scenarios, moderate additions of dynamic or static reactive resources improved stability margins in a cost-effective manner. The most severe need for expanded imports into DFW was observed in the Retirement scenario, although the need occurred after 2022 following the installation of significant dynamic reactive support. In each scenario, DFW needed at least one new import path before 2032 to support steady-state stability. Scenarios, such as the Drought Scenario, with higher system load growth or decreased availability of urban resources required new imports into DFW as early as 2020.

Congestion into DFW varied according to scenario. Correspondingly, the transmission upgrades needed to address the congestion observed also varied according to scenario. All Drought scenarios and all Business as Usual scenarios except the BAU - High Natural Gas Price scenario saw congestion rents accrue on interfaces primarily located south or southeast of Dallas. Hypothetical generation expansion sites south/southeast of Dallas and the limited existing infrastructure to deliver the new, low-cost resources closer to DFW load generally caused this congestion. Expanded wind development associated with the Business as Usual - High Natural Gas Price scenario and all Drought scenarios caused increased congestion from West Texas into DFW. In these scenarios, ERCOT assessed numerous options to increase deliverability of wind with 345-kV and 500-kV projects. ERCOT evaluated several possible DFW transmission line additions or upgrades according to assess whether any were economically justified. Figure 21 shows a map of the various DFW projects.

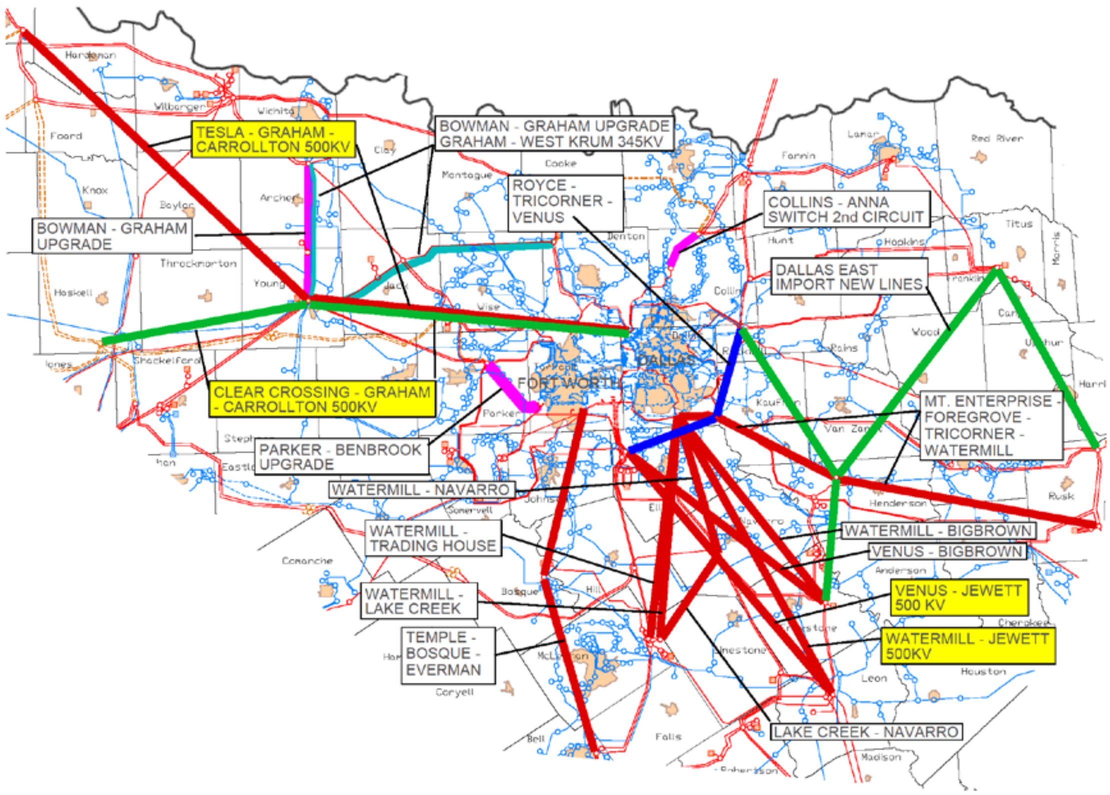


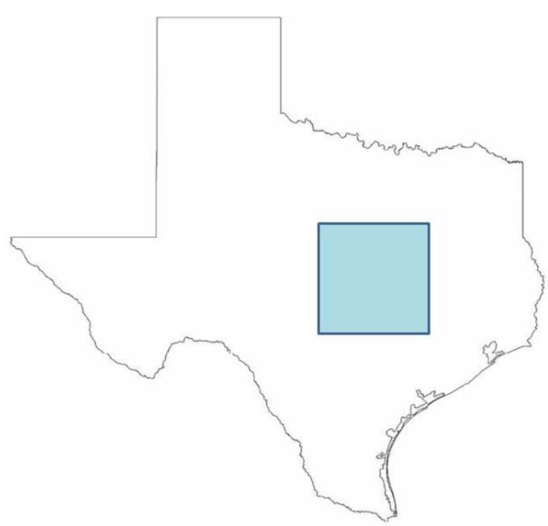
Figure 21 — Potential Projects in the DFW Region Tested for Economic Expansion

Drought scenarios, with their higher load growth and reduced availability of urban resources, incurred significant congestion rents to maintain steady-state voltage stability import limits. For the Drought and Retirement scenarios, ERCOT assessed multiple projects from the areas south, east, and west of the DFW region. These economic/conceptual projects also offset reliability needs in the region. Table 13 shows the DFW projects ERCOT determined satisfied the criteria for economic expansion.

Table 13 — DFW Economic Project Assessments

Tested Project in 2032	Voltage Category (kV)	New Line or Upgrade Existing Line?	Capital Cost (2032 $M)	Economic in Scenarios	Economic in How Many Scenarios?
Tesla to Graham to Carrollton 500-kV line	500	New	**1307**	**Drought - PTC & Emission Costs; BAU - High NG Price**	**2**
Collins to Anna 2nd ckt	345	Upgrade	**11**	**Drought - Low NG Price**	**1**
Parker to Benbrook 345-kV double ckt rebuild	345	Upgrade	**58**	**Drought**	**1**
Bowman to Graham 345-kV rebuild	345	Upgrade	**101**	**Drought**	**1**
Bowman to Graham 345-kV rebuild and Graham to West Krum addition	345	Upgrade	**137**	**Drought**	**1**
Mt. Enterprise to Foregrove to Tricorner to Watermill	345	New	**563**	**BAU - 50-yr Retirements**	**1**

In the most extreme Drought scenario, no dispatch could achieve reliable service in the DFW area, absent at least two new import lines into the region. ERCOT is working with the incumbent TDSPs to develop conceptual, economically justified solutions should higher-than-anticipated loading or accelerated urban resource retirement occur. As this is currently a scenario-specific result, it is expected that new import paths into the DFW area will be identified in a shorter-term planning horizon when generation-siting expectations are better known.



9.3.4 Austin Region

The Austin metropolitan region, as modeled, showed increasing dependence upon 138-kV infrastructure connecting to the 345-kV system east of the load pocket to serve growing loads to the west of the load pocket. Load growth in counties west of Austin led ERCOT to investigate opportunities to introduce a western 345-kV source to support future needs. Unlike the systems in other major load centers that are predominantly served by 345-kV lines, ERCOT could not simplify Austin's network model as much as other systems because of Austin's reliance on its 138-kV transmission. Therefore, ERCOT retained the original 138-kV network topology in the model for the Austin area.

Automatic upgrades of short-line, low-rated facilities in the Austin region totaled over 285 miles of expanded 138-kV infrastructure. With costs between $0.25 million and $0.55 million per mile for 138-kV upgrades, significant investments in the Austin region would be needed just to address overloads on short lines. While relieving overloads, ERCOT's modeling showed that, despite the 138-kV reliability upgrades, future congestion cost increases occurred in the Austin region.

From a reliability and voltage-stability perspective, the existing infrastructure with incremental upgrades to existing 138-kV circuits supported projected loads through the 10-year study horizon. Over the 20-year course of this study, several major 138-kV circuits became overloaded and required upgrades to maintain reliable operations. In light of these overloaded circuits, ERCOT investigated several options to bring new higher-voltage sources into the Austin area and reduce local congestion. Figure 22 shows the economic alternatives in and around Austin studied by ERCOT.

In this analysis almost all of the alternatives studied by ERCOT were not cost-competitive with upgrading existing 138-kV infrastructure even considering the avoided investment in reliability upgrades. For example, the two economic projects ERCOT studied in the BAU with Retirements scenario avoided reliability investments that offset large fractions of the projects' capital costs, but despite this benefit with its significant reduction to the net capital cost, the production cost savings were too little to justify the project according to the economic criteria.

Additionally, ERCOT assessed the economics of a loop west of Austin. An additional source or loop supports reliable and efficient service by increasing competitive access to load centers, as well as grid flexibility for unforeseen outages, new generation, or future upgrades. This particular project represented the conversion of existing 138-kV lines to 230-kV. Currently, there are no 230-kV lines operating in the ERCOT Region. However, construction of new 345-kV lines in this area may be difficult; hence ERCOT considered the option of converting existing 138-kV lines with sufficient right of way to a higher voltage.

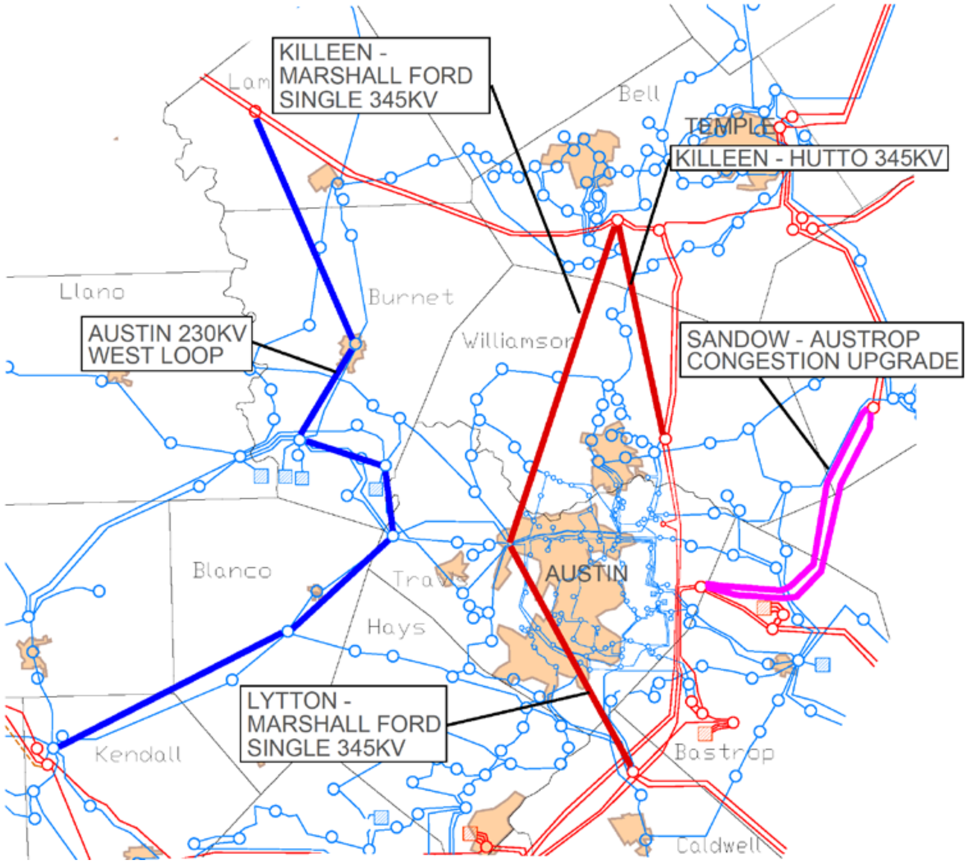
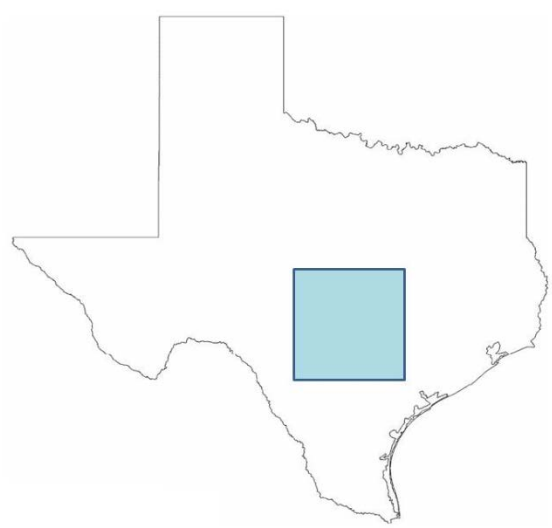


Figure 22 — Economic Projects Tested across scenarios in the Austin Region

As previously mentioned, most of the EHV projects studied could not sufficiently reduce system-wide production costs to meet the current ERCOT criteria for economic upgrades, even considering the possible avoided investment by the displacement of reliability upgrades by the evaluated economic projects. A less expansive project, the Killeen to Hutto 345-kV line, provided a small loop to mitigate the effect of a contingency for the Hutto to Salado 345-kV line. The Killeen to Hutto line proved economic in 2032 for the Drought scenario.

9.3.5 San Antonio Region



San Antonio is notably different from other load pockets within ERCOT, possessing a well-defined 345-kV loop around the metropolitan area. This grid topology provides San Antonio with the flexibility to move imported power to all parts of the city and provide a redundant path should any segment on the loop experience an outage.

In this study, to maintain reliable operations, ERCOT determined that the Hill Country to

Skyline circuit required upgrading in almost every scenario. Further, in addition to an upgrade to the Hill Country to Skyline line, by 2032 ERCOT needed to add one or more new or expanded connections to the 345-kV loop to operate the grid reliability. Thermal limitations of existing 345-kV import connections to the San Antonio loop were exceeded before steady-state voltage limitations in most scenarios. To maintain reliable operations in this planning study, ERCOT determined that continued load growth and/or retirement of existing urban resources internal to the 345-kV loop required additional connectivity from the 345-kV loop to the 138-kV system between 2022 and 2032. To maintain system reliability, the Drought with PTC and Emission Costs scenario studied by ERCOT required upgrades of multiple connections to San Antonio's 345-kV loop, shown in Figure 23.

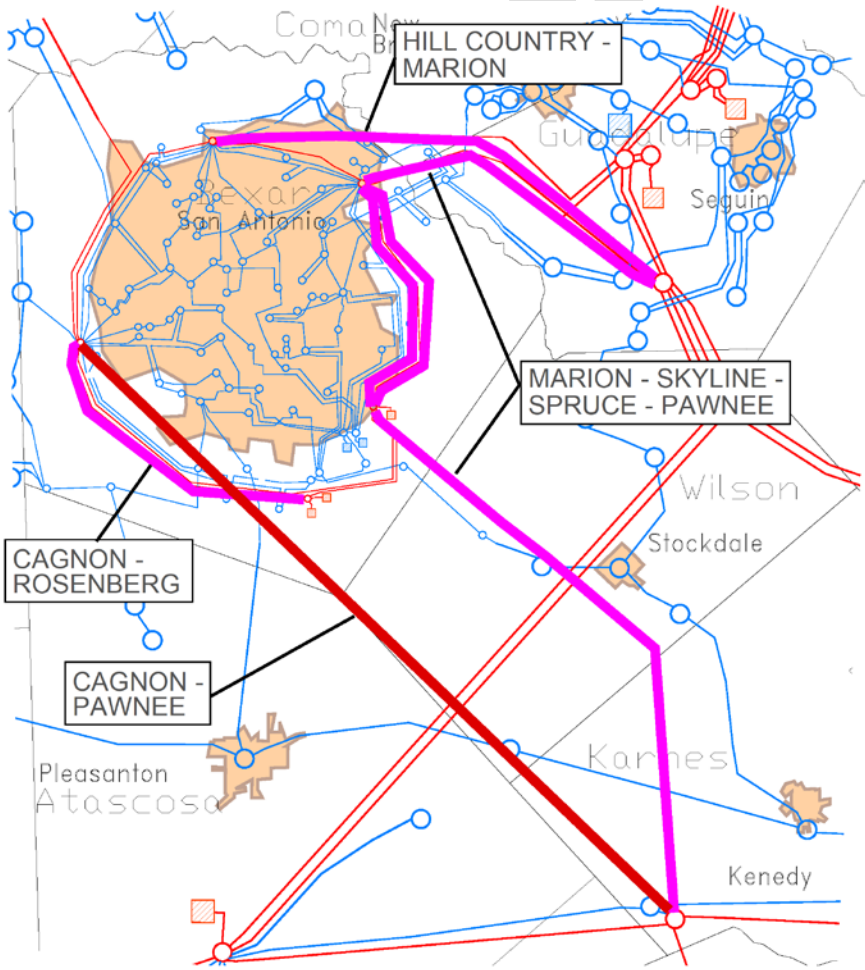


Figure 23 —Reliability Upgrades for San Antonio/Drought with PTC Scenario

High loads associated with the Drought scenarios accelerated the need for dynamic reactive support and/or additional 345-kV connections to the loop. Similarly, the Retirement scenario required amounts of expanded connections and/or dynamic reactive support. Alternatively, if West Texas wind development reaches levels comparable to what was modeled for the

Business as Usual with Updated Wind Patterns scenario, then new import needs to maintain voltage stability are delayed until 2030.

From an economic perspective, the import lines (Hill Country to Marion and Skyline to Marion) connecting the 345-kV San Antonio loop to the 345-kV corridor that runs parallel to Interstate Highway 35 (Hutto to Clear Springs) exhibit significant congestion across multiple scenarios. To address the loss of either of these two circuits, ERCOT identified limited options to redispatch the resources internal to the San Antonio loop and those options resulted in significant congestion. These redispatch limitations were most pronounced in the Retirement scenario because fewer thermal resources remained available in that study. A map of the economic expansion projects that ERCOT evaluated are in Figure 24.

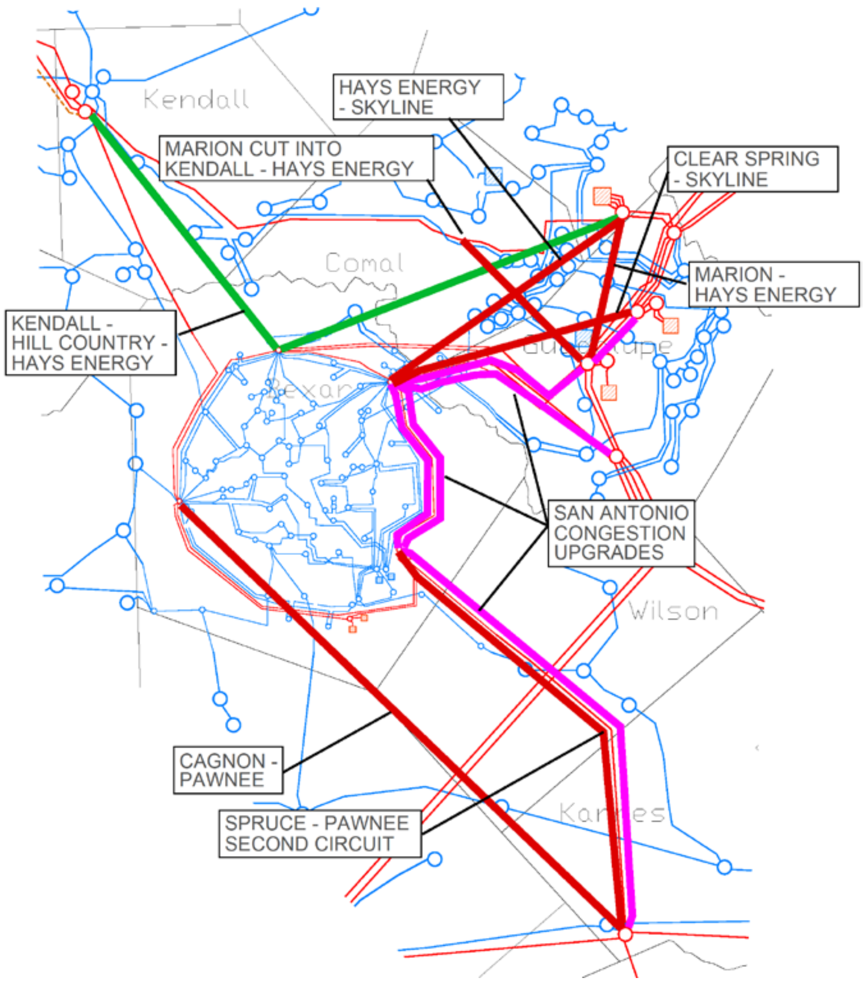


Figure 24 — Economic Options Tested in San Antonio

ERCOT assessed multiple options to add additional connectivity to the 345-kV ring and mitigate the individual impact of a contingency to any 345-kV circuit connection to the ring. System upgrades on all sides (north, south, east, and west) of the outer ring were evaluated. Over the 10-year horizon, upgrading the capacity of the existing Marion to Skyline and Skyline to Hill

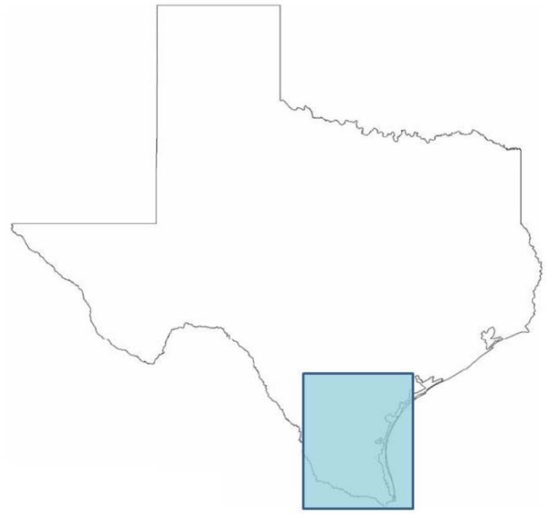
Country 345-kV lines was the most economic option tested, although the analysis did not consider congestion costs associated with the outage to upgrade these circuits. As will be discussed in Section 9.6, The Brattle Group proposed additional metrics to evaluate economic transmission projects which included consideration of avoided congestion costs during outages. Table 14 shows the expansion projects that satisfied the economic justification.

Table 14 — San Antonio Economic Project Assessments

Tested Project in 2032	Voltage Category (kV)	New Line or Upgrade Existing Line?	Capital Cost (2032 $M)	Economic in Scenarios	Economic in How Many Scenarios?
Spruce to Pawnee 2nd ckt	345	Upgrade	**38**	**Drought; Drought - Low NG Price**	**2**
Cagnon to Pawnee	345	New	**295**	**BAU - 50-yr Retirements; BAU - High NG Price**	**2**
Clear Spring to Skyline	345	New	**91**	**Drought - Low NG Price**	**1**
Hays Energy to Skyline 345-kV line	345	New	**120**	**Drought**	**1**
Kendall to Hill Country to Haysen	345	New	**412**	**BAU - 50-yr Retirements**	**1**

By 2032, new 345-kV connections to the San Antonio loop were economically justifiable for the Drought, BAU - Retirement, and BAU - High Natural Gas Price scenarios, despite expansive upgrades needed to maintain reliability. Scenarios with high coastal wind, such as the Business as Usual with a High Natural Gas Price or Drought scenarios favored southern connections to the 345-kV loop. Some uncertainty surrounds the reliability upgrades modeled in this study because they may ultimately be difficult or impractical to perform because of the duration and outage requirements associated with such upgrades. As such, the identified reliability upgrades should be viewed as surrogates for new import paths should they prove to be infeasible. Therefore, if any of the 345-kV projects connecting to the San Antonio loop are infeasible, then it is likely that a similarly designed project, connecting to the 345-kV loop at a new substation and sectionalizing the 345-kV loop would achieve the same objectives.

9.3.6 Lower Rio Grande Valley



The Lower Rio Grande Valley (LRGV) area is located at the southernmost portion of the ERCOT region along the international border with Mexico. It includes the cities of Edinburg, McAllen, Harlingen, and Brownsville. The area is experiencing high rates of population and economic growth and, consequently, a corresponding high rate of electric load growth. Currently, local natural gas generation and power imports from the rest of the ERCOT system primarily serve the load. The region currently relies upon two existing major 345-kV import paths from the rest of the ERCOT system, the Ajo to Rio Hondo and the Lon Hill to North Edinburg lines.

For the scenarios in this study, ERCOT determined that already planned transmission expansion projects will likely provide sufficient and reliable bulk transmission service for the 20-year planning horizon assuming that additional generation resources are developed within the LRGV. This area does not currently have the resource siting constraints that limit other, more urbanized load centers in ERCOT. Additionally, if coastal wind resource development expands significantly, ERCOT identified potential economic advantages to construction of higher-voltage transmission lines to facilitate power exports.

Two major 345-kV transmission additions serving the LRGV are underway. The first project, a third 345-kV line in to the LRGV, will improve the power transfer capability into the region, add redundancy with the two existing circuits, provide ready expansion to serve future needs, and increase the maintenance window for the two existing 345-kV circuits. This project has received the necessary regulatory approvals and construction has begun. The other major LRGV project, referred to as the Cross-Valley project, will traverse the region to strengthen the bulk-power infrastructure within the LRGV so the region will meet the reliability requirements of the ERCOT system and will prevent a large amount of load shed in the Brownsville area under certain contingency conditions. The Cross-Valley project is pending regulatory approval, which is expected by the end of 2013. ERCOT expects completion of both of these projects by 2016. Figure 25 shows a map of the new and existing transmission lines that serve the region.

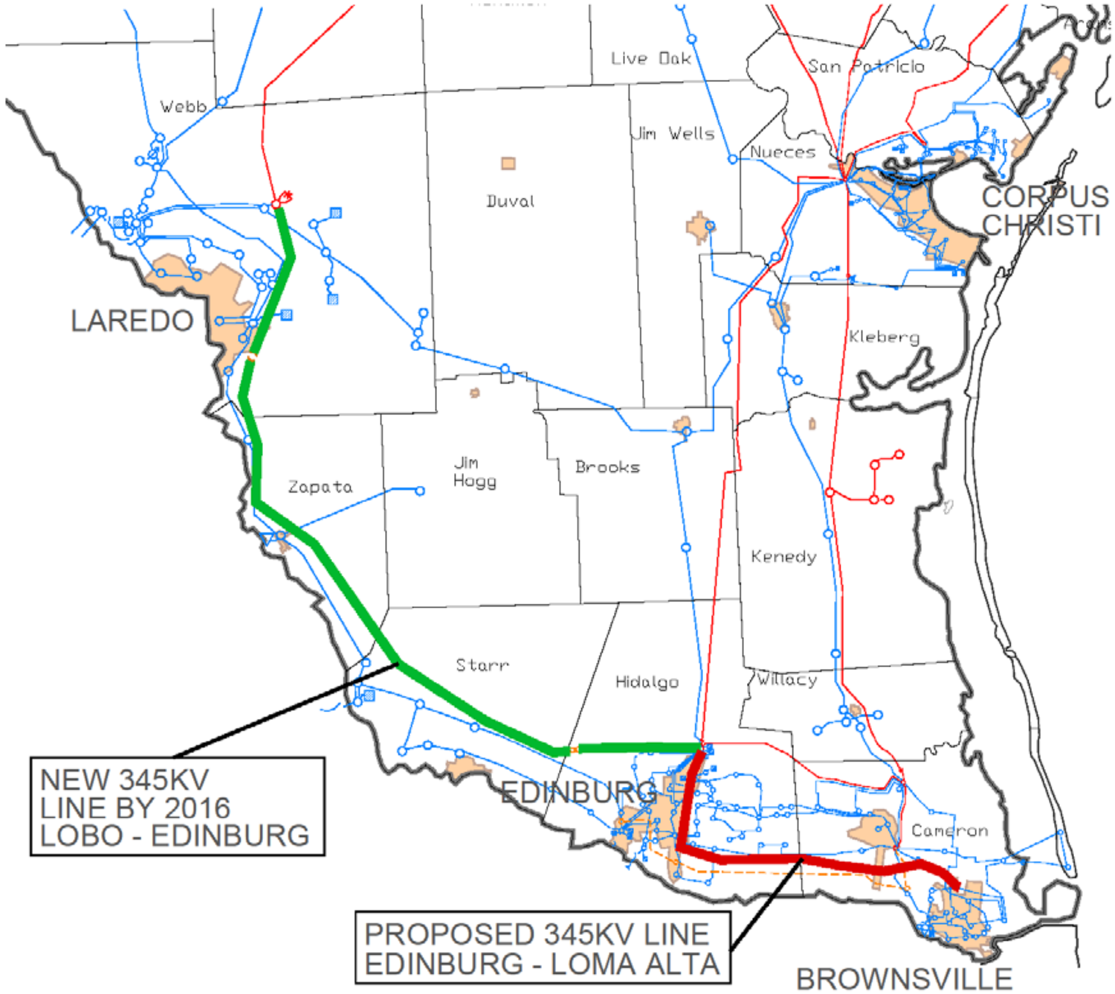


Figure 25 — Lower Rio Grande Valley New and Existing Lines

If no new generation resource development in the LRGV occurs, the region will require an additional import path to address voltage stability issues by 2021. Additionally, the Brownsville Public Utilities Board advised ERCOT about a possible large, discrete load addition as large as 250 MW. ERCOT evaluated the transmission needs with and without the possible load additions. ERCOT's evaluation indicated that if the region added that load but did not add any local generation, the additional import path could be needed as early as 2016. After ERCOT completed its analysis regarding the possible load expansion, the Brownsville Public Utilities Board reduced their proposed load addition to 150 MW. With or without the discrete load addition, the need for the second circuit occurs within the next 10 years of the study, assuming no new generation resource development in the LGRV area.

After the completion of the third import path to the LRGV, the transmission system will have significant flexibility to address any new load or voltage stability issues that develop. While the third 345-kV import path will be constructed as a single-circuit line, it will be placed on double-circuit capable towers. The addition of a second circuit to the line could become the most cost-effective option to increase import (and export) capability to and from the LRGV area or address voltage stability issues.

Significant coastal wind development in South Texas, however, would create opportunities for expanded exports from the LRGV. Because of the long distances between the major load centers in ERCOT and the LRGV, ERCOT assessed the effectiveness of 500-kV lines for scenarios with high wind resource additions associated with

- elevated natural gas prices,
- extended periods of drought, and/or
- continued policy support for renewable generation.

In all the scenarios, the construction of 500-kV infrastructure to transport energy from the hypothetical wind units in South Texas satisfied the ERCOT economic planning requirements. If wind resource expansion becomes prolific along the Texas Gulf Coast, ERCOT will study exports from South Texas to major ERCOT load zones in shorter-term study horizons and consider possible higher voltage solutions.

9.3.7 ERCOT-wide Transmission Upgrades

The aggregation of the various upgrades ERCOT identified in its regional analyses provides insight into the differing degree of additional transmission lines and transformers the scenarios require over their 20-year transmission plans. Table 15 summarizes the miles of transmission lines added or upgraded and the number of transformers added or upgraded for each scenario. Depending on the scenario, during the first 10 years, ERCOT added or upgraded between 4 and 49 138 kV/345 kV transformers by 2022 and as many as another 72 in the next 10 years. In addition to the transformers, ERCOT modeled the addition or upgrading of transmission lines. Again, depending on the scenario, the miles of new or upgraded transmission lines ranged from 301 to 1,727 miles by 2022. During the next 10 years, ERCOT modeled the need for at least 684 miles of additional transmission lines, for the Drought with Low Natural Gas Prices up to over 3,000 miles for the Business as Usual – Retirement Scenario. The transmission plans and needs varied notably among the scenarios.

Table 15 — Aggregate Transmission Upgrades by Scenario

Scenario	2022 Transmission Lines Addes or Upgraded (miles)	2032 Transmission Lines Added or Upgraded (miles)	2022 138 kV/345 kV Transformers Added or Upgraded (MVA)	2032 138 kV/345 kV Transformers Added or Upgraded (MVA)
BAU All Technologies	628	1,930	14	35
BAU Retirements	796	3,099	4	72
BAU w/ Updated Wind Shapes	301	1,847	16	53
BAU w/ High NG Price	942	1,103	28	44
Drought	534	911*	29	*
Drought w/ Low NG Prices	614	684*	49	*
Drought w/ PTC and Emission Costs	1,727	1,017*	27	*
*** For the 2032 drought scenarios, results reflect only the 345-kV system.**				

9.4 Major Findings

9.4.1 Dependency on Legacy Resources

In the 2000s the ERCOT market experienced significant addition of new generation and retirement of older, less-efficient generation. The notable exception to this trend occurred in the major metropolitan areas where the remaining units, which were built in a regulated era to serve the major metropolitan area where they are located. As Dallas, Houston, Austin, and San Antonio become increasingly urban, redevelopment and expansion of existing and/or new resource construction in these areas may become increasingly difficult because of public opposition and increased environmental scrutiny. The remaining urban legacy units have become critical contributors to the reliability and stability of major ERCOT load centers. As mentioned in the Scenario Development section, the BAU with Retirements scenario was developed to assess the impact on transmission system needs of assuming the retirement of these older units.

In this scenario, retirement of gas-fired units over 50-years in age removed both reactive support and local real power sources from heavily loaded urban regions. Consistent with other scenarios, ERCOT assumed that sites located within National Ambient Air Quality Standards nonattainment areas were not eligible for redevelopment. Figure 26 shows the location and timeframe for the retirement of the resultant loss of resources. As mentioned previously, a complete list of the resources retired in that scenario appears in Appendix C.

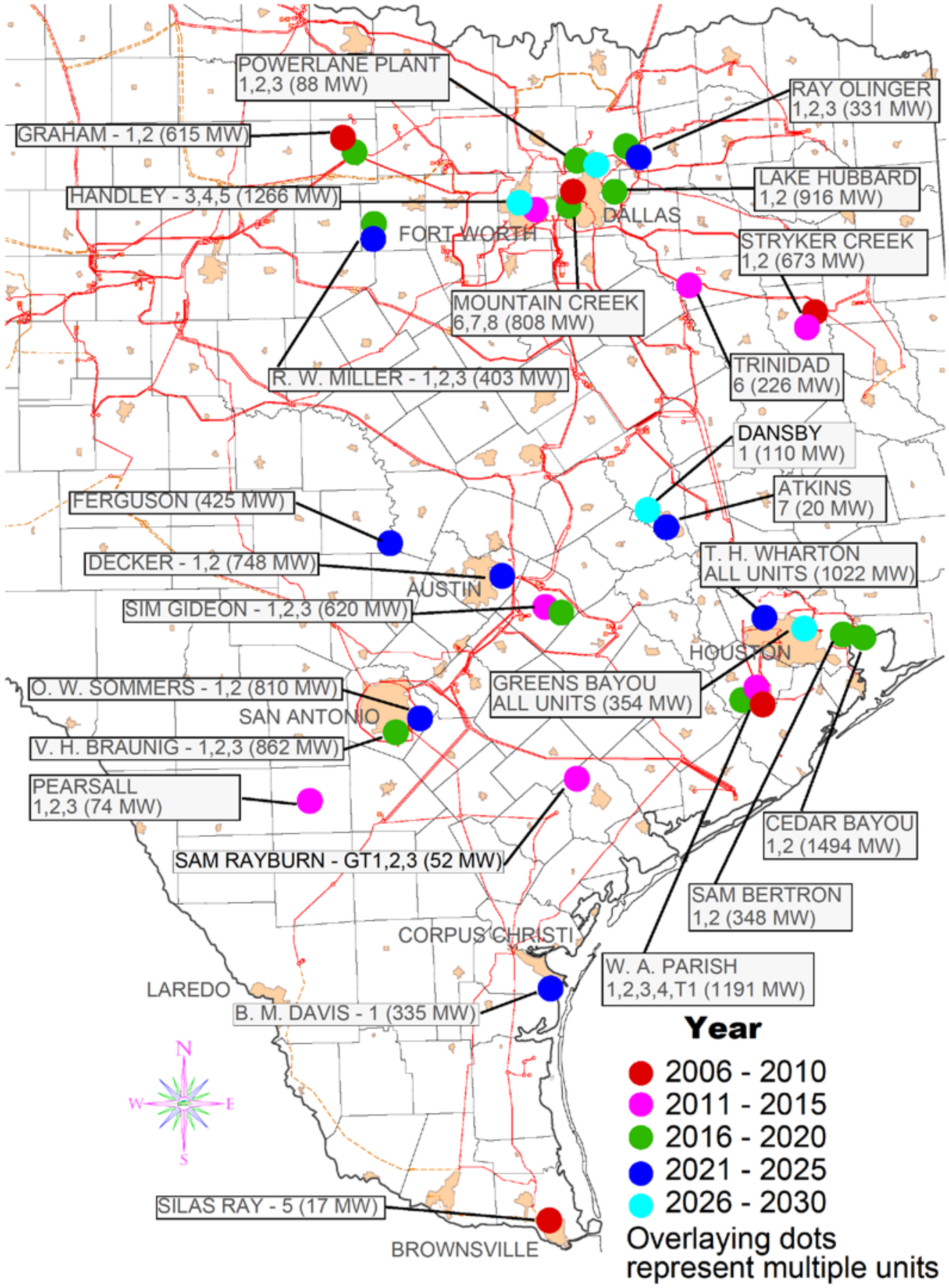


Figure 26 — Resources in ERCOT Approaching 50 Years of Commercial Operation before 2030

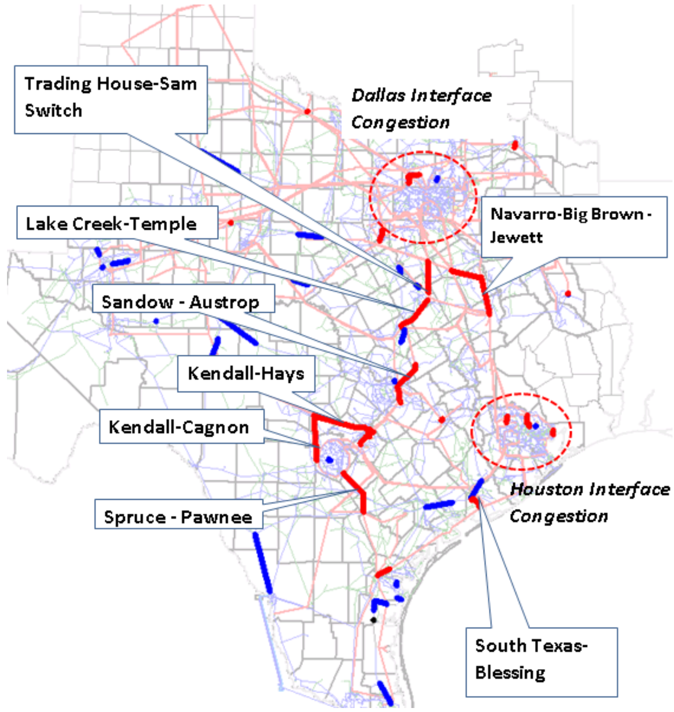
All major ERCOT load pockets experienced significant resource retirements in this scenario. Each load pocket suffered a decrease in real and reactive power sources, decreasing both local generation and import capabilities on a pre- and post-contingent basis. In general, transmission needs (both for new import pathways and increased autotransformer capacity) increased by approximately 30%. The resultant loss of resources was most notable in the DFW and Houston metropolitan regions. The lack of critical, significant reactive resources threatened stable operations as early as 2018 in the Houston region. Analysis conducted as part of this study indicated that the loss of this generation could not be offset by addition of dynamic reactive devices in the urban centers. Rather, those areas required new import pathways given these scenario assumptions.

The DFW and Houston metropolitan regions will each need multiple new import lines without timely and suitably located development of new sources of generation (i.e., a combination of continued operation of legacy resources, redevelopment of existing resources and/or development of new resources within each load pocket). To satisfy reliability criteria Houston required new import paths before 2022. Consistent with ERCOT's conclusion, CenterPoint Energy brought a proposal for a new import path into Houston to the RPG. In the Retirement scenario, new import lines would be needed by 2027 and 2030, to allow for approximately 2 GW of gas-fired resources to retire upon reaching 50 years of commercial operation. The DFW region was less affected by retirements than Houston; however the region required one new import path before 2022 to develop maintain reliability. DFW retirements were more prominent in the 2022-2032 timeframe, calling for incremental import paths by 2029 and 2032 for stability, following retirements of 1.4 GW of gas-fired capacity. Retirements in this scenario would also affect reliability in the Austin and San Antonio regions by 2028 and 2024, respectively.

The retirements in all regions created significant increases in congestion rents, shown in Table 16. The Houston area import paths were among the most congested on the ERCOT system. Because studies have already shown the need to increase import capability into the region for steady-state stability, ERCOT tested conceptual economic projects in and around Houston. By 2022, multiple Houston import projects satisfied ERCOT's current economic criteria for transmission expansion based on production cost savings.

Table 16 — Congestion Rents Experienced in 2032 for the Natural Gas Retirement Scenario

From Bus Name	To Bus Name	Congestion Cost ($M)
Houston Interface	Houston Interface	629.6
DFW Interface	DFW Interface	605.9
ELDORADO LIVE OAK	SONORA	51.2
BIG BROWN SES	NAVARRO_345	39.4
NACOGDOCHES SOUTHEAST	NACOGDOCHES SOUTHEAST	33.8
CRMWD#8 TAP	GLENHAVEN	23.2
HAYS ENERGY	KENDALL	20.6
COBISA_T1	MONTICELLO SES	20.3
FAYETTE POWER PLANT	SALEM	19.9
HIGHWAY 9	GILA	12.4
ZORN	HAYS ENERGY	11.6
LEWISVILLE SWITCH	ROANOKE 345 KV TAP #2	10.9
L_SWEETWN3_5	L_SWEETWN3_8	9.9
GREENS BAYOU PLANT	KING	8.9
WHARTON, T H PLANT	ADDICKS	7.7
MERIDA	WESTSIDE	7.3
MOSS	ODESSA SOUTHWEST	6.3
PFLUGERVILLE	GILLELAND CREEK	5.9
BOSQUE SWITCH	LAKE WHITNEY TNP	4.6
ZORN	MARION	3.9
LOLITA	VICTORIA PLANT	3.9
CAGNON 345	KENDALL	3.7
ELM MOTT	ELM MOTT	3.4
DOW-VELASCO	DOW CHEMICAL-FREEPORT	3.4



Despite the extensive reliability upgrades required through the study, ERCOT identified opportunities for economic expansion of the transmission network in the DFW, Houston, and San Antonio regions. With few resources remaining to buttress stability-constrained import limits on existing and reliability upgraded 345-kV lines, congestion rents into Houston, DFW, and San Antonio were among the highest modeled on the system. New 345-kV lines into the DFW and Houston regions satisfied economic expansion criteria Regardless of new resource locations, if urban gas-fired resources retire, then multiple 345-kV imports into the Houston region would be required by 2032 and several expanded import options would be justified based on their production cost savings to the system

While only natural gas fired plant retirements were modeled in the Retirement scenario, other thermal retirements, such as the announced the retirement of the J.T. Deely plant, would have a similar effect on congestion rents and reliability needs. The J.T. Deely plant is an 871-MW coal resource connected to the 138-kV system internal to the 345-kV loop around San Antonio.

The disparate timelines for the retirement of generation units and for construction of transmission upgrades further complicates the associated planning. New import transmission lines into major load centers may take five to six years to design and construct. Currently ERCOT Protocols require a generation resource owner to notify ERCOT only 90 days before retiring a resource.[29] Because generation resource retirement may drive the sudden need for a

[29] *ERCOT Nodal Protocols*, Section 3.14.1.1.

new import transmission line, ERCOT believes future long-term studies and annual Regional Transmission Plans should examine such a possibility to identify possible solutions and quantify the possible costs and risks.

9.4.2 Continued Drought Conditions

The extended drought scenarios imposed higher loads and water costs on system simulation, as further described in Section 5.1.10. The increased system loads coupled with water costs called for vast expansion of existing import paths into the load pockets within the major metropolitan areas of San Antonio, Houston, and DFW. The most severe need for expanded imports into all load zones was observed when high loads were coupled with water costs and emission costs.

For this scenario, ERCOT needed several upgrades or additions to the 345-kV network in its models to achieve reliable operations. ERCOT achieved no reliable dispatch solution for this scenario without expansive upgrades on the 345-kV network. Houston required upgrades of all existing 345-kV imports into the region, plus an additional new line to resolve overloads. DFW required at least two new lines into the region. San Antonio required multiple new and expanded connections to its existing 345-kV ring. Figure 27 shows the transmission upgrades needed for the drought scenarios.

If low natural gas prices occur coincident with an extended drought, then the profitability of certain generation units located within urban areas improves greatly. If low natural gas prices, grandfathered water rights, and opportunities to generate electricity during high-priced shortage hours keep urban units competitive, then the need to expand import paths into major load zones is delayed slightly, though the overall impact is still prolific in terms of upgrades to the existing 345-kV network.

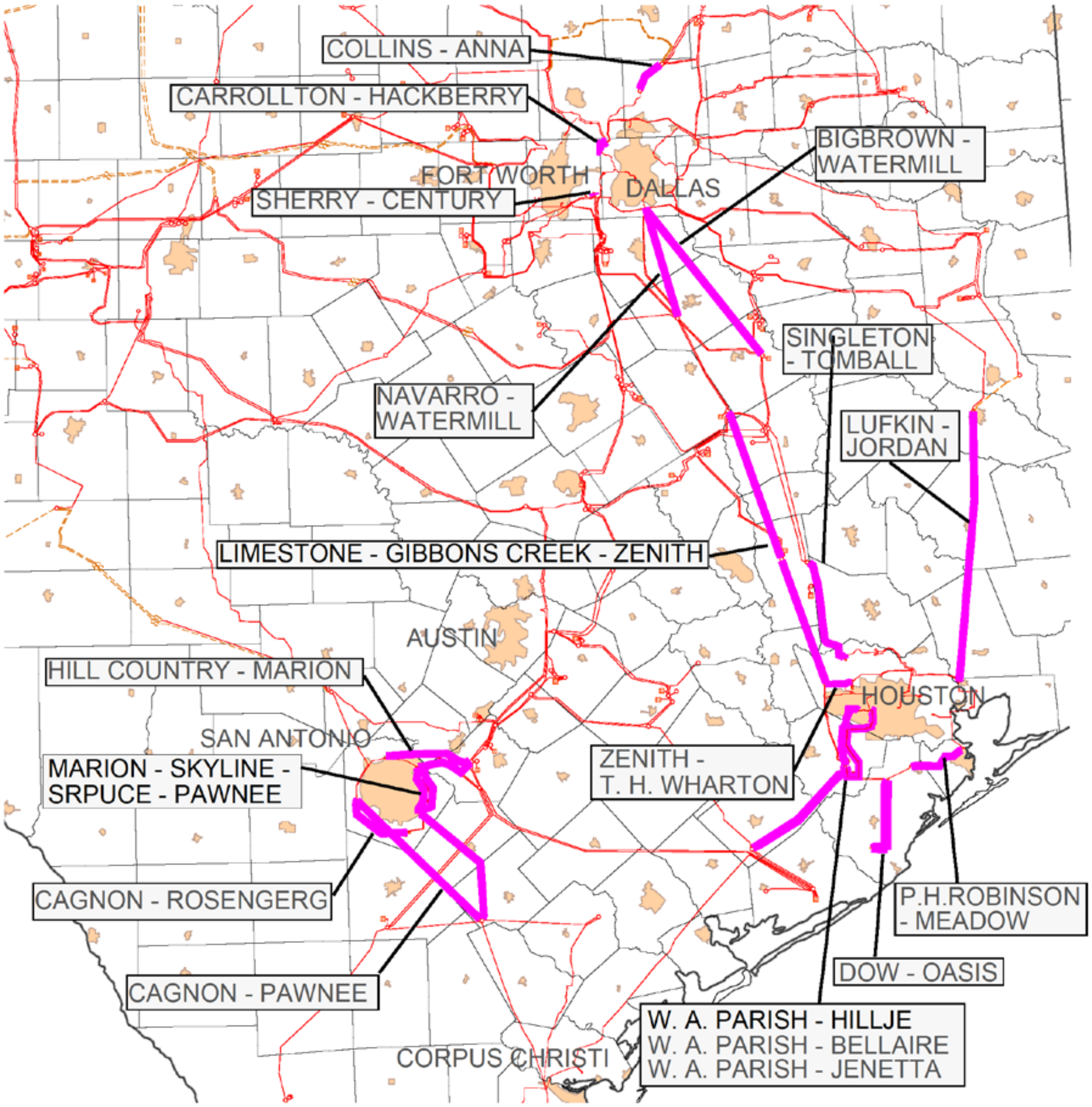


Figure 27 — 2032 345-kV Overloads for the Drought Scenario

After considering must-have reliability upgrades for drought scenarios and sensitivities, ERCOT's studies justified other economic expansion of import paths into major load zones. Exports from wind-dominated regions created opportunities to expand the existing EHV system into the 500-kV voltage class. Five-hundred-kilovolt projects transporting wind power from both West Texas and coastal regions demonstrated savings commensurate with their cost.

