ERCOT Interconnection

Long-Term Transmission Analysis
2010 – 2030
Interim Report
Volume 2: Technical Process Review

Long-Term Study Task Force
Electric Reliability Council of Texas, Inc.

Topic A and B Phase 1 Report
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1 Introduction

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. By State law, ERCOT is required to conduct a review of generation and transmission needs by the end of each even-numbered year; ERCOT had completed two long-range studies when they applied for the DOE grant. These efforts were limited to 10-year horizons, and included only a small range of potential future scenarios due to limited staff and competing departmental priorities.

The funds obtained from the DOE are being used to augment and enhance the existing long-range planning efforts for the ERCOT region. Approximately two-thirds of the grant funding is intended to increase the technical knowledge and capabilities of ERCOT staff. Specifically, this funding is being used to expand the long-range planning horizon to 20-years; to support evaluation and development of new tools and processes; to develop the capability to analyze a broader range of potential future scenarios; and to incorporate operational reliability considerations into the evaluation of likely future resource options. The remaining grant funding is intended to support 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 provides an interim status update for the study process. It is separated into two volumes. The first volume provides an overall update on the intent of the project, the current status, contributions from stakeholders, and future work expected to be completed by the end of the grant funding in 2013. This second volume provides a detailed description of the tools developed and the technical analysis conducted as part of this study. Initial technical efforts have been focused on acquiring and implementing the foundational tools required to conduct scenario analysis, i.e., to evaluate the economic viability of potential future resource additions given specific assumptions regarding future market conditions, to site these resource additions in potential locations in the transmission grid, and to determine the cost-effectiveness of a variety of potential transmission solutions. These new tools and processes are described in this volume, along with the results of their implementation on an initial “Business as Usual” future scenario, in which current market conditions are expected to continue throughout the next twenty years.

2 Background

2.1 Summary of Work Activities

The intent of this study is to evaluate the long-range transmission needs of the ERCOT system. These needs will change over time due to changes in customer demand and changes in the set of resources available to meet customer demand. Accordingly, the study of transmission needs must begin with a forecast of customer demand, and an evaluation of likely future resource additions.

Specifically, the long-range planning process is envisioned to include the following steps:

1. Determine the types of resources and technologies, and their characteristics and costs, to be included in the study
2. Define specific future scenarios by setting the following input assumptions:
    a. Economic conditions
    b. Capital markets forecasts
    c. Regulatory policies that will affect resource development
    d. Fuel forecasts
    e. Technology development
    f. Resource limitations (e.g. water)
3. Develop forecasts of customer demand for each scenario
4. Use system operations simulations (production cost modeling) to evaluate likely resource additions and potential resource retirements for each scenario
5. Site the identified resource additions in potential locations on the ERCOT system
6. Given the changing customer demand and set of resources, evaluate the cost-effectiveness of different transmission projects that meet system needs.

This volume of the Interim Report provides a description of the tools and processes that have been developed to date to accomplish the tasks listed above. Most of these steps are addressed in this report. Steps that require additional work are discussed in the last section of the report.

The desired end-result of this analysis is both a better understanding of the long-range transmission needs of the ERCOT interconnection and full implementation of a suite of new tools and processes that can be used on a continuing basis to analyze transmission needs.

2.2 Current ERCOT System

The ERCOT grid consists of approximately 550 generating units, connected to customer distribution systems by a network of 69-kiloVolt (kV), 138-kV and 345-kV transmission circuits. The ERCOT grid contains approximately 75% of the land area of Texas, and approximately 85%

of the electricity usage. It includes the major load centers of Dallas/Fort Worth (DFW), Houston and San Antonio. The hourly peak load of 65,776 megawatts (MW) was recorded on August 23, 2010.

Figure 1: Summary of ERCOT Generation Capacity

ERCOT Region	Natural Gas	Coal	Nuclear	Wind	Other	Total
North	17,242 MW	9,597 MW	2,407 MW	293 MW	175 MW	29,714 MW
South	14,021 MW	6,057 MW	2,724 MW	1,216 MW	464 MW	24,482 MW
West	3,162 MW	650 MW	-	7,943 MW	-	11,755 MW
Houston	12,834 MW	2,470 MW	-	-	40 MW	16,344 MW
Total	**47,259 MW**	**18,774 MW**	**5,131 MW**	**9,452 MW**	**679 MW**	**81,295 MW**

Notes: Other resources include hydro, biomass, and landfill gas generation

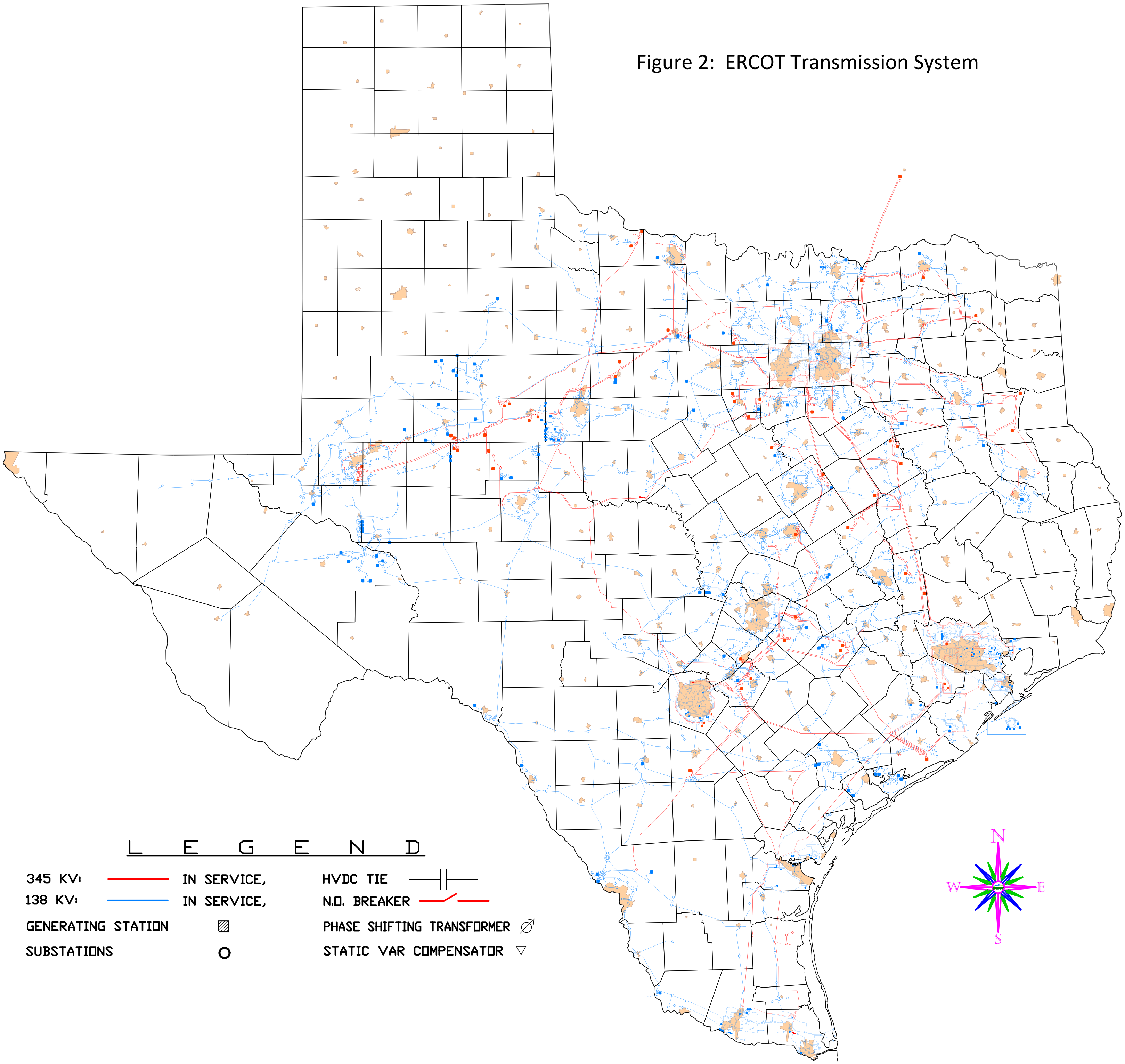
Natural gas capacity includes private-use network generation and switchable units

Wind generation is listed at nameplate capacity

Figure 2 on the following page depicts the ERCOT transmission system.

A list of references is provided in Appendix A, and a glossary of terms used in this report is provided in Appendix B.

Figure 2: ERCOT Transmission System



3 Analysis of Existing and Emerging Technologies

An initial task in this long-range planning effort was a review of existing and emerging technologies. Capturing the potential for system changes resulting from advances in technologies is a key component of the long-range study process. The information obtained from this effort is being used by ERCOT and stakeholders to select which technologies to include in future scenarios and to evaluate the potential impact of these new technologies on the ERCOT system. The following section provides a summary of some of the technologies that have been evaluated to date. Additional technologies will be reviewed as the study progresses based on discussions with stakeholders.

3.1 Generation Technologies

3.1.1 Combined-Cycle Gas Turbine

In a combined-cycle (CC) generating unit (also known as a combined-cycle gas turbine unit) a gas turbine generator is used to generate electricity and heat. This heat is captured in a heat recovery steam generator (HRSG), and the resulting steam is used to generate additional electricity via a steam turbine. Combined-cycle technologies are 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 HRSG's to power a single steam turbine. The total capacity of the combined cycle plant will depend 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.

To increase output, some combined cycle plants are designed with supplemental gas firing (or duct firing) in the HRSG. The additional burners allow the HRSGs to produce more steam, which increases the output of the steam turbine. Duct firing provides efficient peak energy at a low capital cost.

3.1.2 Simple-Cycle Turbine

The simple-cycle gas turbine, also known as a combustion turbine, is used in a variety of industries, including power generation, oil and gas facilities, process plants, and aviation. The compressor, combustor, and turbine modules connected by one or more shafts are collectively called the gas generator. A gas turbine collects the air into the compressor module and combines with fuel; this combined vapor is then ignited. The resulting gases are expanded through a turbine. In the turbine, the expanding gases are directed through a nozzle over the turbine's blades. A separate starter unit is used to provide 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.

3.1.3 Coal Gasification-IGCC

Gasification can be used to decompose coal or virtually any carbon-based fuel into its 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, molecules in coal 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. Gasification of coal can be used to 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.

3.1.4 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) has defined the ultra-supercritical steam cycle as a steam cycle with an operating pressure exceeding 3,600 pounds per square inch (psi) and main superheat steam temperature above 1,100°F. Current subcritical and supercritical boiler designs with full environmental controls typically yield efficiencies in the range of 35 percent and 40 percent, with supercritical units at the upper end of range. Ultra-supercritical plants may be able to achieve efficiencies of as much as 45 percent. This equates to heat rates of approximately 7500 Btu/kWh.

3.1.5 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 (PWR) and Boiling Water Reactor (BWR). In a PWR, water flowing through the reactor is isolated (physically, not thermally) from the water vapor going through the turbine. In a BWR, the same water heated by the reactor travels through the turbine. New designs, such as modular reactors and light-water 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).

3.1.6 Combined Heat and Power

Combined Heat and Power (CHP), also known as cogeneration, is a term used to designate the simultaneous generation of multiple forms of useful energy in a single, integrated system. CHP systems consist of a number of individual components, such as a prime mover (heat engine), generator, heat recovery, and electrical interconnection. By using the energy from the fuel used in the prime mover for a number of different purposes, high levels of fuel efficiency are achieved. Prime movers for CHP systems include reciprocating engines, combustion turbines, steam turbines, micro-turbines, and fuel cells. Mechanical energy from the prime mover can be used to drive a generator to produce electricity or to drive rotating equipment such as compressors, pumps and fans. Thermal energy from the system can be used directly in process applications or indirectly to produce steam, hot water, hot air for drying or chilled water for process cooling. The capacity of CHP systems can range from as low as 5 kW to several hundred megawatts.

3.1.7 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 Type I and 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): This turbine was superior to Type I turbines because it operated at variable blade speed, allowing it to capture wind energy more efficiently at lower wind speeds. Like Type I turbines, this turbine has no reactive power control but 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 is able to achieve variable speed and is capable of 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 is able to offer the same features as Type III turbine, namely variable speed and sophisticated reactive power control. Because the generator is completely isolated from the grid by the inverter, 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 is 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 is directly connected 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.

3.1.8 Solar Photovoltaic

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

3.1.9 Solar Thermal

Solar thermal technologies convert 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 Sterling system, where a parabolic dish transfers heat directly to a small engine located at the dish's focal point. The small Sterling 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 which 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 which reflect sunlight onto a single collection tower. Tower collector technologies have the potential to achieve higher thermal efficiencies than trough collectors due to the higher temperatures and reduced transfer losses. The Sterling system typically uses a Heliostat dish receiver as its collector.

3.1.10 Geothermal

There are four basic types of geothermal reservoirs. Hydrothermal geothermal resources are composed of hot water and/or steam that are found 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 and found in large, deep aquifers that are under higher pressure due to water trapped in the burial process. These resources are often found in sedimentary strata depths of 3-6 km. Hot dry rock (HDR) resources are heated geological formations formed in the manner of hydrothermal resources, but containing no water due to the absence of aquifers or fractures required to transport water. The deeper interior of the earth is in molten form. As molten rock is found at depths of 3 - 10 km, it is not easily accessible.

Research performed by Southern Methodist University (SMU) and Massachusetts Institute of Technology (MIT) show that binary-cycle plants may be appropriate for the geo-pressured resources prevalent in Texas. Using this process, the geothermal fluid is brought to the surface and passed through a heat exchanger. The secondary fluid in the heat exchange system is a fluid with a lower boiling point than water, such as isobutene, pentane or ammonia. This secondary fluid is vaporized and passed through the 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.

3.1.11 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, bio-mass generation potential will depend on technology advances and on competition for feedstock use and with 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.

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.

3.1.12 Fuel Cells

Fuel Cells generate electricity through an electro-chemical reaction in which oxygen and fuel combine to form water. A fuel-cell stack is composed of a number of individual cells. Fuel cells are classified according to the nature of the electrolyte used. The main types of fuel cells are: proton exchange membrane, direct methanol, alkaline, phosphoric acid, molten carbonate, and solid-oxide.

3.1.13 Distributed Generation

Distributed generation (DG) facilities are small generation units that are typically connected to the distribution system, rather than to the transmission network. Distributed generation technologies include: internal combustion engines; small gas turbine generators; microturbines; fuel cells, as well as variable generation such as wind and solar.

3.2 Storage Technologies

3.2.1 Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) uses stored energy in compressed air to assist in the operation of a gas turbine. Electric energy is used to charge the 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.

3.2.2 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.

3.2.3 Flywheel

A flywheel is a mechanical device that converts electrical energy into rotational energy and vice versa. In a flywheel, the inertia of a rotating mass inside a vacuum-sealed housing is used to store energy. To charge the flywheel, pulses of electrical current are fed to stator windings and the resulting magnetic fields cause the mass to rotate. When the voltage supplied to the flywheel drops below a preset value, the flywheel discharges energy to maintain that voltage. The flywheel will absorb energy when the voltage rises above the pre-set value, also maintaining voltage at the desired level. Similar to batteries, flywheels can balance fluctuations by providing fast frequency regulation response. Flywheels can typically be charged to full capacity more quickly than batteries (often in just minutes).

3.3 Load Modifying Technologies

3.3.1 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 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.

3.3.2 Energy Efficiency

Energy Efficiency (EE) is a term used to describe 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.

3.3.3 Electric Vehicles

Plug-in Hybrid Electric Vehicles (PHEVs) are similar to 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. Since they have no back up gas engine when the battery is depleted of its charge, their use is currently limited to areas in which charging locations are available.

As PEV and PHEV’s have significant energy storage capability (up to 24 KWh), they may become an integral part of the distribution system, providing storage, emergency energy supply, and supporting grid stability. Development of these types of Vehicle-to-Grid (V2G) programs is currently being researched.

4 Scenario Development

The second task listed in Section 2 is the development of future scenarios. Scenario planning is a strategic planning process used to create more flexible long-term plans. It combines many complex and sometimes divergent factors in ways that can result in futures that may not be intuitive. The scenario approach used in this study will allow planners to evaluate many plausible alternative futures that effectively bracket future outcomes rather than seeking a single preferred alternative.

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 makes it nearly impossible to predict with certainty how the electric system will change over the next ten or twenty years. As such, it is important 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. It should be mentioned that the results from the scenarios developed as part of this effort are not definitive statements of what will happen but more highlighting implications of what might happen based on the assumptions and methodologies used within this study.

4.1 Review of Published Studies

It is the goal of this long-term study to provide insights into what the needs of the ERCOT transmission system could be under various market-simulated conditions. To achieve this goal, the stakeholders in the Long-Term Study Task Force will be asked to develop specific future scenarios, each with a complete set of defined assumptions. In order to assist with this development, ERCOT researched various energy outlooks published during the summer and early fall of 2010 from the Energy Information Administration (EIA), International Energy Agency (IEA), Shell, and ExxonMobil. Each of these organizations analyzed a variety of current and future policies and market trends.

The EIA utilizes a form of scenario development to make their projections through 2035 in their Annual Energy Outlook (AEO) published in April 2010. EIA creates a "Reference Case" as a starting point for their analysis. Additional cases are developed as a way to understand how various assumptions have an impact on the results by comparing them to the results of the Reference Case. The EIA AEO 2010 focuses on Low and High Economic Growth cases and Low and High Oil Price cases, with multiple cases that include varying technological advancements which highlight the uncertainty in the Reference Case assumptions.

EIA's Reference Case projections are based on Federal, State, and local laws and regulations in effect as of the end of October, 2009. The Reference Case assumes that current laws and regulations are maintained through the time period studied. The projections from the Reference Case can be used as a baseline to analyze policy initiatives. The projections in the EIA Annual Energy Outlook 2010 (AEO 2010) are business-as-usual trend estimates which reflect known technology and technological and demographic trends. The Low and High Economic Growth cases are designed to examine the impacts of these alternative assumptions on the economy. The Low and High Economic Growth cases contain lower and high growth rates, respectively, in the following indicators: real GDP, labor force, nonfarm employment, and labor productivity.

