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Long-Term System Assessment for the ERCOT Region

December, 2010

ERCOT Long Term System Assessment

Executive Summary

Senate Bill 20 requires that the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas, Inc. (ERCOT) study the need for increased transmission and generation capacity throughout the state of Texas and report on these needs to the Legislature. A report documenting this study must be filed with the legislature each even-numbered year.

In order to meet this requirement, ERCOT completes a Long-Term System Assessment (LTSA) every other year. The LTSA provides a 10-year-out assessment of transmission needs. This assessment is not conducted to provide specific recommendations for transmission projects. Rather it is used to inform the five-year planning process in two ways. First, the 10-year plan provides a longer term view of system reliability needs. Whereas in the five-year planning horizon a small transmission improvement may appear to be sufficient, the 10-year planning horizon may indicate that a larger project will be required. In this case, the larger project may be more cost-effective than multiple smaller projects, each being recommended in consecutive Five-Year Plans. Second, the 10-year plan can indicate system needs that require solutions that will take longer than 5 years to implement. In such cases, it is desirable to incorporate these projects into the 5-year evaluation process as early as possible.

The 2010 LTSA is developed from the results of the ERCOT Five-Year Plan. It incorporates all generation currently in operation (and expected to remain so) and all generation for which there is a signed interconnection agreement. Other input parameters, such as natural gas price and emissions allowance costs, were modified by scenario in order to determine their impact on the model results.

The study consisted of two parts. The first was an analysis of peak-load system conditions, using AC contingency analysis and voltage stability analysis, to evaluate transmission improvements needed to maintain system reliability. The second was an evaluation of the cost-effectiveness of potential economic projects using scenario analysis.

This analysis leads to the following conclusions:

- Numerous transmission system upgrades will be needed, particularly in the Dallas/Fort Worth (DFW) and Houston areas, due to expected load growth over the next ten years. These projects are not expected to require long lead times and will be fully evaluated as a part of the five-year transmission plan.

- As with previous LTSA, there is a potential need for new transmission import capacity into the Houston metropolitan area. This need was noted through analysis of under-voltage excursions in steady-state contingency analysis, and through PV analysis. Several projects were analyzed, although the need for and choice of the most cost-effective solution will be dependent upon the amount and location of new generation resources. The installation of dynamic reactive equipment could also delay the need for additional import capacity.
- Load growth in areas north and west of DFW may require additional transmission infrastructure in the next ten years. Specific projects were developed and analyzed in this study in conjunction with the local transmission service provider.
- While certain projects were found to be economically viable in specific future scenarios, no projects were viable across a broad range of future scenarios. This overall result is likely due to reductions in expected future loads due to the lingering impacts of recent economic conditions, as well as the diversity of potential future generation outcomes that may develop.

The above conclusions, and this report in general, are based on high level assumptions and are intended to inform the five-year planning process, which provides a more detailed review of specific transmission projects. The technologies and locations of generation projects assumed in the analyses that support the above conclusions may not reflect all issues that necessarily must be considered and/or affect generation development decisions. Accordingly, this report is intended to provide guidance to ERCOT and ERCOT market participants in evaluating system needs, and is not intended to suggest changes to market policy or support changes to market activities.

ERCOT Long-Term System Assessment

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1. Introduction

Section 39.904(k) of the Public Utility Regulatory Act (PURA) requires the Public Utility Commission of Texas (PUC) and the Electric Reliability Council of Texas, Inc. (ERCOT) to study the need for increased transmission and generation capacity throughout the state of Texas and report to the Legislature the results of the study. The report must be filed with the Legislature no later than December 31 of each even-numbered year.

Two reports have been prepared to meet this requirement:

- *Annual Report on Constraints and Needs in the ERCOT Region*, which provides an assessment of the need for increased transmission and generation capacity for the next five years (2011-2015) and provides a summary of the ERCOT Five-Year Transmission Plan to meet those needs.
- *Long-Term System Assessment (LTSA) for the ERCOT Region*, which provides an analysis of the system needs in the tenth year, in order to provide a longer-term view to guide near-term decisions made in the five-year transmission planning process.

Together, these reports provide an overall assessment of the needs of the ERCOT system over the next ten years.

In addition, the North American Electric Reliability Corporation (NERC) standards require ERCOT to perform an assessment of its portion of the interconnected transmission system to ensure the electric system is sufficient to meet projected system demands. The LTSA is developed to support the longer-term (years six through ten) requirements of Transmission Planning (TPL) Standards TPL-001, TPL-002, and TPL-003.

The LTSA is intended to provide guidance to near-term planning and is not intended to provide recommendations for specific transmission projects. The LTSA analysis is based on projected system loads and forecasts of certain variables, such as the price of natural gas and changes in regulations, that will likely drive market decisions on generation investment. These projections lead to assumptions regarding the types and locations of new generation units, and conclusions regarding expected system needs. The exact placement and size of these new units together with changes in system load have a significant effect on the transmission needs of the system. Yet all projections are less certain the farther into the future they are based. Thus the conclusions derived from the analysis conducted as part of this study are intended to guide near-term planning with an understanding of possible long-range system needs. The decisions to endorse specific transmission projects for implementation remain with the Five-Year Transmission Plan process and Regional Planning Group review of specific projects.

2. Methodology

This study is designed to complement the Five-Year Transmission Plan developed for the ERCOT region. While the LTSA does not recommend specific transmission improvements, it is used to inform the five-year planning process in two ways. First, the LTSA provides a longer term view of system reliability needs. Whereas in the five-year planning horizon a small transmission improvement may appear to be sufficient, the 10-year planning horizon may indicate that a larger project will be required. In such a case the larger project may be more cost-effective than multiple smaller projects, each being recommended in successive Five-Year Plans. Second, the LTSA can indicate system needs that require solutions that might be expected to take longer than 5 years to implement. In such cases, it is desirable to incorporate these projects into the five-year evaluation process as early as possible.

In the five-year planning horizon, the location, size, and variable cost of new generation is relatively well-known, and the load growth can be predicted with limited error. With such variables known, the need for specific transmission improvements can be evaluated through modeling. In the ten-year planning horizon, the technology, location, and sizes of new generation are not well known. For example, in 2000 it would have been hard to predict that by 2010 there would be almost 10,000 MW of installed wind generation capacity in ERCOT. Since the restructuring of the Texas wholesale electric market in 1999, transmission planners have generally adopted the approach of considering new generation in the transmission planning process only when an interconnection agreement is signed. However, in order to conduct a 10-year analysis of transmission system needs, assumptions regarding new generation must be made.

The LTSA does not intend to impose generation type and siting decisions on the market, nor does it propose transmission construction that would be justified by new generation be made in advance of firm siting decisions. It does, however, attempt to look proactively at the needs of the system by making a reasonable assessment of what type, amount and location of the future generation may be built by the market, with the intent of guiding nearer-term decisions toward what are reasonably expected to be the longer term needs of the system and shortening the timeframe required to study the bulk transmission needs due to firm new generation by anticipating what those needs may be.

In addition, load growth can be a challenge to forecast, as economic growth and customer demand patterns can change over time. From a system standpoint, overall economic growth, technology developments, energy consumption efficiency, and weather all affect electricity demand. Further, in transmission planning, the load must be attributed to each substation, including new substations built in areas of growth, in order to develop a meaningful transmission plan.

As the focus of the LTSA is on large, long-lead time projects, smaller projects that are more appropriately analyzed in the five-year planning process are not fully evaluated. However, in order to develop the LTSA, smaller projects must be evaluated to the extent necessary to determine overall system needs and to determine if larger projects are cost-effective.

2.1 Input Assumptions

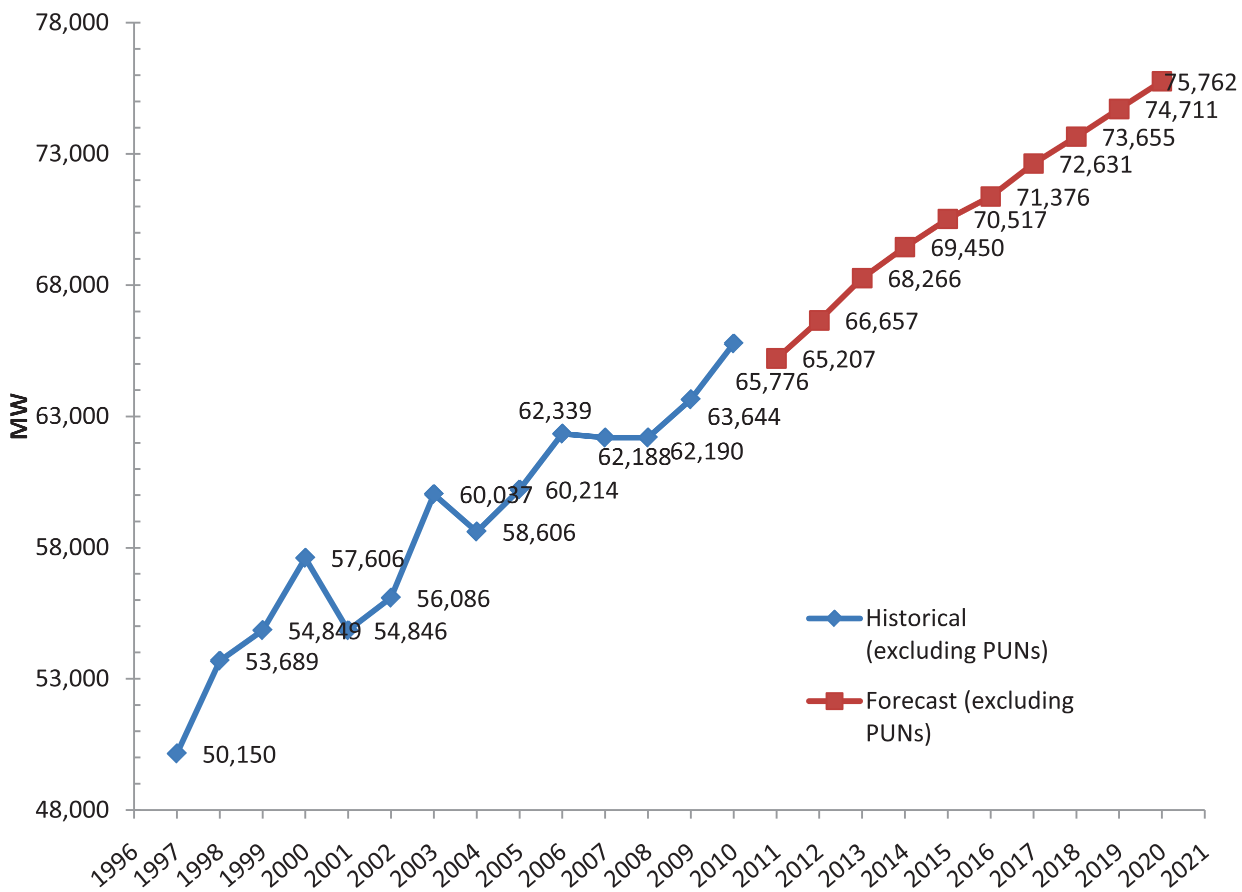
This study has been developed using the latest year of the most recent Five-Year Plan as the base case. This case was derived from the work conducted by the Steady-State Working Group (SSWG), a stakeholder committee consisting of representatives from the transmission service providers in ERCOT. All recommended transmission projects as of September 1, 2010, are included in this model, as are all generating units either currently operational (and expected to remain in-service) or with signed interconnection agreements as of September 1, 2010. This base case includes the transmission improvements ordered by the PUC as part of Docket No. 33672, Commission Staff's Petition for Designation of Competitive Renewable Energy Zones (CREZ).