If a drought scenario were to persist in the ERCOT region, and fuel and environmental constraints favored wind resource expansion, then the accompanying transmission system needs would far exceed the existing CREZ capacity. Note that the wind integration proposed in the Drought Scenario with continued production tax credit far exceeds what has been studied for reliable system operation.

9.4.3 Integration of Wind and Renewable Resources beyond CREZ capacity

Various scenarios studied in the context of this assessment demonstrated increasingly favorable economics for continued wind generation expansion. When the PUCT approved the CREZ transmission construction, it selected a design that would deliver a total of 18.5 GW of wind generation from West Texas, given assumptions regarding placement of wind. In the scenarios with the greatest wind expansion, the existing design capacity for CREZ transmission lines is exceeded within the 10-year horizon. General findings from these scenarios include:

- A strong CREZ system with total wind resources nearing 18,500 MW of capacity greatly negates the congestion-related need for new south and eastern import pathways into the DFW metropolitan region.
- At wind levels beyond CREZ design specifications, additional import capacity is required from the west into the DFW region. CREZ facilities that were designed to be double-circuit capable, but built as a single-circuit line, will require the second circuit to accommodate wind beyond original design specifications. In several resource expansion studies, this need occurred before the year 2022.
- Voltage-stability limits may constrain wind power delivery from the Texas Panhandle to the rest of the ERCOT system thus requiring one or more additional export lines.

The most advantageous wind patterns exist in the northern-most regions of the ERCOT System, within the Texas Panhandle. These sites are currently under development for existing and pending interconnection requests. If developers continue to build projects in the Texas Panhandle over the next 10 years, then stability limits constraining exports from that region may threaten further expansion and reliable wind power deliverability. Based on steady-state model analysis, once wind output from the Panhandle region exceeds 6 GW of exports, one or more additional export lines from the Panhandle may be needed. Figure 28 depicts preliminary projects that ERCOT considered in this long-term study.

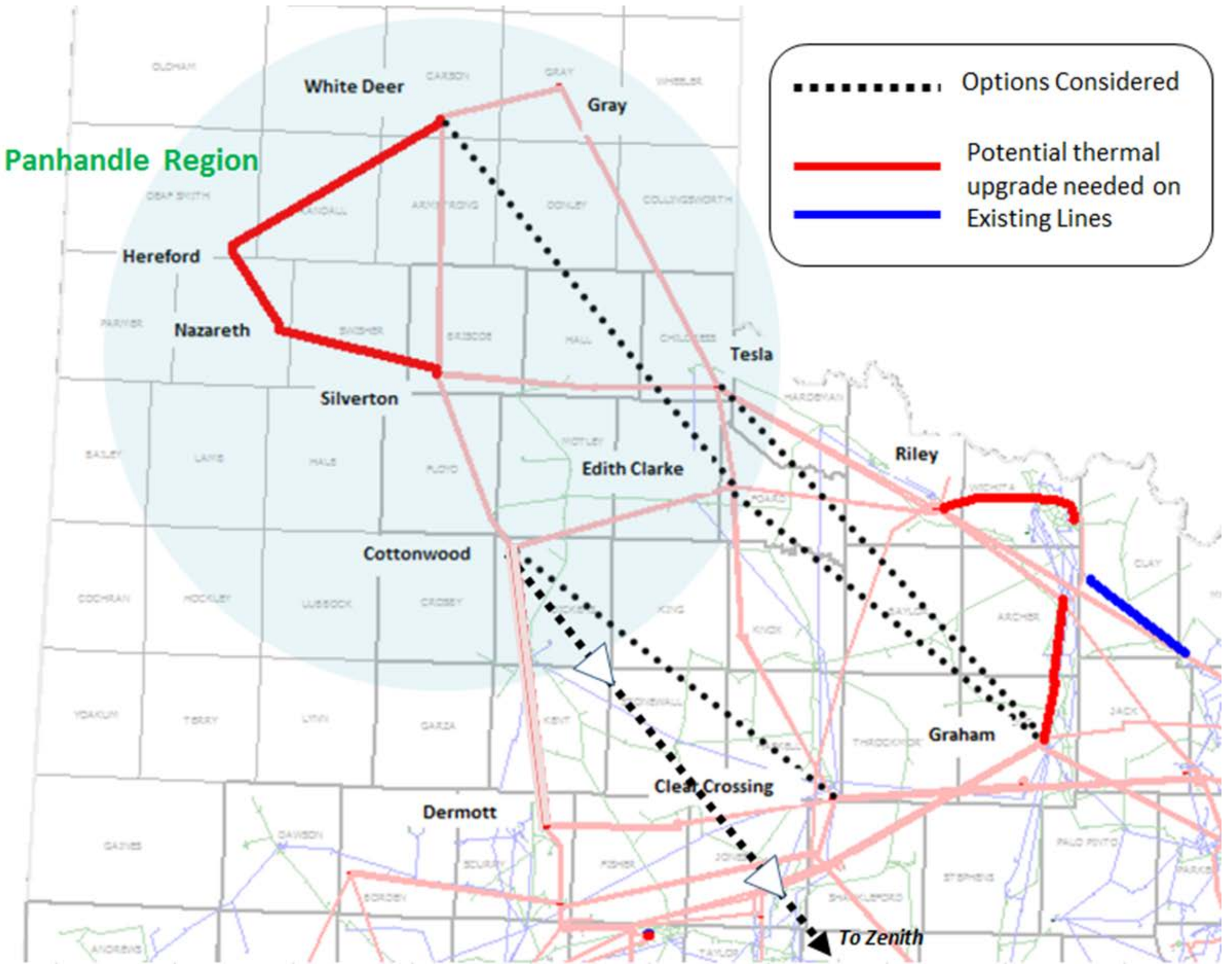


Figure 28 — Expanded Connectivity to the Texas Panhandle

Based on the results of this analysis and because more than 10 GW of wind generation in the Texas Panhandle was in the interconnection study process, apart from this report, ERCOT initiated a special study in early 2013 to determine the next set of transmission system improvements that will be needed to support wind generation exports from the area.

9.4.4 Expanding the ERCOT Transmission Network beyond 345 kV

The ERCOT system includes transmission elements energized at voltages from 69 kV up to 345 kV. Historically, the benefits of a low-impedance, high-capacity EHV line greater than 345 kV have not been cost-effective when compared against lesser-cost 345-kV solutions. The increase in rights-of-way and substation costs associated with construction, when compared to transmission construction at lower voltages, has outweighed the incremental benefits of 500 or 765-kV connections. However, in this study, ERCOT identified numerous opportunities for EHV expansion at voltages above 345 kV, given scenario-specific assumptions.

ERCOT identified several large projects designed to move low-cost power long distances into major load regions. All of these projects required significant investments, greater than

$1 billion, but had this high cost offset by significant production cost savings. Table 17 shows the basic financial results of the 500-kV projects that satisfied the economic justification criteria. The adjusted capital cost column includes the capital costs of the economic project, less avoided or deferred reliability projects, plus any additional projects needed to maximize the economic benefit of the overall project. Three projects satisfied the economic criteria in more than one scenario. Figure 29 show a map of the 500-kV transmission projects listed in Table 17.

Table 17 — 500-kV Transmission Projects that Satisfied the Economic Justification Criteria

Tested Project	Scenario	Adjusted Capital Cost ($M)	1/6 of Adjusted Capital Cost ($M)	Production Cost Savings ($M)	Meet ERCOT Economic Criteria?	Benefit Cost Ratio
Tesla to Graham to Carrollton 500-kV line	BAU w/ High NG	1,247.8	208	370	Yes	1.8
Rio Hondo to O'Brien 500-kV line	BAU w/ High NG	2,384	397.3	533	Yes	1.3
Cottonwood to Clear Crossing to Zenith 500-kV line	BAU w/ High NG	2,293.7	382.3	710	Yes	1.9
Bowman to Zenith 500-kV line	Drought	1,196.8	199.5	229.5	Yes	1.2
Tesla to Graham to Carrollton 500-kV line	Drought w/ PTC	2,066.9	344.5	1,172.9	Yes	3.4
Rio Hondo to O'Brien 500-kV line	Drought w/ PTC	3,581.9	597	1,989.7	Yes	3.3
Cottonwood to Clear Crossing to Zenith 500-kV line	Drought w/ PTC	3,654.6	609.1	911.6	Yes	1.5

Building transmission infrastructure to allow low-cost power to reach a region with high-cost power is the essence of economic transmission expansion. Highly concentrated new wind development in the Texas Panhandle and West Texas, as modeled in the High Natural Gas Price scenario, would economically justify 500-kV connections from the existing CREZ areas in West Texas to Houston and DFW. Similarly, if the coastal region of South Texas becomes an area of concentrated incremental wind capacity, then the analysis indicates that 500-kV connections between South Texas and Houston would also return sufficient production cost savings to satisfy ERCOT's current economic criteria.

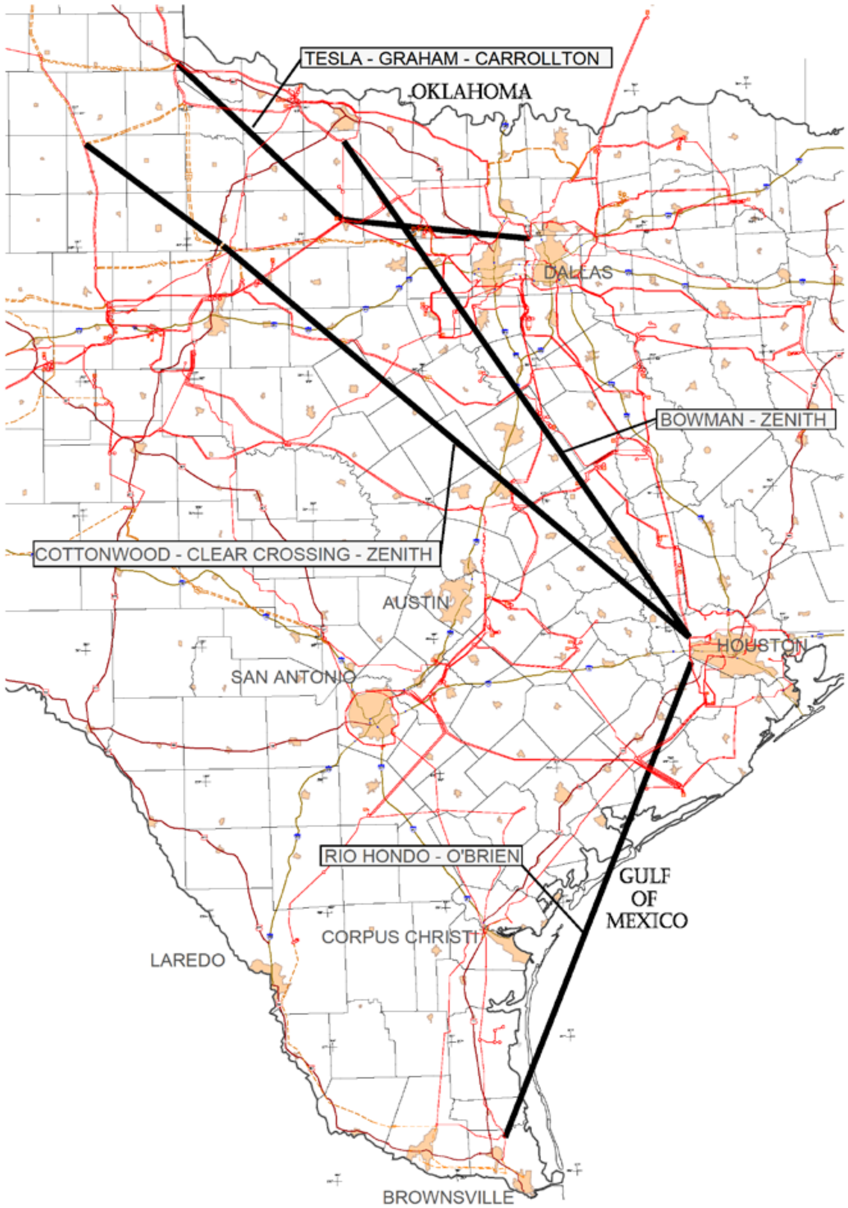


Figure 29 — 500-kV Transmission Projects that Satisfied the Economic Justification Criteria

Similarly, with increased water costs associated with a sustained drought, and slightly elevated loads, as modeled in the Drought and Drought with PTC scenarios, ERCOT identified some 500-kV transmission projects that would satisfy the economic justification criteria and facilitate the transport of the scenario's anticipated significant wind generation resource build out. The direct connections to Houston and DFW from wind-dominated regions in West Texas and the Texas Panhandle studied in this scenario returned production cost savings and reliability benefits commensurate with their cost.

The analysis in this study indicated the benefits of transmission projects at voltages greater than 345 kV in scenarios containing significant expansion of low-cost generation distant from loads. ERCOT will continue to evaluate 500-kV solutions as part of its transmission evaluation process.

9.5 Assessing the Future Adequacy of Ancillary Services (KERMIT)

To determine the viability of future scenarios that include increasing proportions of wind, solar, energy storage, or demand-response resources, ERCOT studied the ability of these hypothetical resource expansions to maintain system frequency. The adequacy of system frequency response is driven by technology-specific response and availability characteristics of the deployed generation resources. Wind and solar resources inherently have operational limitations because their maximum output varies from moment to moment and that variability depends on the instantaneous availability of their primary resource. The variability of wind and solar resources when combined with the changing load is called "net load." With intermittent resources on the system, load-following resources must follow the changes in net load, which can be greater than changes in load alone. Further, because the output from intermittent resources can change in the opposite direction as load, in certain circumstances net load changes can be much larger than the load changes alone.

As mentioned previously, ERCOT procured KERMIT to evaluate its effectiveness for modeling the intra-hour operations of the electric system and thereby evaluate the impacts of greater penetration of intermittent resources and technologies that support their integration. This analysis, as detailed below, determined that ERCOT's existing ancillary service products and procurement levels are inadequate to support the levels of wind penetration modeled in several scenarios in this long-term study.

Wind generation dominated the resource expansion portfolios in scenarios with market or regulatory conditions favoring renewable resource additions. The modeling for the Environmental scenario suggested that absent transmission or system operations constraints over 70 GW of wind generation may be present on the ERCOT system within the next 20 years, based solely on evaluation of hourly system dispatch. However, the resultant system simulation included inter-hour generation ramps in excess of 12 GW. Balancing intermittency of this magnitude exceeds the generally accepted ability of the existing market and system dispatch tools.[30] The Environmental Scenario provided an opportunity for ERCOT to assess the ability of current ancillary service products and procurement practices to balance the large real-time net-load changes and to identify complementary regulation resources needed to meet

[30] *Analysis of Wind Generation Impact on ERCOT Ancillary Service Requirements*, General Electric, (Mar. 28, 2013).

existing balancing and frequency control standards if significant wind development occurs on the electric system.

As wind-dominated hours pushed conventional generation to minimum output levels, and unit-commitments included fewer thermal resources, the simulated system had less ability to meet intra-hour ramps and/or recover from large system disruptions. Where hourly production cost models fail to recognize the impact of increased intra-hour disturbances or changes in resource availability, KEMA's KERMIT model quantifies, by means of a second-by-second simulation, the performance and ancillary service needs of a system dominated by intermittent resources.

Ancillary service needs for increasing proportions of intermittent resources were quantified as the amount of aggregated ramping capability needed to maintain system frequency, also referred to as balancing. As the amount of integrated wind increased and the magnitude of net-load ramps correspondingly increased, the necessary amount and speed of ancillary service deployment also increased. In other words, the KERMIT tool simulated how much balancing energy is needed to manage both normal net-load intermittency and the largest simulated wind-resource net-load change.

ERCOT performed KERMIT simulations of two Long-Term Study scenarios with differing proportions of wind. The Business as Usual with Updated Wind scenario resembled a full build-out of the CREZ system with approximately 20 GW of total wind resources. The Environmental scenario represented a future where stringent environmental restrictions favored significant wind development. This portfolio included 50 GW of interconnected wind. Table 18 and Table 19 show characteristics of the intermittent generation and system load for the 20-GW and 50-GW scenarios studied in KERMIT. From its modeling results and intermittent generation data, ERCOT identified the hour during the year when the largest amount of intermittent energy was produced, when the contribution of intermittent generation at minimum system load occurred, and when intermittent generation contributed the greatest share toward satisfying load.

Table 18 — Characteristics of the 20 GW Renewable Scenario

20 GW Scenario (18 GW wind & 2.5 GW solar)	Intermittent Production, MW	Intermittent Contribution as % of load	Load, MW	Date, Time
Max Intermittent prod.	14,200	29%	48,400	04/08, 11 am
Min load	9,700	33%	29,500	10/28, 2 am
Max Intermittent contrib.	14,155	38%	37,600	04/08, 4 am

Table 19 — Characteristics of the 50 GW Renewable Scenario

50 GW Scenario (50 GW wind & 1.5 GW geothermal)	Intermittent Production, MW	Intermittent Contribution as % of load	Load, MW	Date, Time
Max Intermittent prod.	29,200	41%	71,800	08/02, 3 pm
Min load	9,700	29%	33,000	10/15, 5 am
Max Intermittent contrib.	24,600	72%	34,000	03/22, 2 am

From an ancillary services adequacy perspective the most challenging hours are those with intermittent resources serving a high percentage of load. These hours will have less conventional generation online capable of responding to net ramp changes and supporting system frequency. Output from the model analysis of the Business as Usual with Updated Wind scenario indicates results similar to current operations with high intermittent contribution during early hours of spring and fall days. However, in the 50-GW study, peak hours in summer appear to exceed acceptable operating conditions because of the increased contribution from intermittent generation and elevated net load variability. To prepare adequately for the largest anticipated net-load change, ERCOT procures ancillary services sufficient to serve the highest anticipated seasonal magnitude of change in net load. As demonstrated in the tables above, increased diversity of location and technology of renewable resources has the potential to increase, seasonally, the minimum procurement of ancillary services.

DNV KEMA helped ERCOT identify a statistically significant sample of days to simulate. Utilizing 2011 actual ERCOT data to build this sample, DNV KEMA verified that the sampled days adequately represented a full year of operation. ERCOT and DNV KEMA performed simulations on these sample days to identify both normal and large system ramps and the corresponding system response with both traditional and enhanced ancillary service portfolios.

Figure 30, Figure 31, and Figure 32 illustrate 5, 15, and 30-minute net-load changes for the 50-GW Study scenario, the 20-GW Study scenario, and 10-GW historical data. Operational data from 2011 provides a reference level in each figure. Intuitively, for larger proportions of wind energy, net-load ramps increased in magnitude. Diversified wind plant locations tended to cause a slight reduction in the frequency of relatively small magnitude net-load ramps. Similarly, less frequent high-magnitude ramps became more prevalent in all time horizons for both scenarios. These impacts appeared most clearly in Figure 32. The histogram for the 50-GW Study scenario, which has the largest proportion of intermittent generation, shows the occurrence of larger net-load ramps than present in the results of the 20-GW Study scenario or the 2011 historical data. Beyond the expected observation that the magnitude of net-load ramps increase along with greater net-load on the system, the system challenge became the reduction in resources to provide that needed generation ramping capability as intermittent resources displaced conventional resources.

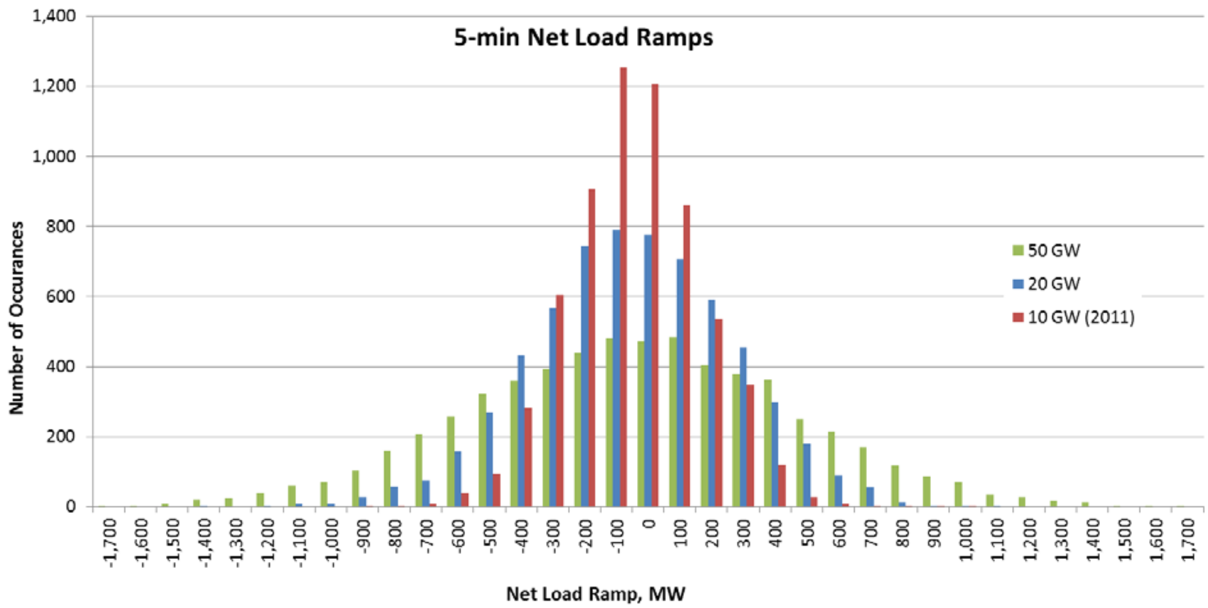


Figure 30 — 5-minute Net Load Ramps for 20 GW, 50 GW, and 2011 Renewable Levels

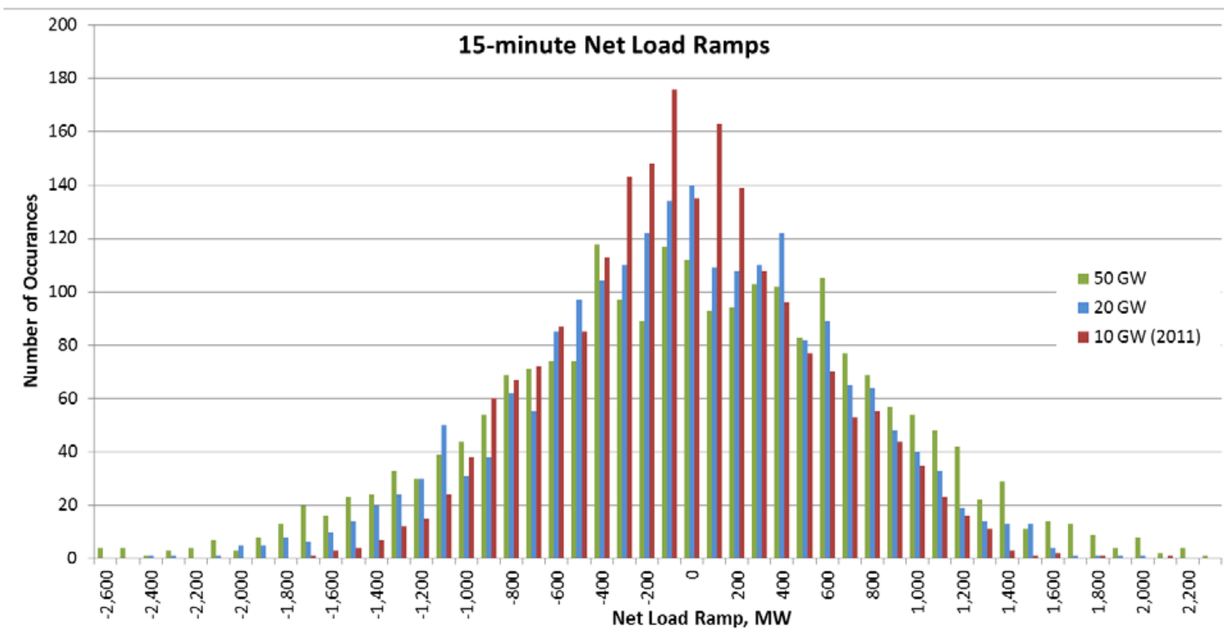


Figure 31 — 15-minute Net Load Ramps for 20 GW, 50 GW, and 2011 Renewable Levels

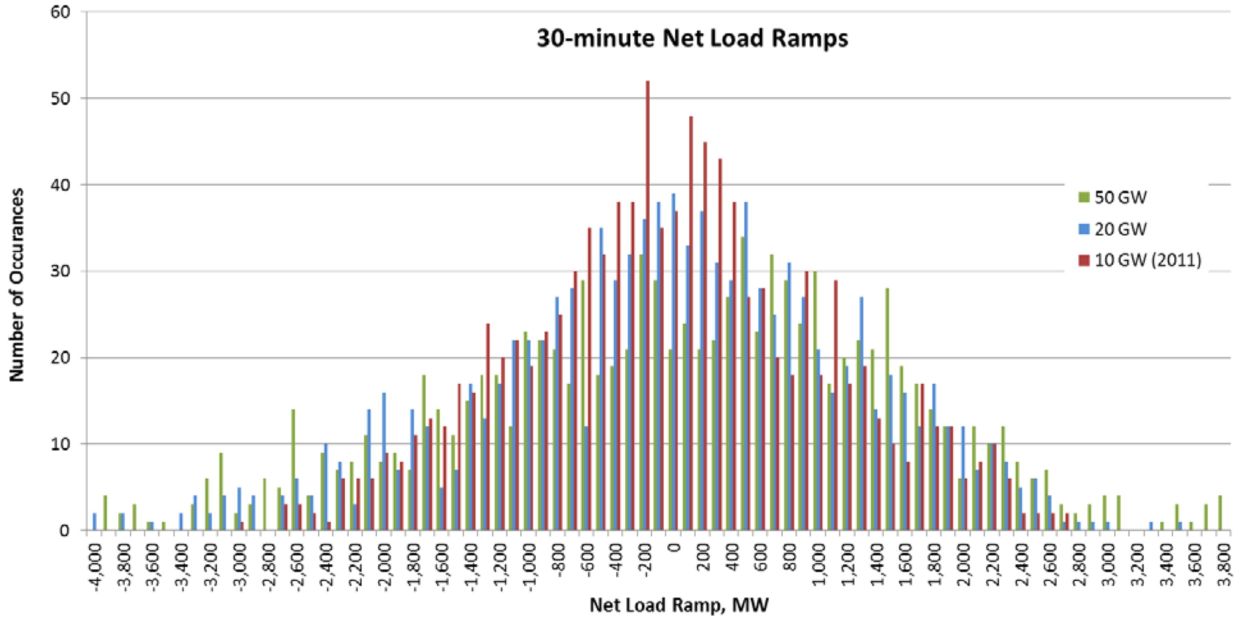


Figure 32 — 30-minute Net Load Ramps for 20 GW, 50 GW, and 2011 Renewable Levels

For the studied scenarios, the increased demand for balancing energy for varying durations were identified by:

- Quantity (MW) needed, and
- Time duration for full deployment of the balancing resource.

For this assessment, ERCOT introduced a hypothetical, new, quick responding product capable of providing power in less than five minutes. The results were both informative and expected. As net-load ramps increased with higher proportions of interconnected wind, KERMIT identified a need for more resources capable of providing power on a zero-to-five minute basis. Table 20 illustrates the ancillary services requirements needed to balance the scenarios studied. The ancillary service requirements from 2012 were included in the table for reference. ERCOT also included 600 MW of regulation reserves to approximate the historical quantity of that service procured. For 20 GW of wind generation, KERMIT identified the need for an additional 800 MW of capacity capable of deployment in the zero-to-five minute range to achieve comparable balancing to current frequency maintenance performance standards. For the 50 GW of wind scenario, the needed additional capacity of the hypothetical zero-to-five minute product increased to 1,300 MW. This product could be added either as new five-minute ancillary service product or additional Regulation Service requirement. The needs for a 30-minute (potentially off-line resource) remained unchanged for both scenarios when compared to the initial KERMIT run. Total ancillary service capacity increased from 3,300 MW to 4,100 MW and 4,600 MW in the 20-GW and 50-GW studies, respectively. While the installed intermittent resource base increased 400% in the 50-GW Study scenario, the amount of additional ancillary services increased only 50%. However, the need for a new, more flexible ancillary service product was evident.

Table 20 — Reserves Requirements for Simulations of 20 GW and 50 GW of Wind and Historical Operations

	Historical Reserves 2012		Initial KERMIT Run	20 GW Scenario	50 GW Scenario
Total Nameplate Wind (GW)	10		10	18	40
	Min	Max	Max	Max	Max
Regulation Reserves (MW)	240	940	600	600	600
Responsive Reserves (MW)	1,400	1,400	1,050	1,050	1,050
Additional zero-to-five minute product (MW)	-	-	-	**800**	**1,300**
Non Spin Quick Start – 5-minute start, 10-minute ramp (MW)	470	2,000	1,650	1,650	1,650
Total (MW)	2,110	4,340	3,300	4,100	4,600

The hypothetical 5-minute product in these solutions does not correspond to any particular technology or currently existing market product. This solution assumed that any technology that can start-up and deploy within five-minutes notice (e.g. batteries, demand response resources, etc.) may provide this service. While there is no existing market product for resources that can dispatch from zero to full capacity within five minutes, ERCOT assumed that should the need arise in the next 20 years, that emerging or existing market technologies would provide a market-based solution. Alternatively, this need can be addressed by increasing capacity procured for Regulation Service. One of the advantages of the KERMIT model is its ability to evaluate combinations of capabilities and operating characteristics to satisfy ancillary service needs. This flexibility permits the study of possible resource characteristics different than those associated with existing technologies.

Figure 33 and Figure 34 show frequency performance on the simulated days with and without additional reserve capacity for the 20 GW and 50 GW of wind scenarios. Each graph also includes actual 2011 frequency observations as a reference. The probability distribution curve in those figures displays the frequency performance for each scenario. For any frequency level, measured in Hz and plotted on the x-axis, the curve shows the probability that this frequency occurred on y-axis. Frequency is usually well controlled around 60 Hz with little deviation. Increased net-load variability associated with a larger percentage of renewable integration caused KERMIT to indicate frequency observations outside of the desired range. With additional reserves, as shown in Table 20, KERMIT resolved the balancing challenges and system frequency remained within the acceptable ranges, as shown in the histograms. Therefore, KERMIT predicted that frequency performance comparable to that achieved in historical operation is achievable. As modeled, frequency performance appears slightly better than would be expected in reality. In the model, generators respond without delay that would be observed with real-world control systems and computational delay. Further, no forced unit outages were simulated after model calibration.

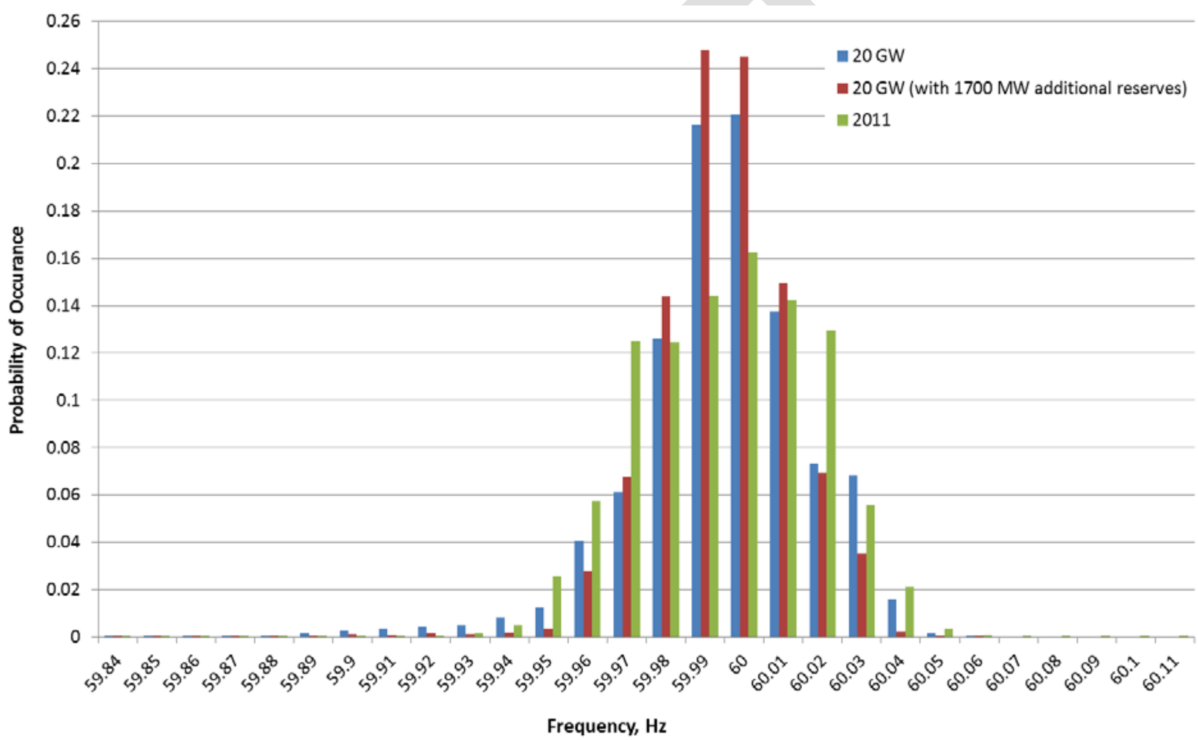


Figure 33 — Frequency Probability Distribution, 20 GW of Wind.

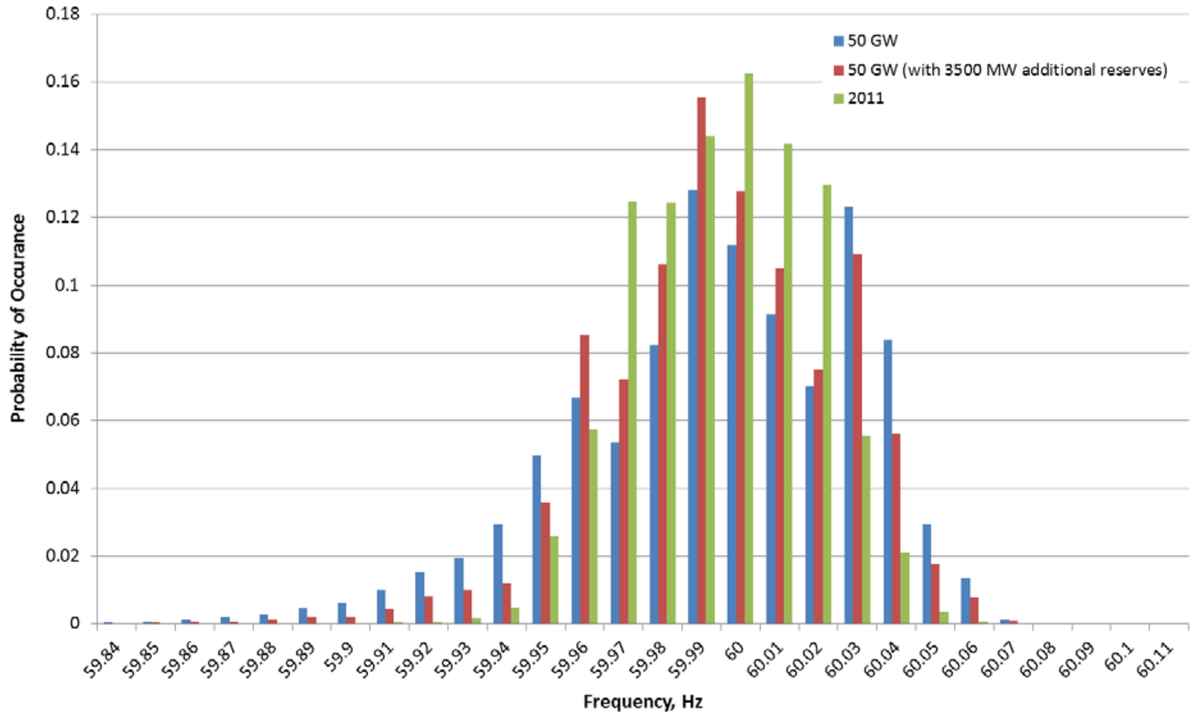


Figure 34 — Frequency Probability Distribution, 50 GW of Wind

The future price of ancillary services was not considered in the scope for this study. Qualitatively, significant increases in the demand for ancillary services would likely be accompanied by an increase in price. Increased deployment of ancillary services may also cause suppliers to adjust their offers to consider their opportunity cost in other markets. Typically, system regulation is primarily provided by units also providing energy. If a unit has already committed to provide energy, participation in an ancillary service market does not consider start-up costs, as it is a forgone (sunk) cost. Wind-dominated scenarios studied as part of this assessment identify hours where wind is on the margin, and, given the low marginal cost of energy, thermal units may de-commit. If thermal units cycle to provide the grid flexibility needed to integrate incremental wind resources, then the cost of regulation service would likely include start-up costs or the costs to keep units on-line despite very low market prices. The price of ancillary services should increase to reflect the reliability benefit provided from this flexibility such that payments to providers are commensurate with their costs (including opportunity costs associated with non-participation in other energy markets) and required rates of return.

As the cost of ancillary services increases with increased demand to balance intermittent output, the economics of a resource portfolio may change. For example, if thermal, dispatchable resources generate a larger percentage of their revenue from ancillary services, then emerging storage technologies may become more competitive. On the other hand, if no competitive procurement process can yield sufficient system ramping capability, then further integration of intermittent resources may impair system reliability or ERCOT will take other actions to ensure reliable grid operation. Either outcome should trigger a re-assessment of the economics of each technology modeled in the scenarios. The re-assessment would consider the economics of every resource inclusive of ramping needs, ancillary service revenue, and the resultant competitiveness of each technology. In this study, the increased cost of ancillary services associated with higher levels of renewable integration was not reflected in the economic assessment of probable resource expansion portfolios, but it should be considered in future studies.

9.5.1 Societal Cost of Continued Intermittent Resource Integration

The assessment of ancillary service adequacy, thus far, solely identified viable ancillary service portfolios to accompany varying levels of wind integration. ERCOT's primary purpose in acquiring the KERMIT software for this study was to implement and evaluate the model itself. It was not within the scope of this study to determine how the price and availability of ancillary services may change with increased demand and deployment of ancillary resources. For example, ERCOT routinely procures interruptible loads, quick start, and other resources to support current levels of intermittent resource integration. In this study, ERCOT modeled a scenario with significant deployment of these ancillary resources to support a large proportion of modeled wind generation in the available generation fleet. ERCOT did not investigate how a load or a resource might respond to the opportunity to provide such a service nor did ERCOT attempt to predict the price for such a service or the revenues different technologies might produce or the opportunity costs they might incur by providing those services.

Similarly, as wind generation provided a greater proportion of the energy demanded in the scenarios of this study, revenues to traditional resources decreased. In certain scenarios, significantly less thermal resource expansion occurred as wind set the marginal cost of energy in more hours. This reduction in thermal resource expansion further eroded reserve margins, because, as previously discussed, ERCOT currently includes wind resources at only 8.7% of nameplate capacity when determining the system reserve margin. However, with diverse wind resource sites and site-specific wind patterns, adequate energy was available to serve anticipated future demand. In ERCOT's studies, the effective deliverable capacity of wind far exceeded the capacity contribution traditionally included in ERCOT's reserve margin calculation.

As mentioned in an earlier section, many of the scenarios produced resource expansion plans with low reserve margins, in part because the ERCOT's ELCC for wind is lower than the observed capacity contribution from wind resources in the modeling. To perform transmission analysis, ERCOT required flexibility in the generation fleet to re-dispatch generation to relieve congestion issues. In this context, flexibility of resources ensured that transmission needs were not exaggerated because of a lack of resources. ERCOT supplemented the generation resources with additional thermal capacity, “administrative units,” sufficient to satisfy the planning reserve margin of 13.75%. Each “administratively” added resource was modeled as the lowest capacity-cost resource available, a combustion turbine. The amount of administrative capacity varied across scenarios depending on the resource expansion additions determined by economics. During the transmission analysis portion of this study, the administrative units ran with less than a one percent capacity factor.

When assessing this practice after the fact, the presence of these units had little to no impact on the resulting transmission system results. Capacity factors on these resources were very low. Many units never delivered energy in the simulation.

However, given the decreasing reserve margins, ERCOT found it reasonable that in times of scarcity, some of these resources either provided energy or met balancing needs. Reduced reserve margins placed a higher priority on all resources to serve energy needs. Ancillary services prescribed from the KERMIT assessment may be increasingly dependent upon this “administratively” created capacity. As previously discussed, ERCOT models the resource entry and exit from the market by simulating the financial incentives for those resources. Because it does not want to distort that competitive behavior, ERCOT will continue to identify and assess circumstances in which its models rely on otherwise-uneconomic resources and evaluate appropriate methods to better address the needs those administrative resources satisfy.

9.6 Assessing the Societal Benefit of Transmission Network Expansion

ERCOT’s current economic transmission planning criterion considers the economic value of a proposed economic project against its estimated first-year cost to transmission service customers.[31] When considering the economic value of a project, ERCOT currently determines it by estimating the anticipated production cost savings over the first in-service year of the project. If estimated production cost savings in the first year exceed one-sixth of total project cost, then ERCOT endorses the project as meeting the criterion for economic transmission expansion. ERCOT’s reliance on the financial measures from the first year of operation provides a margin for error in that evaluation because in most instances the benefits typically increase in later years and the production costs drop as the installed transmission assets depreciate in value and the regulated return on those assets declines accordingly.

When conducting near-term analyses, such as those in the RTP, ERCOT evaluates the societal benefit of potential economic transmission expansions according to the PUCT’s rules and ERCOT protocols. For longer-term studies, such as ERCOT’s biennial LTSA or this study, which

[31] *ERCOT Nodal Protocols*, Section 3.11.2.

do not include final recommendations for specific lines or transmission solutions, ERCOT can explore broader considerations regarding the financial merit of a potential project. This study provided ERCOT the opportunity to assess whether other measures should be considered in future long-term studies.

ERCOT retained The Brattle Group to review ERCOT's economic planning process, and to provide recommendations about expanding the planning criteria and metrics to quantify more accurately the societal benefit associated with transmission network expansion. For example, ERCOT would like to improve its process to consider the fact that network expansion may improve reliability, dispatch flexibility, and/or outage availability. Each of these factors, among others, offers real value to society that ERCOT's existing economic planning methodology does not capture. Underestimating the benefits of proposed transmission expansions and upgrades will result in underinvestment in economically efficient projects and can lead to higher societal costs and higher delivered cost of power for electric customers.

The Brattle Group participated in several recently completed projects of similar size and scope. Notably, Brattle helped the Southwest Power Pool (SPP) define new metrics for their Integrated Transmission Planning process through the "Metrics Task Force" that developed benefit metrics for the SPP. SPP's traditional benefit metrics were already more comprehensive than ERCOT's – emphasizing not only production cost and avoided reliability project cost savings, but also qualitatively considering a range of other benefits. Brattle helped SPP monetize a range of other benefits, including mitigation of transmission outage costs, capital savings attributable to reduction of minimum required capacity margins, reduced loss of load probability (LOLP), and reduction of the cost of extreme events, among others.

Traditionally, ERCOT transmission planners derive the economic merit of a conceptual economic transmission project by comparing system production costs of a Base Case without the project of interest to the production costs of a Change Case that includes the project of interest. Production cost simulations provide estimated total annual "production costs," which are composed of fuel and variable operating costs for a given set of network topology, system loads, and simulated short-term variable costs of each resource on the system. This metric is a commonly-used measure of economic savings associated with transmission upgrades and planners have been using it because it is easy to interpret and expedient to calculate. However, by assessing production cost savings exclusively for the first year of a transmission project's operation, the evaluation process will tend to overlook any of the benefits to transmission system expansion that are not included in traditional production cost methodology.

Brattle recommended that ERCOT modify its economic benefit methodology to capture the longer-term benefits of potential economic transmission projects as well as other factors to quantify and capture other benefits. Specifically, Brattle recommendations included: (1) linking near- and long-term planning processes; (2) evaluating economic projects based on their net present value (NPV) or a comparison of levelized benefits and costs rather than solely their first year of benefits; (3) expanding the scope of benefits considered and quantified; (4) improving the use of scenarios and sensitivities; and (5) enhancing the process for identifying projects and the benefits/costs associated with specific projects. These additional metrics could be applied to each major economic project or portfolios of projects found most promising based on production cost savings and avoided or deferred reliability projects. Among the benefit metrics they identified, Brattle recommended that ERCOT:

1. modify its long-term market simulations to capture the impact of forced generation unit outages and ancillary service unit designations;
2. more fully estimate the reduced (or possibly increased) production cost associated with project-related changes in transmission losses;
3. study the typical impact of transmission outages on project-related production cost savings to develop a multiplier applicable to standard estimates of production cost savings going forward;
4. similarly develop a multiplier to capture the disproportionately higher project-related benefits during weather-related spikes in peak loads and associated transmission congestion costs;
5. modify simulations to capture more completely cost reductions (or increases) attributable to a project's impact on the operational cycling of power plants;
6. estimate any decreases (or increases) in installed generation requirements because of changes in on-peak transmission losses; and
7. more fully consider emission-related costs (including for long-term risk mitigation benefits).

The Brattle Group's full report to ERCOT appears in Volume 2 of this report and contains more thorough discussions about the various improvements they proposed.

Toward this effort, ERCOT undertook some initial effort to test different approaches and metrics for assessing the societal benefits of transmission improvements with the intention to capture more completely the societal benefits associated with transmission network expansion. ERCOT and its stakeholder community may further investigate additional or alternative metrics to identify indirect benefits and costs associated with transmission expansion. In this report ERCOT examined the following items:

- The net present value assessment of a potential economically justified transmission line;
- The potential for additional production cost savings through increased system flexibility, particularly during transmission outages;
- The consideration of load and weather uncertainty; and
- The reduction in on-peak system losses achieved through transmission expansion.

9.6.1 The Net Present Value Assessment of a Potential Economically Justified Transmission Line.

According to current ERCOT practice, economic justification of a transmission project occurs when the simulation of the production cost savings during the project's first year of operation, which represents the estimated benefit of the transmission project, exceeds one-sixth of the construction cost, which serves as an approximation of the project's first-year revenue requirement. In their evaluation of ERCOT's transmission planning process, Brattle observed that this method could potentially miss beneficial projects for three main reasons:

- Production cost savings tend to grow over time with increases in load and fuel prices. Therefore the production cost savings during the first year are generally lower than the levelized benefit over a longer term.
- Transmission revenue requirements decline over time as the assets are depreciated. Therefore the first-year project cost, which is currently estimated as one-sixth of the construction cost, is higher than the levelized cost over a longer term.
- There are other potential benefits and avoided costs beyond only simulated production cost savings that ERCOT should consider.

For these reasons and others, the industry, including other RTO/ISOs, generally use an NPV-based approach that calculates the present value of future production cost savings over a longer-term period and compares that with the present value of other measurable benefits and costs over that same time period. A typical practice for determining production cost savings would be to calculate the difference between two sets of production cost simulation cases, one with the new economic transmission project under evaluation, the Change Case, and another without it, the Base Case, while holding all other assumptions constant. The net present value of these future production cost savings, when compared to the net present value of the revenue requirements of the economic upgrade in the Change Case, would indicate the net economic value of the project. For an economic project, the present value of the benefits would need to exceed the present value of the costs.

Brattle recommended that the costs and benefits associated with proposed economic transmission projects be compared based on their present-values or levelized values, as a more standard and accurate comparison that is more consistent with common industry practice. The present values of benefits and costs are estimated as the sum of future annual benefits and annual costs, both discounted at an appropriate discount rate to reflect the fact that a dollar spent or saved 10 or 20 years from now is significantly less valuable than a dollar saved or spent today. Alternatively, ERCOT could compare the "levelized" values of costs and benefits, as they are the equalized annual values that yield the same present values as the estimated time-varying amounts.

The time frame over which the present values of benefits and costs are calculated is typically 20 or 40 years in other planning regions, although some system operators use time horizons as short as 10 years while others estimate values over the full 50 years of a project's assumed life. The discount rates applied to calculate present values of both costs and benefits are usually approximately equal to the weighted average cost of capital of the transmission owners, although some planning regions, such as the Midcontinent Independent System Operator, also calculate present values by using a lower "societal" discount rate for both costs and benefits.