The other alternate scenarios, the Low and High Oil Price cases, alter the availability and thus price of a broad range of low-sulfur, light crude oil delivered to Cushing, Oklahoma, to reflect the inherent volatility and uncertainty of world oil prices. The Low Oil Price case shows a future oil market where non-OPEC producing countries develop stable fiscal policies and investment strategies that encourage the development of their resources. The High Oil Price case reflects conventional production being restricted by political decisions and economic access to resources. Other sensitivities included with the AEO 2010 include changes to reflect various technological advancements regarding the transportation industry, residential and commercial categories, capital costs for electric generating plants (both conventional and renewable), drilling policies in both the oil and natural gas industries, and combinations of these factors.

The IEA creates an annual World Energy Outlook which looks ahead 25 years across many different energy indicators, specifically focusing on energy demand and supply, related carbon-dioxide (CO_2) emissions and investment requirements to meet the various emission mitigation levels. Although the EIA Annual Energy Outlook mentions interactions between countries, its focus is the impact to the energy industry in the United States. In contrast, the IEA's World Energy Outlook presents a bigger picture view, focusing on many individual economies and their individual impacts on the global energy outlook.

The 2010 World Energy Outlook includes three scenarios. The first scenario is the New Policies Scenario, which the IEA considers their central scenario. It includes in its assumptions many of the environmental or energy-security policy commitments and plans that have been announced by countries, even if the levels or exact details of the actions have yet to be determined. This particular scenario does not assume all policies reach full implementation by 2035; however for the policies with limited detailed action plans, IEA assigns a set of cautious interpretations and implementation rates. Countries that established a specified target or target range are assumed to adopt policies consistent with the most aggressive end of the range. It should be noted that the majority of the policies mentioned in the World Energy Outlook 2010 are for the period up to 2020; additional policies are assumed from 2020 to 2035 to maintain the pace of declining carbon intensity on a global scale.

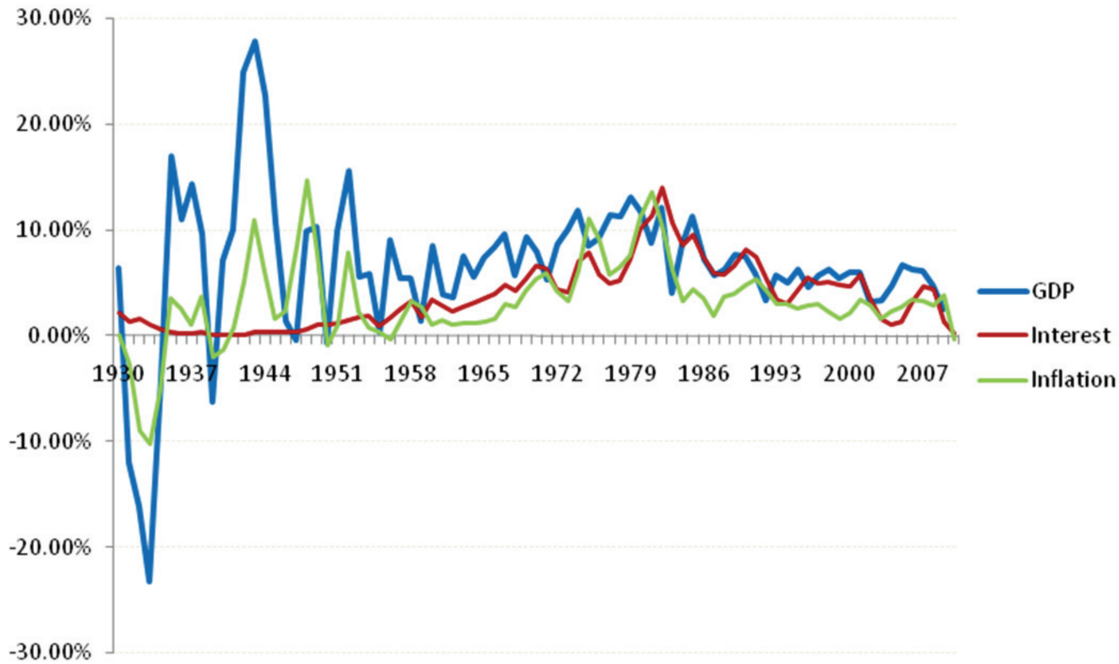
The second scenario evaluated by IEA, the Current Policies Scenario, represents a future in which policies currently in effect will remain as written. This scenario is intended of serve as a baseline to measure the impact of new policies. Any environmental policy enacted by the middle of 2010 was included in this scenario. The third scenario is the 450 Scenario, where fossil-fueled subsidies are completely phased out by 2020 in all net-importing countries and in all net-exporting countries by 2035, except the Middle East where the subsidization rate declines to 20% by 2035. The basis for the 450 Scenario is the expectation of a 2°C increase in global temperature resulting in a global effort to reduce greenhouse gases in the atmosphere to 450 parts per million (ppm) of carbon dioxide equivalent.

For their future studies, Shell International BV created two energy scenarios that look into the future through 2050. The first scenario is called Scramble and embodies political pressure driving energy security for the future. In this scenario government attention focuses on supply-side actions, including the negotiation of bilateral agreements and incentives for local resource development. Demand-side policies are not addressed in this scenario and no environmental policy changes are assumed until major climate events occur. By contrast, in the second scenario, Blueprints, the focus is on new local coalitions pressuring national government bodies to make significant environmental policy changes. Together, Scramble and Blueprints lay out the landscape of possibilities, constraints, opportunities, and choices for today and the future.

Future scenario analysis conducted by ExxonMobil is documented in Outlook for Energy: A View to 2030. This review uses a world economic outlook as its foundation, making the assumption that economic activity is a fundamental driver of energy demand. However, it does not include an evaluation of expected gains in energy efficiency to reduce the projected energy-demand growth rate below global GDP growth. Exxon's outlook focuses on an optimistic view of the future and discusses resulting energy supply and demand, technological advancements, increase in electricity needs, and the need for environmental policies within the discussion of future of energy needs.

ERCOT also reviewed historical data from EIA and the BP Statistical Review of World Energy 2010 to develop an understanding of national and global historical trends and relationships. This evaluation included review of historical production and consumption 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. The following graph depicts growth of gross domestic product (GDP), as well as interest and inflation rates since 1930.

Figure 3: U.S. Economic Indicators: GDP Growth, Interest, and Inflation Rates



Source: Bureau of Economic Analysis – U. S. Department of Commerce

4.2 Stakeholder Activities

Members of the Long Term Study Task Force, and its subgroup, the Scenario Development Working Group (SDWG), have been working since June 2010 to define specific future scenarios for this study. In discussions with the SDWG, ERCOT staff presented historical information to provide an understanding of the relationship between economic indicators and memorable events (such as the energy crisis in 1979, which led to high inflation and low GDP rates in the early 1980s). ERCOT also presented key concepts from the studies described in the previous section.

After numerous discussions, the Long Term Study Task Force developed specific parameters to be included in the scenario development process. These parameters range from policy considerations, economic assumptions, load growth modifiers, technology impacts, and fuel prices and availability. For each scenario, a specific assumption will be developed for each parameter.

Policy considerations to be included in future scenarios include environmental regulations, renewable mandates, and requirements that affect the siting of specific generating technologies. Environmental regulations include potential greenhouse gas emissions limits, as well as requirements currently pending for reductions in emissions of hazardous and criteria air pollutants.

Load growth rates will be evaluated for each future scenario, as will load modifiers such as energy efficiency programs, demand response, and electric vehicles. Fuel prices will be considered as well. A current list of parameters, as well as initial scenarios, is provided in Appendix C.

4.3 Load Forecast Development

Load forecasts for the long-term study scenarios are provided by the ERCOT Load Forecasting group using the ERCOT long-term forecasting process. The long-term forecast is developed using a set of econometric models describing the hourly load in the region as a function of certain economic and weather variables. Economic and demographic data, including a county-level forecast, are obtained on a monthly basis from Moody's Economy.com. In addition, 15 years of weather data are provided by Telvent for 20 weather stations in ERCOT. The data provided by these vendors under contract with ERCOT are used as input variables to the energy and demand forecast models.

The ERCOT region consists of eight distinct weather zones. Each county within the ERCOT region is assigned to a weather zone. At least two weather stations, located within each weather zone, are used to provide weather data that is representative of the particular weather zone. The primary economic variable used to forecast load growth is non-farm employment. Previous analyses have indicated that this parameter is sufficient to characterize load growth due to economic activity in the ERCOT region.

Independent models are created for each weather zone. Two different models are employed in the forecasting process: a monthly energy model and an hourly energy model.

The monthly energy models are linear regression models that utilize average temperature data from the corresponding weather stations in the weather zone and non-farm employment data from the corresponding counties in the weather zone as variables to forecast the monthly energy of the weather zone.

The hourly energy models are a collection of neural network models that were developed for each weather zone, for each day-type, for each hour. Day types are Saturday, Sunday or holidays, and weekdays excluding holidays. The neural network forecasts the fraction of energy to be allocated to each hour within a month. The hourly energy model is based on:

1. Sunset time,
2. Current day's maximum and minimum temperatures,
3. Previous day's maximum and minimum temperatures,
4. Current day's temperatures at 7 a.m., noon, and 7 p.m,
5. Hourly fraction of the prior hour, and
6. Average monthly temperature.

Multiplying the weather zone's hourly fraction times the weather zone's forecasted energy for the month produces the hourly energy forecast for each Weather Zone. The eight weather zone forecasts are summed to create the ERCOT hourly load forecast.

Figure 4 shows the historical peak demands for 2002 through 2010 and peak demand forecasts for 2011 through 2031 using the base economic data from Moody's. The historical compound growth rate for 2002 to 2010 was approximately 2.0%. The forecasted compound growth rate for 2011 to 2031 is approximately 1.8%.

Figure 4: Historical and Forecast Summer Peak Demand

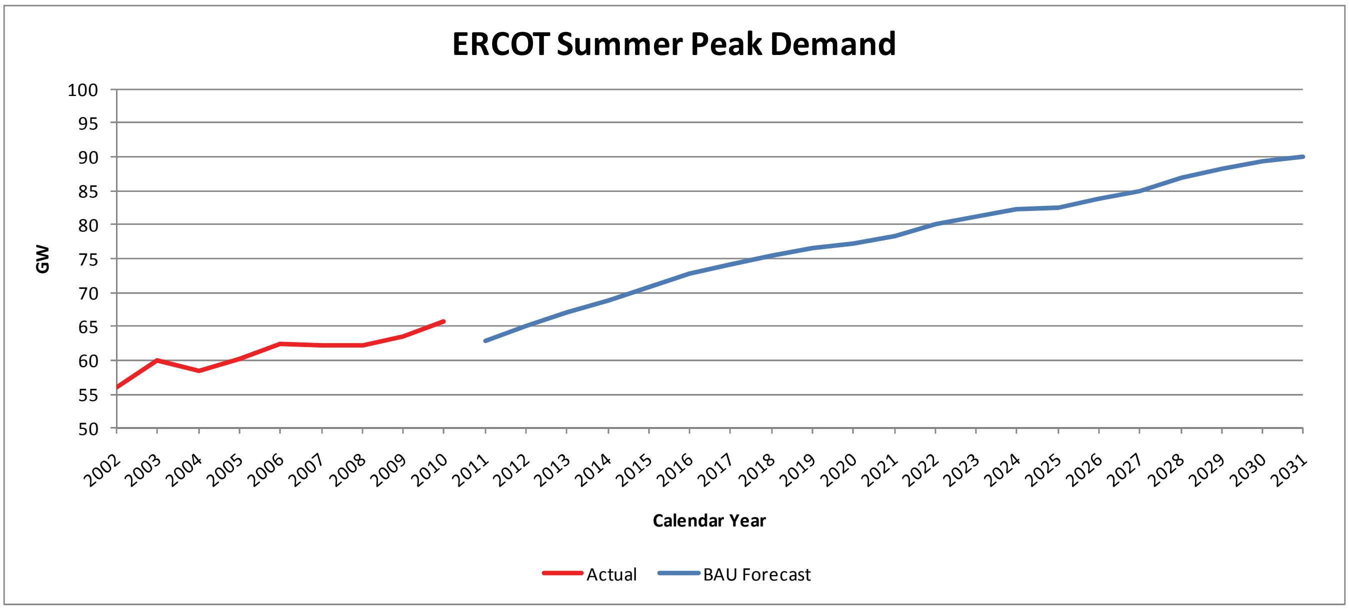
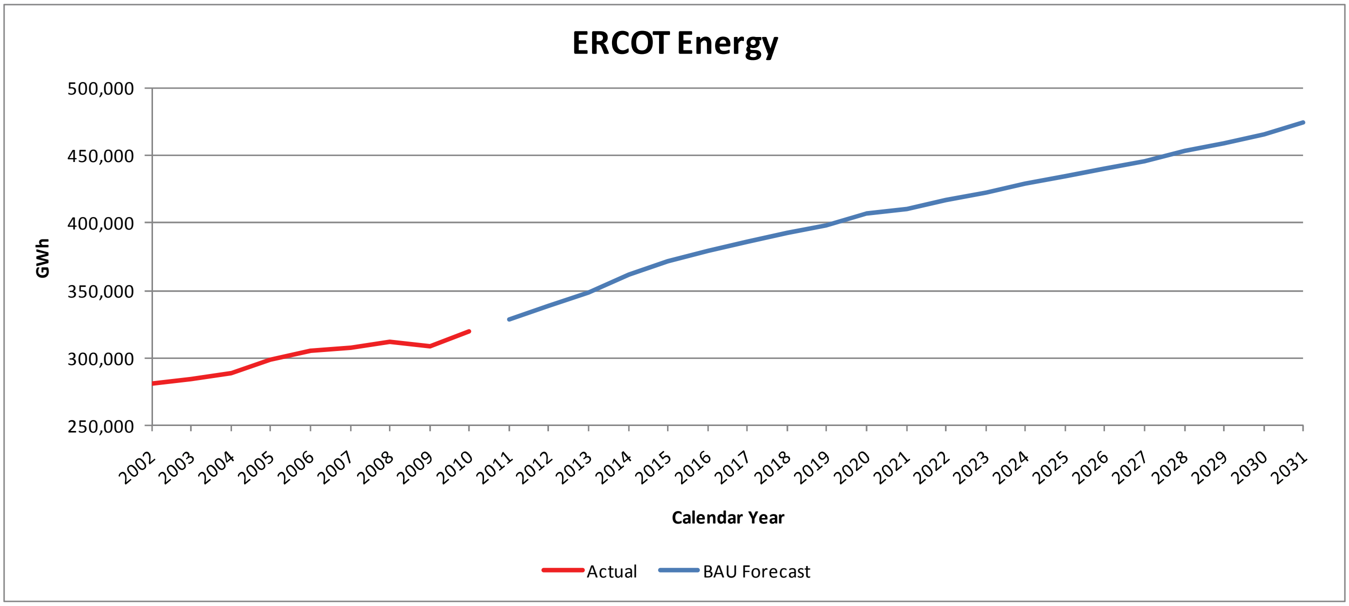


Figure 5 shows the historical energy for 2002 through 2010 and energy forecasts for 2011 through 2031 using the base economic data from Moody's. The historical compound growth rate for 2002 to 2010 was approximately 1.6%. The forecasted compound growth rate for 2011 to 2031 is approximately 1.8%.

Figure 5: Historical and Forecast Energy (GWh)



Fifteen years of weather data are available from Telvent for twenty weather stations in ERCOT. Data from these weather stations were input into in the hourly energy models and the model shapes were compared to the actual load shapes from 2002 – 2010. The hourly energy results from the model closely reflected the actual load shape during this historical timeframe.

This base forecast does not include any significant demand impacts due to energy efficiency, demand response, and plug-in electric vehicles over the levels which were observed during the historical time period (2002 – 2010). Separate models and scenario assumptions will need to be developed in order to reflect the demand and energy impacts attributable to these issues.

4.4 Business as Usual Scenario

In order to have a point of reference for the selection of other future scenarios and to evaluate the effectiveness of the tools described in this report, the Long-Term Study Task Force requested that ERCOT create a Business as Usual (BAU) scenario. This BAU scenario was developed to be consistent with the EIA AEO 2011 Reference Case. The BAU is based on the assumption that current policies and regulations will remain, and no new policies will be introduced. Commodity prices (crude oil, natural gas, and coal) were obtained from the EIA AEO 2011 Reference case (these parameters are provided in Appendix D). The load forecast was developed using the ERCOT long-term load forecast model, based on Moody's base economic data and an average weather year, as described in the previous section.

The BAU scenario was evaluated with and without the continuation of the Federal renewable energy Production Tax Credit (PTC), and with a high natural gas price. The PTC is a tax credit of approximately \$20/MWH that can be applied to some renewable energy projects within the first 10 years of operations. This tax credit is scheduled to expire in 2012, but can be extended by act of Congress. In the high natural gas price sensitivity, the price of natural gas is increased by \$5.00/MMBtu for all years.

It should be noted that this analysis represents the first steps of the analysis of future scenarios for the ERCOT region. It is vital for the Long-Term Study Task Force to settle on a set of scenarios that effectively span the potential futures so that the possible transmission needs of the ERCOT system can be evaluated.

5 Resource Expansion Analysis

5.1 Resource Expansion Tools

The next step in analyzing the transmission needs of the ERCOT system is the analysis of likely resource additions. Given peak load increases over time, new resources will need to be developed in order to maintain system reliability. These new resources are likely to be more efficient than existing generation, possibly resulting in some retirements of existing generation. In turn, this will cause a need for additional new resources to be developed. The following is a description of the tools that have been acquired and developed to conduct resource expansion analysis for the long-term study, as well as initial results for the BAU scenario.

The intent of the resource expansion process is to develop outcomes consistent with the deregulated energy market in ERCOT. The underlying assumption is that individual investors will evaluate market conditions and will base their investment decisions on the expected market return of investments in their portfolio. The purpose of this expansion process is not to develop an optimal mix of resource additions. Rather it is to capture as closely as possible the market conditions that are apparent to a specific generating resource and to add resources that appear to be economically viable in that they will provide adequate return on investment. To identify tools that will allow 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 PowerBase, PROMOD IV and MarketPower from Ventyx. To complement this suite of software tools, ERCOT developed a pro-forma financial spreadsheet to measure the financial return on investment of expansion resources.