The load forecast for 2020 is derived from the ERCOT Long-Term Demand and Energy forecast. This forecast is produced with a set of econometric models that use weather, economic and demographic data, and calendar variables to capture and project the long-term trends in the historical load data for the past six years.

To develop this forecast, a representative hourly load shape by weather zone is forecasted using an average weather profile of temperatures, Cooling Degree Hours (CDH) and Heating Degree Hours (HDH) obtained from historical data. The ERCOT weather zones are depicted in Appendix A. Other factors, such as seasonal daily, weekly, monthly and yearly load variations and holidays, as well as interactions between variables such as weather, weekends, and weekdays are also considered. This hourly ERCOT Load Shape describes the hourly load fluctuations within the year, but does not reflect the long-term trend.

The long-term trend is provided by the energy forecast. The monthly energy forecast models by weather zone use Cooling Degree Days (CDD) and Heating Degree Days (HDD), economic and demographic data, and monthly indicator variables to project the monthly energy for the next eleven years (2010 - 2020). Below is a graph of the historical system peak demands and the forecasted system peak demands (without inclusion of loads on private-use networks [PUNs]).

Figure 1: ERCOT Annual System Peak Loads, Historical and Forecast



2.2 Reliability Analysis

To analyze system improvements that may be needed to reliably serve expected future loads, line flows on the ERCOT transmission system were modeled using AC contingency analysis and voltage stability analysis. AC contingency analysis was used to evaluate steady-state system conditions following the loss of single transmission elements (n-1 analysis), as defined in the contingency files developed as part of the SSWG base case. This analysis was conducted following NERC and ERCOT planning standards. Thermal overloads and bus voltage excursions noted during the contingency analysis were evaluated to assess the need for system improvements.

Voltage stability analysis was used to gauge the availability of reactive capability throughout the system in order to maintain reliability following fault conditions. In voltage stability analysis, the system is considered reliable if, under contingency, the system is capable of transferring additional power beyond what is normally anticipated without exceeding stability limits.

Two system cases were tested using these analyses: a Reliability Base Case with peak 2020 loads (increased by 6% to reflect unusually hot summer weather), and an off-peak load case with large amounts of location-constrained generation (nuclear and wind). In both cases, specific upgrades were evaluated to resolve reliability issues.

2.3 Economic Analysis

Reliability transmission projects are required in order to meet customer demand while adhering to applicable NERC and ERCOT reliability standards. These projects are required because there is no possible dispatch of generating units with which customer demand can be served reliably. In other situations, there are feasible combinations of generating unit output levels that can be used to reliably serve load, but in order to do so, high-variable-cost generation must be utilized in the place of low-variable-cost generation. The displacement of low-cost generation with high-cost generation in order to respect transmission system limits is called transmission congestion. This displacement leads to system inefficiencies and nodal price disparities. In some cases, transmission improvements that are not required in order to reliably serve load can increase system efficiency to such an extent that the reduction in the annual cost to serve load is greater than the annual carrying cost of the transmission improvement. System improvements that meet these criteria can be recommended as economic projects.

Although economic projects are not required to maintain system reliability, they provide significant system benefits by allowing the most efficient generation to serve load. New economic transmission projects are often the result of the development of low-variable-cost generation. However, as has been noted, the size, location, technology and efficiency of much of the generation that will be developed over the next ten years are unknown at this time. In order to evaluate potential future economic projects, the possibilities for future generation development were evaluated.

2.3.1 Scenario Analysis

The use of potential future scenarios to analyze system needs is helpful in long-range planning horizons. Scenario analysis reduces the risks associated with planning transmission using assumptions regarding load growth and generation additions as described above. By developing future scenarios based on significantly different assumptions regarding future conditions such as fuel prices, economic conditions and regulatory requirements, a broad range of potential system needs can be assessed. An assessment of likely system needs can then be developed not through the findings from one specific scenario, but rather from a comparison of the needs indicated across the range of different scenarios. Differences between transmission requirements across scenarios can be attributed back to underlying assumptions. The correlations between system needs and potential future conditions can inform near-term planning. In addition, transmission projects that show benefits across a wide range of future conditions represent potential "no-regrets" upgrades that should be included in near-term planning assessments.

2.3.2 Generation Expansion

Generation expansion alternatives can be compared using a levelized cost of energy (LCOE) analysis. LCOE analysis provides total costs for generation technologies (including both fixed and variable costs), which can be easily adjusted to reflect assumptions used in specific future scenarios. The resulting "all-in" costs can be compared to determine the most cost-effective generation alternatives for each scenario. In a deregulated energy-only market structure such as ERCOT's, generation technologies that can produce energy at the lowest total cost of production are likely to be strongly represented in future interconnection queues.

The main input variables in a levelized-cost analysis are capital cost, financing assumptions, operation and maintenance costs, fuel costs, and estimated energy production. The LCOE calculation captures all of the variables and converts them into a common metric: $/MWh. The following equations show how the overall levelized cost is calculated.

$$LCOE=\sum_{i=1}^{t}\left[\frac{\{(initial\ equity\ investment)^{t=0}+(debt\ payment)^{t}+(fuel\ cost)^{t}+(O\&M)^{t}\}}{(annual\ energy\ production)^{t}}\right]$$

$$FuelCost=\frac{(Fuel\ Price*Heat\ Rate*Annual\ energy\ production)}{1000}$$

$$Annual\ energy\ production=Capacity(MW)*Capacity\ Factor\ (\%)*8760$$

Where:

Initial equity investment: The percent of total capital paid in year t=0

Debt payment: Expected annual payment made to pay back debt taken out to pay the remainder of the total capital investment not covered by the initial equity investment

Fuel cost: The amount spent annually on fuel

O&M: Expected annual fixed and variable operation and maintenance costs

Annual energy production: The total amount of energy produced in a given year

Heat rate: The operational efficiency of the technology. In other words, a measure of the amount of fuel required to produce a set amount of electric power.

Capacity: Maximum output of the unit

Capacity Factor: Assumed amount of annual energy produced by the technology, compared to the maximum capacity times the number of hours in a year (8,760).

The calculated debt payment will vary depending on the financing life of the loan and the interest rate for the loan. As the financing life increases, the annual debt payment decreases but the total paid in interest will increase. As the interest rate increases, the total amount paid in interest increases, which increases the annual debt payment. In this study, the financing life of all technologies except nuclear was assumed to be 20 years; the assumed financing for nuclear technology was 60 years. For this analysis, the expected cost of capital is assumed to be 9%. The capital cost will vary depending on the credit rating and organizational structure of the generation developer.

For each technology evaluated, generic operating assumptions were obtained from the Updated Capital Cost Estimates for Electricity Generation Plants report produced by the Energy Information Administration (EIA; November, 2010). These values are provided in Appendix B. In applicable scenarios, carbon emission costs were derived by multiplying the emission rate (tons/MWh) by the annual energy production (MWh) and the assumed carbon cost ($/ton) to achieve an annual carbon cost. These costs were added to the total life cycle cost of the plant. Levelized cost comparisons for various technologies are provided in Appendices C and D.

Generation expansion in each scenario was assumed to be sufficient to maintain the current target reserve margin for the ERCOT region (13.75%). Given a forecasted summer peak load of 75,762 MW in 2020, a minimum aggregate generation capacity of 86,179 MW was required. For the purposes of calculating generation capacity, the effective-load-carrying capability (ELCC) of wind generation was assumed to be 8.7%, following current ERCOT criteria, and the ELCC of solar generation was assumed to be 60%. All other generation technologies were included in the generation reserve margin calculation using their nameplate rating.

The development of new generation in a deregulated energy-only market requires confidence from generation developers and capital investors in the profit-potential of generation investments. These profits can be derived from market competitiveness of new generation technologies, risk-aversion of load-serving entities, ancillary services revenues, and/or scarcity market prices. Analysis of these factors was beyond the scope of this analysis.

Expansion generation units included in each scenario were sited based on several factors. In general, new generation units were connected to existing 345-kV substations. Locational marginal prices (LMP), by bus, from the 2015 Five-Year Transmission Plan were analyzed to determine locations with favorable market conditions. Locations where generation has been retired or mothballed were considered, although new thermal generation was not sited within air quality non-attainment zones. A list of the counties in non-attainment zones is provided in Appendix E.