Figure 35 illustrates how the long-term, levelized benefits of a given project can be much larger than that of only the first year. In fact, one-sixth of the capital investment amount used to approximate the first-year revenue requirement tends to exceed the first-year production cost savings (shown as "Negative First-Year Net Benefits" in the figure), thus making the project appear uneconomic according to ERCOT's current evaluation criterion. In fact, the levelized long-term production cost benefits exceed the levelized annual revenue requirements, which would indicate that the project is actually economically beneficial over the time horizon that Brattle recommended ERCOT use.

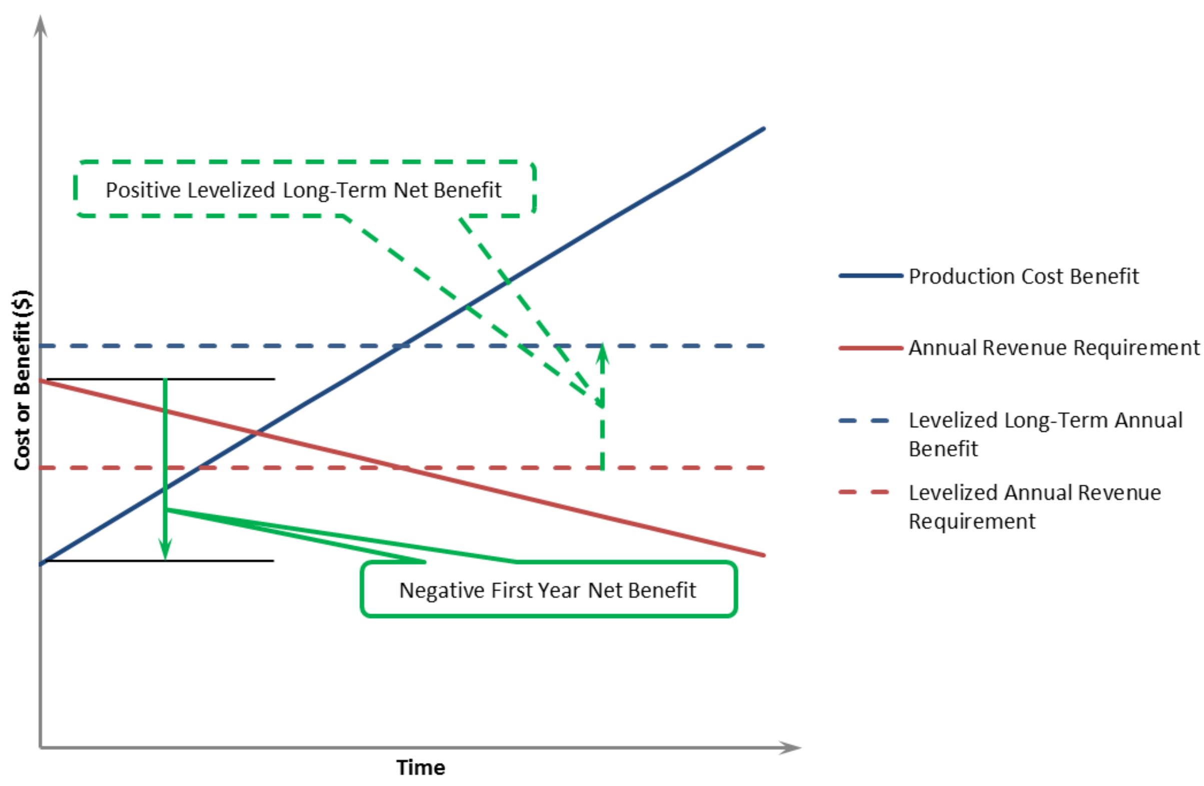


Figure 35 — Comparison of Levelized Savings and Costs

Often, ERCOT evaluates possible economic projects that defer or avoid an otherwise needed reliability project. ERCOT performs economic evaluations based on production simulations after it has resolved any reliability violations (i.e. transmission overloads) present in the base case. For example, if the Change Case (with the new economic transmission project) shows no reliability violations while the Base Case (without the new economic transmission project) shows reliability violations, ERCOT would identify and add the needed reliability projects to the Base Case as a remedy. The Base Case would reflect the production cost savings that accrue from the reliability upgrade. The inclusion of the reliability project permits ERCOT to compare a reliable Base Case against a reliable Change Case. However, these evaluations are performed only for the project's first year of operation.

Brattle recommended that the scope of production cost savings, as currently estimated by ERCOT, should be expanded to include estimates of savings beyond a project's first year to include, for example, estimated savings for years 5 and 10 of the project and using these annual estimates to develop estimates for the long-term present value of a project's production cost benefits. The benefit associated with an economic project's ability to defer or avoid reliability projects should similarly be expanded beyond the project's first year to reflect the present value of reduced or deferred reliability investments.

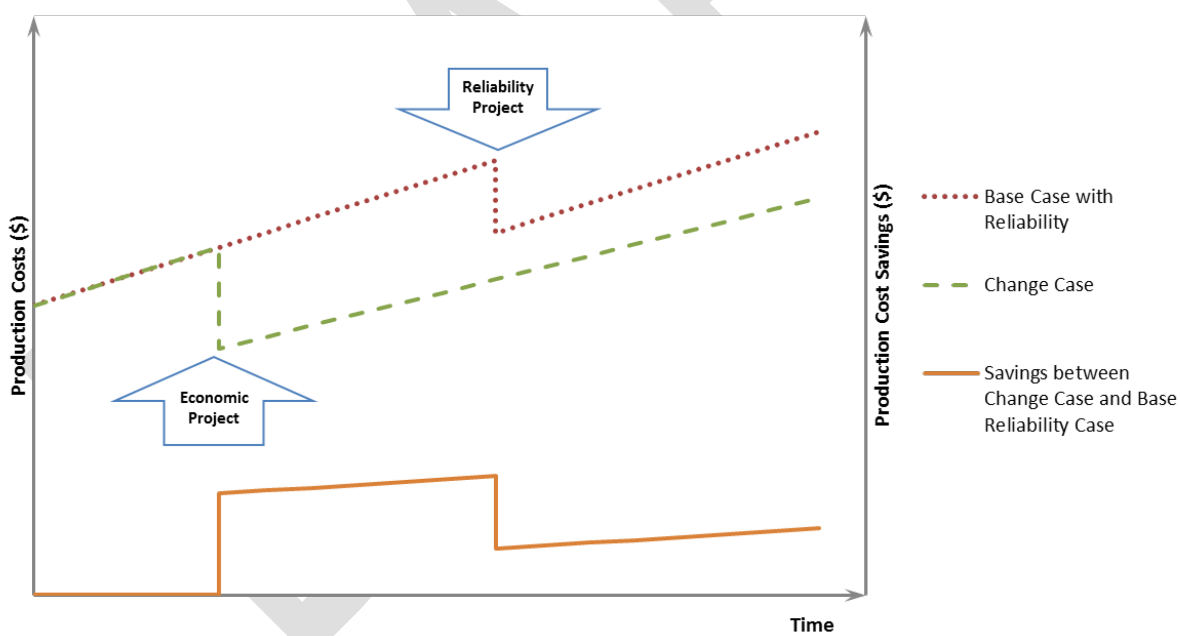


Figure 36 — Comparison of Production Cost Savings

Figure 36 illustrates the production cost comparison when the economic project entirely eliminates the need for a reliability project. The Base Case, the dark red dashed line, includes the reliability project and its production costs reflect the savings that will result from the addition of that project. The Change Case production costs, the green dashed line, include the economic project and reflect the fact that there is no longer a need for the reliability project. The orange line reflects the difference between the two production cost cases. Note the reduced production cost savings after the reliability project would be in service in the Base Case. Because these production costs savings accrue to the otherwise necessary reliability project, they should not be used to justify the economic project. This reduction credits the Base Case with the production cost savings that the reliability project would have created. According to the Brattle methodology, the present value of the reduced production cost savings should be compared to present value of the economic project's revenue requirement, net of the present value of the avoided reliability project's revenue requirement. Thus, a complete economic analysis considers more benefits than just the production cost savings and avoided reliability project costs.

At a minimum, in this example, because the economic project eliminated the otherwise necessary reliability project, the justification for the economic project also includes the credit for the avoided capital investment. While, as mentioned above, the Change Case cannot take credit for production costs savings from the reliability project that would be added in the Base Case, the economic project made the reliability project entirely unnecessary in the Change Case. So the economic project's justification needs to reflect as a benefit the avoided reliability investment. Accordingly, the Change Case needs to reflect the present value of the avoided revenue requirement for the reliability project. The complete economic evaluation in this example includes (1) the present value of the adjusted production cost savings, less (2) the present value of the revenue requirement of the economic project, plus (3) credit for the present value of the revenue requirement of the avoided reliability project.

In a case with a deferred reliability project, the economic justification should reflect the present value of the deferred revenue requirement, but add back in the present value of the reliability project revenue requirement when it would go into rates. The Brattle report in Volume 2 of this report provides a more comprehensive discussion about the net present value analysis as well as the other potential benefits and costs that could be accounted for in the analysis. ERCOT plans to investigate utilization of this NPV approach for evaluation of long-term project benefits in the near future.

9.6.2 Increased System Flexibility/Transmission Outages

Transmission lines and substation components require routine maintenance to deliver reliable service. Typically, logistical issues and safety concerns discourage transmission providers from performing maintenance on energized equipment. "Hot" line work (either expansion or maintenance) is performed only in rare cases when the outage would result in a significant reliability consequence, significant congestion rents, or both. When "hot" line work was not practical or achievable, ERCOT has observed that congestion associated with maintenance outages resulted in some of the highest observed congestion costs. Forced outages also contribute significantly to the accumulation of congestion costs. These planned and unplanned events can significantly increase system production costs.

For example, planned and unplanned outages of parallel autotransformers represented three of the top constraints accruing congestion rents in 2012. The San Angelo Red Creek 345/138-kV autotransformer #2 constraint, shown in Table 21, was among the top 15 most congested elements in the system in 2012 and generated its highest congestion rent in early summer 2012 when a parallel transformer experienced a forced outage. The forced outage lasted three months, from mid-April to mid-July, when the temperatures were warmer and the loads were higher than under normal conditions. ERCOT modeled a similar situation in a future case to determine the effect it would have on congestion if a 345/138-kV parallel transformer experienced a forced outage. In its simulation, ERCOT disconnected one of the Houston-area autotransformers at Greens Bayou from the system for a similar period of time in the early summer and, as a result, the total congestion rent on the system for those three months rose by $23 million, an increase of almost 10% to total system congestion rent.

Table 21 — Highest Congestion Rents, 2012[32]

Constraint	Congestion Rent
Odessa North 138/69kV autotransformer	$134,066,150
China Grove Switch - Bluff Creek Switch 138kV line	$61,898,847
West to North Stability Limit	$27,824,327
Moore Switch - Downie Switch 138 kV line	$20,422,574
Odessa - Odessa North 138 kV line	$18,830,852
San Angelo Red Creek 345/138 kV autotransformer 2	$18,360,051
Turnersville - Buda 138kV line	$17,352,442
Lewisville Switch - Jones Street 138 kV line	$17,099,428
Morgan Creek 345/138 kV autotransformer 4	$14,673,592
Belton - Belton Southwest 138 kV line	$14,490,150
PH Robinson 345/138 kV autotransformer 1	$12,216,587
Amoco North Cowden Tap - Moss Switch 138 kV line	$9,686,322
Buttercup - Whitestone 138 kV line	$7,020,443
Odessa North - Odessa Basin Switch 69kV line	$6,762,448
Fort Stockton Switch - Barilla 69kV line	$6,135,940

Binding constraints with the highest congestion rent from January through October 2012

The ERCOT stakeholder community recognized the impact of such outages as an opportunity to expand and improve planning criteria by adding a new planning criterion that considers the

[32] *Report on Existing and Potential Electric System Constraints and Needs*, ERCOT (Dec. 2012).

extended unavailability of any autotransformer on the ERCOT system.[33] If the removal of any transformer creates an unavoidable overload after the next contingency, then ERCOT or an ERCOT stakeholder may propose a project to relieve that overload. Fixing or maintaining transformers typically requires long-lead times, and their failure or maintenance can lead to lengthy and expensive outages. ERCOT stakeholders observed the adverse impact of these contingencies in real-time during 2012, and expanded the ERCOT planning criteria to ensure that future system planning considers these impacts and mitigate their occurrences. Similarly, critical line or substation outages of extended duration, whether planned or forced, can impose considerable societal costs. High-cost outages or the inability to schedule planned outages needed to maintain and/or expand critical system elements limit the flexibility and impose real costs upon society. Further, increased dependence on existing elements limits outages needed for upgrades and thus the available options for upgrades.

Consider the northern import paths into Houston on the 345-kV system. In every scenario ERCOT studied, these lines were either overloaded or heavily congested by 2022. Upgrading Singleton to Zenith, Singleton to Tomball, or Singleton to Kuykendahl 345-kV lines would require lengthy and costly outages of the existing lines. A planned outage with a sufficient duration to upgrade any one of these lines, each greater than 50 miles in length, would be difficult to schedule. As future loads continue to grow in Houston, these outages (forced or planned) will become increasingly more costly to society.

To illustrate the financial impact of an extended outage of a critical facility, ERCOT modeled a hypothetical outage of the Singleton to Zenith line. Planning engineers simulated the ERCOT system in 2022 with both circuits of the Singleton to Zenith line unavailable for six non-summer months, November to April. With both circuits out of service, the model did not meet reliability criteria. When ERCOT modeled a similar outage on the same line in 2032, both circuits of the line could be removed from service and the system operated reliability, but only because of the construction of an additional, reliability-justified, import path into Houston allowed ERCOT to achieve such reliable operations even under outage conditions. This demonstrates that the both circuits of the Singleton to Zenith line cannot be taken out of service simultaneously without some reliability violations, which indicates that any maintenance requiring taking down these circuits could cause reliability events in addition to congestion costs. When the outage was simulated for 2032 after a new line into Houston was constructed, significant congestion costs still accrued during that modeled outage. In that hypothetical 2032 six-month outage, ERCOT observed that $325 million in congestion rents accrued on the parallel 345-kV lines into Houston.

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[33] *Section 4.1.1.2, Reliability Performance Criteria*, ERCOT Planning Guide, (Jun. 2013).

This example provides some insight into the financial impact that a major outage could impose on the market. The actual outage duration could be different than that modeled by ERCOT. The duration of such an upgrade will depend heavily on the extent of the required upgrades. The financial impact of the outage would also differ depending on duration of the outage, the time of year the outage is taken, and whether or not the TDSP could keep one circuit in service during the upgrade. Nevertheless, these outage-related costs are significant and should be added to the economic evaluation process for new transmission lines.

As major load centers become increasingly dependent upon critical elements, upgrades of existing lines become increasingly costly to accomplish. ERCOT opted to illustrate the same outage scheduling challenge in the Austin region, where the newly built Hutto to Salado 345-kV line is anticipated to become a critical element within the 20-year study horizon. Similar to the hypothetical Houston-area upgrade, the duration of the modeled outage of the Hutto to Salado 345-kV line represented an approximation of the time required to upgrade the existing double-circuit line. Assuming that upgrade was scheduled in 2022, the Change Case created no additional overloads, and accrued only $2 million in additional congestion rent in 2022. If planners delayed the same upgrade with its associated outage until 2032, the congestion rent associated with the outage increased to $257 million.

While by themselves the difference between the congestion rents in 2022 and 2032 seems large, the possible economic advantage of upgrading that circuit earlier becomes more pronounced when considered along with the construction costs of the upgrade. ERCOT estimated the upgrade would cost $159 million in 2022 and $194 million in 2032. In 2032, the cost of the congestion rents customers would experience exceeded the cost of the upgrade.

These two examples demonstrate the societal cost of delaying an upgrade until that upgrade is absolutely necessary for reliable service. In the Austin-area example, accelerating a reliability project in advance of the required in-service date would reduce outage-related costs to load. Further, the financial impact to customers would be significant because the construction cost of the upgrade would be folded into the transmission rates customers pay and amortized over years but the congestion costs would be paid by customers as they were incurred. As these examples show, in some cases, including the avoided congestion costs in a benefit estimation and associated net present value calculation could economically justify undertaking an upgrade earlier than when it is needed to satisfy reliability criteria.

The following types of outages may be considered when determining the societal benefits of transmission network expansion:

- Maintenance-related outages of critical facilities,
- Upgrade-related outages of critical facilities,
- Historical outages of high consequence,

- High-consequence, low-probability events,
- Low to medium-consequence, high-probability events, and
- Other extreme system events or disasters.

These outages are not traditionally considered in economic transmission planning criteria. The number of possible outage combinations is limitless, and the probability of occurrence diminishes as additional elements are considered a single contingency. Accordingly, Brattle suggests that while it would be useful to develop a multiplier that can be used across various situations, it also may be useful to determine the relevance and potential magnitude of these benefits on a project-by-project basis. ERCOT will continue to evaluate these metrics as appropriate to the scope of the study and/or project.

9.6.3 Consideration of Load and Weather Uncertainty

Long-term studies typically consider only loads associated with a normalized "50/50" weather forecast. These "average" weather conditions ignore the occurrence of periodic heat waves and extreme weather over the course of a 10 or a 20-year horizon. To consider extreme conditions, ERCOT studied three drought scenarios with a load forecast higher than the load forecast based on normal weather.

ERCOT considered these drought scenarios as extreme load years and, by modeling them, ERCOT observed a tremendous increase in overloads and congestion rents accrued to imports into major load centers. Most notably, Houston, DFW, Austin, and San Antonio all required expansion and/or upgrade of existing import paths.

While a sustained drought may be unlikely, the load modeled in the drought scenarios suggested that these scenarios were worthy of analysis and consideration. Further, periodic heat waves and occasional extreme weather conditions will occur over the course of a transmission upgrade's useful life. Thus, analyzing an individual year or span of years under drought or heat wave condition will be useful for understanding the impacts of variations that occur around projected "normal" weather conditions. Periodic or even infrequent occurrences of such non-normal weather year could have a significant impact on the economic value of certain transmission projects. Future ERCOT long term studies may consider more variations of the weather basis or system load growth rates.

Brattle also noted that short-term uncertainties that exist within any one of the scenarios—such as weather-related load fluctuations, hydrological uncertainties, short- and medium-term fuel price volatility, and generation and transmission contingencies—should not drive long-term scenario definitions. Rather, such uncertainties should be simulated probabilistically or through sensitivity analyses for each of the chosen scenarios to capture the full range of societal value of transmission investments. The scenarios should reflect a wide range of possible future outcomes in terms of ERCOT-wide and localized load growth, generation mix and locations, and fuel prices. The range in long-term values of economic transmission projects under the various scenarios should be used to assess the robustness of a project's cost effectiveness. ERCOT and its stakeholders will need to consider how to handle these types of uncertainties in the next LTSA.

9.6.4 System Losses

System losses represent excess energy generated that is not delivered to electric customers. The transmission system in ERCOT is generally efficient, averaging approximately 2% of lost energy for transmitting power through the transmission network. However, remote loads, located electrically distant from system resources, may be more prone to experiencing higher system losses in supplying power. Because network losses increase proportionally to the square of throughput, incremental losses will also be higher than average losses, particularly during peak conditions. The expansion of the transmission network can reduce such energy losses on the transmission system. Specifically, network expansion reduces system losses by decreasing impedance, or the electrical equivalent distance, between generation and loads. This benefit can be quantified as (1) increased *deliverable* capacity, and (2) decreased production costs (associated with less energy generated for equivalent energy delivered).

In its report, Brattle suggested several methods to calculate the reduction in line losses, which included the use of production cost models to simulate the change in transmission losses attributable to a transmission upgrade. The production cost modeling software used by ERCOT provides several options for the locational assessment of system losses. Brattle also included several examples where the savings attributable to reduced line losses provided meaningful contributions to the justification for an economic transmission project.

9.6.5 Other Metrics under Consideration

The new metrics considered in this report represent only a few of the suggestions that The Brattle Group proposed to ERCOT. ERCOT will continue to review the entire list of additional metrics for transmission project assessment as part of future long-term studies on a case-by-case basis, including considering many benefits qualitatively when appropriate. Volume 2 of this report contains The Brattle Group's complete report, which contains the full list of transmission project assessment metrics.

10 Improvements and Advantages from the Enhanced Long-Term Study

With DOE's financial assistance, ERCOT has significantly improved it long-term planning process and the Texas Interconnect will benefit from these enhancements for years. The DOE funding allowed ERCOT to develop tools and processes that made four general improvements. ERCOT created a functional venue for the participation of stakeholders in the long-term planning process. Both ERCOT's generation planning and transmission planning benefited from the acquisition or development of new analysis tools that facilitated more-detailed examination further in the future. ERCOT acquired a unique tool that will facilitate the reliable integration of greater amounts of intermittent generation, which ERCOT's analysis suggests might expand significantly. ERCOT also has supplemented the general electricity market knowledge with better data about wind, solar, water, and natural gas resources. Finally, with the benefit of a review of an external planning process review, ERCOT received guidance for ways to improve its planning process.

First, ERCOT directly engaged its stakeholder community in long-term planning for the first time. This engagement mimicked ERCOT's typical stakeholder interactions upon which ERCOT, its staff, and the market rely for support. Stakeholders now have a forum to engage and develop long-term planning inputs and strategies. ERCOT believes that it has engaged a broad range of stakeholders including all the traditional segments of the industry participating at ERCOT: generation, transmission, load serving/distribution entities, retail electric providers, and regulators and significant newcomers: those representing alternative generation technologies, demand side aggregation, environmental interests, water resource interests, transportation, and a robust set of other potentially affected stakeholders. Stakeholder involvement will supplement key issue development to form broadly designed scenarios and provide a vehicle for meaningful criticism of modeled results. By building on ERCOT's and the stakeholders' familiarity with the processes developed for this study, in the future ERCOT can develop assumptions and scenarios more quickly and focus on incremental improvements to its stakeholder process for long-term planning and develop plans that reflect the diverse interests present in the Texas competitive market.

Second, ERCOT acquired or developed numerous tools to model resource expansion and retirement in a competitive market and then to identify reliable and cost-effective transmission plans to deliver that electricity to customers. Coupled with a database of costs and operating characteristics of various resource technologies developed in cooperation with stakeholders, ERCOT designed its expansion process with the underlying assumption that individual investors, after evaluating market conditions, will base their investment decisions on the expected market return of investments in their portfolio. The purpose was to capture, as closely as possible, the market conditions that experienced by a specific resource and to add resources that appeared to be economically viable, in other words, resources that would provide adequate return on investment. With these tools, ERCOT modeled the various generation technologies and non-generation options to meeting load. Under the various scenarios developed in cooperation with the stakeholders, ERCOT studied likely resource development. These resource expansion studies provided ERCOT with insights to possible future resource mixes and market or policy conditions that favor the development of certain technologies over others. With the experienced gained from these new tools, ERCOT will efficiently evaluate resource expansion options in future long-term studies.

With each scenario's resource expansion plans and ERCOT's six-year RTP as a starting point, ERCOT can use its transmission planning tools and new techniques to identify and resolve transmission issues that develop during the 20-year planning horizon. With its portfolio of planning tools, ERCOT can identify transmission needs to meet each scenario's load and resource expansion. Less granular tools allow ERCOT to examine different cases very quickly. More granular models help ERCOT site the expansion generation appropriately. Ultimately, ERCOT can develop multi-year transmission plans and alternative for the various scenarios it studied. The network simplification process it developed helps ERCOT test possible transmission solutions more quickly and with comparable accuracy. ERCOT developed confidence in its methodology and believes that it forms a solid foundation upon which ERCOT can undertake future long-term transmission studies.

ERCOT also procured the KERMIT tool to evaluate whether it could operate the grid reliably with the expansion resources identified or if the resource expansion must be reevaluated within the constraints of any identified operational limits. ERCOT used the KERMIT model to study the need for increased ancillary services were greater amounts of intermittent generation integrated into the transmission system and to validate whether the generation expansion plan for operational reliability. Analyzing the ability of a resource mix to comply with current balancing metrics required a second-by-second time series simulation of events, as modeled in KERMIT. Assessing both the system ancillary service needs and the resultant shift in resource economics will help ERCOT understand the type of resources is expected to indicate the type and size of technologies required to maintain system balancing capability and how system balancing (regulation service) revenues change the resource value proposition. Because of its ability to examine such granular intervals on the transmission system, KERMIT may become a tool ERCOT uses regularly outside its long-term planning process. ERCOT envisions using KERMIT to help identify cost-effective changes to ancillary service procurement practices, as intermittent resource integration in ERCOT continues. In future studies, ERCOT will be able to use the results of the KERMIT model to reflect the increased cost of ancillary services in scenarios with increased penetration of intermittent generation.

Additionally, the four resource studies ERCOT commissioned will provide a valuable, public dataset useful for several years in the ERCOT market. Developers, transmission planners, ERCOT and others interested in a good understanding of the wind and solar resource in Texas will have access to very detailed wind and solar resource data and output. Also, the ERCOT market can rely on the natural gas supply and delivery assessment for several years. Especially valuable to ERCOT and the market is the water availability study. As the drought continues in Texas, the electric industry can use the information in the water report to help shape any policy or investment decisions that may be faced in coming years.

Finally, ERCOT made several process enhancements to its long-term planning process as part of this study and many of those will likely endure beyond this study. First, ERCOT increased the study horizon of it long-term study. As study horizons lengthen, uncertainty associated with underlying study assumptions increases. The remedy for this increased uncertainty is to study divergent scenarios with varying sensitivities on key study input assumptions (e.g. fuel prices, future resource incentives, load growth, etc.) Accordingly, ERCOT used a diverse set of scenarios to evaluate the possible impact of the uncertainty on planning outcomes. While the evaluation of the various scenarios will not reveal the future, it will provide insights into common needs and solutions or identify key indicators that signal whether a scenario will become more or less likely. This 10-year extension beyond ERCOT's traditional planning horizon provided valuable insight into the future needs and operations of the transmission system. As discussed in previous sections, ERCOT gleaned several valuable long-term planning insights by studying 20 years in the future, for instance, the probable need for major import upgrades into Houston, DFW, and San Antonio and circumstances that could justify the construction of 500-kV transmission to move power from remote regions to major urban load centers. Many of those conclusions could not have been reached in a 10-year study horizon.

Some improvements to ERCOT's planning process may not occur until later. While ERCOT does not know the ultimate impact Brattle's recommendations will have on the evaluation of economic transmission options, Brattle has provided strong reasons to reexamine ERCOT's current evaluation process. Brattle raised concerns that ERCOT's planning process may miss economic upgrades because the evaluation criterion used does not capture the costs and benefits correctly. ERCOT will evaluate whether the net present value approach recommended by Brattle provides a better assessment of a potential project.

Although the next time ERCOT conducts a long-term transmission study it will not have the benefit of the additional resources the DOE grant provided for this report, it can begin immediately with a developed process. When ERCOT and the stakeholders begin to develop scenarios or identify the pool of possible resource technologies, they will already understand what information the models need and how ERCOT will use those data.

In summary, ERCOT has used the DOE grant funding to make significant improvements to the long-range planning process for the Texas Interconnection. New toolsets and new processes have been developed, and new databases have been acquired that allow ERCOT, in conjunction with key stakeholders through an enhanced regional planning process, to better understand future transmission needs and to better quantify the benefits of transmission expansion.

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Appendix A Glossary of Terms and Acronyms

AC — Alternating Current

AEO — Annual Energy Outlook

ARRA — American Reinvestment and Recovery Act 2009 (ARRA)- commonly referred to as the Stimulus or The Recovery Act, is an economic stimulus package enacted by the 111th United States Congress in February 2009 and signed into law on February 17, 2009 by President Barack Obama.

Base load — A resource that is most economically used by running at an annual capacity factor of 65% or greater.

BAU — Business as Usual

Btu — British thermal unit

BWR — Boiling Water Reactor

CAES — Compressed Air Energy Storage

Capacity — Generator output at a point in time, measured in MW or kW

Capacity Factor — Actual energy generated over a certain time period divided by theoretical ability to generate electricity over that same time period. Capacity factor is most often referenced as an annual calculation and presented as a percentage value.

Carbon dioxide — Carbon dioxide (CO_2) is an important greenhouse gas because of its potential to contribute to global warming. While it is not currently a regulated pollutant, it is the subject of pending federal legislation seeking to make it a regulated pollutant. Pending legislation would seek to reduce production by penalizing power plants for its emission into the atmosphere.

CC — Combined Cycle

CCS — Carbon Capture and Sequestration

CDR — Capacity, Demand, and Reserves Report as described in ERCOT Protocol 3.2.6.2

CEMS — Continuous Emissions Monitoring System

CHP — Combined Heat and Power, also known as cogeneration. The use of a heat engine or a power station to simultaneously generate both electricity and useful heat for domestic or industrial processes.

CO_2 — Carbon dioxide, see definition above.

CT — Combustion Turbine

DC — Direct Current

Demand — Usage at a point in time, measured in MW or kW. The amount of instantaneous electric power in MW delivered at any specified point or points on a system.

Demand Response — Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Demand-side resources — Resources that can be called on or developed to supply energy by means of reducing usage of energy by the end user. Energy efficiency and load management programs are examples of a demand-side resource.

Distributed Generation (DG) — Electric generation that is sited at a customer's premises, providing energy to the customer load at that site and/or providing electric energy for use by multiple customers in a contiguous distribution substation area.

DOE — The United States Department of Energy

DSI — Drought Severity Index

Economic Life — length of time a power plant can be depreciated in a financial analysis

EE — Energy Efficiency

EIA — Energy Information Administration

EIPC — Eastern Interconnection Planning Collaborative

ELCC — Effective Load Carrying Capability — The amount of wind generation that the Generation Adequacy Task Force (GATF) has recommended to be included in the CDR. The value is currently 8.7% of the nameplate capacity listed in the Unit Capacities tables, both installed capacity and planned capacity.

Energy — Usage over a period of time, measured in GWh, MWh, or kWh

Energy Efficiency — Installed measures (e.g. products, equipment, systems, services, practices, and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment, and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment measures, including energy conservation measures, or programs that target consumer behavior, equipment or devices to result in a decrease in consumption of electricity without reducing the amount or quality of energy services

EPA -— United States Environmental Protection Agency

EPWSim — Energy-Power-Water Simulation

ERCOT — Electric Reliability Council of Texas, Inc.

Fixed costs — Costs of a resource that that are independent of output

Forced Outage Rate (FOR) — The probability that an outage occurs that was initiated by protective relay, or manually in response to an observation by personnel that the condition of equipment could lead to an event, or potential event, that poses a threat to people, equipment, or public safety.

GADS — Generating Availability Data System — A database produced by the North American Electric Reliability Corporation (NERC). It includes annual summary reports comprising the statistics for power stations in the United States and Canada.

GDP — Gross Domestic Product

GHG — Greenhouse gas

HDR — Hot Dry Rock resource is a heated geological formation formed in the manner of hydrothermal resources, but containing no water due to the absence of aquifers or fractures required to transport water.

Heat rate — The ratio of energy inputs used by a generating facility expressed in BTUs (British Thermal Units), to the energy output of that facility expressed in kilowatt-hours

HRSG — Heat Recovery Steam Generator

IEA — International Energy Agency

IGCC — Integrated Gasification Combined Cycle plant

kWh — Kilowatt-hour

kWh/m^2 — Kilowatt-hour per square meter

Levelized cost — An economic assessment of the cost of an energy-generating system including all the costs over its lifetime including initial investment, operations and maintenance, cost of fuel, cost of capital, depreciation, and others represented as an uniform annual cost with an equivalent lifetime costs.

LFG — Landfill Gas

Loss of load probability — A measure of the probability that a system demand will exceed capacity during a given period; often expressed as the estimated number of days over a long period, frequently 10 years or the life of the system.

LTSTF — Long Term Study Task Force

Market Clearing Price (MCP) — The price of goods or a service at which quantity supplied is equal to quantity demanded. Also called the equilibrium price.

Markov Chain Monte Carlo Simulation — The probabilistic simulation of a Markov chain, where Markov chain is a mathematical model of the different states that a system can take.

MGD — Million Gallons of Water per Day

MVA — Megavolt-amperes

MW — Megawatt

MWh — Megawatt-hour

NAESB — North American Energy Standards Board

Net Present Value (NPV) — The total present value (PV) of a time series of cash flows

NG — Natural Gas

Non-Attainment Zone — A "non-attainment area" as a locality where air pollution levels persistently exceed National Ambient Air Quality Standards, or that contributes to ambient air quality in a nearby area that fails to meet standards.

NO_x — Nitrogen oxides

NREL — National Renewable Energy Lab

OPEC — Organization of the Petroleum Exporting Countries

Peak load/demand — Occurs when demand for energy is at its greatest

PEV — Plug-in Electric Vehicles, all-electric vehicles

PHEV — Plug-in Hybrid Electric Vehicles

Planning horizon — The future period for which a utility develops its expansion plans. Generally speaking it is a period lasting 5, 10, or 20 years.

PPM — parts per million

Production Tax Credit (PTC) — A tax credit that businesses creating electricity using renewable energy technology can apply to their federal tax returns. The tax credit is referred to as a production tax credit because the credit is assessed based on the amount of energy that the company generates.

Prototype — A generating facility that can be considered during the generation expansion process. These are the new units (combined cycles, combustion turbines, etc.) that could be added to the model in future years.

PUN — Private Use Network — An electric network connected to the ERCOT Transmission Grid that contains Load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation).

PV — Photovoltaic

PWR — Pressurized Water Reactor

Reliability — The ability of the electric system to supply the demand and energy requirements of the customers when needed and to withstand sudden disturbances

Renewable — A generating resource that is based on a renewable fuel supply

RFP — Request for Proposal

RPG — Regional Planning Group

RPS — Renewable Portfolio Standards

Sandia — Sandia National Laboratories

SCED — Security-Constrained Economic Dispatch — The determination of desirable Generation Resource output levels by using Energy Offer Curves while considering State Estimator (SE) output for Load at transmission-level Electrical Buses, Generation Resource limits, and transmission limits to provide the least offer-based cost dispatch of the ERCOT System.

SDWG — Scenario Development Working Group

Sequestration — The storage of carbon dioxide through biological or physical processes

Solar Photovoltaic — Photovoltaic technology is a means to generate electrical energy by converting sunlight directly into electricity. This technology is usually employed through solar panels – flat, weather-resistant panels that encapsulate semiconducting photovoltaic material. Direct current energy is produced, which can either be utilized directly in stand-alone applications, or must be converted to alternating current by means of a power inverter for grid tie-connected applications.

Solar thermal — (also called **concentrating solar power**, **concentrated solar thermal**, and **CSP**) Solar thermal is the harvest of thermal energy from sunlight. Common applications include domestic water heating, swimming pool heating, and commercial material drying. Systems use mirrors or lenses to concentrate a large area of sunlight, or solar thermal energy, onto a small area. Electrical power is produced when the concentrated light is converted to heat, which drives a heat engine (usually a steam turbine) connected to an electrical power generator

Standard Deviation — A measure of the dispersion of a collection of numbers. A large standard deviation indicates that the data points are far from the mean and a small standard deviation indicates that they are clustered closely around the mean.

Supply / demand balance — This concludes that in a competitive market, the unit price for a particular good will vary until it settles at a point where the quantity demanded by consumers (at current price) will equal the quantity supplied by producers.

Switchable Generation — A generation resource that can be connected to either the ERCOT transmission grid or a grid outside the ERCOT Region.

Syngas — is the name given to a gas mixture that is produced from the gasification of coal, biomass, and some types of waste-to-energy gasification facilities.

TCEQ — Texas Commission on Environmental Quality

Traditional resources/Conventional thermal resources — Coal, nuclear, hydro, and natural gas resources that have historically been the most commonly used to supply electricity.

TWDB — Texas Water Development Board

USGS — United States Geological Survey

Variable costs — Costs that change with unit output or operation

Weather Zones — A geographic region designated by ERCOT in which climatological characteristics are similar for all areas within such region.

WECC — Western Electricity Coordinating Council

WGA — Western Governors' Association

WSWC — Western States Water Council

Appendix B Participants in the Long-Term Study

Groups that Participated in Long-Term Study Meetings

Independent Power Producers

- Constellation Energy
- Duke Energy
- E.On
- LS Power
- Luminant Energy
- Nextera Energy
- Panda Power Funds
- PSEG Texas
- Shell
- Tenaska
- Horizon Wind

Transmission Providers

- American Electric Power
- American Transmission
- CenterPoint Energy
- Clean Line Energy
- Electric Transmission Texas
- Hunt Transmission
- Lone Star Transmission
- Oncor
- Pattern Energy Group
- Texas-New Mexico Power

Municipal/Cooperative Utilities

- Austin Energy
- Brownsville Public Utilities Board
- City of Denton
- CPS Energy
- Garland Power & Light
- Golden Spread Electric Cooperative
- Lower Colorado River Authority
- South Texas Electric Cooperative

Power Marketers

- DC Energy
- Direct Energy
- Morgan Stanley
- Noble Solutions

Government/Regulators

- California Energy Commission
- Comptroller of Public Accounts - Texas
- Federal Energy Regulatory Commission
- General Land Office - State of Texas
- Office of the Governor - State of Texas
- Public Utility Commission of Texas
- Texas Commission on Environmental Quality
- Texas Parks and Wildlife Division
- Texas Water Development Board
- Railroad Commission of Texas
- United States Department of Energy
- State Energy Conservation Office

Consultants

- Burns & McDonnell
- CLEAResult
- Crescent Power, Inc.
- Customized Energy Solutions
- Dashiell Corporation
- Electric Power Engineers
- Energy Online
- Good Company Associates
- Navigant Consulting
- Quanta Technology
- Stratus Energy Group LLC
- Virtus Energy

Research and Development

- Center for Commercialization of Electric Technologies
- Oak Ridge National Laboratory

Industry Groups

- Texas Public Power Association
- Texas Renewable Energy Industries Association

Concern Groups

- Environmental Defense Fund
- Heart of Texas Council of Governments
- Public Citizen
- Texas Competitive Power Advocates
- Save Our Scenic Hill Country Environment
- Sierra Club
- Wind Coalition

Other

- America's Natural Gas Alliance
- The Butler Group
- General Electric
- Longhorn Power
- Mitsubishi
- Occidental Chemical Corporation
- Occidental Petroleum Corporation
- Tres Amigas, LLC
- Tulane University
- The University of Texas at Austin
- Ventyx

Appendix C Generation Resource Retirements at 50-Years Old

Name	Category	Area	Maximum Capacity (MW)	Commission Date	Retirement Date
Mountain Creek 6	ST Gas	NORTHCEN	122	2/1/1956	12/1/2006
Silas Ray 5	ST Gas	SOUTHERN	17	5/1/1951	12/1/2006
Mountain Creek 7	ST Gas	NORTHCEN	118	3/1/1958	12/1/2008
Stryker Creek 1	ST Gas	EAST	171	6/1/1958	12/1/2008
W A Parish 1	ST Gas	COAST	174	6/1/1958	12/1/2008
W A Parish 2	ST Gas	COAST	174	12/1/1958	12/1/2008
Graham 1	ST Gas	NORTHCEN	225	12/1/1960	12/1/2010
Pearsall 1	ST Gas	SOUTHERN	25	5/1/1961	12/1/2011
Pearsall 2	ST Gas	SOUTHERN	25	7/1/1961	12/1/2011
Pearsall 3	ST Gas	SOUTHERN	24	9/1/1961	12/1/2011
W A Parish 3	ST Gas	COAST	278	3/1/1961	12/1/2011
Handley 3	ST Gas	NORTHCEN	395	7/1/1963	12/1/2013
Sam Rayburn GT 1	CT Gas	COAST	13	1/3/1963	12/1/2013
Sam Rayburn GT 2	CT Gas	COAST	13	1/3/1963	12/1/2013
Sam Rayburn 3	ST Gas	COAST	26	7/1/1965	12/1/2015
Sim Gideon 1	ST Gas	SOUTHCEN	140	5/1/1965	12/1/2015
Stryker Creek 2	ST Gas	EAST	502	12/1/1965	12/1/2015
Trinidad 6	ST Gas	EAST	226	5/1/1965	12/1/2015
Sam Bertron 2	ST Gas	COAST	174	4/1/1956	1/1/2016
Powerlane Plant 1	ST Gas	NORTHCEN	20	8/1/1966	12/1/2016
V H Braunig 1	ST Gas	SOUTHCEN	220	3/1/1966	12/1/2016
Mountain Creek 8	ST Gas	NORTHCEN	568	7/1/1967	12/1/2017
Powerlane Plant 2	ST Gas	NORTHCEN	26.5	8/1/1967	12/1/2017
Ray Olinger 1	ST Gas	NORTHCEN	78	7/1/1967	12/1/2017
T H Wharton G 1	CT Gas	COAST	13	7/1/1967	12/1/2017
W A Parish T1	CT Gas	COAST	13	7/1/1967	12/1/2017
Sam Bertron 1	ST Gas	COAST	174	3/1/1958	1/1/2018
R W Miller 1	ST Gas	NORTHCEN	75	10/1/1968	12/1/2018
Sim Gideon 2	ST Gas	SOUTHCEN	140	3/1/1968	12/1/2018
V H Braunig 2	ST Gas	SOUTHCEN	230	4/1/1968	12/1/2018
W A Parish 4	ST Gas	COAST	552	6/1/1968	12/1/2018
Graham 2	ST Gas	NORTHCEN	390	6/1/1969	12/1/2019
Cedar Bayou 1	ST Gas	COAST	745	12/1/1970	12/1/2020
Lake Hubbard 1	ST Gas	NORTHCEN	392	6/1/1970	12/1/2020
Lake Hubbard 2	ST Gas	NORTHCEN	524	11/1/1970	12/1/2020
V H Braunig 3	ST Gas	SOUTHCEN	412	5/1/1970	12/1/2020
Decker Creek 1	ST Gas	SOUTHCEN	320	7/1/1971	12/1/2021
Ray Olinger 2	ST Gas	NORTHCEN	107	1/1/1971	12/1/2021
Cedar Bayou 2	ST Gas	COAST	749	3/1/1972	12/1/2022
O W Sommers 1	ST Gas	SOUTHCEN	410	4/1/1972	12/1/2022
R W Miller 2	ST Gas	NORTHCEN	120	7/1/1972	12/1/2022
Sim Gideon 3	ST Gas	SOUTHCEN	340	5/1/1972	12/1/2022
Atkins 7	CT Gas	EAST	20	5/1/1973	12/1/2023
B M Davis 1	ST Gas	SOUTHERN	335	5/1/1974	12/1/2024
O W Sommers 2	ST Gas	SOUTHCEN	400	1/1/1974	12/1/2024
T H Wharton 3	Combined Cycle	COAST	332	8/1/1974	12/1/2024
T H Wharton 4	Combined Cycle	COAST	332	8/1/1974	12/1/2024
Thomas C Ferguson 1	ST Gas	WEST	425	8/1/1974	12/1/2024

Name	Category	Area	Maximum Capacity (MW)	Commission Date	Retirement Date
R W Miller 3	ST Gas	NORTHCEN	208	8/1/1975	12/1/2025
Ray Olinger 3	ST Gas	NORTHCEN	146	6/1/1975	12/1/2025
T H Wharton GT 51	CT Gas	COAST	58	11/1/1975	12/1/2025
T H Wharton GT 52	CT Gas	COAST	59	11/1/1975	12/1/2025
T H Wharton GT 53	CT Gas	COAST	58	11/1/1975	12/1/2025
T H Wharton GT 54	CT Gas	COAST	56	11/1/1975	12/1/2025
T H Wharton GT 55	CT Gas	COAST	58	11/1/1975	12/1/2025
T H Wharton GT 56	CT Gas	COAST	56	11/1/1975	12/1/2025
Greens Bayou 73	CT Gas	COAST	54	12/1/1976	12/1/2026
Greens Bayou 74	CT Gas	COAST	54	12/1/1976	12/1/2026
Greens Bayou 81	CT Gas	COAST	54	12/1/1976	12/1/2026
Greens Bayou 82	CT Gas	COAST	64	12/1/1976	12/1/2026
Greens Bayou 83	CT Gas	COAST	64	12/1/1976	12/1/2026
Greens Bayou 84	CT Gas	COAST	64	12/1/1976	12/1/2026
Handley 4	ST Gas	NORTHCEN	435	10/1/1976	12/1/2026
Handley 5	ST Gas	NORTHCEN	436	10/1/1977	12/1/2027
Dansby 1	ST Gas	EAST	110	9/1/1978	12/1/2028
Decker Creek 2	ST Gas	SOUTHCEN	428	1/1/1978	12/1/2028
Powerlane Plant 3	ST Gas	NORTHCEN	41.9	8/1/1978	12/1/2028

Appendix D Generating Resource Technologies

Combined-Cycle Gas Turbine

In a combined-cycle (CC) generating unit (also known as a combined-cycle gas turbine unit) a gas turbine generator produces both electricity and heat. Capturing this heat in a heat recovery steam generator (HRSG) and using the resulting steam to generate additional electricity via a steam turbine makes combined-cycle technologies very efficient; newer designs achieve efficiencies of nearly 60%. Combined-cycle plants can be designed in different arrangements of gas turbines and steam turbines; most often the heat from one, two or three gas turbines is recovered through HRSGs to power a single steam turbine. The total capacity of a combined-cycle plant depends on the size and number of the gas turbine generators, the HRSGs and the steam turbine; total capacities can vary from 60 MW to over 750 MW.

Some combined cycle designs increase output by augmenting steam production with supplemental gas firing (or duct firing) in the HRSG. The additional steam increases the output of the steam turbine. While not quite as thermally efficient as the complete combined cycle process, the additional output from duct firing provides efficient peak energy at a low additional capital cost.

Simple-Cycle Gas Turbine

Several industries use the simple-cycle gas turbine, also known as a combustion turbine, including power generation, oil and gas facilities, process plants, and aviation. The compressor, combustor, and turbine modules, connected by one or more shafts, constitute the gas generator. A gas turbine collects air into the compressor module and combines it with fuel; this combined vapor is then ignited. The resulting gases expand through a turbine. In the turbine, the expanding gases are directed through a nozzle over the turbine's blades causing them to rotate. A separate starter unit provides the initial motor rotation until the turbine's rotation is up to design speed.

Combustion turbines are used to power aircraft, trains, ships, generators, and even tanks. These generators can range in capacity from 1 MW to over 300 MW.

Internal Combustion Engine (Reciprocating Engine)

The internal combustion engine (ICE) has been refined and developed over the last 100 years for a wide variety of applications from tiny 1 cc engines powering model aircraft to gigantic marine engines with power outputs of tens of megawatts. The reciprocating engine with its compact size and its wide range of power outputs and fuel options is an ideal prime mover for powering electricity generating sets used to provide primary power in remote locations or, more generally, for providing mobile and emergency or stand-by electrical power.

Some gas engines with modern technology controls reach over 45% electrical efficiency. Multi-unit configuration creates a part-load profile that enables optimization over the entire output range of the plant. For a given total plant load, an operator simply uses as many individual generating sets as required at their optimal efficiency. The multiple-unit concept ensures high reliability and availability. All maintenance can be performed one unit at a time, leaving the remaining units available for operation.

Coal Gasification-IGCC

Gasification can be used to decompose coal or virtually any carbon-based fuel into more basic chemical components. In a gasifier, coal is typically exposed to steam and carefully controlled amounts of air or oxygen under high temperatures and pressures. Under these conditions, the coal molecules break apart, initiating chemical reactions that typically produce a mixture of carbon monoxide, hydrogen, and other gaseous compounds. The resulting synthetic gas (syngas) fuel can be used in an efficient combined-cycle unit as well as other turbine technologies. Gasification of coal can achieve significant reductions in pollutant emissions when compared to traditional pulverized coal facilities and allows the use of a lower priced fuel, coal, with the highly efficient combined-cycle technology.

Ultra-Supercritical Coal

Recent advances in electrical generating unit technology have led to the creation of a new subset of the supercritical category, known as “ultra-supercritical” technology. The U.S. Department of Energy (DOE) defined the ultra-supercritical steam cycle as a steam cycle with an operating pressure exceeding 3,600 pounds per square inch (psi) and main superheated steam temperature above 1,100°F. Current subcritical and supercritical boiler designs with full environmental controls typically yield efficiencies in the range of 35% to 40%, with supercritical units at the upper end of the range. Ultra-supercritical plants may be able to achieve efficiencies of as much as 45%, which equates to heat rates of approximately 7,500 Btu/kWh.

Nuclear Power

Nuclear power plants utilize the phenomena of nuclear fission of heavier elements, such as uranium or plutonium, into lighter atoms to create heat. The thermal energy is used to create steam, which is used to power a turbine.