PowerBase functions as the data management software for PROMOD IV and MarketPower. PowerBase provides the ability to gather, maintain and manage data that is shared between PROMOD IV and MarketPower. All generator characteristics, such as heat rate, capacity, ramp rates, operating costs, fuel assignments, etc., are maintained within this database. In addition, all information regarding load, transmission lines and buses are contained in the PowerBase database. The ability for both PROMOD IV and MarketPower to utilize the same database allows for easy exchange of data as well as ensuring the consistency of the output of the two models.

PROMOD IV is an hourly dispatch model that provides unit specific operation and production cost values given user defined inputs (e.g. load, transmission constraints, fuel costs, etc). PROMOD IV performs a security-constrained unit commitment and economic dispatch that is co-optimized with operating reserve requirements. PROMOD IV 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. 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.

MarketPower is a long-term generation expansion modeling platform that performs a quick economic analysis based on user-defined input assumptions. MarketPower starts with the database of existing resources built in PowerBase and determines how much capacity is needed to service a user-defined reserve margin and load forecast.

The simulation in MarketPower provides the ability to create market-based expansion plans based on various input assumptions. The modeling platform is aware of the marginal costs of all generating resources in the market, which is critical to determining the trend of locational marginal prices (LMPs). Generating units considered for expansion are considered “prototypes” in MarketPower. The prototype units have generic operational characteristics according to the resource technology categories built for this study. These categories can be found in Appendix D. In addition to operational characteristics, the prototype units also have capital cost and investment assumptions. The characteristics of the categories are specified in the baseline model section of this report.

MarketPower determines the 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. MarketPower determines expected operating levels using the operational characteristics entered into the PowerBase database. The market revenues are forecasted using the energy bid price of the marginal unit by hour, which is used as the market clearing price for that hour. Both forced and maintenance outages are considered when determining the marginal unit. To determine a unit’s revenue stream, MarketPower will sum all of the hourly energy generated by that unit and multiply it by the hourly market clearing price to determine the annual generator revenue. The costs associated with adding prototype units are determined using the operational costs listed in the database (fixed and variable operation and maintenance costs, fuel costs, and start costs). The annual value of these costs is dependent on the expected operating levels used in the MarketPower simulation. Included in the fixed operation and maintenance costs are the capital cost for the prototype for the year being simulated. This allows MarketPower to determine all of the costs in any given year that a generator owner will need to obtain in revenue to maintain project viability. The annual capital cost is calculated using the following variables associated with the project: total investment cost, economic life, escalation rate of construction costs, terminal value, and desired rate of return.

MarketPower uses screening curves to determine which prototype units are the most cost-effective to build in the year being simulated. The total fixed costs (fixed operation and maintenance plus capital cost) and total energy costs (variable operation and maintenance plus fuel cost) are divided by the firm capacity (specified in the PowerBase database) to determine average fixed and variable costs for the prototype unit and the costs are expressed in $/kW-year. MarketPower then calculates a crossover capacity factor between two prototypes, to determine which prototype is the most cost effective to build in the year being simulated. The crossover capacity factor is the difference in average fixed costs divided by the difference in average variable costs between the two prototypes. This comparison is conducted at the beginning of each year for all prototypes to determine the minimum capacity factor for which one of the proposed prototype units is the most cost effective. Prototypes resulting in a negative crossover capacity factor, meaning both average fixed and average variable costs are higher than an alternative prototype, will not be considered for that simulation in that year.

The final tool used in the generation expansion process is a pro-forma financial spreadsheet developed by ERCOT. The pro-forma financial spreadsheet provides an external analysis to compare the PROMOD IV operational results and the expansion build out suggested by MarketPower. The pro-forma spreadsheet developed with specific financing assumptions (debt/equity ratio, cost of debt, cost of equity, etc.) uses 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.

The pro-forma analysis tool takes the one year of PROMOD IV revenues and forecasts future year revenues based on a fixed escalation rate, consistent with the escalation rate inherent to the natural gas forecast. As natural gas is the marginal fuel in most hours in the ERCOT market, this assumption is reasonable for scenarios that do not diverge significantly from current market conditions.

Production cost values were also escalated for future years. The fixed operation and maintenance cost ($/kW-yr) and variable operation and maintenance cost ($/MWh) were increased by the average inflation rate (1.84%), derived from the EIA AEO 2011 for the years 2011 to 2030. The fixed cost was then converted to an annual cost value by multiplying the $/kW-yr times the capacity of the unit being evaluated. The variable cost was converted to an annual cost value by multiplying the $/MWh by the annual generation, assuming generation from the unit would remain consistent over the life of the plant.

The pro-forma analysis tool, as implemented for the BAU scenario, assumed a resource investment financing of 55% debt to 45% equity, with an 8% cost of debt and a 15% cost of equity. The usable or serviceable life of the plant was dependent on technology (provided in Appendix D). The pro-forma financial spreadsheet uses the revenue stream, production costs, and the financing assumptions to calculate a net present value (NPV) of each project. Projects with positive net present value are considered economically viable.

To utilize the strengths and efficiencies of each of these tools, ERCOT has developed a general process for evaluating potential resource expansion that combines model output from PROMOD IV, evaluated through the pro forma tool, to output from the MarketPower tool. Although MarketPower can evaluate transmission constraints in its analysis, it has been used for this analysis without these constraints, i.e., as though all resources and nodes were located at a single node. This single-node model provides results that indicate 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 seemed consistent with the likely market outcomes to begin this long-term analysis without constraining generation based on potentially short-term localized market conditions. As this process is further developed over the next two years, the impact of transmission constraints on resource development will be explored.

5.2 Resource Database

One of the stipulations of the grant funding from the DOE is that model inputs be available for public review. Existing generation database information utilized by ERCOT for transmission planning analysis contains unit-specific confidential data. As a result, a new generation database was needed for this study. ERCOT developed this new database using several different public sources of information. Data sources included the ERCOT Capacity, Demand and Reserves Report (CDR) that was released December 2010. The CDR provides unit capacities, in-service dates, and other information. As the CDR does not provide the names of private-use network (PUN) generation, the names of these units in the new resource database were listed as PUN1, PUN2, etc.

Each resource in the ERCOT CDR was grouped by its category; these categories were based on fuel source, resource technology type, and unit age. These technology categories are listed in Appendix D.

As an example, all combustion turbines using the LM6000 turbine were categorized into the CT-LM6000 category, and all combined-cycle units that used the LM6000 as the turbine in their train were assigned to the CC-LM6000 category.

Once generators were grouped by category, ERCOT staff established generic operational characteristics for each category of units. These operational characteristics were developed from multiple sources of information, including data from the Energy Information Administration (EIA), NERC Generating Availability Data System (GADS), Continuous Emissions Monitoring System (CEMS) data from the Environmental Protection Agency (EPA), software vendor supplied data, ERCOT internal data, and industry knowledge of ERCOT staff. The resulting generic unit operating characteristics, by resource type, are also provided in Appendix D.

The remaining step was to create additional categories for resource expansion units. These inputs were obtained from EIA's 2011 Annual Energy Outlook, as well as from industry research described in Section 3. Of the technologies reviewed, eleven resource types were selected for initial evaluation in the BAU scenario. These eleven resources are listed below:

1. conventional and advanced combined cycle units,
2. conventional and advanced combustion turbine units,
3. supercritical coal and supercritical coal with carbon capture sequestration (CCS) technology,
4. integrated gasification combined cycle (IGCC),
5. IGCC with CCS technology,
6. nuclear,

7. biomass, and
8. onshore wind.

These technologies were selected for this initial analysis based on availability of information regarding the operation and cost values associated with each specific technology. Capital costs for the various technologies (also obtained from the EIA's AEO 2011) are listed in the following table:

Figure 6: Costs for Resource Technologies

Technology	Capacity (MW)	Heat Rate (MMBtu/MWh)	Overnight Capital Cost* (2010 $/kW)	Fixed O&M Cost (2010 $/kW-year)	Variable O&M Cost (2010 $/MWh)
Coal	600	9	$2,896	$29.67	$3.95
Coal with CCS	625	11.95	$4,582	$63.21	$7.35
IGCC	625	9	$3,271	$48.90	$5.75
IGCC with CCS	539	10.7	$4,851	$69.30	$7.00
Conv. CC	500	7.6	$893	$14.39	$3.00
Adv. CC	400	7.1	$919	$14.62	$2.90
Conv. CT	170	10.5	$679	$6.98	$8.00
Adv. CT	100	9.2	$771	$6.70	$13.00
Nuclear	1100	10.3	$5,130	$88.75	$4.00
Onshore Wind	100	N/A	$2,322	$28.07	$0.00
Biomass	40	13	$3,411	$100.50	$9.50

These capital costs were adjusted for future years using information obtained from a study performed by Pace Global at the request of Austin Energy. ERCOT applied the percent changes in capital costs from this study to the EIA 2010 starting values to develop a forecast of capital cost assumptions in 2010 dollars. These real dollar costs were then escalated using the 1.84% average annual inflation rate forecast from the EIA AEO 2011 to obtain nominal price forecasts.

5.3 Generation Expansion Methodology

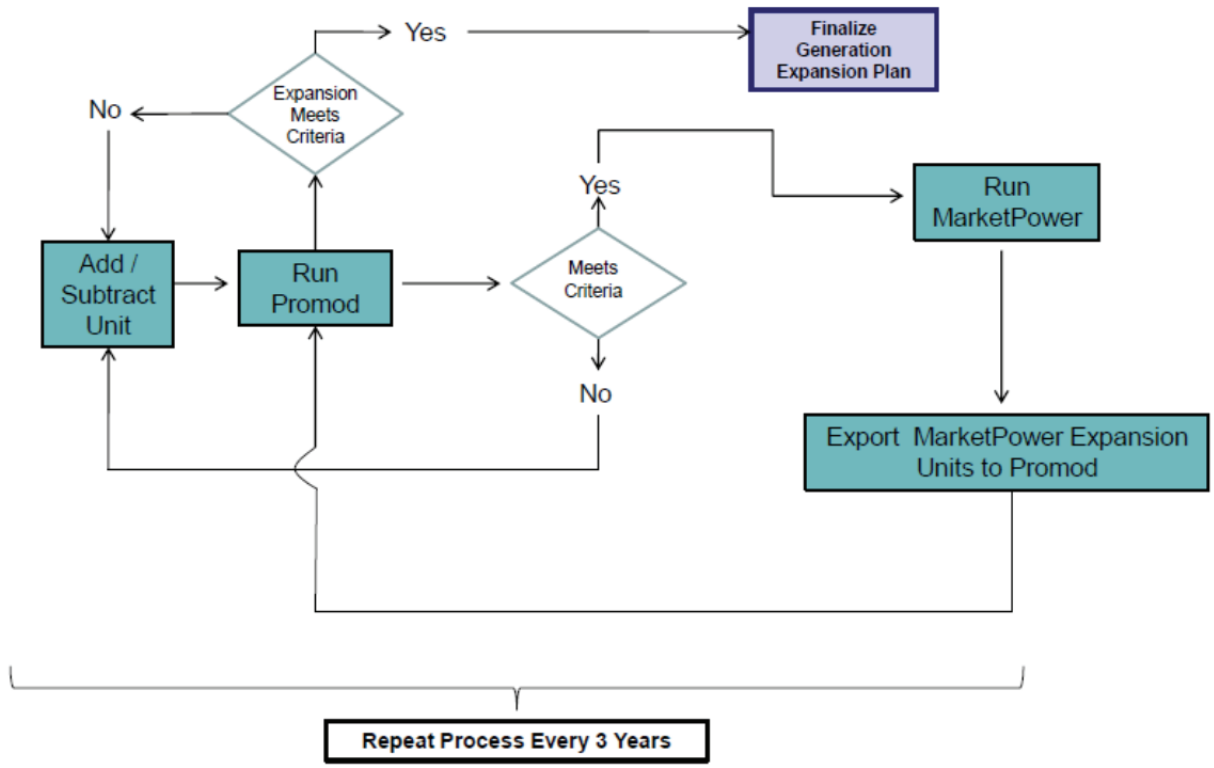
The generation expansion process is based on an iterative approach using PROMOD IV, MarketPower, and the pro-forma analysis tool. It begins with running PROMOD IV in year 2014 (the analysis proceeds in 3 year increments, so 2011 + 3 = 2014 is first year evaluated). In the first iteration, a prototype unit of each energy limited resource is added to the generation fleet. For this analysis of the BAU scenario, wind generation is the energy limited resource evaluated. The unit revenues from the PROMOD IV output are entered into the pro-forma analysis tool to determine the economic viability of that resource. If the pro forma analysis indicates that the resource provides an adequate return on investment, then the energy-limited resource remains in the expansion plan and additional energy-limited resources are added in the model run, until the marginal expansion unit does not receive adequate revenues to justify investment. On the other hand, if the initial resource does not meet the financial criteria, the expansion unit is removed from the expansion plan. When the final amount of energy limited resources has been determined for 2014, the entire resource set is imported into MarketPower to perform an analysis of likely resource expansion for that year.

MarketPower is then run from that year to determine the initial conventional resource expansion plan for 2014. The resulting MarketPower expansion plan is exported back to PROMOD IV and re-run for 2014 to evaluate the overall expansion unit revenue using the pro-forma analysis tool. Note that this 2014 expansion plan includes any energy limited resources that were found to be economically viable in the previous step. All expansion units are reevaluated in this step of the process. This is an iterative process, running PROMOD IV and the pro-forma analysis tool, to determine the best combination of energy limited resources and conventional thermal generation from the MarketPower build out. PROMOD IV is run with multiple combinations of units until all the expansion units meet the financial criteria.

When the expansion plan of energy-limited resources and conventional thermal generation is finalized for 2014, the process moves forward to 2017 (in 3-year time steps). PROMOD IV is run in 2017 with the expansion from 2014 and one additional unit of each energy limited resource. The process continues as described above. It should be noted that both expansion units and existing resources can be evaluated using the PROMOD IV model output to determine market viability. In any year, any of these units which does not return sufficient market revenue can be retired from the resource set. This process is repeated every three years through 2030 (there is a four-year difference between the last two steps). The overall process is graphically depicted below.

Determining the likely set of resource expansion units requires this two-step decision making process because the energy-limited resources (such as wind or solar generation units) are modeled with an hourly generation pattern. Wind generation is much more prevalent in the early morning hours than the daytime hours; this generation pattern is negatively correlated to load and thus to typical market prices in ERCOT. Yet MarketPower does not take this hourly generation pattern of wind units into account. As a result, the market viability of variable generation must be analyzed in an hourly production cost model, so that the impact of the hourly generation pattern can be correctly assessed. However, MarketPower is much faster than PROMOD IV, and can be used to quickly evaluate the likely market return of a number of generation resources. So a combination of the two tools provides the best mix of speed, versatility, and accuracy.

Figure 7: Resource Expansion Process



5.4 Resource Expansion Results

The generation expansion process as described above was performed for the BAU scenario without Production Tax Credit (PTC), the BAU with PTC, and the BAU with a high natural gas price without the PTC.

In general the BAU scenario is characterized by continuation of historic trends and policies. As established in the Long-Term Study Task Force meetings, the generation expansion technologies to be considered in the BAU scenario were based on the economic viability of potential resources. The underlying financial characteristics and estimated capital cost information used in this analysis can be found in the generation expansion section of this report.

These results do not include consideration of the retirement of existing generation, if any, that might not be economic, nor the additional resources that might be warranted to maintain system reliability with this level of variable generation. Also not considered is the amount of demand side resources that might be beneficial in this scenario. These issues will be included in these analyses in the near future following additional discussions with stakeholders.

Additionally, the only non-thermal resource considered for this scenario was wind. ERCOT is still collecting operational data on other energy-limited resources; these will be included in future analyses.

The table below shows the economic additions added by the process in each year analyzed through 2030. The resources shown as being added in 2014 in the table below are actual units with signed generation interconnection agreements - no expansion generation resources were added in that year. These resources are Sandy Creek (925 MW), a pulverized coal generation facility, and 5 wind units totaling 872 MW (Archer-Young, Gunsight Mountain, Penascal, Senate, and Sherbino Mesa). As decided by the Long-Term Study Task Force, these units were added to the model because they have existing interconnection agreements and on-line dates prior to 2014.

Figure 8: Resource Additions for BAU Case without PTC

Description	Units	2010 Actual	2011	2014	2017	2020	2023	2026	2030
CC Adds	MW			-	800	1,600	1,600	4,000	2,800
CT Adds	MW			-	400	3,000	700	500	1,100
Coal Adds	MW			925	-	-	-	-	-
Nuclear Adds	MW			-	-	-	-	-	-
Other Adds	MW			-	-	-	-	-	-
Wind Adds	MW			872	-	-	-	-	-
Annual Capacity Additions	MW			1,797	1,200	4,600	2,300	4,500	3,900
Cumulative Capacity Additions	MW			1,797	2,997	7,597	9,897	14,397	18,297
Reserve Margin	%	21.4	15.9	15.2	8.5	10.2	7.2	9.2	6.2
Coincident Peak	MW	65,776	65,206	73,375	78,869	81,665	85,928	88,318	94,318
Average LMP	$/MWh	34.41	37.42	42.51	56.76	63.23	73.69	81.50	87.75
Natural Gas Price	$/mmbtu	4.38	4.50	4.63	5.10	5.68	6.47	7.35	8.39
Average Market Heat Rate	MMbtu/MWh	7.86	8.32	9.18	11.14	11.14	11.38	11.09	10.46
Natural Gas Generation	%	38.2	41.3	45.8	47.0	49.3	51.0	53.0	59.3
Coal Generation	%	39.5	37.8	36.5	34.3	33.0	31.7	30.6	31.4
Wind Generation	%	7.8	9.2	7.3	8.4	8.0	7.7	7.4	7.6
Scarcity Hours	HRS	-	-	-	29	33	42	49	56
Unserved Energy	GWhs	-	-	-	24.1	39.9	63.9	60.1	68.8

The expansion resource additions for this scenario include 10,800 MW of combined-cycles units and 5,700 MW of combustion turbines for a total of 16,500 MWs of new generation capacity. In total, by 2030, 18,297 MWs of new capacity was added in this scenario. No expansion wind generation was found to be economical in this scenario (primarily due to the assumed termination of the renewable energy production tax credit).