3. Reliability Analysis

3.1 Topology Development

The transmission topology for the ERCOT 2010 Long-Term System Assessment is derived from the 2015 Reliability case from the most recent (2010) ERCOT Five-Year Plan. As the Five-Year Transmission Plan was not complete when the LTSA analysis began, not all of the results of the Five-Year Plan are included in the LTSA topology. However, all of the projects likely to have an impact on higher voltage circuit power flows were included.

To conduct the transmission needs analysis in this LTSA, ERCOT utilized a network reduction tool to create a simplified system topology. This tool, which utilizes the automation features in PSS®E, removes certain elements from the topology and aggregates others. Total load and generation in the system remain unchanged (though real power losses may change), and much of the transmission equipment contributing to bulk system flows remains intact.

The network simplification process is required in order to distinguish long-range system needs from near-term network upgrade requirements. The SSWG base cases developed by ERCOT and the transmission service providers include expected system upgrades for the next 5 years. Similarly, the five-year planning effort conducted by ERCOT, which provides the starting case for the LTSA, meets the load-serving needs of the system only through the horizon of that effort. When loads beyond the 5-year horizon are applied to these cases, the resulting analysis indicates numerous transmission system element overloads, most notably on the load-serving 69-kV system.

System overloads on the lower voltage elements need not be evaluated as part of a long-term plan; these elements can be upgraded, as needed, as part of nearer term planning efforts as better information on the geographic placement of new load growth is known. However, the sheer number of these system limit violations in the model databases for the 10th year hinders assessment of the benefits of long-lead-time or large-scale system upgrades. In order to conduct long-term system assessments such as this study, a simplified topology is required: one in which the lower-voltage load-serving system upgrade requirements are minimized or even hidden, and as a result the need for larger system improvements can be more easily assessed.

There were five distinct steps used in the simplification of the transmission network, as described below. After simplification, the resulting ERCOT network is reduced from approximately 6,000 buses and 7,500 branches to 3,000 buses and 3,900 branches. The number of generators, amount of generation, and the total load remains equal to the full network.

1. Move equivalent load and generation from the 69-kV network to the nearest 138-kV buses
2. Remove the 69-kV network
3. Move loads and generation on radial lines to nearest networked bus then remove radial lines
4. Remove in-line buses where appropriate
5. Eliminate ratings on short lines, as defined below:
    a. Rural lines < 30 miles long
    b. Urban lines < 5 miles long

An inline bus is defined as a bus that connects to exactly two transmission lines. The bus does not contribute to networked connectivity, but rather is usually placed in the middle of a transmission line in order to serve local load. In simplification, inline buses are removed by merging the two adjacent transmission lines into one line.

"Urban lines" are defined as lines in geographic zones near significant population centers (Austin, Dallas/Fort Worth, Houston, San Antonio, Corpus Christi, Abilene, Odessa, Temple, and McAllen), and "rural lines" are defined as lines distant from these higher population centers. These two types of lines are treated differently in the topology simplification process because the intent is to separate projects that can be easily conducted within the near-term planning horizon from those that need to be considered in long-term planning. Urban lines are generally more difficult to site than rural lines due to increased land development. Whereas a 10-mile rural line may be relatively easy to construct, a 10-mile urban line may not.

Following completion of the simplification process, the contingency file is adjusted to reflect the changes made.

3.2 Load Assumptions

ERCOT produces an annual customer demand forecast for the next twenty years. The 2010 published load forecast predicts a peak load of 75,762 MW for year 2020. This forecasted load only includes loads that are settled through ERCOT; when adjusted to include Private Use Network demand, the total load forecast in ERCOT is forecasted to be 81,175 MW. For reliability analysis, this load forecast was increased by 6% to reflect very hot summer conditions. The resulting loads, by weather zone, are provided in the following table:

Table 1: Load Assumptions for Reliability Analysis

Zone	MW Load
Coast	20,361
East	2,934
Far West	1,923
North	1,638
North Central	29,237
South Central	13,678
South	5,668
West	2,013
Non-conforming	9,142
Total	*86,594*

These loads were distributed to individual buses as described in the topology development section.

3.3 Generation Assumptions

Reliability analysis involves evaluating the ability of the power system to reliably serve load. A system should be expected to operate not only under normal conditions, but also under a reasonable amount of stress. System conditions were evaluated under contingency of single transmission elements following North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Standards and ERCOT Operating and Planning Guides. To further stress the system, the reliability base case was constructed with minimal amounts of additional generation available, compared to expected loads.

Generation included in the reliability base case included the following:

- All existing generation and generation for which an interconnection contract has been completed,
- *minus* any generation announced for retirement or mothball status
- *plus* additional wind capacity (~7 GW) reflective of expected CREZ wind generation build-out
- *plus* two 1,000 MW natural gas plants.

The reliability case included 83,844 MW of conventional generation capacity, and 17,517 MW of wind generation capacity. The additional gas generation capacity was required in order to provide sufficient generation for the powerflow cases to solve. The location of this additional generation was varied in change cases so that the selected locations would not affect the results of the overall analysis.

3.4 Criteria

Steady-state contingency analysis was performed in accordance with NERC TPL standards and ERCOT planning criteria: For this study, steady-state contingency analysis involved analysis of steady-state conditions following all potential single-branch contingencies, as well as combined contingencies as specified in the above-listed planning criteria. For each contingency, the system was considered to be in a reliable operating state if no overloads or voltage violations were noted. Voltage and branch loading criteria are provided in the following table:

Table 2: Reliability Criteria

	Base Case	**Contingency**
Bus voltage	0.98 – 1.05 p.u.	0.93 – 1.05 p.u.
Branch loading	Under 100% of Rate A	Under 100% of Rate B

Base case analysis was performed using steady-state positive sequence load-flow programs PSS/E and PowerWorld. Contingency analysis was performed using MUST and TARA. Contingency analysis requiring redispatch was performed using TARA.

3.5 Steady-State Analysis Results

3.5.1 Houston Area

Analysis in the Houston area indicated numerous overloaded elements, especially in the northern and western areas of the city. Like many urban areas, the Houston metropolitan area is a net power importer, and relies on generation located primarily north, west, and south of the city. Most of the overloads noted, especially in the central and southern portions of the metropolitan area, likely can be solved through simple line upgrades. Other overloads may require increasing the number of connections between the 138-kV network and nearby 345-kV circuits.

Contingency overloads to the west and northwest of Houston, especially near the Addicks, T. H. Wharton and Zenith substations, may require significant system upgrades. The following potential projects were developed in conjunction with the local transmission service provider to solve the noted reliability issues in that area:

- Add a new 345-kV/138-kV autotransformer at Zenith substation. Add a new 138-kV double circuit from Zenith to Gertie and a new 138-kV circuit from Zenith to Franz to Katy. Upgrade or reconfigure several other circuits near the Zenith substation.
- Upgrade the Addicks to Britmore 138-kV circuit.
- Upgrade the 345-kV/138-kV autotransformer at P. H. Robinson to a rating of 800 MVA.
- Reconfigure several existing 138-kV circuits near the Channelview substation (including the circuits south to Cardiff and to Morgans Point, and from Colonial to Waburn).
- Upgrade 138-kV equipment at the T. H. Wharton bus.

3.5.2 Dallas/Fort Worth Area

Analysis in the Dallas/Fort Worth (DFW) area indicated overloaded elements under peak load 2020 conditions, particularly in western DFW. Based on the peak-load case contingency analysis, the following projects were developed in conjunction with the local transmission service provider.

For expected continuing load growth near the Roanoke area, the following projects were developed:

- Install two 345-kV/138-kV autotransformers at Hicks
- Connect the new Hicks 138-kV bus to the existing Eagle Mountain to Saginaw lines
- Build two 138-kV lines from Hicks to the a new Elizabeth Creek Substation
- Build two 138-kV lines from Elizabeth Creek to Roanoke
- Upgrade several additional nearby 138-kV lines

Due to the contemporaneous nature of the two studies, some of these projects were also identified in the 2010 Five-Year Plan. An alternative project would be a new 345-kV circuit between the Roanoke and Hicks substations, although such a project could be difficult to site given development in this area. Contingency analysis indicates there may be system benefits to installation of additional breakers and bus-work at substations in the Roanoke area, to reduce the scope of certain contingencies.

The networked distribution circuits outside of the Parkdale Substation may not be sufficient for load growth in that area by 2020. The exact networking arrangement near Parkdale is complex, and some of the contingencies include many elements. As a result, further review of this area is warranted. Based on the topology evaluated in this analysis, it appears that a new 138-kV circuit between the Parkdale and White Rock substations, in combination with additional breakers and/or buswork at the Parkdale, ENet and WNet substations, and potentially new autotransformer capacity, will be sufficient to maintain local system reliability.

Contingency analysis also indicates that upgrades of 138-kV circuits in the Collins and Northwest Carrollton areas may be needed, as well as a second 345-kV/138-kV autotransformer at the Allen substation. To the south of the Dallas area, analysis indicates the potential need for upgrades of existing 138-kV circuits emanating from the Watermill substation.