The two most commonly used nuclear power technologies are pressurized water reactor and boiling water reactor. In a pressurized water reactor, water flowing through the reactor is isolated (physically, not thermally) from the water vapor going through the turbine. In a boiling water reactor, the same water heated by the reactor travels through the turbine. New designs, such as modular reactors may create greater unit flexibility and provide higher financial return and lower risk for the investor. Other designs have been proposed that use different coolant materials and nuclear reactor moderators (or even no moderator at all in a fast reactor).

Wind Turbines

Wind turbines convert wind energy into electrical energy. The size and technology of wind turbines has improved over time. Current turbines have hub heights over 300 feet in the air and blades as long as 150 feet. Wind turbines are generally classified by their electro-mechanical design (including generator machine, inverter, and gearbox if present). There are five major wind turbine designs; each has unique characteristics in terms of energy conversion, reactive power control, and response to dynamic grid events. These five turbine types represent an evolving design, starting with the earliest and most primitive Types I and II evolving to more sophisticated types III, IV, and V, which include sophisticated reactive power control and higher wind-energy capture efficiencies.

Type I (Fixed-speed induction generator): This simple turbine utilizes a simple squirrel-cage induction generator. It has no inherent reactive power control, and consumes reactive power in rough proportion to real power production. This turbine operates at a fixed rotor speed.

Type II (Variable speed, wound-rotor induction generator): The ability to operate at variable blade speed makes this turbine design superior to Type I turbines by allowing it to capture wind energy more efficiently at lower wind speeds. Like Type I turbines, this turbine has no reactive power control and consumes reactive power in proportion to production.

Type III (Doubly-Fed Induction Generator): By utilizing a doubly-fed induction generator and back-to-back inverter, this turbine type operates at variable speed and can provide fast reactive power control. Like Type II, variable speed offers improved capture efficiency. Reactive power can be controlled to regulate voltage and provide fast voltage support during a fault.

Type IV (Full Inverter): By utilizing a full-scale inverter coupled with a synchronous generator, this turbine type offers the same features as Type III turbine, namely variable speed and sophisticated reactive power control. Additionally, because the inverter completely isolates the generator from the grid, this turbine tends to have somewhat better fault system response than Type III and may be immune or less susceptible to sub-synchronous interactions with other power electronics equipment connected to the transmission system.

Type V (Synchronous Generator with Variable Speed Gearbox): This turbine type represents the most recent evolution of turbine design, appearing on the market in the last 3 years. This turbine does not include an inverter, but rather utilizes a special gearbox for variable speed energy conversion. The synchronous generator connects directly to the transmission system. From a transmission perspective, this turbine appears electrically similar to a traditional, albeit small, synchronous power plant. Like Type III and IV turbines, this turbine type offers variable speed and reactive power control. Current wind turbine technologies are able to provide grid frequency control, a response to system disturbances similar to system inertia, and other grid-friendly capabilities. The new turbines are larger and operate with higher capacity factors. Longer rotor blades, increased mechanical efficiency, and improved operational controls have increased output and allowed the turbines to operate at lower wind speeds.

Solar Photovoltaic

Photovoltaic (PV) technologies convert sunlight directly into electricity by using semiconducting materials. The resulting direct-current (DC) energy can be utilized in stand-alone applications or can be converted to alternating current by using a power inverter for grid applications.

Most PV systems use exposed flat panels of photovoltaic material. The resource is well-suited for urban environments as these panels can be installed in any desired amount on any shape roof because of their modular design. Some designs utilize one- or two-axis tracking systems to maximize the exposure to the sun across the span of the day.

Utility scale PV systems come in a few versions, fixed tilt and single-axis tracking configurations. The majority of fixed-tilt PV arrays utilize modules composed of individual crystalline silicon (C-Si) cells. Crystalline silicon (C-Si) is the most common type of solar cell and consequently has the most mature manufacturing process of all solar PV technologies. C-Si cells can be further differentiated into either monocrystalline or polycrystalline silicon. Monocrystalline silicon cells are cut from cylindrical ingots of single-crystal silicon. Polycrystalline silicon cells are cut from large blocks of silicon containing many individual crystals and are typically less efficient and less expensive than monocrystalline silicon cells. Other semiconductors include compounds such as gallium arsenide and indium phosphide and more complex compounds such as copper indium gallium selenide.

Fixed-tilt systems utilize driven piles, ballast, or concrete footers as a foundation for a metallic racking structure that holds the PV modules at a fixed orientation. The ideal orientation to maximize annual energy output from a fixed-tilt solar array has an azimuth pointed due south and a slope (or tilt) of the modules equal to the latitude of the solar array installation location.

Single-axis tracking systems increase the energy produced by a solar array by tracking the sun from east to west diurnally. The tilt of single-axis tracking systems are usually kept flat, normal to the zenith, and have a total east-west tracking range of 90°. A control algorithm keeps the solar modules tilted toward the sun throughout the course of the day.

A range of configurations exist for single-axis tracking systems, but the most common is north-south rows of piles supporting a single torque tube to which individual modules are mounted. The tracking motion of groups of rows is provided through a mechanical linkage and a common drive motor. Single-axis tracking systems are designed to maximize land use without causing self-shading. The balance of system components of a single-axis tracking system are similar to those of a fixed-tilt system.

Solar Thermal

Solar thermal technologies convert direct sunlight into thermal energy. There are two methods currently used to convert the resulting thermal energy into electricity. The first is a conventional steam system, where water is boiled by the thermal energy and the steam is passed through a steam turbine. The second is a Stirling system, where a parabolic dish reflects heat directly to a small engine located at the dish's focal point. The small Stirling engine runs a closed-loop thermodynamic process where a working gas is alternatively moved between a hot and cold cylinder. The gas movement drives a piston that turns an electrical generator. By locating the engine at the focal point, the need for a thermal fluid is eliminated. For either technology, concentrating solar collectors are required to achieve the necessary temperatures for efficient energy conversion.

The solar-steam system can use one of three types of collectors. The parabolic trough is a linear collector of parabolic mirrors which concentrate sunlight onto a long, horizontal pipe where oil or steam is usually used as the heat transfer fluid. The Fresnel trough is similar to the parabolic trough, but uses Fresnel mirrors instead of parabolic mirrors. The heliostat tower field consists of a field of mirrors on 2-axis tracking stations that reflect sunlight onto a single collection tower. Tower collector technologies have the potential to achieve higher thermal efficiencies than trough collectors because of the higher temperatures and reduced transfer losses. The Stirling system typically uses a heliostat dish receiver as its collector.

Geothermal

There are four basic types of geothermal reservoirs. In hydrothermal geothermal resources, hot water and/or steam reside in fractured or porous rock at shallow to moderate depths (100 m to 4.5 km) as a result of the intrusion of molten magma into the earth's crust or from the deep circulation of water through fault or fracture systems. A geo-pressured resource consists of hot brine saturated with methane that originates in large, deep aquifers that are under higher pressure because of water trapped during the burial process. These resources are often found in sedimentary strata at depths of 3 to 6 km. Hot dry rock (HDR) resources consist of heated geological formations formed in the manner of hydrothermal resources, but containing no water because of the absence of aquifers or fractures required to transport water. Exploiting this type of resource requires an injection well to force water into the hot rock formation. Heated water returns through a production well where a heat recovery process converts the heated water into electricity. The fourth type and hardest to exploit is magma. The deep interior of the earth is in molten form. As molten rock is found at depths of 3 to 10 km, it is not easily accessible. Temperatures range from 700 °C to 1,200 °C or more, which while appealing for heat acquisition, the technology for such development is still in its infancy.

Research performed by Southern Methodist University[34] and Massachusetts Institute of Technology show that binary-cycle plants may be appropriate to exploit the geo-pressured resources prevalent in Texas.[35] Using this process, the geothermal fluid is brought to the surface and passed through a heat exchanger to transfer the heat to a secondary fluid. The secondary fluid in the heat exchange system will have a lower boiling point than water, such as isobutene, pentane, or ammonia. This secondary fluid is vaporized and passed through a turbine to generate electricity. The working fluid is then condensed and recycled for another pass through the heat exchanger. All of the geothermal fluid is re-injected into the ground in a closed-loop system.

Biomass Resources

Many plants and plant-derived materials can be used for energy production; the most common today is wood, but other potential fuel sources include food crops, grasses, agricultural residues, manure, and methane from landfills. While Texas contains one of the most diverse and accommodating growing environments in the U.S., barriers to biomass becoming a significant energy resource include feedstock availability and low conversion efficiency. In the long term, biomass generation potential will depend on technology advances, competition for feedstock use, and food and fiber production for arable land use.

Biomass can be used in steam boilers or converted into biogas to fuel gas turbines. Biogas conversion can be accomplished through fast thermo-chemical processes or slow anaerobic fermentation. In the absence of air, bacteria-induced fermentation can be used to convert a variety of organic matter such as animal manures, organic wastes, and green energy crops into biogas. Anaerobic digestion is also the basic process for landfill gas production from municipal green waste.

Municipal solid waste landfills are the largest source of anthropogenic methane emissions in the United States, accounting for about 34% of these emissions in 2004. The amount of methane created in a landfill depends on the quantity and moisture content of the waste and the design and management practices at the site. The gas generated by the anaerobic decomposition of organic material creates a gas that is roughly 50% methane, 50% carbon dioxide, and a small amount of non-methane organic compounds.

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[34] *Geothermal Energy – Power for Texas in the 21st Century* (Presentation to ERCOT), Blackwell, David, Southern Methodist University (Sep. 24, 2010).

Texas Renewable Energy Resource Assessment, Texas State Energy Conservation Office (Dec. 2008).

[35] *The Future of Geothermal Energy*, Massachusetts Institute of Technology, INL/EXT-06-11746 (2006).

Landfill gas must be treated before it can be used in a turbine. In some cases, the landfill gas is chilled to remove the moisture and condensable impurities and is then reheated to ensure that the gas is supplied to the turbine above the dew point temperature. Siloxanes, which are found in trace amounts of landfill gas, are abrasive and can harm turbine components if not removed through pretreatment systems.

Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) uses energy stored as compressed air to assist in the operation of a gas turbine. Electric energy drives a compressor to charge a storage reservoir, typically a cavern or salt dome. When released, the pressurized air is mixed with natural gas and combusted through a turbine to generate power. By utilizing the energy in the compressed air, almost all of the energy from the natural gas can be converted into electrical energy in the gas turbine. The need for appropriate geologic conditions limits the locations where CAES units can be sited.

Batteries

There is a wide range of battery technologies available today, including lithium-ion, sodium-sulfur, lead-acid, nickel-cadmium, and others. These technologies are suited for different applications; the best technology depends on the specific application. On a transmission system, batteries can be used for frequency regulation services, contingency reserves, voltage support, and black start capabilities, in addition to changing the net daily pattern of variable generation and customer demand.

Demand Response

Demand Response (DR), defined by North American Energy Standards Board (NAESB) as "a temporary change in electricity usage by a demand resource in response to market or reliability conditions," incorporates a wide variety of programs and technologies. Demand response resources can respond to signals from reliability coordinators, or can be responsive to market price signals. All classes of customers (residential, commercial, and industrial) can participate in demand-response programs, although in ERCOT participation in demand-response programs has been greater in the industrial customer class.

Energy Efficiency

Energy Efficiency (EE) describes a variety of mature and developing technologies that allow individuals and institutions to achieve the same levels of productivity and comfort while using less electricity. The purpose of EE is to reduce overall energy usage, often referred to as "negawatts," a term coined by Amory Lovins of the Rocky Mountain Institute.

EE should not be confused with energy conservation, which is a deliberate action by a consumer to make do with less energy (e.g. turning thermostats up in the summer and down in the winter). Similarly, EE should not be confused with demand response, which is a deliberate action by a consumer to effect a temporary change in electricity usage in response to market or reliability conditions. Energy efficiency technologies in this category include high efficiency HVAC systems, lighting retrofits, changes to building codes, etc.

Electric Vehicles

Plug-in Hybrid Electric Vehicles (PHEVs) resemble conventional hybrid electrical vehicles, but feature a larger battery and plug-in charger that allows electricity from the grid to replace a portion of the petroleum-fueled drive energy. PHEVs may derive a substantial percentage of their range from grid-supplied electricity stored in on-board batteries, and use a gasoline-fired engine to ease the range restrictions of pure battery electric vehicles.

All-electric vehicles, also known as Plug-in Electric Vehicles (PEV), typically have larger battery storage capability than PHEV, and thus a longer range on electric power. Because they have no back up gas engine their use is currently limited to areas in which charging locations are available.

As PEV and PHEV's have significant energy storage capability they may become an integral part of the distribution system providing storage, supplying emergency energy, and supporting grid stability. Development of these types of Vehicle-to-Grid (V2G) programs is currently being researched.

Appendix E Generating Resource Operating Characteristics

Existing Technologies

Technology	Heat Rate	Min Capacity	Min up time	Min down time	Variable O&M	Fixed O&M	Start Cost	NOx	SO2	CO2
	Btu/MWh	%	hrs	hrs	2011$/MWh	2011$/kW-yr	2011$	lbs/MWh		
Gas Steam Reheat	12,000	38.41	8	8	8.00	13.25	2,500	0.11	0.0006	118
Gas Steam Non-Reheat	13,000	43.13	8	8	5.00	20.50	2,500	0.11	0.0006	118
Supercritical Gas Steam	11,000	28.52	8	8	6.50	15.75	2,500	0.11	0.0006	118
Combustion Turbines (LM6000)	9,500	36.58	1	1	8.00	8.25	2,000	0.11	0.0006	118
Combustion Turbines ("E" Class)	11,500	25.03	1	1	4.00	5.00	1,000	0.11	0.0006	118
Older Combustion Turbines	14,500	25	1	1	5.00	11.00	-	0.11	0.0006	118
Combustion Turbines (LMS 100)	9,200	25	1	1	13.00	10.25	10,000	0.11	0.0006	118
Nuclear	10,000	N/A	168	24	4.00	73.00	-	N/A	N/A	N/A
Coal	9,800	47.44	24	12	5.00	25.50	5,000	0.13	0.8400	218
Combined Cycle (LM6000)	8,000	36.58	4	8	5.00	12.00	5,000	0.11	0.0006	118
Combined Cycle ("E" Class)	8,500	24	4	4	3.00	13.50	3,000	0.11	0.0006	118
Combined Cycle ("F" Class)	7,200	32.2	6	4	3.00	13.25	10,000	0.11	0.0006	118
Combined Cycle ("G&H" Class)	6,700	62.5	6	8	2.90	12.00	15,000	0.11	0.0006	118
Biomass	13,000	25	8	6	9.50	13.25	2,500	N/A	N/A	N/A
Diesel (Internal Combustion Engines)	9,800	20	1	1	3.50	11.50	500	0.018	0.0006	119
Wind	N/A	N/A	N/A	N/A	-	29.25	N/A	N/A	N/A	N/A

Expansion Technologies

Technology	Capacity	Heat Rate	Min Capacity	Min up time	Min down time	Variable O&M	Fixed O&M	Start Cost	NOx	SO2	CO2	Economic Life
	MW	Btu/kWh	MW	hrs	hrs	2011$/MWh	2011$/kW-yr	$	lbs/MWh			yrs
Conventional CC (F type)	500	7,200	200	6	8	2.65		10,000	0.03	0.0006	119	20
Advanced CC (H/G type)	650	6,700	250	6	8	2.90	14.62	15,000	0.03	0.0006	119	20
Conventional CT (F type)	170	10,500	130	2	3	8.00	6.98	7,500	0.01	0.0006	119	20
Advanced CT (LMS100)	100	9,200	70	2	3	13.00	6.70	10,000	0.01	0.0006	119	20
Supercritical Coal	750	9,000	250	24	12	3.95	29.67	5,000	0.06	0.06	220	30
Supercritical Coal W/ CCS	625	11,950	250	24	12	7.35	63.21	7,000	0.06	0.06	11	30
IGCC	625	9,000	250	24	12	6.00	5.00	5,000	0.03	0.0006	119	30
IGCC W/ CCS	539	10,700	250	24	12	7.00	69.30	7,000	0.03	0.0006	6	30
Nuclear	1,150	10,300	600	168	48	4.00	88.75	-	N/A	N/A	N/A	40
On shore Wind	100	-	-	-	-	-	28.07	-	N/A	N/A	N/A	20
Geothermal	50	11,000	20	8	8	10.00	84.27	-	N/A	N/A	N/A	20
Biomass	40	13,000	15	8	8	9.50	100.50	2,500	N/A	N/A	N/A	20
Solar PV	500	-	-	-	-	-	16.70	-	N/A	N/A	N/A	20

Appendix F Fuel Price Forecasts

Year	Base NG	High NG	Low NG	Coal
	$/MMBtu			
2012	$ 4.19	$ 9.19	$ 2.19	$ 2.12
2013	$ 4.33	$ 9.33	$ 2.33	$ 2.16
2014	$ 4.32	$ 9.32	$ 2.32	$ 2.18
2015	$ 4.55	$ 9.55	$ 2.55	$ 2.21
2016	$ 4.64	$ 9.64	$ 2.64	$ 2.25
2017	$ 4.77	$ 9.77	$ 2.77	$ 2.29
2018	$ 5.01	$ 10.01	$ 3.01	$ 2.33
2019	$ 5.23	$ 10.23	$ 3.23	$ 2.40
2020	$ 5.42	$ 10.42	$ 3.42	$ 2.45
2021	$ 5.74	$ 10.74	$ 3.74	$ 2.50
2022	$ 6.13	$ 11.13	$ 4.13	$ 2.56
2023	$ 6.44	$ 11.44	$ 4.44	$ 2.61
2024	$ 6.72	$ 11.72	$ 4.72	$ 2.68
2025	$ 6.97	$ 11.97	$ 4.97	$ 2.73
2026	$ 7.36	$ 12.36	$ 5.36	$ 2.79
2027	$ 7.70	$ 12.70	$ 5.70	$ 2.86
2028	$ 7.88	$ 12.88	$ 5.88	$ 2.92
2029	$ 8.00	$ 13.00	$ 6.00	$ 2.99
2030	$ 8.26	$ 13.26	$ 6.26	$ 3.06
2031	$ 8.70	$ 13.70	$ 6.70	$ 3.13
2032	$ 9.19	$ 14.19	$ 7.19	$ 3.20

Appendix G Prototype Generation — Capital Cost

Natural Gas Fueled ($/kW)

	Combined Cycle		Combustion Turbine		Internal Combustion	
	F Class	G&H Class	F Class	LMS 100	CT	CC
2011	$ 893	$ 919	$ 679	$ 771	$ 900	$ 1,000
2012	$ 909	$ 936	$ 691	$ 785	$ 917	$ 1,018
2013	$ 926	$ 953	$ 704	$ 800	$ 933	$ 1,037
2014	$ 943	$ 971	$ 717	$ 814	$ 951	$ 1,056
2015	$ 961	$ 988	$ 730	$ 829	$ 968	$ 1,076
2016	$ 966	$ 995	$ 750	$ 835	$ 937	$ 1,084
2017	$ 984	$ 1,013	$ 764	$ 850	$ 954	$ 1,104
2018	$ 1,002	$ 1,032	$ 778	$ 866	$ 971	$ 1,125
2019	$ 1,020	$ 1,050	$ 792	$ 882	$ 989	$ 1,145
2020	$ 1,039	$ 1,070	$ 807	$ 898	$ 1,007	$ 1,166
2021	$ 1,058	$ 1,089	$ 822	$ 914	$ 1,026	$ 1,188
2022	$ 1,078	$ 1,109	$ 837	$ 931	$ 1,045	$ 1,210
2023	$ 1,085	$ 1,116	$ 860	$ 937	$ 1,053	$ 1,220
2024	$ 1,105	$ 1,137	$ 876	$ 954	$ 1,073	$ 1,242
2025	$ 1,125	$ 1,158	$ 892	$ 972	$ 1,092	$ 1,265
2026	$ 1,146	$ 1,179	$ 908	$ 990	$ 1,112	$ 1,288
2027	$ 1,167	$ 1,201	$ 925	$ 1,008	$ 1,133	$ 1,312
2028	$ 1,189	$ 1,223	$ 942	$ 1,026	$ 1,154	$ 1,336
2029	$ 1,210	$ 1,245	$ 959	$ 1,045	$ 1,175	$ 1,360
2030	$ 1,233	$ 1,268	$ 977	$ 1,064	$ 1,197	$ 1,385
2031	$ 1,255	$ 1,291	$ 995	$ 1,084	$ 1,219	$ 1,411
2032	$ 1,278	$ 1,315	$ 1,013	$ 1,104	$ 1,241	$ 1,437

Solid Fueled ($/kW)

	Nuclear	Coal		IGCC	
		W/O CCS	With CCS	W/O CCS	With CCS
2011	$ 5,130	$ 2,896	$ 4,582	$ 3,271	$ 4,851
2012	$ 5,224	$ 2,949	$ 4,666	$ 3,331	$ 4,940
2013	$ 5,320	$ 3,003	$ 4,752	$ 3,392	$ 5,031
2014	$ 5,418	$ 3,059	$ 4,839	$ 3,455	$ 5,124
2015	$ 5,518	$ 3,115	$ 4,928	$ 3,518	$ 5,218
2016	$ 6,010	$ 3,143	$ 4,969	$ 3,909	$ 5,794
2017	$ 6,121	$ 3,200	$ 5,060	$ 3,981	$ 5,901
2018	$ 6,233	$ 3,259	$ 5,153	$ 4,054	$ 6,010
2019	$ 6,348	$ 3,319	$ 5,248	$ 4,129	$ 6,120
2020	$ 6,465	$ 3,380	$ 5,344	$ 4,205	$ 6,233
2021	$ 6,583	$ 3,442	$ 5,442	$ 4,282	$ 6,347
2022	$ 6,705	$ 3,506	$ 5,542	$ 4,361	$ 6,464
2023	$ 5,208	$ 3,536	$ 5,587	$ 4,852	$ 7,192
2024	$ 5,303	$ 3,601	$ 5,690	$ 4,941	$ 7,325
2025	$ 5,401	$ 3,668	$ 5,794	$ 5,032	$ 7,459
2026	$ 5,500	$ 3,735	$ 5,901	$ 5,124	$ 7,596
2027	$ 5,601	$ 3,804	$ 6,009	$ 5,218	$ 7,736
2028	$ 5,704	$ 3,874	$ 6,120	$ 5,314	$ 7,878
2029	$ 5,809	$ 3,945	$ 6,232	$ 5,412	$ 8,023
2030	$ 5,916	$ 4,017	$ 6,347	$ 5,512	$ 8,171
2031	$ 6,025	$ 4,091	$ 6,464	$ 5,613	$ 8,321
2032	$ 6,135	$ 4,167	$ 6,583	$ 5,716	$ 8,474

Renewable and Storage ($/kW)

	Geothermal	Biomass	CAES	Gravity Power	Wind Original	Solar PV Original	Wind Updated	Solar PV Updated
2011	$ 1,800	$ 3,411	$ 1,000	$ 1,000	$ 2,322	$ 3,805	$ 2,000	$ 3,805
2012	$ 1,833	$ 3,474	$ 1,018	$ 1,018	$ 2,365	$ 3,691	$ 2,037	$ 3,000
2013	$ 1,867	$ 3,538	$ 1,037	$ 1,037	$ 2,408	$ 3,580	$ 2,074	$ 2,750
2014	$ 1,901	$ 3,603	$ 1,056	$ 1,056	$ 2,452	$ 3,473	$ 2,112	$ 2,480
2015	$ 1,936	$ 3,669	$ 1,076	$ 1,076	$ 2,498	$ 3,368	$ 2,151	$ 2,230
2016	$ 1,991	$ 3,689	$ 1,095	$ 1,095	$ 2,506	$ 3,268	$ 2,169	$ 2,000
2017	$ 2,028	$ 3,757	$ 1,116	$ 1,116	$ 2,552	$ 3,170	$ 2,209	$ 1,800
2018	$ 2,065	$ 3,826	$ 1,136	$ 1,136	$ 2,599	$ 3,074	$ 2,249	$ 1,620
2019	$ 2,103	$ 3,896	$ 1,157	$ 1,157	$ 2,647	$ 2,982	$ 2,291	$ 1,460
2020	$ 2,142	$ 3,968	$ 1,178	$ 1,178	$ 2,696	$ 2,893	$ 2,333	$ 1,320
2021	$ 2,181	$ 4,041	$ 1,200	$ 1,200	$ 2,745	$ 2,806	$ 2,376	$ 1,344
2022	$ 2,221	$ 4,115	$ 1,222	$ 1,222	$ 2,796	$ 2,723	$ 2,419	$ 1,369
2023	$ 2,285	$ 4,139	$ 1,244	$ 1,244	$ 2,807	$ 2,641	$ 2,439	$ 1,394
2024	$ 2,327	$ 4,215	$ 1,267	$ 1,267	$ 2,859	$ 2,561	$ 2,484	$ 1,420
2025	$ 2,369	$ 4,292	$ 1,291	$ 1,291	$ 2,911	$ 2,485	$ 2,529	$ 1,446
2026	$ 2,413	$ 4,371	$ 1,314	$ 1,314	$ 2,965	$ 2,388	$ 2,576	$ 1,473
2027	$ 2,457	$ 4,452	$ 1,338	$ 1,338	$ 3,019	$ 2,294	$ 2,623	$ 1,500
2028	$ 2,503	$ 4,533	$ 1,363	$ 1,363	$ 3,075	$ 2,195	$ 2,672	$ 1,528
2029	$ 2,549	$ 4,617	$ 1,388	$ 1,388	$ 3,132	$ 2,092	$ 2,721	$ 1,556
2030	$ 2,595	$ 4,702	$ 1,414	$ 1,414	$ 3,189	$ 1,984	$ 2,771	$ 1,585
2031	$ 2,643	$ 4,788	$ 1,440	$ 1,440	$ 3,248	$ 1,882	$ 2,822	$ 1,614
2032	$ 2,692	$ 4,876	$ 1,466	$ 1,466	$ 3,307	$ 1,917	$ 2,873	$ 1,644

Appendix H Generation Expansion Summaries

Appendix H.1: Business As Usual (BAU) with All Technologies

Description	Units	2014	2017	2020	2023	2026	2029	2032
CC Adds	MW	-	400	800	3,200	2,800	2,400	3,600
CT Adds	MW	-	700	3,100	800	600	1,300	900
Coal Adds	MW	-	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-	-
Solar Adds	MW	-	-	-	-	-	-	-
Wind Adds	MW	-	-	-	-	-	-	-
Annual Capacity Additions	MW	-	1,100	3,900	4,000	3,400	3,700	4,500
Cumulative Capacity Additions	MW	-	1,100	5,000	9,000	12,400	16,100	20,600
Retirements	MW	-	-	-	-	-	-	-
Residential Demand Response	MW	-	2,200	-	-	-	-	-
Industrial Demand Response	MW	500	-	-	-	-	-	-
Reserve Margin	%	8.32	2.80	2.79	3.04	2.89	2.39	1.33
Administrative Units	MW	-	-	-	-	-	-	-
Coincident Peak	MW	74,148	81,316	85,114	88,805	92,234	96,276	100,744
Average LMP	$/MWh	34.73	55.97	61.88	69.49	77.66	83.06	94.11
Natural Gas Price	$/MMBtu	4.32	4.77	5.42	6.44	7.36	8.00	9.19
Average Market Heat Rate	MMBtu/MWh	8.04	11.73	11.42	10.79	10.55	10.38	10.24
Natural Gas Generation	%	41.3	46.4	48.6	50.4	52.2	54.0	56.1
Coal Generation	%	36.0	33.2	32.0	30.7	29.6	28.4	27.3
Wind Generation	%	10.3	9.0	8.6	8.3	8.0	7.7	7.4
Solar Generation	%	-	-	-	-	-	-	-
Scarcity Hours	hrs	-	17	17	16	20	21	21
Unserved Energy	GWhs	-	29.9	22.0	38.2	40.3	42.7	59.5
SO_2	Tons	354,033	354,439	357,113	356,594	356,561	356,502	357,857
CO_2	(k) Tons	229,961	247,892	251,225	264,772	272,112	280,358	290,395
NO_x	Tons	129,480	138,280	139,958	143,322	143,939	145,780	148,097

Appendix H.2: Business As Usual (BAU) with Retirement of Natural Gas Fired Units Aged 50 years and older

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	800	3,600	1,300	800	2,000	-
CT Adds	MW	1,700	2,400	4,700	3,800	2,000	5,200
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-	-
Gravity Power Adds	MW						
Solar Adds	MW	-	-	2,000	3,000	2,000	3,000
Wind Adds	MW	-	-	-	-	-	1,500
Annual Capacity Additions	MW	2,500	6,000	8,000	7,600	6,000	9,700
Cumulative Capacity Additions	MW	2,500	8,500	16,500	24,100	30,100	39,800
Retirements	MW	3,068	2,249	4,109	2,543	1,796	-
Residential Demand Response	MA	2,200	-	-	-	-	-
Industrial Demand Response	MW	500	-	-	-	-	-
Reserve Margin	%	0.8	0.8	(1.6)	(0.7)	(1.9)	(1.0)
Administrative Units	MW	-	-	13,430	-	-	1,360
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	54.83	59.32	63.27	71.79	79.74	90.89
Natural Gas Price	$/MMBtu	4.64	5.23	6.13	6.97	7.88	9.19
Average Market Heat Rate	MMBtu/MWh	11.82	11.34	10.32	10.30	10.12	9.89
Natural Gas Generation	%	44.9	47.41	49.0	50.2	51.6	52.6
Coal Generation	%	33.9	31.9	31.0	30.2	29.4	28.1
Wind Generation	%	10.4	9.76	9.4	9.2	9.0	9.6
Solar Generation	%						
Scarcity Hours	hrs	15	22	16	18	20	24
Unserved Energy	GWhs	18	30	21	36	51	43
SO_2	Tons	356,148	355,184	356,498	356,399	357,745	357,859
CO_2	(k) Tons	224,284	252,516	259,336	264,152	271,086	279,479
NO_x	Tons	135,712	136,282	137,352	138,184	140,030	142,519

Appendix H.3: Business As Usual (BAU) with Updated Wind Shapes

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW		1,600				2,000
CT Adds	MW	1,190		1,190	1,700	1,360	1,700
Coal Adds	MW						
Nuclear Adds	MW						
CAES Adds	MW						
Geothermal Adds	MW						
Gravity Power Adds	MW						
Solar Adds	MW		1,500	3,000	2,000	1,000	2,500
Wind Adds	MW	300	1,886	4,782	2,291	3,818	3,778
Annual Capacity Additions	MW	1,490	4,986	8,972	5,991	6,178	9,978
Cumulative Capacity Additions	MW	1,490	6,476	15,448	21,439	27,617	37,595
Retirements	MW	-	-	-	-	-	-
Residential Demand Response	MW	-	-	-	-	-	-
Industrial Demand Response	MW	-	-	-	-	-	-
Reserve Margin	%	0.00	(0.80)	(2.37)	(1.95)	(4.00)	(4.35)
Administrative Units	MW	-	-	13,940	-	-	3,910
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	50.52	57.87	63.02	70.03	77.12	87.99
Natural Gas Price	$/MMBtu	4.64	5.23	6.13	6.97	7.88	9.18
Average Market Heat Rate	MMBtu/MWh	10.89	11.07	10.28	10.05	9.79	9.58
Natural Gas Generation	%	44.0	44.1	40.9	39.9	38.7	38.5
Coal Generation	%	35.2	33.3	32.0	30.9	29.8	28.2
Wind Generation	%	9.5	10.8	14.5	16.2	18.7	20.3
Solar Generation	%	-	0.7	2.0	2.8	3.1	3.9
Scarcity Hours	hrs	15	18	21	28	30	37
Unserved Energy	GWhs	20.4	29.4	31.6	48.3	57.1	87.9
SO_2	Tons	356,096	355,301	356,347	356,442	357,140	357,409
CO_2	(k) Tons	246,956	250,747	248,318	249,700	251,057	255,536
NO_x	Tons	276,450	276,541	273,803	273,774	274,846	273,963

Appendix H.4: Business As Usual (BAU) with High Natural Gas Prices

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	-	-	-	-	-
CT Adds	MW	-	-	-	-	-	400
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW						
Geothermal Adds	MW	-	1,500	1,500	600	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	6,000	2,000	2,000	3,000
Wind Adds	MW	17,621	820	2,337	3,907	5,234	6,056
Annual Capacity Additions	MW	17,621	2,320	9,837	6,507	7,234	9,456
Cumulative Capacity Additions	MW	17,621	19,941	29,778	36,285	43,519	52,975
Retirements	MW	-	718	4,174	-	-	-
Residential Demand Response	MW	-	-	-	-	-	-
Industrial Demand Response	MW	-	-	-	-	-	-
Reserve Margin	%	3.7	0.3	(4.5)	(4.1)	(7.8)	(11.0)
Administrative Units	MW	-	-	15,341	-	-	8,650
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	58.47	66.52	75.14	78.59	85.41	95.24
Natural Gas Price	$/MMBtu	9.55	10.01	10.74	11.72	12.70	13.70
Average Market Heat Rate	MMBtu/MWh	6.12	6.65	7.00	6.71	6.73	6.95
Natural Gas Generation	%	27.3	27.81	24.8	22.9	22.5	22.5
Coal Generation	%	33.6	32.14	30.6	29.2	27.9	25.9
Wind Generation	%	28.3	27.55	28.0	29.6	31.7	33.5
Solar Generation	%	0.0	0.01	2.6	3.4	4.0	5.0
Scarcity Hours	hrs	-	2	10	13	18	30
Unserved Energy	GWhs	-	2	14	19	33	38
SO_2	Tons	347,741	348,521	346,179	343,510	340,324	335,050
CO_2	(k) Tons	209,175	213,191	207,738	205,647	204,504	205,314
NO_x	Tons	242,368	246,138	240,107	237,557	236,897	236,855

Appendix H.5: Business As Usual (BAU) with Extension of Production Tax Credit (PTC)

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	-	-	-	-	-
CT Adds	MW	-	-	-	-	-	-
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW						
Geothermal Adds	MW	-	100	400	500	2,600	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	1,000	3,500	2,000	-	4,500
Wind Adds	MW	14,934	2,322	500	100	484	5,025
Annual Capacity Additions	MW	14,934	3,422	4,400	2,600	3,084	9,525
Cumulative Capacity Additions	MW	14,934	18,356	22,756	25,356	28,440	37,965
Retirements	MW	-	1,344	-	-	-	-
Residential Demand Response	MA	-	-	500	500	-	-
Industrial Demand Response	MW	-	500	500	500	500	500
Reserve Margin	%	(0.1)	(4.4)	(6.3)	(7.4)	(9.4)	(12.1)
Administrative Units	MW	-	-	18,020	-	-	8,670
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	40.05	55.52	59.58	68.85	73.86	86.17
Natural Gas Price	$/MMBtu	4.64	5.23	6.13	6.97	7.88	9.19
Average Market Heat Rate	MMBtu/MWh	8.63	10.62	9.72	9.88	9.37	9.38
Natural Gas Generation	%	28.9	29.63	29.8	30.6	29.2	28.4
Coal Generation	%	33.6	32.25	31.3	30.3	29.1	27.4
Wind Generation	%	26.3	26.74	26.0	25.1	24.5	26.3
Solar Generation	%	0.0	0.47	2.0	2.7	2.6	4.2
Scarcity Hours	hrs	7	22	19	17	17	25
Unserved Energy	GWhs	6	29	35	37	43	79
SO_2	Tons	345,326	347,672	351,554	353,136	352,524	350,753
CO_2	(k) Tons	213,529	218,942	223,559	228,455	228,238	229,694
NO_x	Tons	122,693	125,198	127,346	129,627	129,913	130,778

Appendix H.6: Business As Usual (BAU) with Increased DC Tie Capacity

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	2,000	2,800	1,600	1,200	800
CT Adds	MW	-	680	-	-	-	-
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	2,500	1,000	500	3,500
Wind Adds	MW	14,934	2,322	365	409	2,923	7,593
Annual Capacity Additions	MW	14,934	5,002	5,665	3,009	4,623	11,893
Cumulative Capacity Additions	MW	14,934	19,936	25,601	28,610	33,233	45,126
Retirements	MW	-	11,036	1,968	-	-	-
Residential Demand Response	MW	-	-	-		-	-
Industrial Demand Response	MW	-	-	500	500	1,000	500
Reserve Margin	%	(0.13)	(10.60)	(12.29)	(11.95)	(13.12)	(14.66)
Administrative Units	MW	-	-	22,440	-	-	5,100
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	36.79	55.42	62.47	68.36	77.02	83.49
Natural Gas Price	$/MMBtu	4.64	5.23	6.13	6.97	7.88	9.18
Average Market Heat Rate	MMBtu/MWh	7.93	10.60	10.19	9.81	9.77	9.09
Natural Gas Generation	%	42.1	42.8	43.5	44.4	44.2	41.1
Coal Generation	%	34.2	32.7	31.7	30.7	29.7	28.1
Wind Generation	%	24.9	25.4	24.6	24.0	25.0	28.3
Solar Generation	%	-	-	1.1	1.7	1.8	3.1
Scarcity Hours	hrs	-	28	18	16	25	18
Unserved Energy	GWhs	-	68	31	27	47	43
SO_2	Tons	348,032	349,219	352,572	355,020	356,686	357,189
CO_2	(k) Tons	214,463	219,916	225,831	232,345	236,803	236,775
NO_x	Tons	247,667	248,709	249,002	251,857	254,316	253,522

Appendix H.7: Drought

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	2,400	-	-	-	1,200
CT Adds	MW	9,010	510	-	170	510	2,890
Coal Adds	MW						
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW						
Geothermal Adds	MW	300	700	1,500	1,100	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	2,500	2,000	2,000	2,000	2,500
Wind Adds	MW	523	1,211	3,680	2,738	4,533	346
Annual Capacity Additions	MW	9,833	7,321	7,180	6,008	7,043	6,936
Cumulative Capacity Additions	MW	9,833	17,154	24,334	30,342	37,385	44,321
Retirements	MW	-	-	-	-	-	-
Residential Demand Response	MW	-	-	-		-	-
Industrial Demand Response	MW	-	-	-	-	500	500
Reserve Margin	%	2.89	2.74	1.73	0.19	(2.22)	(1.75)
Administrative Units	MW	-	-	11,220	-	-	5,270
Coincident Peak	MW	86,113	91,068	94,728	98,666	103,502	108,981
Average LMP	$/MWh	52.78	59.19	63.42	69.38	77.82	88.05
Natural Gas Price	$/MMBtu	4.64	5.23	6.13	6.97	7.88	9.18
Average Market Heat Rate	MMBtu/MWh	11.38	11.32	10.35	9.95	9.88	9.59
Natural Gas Generation	%	45.1	44.6	42.4	38.2	35.9	38.2
Coal Generation	%	33.1	31.5	31.4	29.1	28.2	26.7
Wind Generation	%	10.8	12.4	17.3	20.4	23.3	22.2
Solar Generation	%	-	1.1	1.9	2.6	3.3	4.0
Scarcity Hours	hrs	22.0	24.0	25.0	15.0	30.0	27.0
Unserved Energy	GWhs	25.5	27.5	39.4	9.5	38.7	38.0
SO_2	Tons	356,652	355,660	355,081	356,699	353,838	359,705
CO_2	(k) Tons	254,938	250,014	245,345	243,602	243,465	251,304
NO_x	Tons	279,508	275,042	270,869	269,274	269,997	274,402

Appendix H.8: Drought with Low Natural Gas Prices

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	1,200	400	2,000	-	800
CT Adds	MW	6,120	3,225	850	2,550	2,550	-
Coal Adds	MW						
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW						
Geothermal Adds	MW	-	-	-	600	200	900
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	2,500	2,500	2,000	2,000
Wind Adds	MW		-	200	203	221	4,926
Annual Capacity Additions	MW	6,120	4,425	3,950	7,853	4,971	8,626
Cumulative Capacity Additions	MW	6,120	10,545	14,495	22,348	27,319	35,945
Retirements	MW	-	-	-	-	-	-
Residential Demand Response	MW	-	-	-		-	-
Industrial Demand Response	MW	-	-	500	500	500	500
Reserve Margin	%	(0.94)	(1.48)	(2.12)	1.06	0.45	(0.86)
Administrative Units	MW	-	-	14,620	-	-	680
Coincident Peak	MW	86,113	91,068	94,728	98,666	103,502	108,981
Average LMP	$/MWh	37.94	41.71	50.72	58.87	64.94	75.31
Natural Gas Price	$/MMBtu	2.64	3.23	4.13	4.97	5.88	7.19
Average Market Heat Rate	MMBtu/MWh	14.37	12.91	12.28	11.85	11.04	10.47
Natural Gas Generation	%	60.9	60.4	56.9	52.2	50.7	47.1
Coal Generation	%	18.5	19.9	23.0	26.5	27.4	26.4
Wind Generation	%	9.8	9.3	9.3	9.0	9.0	13.2
Solar Generation	%	-	-	0.9	2.0	2.7	3.3
Scarcity Hours	hrs	16.0	15.0	20.0	19.0	27.0	36.0
Unserved Energy	GWhs	22.9	12.4	17.5	15.6	25.8	51.0
SO_2	Tons	202,387	228,714	278,670	327,849	347,788	355,010
CO_2	(k) Tons	220,286	232,061	248,045	257,712	270,852	269,595
NO_x	Tons	242,507	254,208	270,832	277,271	289,294	288,671

Appendix H.9: Drought with Emission Costs and Extension of Production Tax Credit (PTC)

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	10,000	-	-	400	-	-
CT Adds	MW	-	170	-	-	-	-
Coal Adds	MW						
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW						
Geothermal Adds	MW	1,500	1,500	600	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	2,000	1,500	-	4,000	-
Wind Adds	MW	31,333	11,691	3,460	7,031	4,660	9,953
Annual Capacity Additions	MW	42,833	15,361	5,560	7,431	8,660	9,953
Cumulative Capacity Additions	MW	42,833	58,194	63,754	71,185	79,845	89,798
Retirements	MW	-	8,635	-	-	-	-
Residential Demand Response	MW	-	-	-		-	-
Industrial Demand Response	MW	-	-	-	-	-	-
Reserve Margin	%	8.02	(3.43)	(5.45)	(7.82)	(9.82)	(13.60)
Administrative Units	MW	-	-	18,020	-	-	11,390
Coincident Peak	MW	86,113	91,068	94,728	98,666	103,502	108,981
Average LMP	$/MWh	56.57	64.40	68.31	73.48	80.97	86.76
Natural Gas Price	$/MMBtu	4.64	5.23	6.13	6.97	7.88	9.18
Average Market Heat Rate	MMBtu/MWh	12.19	12.31	11.14	10.54	10.28	9.45
Natural Gas Generation	%	47.2	39.0	37.9	35.7	33.5	30.9
Coal Generation	%	3.4	2.7	3.2	3.3	3.5	4.3
Wind Generation	%	36.9	45.7	46.1	48.7	49.6	52.2
Solar Generation	%	-	0.9	1.5	1.4	2.9	2.7
Scarcity Hours	hrs	-	8.0	5.0	6.0	11.0	9.0
Unserved Energy	GWhs	-	7.9	4.0	13.3	24.5	18.3
SO_2	Tons	26,293	21,811	28,094	31,100	34,134	47,457
CO_2	(k) Tons	114,157	98,922	103,213	102,523	102,590	106,781
NO_x	Tons	90,487	79,169	82,799	83,463	84,995	91,929

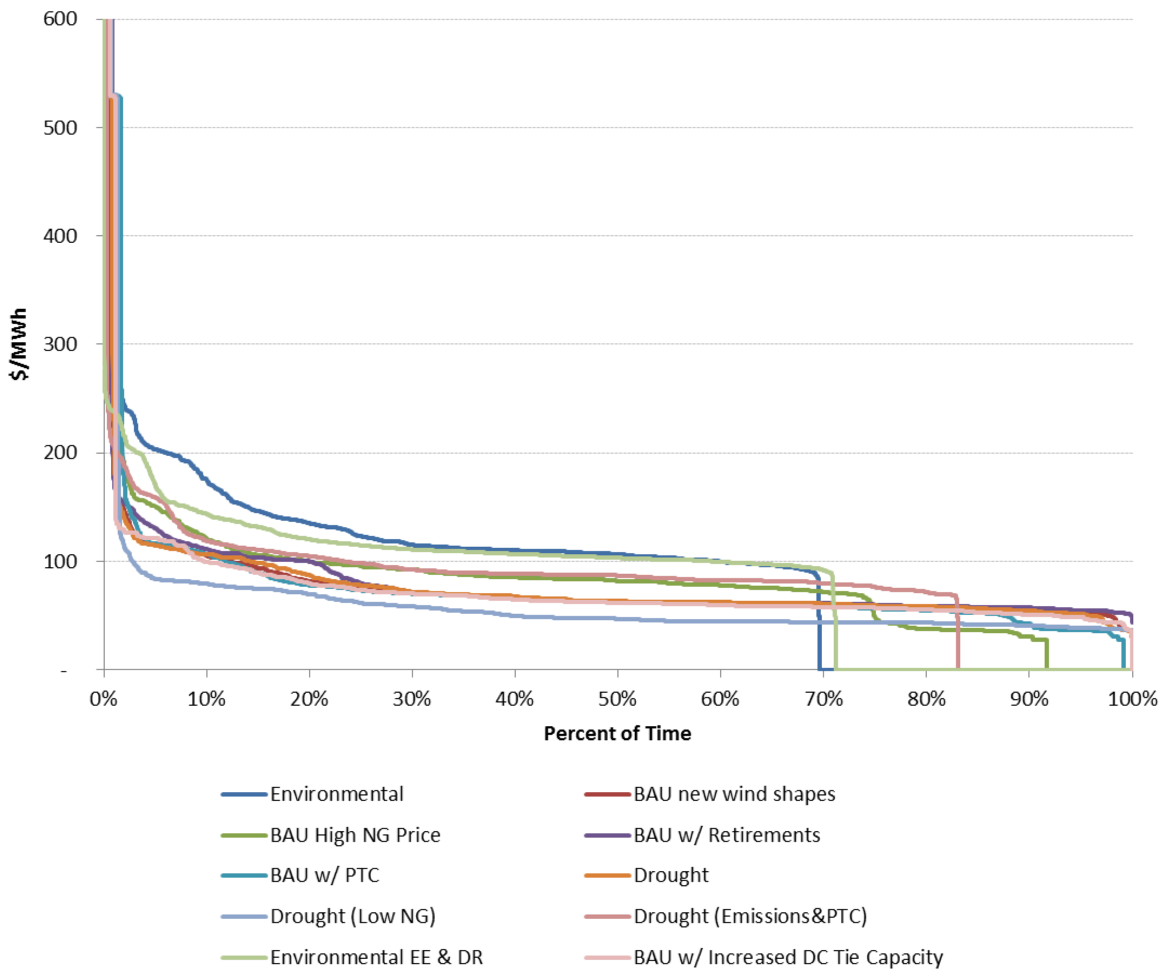
Appendix H.10: Environmental

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	-	-	-	-	-
CT Adds	MW	-	-	-	-	680	2,210
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW						
Geothermal Adds	MW	1,500	1,500	600	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	15,500	500	500	1,500
Wind Adds	MW	38,901	8,768	5,260	8,167	3,523	5,845
Annual Capacity Additions	MW	40,401	10,268	21,360	8,667	4,703	9,555
Cumulative Capacity Additions	MW	40,401	50,669	72,029	80,696	85,399	94,954
Retirements	MW	-	6,938	14,303	-	-	-
Residential Demand Response	MW	-	-	-		-	-
Industrial Demand Response	MW	-	-	500	500	500	500
Reserve Margin	%	5.07	(5.10)	(16.05)	(16.95)	(18.91)	(19.86)
Administrative Units	MW	-	-	25,500	-	-	6,970
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	69.48	72.19	90.05	86.22	95.96	101.85
Natural Gas Price	$/MMBtu	9.55	10.01	10.74	11.72	12.70	13.70
Average Market Heat Rate	MMBtu/MWh	7.28	7.21	8.38	7.36	7.56	7.43
Natural Gas Generation	%	19.7	18.3	24.0	22.2	22.7	23.2
Coal Generation	%	23.2	19.7	6.3	5.8	5.6	5.3
Wind Generation	%	45.1	50.8	50.2	55.0	55.4	55.6
Solar Generation	%	-	-	6.8	6.7	6.7	6.9
Scarcity Hours	hrs	-	4.0	26.0	19.0	15.0	14.0
Unserved Energy	GWhs	-	2.0	46.4	35.4	22.1	33.2
SO_2	Tons	217,810	192,720	23,108	23,003	21,436	21,696
CO_2	(k) Tons	148,543	135,939	86,273	83,035	86,014	90,442
NO_x	Tons	171,238	156,730	83,051	80,534	83,277	86,848