In this scenario, by the end of 2030, the capacity amounts by fuel type in the ERCOT market will be:

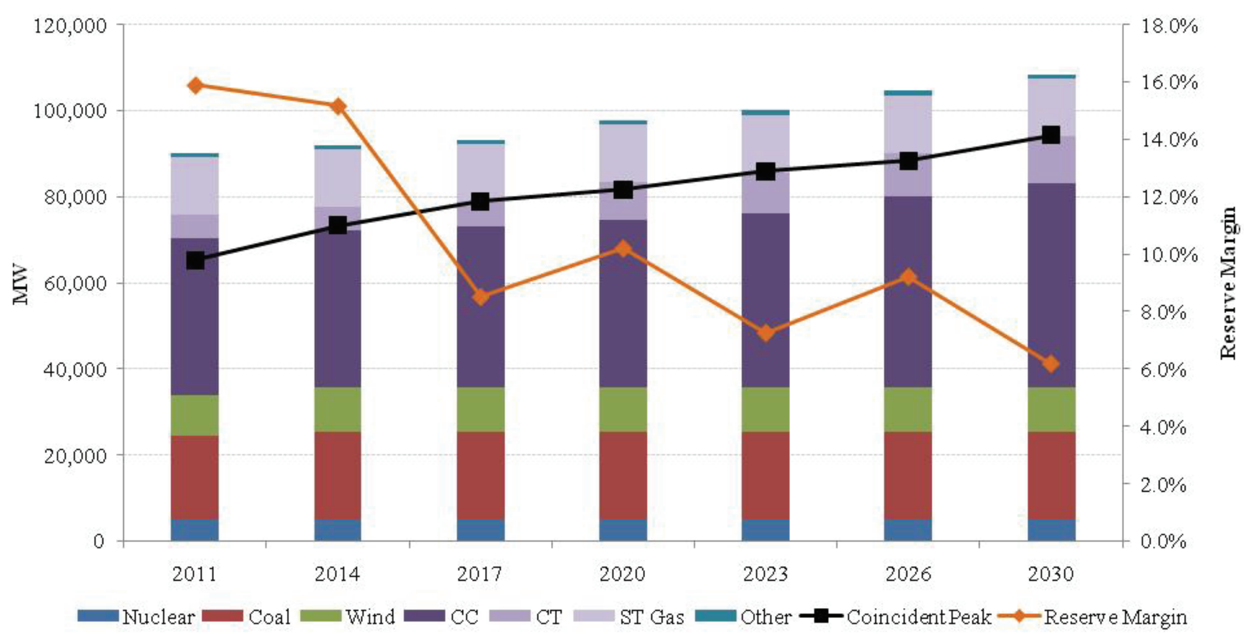
- 65% Natural Gas
- 19% Coal
- 5% Nuclear
- 10% Wind
- 1% Other – Hydro, biomass and Land-fill Gas (LFG)

Several other items from the above table are noteworthy. Only natural gas (NG) resources are built in this scenario. The total percentage of generation from all NG resources in ERCOT increases from about 40% in 2011 to about 60% by 2030; largely due to the relatively low natural gas price projections assumed for this scenario. As NG generation increases the generation from coal-fired resources declines from 40% to about 31% in 2030 while the wind generation remains relatively constant.

Hours of scarcity and un-served energy also increase in this scenario, due to the declining reserve margins shown above and in the chart below. By 2030 the reserve margin is projected to be slightly higher than 6%. The contribution of wind generation to the reserve margin is calculated using the current ERCOT Effective Load Carrying Capability (ELCC) for wind resources, 8.7% of nameplate capacity. Further analysis indicates that ancillary service revenues and additional unit constraints including ramp rates may lead to additional unit revenue and thus higher reserve margins. As a result, these resource expansion results are likely to be revised following additional analyses.

The chart below shows these cumulative capacity amounts along with the projected system load and the projected system reserve margin.

Figure 9: Comparison of Cumulative Capacity, Load and Reserve Margin for BAU Case



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The BAU scenario was also evaluated with the assumption that the Federal renewable energy PTC would be extended by Congress. This additional revenue is incorporated into the pro forma analysis for wind units, and results in an additional approximately $20/MWh of revenue. This tax credit significantly changed the economics of expansion wind units in the analysis. As shown in the table below, the amount of incremental wind resources added through 2030 for this sensitivity is 25,250 MW, plus the 872 MW due to units with signed interconnection agreements which yields a total amount of wind resources through 2030 of 26,122 MW. This results in a total amount of wind resources on the ERCOT system by 2030 of 35,600 MWs. The amount of wind generation in this sensitivity will require detailed ancillary service analysis to determine its impact to the system and what additional resources would be required, if any, to maintain system reliability.

Other resource expansion units found to be economic in this sensitivity are 6,800 MW of combined cycles and 4,200 MW of combustion turbines for a total amount of 11,000 MWs of thermal generation expansion.

Figure 10: Resource Additions for BAU Case with PTC

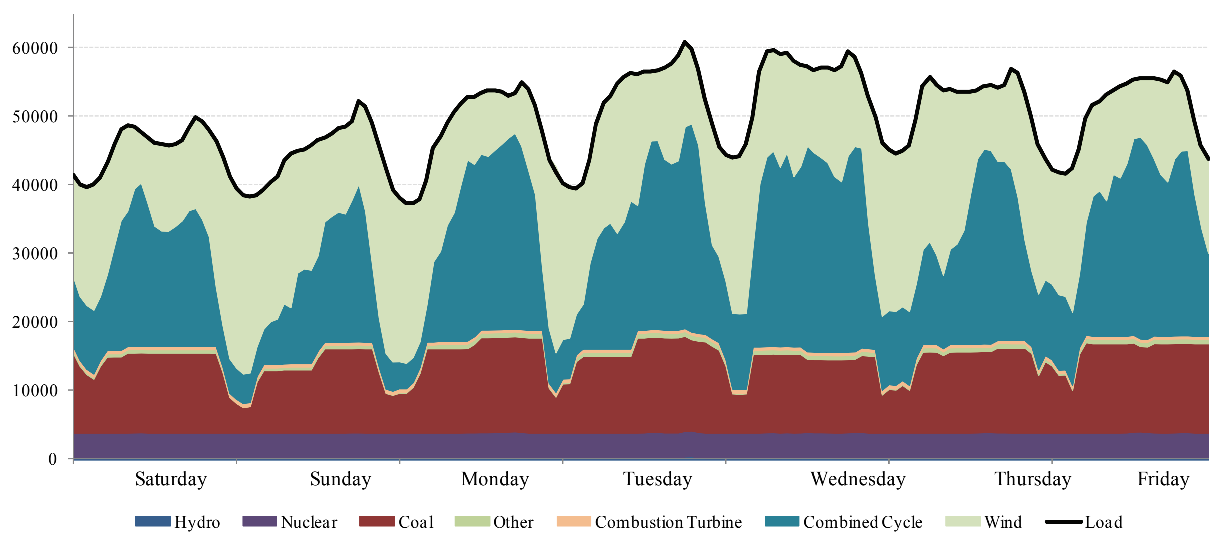
Description	Units	2010 Actual	2011	2014	2017	2020	2023	2026	2030
CC Adds	MW			-	-	1,600	1,600	800	2,800
CT Adds	MW			-	700	1,500	1,000	500	500
Coal Adds	MW			925	-	-	-	-	-
Nuclear Adds	MW			-	-	-	-	-	-
Other Adds	MW			-	-	-	-	-	-
Wind Adds	MW			872	3,250	7,500	5,000	3,500	6,000
Annual Capacity Additions	MW			1,797	3,950	10,600	7,600	4,800	9,300
Cumulative Capacity Additions	MW			1,797	5,747	16,347	23,947	28,747	38,047
Reserve Margin	%	21.4	15.9	15.2	8.3	9.0	6.9	5.8	2.9
Coincident Peak	MW	65,776	65,206	73,375	78,869	81,665	85,928	88,318	94,318
Average LMP	$/MWh	34.41	37.42	42.51	57.86	66.85	67.00	73.68	78.55
Natural Gas Price	$/mmbtu	4.38	4.50	4.63	5.10	5.68	6.47	7.35	8.39
Average Market Heat Rate	MMbtu/MWh	7.86	8.32	9.18	11.35	11.77	10.36	10.02	9.36
Natural Gas Generation	%	38.2	41.3	45.8	40.7	41.6	40.4	40.3	39.3
Coal Generation	%	39.5	37.8	36.5	34.2	32.3	30.6	29.2	27.3
Wind Generation	%	7.8	9.2	7.3	11.0	16.5	19.7	21.5	24.6
Scarcity Hours	HRS	-	-	-	32	52	37	40	37
Unserved Energy	GWhs	-	-	-	36.2	88.3	60.7	75.9	92.8

The resulting reserve margin in 2030 in this sensitivity is 3%. Even though there are over 25,000 MW of wind generation added, given that only 8.7% of this capacity is included in the reserve margin calculation, reserve margins are still well below the target of 13.75% for the ERCOT region. Even so, generation from the wind is significantly larger than the previous scenario: 7.8% in 2011 rising to nearly 25% in 2030. While there are fewer hours of scarcity pricing in this case there is a larger amount of un-served energy.

In terms of other generation resources the proportion of energy produced from NG generation remains relatively flat, even though additional gas generation capacity is added to the system.

The amount of coal generation decreases from roughly 40% in 2011 to just over 27% in 2030. This can be seen in the weekly snap shot shown below, a depiction of the unit generation for week in March, 2030, sorted by fuel type. The amount of wind in this scenario is causing NG generation to be backed down in most hours and coal generation to be backed down in most of the off peak hours. In hour 1 on Sunday of this week a total of 28,850 MWs was being generated by all wind resources in the system.

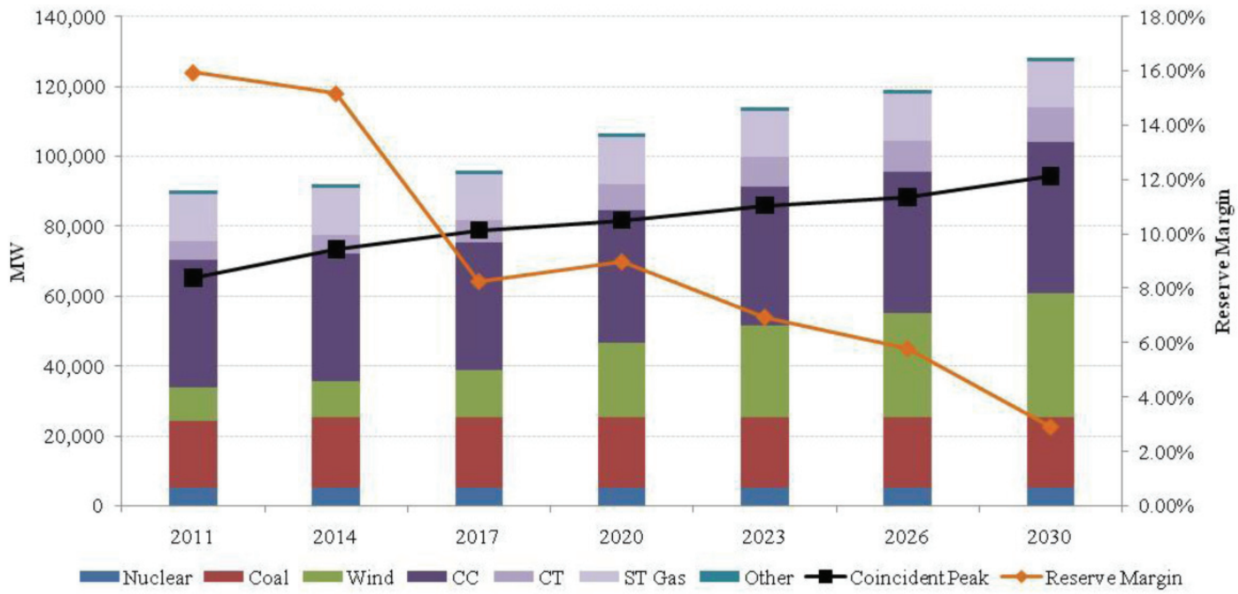
Figure 11: Generation Output for Week in March, 2030



The chart below shows the cumulative capacity amounts for the BAU with PTC case along with the forecasted system load and the projected system reserve margin. This chart also clearly shows the substantial increase in wind generation in this case.

In order to see the impact of higher natural gas price, the BAU case was reanalyzed with a $5/MMBtu higher gas price. This incremental addition was maintained throughout all years of the study, so whereas in the year 2030 in the BAU case the average natural gas price was $8.39/MMBtu, the natural gas price in this sensitivity was $13.39/MMBtu.

Figure 12: Comparison of Cumulative Capacity, Load and Reserve Margin for BAU Case with PTC



The table below shows the results for this sensitivity analysis: 6,000 MW of expansion wind resources are added (above the planned resource additions with signed interconnection agreements) in 2014. This is the only wind expansion proven to be economic in this sensitivity. All the other economic resource additions were coal-fired generation. A total of 17,400 MWs of coal plants were added.

For this sensitivity, by the end of 2030 the capacity amounts by fuel type in the ERCOT market will be:

- 46% Natural Gas
- 33% Coal
- 5% Nuclear
- 15% Wind
- 1% Other

Since no natural gas (NG) resources are built in this sensitivity the percentage of generation from all NG resources decreases from about 40% in 2011 to about 26% by 2030. The increase in coal-fired capacity results in increased generation from coal resources (from 40% in 2011 to about 53% in 2030). There is only a slight increase in wind generation over time in this scenario.

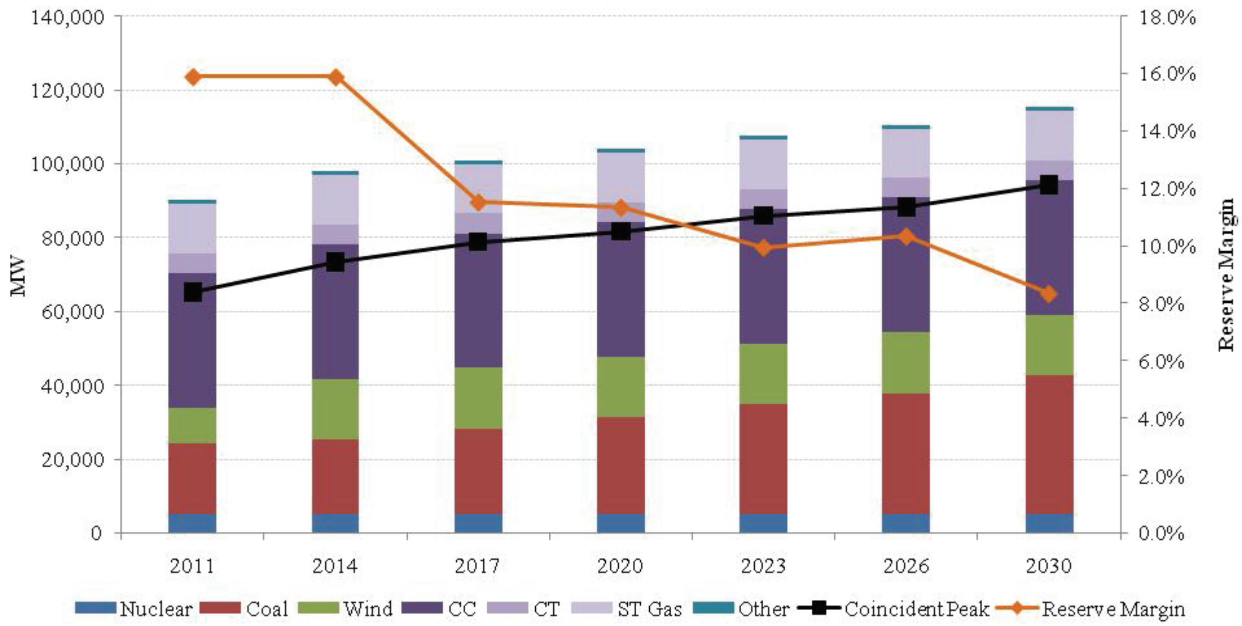
Figure 13: Resource Additions for BAU Case with High Natural Gas Price

Description	Units	2010 Actual	2011	2014	2017	2020	2023	2026	2030
CC Adds	MW			-	-	-	-	-	-
CT Adds	MW			-	-	-	-	-	-
Coal Adds	MW			925	3,000	3,000	3,600	3,000	4,800
Nuclear Adds	MW			-	-	-	-	-	-
Other Adds	MW			-	-	-	-	-	-
Wind Adds	MW			6,872	-	-	-	-	-
Annual Capacity Additions	MW			7,797	3,000	3,000	3,600	3,000	4,800
Cumulative Capacity Additions	MW			7,797	10,797	13,797	17,397	20,397	25,197
Reserve Margin	%	21.4	15.9	15.9	11.5	11.3	9.9	10.3	8.3
Coincident Peak	MW	65,776	65,206	73,375	78,869	81,665	85,928	88,318	94,318
Average LMP	$/MWh	34.41	37.42	77.12	84.54	91.90	98.00	107.28	114.68
Natural Gas Price	$/mmbtu	4.38	4.50	9.63	10.10	10.68	11.47	12.35	13.39
Average Market Heat Rate	MMbtu/MWh	7.86	8.32	8.01	8.37	8.61	8.54	8.69	8.57
Natural Gas Generation	%	38.2	41.3	39.7	36.8	34.7	31.8	29.8	26.3
Coal Generation	%	39.5	37.8	35.5	38.3	41.6	45.3	48.2	52.5
Wind Generation	%	7.8	9.2	12.5	13.2	12.6	12.2	11.7	11.2
Scarcity Hours	HRS	-	-	1	12	22	26	39	46
Unserved Energy	GWhs	-	-	0	7.6	29.0	36.9	44.5	92.5

The increasing amount of scarcity hours and un-served energy over the forecast horizon is consistent in this scenario. Again, these results are likely to be revised following additional analyses. By 2030 the reserve margin is projected to be slightly higher than 8.0%.

As can be expected, the average system LMPs are substantially higher in this sensitivity than in the BAU scenario due to the increased price of natural gas. Average LMPs in the BAU case by 2030 are $87.75/MWh; in this sensitivity average LMPs are above $114/MWh.

Figure 14: Comparison of Cumulative Capacity, Load and Reserve Margin for BAU with High Natural Gas Price



6 Resource Siting Process

The next step in the process of building a forecast of future grid conditions in order to evaluate the need for and cost-effectiveness of transmission upgrades is to place the expansion resources determined from the previous step at specific locations on the transmission grid. Without this step, it would be impossible to determine the likely powerflows, locational market prices, or system congestion. Without siting the resources, one cannot determine the cost-effectiveness of transmission projects, nor which projects are required in order to ensure system reliability.