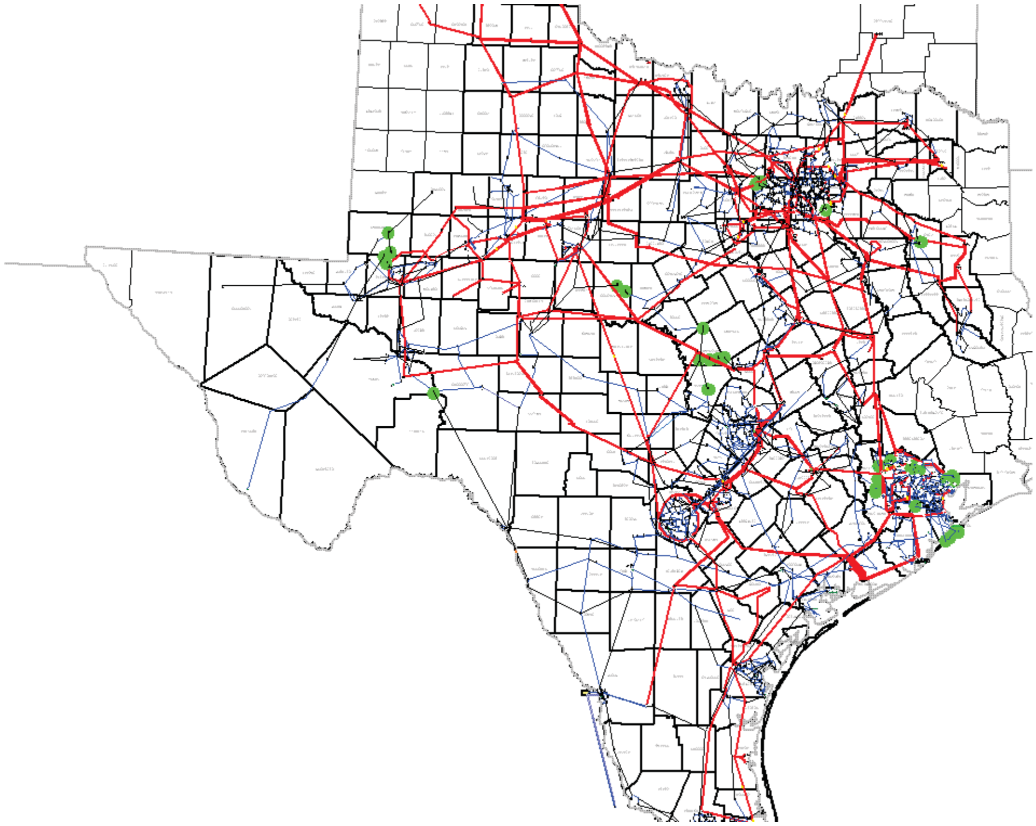
3.5.3 Rio Grande Valley

Analysis of the Rio Grande Valley region revealed few reliability issues. The most significant was the possible overload of the Hamilton to Eagle Pass line extending south from Del Rio, following the loss of the Hamilton to Uvalde line extending east from Del Rio, under peak load conditions. This overload is the result not only of load growth in the Valley area, but also expected power flows from wind generation in west Texas. Consultation with the local transmission service provider indicates that the cost-effective solution is to upgrade this existing circuit.

3.6 Steady-State Voltage Analysis

Substation voltages excursions were noted during the steady-state contingency analysis. Under peak load 2020 conditions, substation voltage excursions were noted in the Houston and DFW areas, as well as in central and west Texas (Figure 2). Although voltage excursions need not be considered as part of a long-term assessment, as they can typically be resolved through the installation of substation equipment, numerous voltage excursions in small areas can indicate a need for additional import capacity. In addition, large concentrations of shunt compensation can create operating difficulties. As such, it is beneficial to identify potential under-voltage conditions as part of long-range planning.

Figure 2: Areas with low substation voltages under contingency are indicated in green.



The under-voltage conditions noted in the analysis were resolved through addition of shunt capacitors into the transmission topology. Only the Houston area required a significant addition of shunt reactive capacity (over 2,500 MVAr). Most of these reactive needs are incurred by heavy line flows on the 345-kV circuits coming into the metropolitan area from the north and west. Additional local generation could reduce the flows on these circuits and thus the resulting reactive needs. Based on these results, ERCOT will conduct further analysis of these potential reactive needs in cooperation with the transmission service provider for the Houston area.

3.7 Steady-State Scenario Analysis

In addition to the base case used for steady-state reliability analysis described above, the scope of this study included review of an additional scenario using AC contingency analysis. Due to the siting limitations of wind generation and nuclear generation, the continued development of both of these technologies could lead to additional transmission system requirements. Specifically, the addition of new units at both of the existing nuclear generation facilities (Comanche Peak and South Texas Project), along with continued development of wind generation in West Texas, could result in off-peak system conditions in which much of the system generation was being provided by the two nuclear stations (4 units each at Comanche Peak and South Texas Project) and by the wind generation in west Texas and in the coastal region. In such a scenario, much of the non-nuclear thermal generation would be dispatched down to minimum output levels, or decommitted. As a result, there could be reduced capability to maintain system voltages in urban centers. To evaluate these conditions, a steady-state case was developed, based on the maximum wind case from the recently completed CREZ Reactive Study. This case was modified through the addition of two additional units at both the Comanche Peak and South Texas Project facilities, as publicly announced by the developers of these projects. The addition of generation from these nuclear units was offset by the decommitment of coal-fired generation.

The following coal units were decommitted from the generation dispatch (selected by installation date): Big Brown 1 and 2 (1,207 MW); Monticello 1 and 2 (1,137 MW); J. T. Deely 1 and 2 (860 MW); Martin Lake 1 and 2 (1,585 MW); and W. A. Parrish 5 (654 MW). These plants were selected to represent potential impacts to coal generation dispatch for this high wind and high nuclear generation scenario. Obviously, other combinations of unit decommitment are possible. The four proposed nuclear units added to the case represent 5,604 MW of generation capacity, and the case included 15,756 MW of dispatched wind generation.

The CREZ transmission system was included in the scenario, along with the potential reactive equipment required for maximum export conditions for the wind generation modeled in this case which was developed through the CREZ Reactive Study. More information is available in the CREZ Reactive Study report available at the ERCOT.com web-site. No additional transmission equipment or reactive support was required to support CREZ wind in this case.

While some additional transmission projects were included in this scenario in order to integrate the additional nuclear units, no other transmission upgrades or reactive support equipment were found to be necessary as a result of this scenario analysis. Integration projects are described in the following section.

3.7.1 Integration Projects

The required transmission upgrades in this scenario to integrate the generation from STP units 3 and 4 would be minor. Potential upgrades include expansion of the Hillje substation to include both Elm Creek to STP 345-kV lines, and upgrades on the 345-kV circuits from W. A. Parrish to Belair to prevent overloads following the outage of both W. A. Parrish to Jeneta 345-kV circuits.

Integrating the output from Comanche Peak units 3 and 4 following development of substantial wind generation will require more transmission system upgrades due to the location of the Comanche Peak facility (on the south-western side of the DFW area). For the purposes of this scenario, the new units were modeled as being connected to an independent high-side bus (called new Comanche). The following transmission projects were developed to fully integrate the proposed Comanche Peak nuclear generation:

- Two new 345-kV circuits from New Comanche to Willow Creek
- Two new 345-kV circuits from New Comanche to an expanded Tricorner substation. These lines do not connect at the Venus substation.
- Upgrades to the existing 345-kV circuits from Everman to Courtland
- Additional 345-kV/138-kV autotransformer capacity at Nacogdoches

The expanded Tricorner substation as modeled includes connections to the Watermill, Forney, Trinidad, and Martin Lake substations, in addition to the new circuits to New Comanche.

This set of projects is not intended to be a recommendation for integrating the new generation at Comanche Peak, but is one option to be considered if development of the nuclear generation at Comanche Peak proceeds.

3.8 Voltage Stability Analysis

As part of NERC Transmission Planning standards TPL-002 and TPL-003, Transmission Planners are required to perform an assessment of system conditions following single-element outages and selected multiple element outages. The power-voltage (PV) analysis conducted as part of this study is designed to meet these requirements.

In a typical PV study, power transfer between two study regions is increased and at each step, contingencies are independently applied, followed by a load flow solution. The transfer level for a given contingency at which the resulting load flow does not solve is flagged as a voltage collapse scenario. The process is repeated for higher power transfer level until the base case voltage collapses under no contingency, or the source region reaches its maximum specified exporting generation capacity. The transfer levels identified in this manner represent limitations to the modeled capability of the system, which are then used to assess overall system transmission requirements.

Voltage violations and branch overloads are monitored, and while they do impose operational limitation of the study network, they may not affect the voltage collapse point. Additional investigation may be required when voltages below 0.80 per unit (p.u.) are noted, because such under-voltage levels could trigger the stalling of motor loads, leading to a voltage collapse scenario.

Voltage collapse is assumed when the load flow fails to converge within the specified error tolerance and number of iterations. Mathematically a non-convergent solution is a set of equations with no numerical solution, i.e., a singularity. As such, a non-convergence could be the result of divergence, or due to numerical instability resulting from cumulative error or oscillatory control actions. In such cases, the solution would not solve, but also would not diverge. For purposes of this study, only solutions that diverge are identified as a voltage collapse outcomes; other non-convergent solutions were investigated to ensure that voltage stability limits are determined only by truly divergent scenarios.

This PV analysis was conducted as follows:

- The regional areas of study were defined as the 2010 Commercially Significant Constraints zones
- Interfaces between the zones were defined as the 345-kV circuits connecting buses across region boundaries
- Transfer study for voltage stability assessment was performed by increasing loads in each target region in turn and increasing generation in the remaining regions.
- For each import region, the most limiting transfer level was determined (either due to reaching regional generation limits or due to a case instability)
- The transfer margin was calculated with respect to forecasted load level in the case to determine if the resulting import limit represents a limitation that must be incorporated into further long-range planning studies. The following margins were reflected in these calculations:
    - Category B contingencies shall allow a margin of at least 5% for all cases.
    - Category C/D contingencies shall allow a margin of at least 2.5% for all cases.

As this analysis was conducted on a case designed around possible system conditions 10 years in the future, it is subject certain limitations. Specifically, it should be noted that not all pre-existing conditions were resolved prior to running this study. The base case may contain overloads, voltage violations and n-1 violations. In addition, the base case dispatch from the LTSA case was not modified, and it is unknown if this generation dispatch is the most severe to the regions under study. In addition, depending on the types of loads being modeled, low bus voltages may trigger motor load stalling conditions that can lead to fast voltage collapse. Such conditions can be studied with full motor model simulations (in the time-domain); such analysis was not in the scope of this study.

3.8.1 Results

The contingency lists for single element and multiple element outages were filtered for each regional area of study to create four sub-lists. For this study it was assumed that contingencies in other areas will not affect the transfer limits for the regional area of interest. The filtered contingency files were further screened using the Voltage Stability Analysis Tool (VSAT), a contingency screening tool, to generate the final list of test contingencies. The criterion for the screening process was contingencies with a voltage stability margin of less than 10%.