Appendix H.11: Environmental with Demand Response and Energy Efficiency Mandates

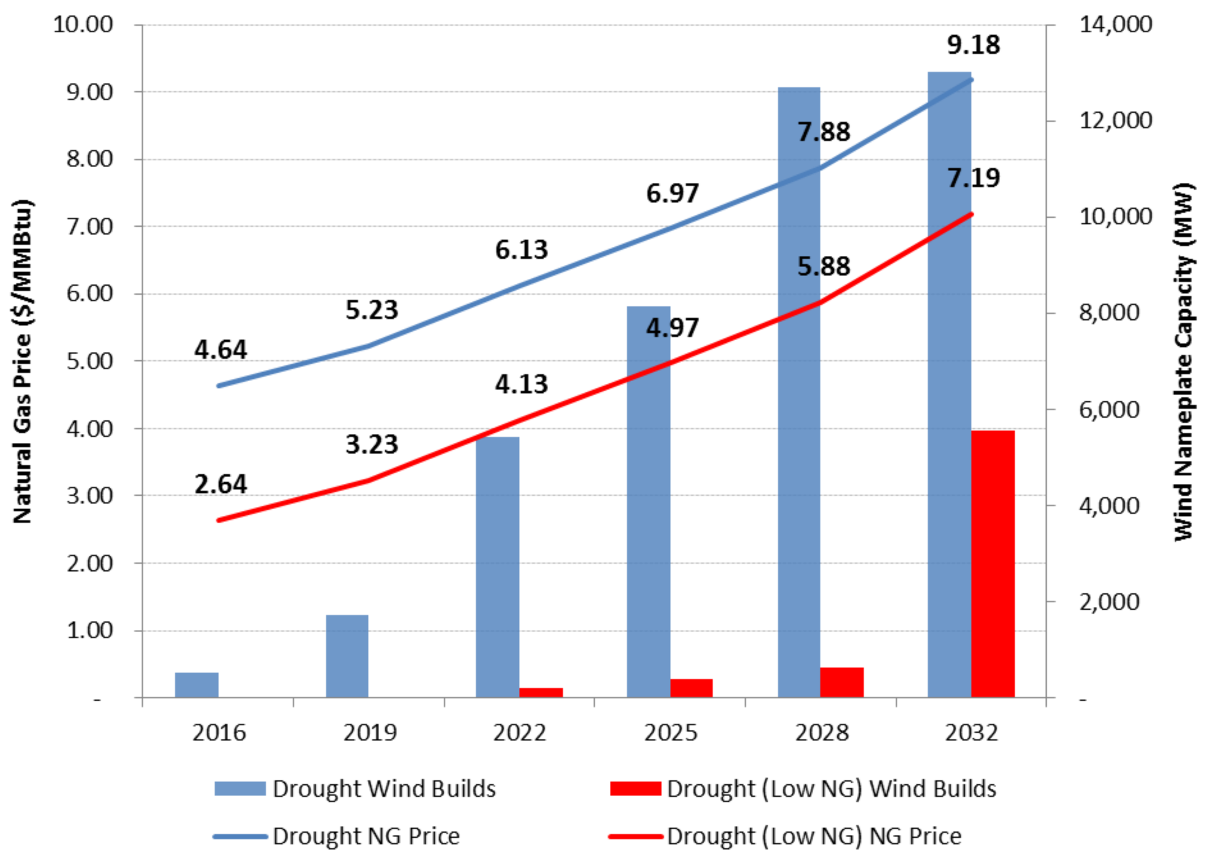
Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	-	-	-	-	-
CT Adds	MW	-	-	-	-	-	-
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW						
Geothermal Adds	MW	1,500	1,500	600	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	-	-	-	-
Wind Adds	MW	38,316	7,050	1,482	820	2,238	1,305
Annual Capacity Additions	MW	39,816	8,550	2,082	820	2,238	1,305
Cumulative Capacity Additions	MW	39,816	48,366	50,448	51,268	53,506	54,811
Retirements	MW	-	7,870	1,841	3,041	-	-
Residential Demand Response	MW	1,284	1,283	1,283	1,283	1,284	1,283
Industrial Demand Response	MW	500	500	500	500	500	500
Reserve Margin	%	13.1	6.8	7.6	6.4	9.6	12.1
Administrative Units	MW	-	-	4,350	-	-	-
Coincident Peak	MW	75,773	76,468	76,706	76,490	76,453	76,851
Average LMP	$/MWh	70.64	68.88	71.76	75.85	78.10	85.02
Natural Gas Price	$/MMBtu	4.64	5.23	6.13	6.97	7.88	9.18
Average Market Heat Rate	MMBtu/MWh	15.22	13.17	11.71	10.88	9.91	9.26
Natural Gas Generation	%	17.9	15.6	14.5	13.6	13.1	13.2
Coal Generation	%	23.9	20.2	20.1	20.8	20.2	20.0
Wind Generation	%	44.4	50.8	52.3	52.5	53.8	54.0
Solar Generation	%	-	-	-	-	-	-
Scarcity Hours	hrs	-	-	-	-	-	-
Unserved Energy	GWhs	-	-	-	-	-	-
SO_2	Tons	212,294	177,701	179,714	191,420	189,299	189,790
CO_2	(k) Tons	140,854	122,408	120,846	122,875	119,865	120,568
NO_x	Tons	161,027	140,359	137,859	141,882	139,983	141,225

Appendix I Price Duration Curves by Scenario

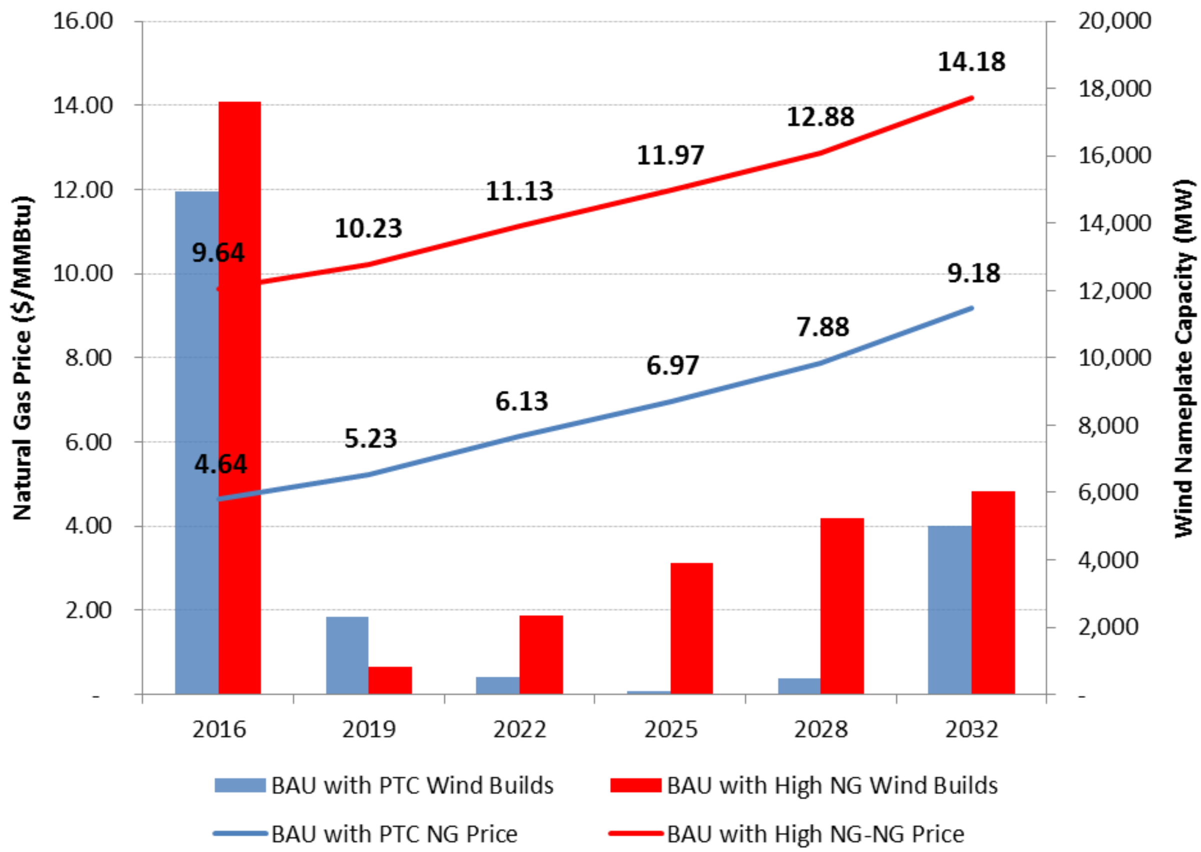


Appendix J Wind Development for Select Scenarios

Wind Development for Drought Scenarios

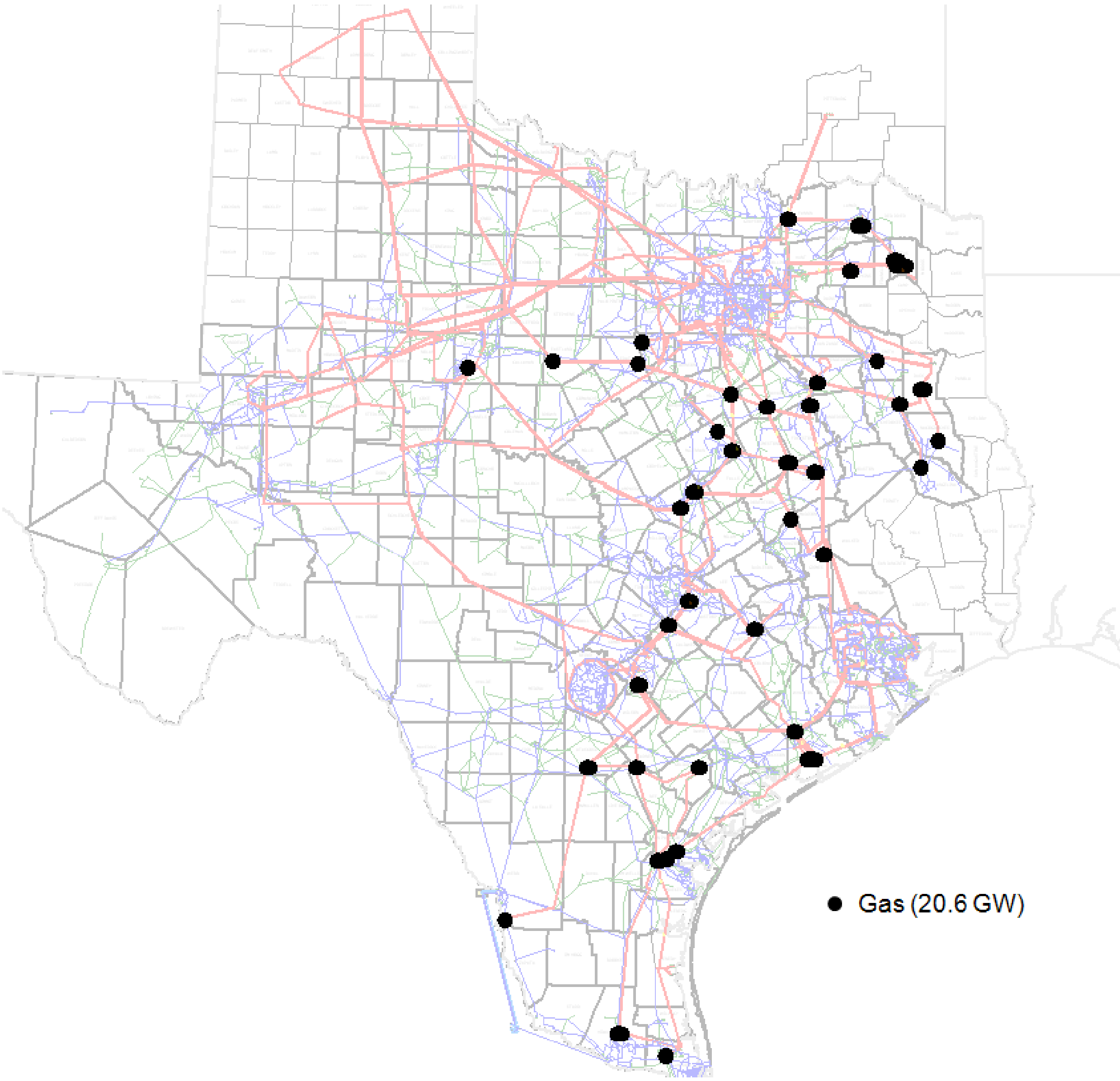


Wind Development for PTC and High Natural Gas Price Scenarios



Appendix K Transmission Results — Business as Usual Scenario in 2032

New Resources Added by 2032



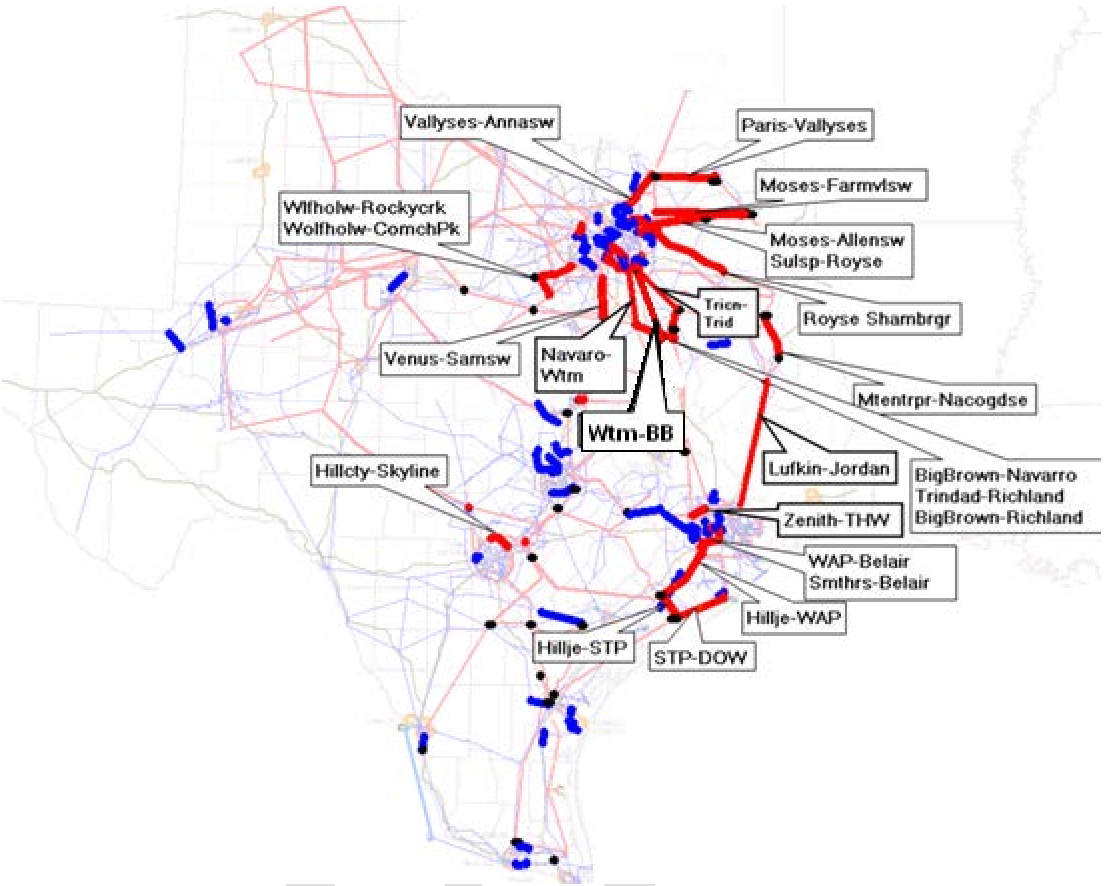
Generation Energy Mix in 2032

Peak load in 2032	Peak Renewable Generation in 2032:
Hour: 8/5/2032 hour 16	Hour: 3/23/2032 hour 4
System load (coincident peak): 101,874 MW	System load: 41,459 MW
Thermal & Hydraulic output: 100,054 MW	Renewable output: 9,291 MW

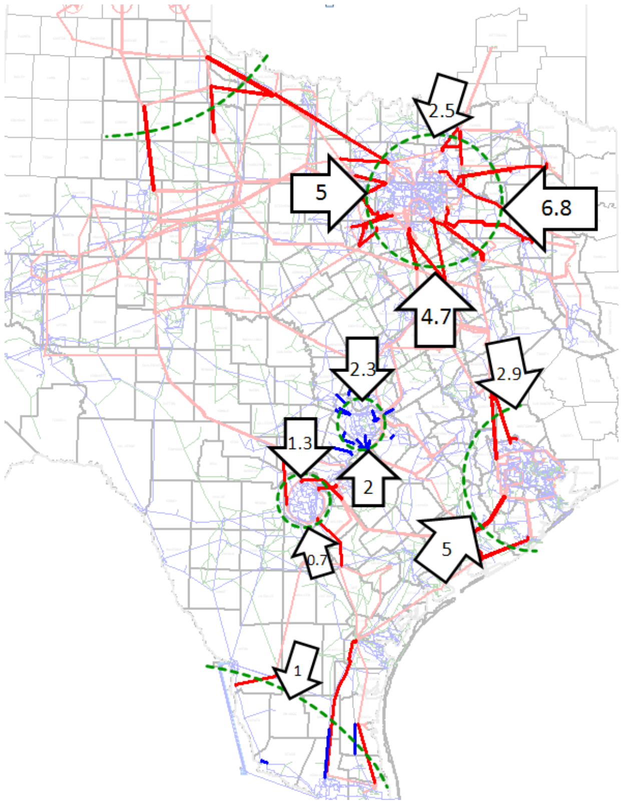
Import Limits Determined by AC Voltage Stability Analysis

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	18,890	2022	Trinidad to Tricorner/Watermill
Houston	8,827	2024	Roan to Kuykendahl & Singleton to Tomball, Fayette to Zenith, Hillje to W.A. Parish, or South Texas to Dow
San Antonio	3,033	2028	Hill Country to Marion & Skyline to Marion
Austin	3,839	2028	Elm Creek to South Texas
Valley	Not tested because incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2,512 MW		

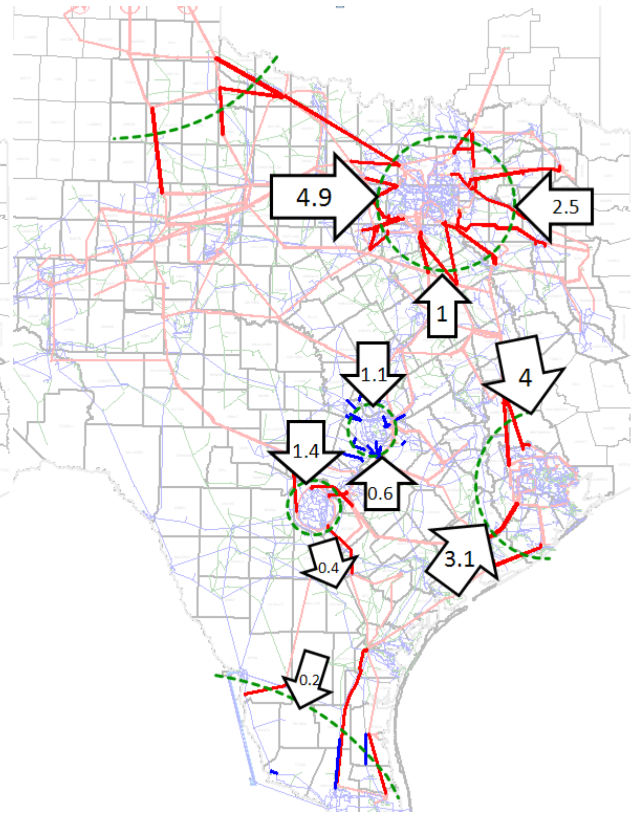
Base Case Overloads in 2032



System Flows at Peak Load Hour in 2032

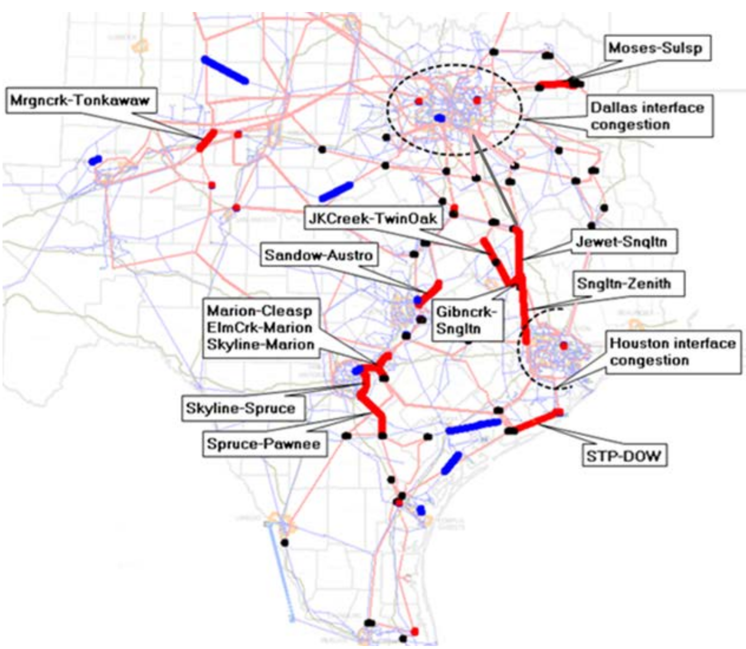


System Flows at Peak Wind Hour in 2032



*All numbers are in GW

Congestion Map in 2032

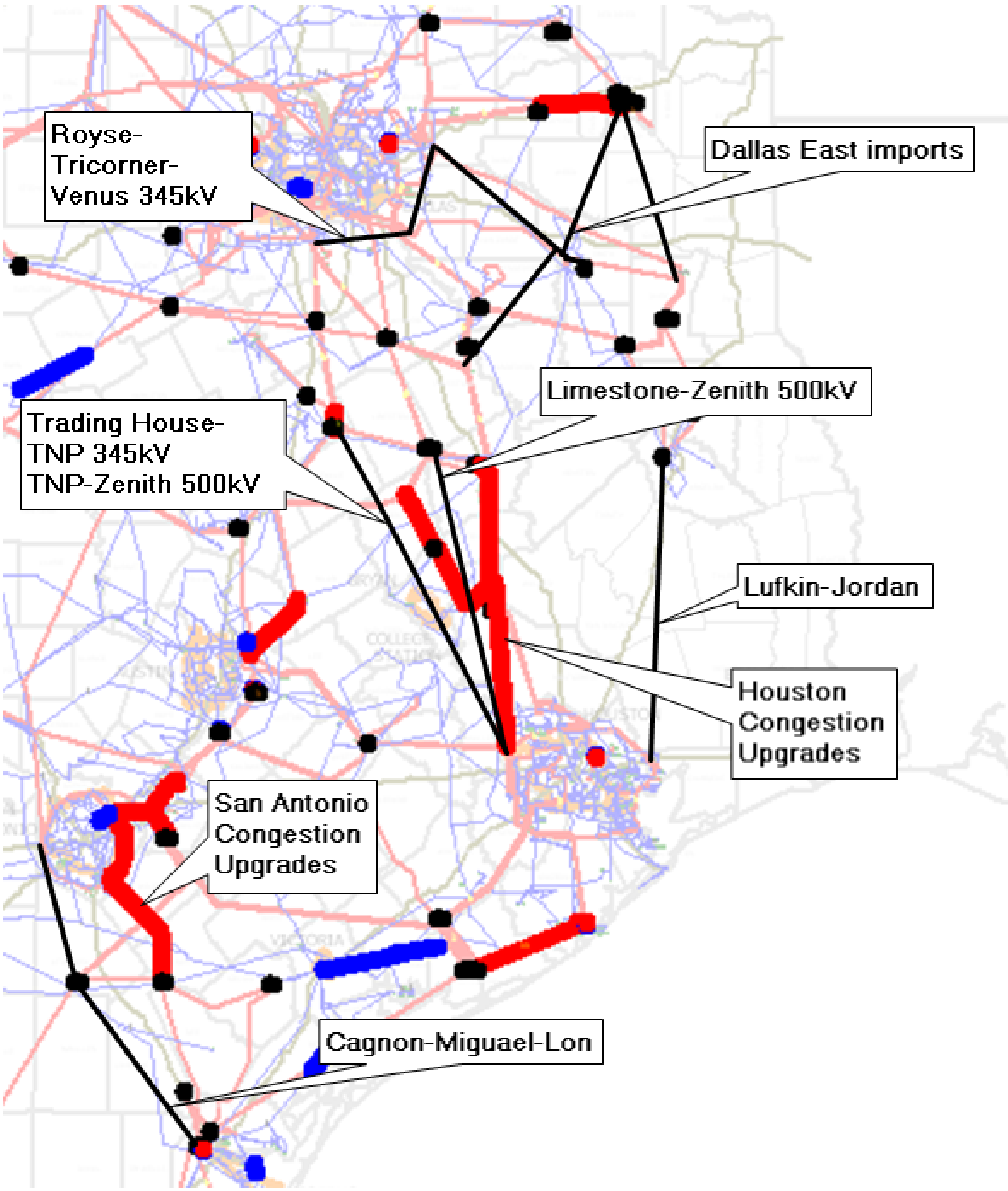


Most Congested Elements in 2032

From Bus Name (Number)	To Bus Name (Number)	Congestion Cost($M)
SINGLETON (44645)	ZENITH (44900)	$131.13
NACOGDOCHES (5315)	SKYLINE (5369)	$79.94
GIBON CRK (967)	SINGLETON (44645)	$51.27
(Houston interface)		$44.89
GILLELAND CRK (7336)	GILLELAND CRK (7340)	$26.64
SKYLINE 345 (5371)	MARION (7044)	$25.23
CRMWD (1118)	GLENHAVEN (1121)	$16.17
FORNEY (2438)	DUCK CRK WWTP TAP (2934)	$16.02
(Dallas interface)		$15.13
GARFIELD (7048)	GARFIELD (9071)	$13.74
SANDOW (3429)	AUSTROP (7040)	$10.51
SPUR (6150)	ASPERMONT (6158)	$9.47
ODESSA EHV (1027)	BIG THREE-ODESSA (1111)	$5.62
JEWETT SOUTH (3390)	SINGLETON (44645)	$5.19
CVEC ORIENT (6441)	SAN ANGELO RED CRK (6442)	$5.09
GIBON CRK (967)	JACK CRK (975)	$3.95
J.K. SPRUCE (5400)	PAWNEE SW ST (5725)	$3.84
MONTICELLO SES (1695)	SULPHUR SPRINGS (1697)	$3.36

Gray items are transformers

Economic Projects Tested in 2032

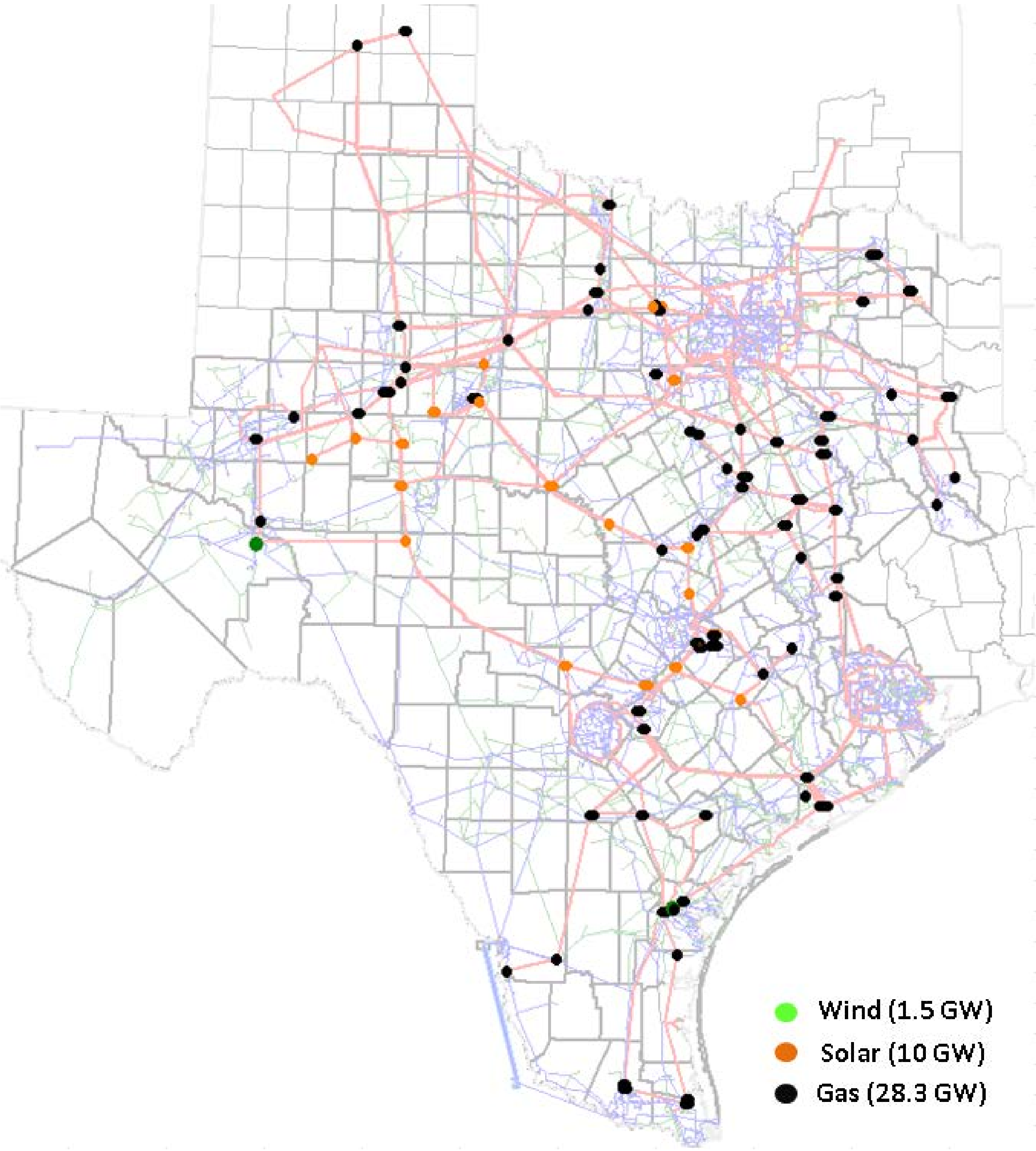


Economic Results in 2032

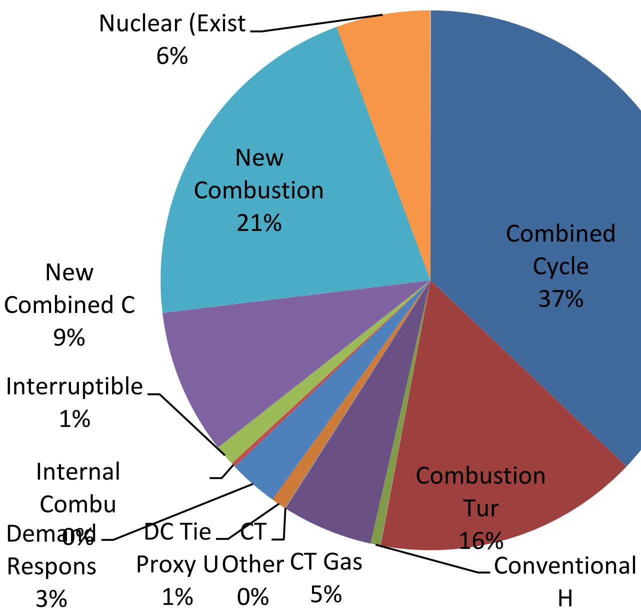
Tested Project in 2032	Adjusted Capital Cost (2032 $M)	1/6 of Adjusted Capital Cost (2032 $M)	Production Cost Savings (2032 $M)	Meet ERCOT Economic Criteria?
Royse to Tricorner to Venus 345-kV line	199.6	33.3	2	No
Dallas East Imports 345-kV lines	40.2	6.7	5.1	No
Trading House to TNP 345-kV line, TNP to Zenith 500-kV line	641.3	106.9	25.4	No
Limestone to Zenith 500-kV line	544.3	90.7	23	No
Houston congestion upgrades	335.6	55.9	20.5	No
Cagnon to Miguel to Lon Hill 500-kV line	726.8	121.1	2.5	No
San Antonio Congestion Upgrades	112.7	18.8	11	No
Tested Project in 2030	**Adjusted Capital Cost (2030 $M)**	**1/6 of Adjusted Capital Cost (2030 $M)**	**Production Cost Savings (2030 $M)**	**Meet ERCOT Economic Criteria?**
Lufkin to Jordan 345-kV line	118.5	19.8	29.9	Yes

Appendix L Transmission Results — Business as Usual with Retirements Scenario in 2032

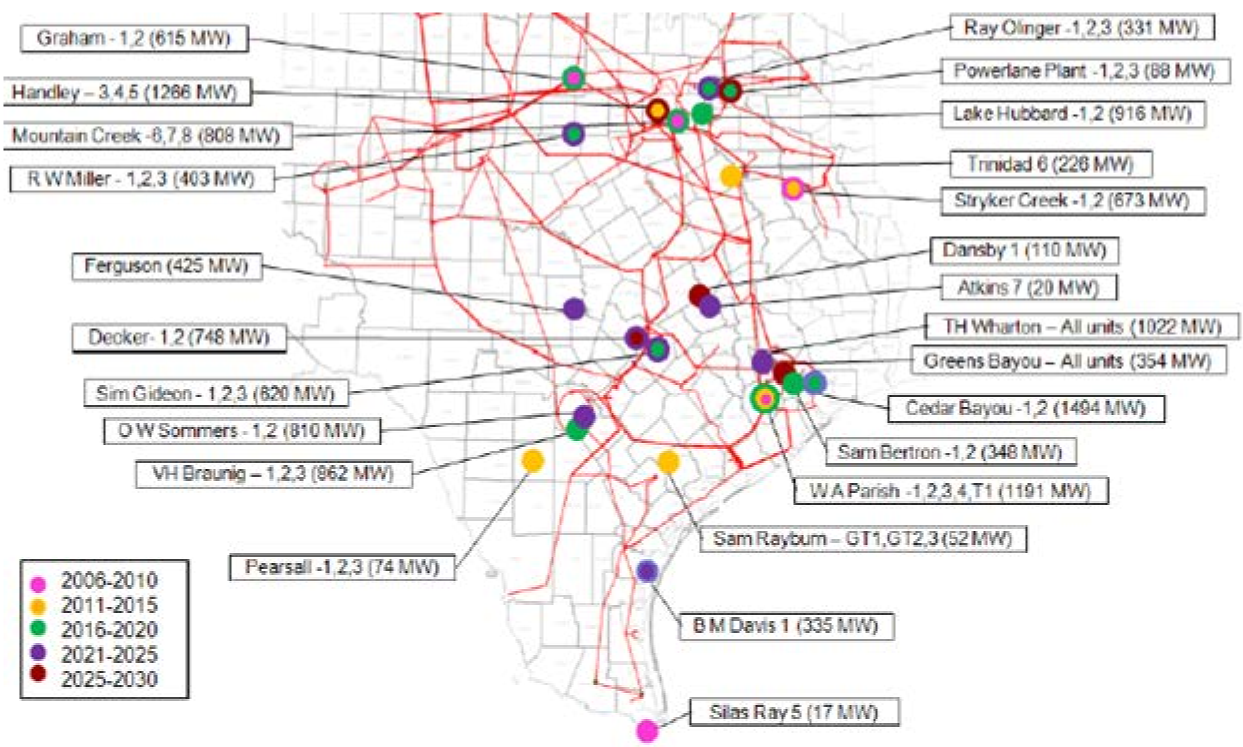
New Resources Added by 2032



Generation Energy Mix in 2032



Generation Retirements by 2032

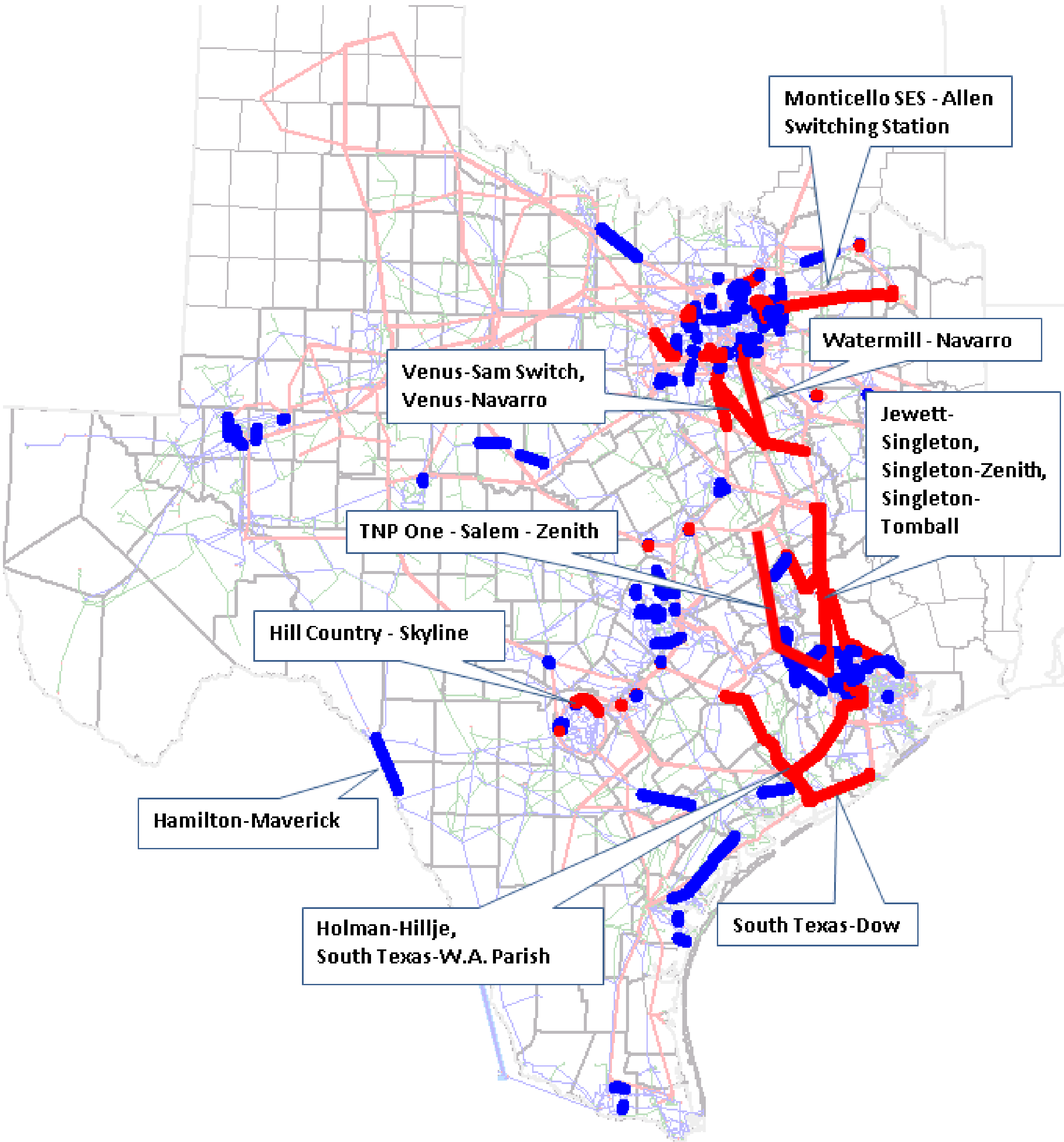


Peak Load in 2032	Peak Renewable Generation in 2032
Hour: 8/5/2032 hour 16	Hour: 3/14/2032 hour 7
System load (coincident peak): 101,874 MW	System load: 46,466 MW
Thermal & Hydraulic output: 94,123 MW	Renewable output: 9,238 MW

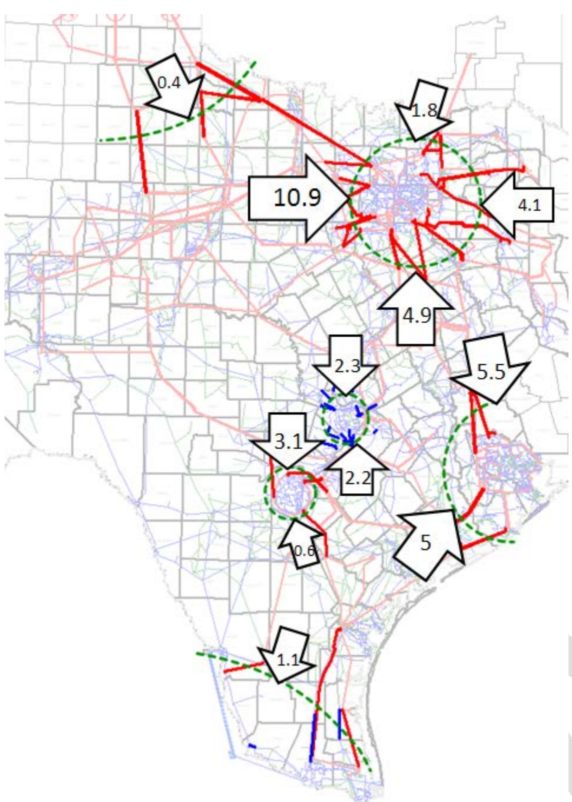
Import Limits Determined by AC Voltage Stability Analysis

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	22,887	2030	Venus to Sam Switch
Houston	13,108	2030	Roans Prairie to Kuykendahl & Singleton to Tomball
San Antonio	5,175	2032	Hutto to Salado
Austin	4,579	Beyond 2032	Hutto to Salado
Valley	Not tested because incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2,512 MW		

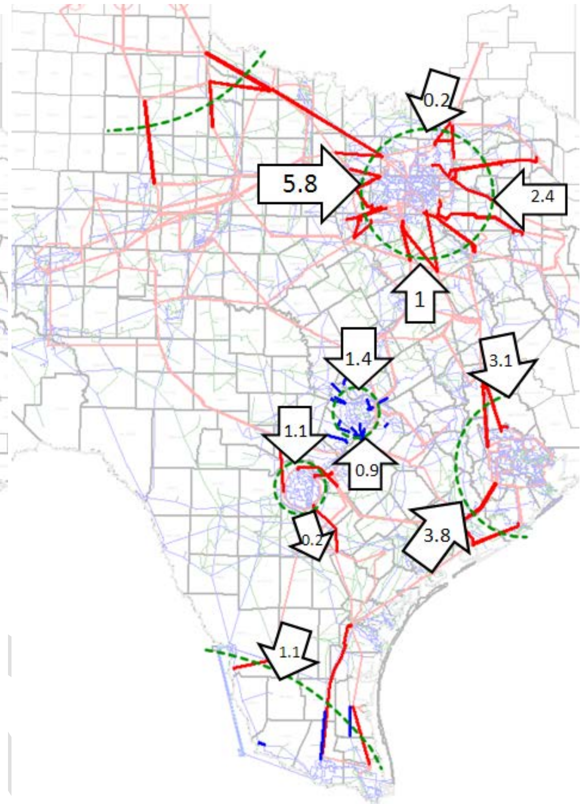
Base Case Overloads in 2032



System Flows at Peak Load Hour in 2032

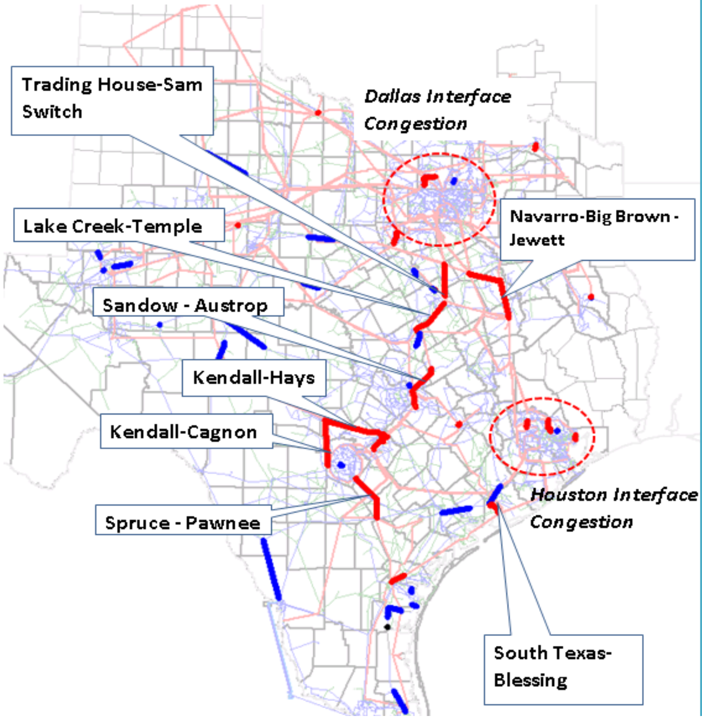


System Flows at Peak Wind Hour in 2032



*All numbers are in GW

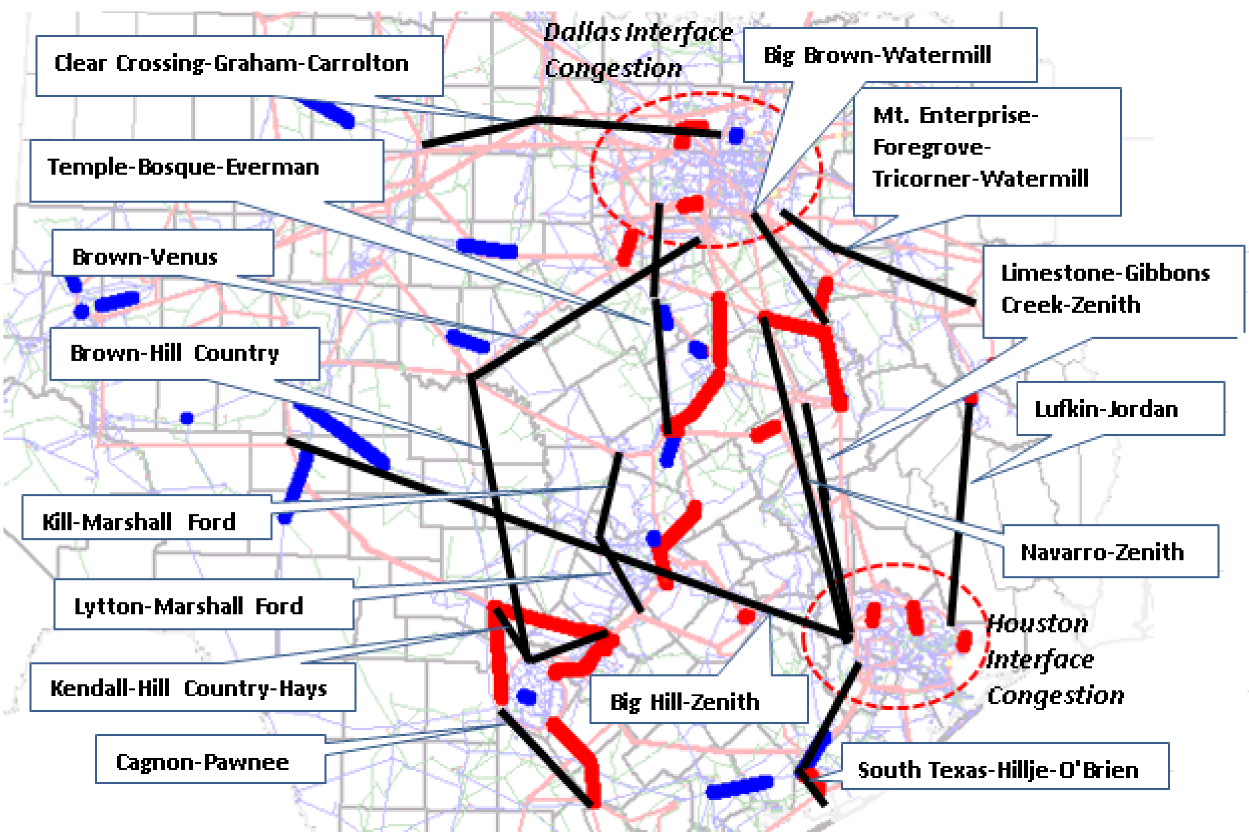
Congestion Map in 2032



Most Congested Elements in 2032

From Bus Name (Number)	To Bus Name (Number)	Congestion Cost ($M)
Houston Interface		629.6
Dallas Interface		605.9
ELDORADO LIVE OAK (6500)	SONORA (6515)	51.2
BIG BROWN SES (3380)	NAVARRO (68091)	39.4
NACOGDOCHES SOUTHEAST (3119)	NACOGDOCHES SOUTHEAST (3120)	33.8
CRMWD#8 TAP (1118)	GLENHAVEN (1121)	23.2
HAYS ENERGY (7043)	KENDALL (7046)	20.6
COBISA (871)	MONTICELLO SES (1695)	20.3
FAYETTE POWER PLANT (7056)	SALEM (7058)	19.9
HIGHWAY 9 (8470)	GILA (80260)	12.4
ZORN (7042)	HAYS ENERGY (7043)	11.6
LEWISVILLE SWITCH (646)	ROANOKE 345 KV TAP #2 (1849)	10.9
SWEETWATER (71067)	SWEETWATER (71065)	9.9
GREENS BAYOU (40700)	KING (40900)	8.9
TH WHARTON (45500)	ADDICKS (45600)	7.7
MERIDA (5310)	WESTSIDE (5490)	7.3
MOSS (1019)	ODESSA SOUTHWEST (1113)	6.3
PFLUGERVILLE (3665)	GILLELAND CREEK (7336)	5.9
BOSQUE SWITCH (252)	LAKE WHITNEY TNP (37410)	4.6
ZORN (7042)	MARION (7044)	3.9
LOLITA (8125)	VICTORIA PLANT (8172)	3.9
CAGNON 345KV BUS (5056)	KENDALL (7046)	3.7
ELM MOTT (3406)	ELM MOTT (3407)	3.4
DOW CHEMICAL (42500)	DOW CHEMICAL (42515)	3.4