To that end, 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 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.

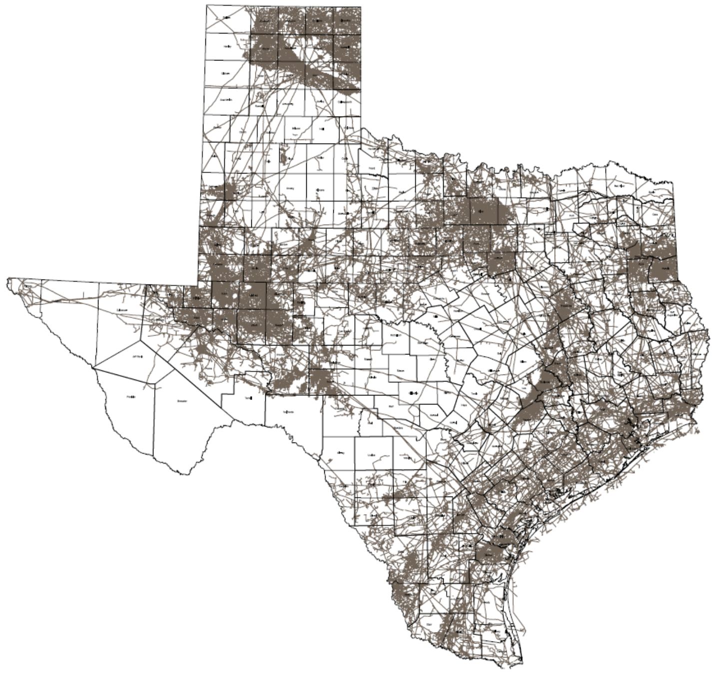
The various factors that were used to evaluate potential siting locations for specific technologies were:

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

ERCOT obtained data from a variety of sources to create criteria for ranking generation sites. 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 is 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.

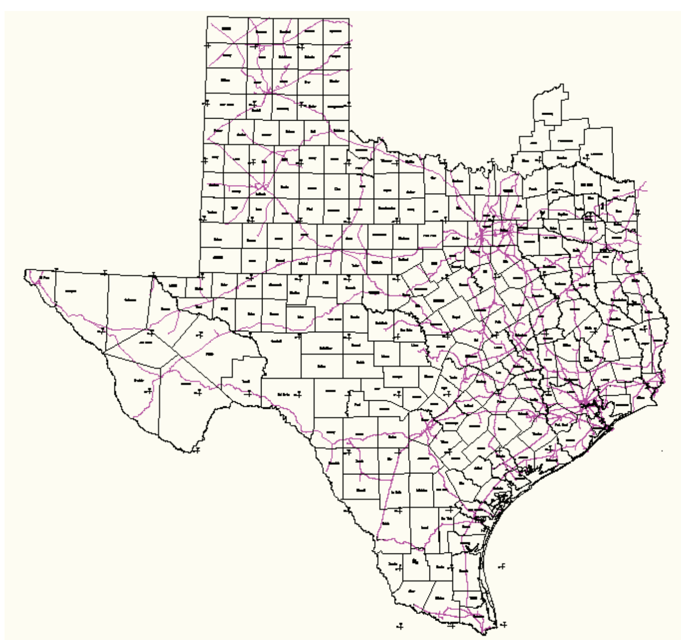
For natural gas pipelines and railroads, maps were visually inspected to categorize each county as having a high, medium, low, and very low pipeline or railroad density. Natural gas pipelines and railroads in Texas are depicted in the following two figures.

Figure 15: Natural Gas Pipeline Density



Source: Railroad Commission of Texas

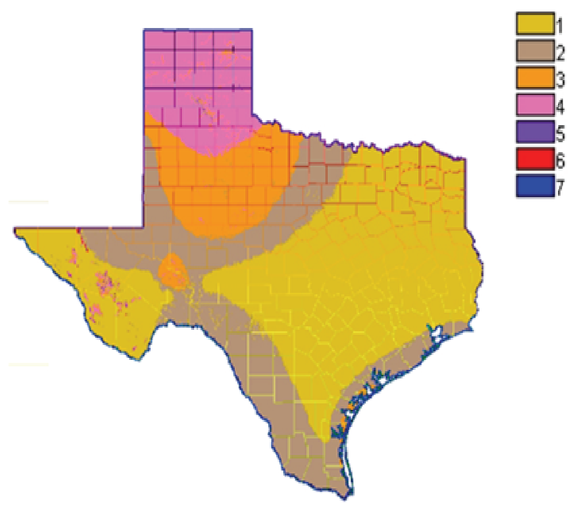
Figure 16: Railroad Lines in Texas



Source: Texas Department of Transportation

Wind resource data was obtained from Alternative Energy Institute at West Texas A&M University. The Institute classifies Texas geographically into seven different zones (1 to 7 in increasing order) based on suitability for development of wind generation. Additional information regarding potential off-shore wind locations was recently received and will be incorporated into this analysis in the future.

Figure 17: Wind Conditions in Texas



Source: Alternative Energy Institute at West Texas A&M University

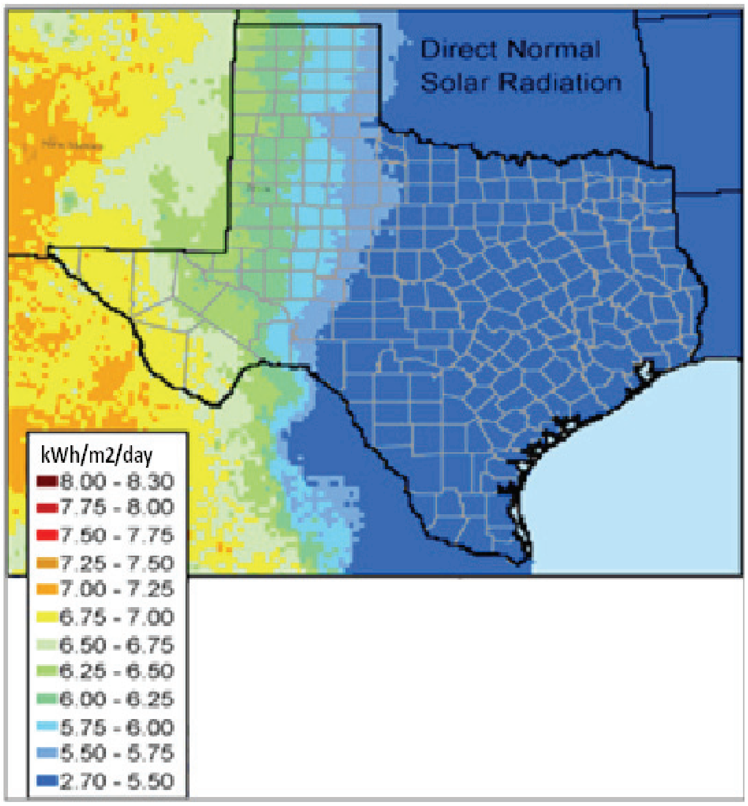
Information regarding solar thermal and solar photovoltaic resources in Texas was obtained from the National Renewable Energy Lab (NREL). This information is depicted in the following two figures. Solar radiation in these maps is measured in units of kilowatt-hours (kWh) per square meter. Direct normal 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/m2
- average: 6-6.5 kWh/m2
- below average: 5.5-6 kWh/m2
- poor: ≤ 5.5 kWh/m2

As per NREL, based on solar irradiance, the Far West weather zone in ERCOT has acceptable sites for solar thermal units. While NREL considers areas having more than 6.75 kWh/m2/day annual average direct normal solar resource ideal, the criterion was relaxed in this siting process in order to find more sites potentially suitable for solar thermal generation.

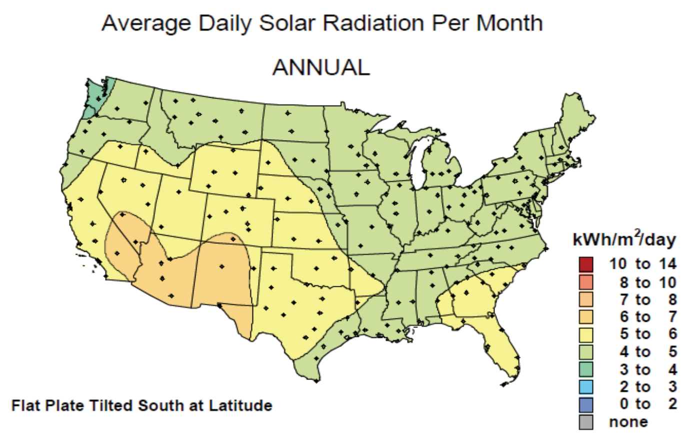
Figure 18: Distribution of Direct Normal Solar Radiation



Source: NREL

Similarly to solar thermal, solar photovoltaic (PV) resource, is measured by energy per surface area squared (kWh/m2). 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. However, unlike solar thermal systems, PV harnesses energy contained in the direct normal radiation as well as the radiation diffused by atmospheric components. The map presented below shows that most of Texas has high levels (>5 kWh/m2/day) of average daily solar radiation.

Figure 19: U.S. Average Daily Solar Radiation per Month



Source: NREL

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. Future collaboration with Sandia National Labs will enhance this preliminary analysis.

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) were also reviewed. 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 indicates that the following counties may soon be designated as non-attainment zones as a result of the possibility of new, more severe 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 NOx emissions from large stationary sources such as power plants, and would likely limit development of such resources in these counties.

Considering all of these factors, along with each resource technology's site requirements, a list of acceptable counties for each expansion resource type was developed. Site requirements by technology are provided in Appendix E. 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 in order 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 only siting on 345-kV buses, the number of additional projects that would have to be added as part of the "interconnection process" for the expansion resources was reduced. The 345-kV buses selected for each technology were further ranked based on a subjective review of locational market prices from preliminary PROMOD IV runs. In order to limit the localized impact of too much new generation resources being injected into certain areas, one bus from each county was selected before a second bus from the first county was chosen.

6.1 Generation Siting for the BAU Scenario

The final resource expansion plan for the BAU scenario (without PTC) was evaluated for siting of generation resources using the process described above. This resource expansion plan includes 10,800 MW of combined-cycle units and 5,700 MW of combustion turbines. Potential sites selected for these resources are depicted in the following two maps. Note that as additional information regarding availability of surface water resources is obtained, these potential locations may be adjusted.

Figure 20: Potential locations of new combined cycle units (BAU scenario; 2030)

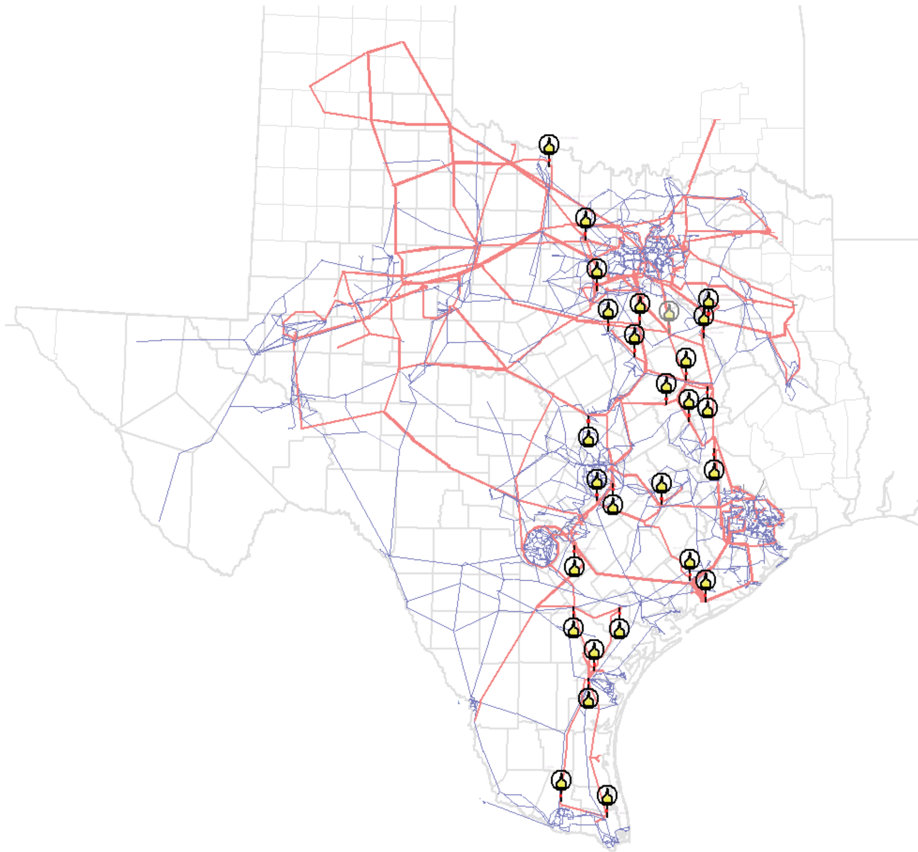
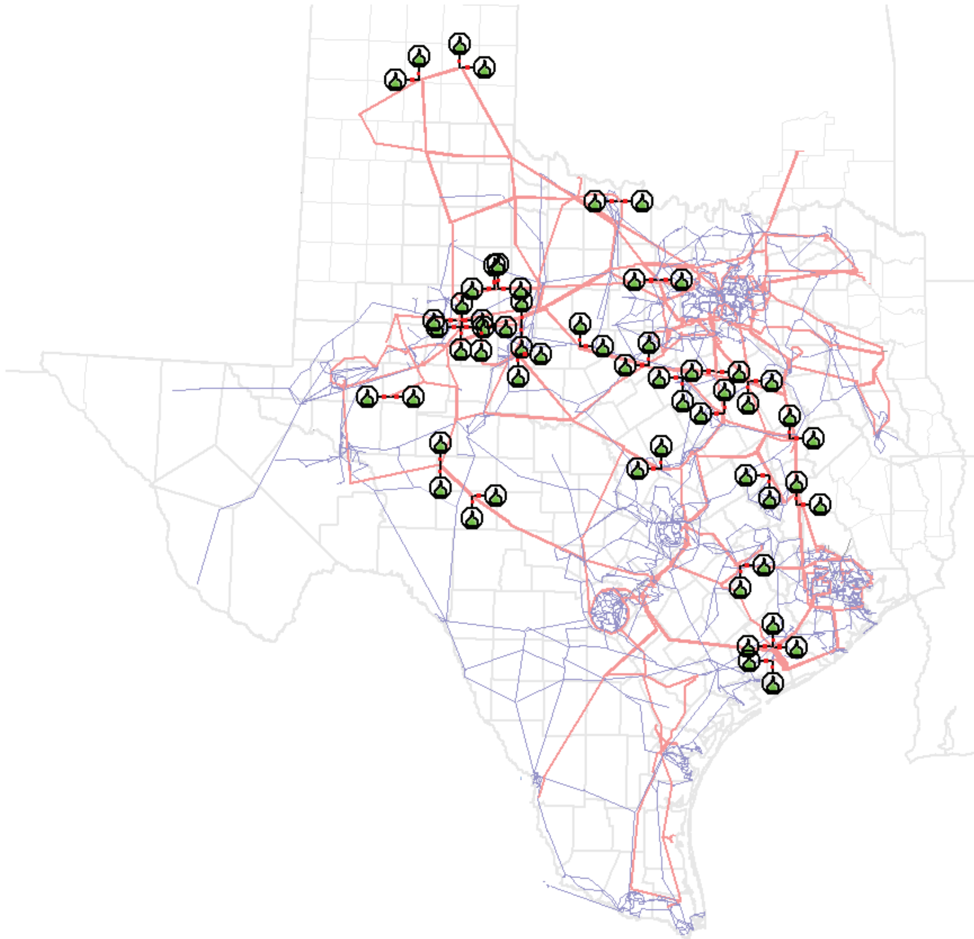


Figure 21: Potential locations of new combustion turbine units (BAU scenario; 2030)



7 Transmission Planning Analysis

The final step in the long-range planning process is the analysis of transmission needs and the development of cost-effective transmission projects. Prior to beginning this analysis, the existing transmission system topology must be incorporated into the planning tools; then the import requirements into load centers and locations of new generation resources must be evaluated, and then a system-wide analysis of transmission congestion, powerflows, and potential transmission upgrades can commence.

7.1 Network Simplification Methodology

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 are designed for load-serving purposes. When these network databases are used for long-range planning, the resulting increased loads typically result in many of the load-serving circuits being shown as being overloaded in the model results. 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 transmission owners 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 correct the model input to reflect the likely upgrades on the lower-voltage circuits. In previous 10-year planning studies in ERCOT, it has taken several weeks for engineers to review all of the circuit overloads and determine which should be included in the long-range planning study and which can be disregarded. For a 20-year study such as this, the amount of effort would be even greater. This required effort results in a lack of flexibility in the ERCOT long-range planning efforts and also causes extended delays in changing to newer transmission databases.

In order 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 or computational efficiency. This tool, created by ERCOT with help from Dave Matthews (when he worked for AEP), removes the 69 kV network, removes radial and inline buses, and increases the ratings of short transmission lines. This tool is useful in improving visibility of long-term system needs by reducing the impact of system upgrades that are best handled in near-term planning.

By simplifying parts of the network which 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 is also useful in computationally-intensive studies such as Loss of Load Probability, where a simplified network can be used to decrease run-times and allow more scenarios to be run.

Because simplification reduces model detail to some extent, this cost 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 steps in the simplification algorithm are as follows:

1. Remove the 69-kV network.
2. Remove radial 138-kV buses.
3. Remove inline 138-kV buses.
4. Remove radial 138-kV buses (second pass).
5. Remove ratings on “short” lines.
6. Update contingency file.

A description of each step follows.

7.1.1 Remove the 69-kV Network

In ERCOT, the 69-kV network is mostly load-serving and does not facilitate bulk system transfers. The first step in removing the 69 kV network is to move load and generation to the higher voltage network. Generators are not simply moved to reconnect to the nearest 138 kV bus; the actual process is more sophisticated. Rather than applying direct connections, generators are connected through “mouse tail” radials, where each mouse tail has an impedance representative to the original connection between the generator and the high voltage network. Thus, if the total impedance originally separating a generator from a high voltage bus is 0.02 + 0.3j, for example, then the mouse tail impedance will also be 0.02 + 0.3j. The generator bus number and name are preserved for recognition.