All contingencies tested with the screening tool for the West, North and South Texas regions were found to have limits larger than 10%. Since these results meet the established NERC and ERCOT criteria for voltage stability, further investigation was not conducted in these regions.

Several contingencies tested with the screening tool were found to have limits less than 10% for the Houston region. Further testing of the screened contingencies revealed limits of 0.5% for single-element outages and 'base-case insecurity' for multiple element outages for the case provided. Switching in existing reactive devices did not improve the transfer limits. The following tables provide the results of these analyses for the Houston area.

As the most common outage for the limiting transfers in this analysis was the interface circuit from Singleton to Tomball in the northern part of the Houston region, these results indicate the potential benefits of additional switched shunt capacitors (300 MVAr) at or near the Tomball 345-kV substation, along with the addition of two new 345-kV circuits between the Twin Oaks and Salem substations. Such an addition would allow distribution of import congestion between the Singleton-Roans Prairie-Tomball-Kuykendahl 345-kV section and the proposed Fayetteville-Zenith double circuit.

With these proposed upgrades, the calculated import limits in the load flow case (with other capacitor banks and switched shunts kept online as necessary) resulted in margins of 5.3% for single-element and 2.9% for multiple-element contingencies. These limits comply with the standards set by NERC and ERCOT.

These analyzed improvements are not being recommended at this time as there may be other, lower-cost projects that could also bring the transfer margins within the required criteria. Further study is needed. System import limitations are highly dependent on future generation development and installation of dynamic shunt reactive devices. However, these projects can be included in projects analyzed as part of near-term planning for system reliability benefits.

Since the system was proven to be stable from a voltage perspective and dynamic models of speculative generation are unavailable at this time, further assessment of the system dynamic response is not necessary.

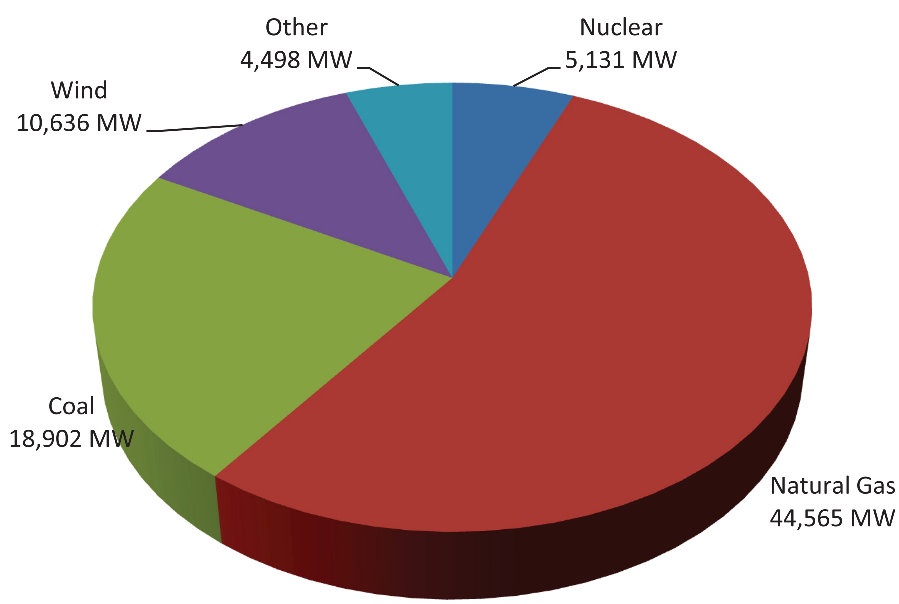
4. Economic Analysis

4.1 Scenario Development

Scenario analysis is often used to incorporate uncertainty into long-range planning studies. Each scenario is based on assumptions regarding future conditions, and then resulting impacts to future loads and generation expansion are evaluated. The resulting proposed transmission upgrades are compared across scenarios resulting in an understanding of potential system needs and the relationship between these needs and market and regulatory drivers. For this analysis, four scenarios have been developed. Generation additions for each were developed based on levelized cost analysis.

The base case generation assumptions listed in the methodology are constant throughout each scenario. The generation units which are listed as either operational, or listed as being associated with a signed interconnection agreement, in the ERCOT Capacity, Demand, and Reserves (CDR) Winter 2010 Update Report are included in all scenarios. Additional generation is included, by scenario, based on input assumptions for each scenario which are described in the following sections. The "Other" category, totaling 4,498 MWs, consists of switchable units, DC ties, biomass, hydro, and available mothballed units included in the 2010 winter update CDR. The generation capacity for the base case is depicted in the following chart:

Figure 3. 2010 ERCOT Region Capacity Portfolio Mix

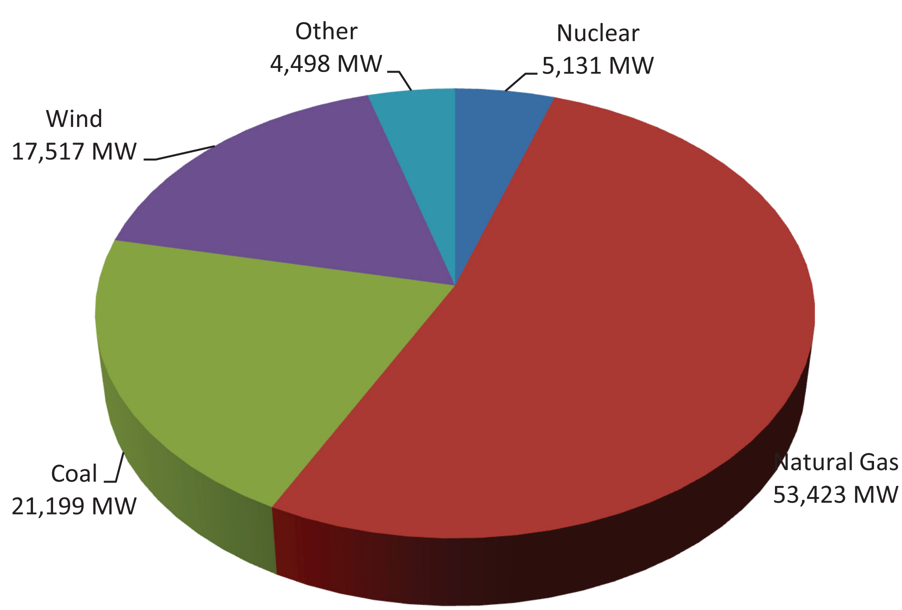


4.1.1 Business As Usual Scenario

The initial scenario evaluated is based on the assumption that market and regulatory conditions in 2020 will be similar to today. Generation expansion for this scenario is expected to continue similar to current expectations, with a mix of gas and coal generation and wind generation. The delivered price of natural gas in this scenario was assumed to be $4/MMBtu and the coal price was $2/MMBtu, similar to current fuel markets.

In this scenario, approximately 8,800 MW of new natural gas generation (made up of combined-cycle and combustion turbine units) were added: 2,600 MW in the Coastal weather zone; 2,700 MW in the North Central weather zone; 450 MW in the Far West weather zone; 800 MW in the South Central; 1,300 Mw in the southern; and 900 MW in the North weather zones. An additional 2,300 MW of supercritical coal units were added to this scenario, with 600 MW in the East weather zone, 600 MW in the South weather zone, and 600 MW in the North Central weather zone. This case includes a total of 17,517 MW of wind generation capacity. All of the additional wind generation units (above the current total of 10,636 MW) are located in the CREZ zones established as part of the PUC docket No. 33672.

Figure 4. 2020 BAU Capacity Portfolio Mix

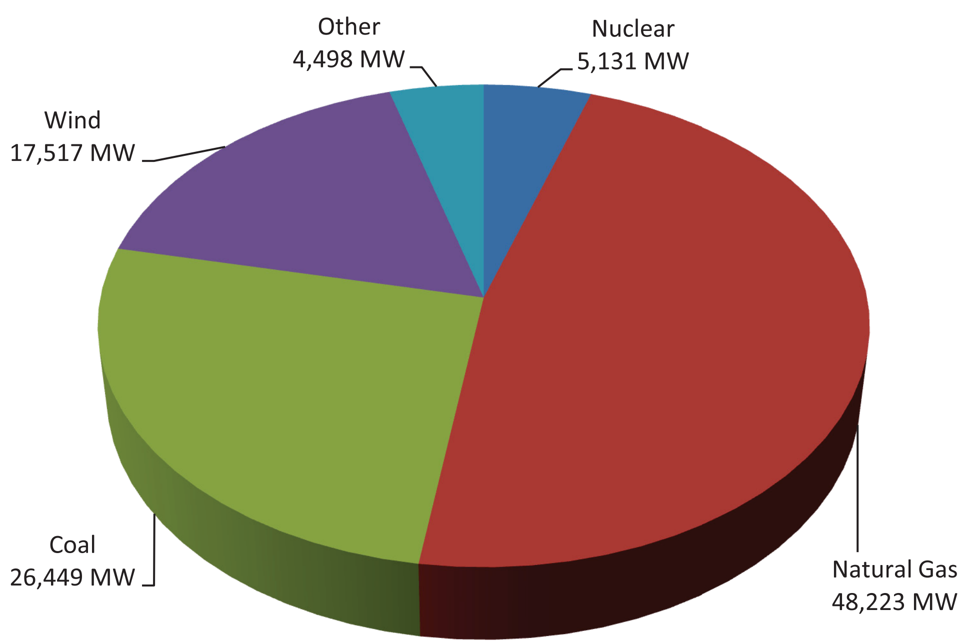


4.1.2 Coal Generation Expansion Scenario

In this scenario, the delivered price for coal is assumed to be $2/MMBtu, while the delivered price of natural gas is assumed to be $8/MMBtu. It is also assumed for this scenario that no additional emission restrictions standards will be enacted. Given these assumptions, a levelized cost analysis using current capital and O&M costs indicates that coal generation will be the most economic. The high natural gas prices also would be expected to drive additional development of wind generation. As a result, this case includes a total of 17,517 MW of wind generation capacity.