Economic Projects Tested in 2032



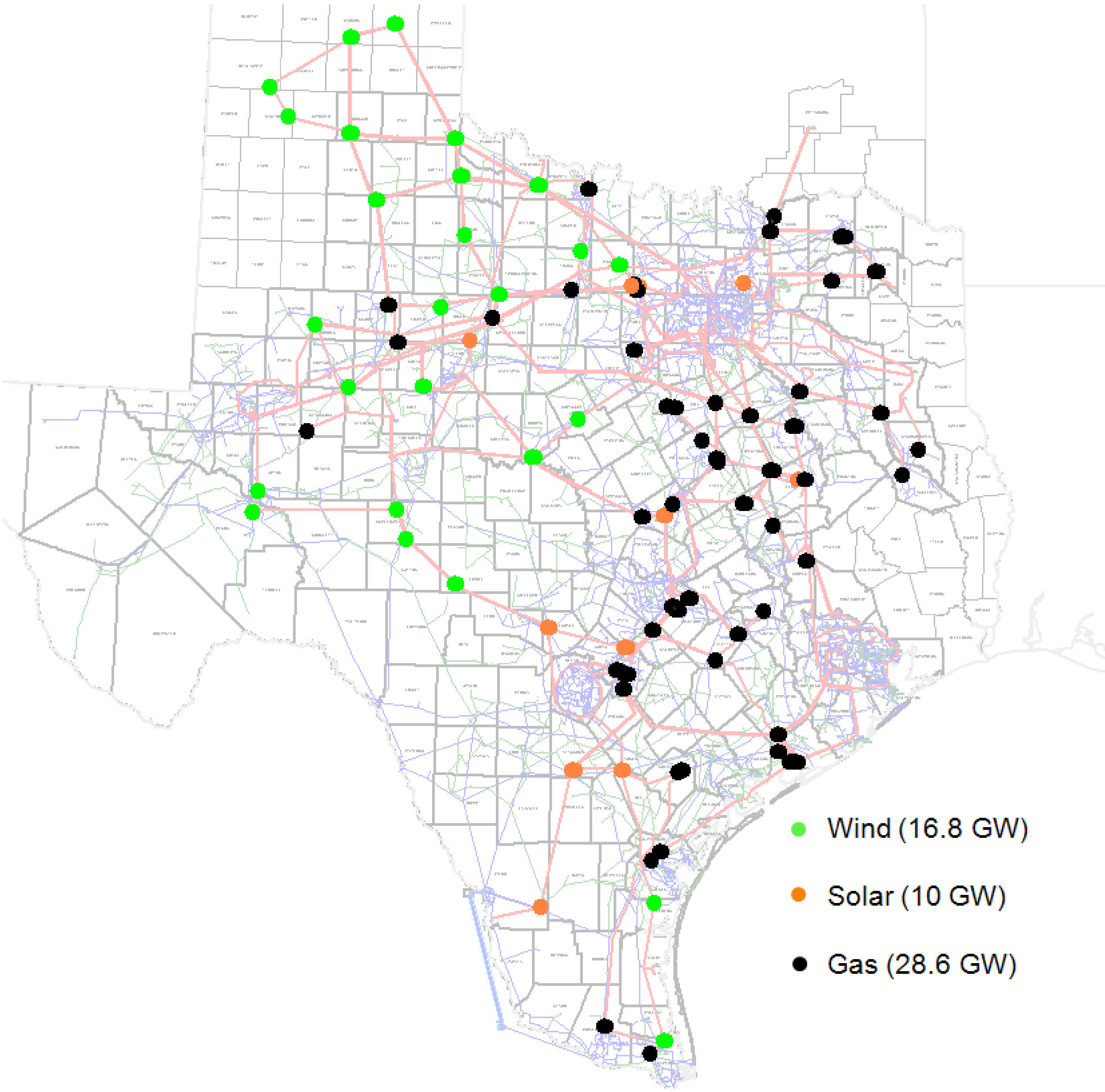
Economic Results in 2032

Tested Project in 2032	Adjusted Capital Cost (2032 $M)	1/6 of Adjusted Capital Cost (2032 $M)	Production Cost Savings (2032 $M)	Meet ERCOT Economic Criteria?
Mt. Enterprise to Foregrove to Tricorner to Watermill	-388.9	-64.8	22.7	Yes
Temple to Bosque to Everman	892	148.7	16.6	No
Brown to Venus	305.8	51	13.5	No
Big Brown to Watermill	140.4	23.4	15.7	No
Clear Crossing to Graham-Carrollton 500-kV line	630.3	105.1	16.6	No
Lufkin to Jordan	-3.5	-0.6	23.8	Yes
Navarro to Zenith	1,080.9	180.1	25.3	No
Limestone to Gibbons Creek to Zenith	-560.4	-93.4	26.8	Yes
South Texas to Hillje to O'Brien	-600.8	-100.1	24.8	Yes
Big Hill to Zenith 500-kV line	1,717.7	286.3	27.1	No
Cagnon to Pawnee	-238.7	-39.8	0.1	Yes
Kendall to Hill Country to Hays Energy	-223.7	-37.3	8.6	Yes
Brown to Hill Country 500-kV line	661.7	110.3	11.2	No
Killeen to Marshall Ford single 345-kV line	126.5	21.1	2.3	No
Lytton-Marshall Ford single 345-kV line	78.7	13.1	0.4	No

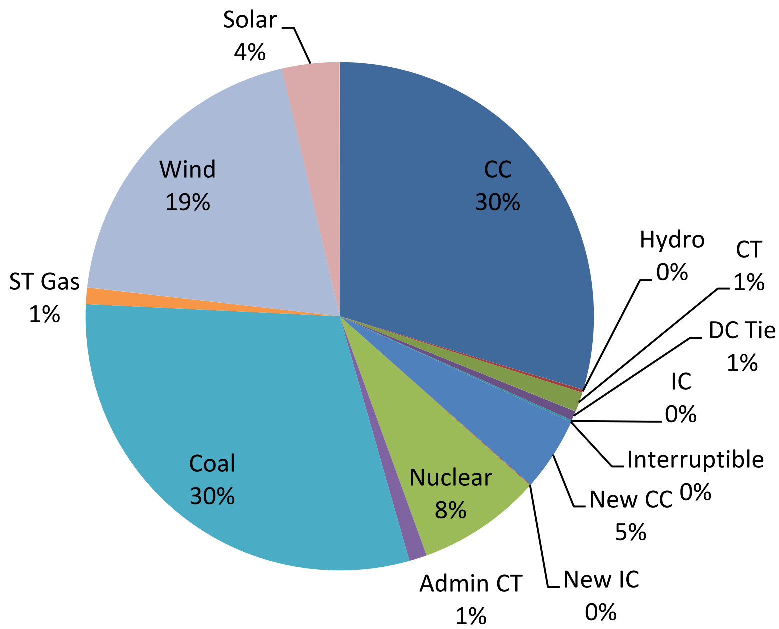
*All numbers except Benefit Cost Ratio are in millions in 2032

Appendix M Transmission Results — Business as Usual with Updated Wind Shapes Scenario in 2032

New Resources Added by 2032



Generation Energy Mix in 2032

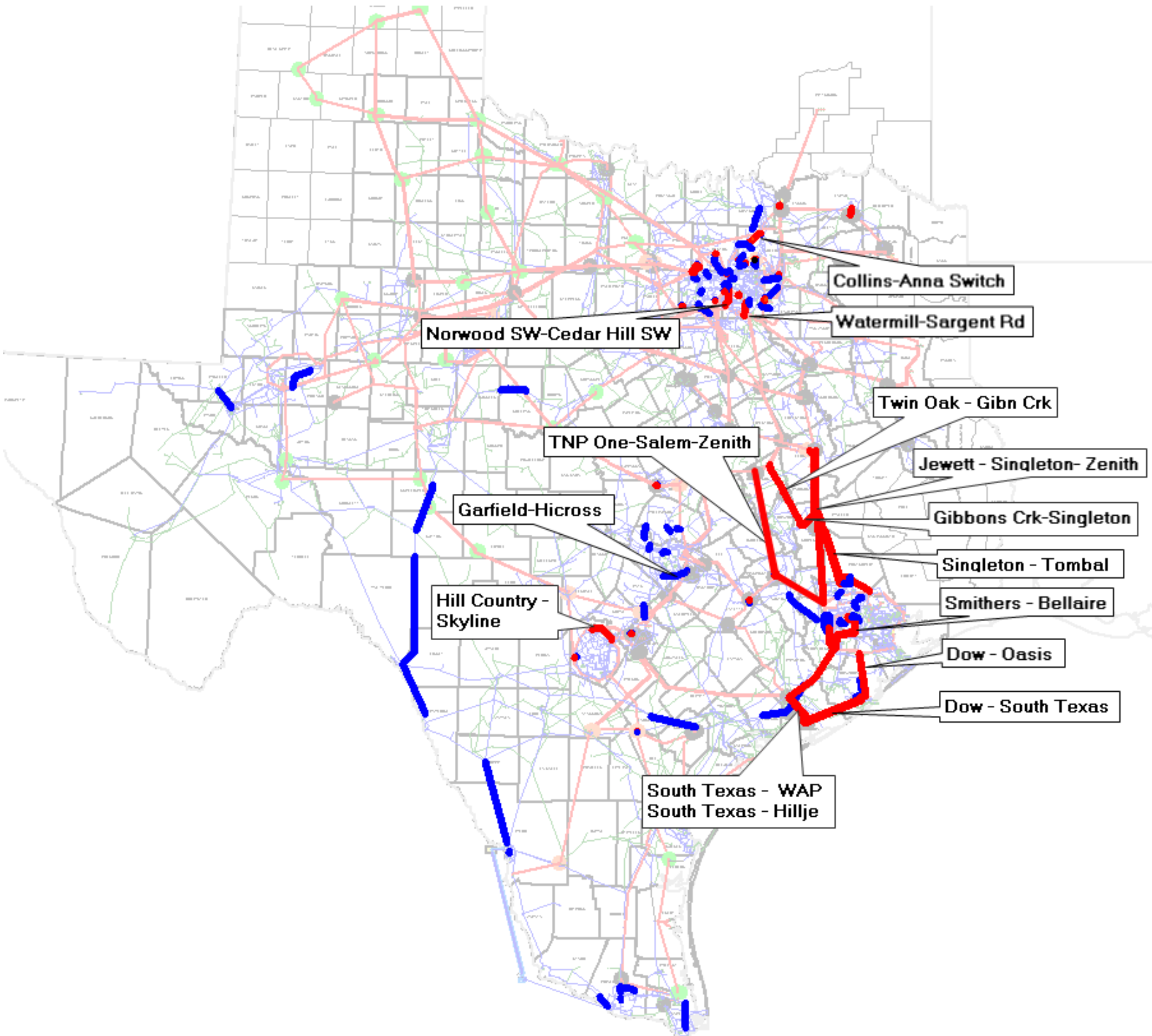


Peak Load in 2032	Peak Renewable Generation in 2032
Hour: 8/5/2032 hour 16	Hour: 3/9/2032 hour 21
System load (coincident peak): 101,874 MW	System load: 66,087 MW
Thermal & Hydraulic output: 88,312 MW	Renewable output: 19,994 MW

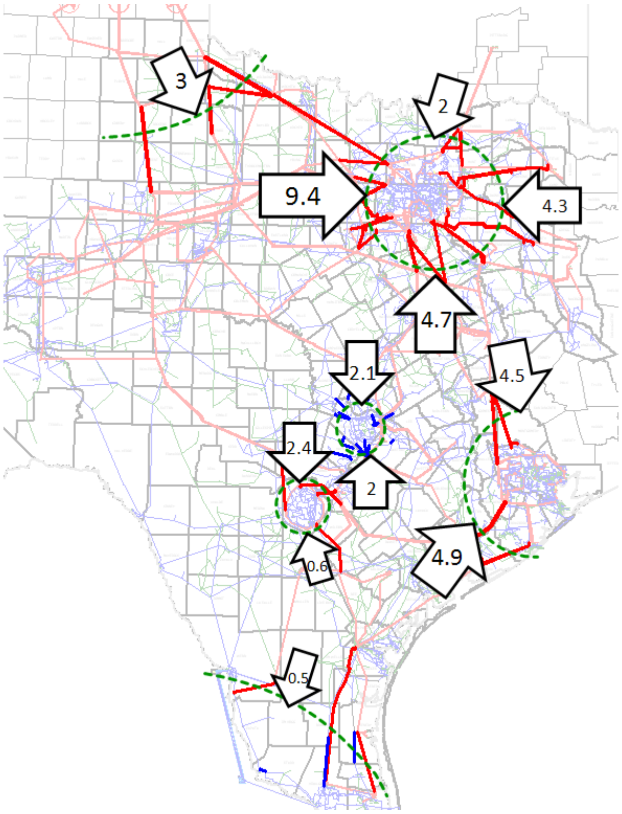
Import Limits Determined by AC Voltage Stability Analysis

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	20,318	2026	Parker to Hicks/Eagle Mountain
Houston	9,440	2028	Roans Prairie to Kuykendahl & Singleton to Tomball
San Antonio	3,796	2030	Hill Country to Marion
Austin	4,572	Beyond 2032	Elm Creek to South Texas
Valley	Not tested because incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2,512 MW		

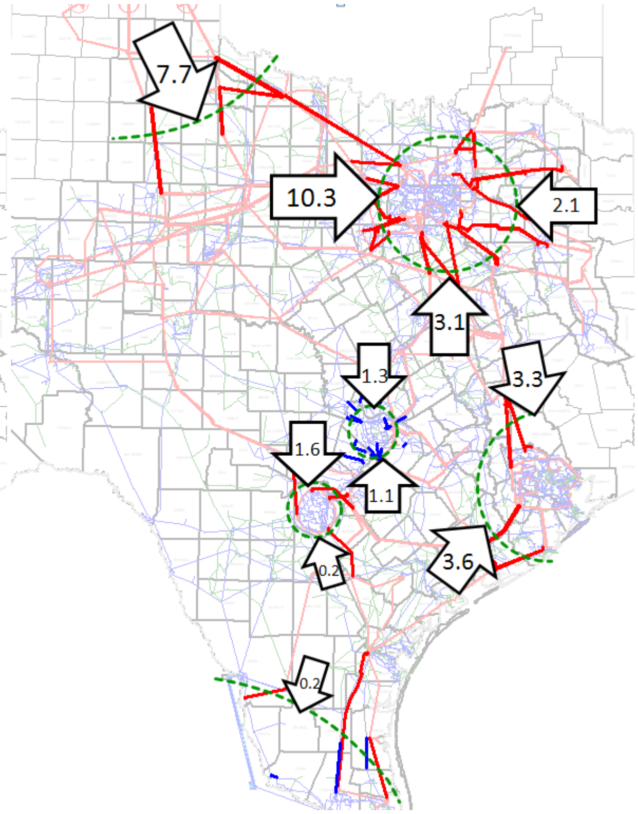
Base Case Overloads in 2032



System Flows at Peak Load Hour in 2032

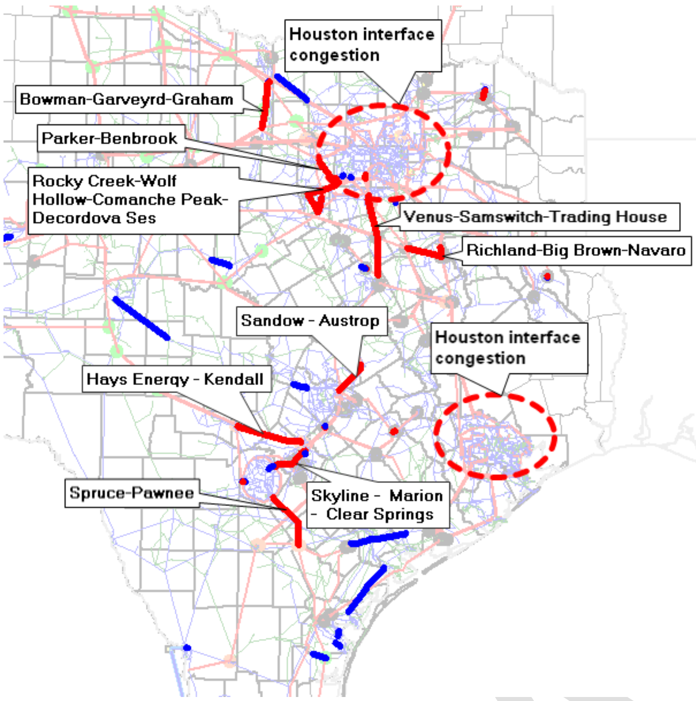


System Flows at Peak Wind Hour in 2032



*All numbers are in GW

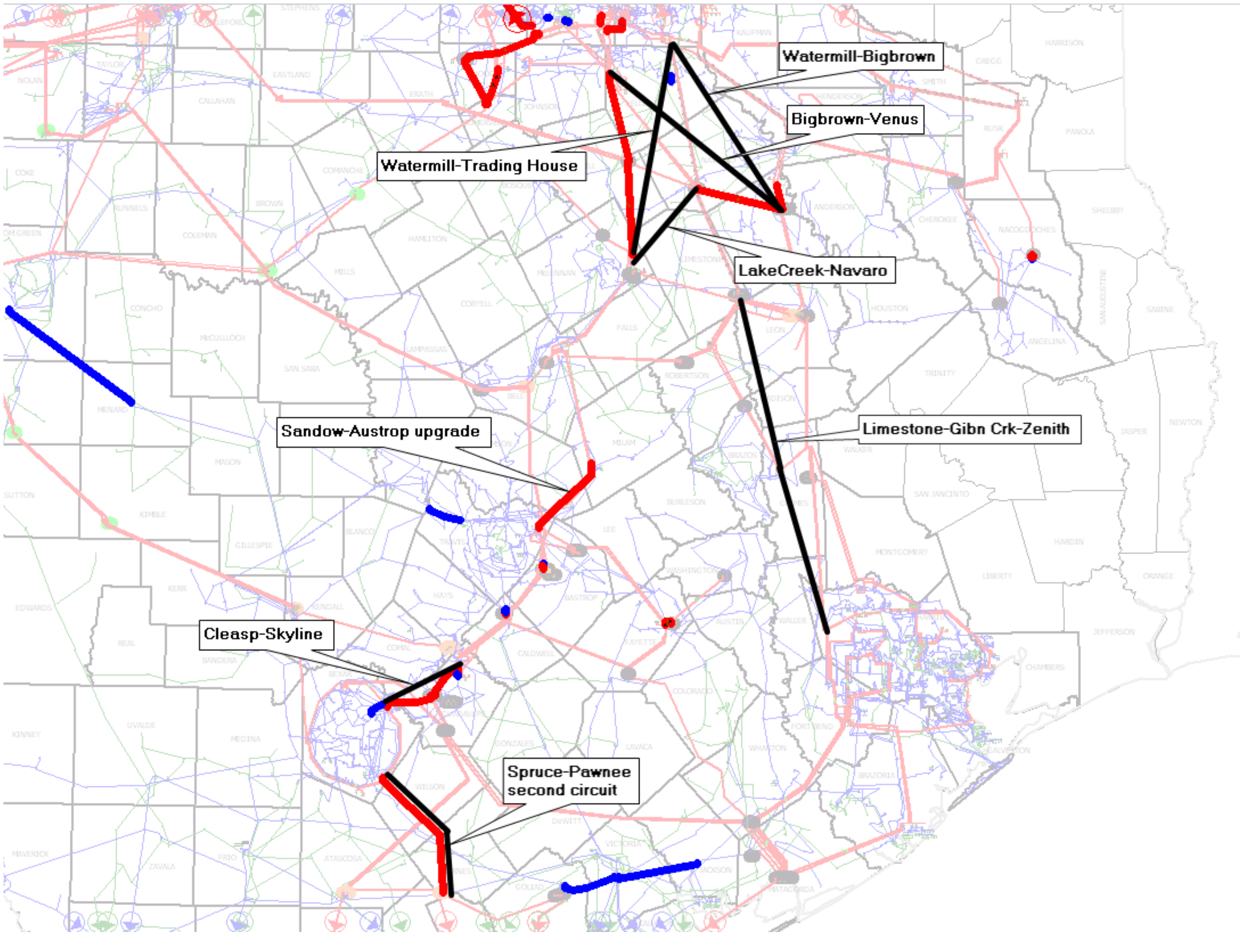
Congestion Map in 2032



Most Congested Elements in 2032

From Bus Name (Number)	To Bus Name (Number)	Congestion Cost($M)
DFW Interface		$65.0
GRAHAM SES (1430)	GARVEYRD_5 (17002)	$64.8
PARKER SWITCH (1436)	BENBROOK SWITCH (1873)	$63.7
WOLF HOLLOW (1876)	ROCKY CREEK (1880)	$52.3
BIG LAKE (6536)	MCCAMEY NORTH SWITCHING STATION (76032)	$39.5
NACOGDOCHES ROAD	SKYLINE (5369)	$38.2
Houston Interface		$33.6
YELLOW JACKET (6365)	SAN ANGELO POWER STATION (6483)	$21.7
WEDGWOOD SWITCH (2184)	EDGECLIFF (2191)	$18.1
FAYETTE PLANT 1 (7056)	FAYETTEVILLE (7057)	$15.4
BOWMAN SWITCH (1422)	GARVEYRD_5 (17002)	$15.4
SANDOW__5 (3429)	AUSTROP (7040)	$13.9
VENUS SWITCH (1906)	SAMSWITC (68090)	$12.5
WOLF HOLLOW (1876)	COMANCHE PEAK SES (1900)	$12.3
NACOGDOCHES SE (3119)	NACOGDOCHES SE (3120)	$10.2
CAGNON (5056)	CAGNON (5054)	$9.9
LA PALMA (8317)	LA PALMA (8314)	$8.8
CRMWD 8 TAP (1118)	GLENHAVEN (1121)	$8.7
HAYS ENERGY (7043)	KENDALL (7046)	$8.5
ELM MOTT (3406)	ELM MOTT (3407)	$7.7
SWEETWATER (71067)	SWEETWATER (71065)	$7.1
DECORDOVA SES (1890)	COMANCHE PEAK SES (1900)	$7.0
GARFIELD LCRA (7048)	GARFIELD AEN (9071)	$6.9
SHRYTAP_T5 (1917)	CENTURY (1929)	$6.8

Economic Projects Tested in 2032



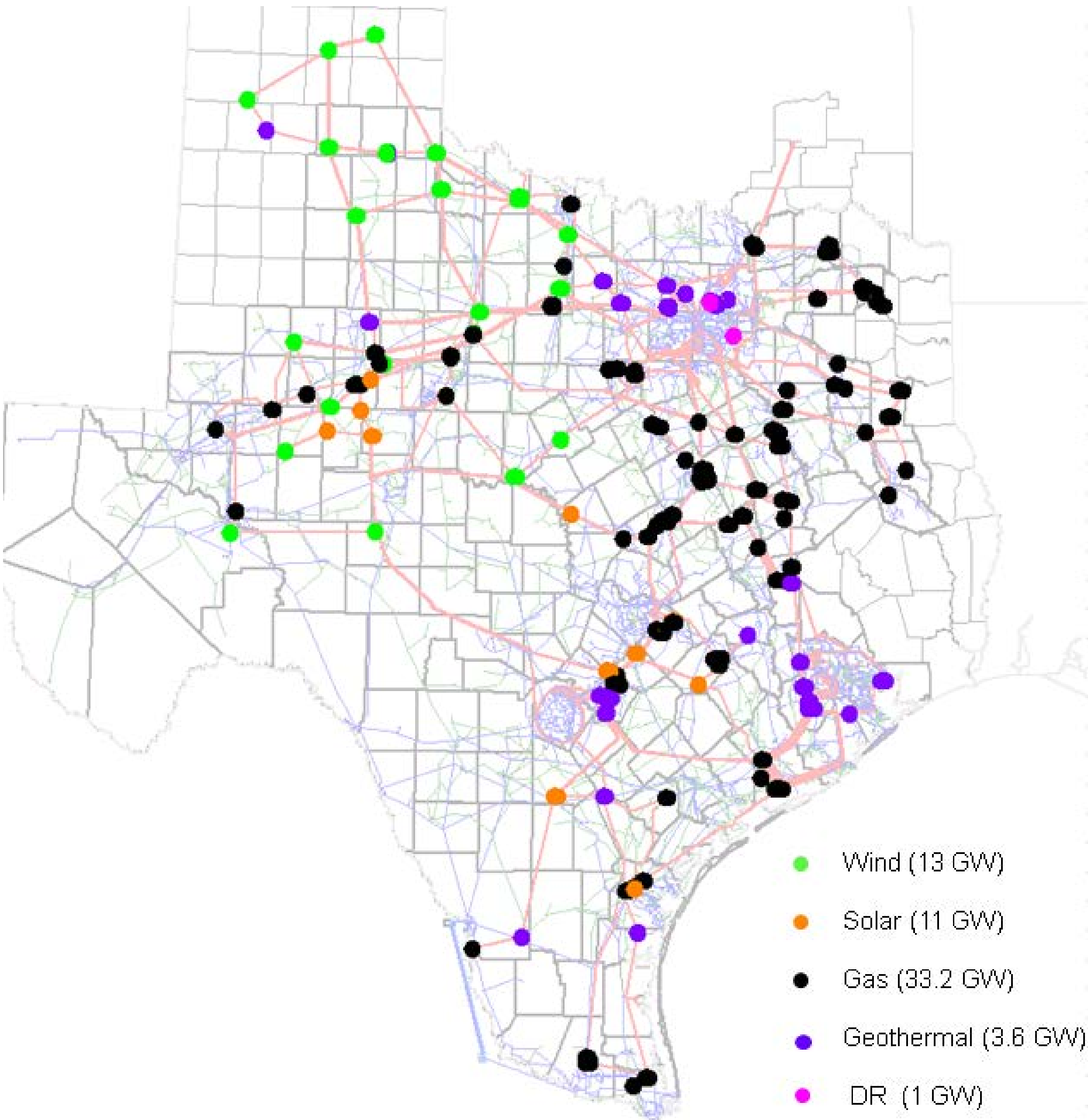
Economic Results in 2032

Tested Project in 2032	Adjusted Capital Cost (2032 $M)	1/6 of Adjusted Capital Cost (2032 $M)	Production Cost Savings (2032 $M)	Meet ERCOT Economic Criteria?
Watermill to Big Brown	167.8	28	6.8	No
Big Brown to Venus	59.5	9.9	0.6	No
Lake Creek to Navarro	103.2	17.2	2.8	No
Watermill to Trading House	218.2	36.4	10.8	No
Clear Spring to Skyline	79.4	13.2	2.6	No
Spruce to Pawnee 2nd ckt	13.9	2.3	1.4	No
Sandow to Austrop	61.9	10.3	3.4	No
Limestone to Gibbons Creek to Zenith	-395.9	-66.0	17.4	Yes

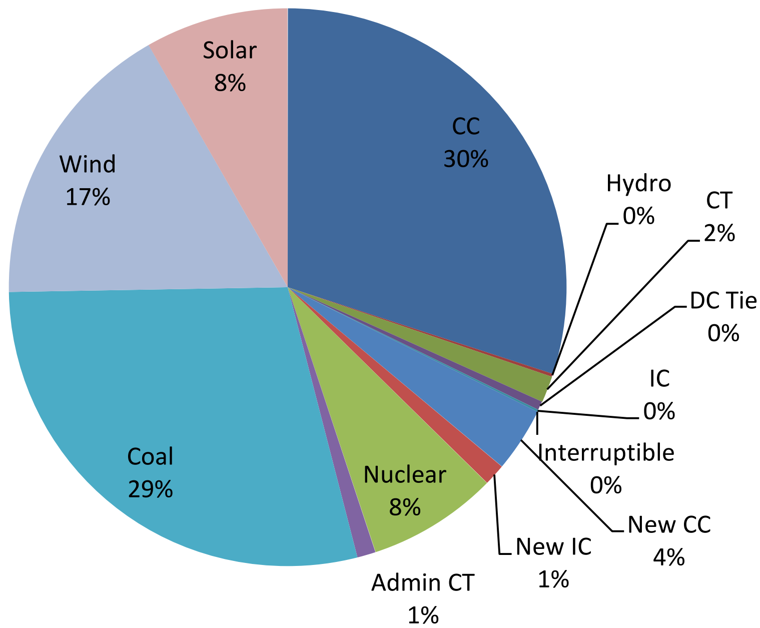
*All numbers except Benefit Cost Ratio are in millions in 2032

Appendix N Transmission Results — Drought Scenario in 2032

New Resources Added by 2032



Generation Energy Mix in 2032

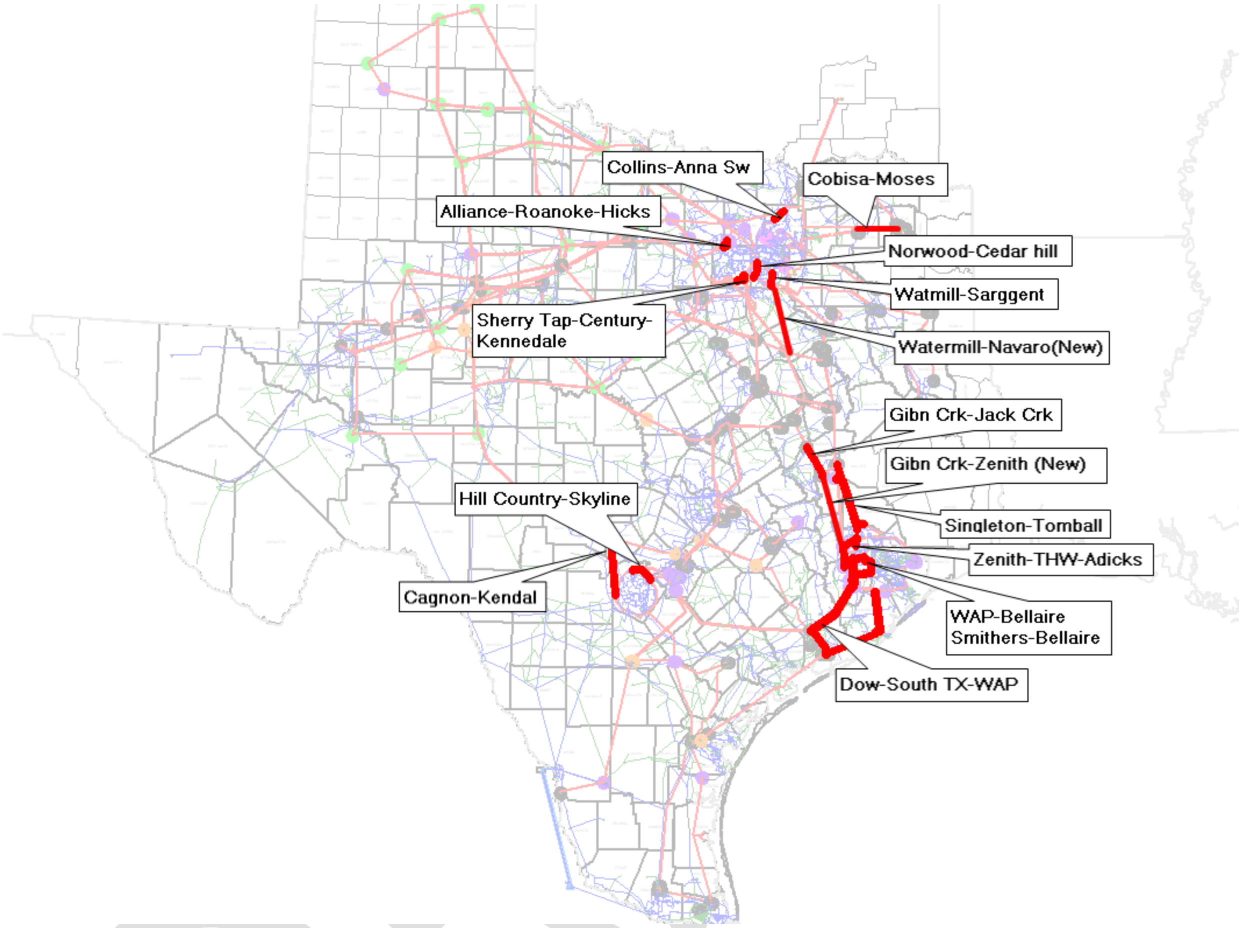


Peak Load in 2032	Peak Renewable Generation in 2032
Hour: 8/17/2032 hour 16	Hour: 3/26/2032 hour 20
System load (coincident peak): 110,109 MW	System load: 62,155 MW
Thermal & Hydraulic output: 88,736 MW	Renewable output: 21,969 MW

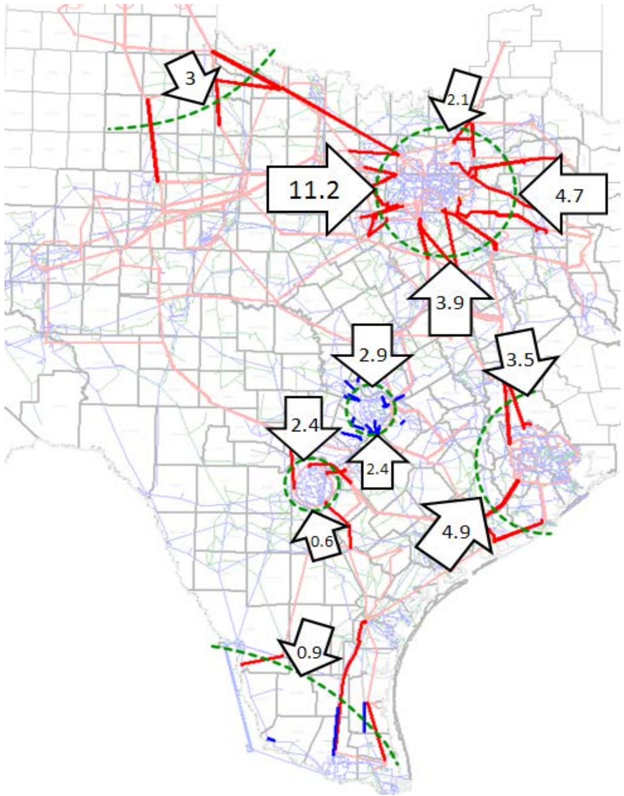
Import Limits Determined by AC Voltage Stability Analysis

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	21,227	2023	Trinidad to Tricorner & Watermill to Trinidad
Houston	8,827	2017	Roans Prairie to Kuykendahl & Singleton to Tomball
San Antonio	3,033	2024	Hill Country to Marion & Skyline to Marion
Austin	4,579	2029	Elm Creek to South Texas
Valley	Not tested because incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2,512 MW		

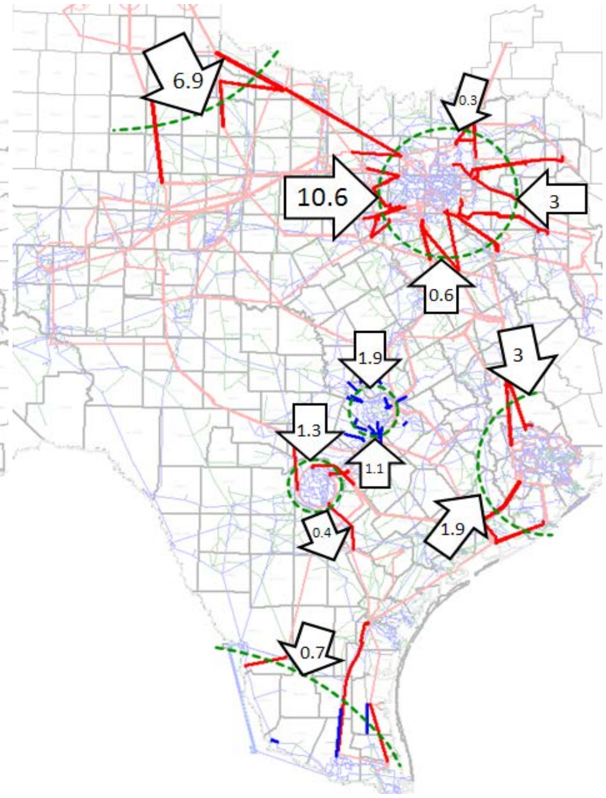
Base Case Overloads in 2032 (monitor 345kV system only)



System Flows at Peak Load Hour in 2032

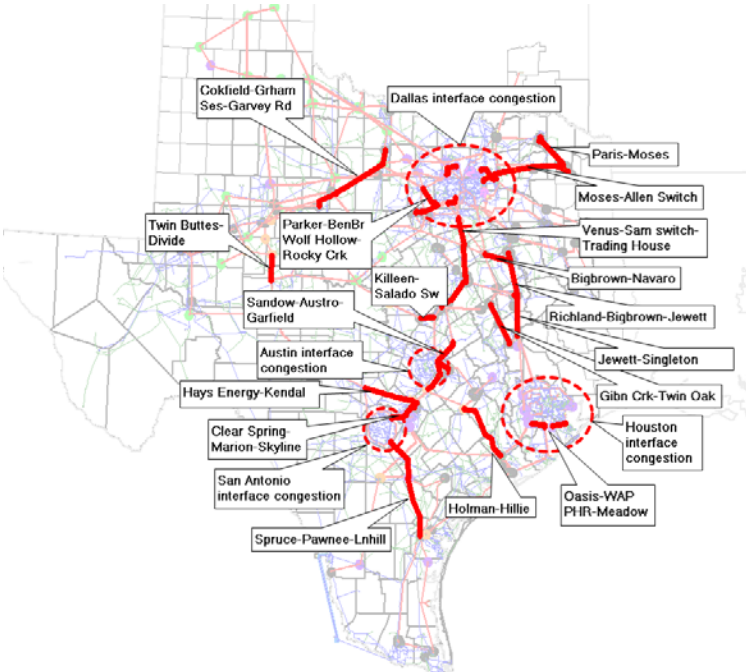


System Flows at Peak Wind Hour in 2032



*All numbers are in GW

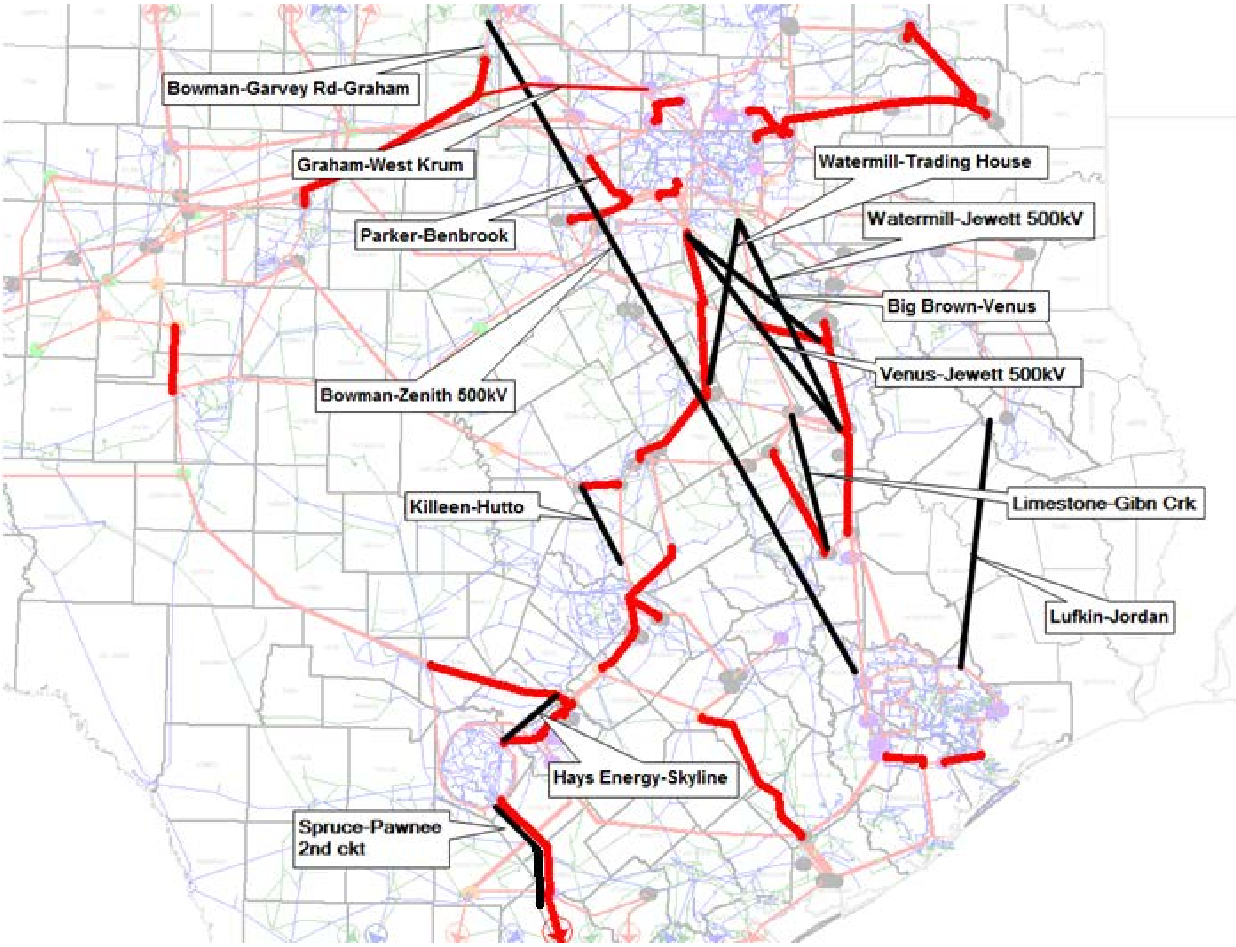
Congestion Map in 2032 (monitor 345-kV system only)



Most Congested Elements in 2032

From Bus Name (Number)	To Bus Name (Number)	Congestion Cost($M)
PARKER (1436)	BENBROOK (1873)	$680.87
345 KV BUS # 5 (967)	TWIN OAK SES (3400)	$542.28
DFW Interface		$514.26
GRAHAM SES (1430)	GARVEYRD (17002)	$349.53
San Antonio Import		$112.09
KILLEEN SS (3422)	STATION (3699)	$98.67
SKYLINE 345 (5371)	MARION (7044)	$54.75
LAMAR POWER (1684)	PARIS SWITCH (1692)	$51.15
EVERMAN BUS TIE 1 (1885)	COURTLAND #1 (1931)	$38.02
SANDOW (3429)	AUSTROP (7040)	$35.61
Houston Interface		$34.32
HAYS ENERGY (7043)	KENDALL (7046)	$30.41
EVERMAN BUS TIE 1 (1885)	COURTLAND #1 (1931)	$23.03
MARION (7044)	CLEAR SPRINGS (7050)	$10.45
Austin Stability Limit		$9.71
TWIN BUTTES (FUT 2003) (76009)	DIVIDE (76090)	$8.40
TRADINGHOUSE SES (3405)	SAM SWITCH (68090)	$7.60
EVERMAN BUS TIE 1 (1885)	COURTLAND #1 (1931)	$7.27
WOLF HOLLOW (1876)	ROCKY CREEK (1880)	$6.13
AUSTROP (7040)	GARFIELD (7048)	$5.77
GRAHAM SES (1430)	COOKFIELD (1442)	$5.72
J.K. SPRUCE (5400)	SWITCHING ST (5725)	$5.33

Economic Projects Tested in 2032



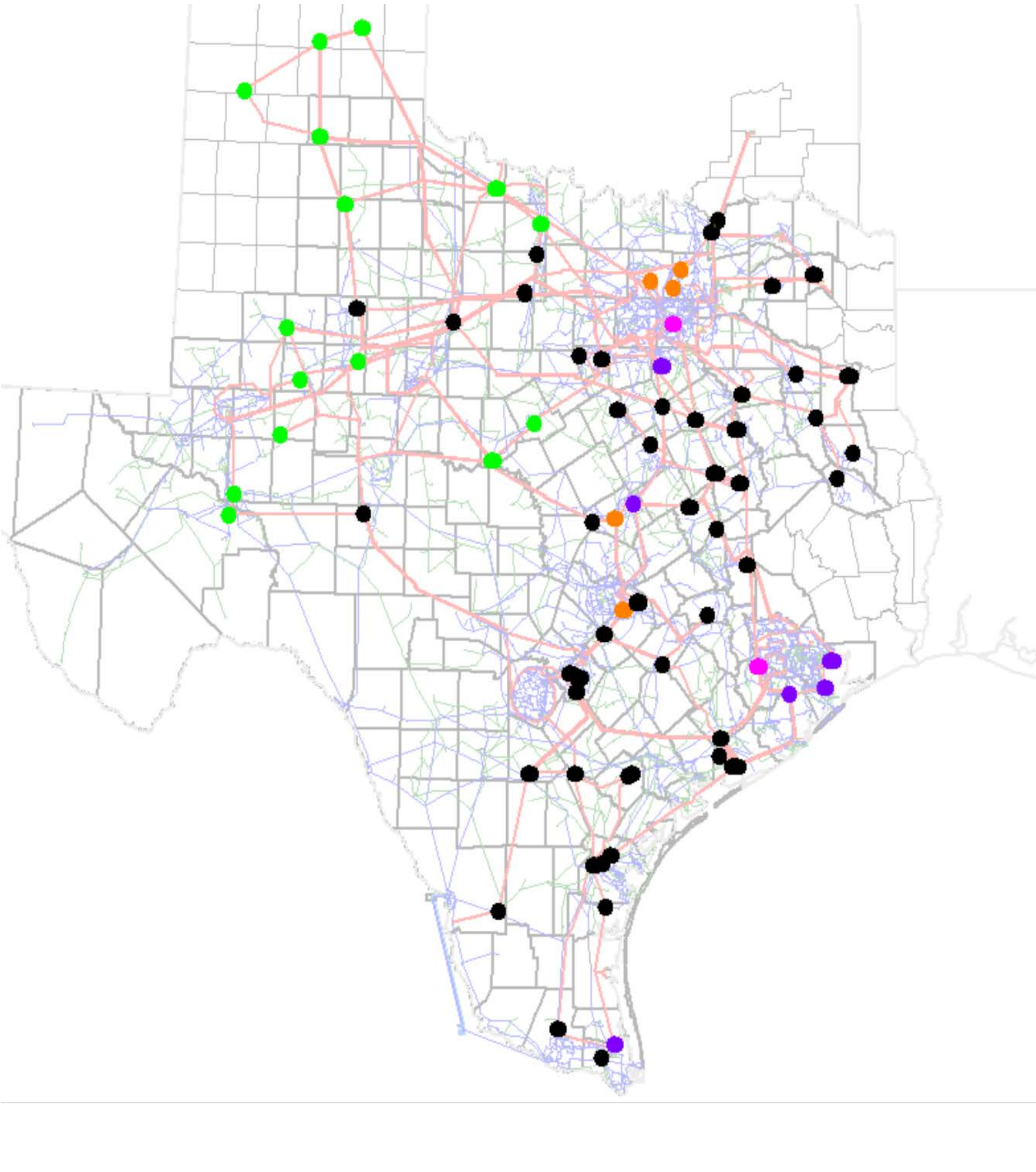
Economic Results in 2032

Tested Project in 2032	Adjusted Capital Cost (2032 $M)	1/6 of Adjusted Capital Cost (2032 $M)	Production Cost Savings (2032 $M)	Meet ERCOT Economic Criteria?
Bowman to Zenith 500-kV line	1,196.8	199.5	229.5	Yes
Lufkin to Jordan 345-kV line	37.2	6.2	76.8	Yes
Limestone to Gibbons Creek 345-kV line	159.5	26.6	80.8	Yes
Watermill to Jewett 500-kV line	515.8	86	10	No
Venus to Jewett 500-kV line	658.6	109.8	6	No
Big Brown to Venus 345-kV line	131.9	22	9.8	No
Watermill to Thouse 345-kV line	131.9	22	11.7	No
Parker to Benbrook 345-kV double ckt rebuild	57.6	9.6	63.4	Yes
Bowman to Graham 345-kV rebuild	100.5	16.8	42.8	Yes
Bowman to Graham 345-kV rebuild and Graham to West Krum addition	136.9	22.8	73.8	Yes
Killeen to Hutto 345-kV line	108.8	18.1	21.4	Yes
Hays Energy to Skyline 345-kV line	52.6	8.8	23.5	Yes
Spruce to Pawnee 2nd ckt 345-kV	-13.8	-2.3	10.7	Yes