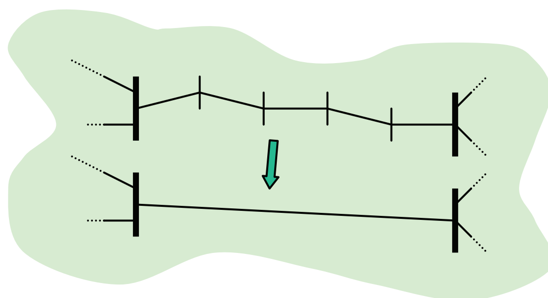
Rather than move load, equivalent loads are placed on the system: first, flows from 138-kV to 69-kV are measured at the connecting transformers. Next, this flow is represented by an equivalent load. This method has the advantage that it accounts for losses and reactive power on the 69 kV network and in doing so does not alter flows on the higher voltage network.

7.1.2 Remove Radial 138-kV Circuits

Radial buses do not contribute to bulk system transfers. Overloads on the radial system are generally solvable through a simple upgrade, and thus are outside the scope of a long-range study. Before removing a radial circuit, load and switched shunts are moved to the neighboring bus.

This method of moving load ignores losses on the radial network. Future versions of the simplification tool will be modified to take real and reactive radial losses into account when moving load.

Figure 22: Before and After Removal of Radial Lines



7.1.3 Remove Inline 138 kV Buses

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 or sectionalize long lines. In simplification, inline buses are removed by merging the two adjacent transmission lines into one line.

Removing inline buses improves both analysis and conceptualization: From a bulk flow perspective, inline buses have little effect on transfers. However, having multiple segments for many lines clutters record keeping. Conceptually, it is simpler to think of a line as connectivity path.

Another important advantage of removing inline buses is that total effective line length can be applied as part of the simplification criteria. For example, the next simplification step (mentioned in the following Section D) removes ratings on lines that are shorter than a certain length.

7.1.4 Increase Ratings for Short Lines

For the recently completed Long-Term System Assessment, the simplification program was set to increase ratings on short lines with low ratings according to the following criteria:

As used here, "urban lines" are defined as lines in geographic zones roughly near significant population centers (Austin, Dallas, Fort Worth, Houston, San Antonio, Corpus Christi, Abilene, Odessa, Temple, and McAllen.) "Rural lines" are defined as lines distant from these higher population centers. The intent of defining separate criteria is to reflect the difficulty in siting urban lines due to limited land availability. A 10-mile rural line may be relatively easy to construct, a 10-mile urban line may not.

Figure 23: Short Line 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

Though they may seem arbitrary, ERCOT developed these criteria after significant trial and error in balancing simplicity over detail loss. The lengths of lines were selected such that major transmission upgrades and potentially major bottlenecks would remain visible even post-simplification. Simplification should not hide these issues by automatically upgrading large sections of the system. Since low-rated rural lines (less than 150 MVA) have a high chance of being upgraded in shorter term study horizons, if they cause congestion, all lines less than 30 miles in length satisfying this criterion were automatically upgraded. Given that higher rated lines are more expensive to upgrade, shorter rural lines (less than 20 miles long) rated between 150 - 440MVA were upgraded to 455MVA. Urban lines shorter than 2.5 miles and rated low were upgraded to 808MVA.

7.1.5 Simplification Results

After simplification, the number of ERCOT buses and lines is reduced by approximately one-half; system upgrade requirements relating to the 69-kV network are eliminated, which is vital for long-term studies. Because network complexity is reduced and certain line rating constraints removed, some planning analysis tools run faster.

Visibility is also improved and workload reduced when analyzing the case. By removing inline and radial buses, long stringy lines become a single line connecting two networked points. This saves time when considering an upgrade, because it avoids the need to upgrade each segment individually.

Simplified models are acceptable for certain types of analysis where the loss in detail will be unlikely to have a significant effect on results. However, using a simplified model can affect the results in certain studies. A thorough understanding of the simplification process is required.

ERCOT has performed significant testing of the simplification process, comparing contingency results of models before and after simplification. Many results are similar, however some differences were noted:

1. Load is moved when removing inline buses. Because urban areas have a large number of inline buses in close proximity, the behavior of urban areas can be changed somewhat during this step. To control this change, a criteria was added in the latest version of the program where loads greater than 20 MW are not moved and the inline bus is left alone.

2. Under contingency, the 69 kV network can have a significant effect on 138 kV voltages. Contingencies which cause high reactive losses on 69 kV lines tend to depress 138 kV voltages as well. This effect is not modeled. This approximation is acceptable in certain studies, such as long range studies, because 69 kV voltage issues are generally seen as limited in scope and easily solvable through near-term upgrades.

In certain cases, simplification can cause the effective load to decrease, causing the slack generator to decrease output substantially. The reason is that when radial lines are removed, system losses decrease. This will be fixed in a future version of the simplification program, where losses are incorporated into load when radial lines are removed.

The Simplified Transmission System is a reasonable approximation of the full ERCOT system. While the definition of certain contingencies may change, those contingencies still represent similar and realistic system events that, on a post-contingent basis, may threaten the reliability and operability of the ERCOT system. Congestion should be evident in the same general areas. Production costs, less the inherent savings in ignoring the constraints of the 69kV system, should be roughly equivalent. ERCOT staff carefully reviewed full and simplified models for congruence and determined that the simplified model was sufficient for the scope of long-term studies. Absent a simplified model, the system overloads and congestion would be unmanageable for 2030 load levels. Network simplification allows the planning engineer the opportunity to focus on system needs that are global to the interconnection without blurring datasets with system needs that are not appropriate for the long-term planning time horizon.

7.2 Urban Area Reliability Analysis

Changes in customer demand and resource mix drive the changing need for transmission. The steps for long-range planning described in Section 2.1 show that a significant amount of economic scenario analysis is required in order to determine possible changes in system resources before an analysis of cost-effective transmission solutions can be conducted. However, any set of transmission solutions will need to maintain required levels of system reliability, as defined by applicable North American Electric Reliability Corporation standards and ERCOT market protocols and operating guides. These reliability requirements are most binding on the needs for additional transmission capacity in and around large load centers.

As part of this long-range study effort, ERCOT has conducted a review of potential system needs resulting from expected load growth in the major urban centers of Dallas/Fort Worth, Houston, and the lower Rio Grande Valley. Specific transmission projects identified in this effort will not necessarily be used in the final transmission solutions developed. Rather, the information obtained from this effort will be used to guide the development of transmission solutions for the scenarios that are developed.

One of the improvements in long-range planning in ERCOT resulting from this project is the extension of the planning horizon from 10 years to 20 years. As no 20-year planning efforts have recently been conducted for the ERCOT region, transmission planners in ERCOT do not have familiarity with the level of new transmission capacity that are likely to be required in the urban centers following 20 years of load growth. The reliability planning effort that will be described in the next few sections can be used by planners to develop an understanding of likely urban system needs. Population growth forecasts indicate that populations in Texas are expected to 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. Also, given the ERCOT market design, in which unregulated developers can build new resources anywhere on the system, future transmission plans must be developed with at least an understanding of what improvements will be necessary if no new resources are built in one or more of the major urban centers.

To some extent, transmission planning within the urban areas must be completed before the need for inter-regional transmission capacity can be evaluated. This type of planning is similar to what would be conducted by control areas in larger interconnections. Also, an understanding of "worst-case" urban system transmission requirements (i.e., with no new intra-urban resources) can also be used to quantify the benefits derived from policies that incent resources to be sited inside urban centers.

The weather zone forecast provided by the ERCOT Load Forecasting group was disaggregated at a bus level, proportionate to the loading on each bus in the SSWG case. With expected loads in 2030 applied to each simulation, additional generation was required in order to have sufficient generation to serve load. For each of the urban areas studied, additional generation capacity outside of that region was included in the model database. Multiple dispatches were evaluated in order to ensure that information from this analysis would be relevant to a range of potential resource expansion scenarios. Where a metropolitan area was heavily dependent upon imports, LTS Staff elected to perform a transfer analysis. All cases, studied using PSSE, PowerWorld and MUST, are available on the Planning and Operations Information section of the ERCOT website.

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

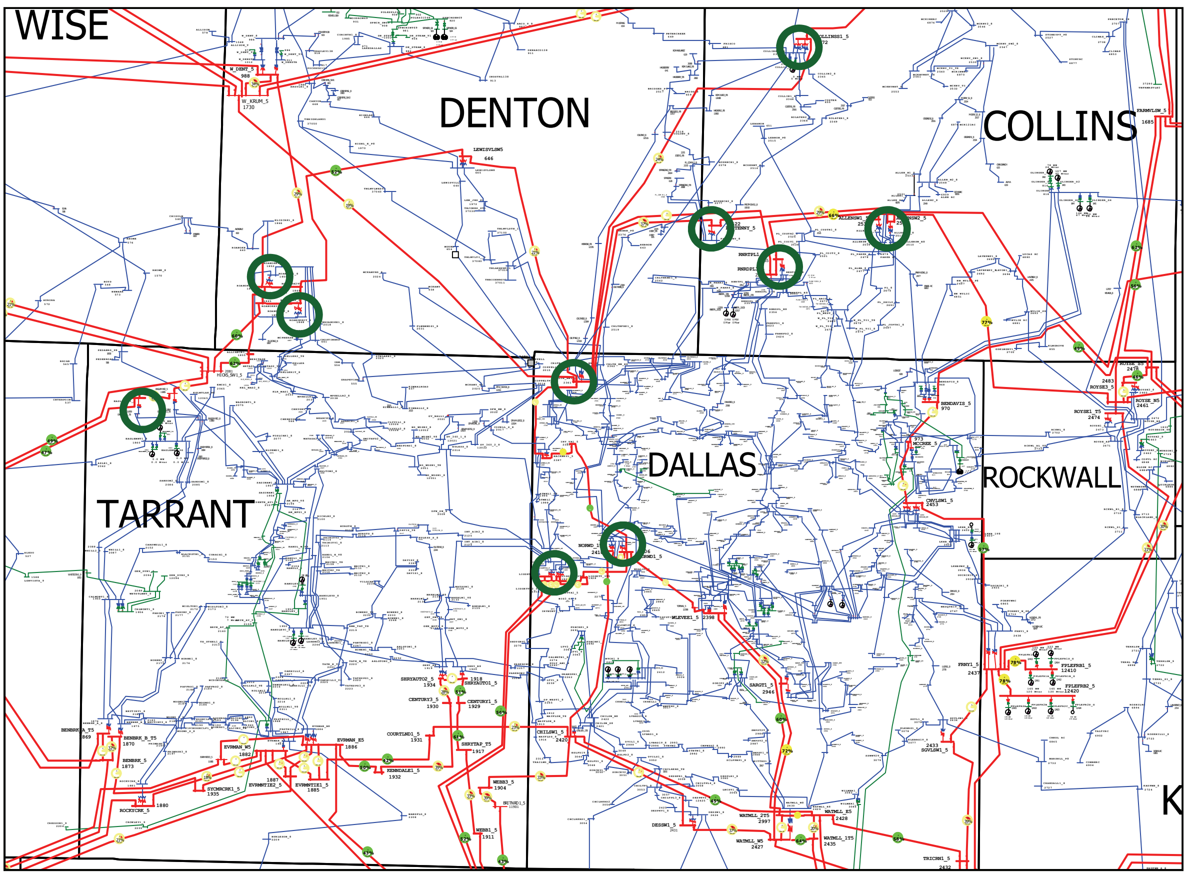
- Base case conditions
- N-1 contingency (loss of one transmission element)
- G-1 contingency (loss of one generation unit)
- Extreme loading (base load + 5% to reflect extreme hot or cold weather)
- G-N: Clusters of generator outages / retirements.

7.2.1 Dallas/Fort Worth Area

The Dallas and Fort Worth (DFW) area is a major ERCOT load center. Load forecasts derived from forecasts for North and North Central weather zones indicate that nearly a third of ERCOT load, over 35,000 MW, will be concentrated in the DFW area by the year 2030. For this analysis, all import paths into the DFW area, defined as Dallas, Tarrant, Denton, Collin, Rockwall, Kaufman, Wise, Parker, Fannin and Hunt counties were analyzed. Reliability needs of DFW were studied using two different generation dispatches. These dispatches stressed the existing system with import powerflows from different directions: one resulted in significant flows from the south, while the other resulted in import flows from multiple directions.

Using the first of two generation dispatches studied, in this case one that led to regional import flows, the initial powerflow analysis indicated depressed voltages across the region. The addition of 7,500 MVar of reactive support system (shunt capacitor banks) were required to allow the AC steady-state tools to converge upon preliminary solutions. These solutions exhibited constraints on the transformation capacity from the 345kV system into 138kV system. Pre-contingency (n – 0) loading of many of the 345/138kV transformers exceeded 100 percent. Locations of these overloaded autotransformers are depicted in the following figure.

Figure 24: Locations of Overloaded 345/138 kV Transformers in N – 0 Steady State Analysis



Overloading of this magnitude, distributed across so many of the major import paths, is indicative of a significant need for additional transformation capacity. These findings were confirmed by a representative of the incumbent transmission provider, who noted that there is limited unused physical space available for incremental transformation at existing substation sites. These results indicate that long-range transmission plans for the DFW region need to include additional 345-kV substations.

Overloading of the existing autotransformers was resolved by adding a total capacity of 5,900 MVA of new autotransformers at the Parker, Collin, Anna, Farmersville and Hicks 345-kV substations. Even with these system improvements, voltages below acceptable criteria were still present on the 345-kV network. These under-voltage conditions were resolved by adding shunt reactive support in the southeastern portion of the DFW region, and by increasing the connectivity of the 345-kV network in the northeast portion.

System conditions were also studied under n – 1, g – 1 and extreme loading conditions. These analyses indicated a need for additional import capacity, modeled in this analysis around the Tricorner area. No additional major branch overloading or voltage issues were identified.

The second of two generation dispatches, in this case creating significant import flows from the south, indicated the general weakness of the eastern and southern portions of the DFW transmission network. Imports into the DFW region in this dispatch cause numerous thermal overloads on the 345-kV system. In addition, nearly all of the major 345-kV and 138-kV buses in the southern portion of the DFW region had severely low voltages, primarily due to the excessive reactive power consumption on the heavily import pathways. In addition, numerous contingencies of major 345-kV circuits into southern DFW resulted in system divergence.

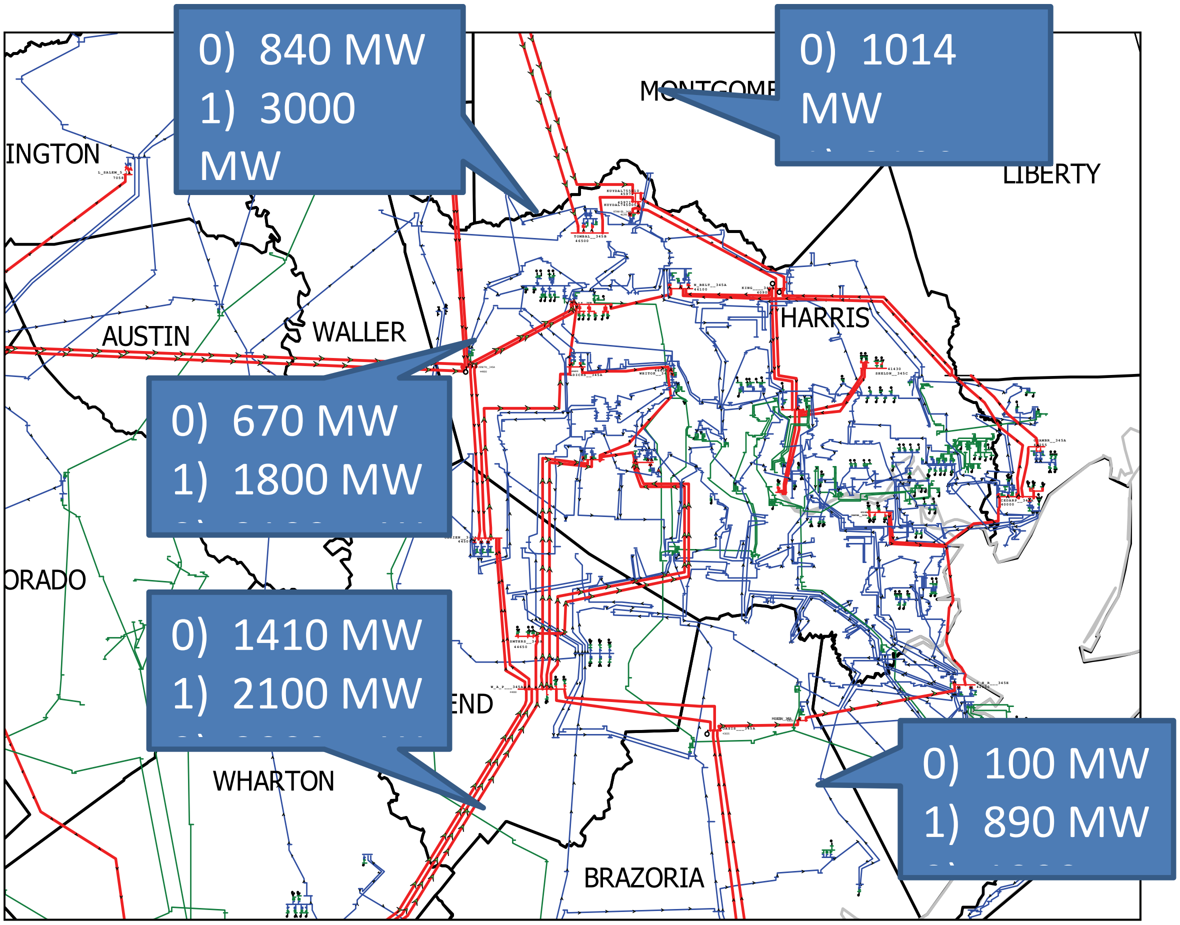
These stability limits were further evaluated using a transfer analysis from generation resources south of DFW. A transfer analysis tests the import capability from defined generation pockets (sources) to defined loads (sinks.) Transfer analysis from southern sources to DFW sinks revealed significant reliability issues. Under n - 1 contingency conditions maximum import transfers from the south were approximately 3,400 MW. Given expected loads in the DFW region, this amount of import capacity is not sufficient. For scenarios analyzed as part of this long-term study that result in no resources being developed within the DFW area and significant resource additions to the south, two or more import pathways are likely to be required in order to ensure adequate reliability (most notably voltage criteria).