For this case, approximately 7,700 MW of coal generation were added: 3,400 MW in the North Central, 1,700 MW in the East, 1,200 MW in the North, and 1,500 MW in the South Central weather zones. Wind generation in this case was included in a similar manner to that of the BAU scenario.

Figure 5. 2020 Coal Generation Expansion Portfolio Mix

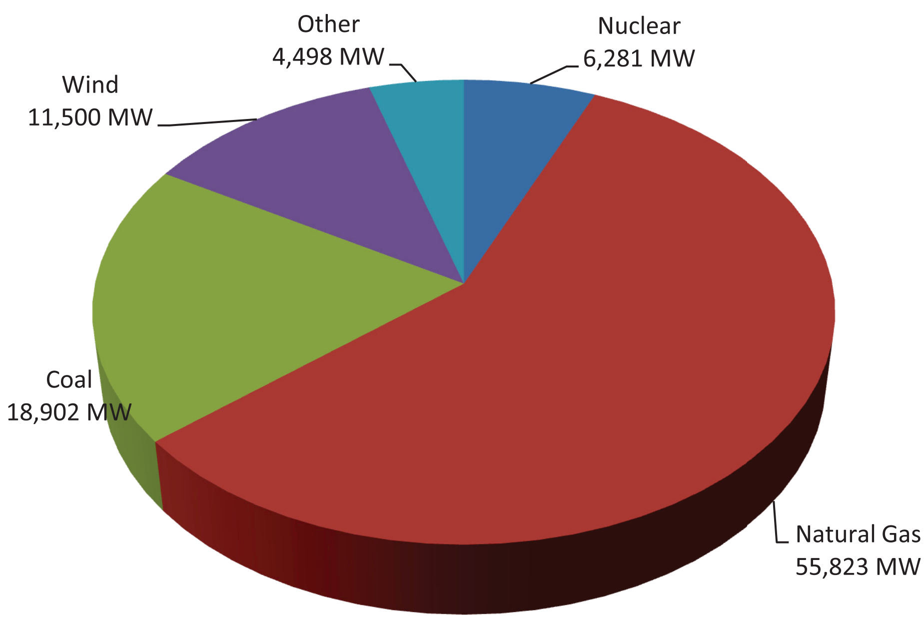


4.1.3 Natural Gas Generation Expansion Scenario

The assumed fuel prices in the same as in the BAU scenario, but the inclusion of a carbon emission allowance cost of $15/ton, along with the expectation of potentially higher future allowance prices results in a generation expansion that consists primarily of natural gas generation. For the purposes of this scenario, the Production Tax Credit is assumed to be retired (the carbon fee can be seen as a replacement for a renewable generation subsidy).

Based on these assumptions, approximately 11,200 MW of natural gas units are added in this scenario: 3,150 MW were added in the Coast; 2,160 MW in the North Central; 450 MW in the Far West; 1,000 MW in the East; 1,300 MW in the South Central; 1900 MW in the southern; and 900 MW in the North weather zones. Wind generation is increased to 11,500 MW from the current 10,636 MW. The additional 900 MW of wind generation were placed at locations in the northern CREZ. Also, one new nuclear unit was added at the South Texas Project facility.

Figure 6. 2020 Natural Gas Generation Expansion Portfolio Mix



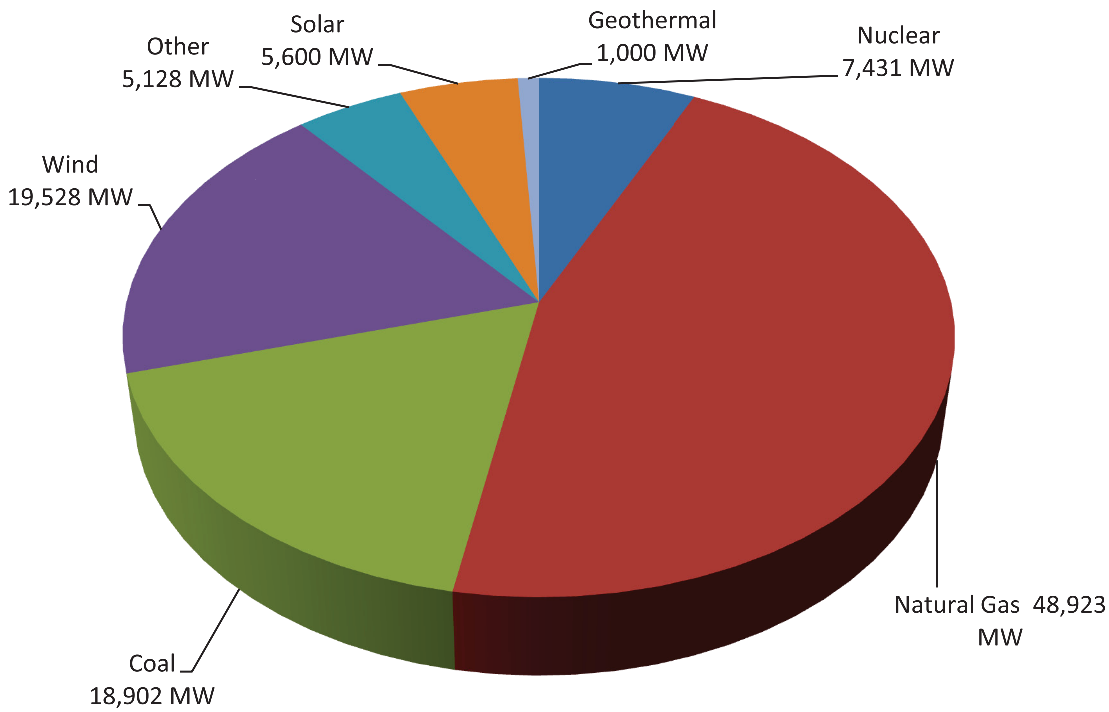
4.1.4 Renewable Generation Expansion Scenario

In this scenario, significantly stricter environmental policies are assumed to lead to a generation expansion consisting entirely of nuclear and renewable generation resources. A carbon tax of $35/ton is included in this scenario, along with an assumed requirement that 25% of annual energy be produced from renewable sources. Generation expansion in this scenario includes South Texas Project (STP) units 3 & 4, 630 MW of biomass generation capacity (sited in the South Central, Coast, and East weather zones); and 1,000 MW of geothermal capacity (60 MW in the West, 120 MW in the East, 240 MW in the Coast, 300 MW in the North Central, and 300 MW in the South Central weather zones). In addition, a total of 19,258 MW of wind generation capacity are included (in the same locations as the BAU scenario, with the additional wind sited in the Coastal zone).

In order to fully determine the potential transmission needs of the ERCOT system, two versions of the renewable generation expansion scenario were evaluated. Each had the generation expansion listed above. However, they differ in the siting of future solar generation projects.

The first renewable scenario includes both solar thermal units (3,000 MW) located in the Far West zone (Pecos, Ector and Upton counties), and solar photovoltaic (PV) units (2,600 MW) located in the urban centers of Dallas, Houston, Austin, and San Antonio. The solar PV units are assumed to be rooftop units installed on commercial/retail buildings and residential locations and or installed as covered parking. The small PV units are aggregated into 50 MW blocks. The second renewable expansion scenario includes only solar thermal units, 5,600 MW of which is located in the Far West weather zone (in Pecos, Ector, Upton, Howard and Borden counties).

Figure 7. 2020 Renewable Energy Production Portfolio Mix



4.2 Other Considerations

A scenario analysis approach is useful in providing a view of potential futures of the ERCOT transmission network. While the probability of any one scenario occurring is not known, by evaluating a range of scenarios, the relationships between potential future occurrences and system needs can be evaluated. However, there are some potential future changes that could affect system needs that are not evaluated as part of this LTSA.

The Environmental Protection Agency has proposed several new regulations that could affect generating units in ERCOT. These include changes to the Maximum Achievable Control Technology (MACT) standard for mercury, acid gases, and other compounds; the Clean Air Transport Rule; revisions to Coal Combustion Residuals regulations, and requirements to use Best Available Technologies to reduce impacts to surface waters from cooling water intake structures. These rules could result in generation unit retirements, or reduce the economic viability of new generation units. In addition, potential changes to non-attainment zones in

ERCOT could have an impact on generation plant siting restrictions. The impacts of these proposed regulations are not included in this study; however, they will be evaluated in upcoming ERCOT studies.

Currently, 59% of the generating capacity in ERCOT is fueled by natural gas. This reliance on natural gas leads to potentially substantial market price increases when natural gas prices rise. As recent market prices indicate, natural gas prices can be volatile – ranging from $3/MMBtu to $13/MMBtu in a short time frame. The impact of volatility of fuel prices is not included in this analysis.

This study did not include an analysis of ancillary service requirements for the high renewables scenarios. As such, it is not known to what extent additional resources may be required to provide sufficient intra-hour ramping and reserve capability to allow integration of the renewable resources contemplated in these scenarios. ERCOT is currently developing new tools that will allow analysis of these ancillary service requirements.

A final consideration is that the deregulated energy-only market in ERCOT provides incentive to investment in new generation through profit inherent in spot market prices and bilateral energy contracts. The scenarios included in this analysis are based on the assumptions that generation investment will be sufficient to maintain the current 13.75% reserve margin target. In theory, reduced reserve margins should lead to increased number of settlement periods with scarcity pricing, which would result in new generation being built. However, this efficient market result may not continuously be achieved over the time frame for which reserve margins are calculated.

The potential impact of insufficient return on investment on generation reserve margins, and resulting potential impact on transmission needs is not evaluated as part of this study. In general, additional generation capacity increases the overall flexibility of the generating fleet, and thus increases the capability of generating units to be redispatched in order to relieve transmission system congestion. Reduced generation reserve margins can lead to a need for more transmission projects to reliably serve loads, as more of the existing generation is required to meet customer demand, and less is available for redispatch.