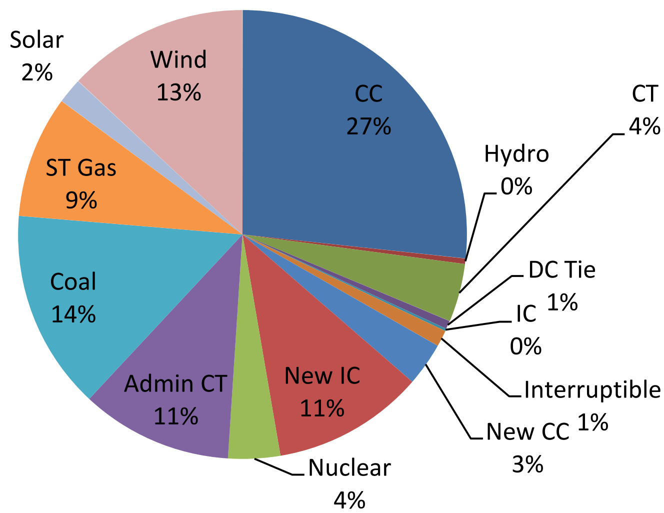
*All numbers except Benefit Cost Ratio are in millions in 2032

Appendix O Transmission Results — Drought with Low Natural Gas Price Scenario in 2032

New Resources Added by 2032



Generation Energy Mix in 2032

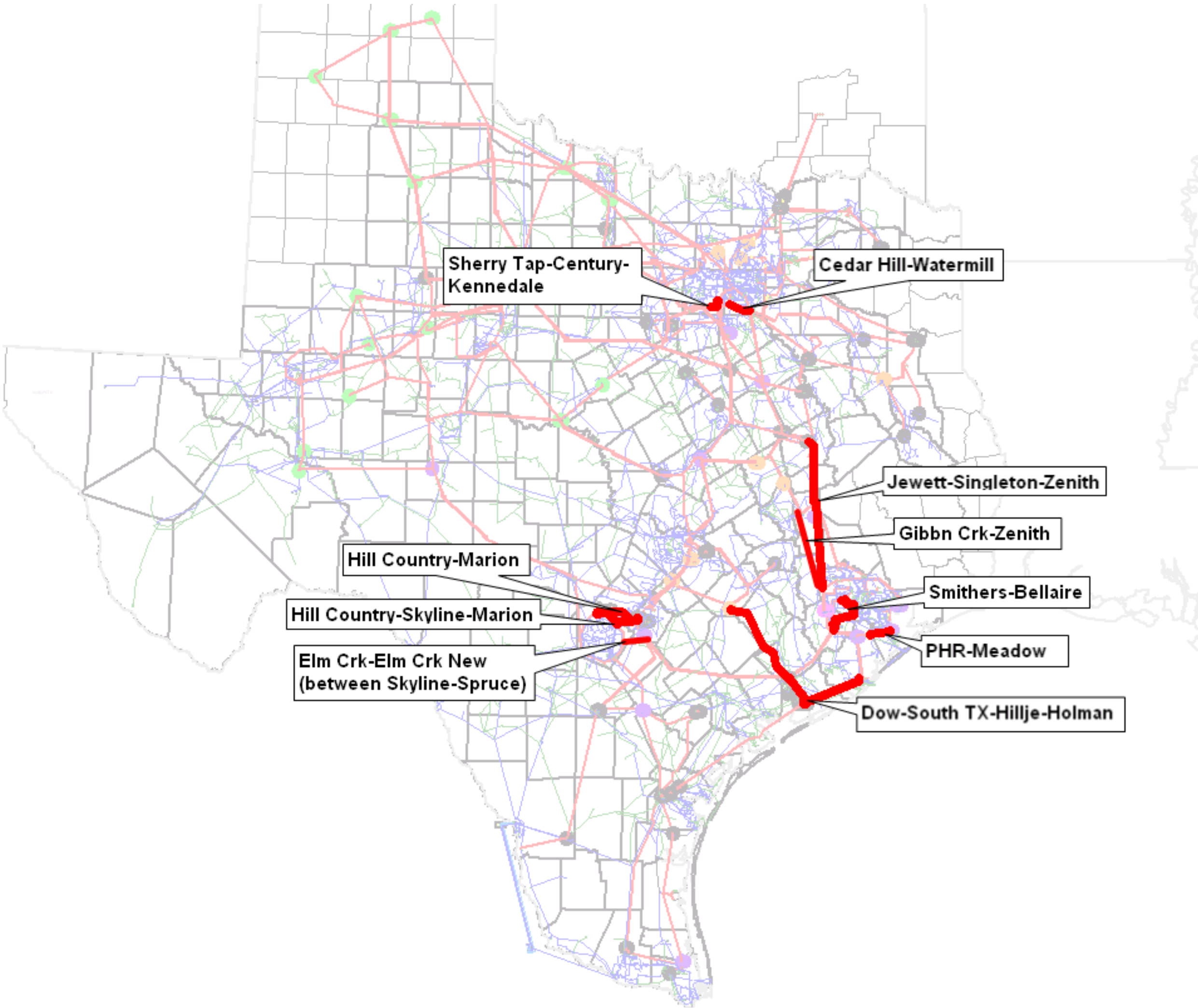


Peak Load in 2032	Peak Renewable Generation in 2032
Hour: 8/17/2032 hour 16	Hour: 3/22/2032 hour 20
System load (coincident peak): 110,109 MW	System load: 62,721 MW
Thermal & Hydraulic output: 97,759 MW	Renewable output: 16,200 MW

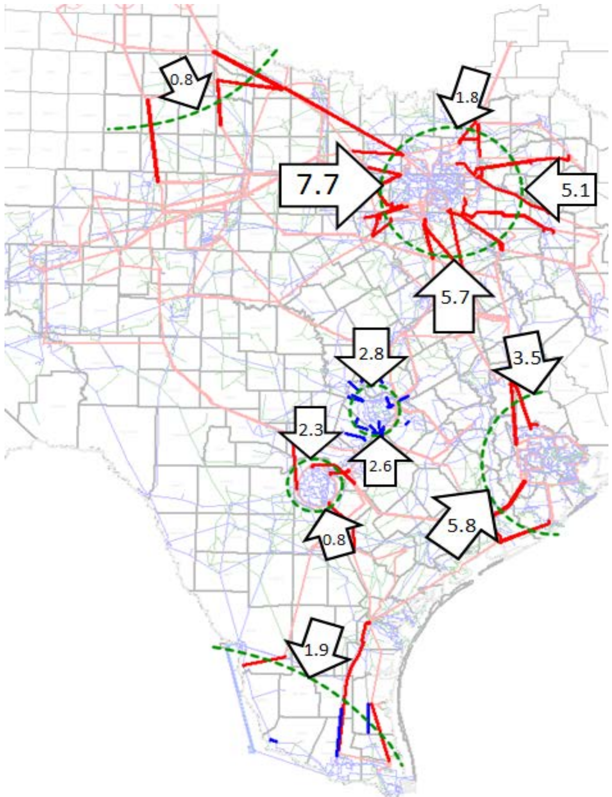
Import Limits Determined by AC Voltage Stability Analysis

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	20,837	2021	Navarro to Watermill
Houston	9,336	2020	Roans Prairie to Kuykendahl & Singleton to Tomball
San Antonio	3,033	2019	Hill Country to Marion & Skyline to Marion
Austin	4,721	2030	Elm Creek to South Texas
Valley	Not tested because incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2,512 MW		

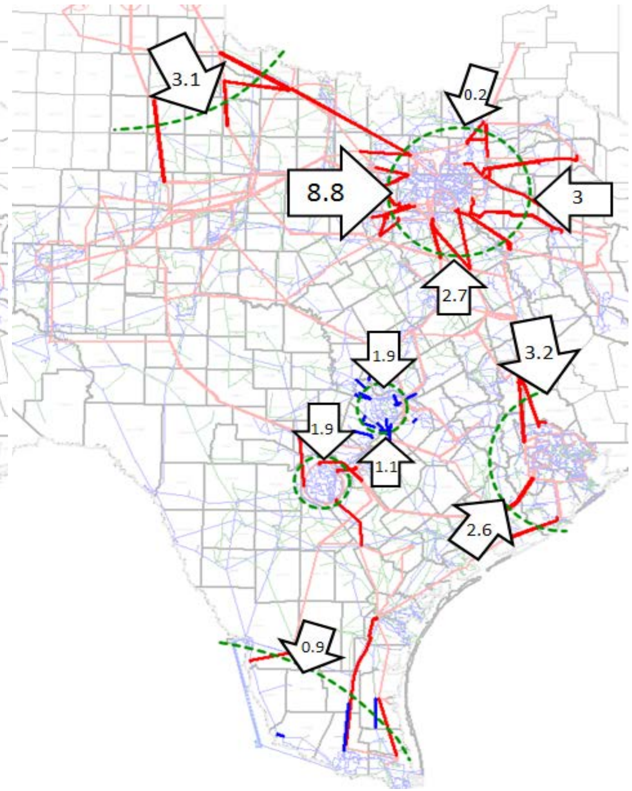
Base Case Overloads in 2032 (monitor 345-kV system only)



System Flows at Peak Load Hour in 2032

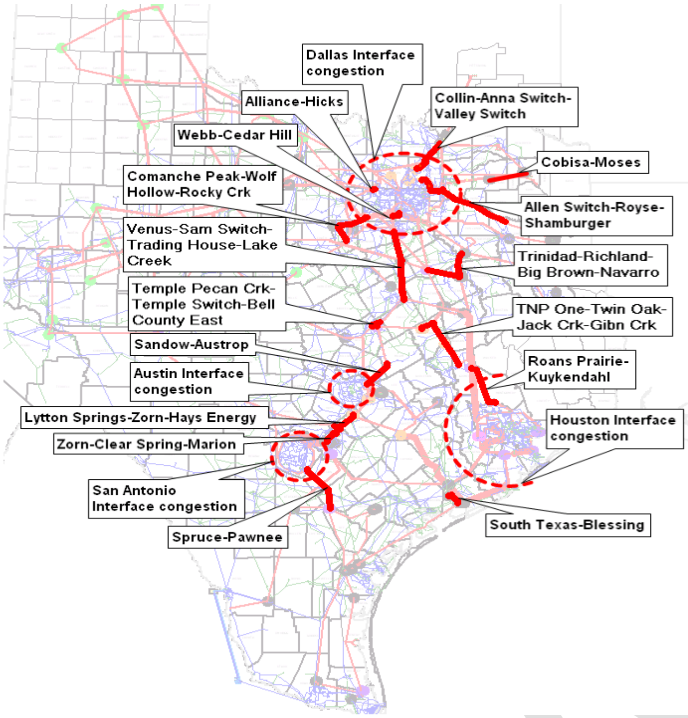


System Flows at Peak Wind Hour in 2032



*All numbers are in GW

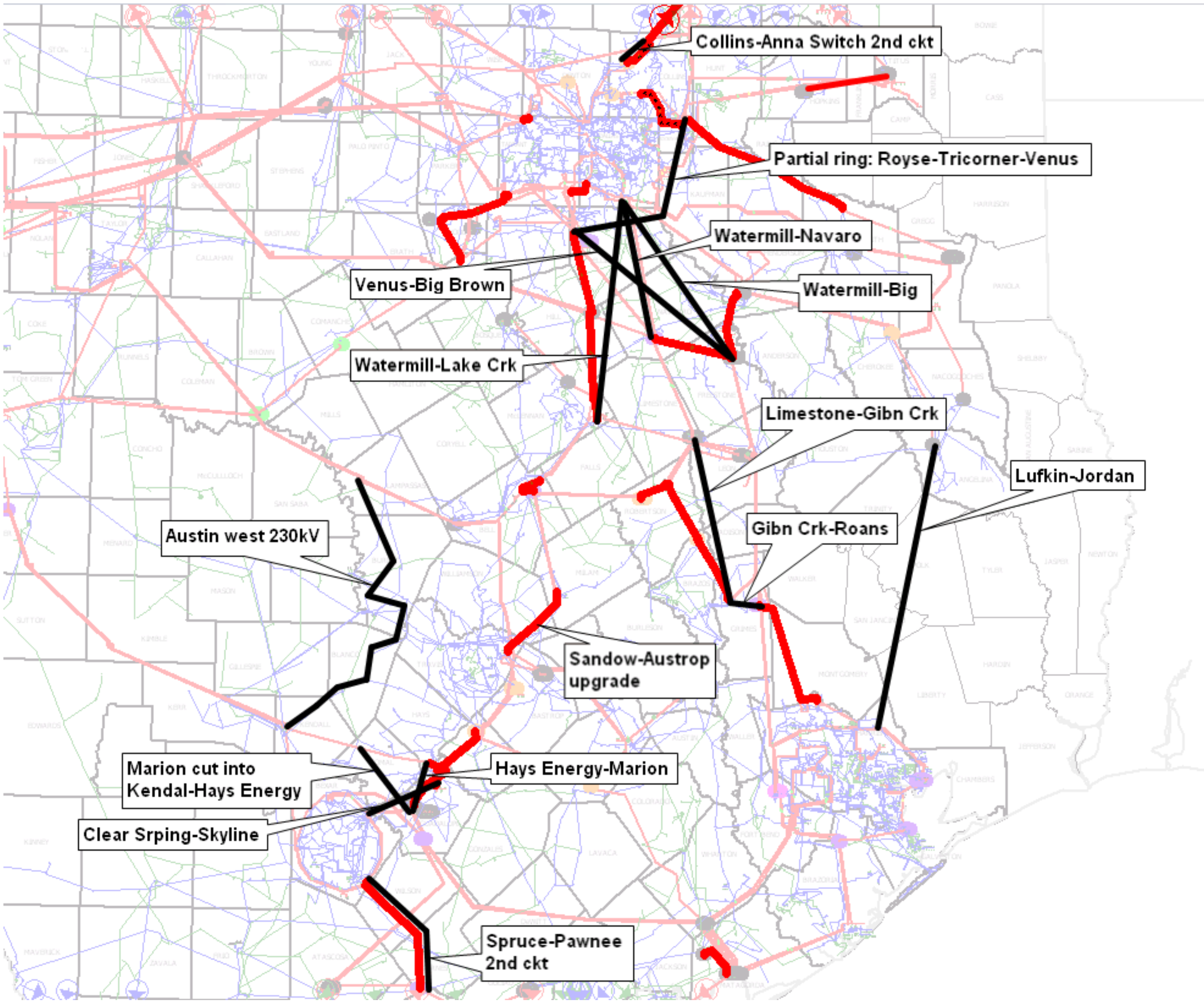
Congestion Map in 2032 (monitor 345-kV system only)



Most Congested Elements in 2032

From Bus Name (Number)	To Bus Name (Number)	Congestion Cost($M)
Gibbn Creek (967)	345 KV JACKCREEK # 1 (975)	$249.7
DFW Interface		$213.7
345 KV JACKCREEK # 1 (975)	TWIN OAK SES (3400)	$146.1
COLLIN SS (2372)	ANNA SS (2373)	$103.6
Houston Interface		$101.5
ROANS PRAIRIE (40600)	KUYKENDAHL (45972)	$72.0
ALLIANCE (1855)	HICKS #1 (2081)	$61.7
WEBB #3 (1904)	CEDAR HILL (2420)	$49.3
WOLF HOLLOW (1876)	ROCKY CREEK (1880)	$48.4
ROYSE NORTH BUS (2461)	ALLEN SWITCHING STATION (2513)	$42.2
VENUS SOUTH (1906)	SAM SWITCH (68090)	$39.7
San Antonio Interface		$36.8
WOLF HOLLOW (1876)	COMANCHE PEAK WEST (1900)	$31.4
(871)	MONTICELLO SES (1695)	$23.8
J.K. SPRUCE (5400)	PAWNEE 345KV SWITCHING STATION (5725)	$13.5
ROYSE SOUTH BUS (2478)	SHAMBURGER (3103)	$12.4
WOLF HOLLOW (1876)	ROCKY CREEK (1880)	$11.2
BIG BROWN SES (3380)	NAVARRO (68091)	$10.4
MARION (7044)	CLEAR SPRINGS (7050)	$9.1
TRADINGHOUSE SES (3405)	SAM SWITCH (68090)	$8.1
SOUTH TEXAS PROJECT PLANT SUB (5915)	BLESSING (8123)	$7.1
VALLEY SES (1690)	ANNA SS (2373)	$5.3
Austin Interface		$4.0
SANDOW (3429)	AUSTROP (7040)	$2.9

Economic Projects Tested in 2032



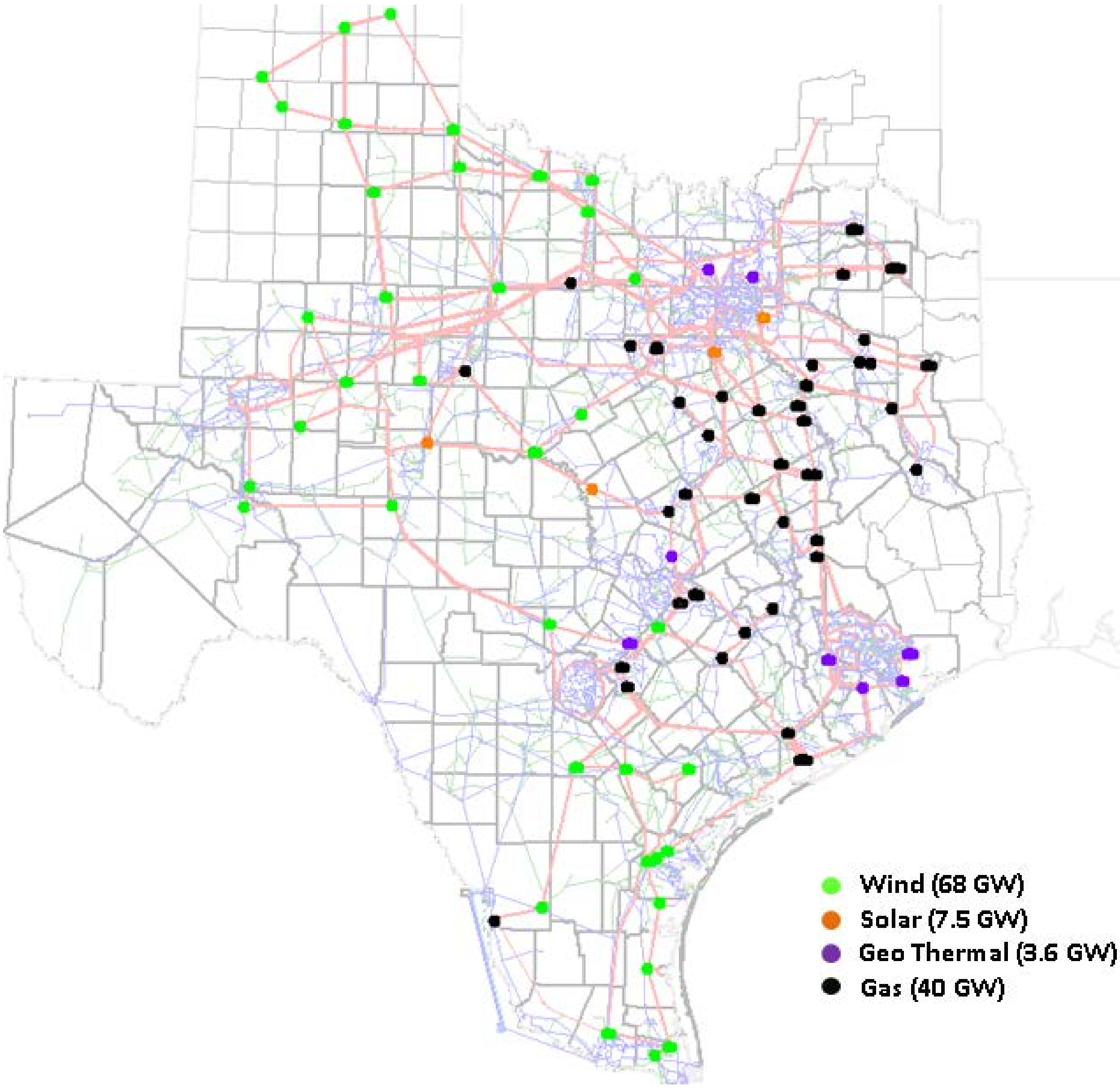
Economic Results in 2032

Tested Project in 2032	Adjusted Capital Cost (2032 $M)	1/6 of Adjusted Capital Cost (2032 $M)	Production Cost Savings (2032 $M)	Meet ERCOT Economic Criteria?
Limestone to Gibbon Creek 345-kV line	180	**30**	**114.5**	Yes
Gibbon Creek to Roans 345-kV line	36.3	**6**	**12.5**	Yes
Lufkin - Jordan 345-kV line	387.3	**64.5**	**61.9**	No
Collins to Anna 2nd ckt	11	**1.8**	**4.2**	Yes
Big Brown to Venus 345-kV line	234.4	**39.1**	**12.2**	No
Watermill to Navarro 345-kV line	171.9	**28.6**	**11.6**	No
Watermill to Big Brown 345-kV line	304	**50.7**	**17**	No
Watermill to Lake Creek 345-kV line	271.9	**45.3**	**11.7**	No
Dallas East Partial Ring	397.7	**49.6**	**2.3**	No
Clear Spring to Skyline	-2	**-0.3**	**5.9**	Yes
Spruce to Pawnee 2nd ckt	-55	**-9.2**	**12.2**	Yes
Hays to Marion 345-kV line	72.5	**12.1**	**1.6**	No
Marion cut into Kendall to Hays Energy 345-kV line	222.6	**37.1**	**0.6**	No
Austin 230-kV loop	374.8	**62.5**	**4.2**	No
Sandow to Austrop upgrade	73.6	**12.3**	**1.1**	No

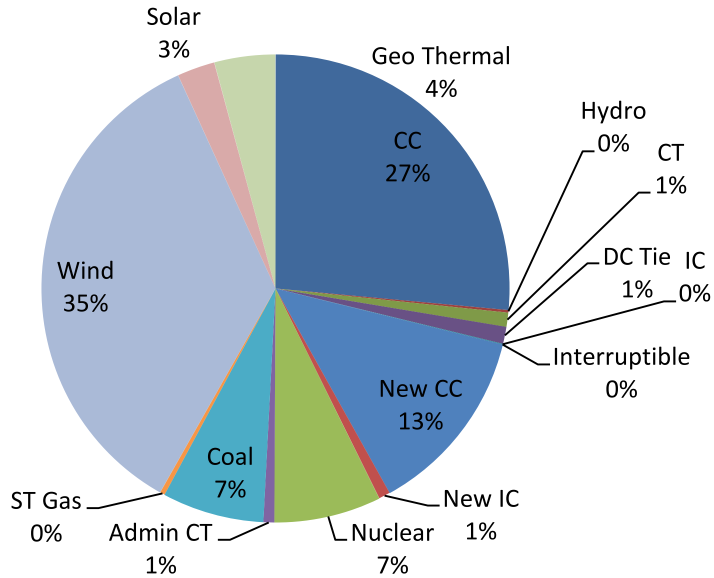
*All numbers except Benefit Cost Ratio are in millions in 2032

Appendix P Transmission Results — Drought with PTC Scenario in 2032

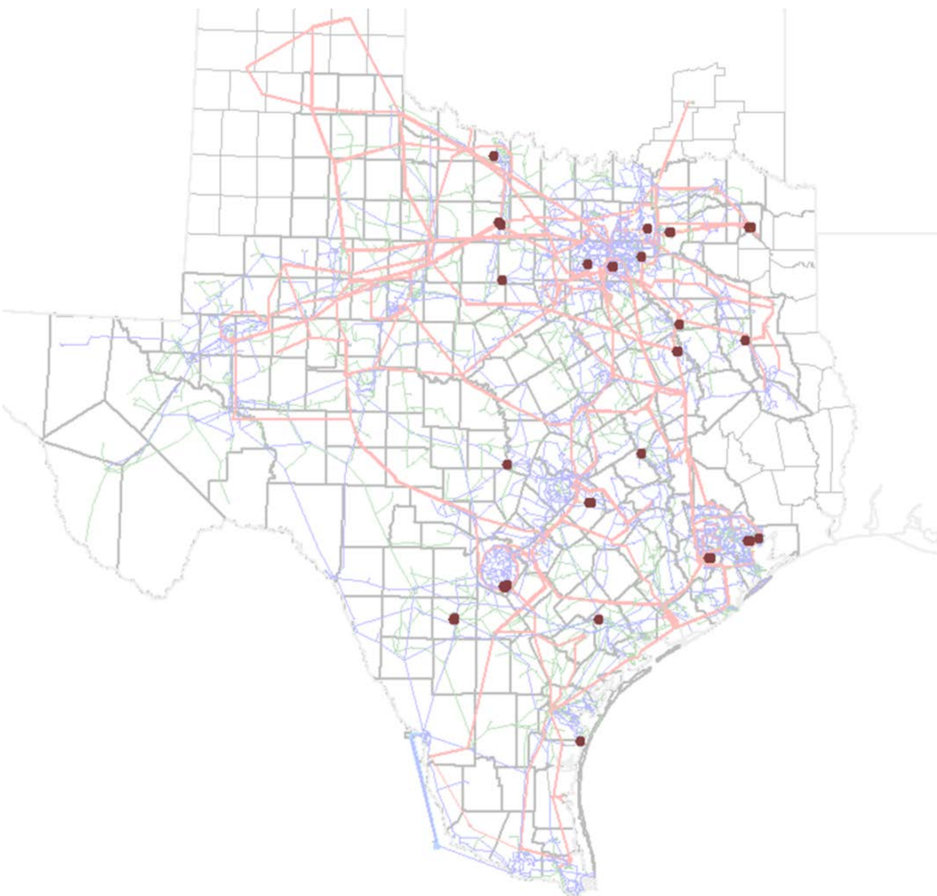
New Resources Added by 2032



Generation Energy Mix in 2032



Generation Retirement Map and Summary List:



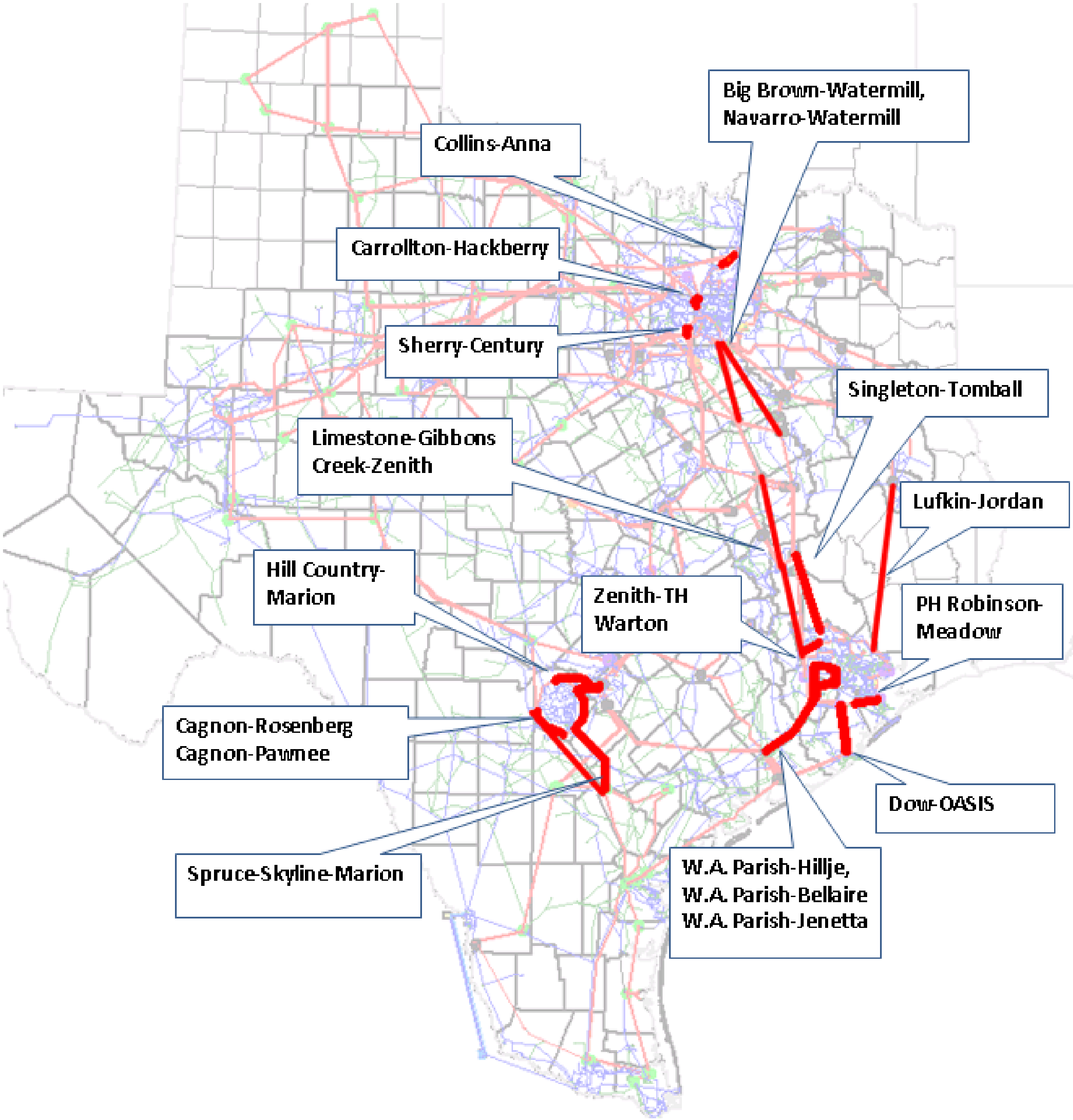
Generation Technology	Capacity (MW)
Steam Coal	2,383
Steam Natural Gas	6,509
Combined Cycle	79

Peak Load in 2032	Peak Renewable Generation in 2032
Hour: 8/17/2032 hour 16	Hour: 3/18/2032 hour 18
System load (coincident peak): 110,109 MW	System load: 62,673 MW
Thermal & Hydraulic output: 77,668 MW	Renewable output: 27,352 MW

Import Limits Determined by AC Voltage Stability Analysis

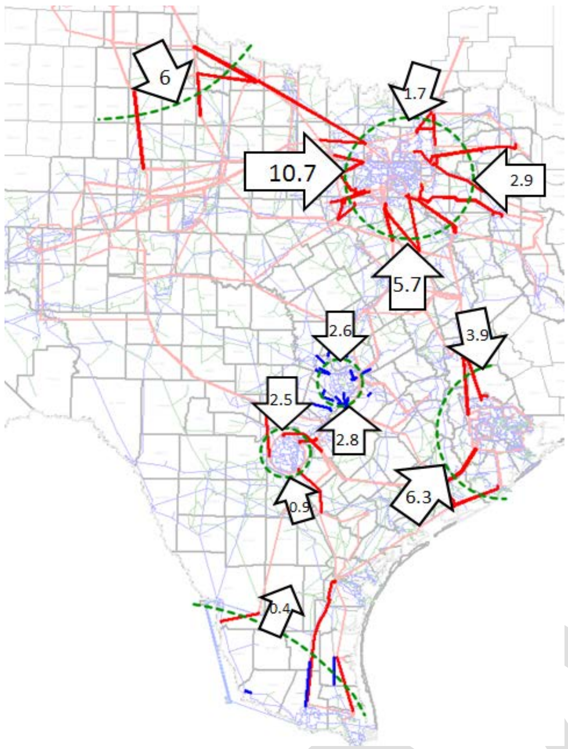
Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	20,485	2020	Trinidad to Tricorner & Watermill to Trinidad
Houston	9,361	2022	Roans Prairie to Kuykendahl & Singleton to Tomball
San Antonio	3,803	2024	Hill Country to Marion & Skyline to Marion
Austin	4,579	2029	Hutto to Salado
Valley	Not tested because incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2,512 MW		

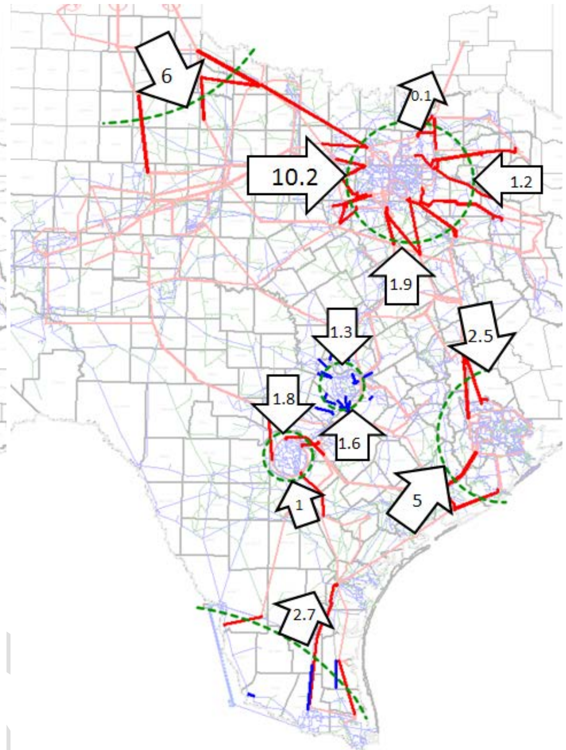
Base Case Overloads in 2032 (monitor 345-kV system only)



System Flows at Peak Load Hour in 2032

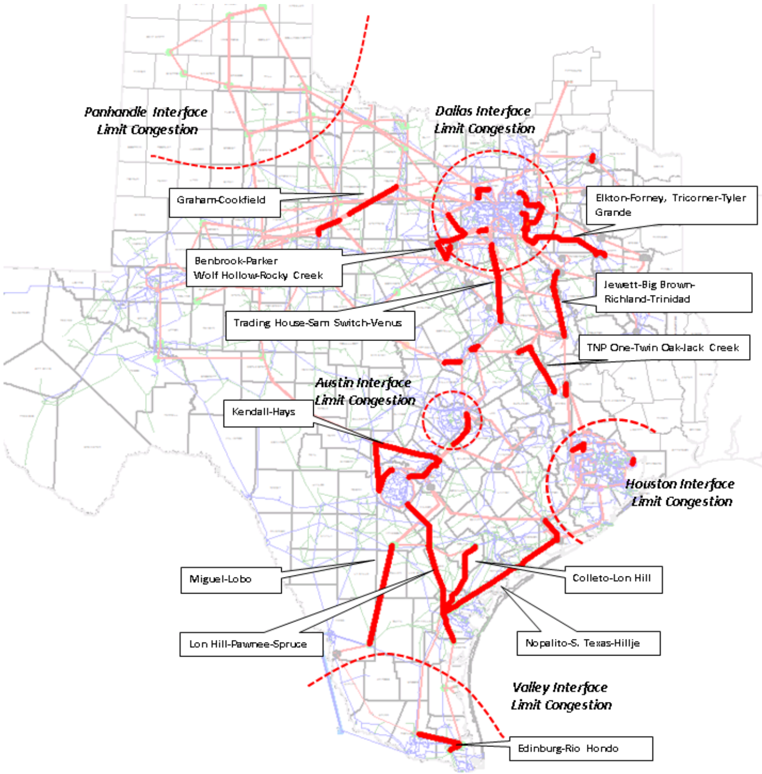
System Flows at Peak Wind Hour in 2032





*All numbers are in GW

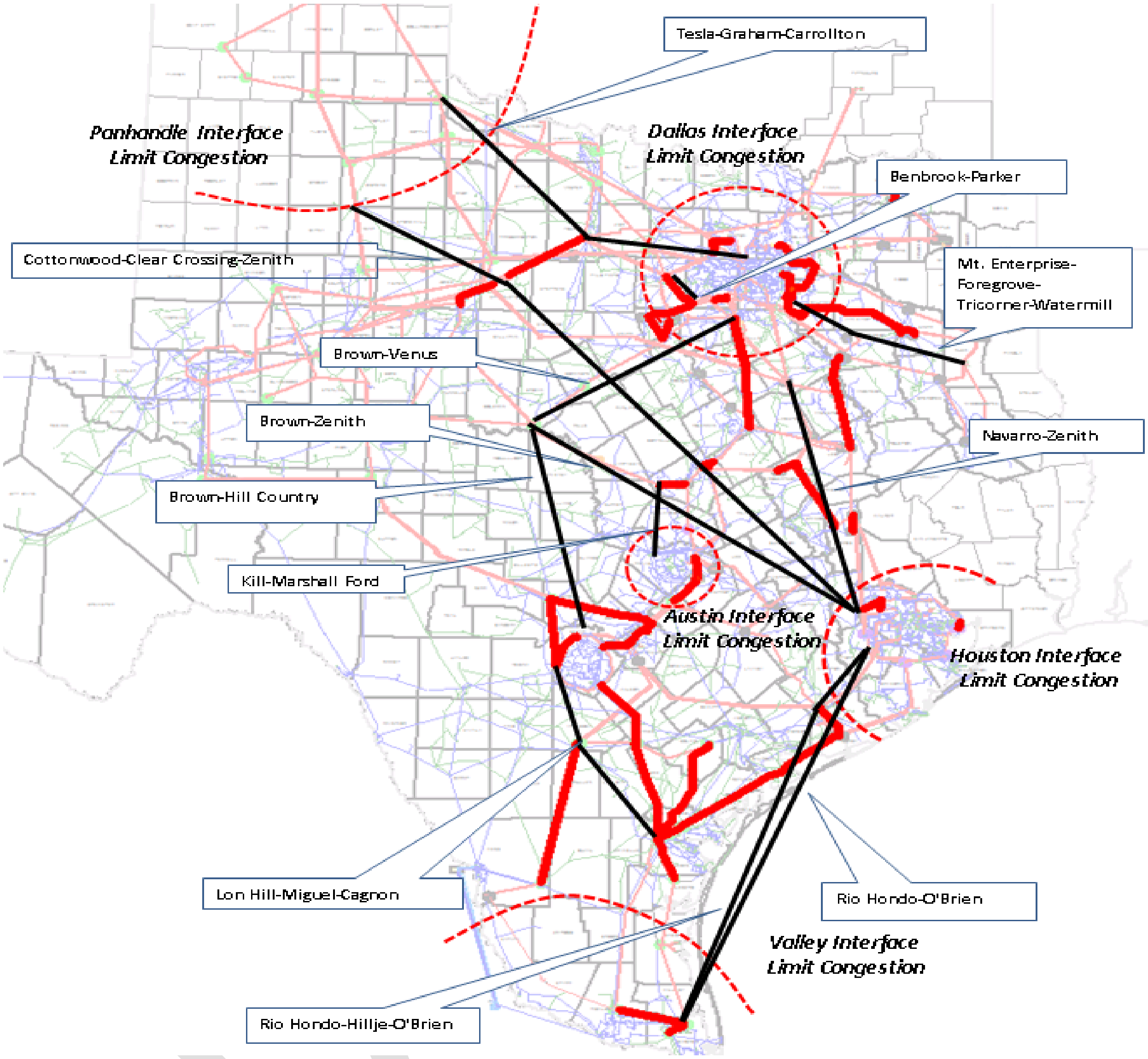
Congestion Map in 2032 (monitor 345-kV system only)



Most Congested Elements in 2032

From Bus Name (Number)	To Bus Name (Number)	Congestion Cost($M)
Panhandle Interface		$2,347.94
PAWNEE 345KV SWITCHING STATION (5725)	LON HILL (8455)	$1,190.33
PARKER (1436)	BENBROOK (1873)	$951.43
SOUTH TEXAS PROJECT (5915)	NOPALITO (80382)	$861.64
DFW Interface		$707.02
WOLF HOLLOW (1876)	ROCKY CREEK (1880)	$318.46
EVERMAN BUS TIE 1 (1885)	COURTLAND #1 (1931)	$237.64
SOUTH TEXAS PROJECT (5915)	HILLJE (44200)	$173.89
SAN MIGUEL 345 KV SWITCHYARD (5901)	LOBO (80219)	$150.05
HAYS ENERGY (7043)	KENDALL (7046)	$144.05
RIO HONDO (8318)	NORTH EDINBURG (8383)	$116.74
VENUS SOUTH (1906)	SAM SWITCH (68090)	$109.63
CAGNON 345KV BUS (5056)	KENDALL (7046)	$85.05
J.K. SPRUCE (5400)	PAWNEE 345KV SWITCHING STATION (5725)	$83.92
LAMAR POWER (1684)	PARIS SWITCH (1692)	$62.69
345 KV BUS # 5 (967)	345 KV JACKCREEK # 1 (975)	$58.38
TH WHARTON (45500)	ADDICKS (45600)	$53.98
VENUS NORTH (1907)	SAM SWITCH (68090)	$46.87
DECORDOVA SES (1890)	COMANCHE PEAK WEST (1900)	$35.53
RICHLAND CHAMBERS SS 2 (3134)	BIG BROWN SES (3380)	$34.82
Houston Interface		$26.51
ZORN (7042)	HAYS ENERGY (7043)	$25.78
LON HILL (8455)	NOPALITO (80382)	$25.48
WOLF HOLLOW (1876)	COMANCHE PEAK WEST (1900)	$22.69
COLETO CREEK (8164)	LON HILL (8455)	$15.28
ZENITH (44900)	TH WHARTON (45500)	$13.78
TRI-CORNER (2432)	SEAGOVILLE SS (2433)	$11.87

Economic Projects Tested in 2032



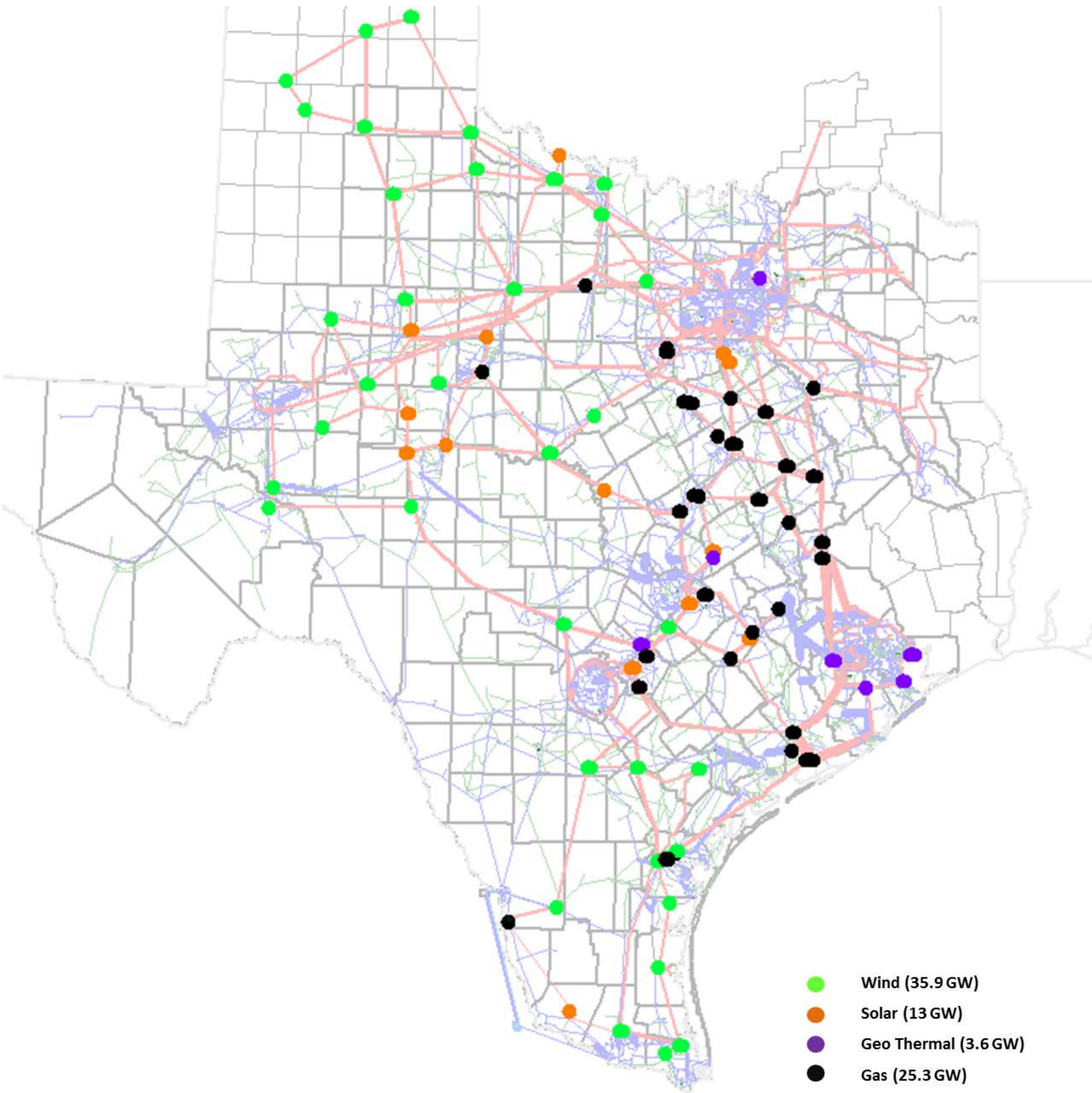
Economic Results in 2032

Tested Project in 2032	Adjusted Capital Cost (2032 $M)	1/6 of Adjusted Capital Cost (2032 $M)	Production Cost Savings (2032 $M)	Meet ERCOT Economic Criteria?
Parker to Benbrook	480.4	80.1	77.7	No
Brown to Venus	786.7	131.1	89.9	No
Mt. Enterprise to Foregrove to Tricorner to Watermill	629.5	104.9	19.9	No
Tesla to Graham to Carrollton 500-kV line	2,066.9	344.5	1,172.9	Yes
Rio Hondo to Hillje to O'Brien	3,193.6	532.3	1,402.3	Yes
Rio Hondo to O'Brien 500-kV line	3,581.9	597	1,989.7	Yes
Cottonwood to Clear Crossing to Zenith 500-kV line	3,654.6	609.1	911.6	Yes
Navarro to Zenith	1,096.8	182.8	-14.7	No
Brown to Zenith	1,100.3	183.4	70.9	No
Lon Hill to Miguel to Cagnon	1,100.5	183.4	957.9	Yes
Brown to Hill Country	331.1	55.2	50.7	No
Killeen to Marshall Ford single 345-kV line	300.8	50.1	3.5	No

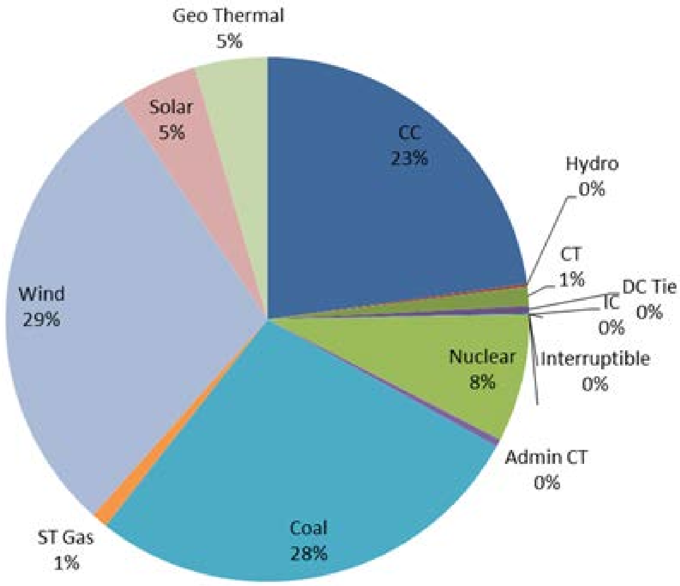
*All numbers except Benefit Cost Ratio are in millions in 2032

Appendix Q Transmission Results — Business as Usual with High Natural Gas Prices Scenario in 2032