7.2.2 Houston Area

The Houston metropolitan area, including Grimes, Montgomery, Harris, Chambers, Galveston, Brazoria, Fort Bend, and Waller counties, is expected to have a total peak load of over 20,000 MW by the year 2030; this is almost a fifth of the ERCOT system peak. The Houston area currently has five existing import paths: power is imported from the north along Singleton – Zenith and Singleton – Kuykendahl circuits; from the west along the proposed Fayette – Zenith circuit (this circuit is scheduled to enter service in 2015 and is included in all analyses described below); and from the south along Dow – Oasis and Hillje – W.A. Parish circuits. Two generation dispatches were evaluated in order to determine possible transmission needs for the Houston region: one that stressed the import capability into Houston from the north, and one that stressed the import pathways from the south and west. The figure below indicates real power flows on these circuits for three different generation dispatches.

Additional reactive support of 8,000 MVAr of shunt capacitors were in both dispatches to the Houston area to achieve model convergence.

**Figure 25: Real power flows under a variety of dispatches and loads.
N-0 Corridor flows for (0)**



Steady-State Working Group 2016 case; (1) 2030+5% High North Imports case, and

(2) 2030+5% High South/West imports

With incremental generation located generally north of the Houston region, the north to Houston import paths become very heavily loaded. Under N-0, these lines carry approximately 3,000 MW per double circuit. Both set of circuits overload under contingency of the other set. Similarly, with incremental generation placed south and west of Houston, the lines extending from these regions (from Zenith to T.H. Wharton to Addicks, and from S. Texas to W.A. Parish to Bellaire) become overloaded under contingency. Heavy reactive power losses on these circuits under contingency also indicate the need for additional import pathways.

One option evaluated was a new double-circuit 345-kV line connecting the Lufkin substation and a new substation (referred to as Canal) located northeast of Houston. As proposed, the Canal substation would be located near the intersection of Liberty, Chamber, and Harris counties, and would tap into the existing double circuit 345-kV line connecting the Chamber and King substations. The existing Chamber – King 345-kV line is not truly double circuit in the sense that one circuit flies over (bypasses) both King and Chamber stations to connect directly from North Belt to Cedar Park. This configuration creates a flow imbalance among the two circuits, which would be exasperated by a new import point Canal, so a tie-in of the N Belt-C Park circuit to King would be advantageous to balance flows.

Powerflow analysis indicates that this solution is not adequate to resolve reactive losses under contingency. Before adding the new Lufkin – Canal circuits, the Singleton – Zenith line carries 5,100 MW and consumes 3,500 MVAr under contingency of Singleton – Kuykendahl. After adding the Lufkin – Canal circuits, under the same contingency, the Singleton – Zenith line carries 4,100 MW and consumes 2,000 MVAr, while the Lufkin – Canal line carries 2,600 MW and consumes 1,520 MVAr. Although the reactive losses are distributed to an additional set of circuits, they are still high enough to indicate a potential need for additional import capacity, or the need to operate the Lufkin to Canal circuit at a higher voltage (due to reduced impedance, higher voltage circuits can support higher power flows with reduced reactive power requirements).

A new import pathway from the west (Salem to North Belt) was analyzed for both the dispatch with increased flows from the west and south and the dispatch with increased flows from the north. Again, this pathway was found to be inadequate to meet the import needs of the region.

This analysis indicates that without significant resource additions, Houston will likely need at least two additional import paths by year 2030. The appropriate location of these new import paths will depend on expected locations of expansion resources

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This analysis indicates that without significant resource additions, Houston will likely need at least two additional import paths by year 2030. The appropriate location of these new import paths will depend on expected locations of expansion resources.

7.2.3 Lower Rio Grande Valley Area

The Rio Grande Valley consists of the southern portion of Texas extending from Laredo to the south. The southern-most portion of this region, called the Lower Rio Grande Valley region, includes only the area surrounding the cities of McAllen, Edinburg, Harlingen, and Brownsville. Pockets of these areas are experiencing very rapid population growth. By 2030, the South weather zone is forecasted to 7,325 MW of peak load; the counties of Starr, Hidalgo and Cameron are forecasted to have 3,870 MW of peak load.

The city of Laredo is served by one (RPG-approved) 345 kV line extending from Miguel (south of San Antonio), and five 138 kV lines: one connecting to Eagle Pass; another connecting to more network in Frio county; another extending east; and another extending south. The Lower Rio Grande Valley cities of McAllen, Edinburg, Harlingen, and Brownsville are served by two 345-kV single-circuit transmission lines and two 138-kV single-circuit transmission lines, all extending south from Corpus Christi. Due to electrical characteristics, long 345-kV lines such as the circuits that service the Lower Rio Grande Valley tend to have a stability limit below their thermal rating, thus reducing the effective capacity of the line.

Contingency and transfer capacity analyses indicate that without additional resource development in the Valley area, an additional import path is likely to be required. This is true even if second circuits are placed on both of the existing single-circuit lines currently connecting Corpus Christi to the Valley (installing these second circuits may not be cost-effective as it may require rebuilding the existing towers). A new 345-kV circuit may also be required to connect the cities of Rio Hondo and Edinburg, possibly along the southern edge of the lower Valley.

7.2.4 San Antonio/Austin Area

A similar evaluation of the San Antonio/Austin area is on-going. The results of this analysis will be presented to the Long-Term Study Task Force when it is complete.

8 Future Work

The work described in this section reflects specific technical analyses that are contemplated at this time. These activities are in addition to the stakeholder discussions and expectations described in Volume 1.

8.1 Water Availability Analysis

Adequate surface water supplies are a vital component of the current ERCOT system. In order to maintain reliability of the system, sufficient water resources are required. Natural gas-fired, nuclear and coal units rely heavily on water for cooling purposes. This water may be sourced directly from nearby lakes, rivers or the local municipality. During extreme summer weather, generators may be de-rated or outaged due to environmental restrictions and low water levels (drought conditions). In conjunction with high loads due to high temperatures, this could lead to shortage in capacity. Since Texas is a drought-prone state, the impact of reduced water levels on generator capacity needs to be determined.

The analysis of potential impacts of water is underway; results should be available to be incorporated into scenario development analysis later this year. The analysis began with a review of the impacts of drought conditions on system capacity in the past. Using EIA – 860 annual generator reports and ERCOT maps, generators in ERCOT that are water-cooled were mapped to their water sources: lakes, rivers, groundwater or municipalities. There were some generators, however, for which the water sources were not obvious. For these, the mapping was somewhat arbitrary. Historical monthly stream flow data for rivers (1991 - 2011) and percent-fullness information for lakes (1991 - 2011) were obtained from the Texas Water Development Board (TWDB) and U.S. Geological Survey (USGS).

In order to identify the months and years with the worst drought conditions, National Oceanic and Atmospheric Administration's Drought Severity Index (DSI) was used. Generators drawing cooling water from water sources that showed below average water levels and discharge rates during months with the lowest DSI were singled out. These generators, however, were not outaged/de-rated during those months. As an alternate approach, data regarding de-ration and outages during those months were studied and generators that were outaged/de-rated due to cooling-related problems were shortlisted. Communication with resource entities owning these units, though, revealed no direct link between the capacity reduction and water shortage.

The process was refined by more accurately mapping generators to their respective water sources and also using parameters other than fullness levels of lakes/reservoirs and discharge rates of rivers as indicators of impending water problems. As a part of a recent survey of preparedness for extreme weather conditions, ERCOT asked generators to provide information regarding their cooling water sources and their experiences with water scarcity. With this information, generators can be mapped precisely with their respective water sources, and details such as date and time of deration/outage due to cooling water shortage and the reduction in capacity in case of deration can be determined.

Concurrently, Sandia National Laboratories, in conjunction with the Western Governors' Association, the Western Electric Coordinating Council, and ERCOT, is conducting an analysis of the potential impact of sustained drought conditions on electric generation and grid reliability in the Western United States.

This study has three overarching objectives:

1. Develop an integrated Energy-Water Decision Support System (DSS) that will enable planners in the Western Interconnection to analyze the potential implications of water stress for transmission and resource planning.
2. Pursue the formulation and development of the Energy-Water DSS through a strongly collaborative process between ERCOT, WECC, Western Governors' Association (WGA), the Western States Water Council (WSWC) and their associated stakeholder teams.
3. Exercise the Energy-Water DSS to investigate water stress implications of the transmission planning scenarios put forward by ERCOT, WECC, WGA, and WSWC.

The lead entity for this effort is Sandia National Laboratories (Sandia) supported by Argonne National Laboratory, Idaho National Laboratory, the National Renewable Energy Laboratory, Pacific Northwest National Laboratory, the University of Texas, and the Electric Power Research Institute.

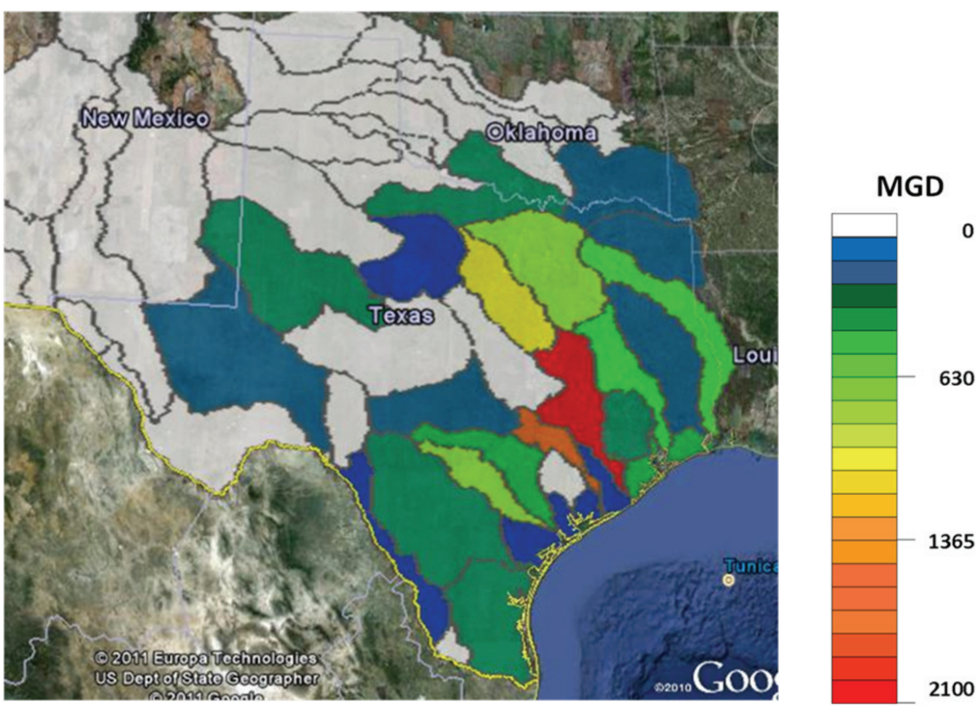
The foundation for the Energy-Water DSS is Sandia's Energy-Power-Water Simulation (EPWSim) model (Tidwell et al. 2009). This decision framework is formulated within a system dynamics architecture and implemented within the commercial software package Studio Expert 2008, produced by Powersim, Inc. (www.powersim.com). The model is designed to operate on an annual time step with a spatial extent that includes the western United States; however, each interconnection can be investigated independently. EPWSim has been modified to accept thermoelectric power production data directly from ERCOT and WECC's PROMOD IV modeling. Specifically, each interconnection provides PROMOD IV output in the form of annual and monthly power production for each thermoelectric power plant (existing and future). This data is then used to calculate the water implications of the proposed fleet/operational schedules.

At its highest level, EPWSim is organized according to four primary sectors: demographics, thermoelectric water demand, non-thermoelectric water demand, and water supply. The demographic sector model simulates changes in population and gross state product (GSP) that in turn drives the demand for water in the non-thermoelectric sector. Within the thermoelectric water demand module, thermoelectric power production output from PROMOD IV modeling is used to calculate associated water withdrawals and consumption at each thermoelectric plant. The model allows control of the type of cooling (i.e., open-loop, closed-loop tower, closed-loop pond, or air cooled) and source of water (surface water, groundwater, saline) utilized in all new construction. For the non-thermoelectric water demand module both withdrawals and consumption are calculated according to the primary use sectors, municipal, industrial, mining, livestock, and agriculture. These growing demands are then compared to various water supply metrics to identify regions in danger of water stress. Additional detail on the model can be found in Tidwell et al. (2009).

The decision support tool is designed to be accessible to the professional and lay public alike, requiring no specialized software. This framework provides an interactive environment to explore trade-offs, and “best” alternatives among a broad list of energy/water options and objectives, facilitating tailored analyses over different geographical regions and scales (e.g., ERCOT, state, county, watershed). The model operates in real-time with a user-friendly interface that includes slider bars, buttons and switches for changing key input variables, and real-time output graphs, tables, and geospatial maps (displayed interactively through Google Earth™) showing results. These features allow a wide range of users to experiment with alternative electric power-water use strategies and learn from the results.

Initial analysis indicates that thermoelectric power production in ERCOT accounted for the withdrawal of 9,712 million gallons of water per day (MGD), representing the largest user of water in the region. Coal and gas steam plants accounted for the vast majority of the thermoelectric withdrawals. Withdrawals by other sectors include 4,760 MGD for agriculture, 3,903 MGD for municipal uses, 285 MGD by industry, and 123 MGD for mining. Figure 20 shows how these withdrawals for thermoelectric generation are unevenly distributed across the ERCOT region.

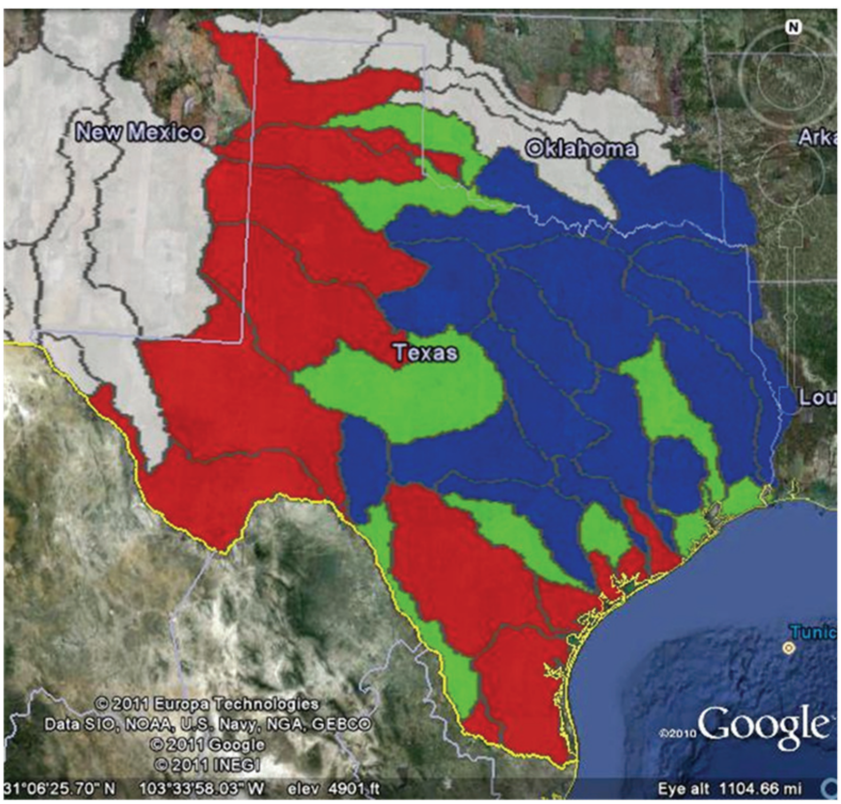
Figure 26: Thermoelectric water withdrawal in 2010



Consumption shows a very different relationship across the competing water sectors. Agriculture is the largest consumer of water at 3,850 MGD followed by municipal at 1,122 MGD, mining at 123 MGD, and industry at 110 MGD. Consumption by thermoelectric generation only accounts for 242 MGD, significantly smaller than the agriculture or municipal sectors.

Water stress occurs where the demand for water approaches the accessible supply. To explore the potential for water stress a map at the 6-digit watershed level has been developed. Mean gauged stream flow is taken as a measure of water supply while total water consumption in the watershed is taken as a measure of water demand. Where the ratio of supply to demand is large, shortages of water are unlikely, where the ratio is small, supply is on the order of demand thus there is little room for new growth. For the purposes of this analysis, areas prone to water stress are taken as regions with a supply to demand ratio of 2 or less. While this value is somewhat arbitrary it does represent a natural threshold in the data. Areas prone to surface water stress are given in Figure 21.

Figure 27: Watersheds prone to water stress in 2010



Red - High Risk
Green - Moderate Risk
Blue - Low Risk
White - Out of Region

A quick review of the data reveals that much of western and southern Texas is prone to water stress largely reflecting the aridity of the region. While it is not impossible to site a new power plant in areas prone to water stress it is likely to be much more difficult to obtain necessary water permitting. Also, this is but one metric that can be used to assess water availability. Future analyses will explore a broader range of metrics, as discussed below.

Efforts are currently being made to improve power plant level water withdrawal and consumption estimates for the current fleet along with verifying information on cooling technology and source of water. Potential impacts due to new policies on open-loop cooling and/or carbon emissions are also being explored. Potential future water requirements for extraction and processing of traditional (e.g., coal, oil) and non-traditional (e.g., oil shales, biofuels) energy fuels are being mapped. The project team is also working directly with state water managers to acquire, integrate and vet regional water use and supply data into the energy-water decision support system. This analysis considers water availability under both normal and drought conditions. Beyond the physical availability of water, the project team is working with state water managers to model the institutional controls (e.g., water rights) on water within their state.

Ultimately the output from the Energy-Water DSS will be tailored to the specific needs of the ERCOT transmission planning team. The DSS is designed to work directly with PROMOD IV simulation results for the selected planning scenarios. Water implications associated with these scenarios will be evaluated by the Energy-Water DSS. Additionally, simulation results will assist in plant siting and technology choices by providing insight into the variability of water availability across the ERCOT region.