4.3 Economic Criteria

Economic analysis consists of evaluating the net benefits of transmission projects, and identifying projects that are expected to result in a net overall cost savings to the ERCOT system, i.e., they will result in sufficient cost savings in improved efficiency of system operations to offset the total cost of the transmission project. Cost savings occur when a project allows increased utilization of less expensive generation over more expensive generation.

Economic analysis is performed by simulating system operations using a security-constrained economic dispatch model. For this study, the model UPLAN was utilized. ERCOT maintains a generation database which includes economic and operating characteristics, such as minimum up times, minimum down times, ramp rates, and unit efficiency characteristics for each generating unit in the ERCOT system. For each of the scenarios described in the previous section, a new generation database was developed, one that included the existing generation the additional generation described above. The starting transmission topology was the same for the different scenarios, except for any circuits required to connect additional generation specific to that scenario. The economic model simulates system operations over all hours of a year, serving expected loads in each hour using the lowest-cost combination of generation units while adhering to n-1 transmission security constraints. As output, the model provides information regarding unit operations, transmission line flows, locational market prices (LMPs), and system costs. The merit of a project can be evaluated by comparing production cost before and after adding the project.

Transmission projects that significantly reduce congestion will result in improvements in system efficiency (defined as reductions in overall system production costs). By analyzing system efficiency with and without proposed transmission projects, the benefits of these projects can be compared to the estimated project costs. Projects that are expected to result in greater system efficiency gains than the resulting increase in annual transmission revenue requirements charged to consumers are considered to be cost-effective. Based on previous analysis, average first-year revenue requirements charges for transmission projects in ERCOT are approximately 16.5% of the project's estimated capital cost. As such, a transmission project is considered economic if the expected annual reduction in system production costs (i.e., increase in system efficiency) is greater than 16.5% or approximately 1/6 of the capital cost of the project.

4.4 Economic Projects

In addition to reviewing simulation model output reports for each scenario in order to identify potentially beneficial transmission improvements, several major pre-identified transmission projects were considered in many of the scenarios. These projects were identified through system congestion noted in previous studies, while others were considered following engineering judgment of potential system needs.

Projects evaluated to support continued load growth in the western Williamson County include a new 345-kV circuit from a tap off one of the existing Hutto to Salado double circuits to a new

345-kV bus adjacent to the existing Leander substation (approximately 25 miles). The existing 138-kV Leander substation would be expanded to include a 345-kV/138-kV autotransformer. An alternative project evaluated was a new 345-kV circuit between the CREZ Newton substation and the existing Leander substation (expanded similarly to the previous project).

Expanded import capacity into Houston has been shown to be beneficial in previous LTSAs. Reliability analysis described above indicates a potential need for additional Houston import capacity through under-voltage contingency results and PV analysis. Houston import projects evaluated in this study include: a new 88-mile 345-kV double-circuit transmission line from Salem to Twin Oak Switch; and a new approximately 50-mile 345-kV single-circuit transmission line from Gibbons Creek to Salem.

An upgrade of the circuit connecting the Cagnon and Kendall substations northwest of San Antonio was proposed as a method of reducing congestion resulting from high levels of renewables generation in southwestern Texas. This proposed upgrade included adding a second circuit to the existing single-circuit connecting these substations.

A new 345-kV circuit connecting the Coleto Creek substation with a new substation tapping into the circuit connecting Elm Creek and the South Texas Project (STP) southeast of San Antonio was evaluated as a way to better interconnect new generating resources in the Coastal and Southern zones.

Scenarios that included the addition of 1,710 MW of coastal wind and two new nuclear units at the South Texas Project (STP) indicated the potential for significant congestion on the circuits immediately south of the region between San Antonio and Houston. Projects evaluated to resolve this congestion included upgrades to the circuits connecting STP and Hillje; upgrades to the existing circuits from STP to W. A. Parrish and from W. A. Parrish to BelAir. Another alternative project was upgrading the existing 345-kV circuits from STP to Dow.

Upgrades to the CREZ circuits out of the McCamey area were evaluated as part of the two renewable scenarios. The addition of solar resources in this area indicated a potential need for placing second 345-kV circuits on the single circuit CREZ lines connecting Bakersfield and Big Hill, and from Bakersfield to Odessa - Ector.

4.5 Economic Analysis Results

Few of the projects described above provided sufficient savings in efficiency of system operations to justify the capital expense of the project. Projects that showed sufficient economic value included:

- The Gibbons Creek to Salem was cost-effective in the first Renewable Scenario (with solar resources in both West Texas and in urban areas)
- Several of the proposed improvements near STP were economically justified, or nearly so, for the two renewable scenarios (which included two additional nuclear units at STP).
- The Bakersfield to Big Hill 345-kV upgrade project was economically justified in both of the renewable scenarios, while the Bakersfield to Odessa project was economically justified in the second renewable scenario with additional thermal solar generation

No other economically viable projects were identified as part of this analysis. There are several likely factors that contribute to these results. The first is the recent decrease in the long-term load forecast for the ERCOT region. The recent economic downturn has resulted in lower expectations for near-term load growth. As a result, fewer incremental transmission projects (above those already planned, based on the higher load forecast, for the next five years) are likely to be required. A second factor is the thoroughness of other planning studies conducted at ERCOT, including the planning conducted by the transmission services providers for their individual systems, as well as the Five-Year transmission plan developed by ERCOT and the TSPs. In addition, the LTSA planning effort is focused on long-lead-time, large transmission projects. It is likely that a ten-year horizon is not sufficient to indicate the economic benefits of such projects. Future studies are planned that will include longer time horizons to evaluate the potential impacts on economic planning results.

5. Conclusions

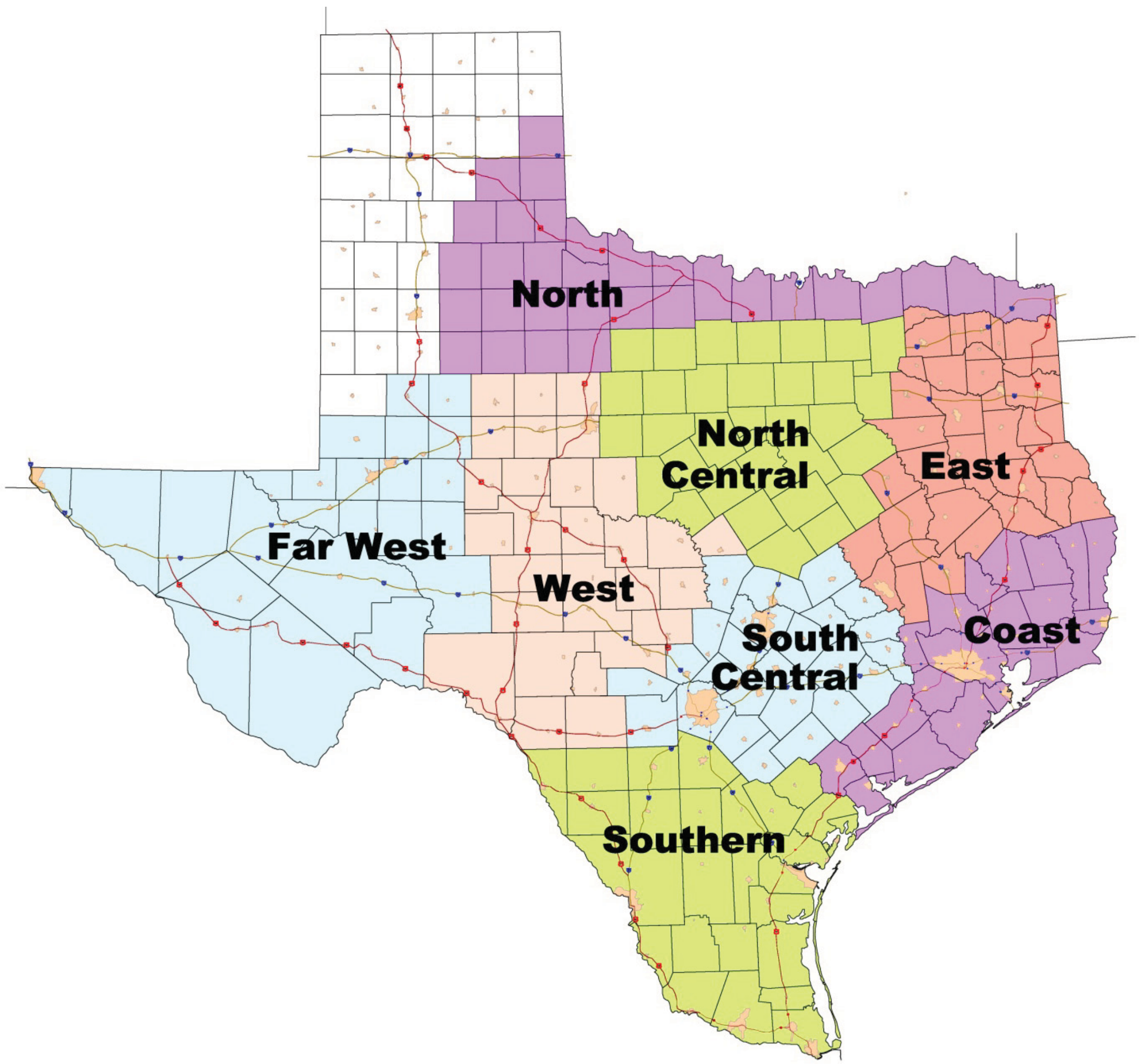
ERCOT has conducted an analysis of the needs of the ERCOT transmission system through the year 2020. Based on this analysis, the following conclusions can be made:

- Numerous transmission system upgrades will be needed, particularly in the DFW and Houston areas, due to expected load growth over the next ten years. These projects are not expected to require long lead times and will be fully evaluated as a part of the five-year transmission plan.
- As with previous LTSA, there is a potential need for new transmission import capacity into the Houston metropolitan area. This need was noted through analysis of under-voltage excursions in steady-state contingency analysis, and through PV analysis. Several projects were analyzed, although the need for and choice of the most cost-effective solution will be dependent upon the amount and location of new generation resources. The installation of dynamic reactive equipment could also delay the need for additional import capacity.
- Load growth in areas north and west of DFW may require additional transmission infrastructure in the next ten years. Specific projects were developed and analyzed in this study in conjunction with the local transmission service provider.
- While certain projects were found to be economically viable in specific future scenarios, no projects were viable across a broad range of future scenarios. This overall result is likely due to reductions in expected future loads due to the lingering impacts of recent economic conditions, as well as the diversity of potential future generation outcomes that may develop.