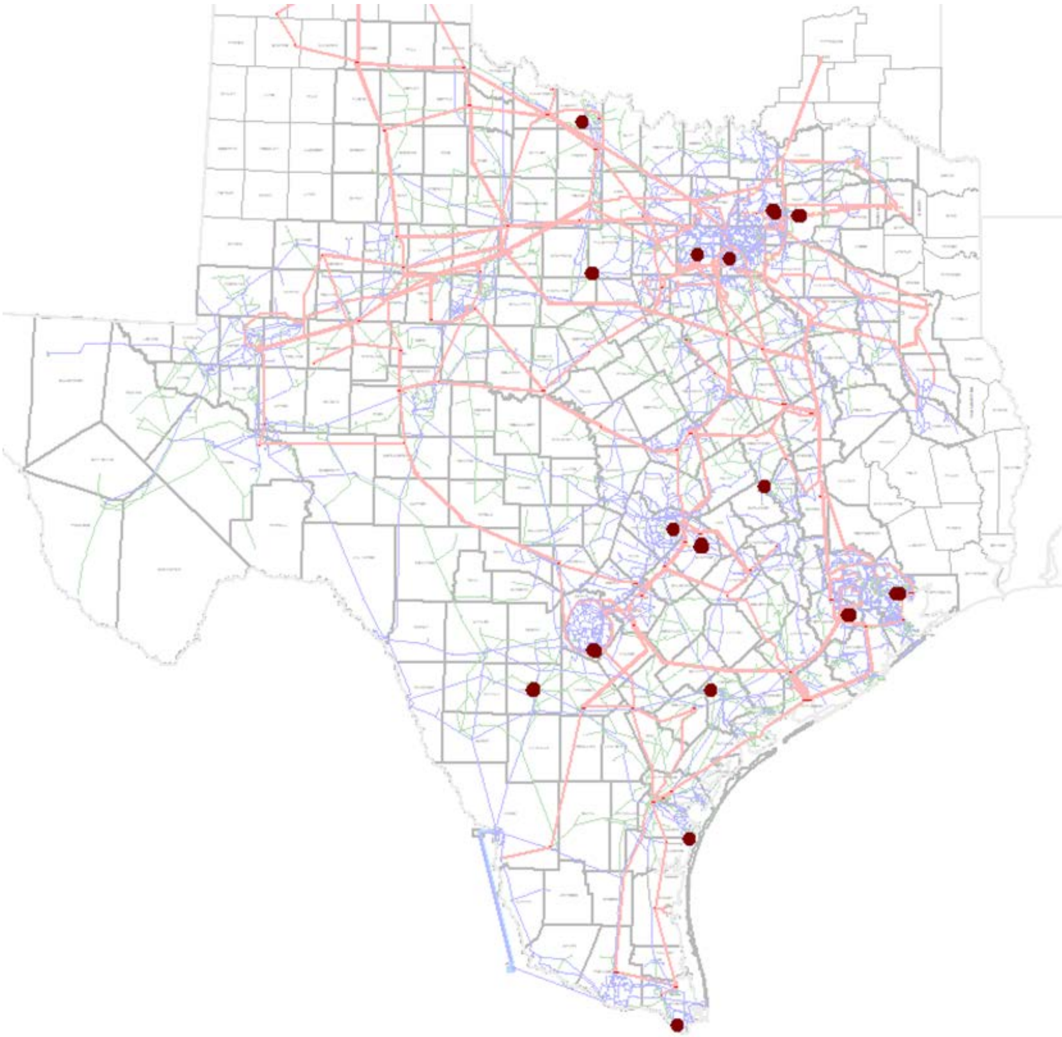
New Resources Added by 2032



Generation Energy Mix in 2032



Generation Retirement Map and Summary List



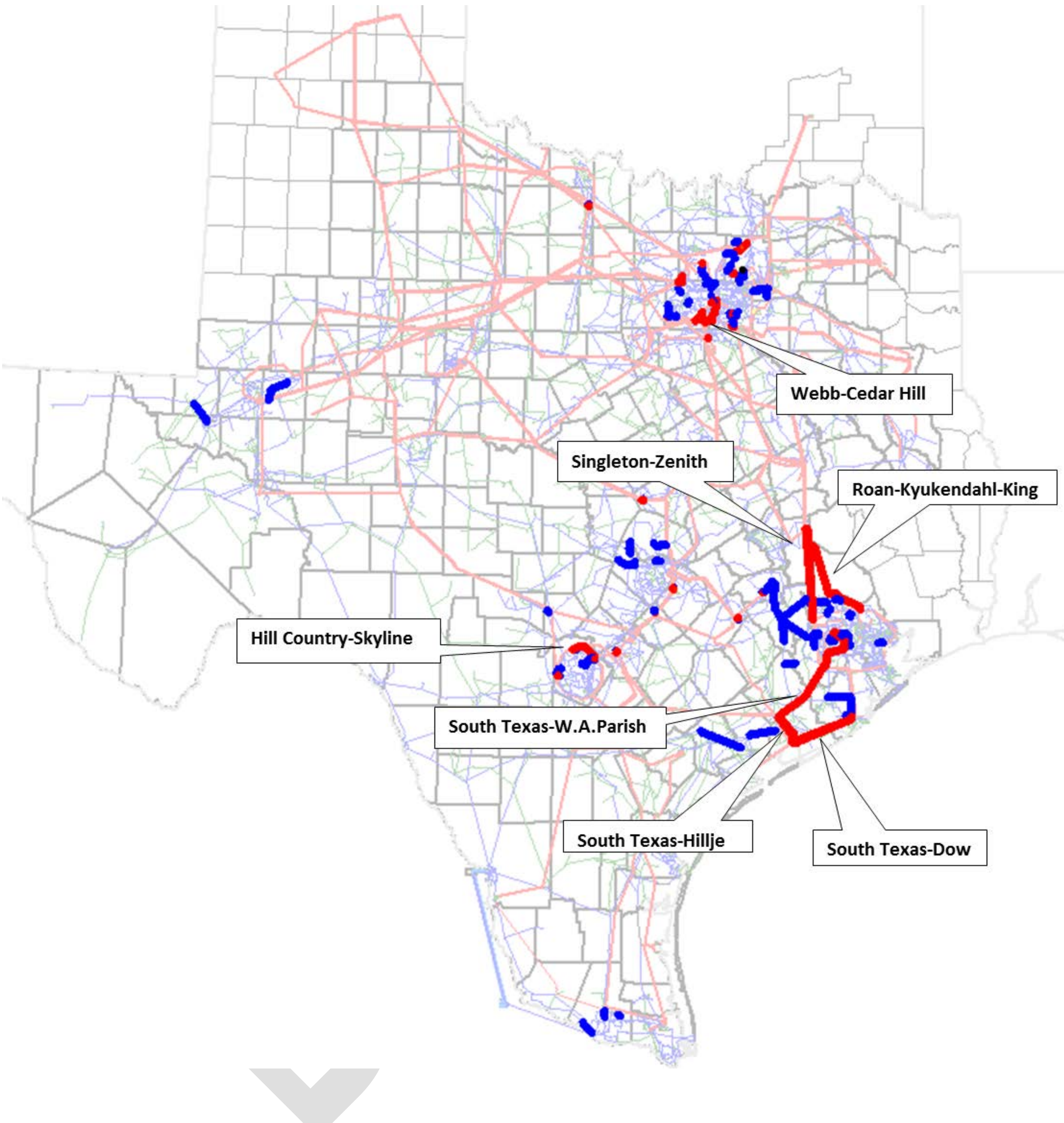
Generation Technology	Capacity (MW)
Steam Natural Gas	4678
Combined Cycle	137

Peak Load in 2032	Peak Renewable Generation in 2032
Hour: 8/5/2032 hour 16	Hour: 3/12/2032 hour 7
System load (coincident peak): 101,874 MW	System load: 66,108 MW
Thermal & Hydraulic output: 72,489 MW	Renewable output: 26,195 MW

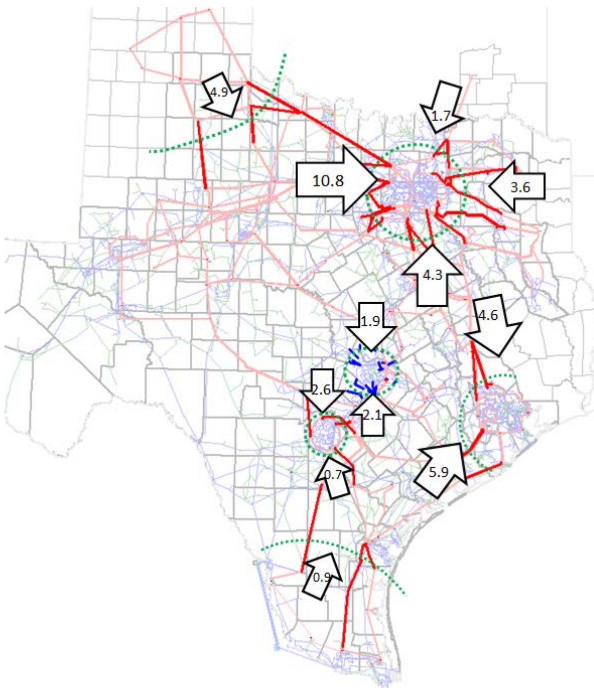
Import and Export Limits Determined by AC Voltage Stability Analysis

Area	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1 for Houston)
Dallas	19,984	2025	Navarro to Watermill
Houston	10,431	Beyond 2028	Roans Prairie to Kuykendahl & Singleton to Tomball
Austin	4,579	Beyond 2032	Hutto to Salado
San Antonio	3,803	2031	Hill County to Marion and Skyline to Marion
Panhandle	6,014.6	N/A	Dermot to Cottonwood
Valley	3,703.8	N/A	Ajo to Sharpe

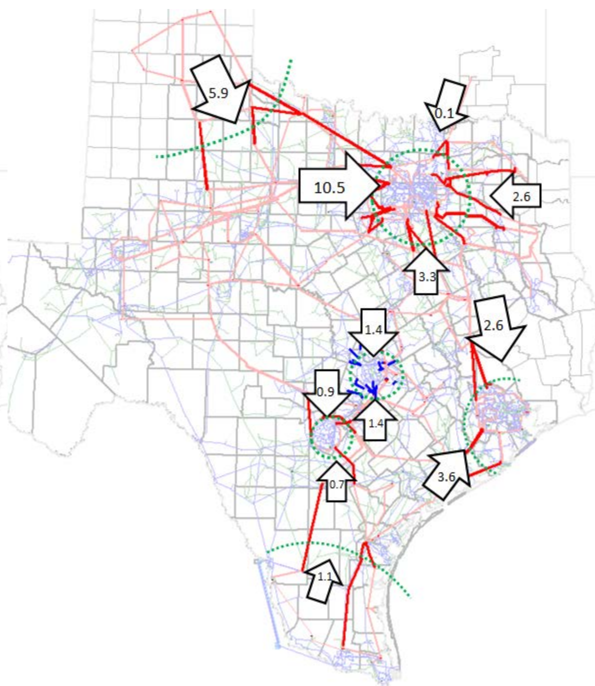
Base Case Overloads in 2032



System Flows at Peak Load Hour in 2032

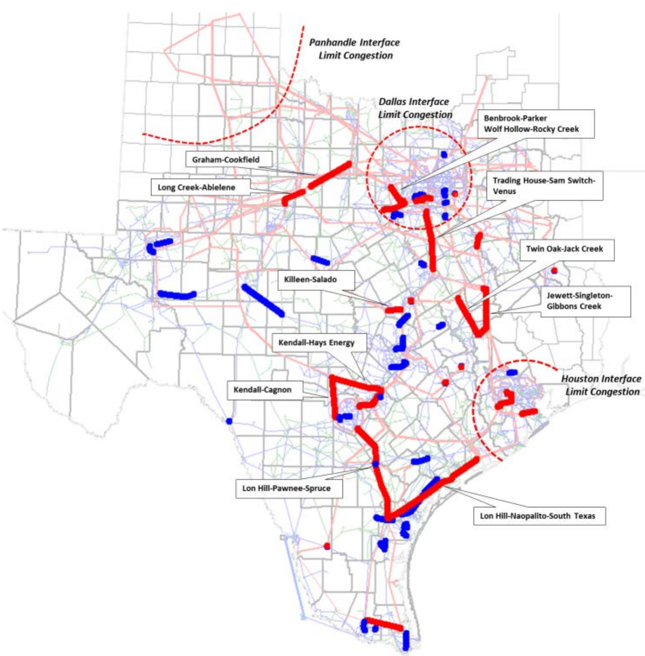


System Flows at Peak Wind Hour in 2032



*All numbers are in GW

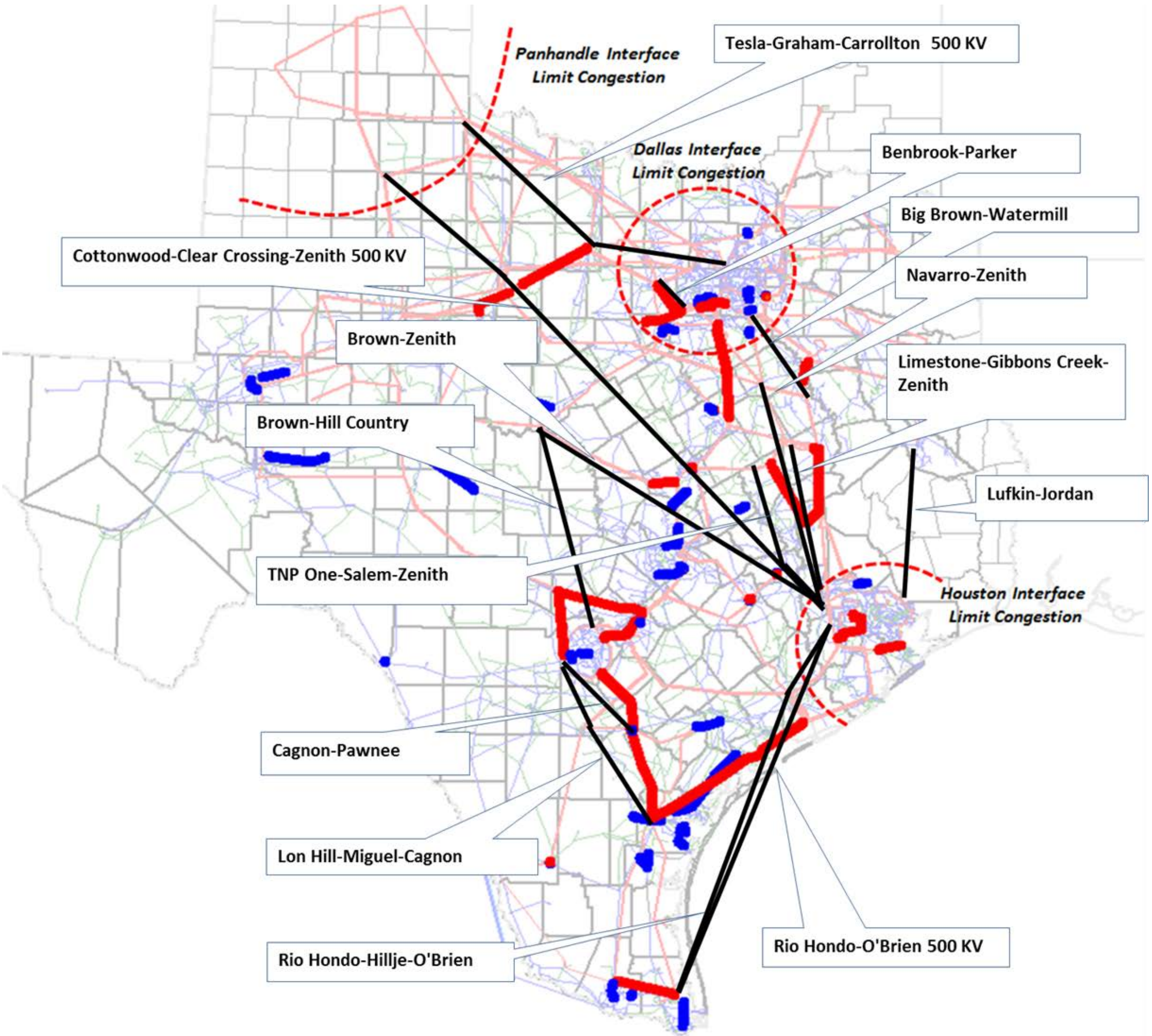
Congestion Map in 2032 (monitor 345-kV system only)



Most Congested Elements in 2032

From Bus Name (Number)	To Bus Name (Number)	Congestion Cost($M)
Panhandle Interface Limit		$1,301.6
J.K. SPRUCE (5400)	PAWNEE 345KV SWITCHING STATION (5725)	$593.2
PARKER (1436)	BENBROOK (1873)	$520.5
DFW Interface limit		$497.4
GIBBONS CREEK (967)	SINGLETON (44645)	$426.6
LON HILL (8455)	LON HILL (8452)	$376.7
Houston Interface limit		$374.9
JEWETT SOUTH (3390)	SINGLETON (44645)	$234.3
COLETO CREEK (8162)	VICTORIA PLANT (8172)	$213.5
PH ROBINSON (42000)	MEADOW (43030)	$148.0
GIBBONS CREEK (967)	345 KV JACKCREEK # 1 (975)	$145.5
EVERMAN BUS TIE 1 (1885)	COURTLAND #1 (1931)	$141.2
345 KV JACKCREEK # 1 (975)	TWIN OAK SES (3400)	$135.4
RINCON (8418)	MELON CREEK (80065)	$100.8
WOLF HOLLOW (1876)	ROCKY CREEK (1880)	$98.6
SKYLINE 345KV BUS (5371)	MARION (7044)	$90.0
JEWETT NORTH (3391)	SINGLETON (44645)	$86.9
WESLACO SWITCHING STATION (8354)	WESLACO (MVEC) (8768)	$66.3
KINGSVILLE (8518)	KLEBERG (8519)	$60.7
FAYETTEVILLE (7057)	FAYETTEVILLE (7286)	$59.9
CAGNON 345KV BUS (5056)	KENDALL (7046)	$56.1
BROWNWOOD (1661)	FIREROCK LOAD (6359)	$54.9

Economic Projects Tested in 2032



Economic Results in 2032

Tested Project in 2032	Adjusted Capital Cost (2032 $M)	1/6 of Adjusted Capital Cost (2032 $M)	Production Cost Savings (2032 $M)	Meet ERCOT Economic Criteria?
Big Brown to Watermill	365.7	61	10	No
Parker to Benbrook	281.5	46.9	26	No
Tesla to Graham to Carrollton 500-kV line	1,247.8	208	370	Yes
TNP One to Salem to Zenith	264.6	44.1	283	Yes
Rio Hondo to Hillje to O'Brien 345-kV line	1,137.1	189.5	419	Yes
Rio Hondo to O'Brien 500-kV line	2,384	397.3	533	Yes
Cottonwood to Clear Crossing to Zenith 500-kV line	2,293.7	382.3	710	Yes
Navarro to Zenith	824.1	137.4	218	Yes
Limestone to Gibbons Creek to Zenith	367.2	61.2	309	Yes
Brown to Zenith	1,094.2	182.4	232	Yes
Lufkin to Jordan	827.9	138	227	Yes
Lon Hill to Miguel to Cagnon	1,219	203.2	358.03	Yes
Cagnon to Pawnee	389	64.8	215.61	Yes
Brown to Hill Country	557.4	92.9	78.8	No

*All numbers except Benefit Cost Ratio are in millions in 2032

Appendix R Generation Resource Siting Process

ERCOT obtained data from a variety of sources to create criteria for ranking generation sites. For each county, ERCOT evaluated each siting factor to determine the counties suitable to support each different possible expansion resource. Each siting constraint was assessed on a county-by-county basis. Then, the requirements for each expansion resource technology were determined, and the set of counties which met the technology-specific criteria were considered viable counties for a resource. The 345-kV buses in these selected counties were then used as potential siting locations for expansion resources. This process was not intended to result in precise locations for the new resources; instead it is designed to provide sufficient indication of the likely locations of new generation development to guide the assessment of the impacts of these resources on the need for changes to the extra-high voltage transmission network. Ultimately, ERCOT developed a ranked list of counties for each resource type that it could use to place the resources from the expansion process.

For natural gas pipelines and railroads, maps were visually inspected to categorize each county as having a high, medium, low, and very low pipeline or railroad density. To classify the natural gas pipelines, ERCOT performed a visual inspection of map of the network of gas pipelines in Texas from The Railroad Commission of Texas, one county at a time. According to the number and density of pipelines running through each county, ERCOT classified the counties into four grades (high, medium, low and very low). Combined cycle units and combustion turbines are the generation types that require gas pipelines near the site. The vast majority of Texas graded as medium or high density for natural gas pipelines. The following two figures show a map of natural gas pipelines in Texas and the pipeline grading ERCOT prepared and used for siting expansion resources.

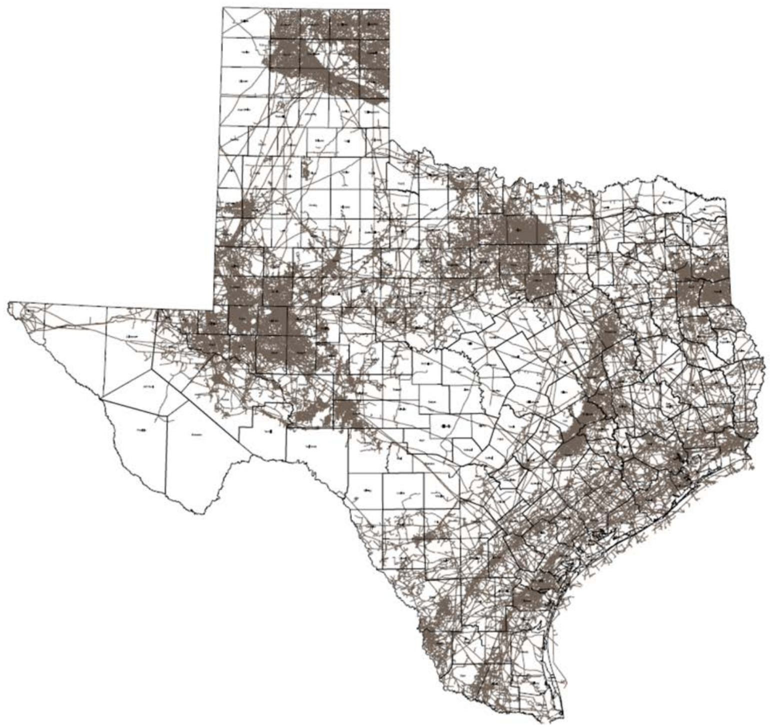


Figure R.1 — Natural Gas Pipeline Density[36]

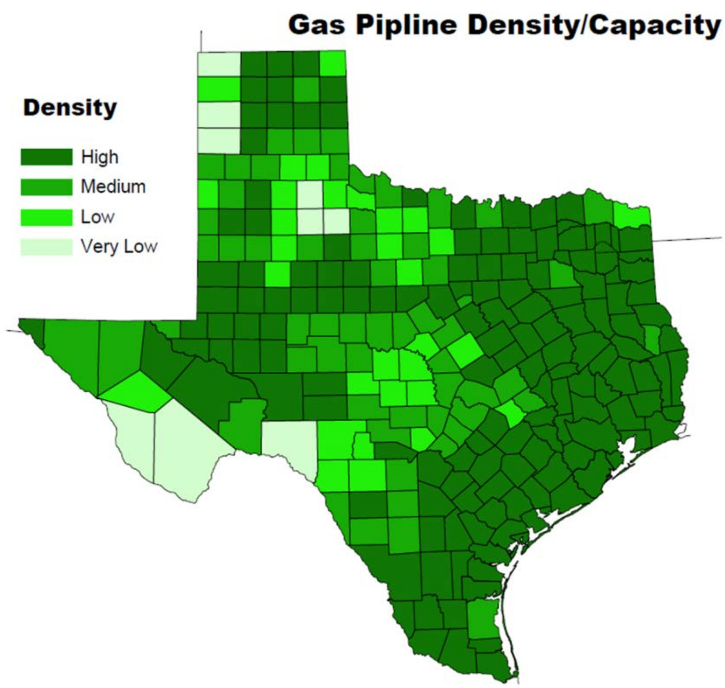


Figure R.2 – Natural Gas Pipeline Density Map for Resource Siting

[36] Source: Railroad Commission of Texas.

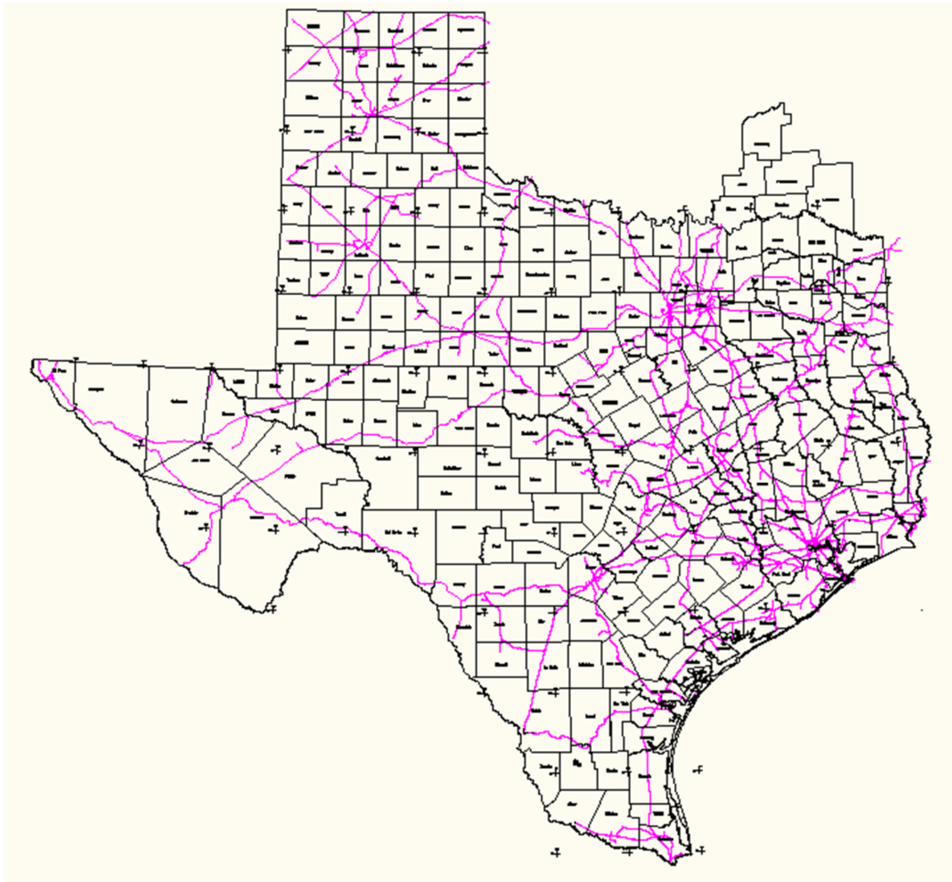


Figure R.3 — Railroad Lines in Texas[37]

To classify the quality of railroad access, ERCOT visually inspected a map of railroads in Texas from the Texas Department of Transportation to determine the number and density of railroads in each county. ERCOT considered a county with three or more railroads as having high density. ERCOT classified counties with two, one, or no railroads as medium, low, and very-low density, respectively. Figure R.4 shows the graded county map of railroad density ERCOT used in siting expansion resources. East Texas contained the majority of counties with railroad high density grades for railroads. Numerous counties in other parts of Texas graded as having medium railroad density.

[37] Source: Texas Department of Transportation.

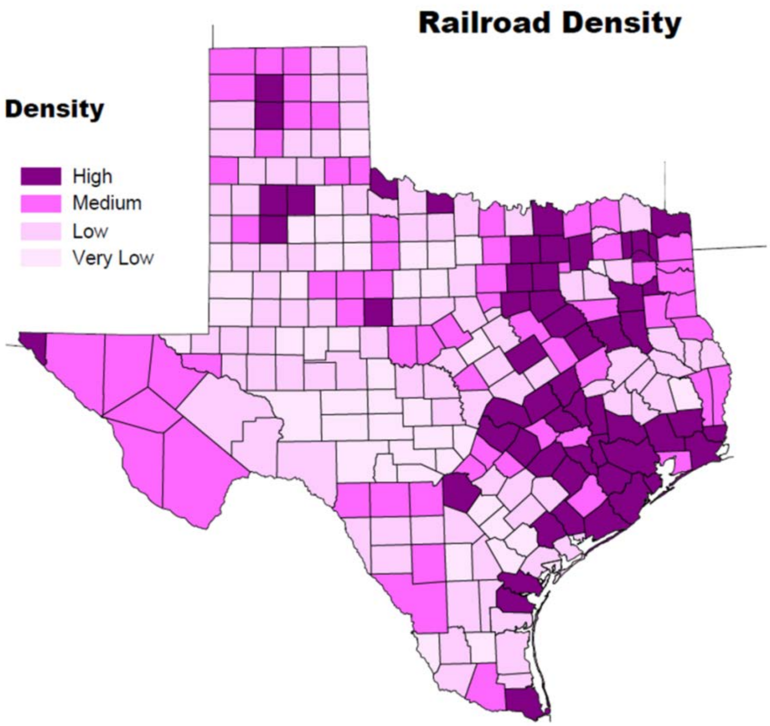


Figure R.4 - Railroad Density Map for Resource Siting

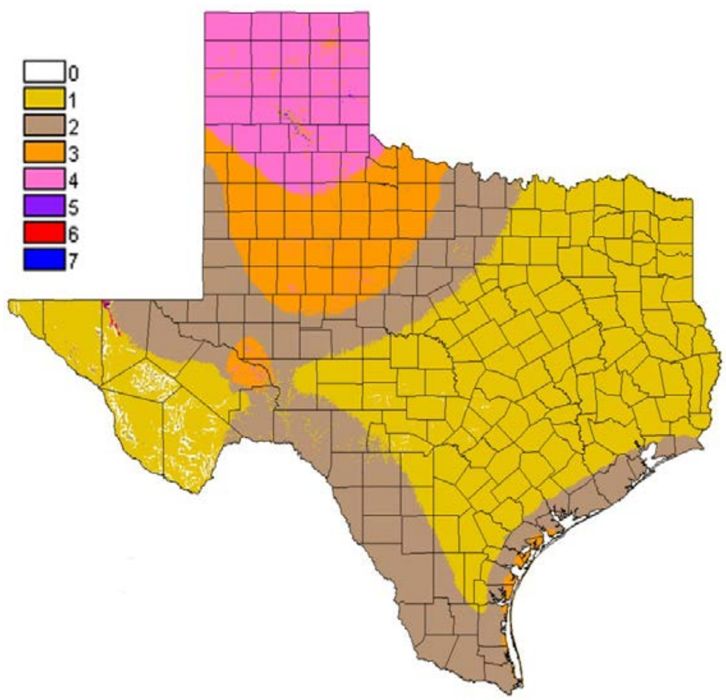


Figure R.5 — Texas Wind Class Map[38]

[38] *Simple Wind Class Map*, Alternative Energy Institute at West Texas A&M University (2004).

Wind resource data was obtained from Alternative Energy Institute at West Texas A&M University.[39] The Institute classifies Texas geographically into seven different zones, ranked 1 to 7, based on suitability for development of wind generation. Higher wind ranking numbers correspond to higher average wind speeds. Additional information regarding potential offshore wind locations was also incorporated into this analysis.

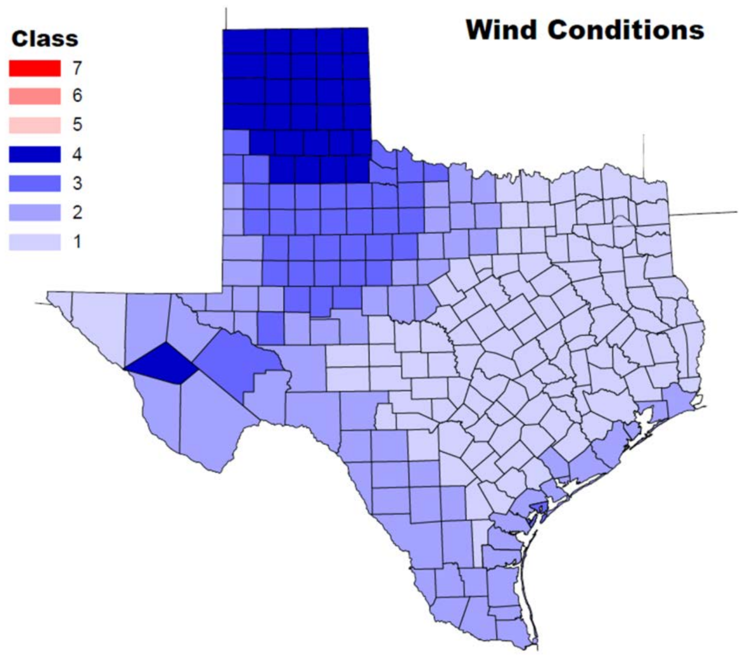


Figure R.6 – Wind Resource Quality by County

ERCOT obtained information regarding solar thermal and solar photovoltaic resources in Texas from the National Renewable Energy Lab (NREL). This information is depicted in the following two figures. Solar radiation in these maps is measured in units of kilowatt-hours (kWh) per square meter. Direct normal irradiance, which is the component of solar radiation that is tracked by solar thermal concentrators, is the amount of solar radiation received per unit area by a surface held normal to the sun's rays.

The following groupings were assigned ranges of solar radiation:

- good: 6.5-7 kWh/m^2
- average: 6-6.5 kWh/m^2
- below average: 5.5-6 kWh/m^2
- poor: ≤ 5.5 kWh/m^2

[39] Alternative Energy Institute, West Texas A&M University.

As per NREL, based on solar irradiance, the Far West weather zone in ERCOT has acceptable sites for solar thermal units. NREL considers areas having more than 6.75 kWh/m^2/day annual average direct normal solar resource ideal. To identify more potential sites suitable for solar thermal generation, ERCOT did not restrict itself to only resource areas with average annual direct normal solar radiance equal to or greater than NREL's threshold. Figure S.4 shows a map of the direct normal solar radiation in Texas. The map clearly shows the direct solar resource in Texas increases from the east to the west.

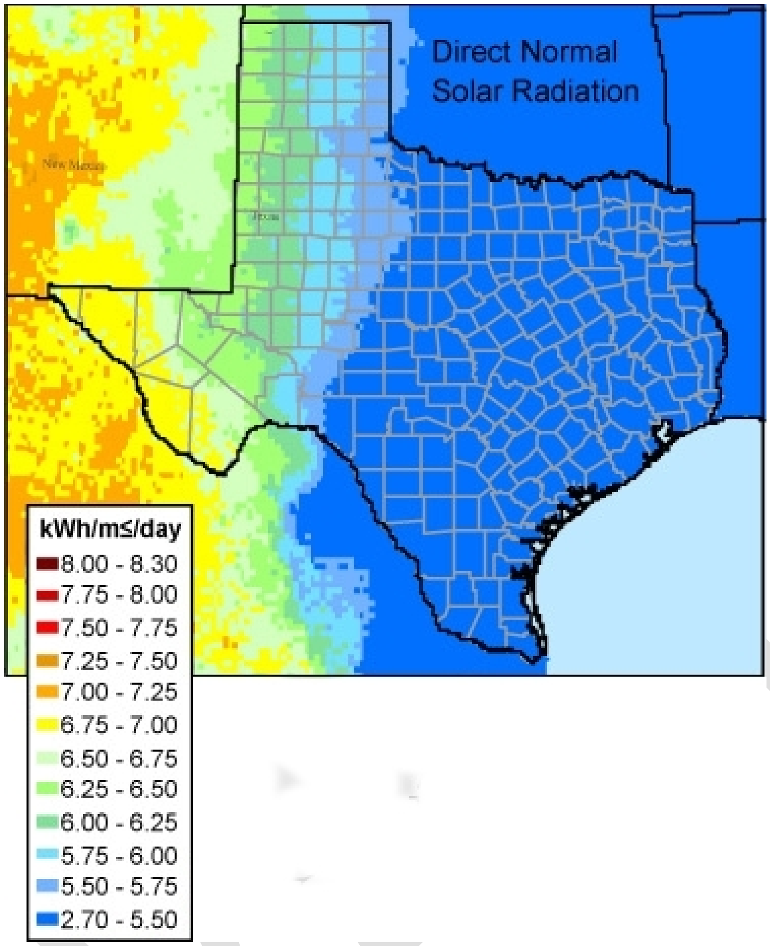


Figure R.7 — Distribution of Direct Normal Solar Radiation[40]

[40] Source: NREL.

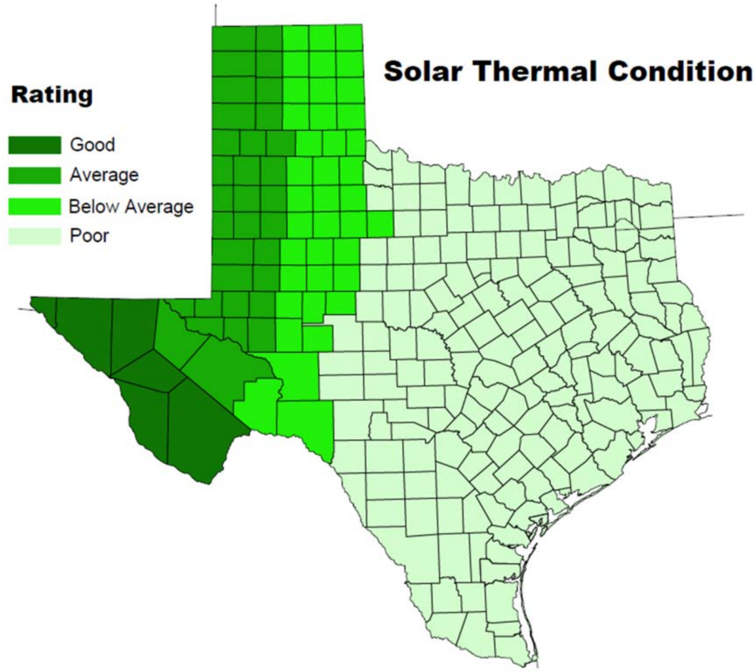


Figure R.8 – Solar Thermal Resource Quality by County

Similarly to solar thermal, solar photovoltaic (PV) resource, is measured by energy per surface area squared (kWh/m^2). However, unlike solar thermal systems, PV harnesses energy contained in the direct normal radiation as well as the radiation diffused by atmospheric components. The counties suitable for solar PV were divided into very high, high and medium insolation groups. PV energy production increases proportionally with increases in the solar radiation that strikes the panel. The map presented in Figure R.7 shows that most of Texas has high levels (>5 kWh/m^2/day) of average daily solar radiation.

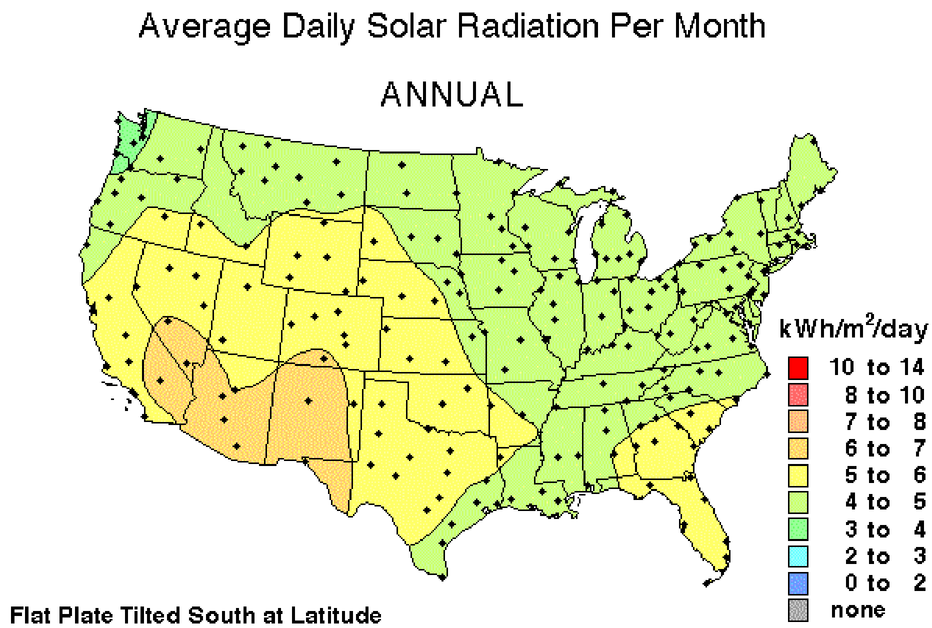


Figure R.9 — U.S. Average Daily Solar Radiation per Month[41]

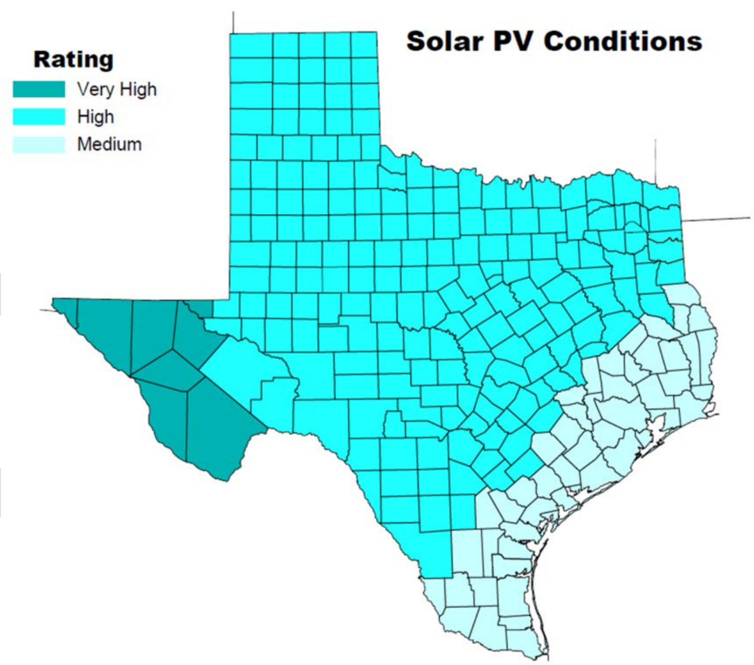


Figure R.10 – Photovoltaic Resource Quality by County

Similarly, prevalence of surface water supplies (streams, rivers, and lakes) were categorized by county based on visual inspection into areas of high, medium and low surface water conditions

41 Source: NREL.

depending on the number and density of rivers/streams and lakes. ERCOT relied on work by Sandia National Laboratories and Black & Veatch to develop an effective way to incorporate water resource considerations into the siting selection process.

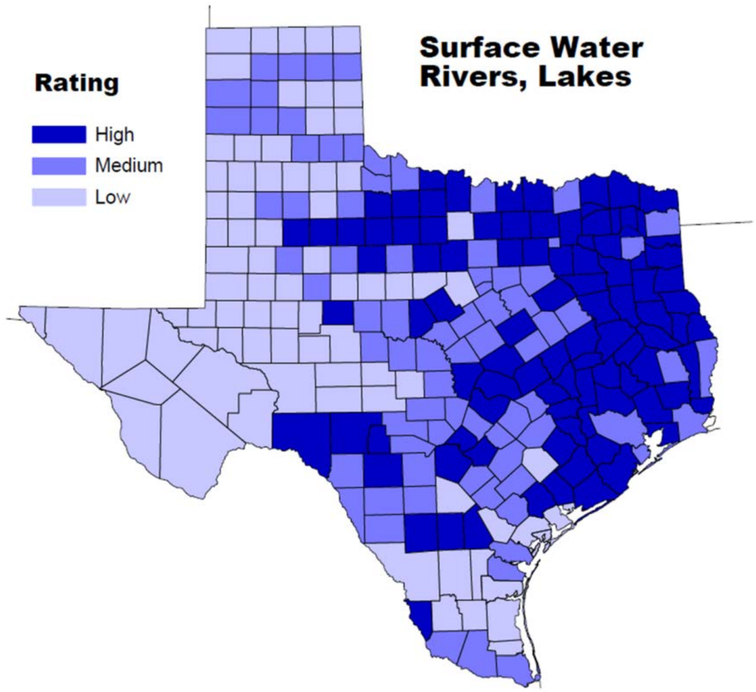


Figure R.11 – Water Availability by County

For those resources that require air permits to operate, ERCOT identified, counties designated as non-attainment zones based on ambient air quality standards by the Environmental Protection Agency (EPA) and the Texas Commission on Environmental Quality (TCEQ). These counties are listed below:

- Houston/Beaumont Region: Brazoria, Chambers, Fort Bend, Harris, Galveston, Liberty, Montgomery, and Waller
- Dallas/Ft. Worth Region: Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant

Information obtained from the TCEQ also indicated that the following counties may soon be designated as non-attainment zones as a result of the possibility of new, more stringent ozone standards: El Paso, Smith, Hood, Gregg, Rusk, Travis, and Bexar. The designation of a county as a non-attainment zone results in additional restrictions on NO_X emissions from large stationary sources such as power plants, and would likely limit development of such resources in these counties or the redevelopment of existing sites.

Table R.1: Generation Technologies and Resource Limitations	
Resource Type	**Resource Limitations**
Wind good	Low Urban Density; Wind Zone 3-4
Wind average	Low Urban Density; Wind Zone 2
Solar Thermal - good	Low Urban Density; Good Direct Solar Resource; High Water Availability
Solar Thermal - average	Low Urban Density; Average to Good Direct Solar Resource; Medium to High Water Availability
NG CT - good	Low Urban Density; High Availability of Natural Gas Supply; Cannot Build in Non-Attainment Area
NG CT - average	Low Urban Density; Medium to High Availability of Natural Gas Supply; Cannot Build in Non-Attainment Area
NG CC - good	Low Urban Density; High Availability of Natural Gas Supply; Cannot Build in Non-Attainment Area or Potential Non-Attainment Area: Medium to High Water Availability
NG CC - average	Low Urban Density; Medium to High Availability of Natural Gas Supply; Cannot Build in Non-Attainment Area or Potential Non-Attainment Area: Medium to High Water Availability
Coal	Low Urban Density; Medium to High Availability of Rail Transportation; Cannot Build in Non-Attainment Area: Medium to High Water Availability
Biomass	Low Urban Density; Low to High Availability of Rail Transportation
Nuclear	Low Urban Density; High Water Availability
Geothermal	Low Urban Density
Solar PV - good	High to Very High Total Solar Resource
Solar PV - average	

Considering all of these factors, along with each resource technology's site requirements, ERCOT developed a list of acceptable counties for each expansion resource type. Site requirements by technology are provided in Table R.1. For each resource technology, the 345-kV buses that were located in the list of acceptable counties were used as potential siting locations. New resource locations were limited to 345-kV buses to facilitate transmission planning. Resources placed on 138-kV buses would likely require additional nearby transmission infrastructure added to the model to allow the unit to reach full output. By siting expansion resources only on 345-kV buses, ERCOT reduced the number of additional projects that would have to be added as part of the "interconnection process." The 345-kV buses selected for each technology were further ranked based on a review of locational market prices from preliminary PROMOD IV runs. To limit the localized impact of adding too many new generation resources into certain areas, for each technology type, ERCOT would locate only one expansion plant in each county until it exhausted all counties capable of supporting that technology. After it exhausted the counties capable of hosting a specific technology type, ERCOT would begin to reuse counties.

Ultimately, ERCOT combined all the technology requirements with the graded resource assessments and access to nearby bulk power transmission to identify specific buses on the transmission system appropriate for each technology type. Table R.2 shows the technology types and the Texas counties that fulfill their resource requirements and the number of buses to which those potential expansion generators could connect.

Table R.2: Number of Counties in ERCOT Suitable for Siting Generation and Number of 345-kV Buses		
Generation Type	**No. of Texas Counties Fulfilling Generation-Type Requirements**	**No. of 345-kV Buses in Counties Fulfilling Generation-Type Requirements**
Wind - good	39	68
Wind - average	99	123
Solar Thermal - good	0	0
Solar Thermal - average	6	0
NG CT - good	99	161
NG CT - average	143	201
NG CC - good	63	108
NG CC average	107	171
Coal	60	93
Biomass	150	227
Nuclear	74	107
Geothermal	191	260
Solar PV - good	156	212
Solar PV - average	196	333

Appendix S ERCOT Solar Generation Patterns

See Volume 2 for the URS Solar Generation Patterns Report.

Appendix T Simulation of Wind Generation Patterns for the ERCOT Service Area

See Volume 2 for the AWS Truepower Simulation of Wind Generation Patterns for the ERCOT Service Area Report.

Appendix U Long-Term Assessment of Natural Gas Infrastructure to Serve Electric Generation Needs within ERCOT

See Volume 2 for the Black & Veatch Long-Term Assessment of Natural Gas Infrastructure to Serve Electric Generation Needs within ERCOT.

Appendix V Water Use and Availability in the ERCOT Region

See Volume 2 for the Black & Veatch Water Use and Availability in the ERCOT Region.

Appendix W Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process

See Volume 2 for The Brattle Group's Recommendations for Enhancing ERCOT's Long-Term Transmission Planning