The above conclusions, and this report in general, are based on high level assumptions and are intended to inform the five-year planning process, which provides a more detailed review of specific transmission projects. The technologies and locations of generation projects assumed in the analyses that support the above conclusions may not reflect all issues that necessarily must be considered and/or affect generation development decisions. Accordingly, this report is intended to provide guidance to ERCOT and ERCOT market participants in evaluating system needs, and is not intended to suggest changes to market policy or support changes to market activities.

Appendix A

Weather Zones in the ERCOT Region



Appendix B

Generation Assumptions for Levelized Cost of Energy Comparison

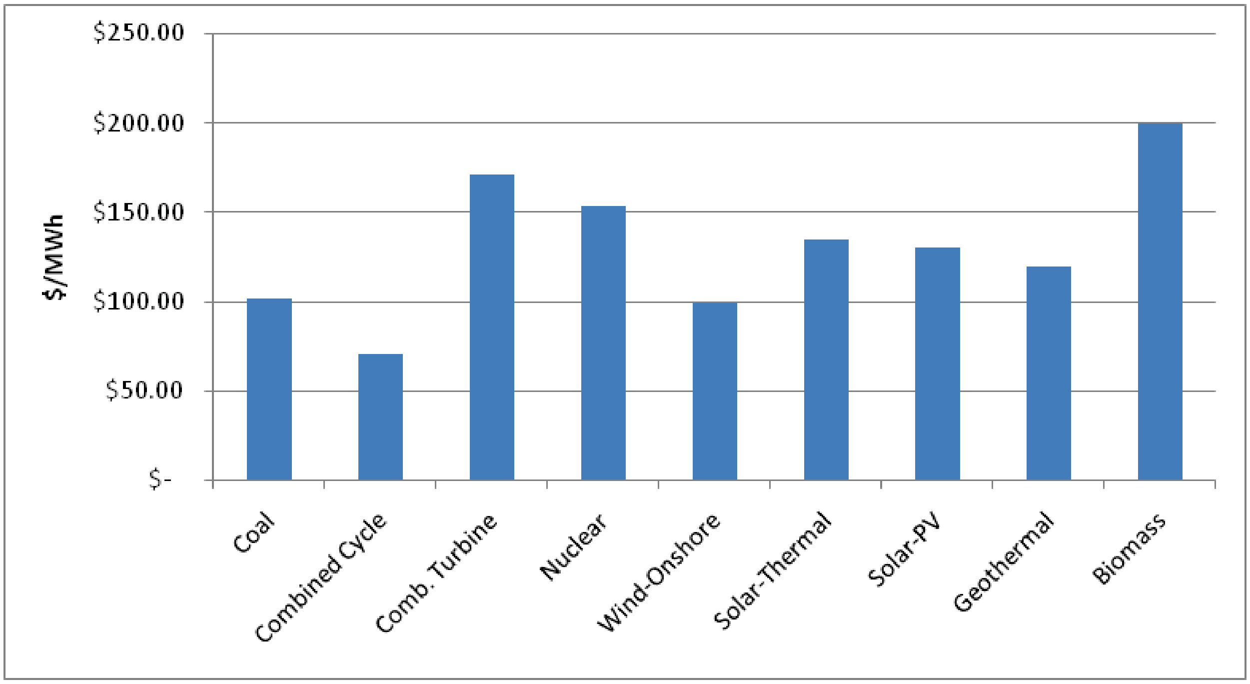
	Coal with CCS	Coal	Combined Cycle	Combustion Turbine	Nuclear
Capacity (MW)	650	650	540	85	1118
Capacity Factor	80%	78%	50%	10%	90%
Heat Rate	12,000	8,800	7,050	10,850	10,488
Debt Ratio	80%	80%	80%	80%	80%
Interest Rate	9%	9%	9%	9%	9%
Capital ($/kW)	$4,582	$2,986	$893	$907	$5,335
Total Capital Cost	$2.9 billion	$1.8 billion	$482.2 million	$77 million	$5.9 billion
Plant Life (yrs)	20	20	20	20	60
Fuel Cost ($/mmbtu)	$2.00	$2.00	$4.00	$4.00	$0.75
Fixed O&M ($/kW)	$76.62	$35.97	$14.39	$14.70	$88.75
Variable O&M ($/MWh)	$9.05	$4.25	$3.43	$6.98	$2.04
Decommissioning	$0	$0	$0	$0	$1 billion

Generation Assumptions for Levelized Cost of Energy Comparison (continued)

	Wind Onshore	**Solar-Thermal**	**Solar-PV**	**Geothermal**	**Biomass**
Capacity (MW)	100	250	50	50	40
Capacity Factor	35%	33%	33%	79%	76%
Heat Rate	0	0	0	10,990	13,000
Debt Ratio	80%	80%	80%	80%	80%
Interest Rate	9%	9%	9%	9%	9%
Capital ($/kW)	$2,332	$4,030	$4,274	$1,749	$3,411
Total Capital Cost	$232.2 million	$1 billion	$213.7 million	$87.4 million	$136.4 million
Plant Life (yrs)	20	20	20	20	20
Fuel Cost ($/mmbtu)	$0	$0	$0	$0	$3.00
Fixed O&M ($/kW)	$28.07	$26.04	$16.70	$84.27	$100.50
Variable O&M ($/MWh)	$0	$0	$0	$9.64	$5.00
Decommissioning	$0	$0	$0	$0	$0

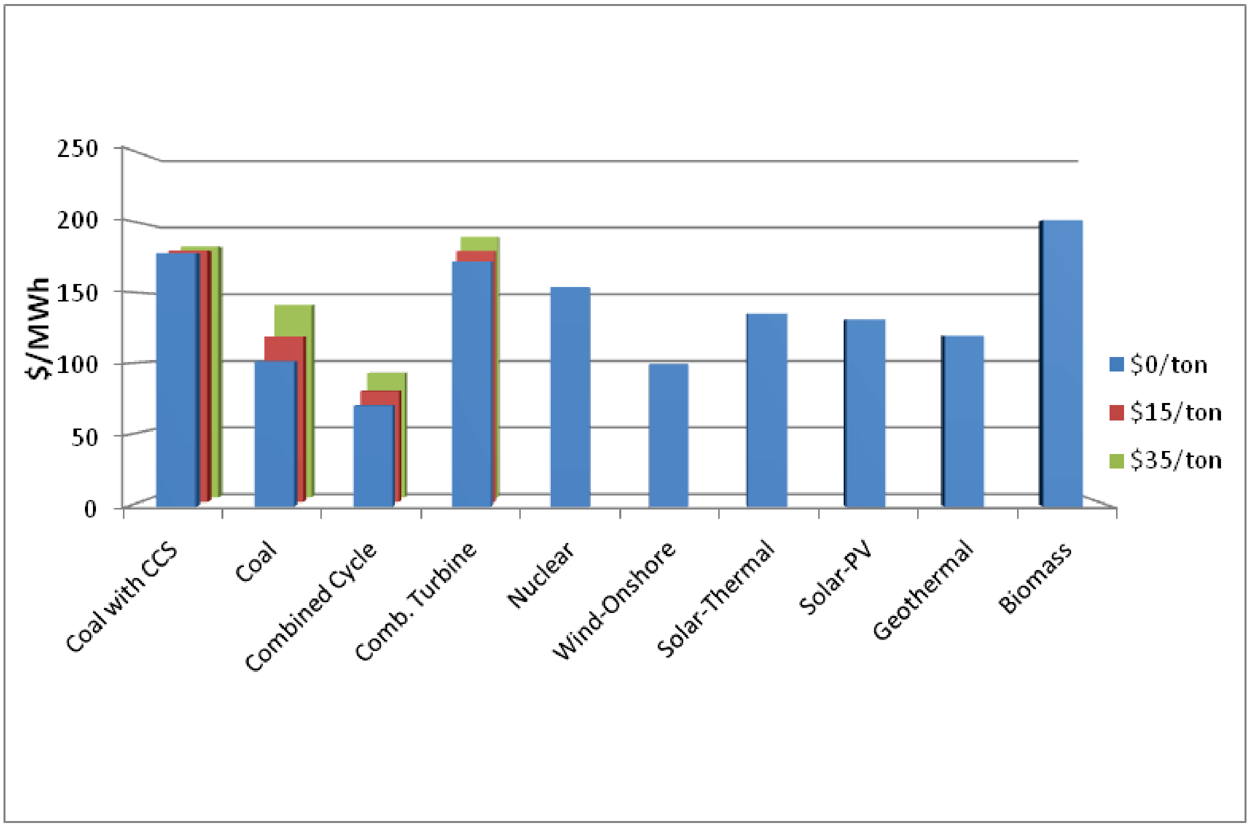
Appendix C

Levelized Cost of Energy Comparison of Generating Technologies



Appendix D

Levelized Cost of Energy Comparison of Generating Technologies: Sensitivity to Carbon Costs



Appendix E

Current Non-Attainment Counties in the ERCOT Region

Brazoria

Chambers

Collin

Dallas

Denton

Ellis

Fort Bend

Galveston

Hardin

Harris

Jefferson

Johnson

Kaufman

Liberty

Montgomery

Orange

Parker

Rockwall

Tarrant

Waller

Potential Future Additional Non-Attainment Counties in the ERCOT Region

El Paso

Smith

Hood

Gregg

Rusk

Travis

Bexar

Source: Texas Commission on Environmental Quality