8.2 Modeling Variable Generation

With nearly 10 GW of wind generation capacity installed, and much more wind generation being analyzed as part of the long-term study scenarios, accurate modeling of wind power and other variable generation resources is important. In order to derive usable results from production-cost models with high levels of variable generation, both the variable nature of the generation, as well as the forecasting error must be appropriately incorporated into the model input. These characteristics of variable generation will have an impact on both the unit commitment and security-constrained economic dispatch (SCED) algorithms of the production cost model runs.

Over the past few years wind forecasting techniques have improved significantly as forecasters have adapted their models to better reflect real world operations. Still, operational experience has shown that there are often large deviations among the day-ahead forecasts in unit commitment decisions and actual real-time wind power availability operational data. This result justifies a different approach for the modeling of wind generators when compared to conventional generators in production cost models. As part of this long-term study, ERCOT has been developing a new approach to modeling the variability and predictability of variable generation resources.

Data from ERCOT operations has been analyzed to extract the statistical characteristics of both the day-ahead historic wind forecast values and the wind power available in real time. Forecast values are not only related on average to actual real-time values but also to the values forecasted for the previous hours. In other words, if the day-ahead forecast is accurate for one hour it will probably be accurate for the next hour as well, while the same is true for inaccurate forecasts. In order to capture the relationship described above a family of probability matrices of the following form was extracted from the operational data:

$$P(DAFW_t = X|RTAW_t = Y \cap DAFW_{t-1} = Z)$$

Where $DAFW_t$ is the day-ahead forecasted wind for hour t in the year, and $RTAW_t$ is the real-time actual wind for hour t in the year.

These probabilities capture the likelihood for the forecast of an hour to have attained a specific value when the actual energy realized – which in our case is represented by the wind power profiles in the production cost simulation – and the forecast of the previous hour are known. Having these transition probability matrices available and starting from the first hour of the year we can now proceed with performing a Markov Chain Monte Carlo simulation. Using the wind power profiles as a pivot, the analysis moves from one hour of the year into the next by performing random draws. In that way it creates a simulated, pseudo-forecast to be employed by the unit commitment algorithm while the original wind power profiles are used by SCED. This step can be repeated a number of times in order to create a family of simulated forecasts, a feature that allows analysis of the relationship between different wind forecast patterns and system wide costs.

This methodology creates a pseudo-forecast of wind power generation that exhibits a relationship to the hourly wind power profiles similar to the one between day-ahead forecasts and real-time wind availability. In this way the impact of wind generation forecast error is correctly modeled in the production cost simulations.

The last step of this part of the analysis is to prepare a forecast profile for each individual unit. Current analysis has been based on total aggregate wind data; in order to prepare forecasts for individual wind farms the forecast error will be distributed among units while adhering to the generating limits of the units (Pmin which is zero for all wind plants and Pmax). The following two formulas, depending on whether the forecasted values are higher or lower than the actual values, will be used to accomplish this.

$$\Delta P_{up} = \frac{P_{max} - P_{gen}}{\sum P_{max} - \sum P_{gen}} \times forecasterror$$

$$\Delta P_{down} = \frac{P_{gen}}{\sum P_{gen}} \times forecasterror$$

These equations will distribute the forecast error to the various wind units contingent upon how much capacity is available to each unit.

In order to further improve our modeling of wind generation resources, ERCOT is also evaluating the possibility of improving the wind generation patterns used in our production cost models. The patterns currently being used represent generic locations in 25 zones covering much of Texas; these patterns were derived using generic turbine power generation curves and average weather year conditions. These wind patterns could be improved by obtaining wind generation patterns derived using turbine power generation curves representative of actual turbine technologies installed in ERCOT at the actual locations of wind generation facilities. An additional improvement would be the use of actual historical weather patterns to generate the wind generation hourly profiles. Pairing these wind generation patterns with load profiles developed using weather patterns from those same years would provide realistic correlation between wind and load profiles in our models. It also will be necessary for this study to use these same techniques for solar power resources.

8.3 Operational Reliability Analysis

ERCOT is evaluating tools to provide an assessment of the operational reliability of a set of system resources, independent of existing ancillary service requirements. The purpose of this effort is two-fold. First, using these tools, sets of resource expansion units, as determined through economic analysis, can be reviewed to ensure that there are adequate resources to maintain system reliability. In the event that the calculated reliability index falls below a predetermined level, additional resources can be included in the set of expansion units, or additional constraints can be placed on the resource expansion analysis for that scenario. Second, these tools will facilitate cost/benefit analyses of emerging technologies that can support the reliability of the transmission system, but cannot meet the requirements of existing ancillary services. ERCOT expects to provide a status update on these efforts to the Long-Term Planning Task Force by the end of the third quarter of 2011.

8.4 Transmission Analysis

The analysis of cost-effective transmission projects for the Business as Usual scenario is just beginning. Following this analysis, transmission planning will be conducted for other scenarios, with the intent that the similarities and differences between future system needs in different scenarios will provide insights into the underlying relationships of market forces, regulatory changes, resource constraints and changing system transmission needs.

Determining the set of transmission projects that cost-effectively ensure adequate levels of reliability will require a combination of reliability analyses and economic analyses. As part of this study, different processes to identify and assess transmission projects will be reviewed, and recommendations for on-going studies will be developed.

Appendix A: List of References

Alternative Energy Institute, West Texas A&M University (Wind Data)

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Appendix B: Glossary of Terms and Acronyms

AC-Alternating Current

AEO- Annual Energy Outlook

AEP- American Electric Power

ARRA- American Reinvestment and Recovery Act 2009 - abbreviated ARRA and 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 typically operates at a capacity factor of 65% or greater on an annual basis.

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.

Carbon dioxide - Carbon dioxide (CO_2) is an important greenhouse gas because it is thought 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.

Carbon Sequestration - The storage of carbon dioxide in a solid material through biological or physical processes

CC – Combined Cycle

CCS- Carbon Capture and Sequestration

CDR- ERCOT Capacity, Demand and Reserves Report

CEMS- Continuous Emissions Monitoring System

CHP- Combined Heat and Power, also known as cogeneration

CO2 – Carbon Dioxide

Combined Heat & Power - The use of a heat engine or a power station to simultaneously generate both electricity and useful heat for domestic or industrial processes

Controllable Load Resource - A Load Resource capable of reducing or increasing consumption under dispatch control (similar to Automatic Generation Control (AGC)) and provides Primary Frequency Response.

CT- Combustion Turbine

DC- Direct Current

Demand - Usage at a point in time, measured in MW or kW

Demand Response - A resource that is comprised of programs that compensate electricity users in exchange for the ability to interrupt or reduce their electric consumption when system demand is particularly high and/or system reliability is at risk

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 contiguous distribution substation areas

DOE- Department of Energy

DSI- Drought Severity Index

Economic Life- length of time a power plant is depreciated in a financial analysis

EE – Energy Efficiency

EIA- Energy Information Administration

EILS – Emergency Interruptible Load Service

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 8.7% of the nameplate capacity listed in the Unit Capacities tables, both installed capacity and planned capacity.

Emergency Interruptible Load Service - A special emergency service consistent with subsection (a) of P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Interruptible Load Service (EILS), used during an Energy Emergency Alert (EEA) Level 2B to reduce Load and assist in maintaining or restoring ERCOT System frequency. EILS is not an Ancillary Service.

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

Energy Efficiency - 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

Energy Limited Resource- In the PROMOD IV and MarketPower models, an energy limited resource is a resource that is non-dispatchable.

EPA- Environmental Protection Agency

EPWSim- Energy-Power-Water Simulation

ERCOT- Electric Reliability Council of Texas

Fixed costs - Costs that are independent of output

Forced Outage Rate (FOR) - is the probability that the unit will not be available for service when required.

GADS- Generating Availability Data System - is 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

GSP- Gross State Product

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

Insolation Groups – These are counties with average daily solar radiation of 4- 5 kWh/m2/day, 5 –7 kWh/m2/day and >7kWh/m2/day are considered to have medium, high and very high insolation respectively.

KWh- Kilowatt-hour

KWh/m2 –Kilowatt-hour per square meter

LaaR – Load Acting as a Resourse

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

LFG- Landfill Gas

Loss of load probability - Percent of time load is un-served

LTSTF- Long Term Study Task Force

Market Clearing Price (MCP)- is 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-amps

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" is 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.

NOx- 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 - is a tax credit that businesses creating electricity using renewable energy technology can apply to their income 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.

PSI- Pounds per square inch

PTC- Production Tax Credit

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 Product

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 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.

Scenario - A combination of sensitivity values used to generate portfolios

SDWG- Scenario Development Working Group

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 which 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 applications.

Solar thermal - Solar thermal is the harvest of thermal energy from sunlight. Common applications include domestic water heating, swimming pool heating, and commercial material drying. Through a thermodynamic energy conversion process, production of electricity is possible, and a handful of large solar-thermal electric power plants.

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 – These are units that the output from their operation could be switched either to the ERCOT system or to another reliability council such as the Southwest Power Pool (SPP)

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 - Coal, nuclear, hydro and natural gas resources that have historically been the most commonly used to supply electricity

TWDB- Texas Water Development Board

Un-served Energy – A condition that can exist when a utilities load can't be met by available generating resources causing a reduction in voltage or blackout

USGS- United States Geological Survey

Variable costs - Costs that change with unit output

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 C: Draft Scenario Information

	Policy Considerations			Economic Assumptions	Load/Demand Growth Modifiers	Technology Impacts	Fuel Concerns
	Environmental Regulations	Mandates	Siting Restrictions				
Business As Usual (BAU)							
Reduced Natural Gas Supply / High Natural Gas Prices	Carbon Reduction Initiatives: medium						High Natural Gas Prices
High Economic Growth	Carbon Reduction Initiatives: medium			Texas employment: high; leads to high demand for capital	Load growth rate: high		
Nuclear Incentives / Guarantees	Carbon Reduction Initiatives: high; all EPA initiatives in place					Enhanced federal loan guarantees for nuclear power	High Natural Gas Prices
High Renewables / High Economic Growth				Texas employment: high; leads to high demand for capital	Load growth rate: high	Add'l tax credits and decrease in capital costs for renewable resources	
Low CO2 Concerns / High Coal Prices						No PTC for renewables	High Coal prices
Long-Term Recession Question: How long?		No Technology Specific mandate for renewable generation		Texas employment: low; low demand for capital	Load growth rate: low	No PTC for renewables	Low coal and natural gas prices
Sustained Drought / High Environmental Regulations	Carbon Reduction Initiatives: high; all EPA initiatives in place	33 GW of renewable generation by 2030; of which 5 GW is non wind	Restricted water use and availability	New Technology requirements due to drought; increased demand for capital			Low coal prices; high natural gas prices
High Clean Energy Note: Define clean energy	Carbon Reduction Initiatives: high; all EPA initiatives in place	80% of energy from clean energy resources				Group Discussion	Group Discussion
Carbon Capture and Sequestration (CCS) Implementation	Carbon Reduction Initiatives: high; all EPA initiatives in place	CCS technology must be used on all new coal plants				Federal Loan Guarantees for CCS technology	High Natural Gas Prices
High Petroleum Prices				Group Discussion	Group Discussion	Group Discussion	Fuel Prices Increase
Retirement of Coal Fleet	All EPA initiatives are in place					Incentives to retire older coal plants	

Appendix D: Resource Modeling Data

Prototype Category Characteristics

Unit Type	Max Capacity	Installed Capital Cost	FLA Heat Rate	Min Cap	Min Down time	Min Run time
	MW	$/kW	MMBtu/kWh	%	Hrs	Hrs
Advanced Combined Cycle-H/G Type	400	919	7.1	62.5	8.0	6.0
Advanced Combustion Turbine-LMS100	100	771	9.2	70.0	3.0	2.0
Biomass	40	3,411	13.0	15.0	8.0	8.0
Conventional Combined Cycle-F Type	500	893	7.6	40.0	4.0	6.0
Conventional Combustion Turbine-F Type	170	679	10.5	75.0	1.0	1.0
IGCC	625	3,271	9.0	40.0	12.0	24.0
IGCC with CCS	539	4,851	10.7	45.0	12.0	24.0
Nuclear	1,100	5,130	10.3	55.0	48.0	168.0
Solar PV	100	4,274				
Solar Thermal	250	4,030				
Supercritical Coal	600	2,896	9.0	40.0	12.0	24.0
Supercritical Coal with CCS	625	4,582	12.0	40.0	12.0	24.0
Wind Onshore	100	2,322				

Unit Type	Var O&M	Fix O&M	Economic Life	SO2	NOx	CO2
	$/MWh	$/kW-yr	Yrs	llbs/MMBtu	llbs/MMBtu	llbs/MMBtu
Advanced Combined Cycle-H/G Type	2.9	14.6	20	0.0006	0.03	119
Advanced Combustion Turbine-LMS100	13.0	6.7	20	0.0006	0.01	119
Biomass	9.5	100.5	20			
Conventional Combined Cycle-F Type	3.0	14.4	20	0.0006	0.03	119
Conventional Combustion Turbine-F Type	8.0	7.0	20	0.0006	0.01	119
IGCC	5.8	48.9	30			
IGCC with CCS	7.0	69.3	30			
Nuclear	4.0	88.8	40			
Solar PV		16.7	20			
Solar Thermal		64.0	20			
Supercritical Coal	4.0	29.7	30	0.06	0.06	205
Supercritical Coal with CCS	7.4	63.2	30	0.06	0.06	10
Wind Onshore		28.1	20			

2. Existing Unit Category Characteristics

Unit Type	FLA Heat Rate	Min Cap	Min Down time	Min Run time	Var O&M	Fix O&M
	MMBtu/kWh	%	Hrs	Hrs	$/MWh	$/kW-yr
Gas Steam Reheat	12.0	38.0	8.0	8.0	8.00	13.25
Gas Steam Non-Reheat	13.0	43.0	8.0	8.0	5.00	20.50
Supercritical Gas Steam	11.0	28.0	8.0	8.0	6.50	15.75
Combustion Turbines (LM6000)	9.5	36.0	1.0	1.0	8.00	8.25
Combustion Turbines (E Class)	11.5	25.0	1.0	1.0	4.00	5.00
Combustion Turbines (F Class)	10.5	25.0	1.0	1.0	8.00	7.00
Nuclear	10.0	100.0	24.0	168.0	4.00	73.00
Coal	9.8	48.0	12.0	24.0	5.00	25.50
Combined Cycle (F Class)	1.6	32.0	4.0	6.0	3.00	13.25
Combined Cycle (LM6000)	8.0	36.0	8.0	4.0	5.00	12.00
Combined Cycle (E Class)	8.5	24.0	4.0	4.0	3.00	13.50
Biomass	13.0	25.0	6.0	8.0	9.50	13.25
Older Combustion Turbines	14.5	25.0	1.0	1.0	5.00	11.00
Diesel/Internal Combustion	9.0	20.0	1.0	1.0	3.50	11.50

3. Prototype Capital Cost ($/kW)

Year	Adv. Coal	Adv. Coal with CCS	IGCC	IGCC with CCS	Conv. CT (F Class)	Adv. CT (LMS100)	Conv. CC (F Class)	Adv. CC (G/H Class)	Nuclear	Wind 250 MW	Biomass	Solar PV 10 MW	Solar PV 100 MW
2011	2,896	4,582	3,271	4,851	679	771	893	919	5,130	2,322	3,411	5,493	4,274
2012	2,949	4,666	3,331	4,940	691	785	909	936	5,224	2,365	3,474	5,329	4,146
2013	3,003	4,752	3,392	5,031	704	800	926	953	5,320	2,408	3,538	5,168	4,021
2014	3,059	4,839	3,455	5,124	717	814	943	971	5,418	2,452	3,603	5,014	3,901
2015	3,115	4,928	3,518	5,218	730	829	961	988	5,518	2,498	3,669	4,863	3,783
2016	3,143	4,969	3,909	5,794	750	835	966	995	6,010	2,506	3,689	4,717	3,670
2017	3,200	5,060	3,981	5,901	764	850	984	1,013	6,121	2,552	3,757	4,576	3,561
2018	3,259	5,153	4,054	6,010	778	866	1,002	1,032	6,233	2,599	3,826	4,439	3,453
2019	3,319	5,248	4,129	6,120	792	882	1,020	1,050	6,348	2,647	3,896	4,305	3,350
2020	3,380	5,344	4,205	6,233	807	898	1,039	1,070	6,465	2,696	3,968	4,177	3,249
2021	3,442	5,442	4,282	6,347	822	914	1,058	1,089	6,583	2,745	4,041	4,051	3,152
2022	3,506	5,542	4,361	6,464	837	931	1,078	1,109	6,705	2,796	4,115	3,929	3,058
2023	3,536	5,587	4,852	7,192	860	937	1,085	1,116	5,208	2,807	4,139	3,812	2,967
2024	3,601	5,690	4,941	7,325	876	954	1,105	1,137	5,303	2,859	4,215	3,698	2,877
2025	3,668	5,794	5,032	7,459	892	972	1,125	1,158	5,401	2,911	4,292	3,587	2,791
2026	3,735	5,901	5,124	7,596	908	990	1,146	1,179	5,500	2,965	4,371	3,447	2,682
2027	3,804	6,009	5,218	7,736	925	1,008	1,167	1,201	5,601	3,019	4,452	3,311	2,576
2028	3,874	6,120	5,314	7,878	942	1,026	1,189	1,223	5,704	3,075	4,533	3,168	2,466
2029	3,945	6,232	5,412	8,023	959	1,045	1,210	1,245	5,809	3,132	4,617	3,019	2,350
2030	4,017	6,347	5,512	8,171	977	1,064	1,233	1,268	5,916	3,189	4,702	2,864	2,229

4. Fuel Forecast

Year	Natural Gas	High Natural Gas*	PRB†	Lignite†	Uranium
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2011	4.90	9.90	1.17	2.27	0.94
2012	4.85	9.85	1.14	2.24	0.94
2013	4.99	9.99	1.13	2.23	0.94
2014	5.04	10.04	1.15	2.25	0.94
2015	5.22	10.22	1.23	2.33	0.94
2016	5.37	10.37	1.28	2.38	0.94
2017	5.55	10.55	1.34	2.44	0.94
2018	5.76	10.76	1.39	2.49	0.94
2019	5.95	10.95	1.45	2.55	0.94
2020	6.18	11.18	1.51	2.61	0.94
2021	6.45	11.45	1.57	2.67	0.94
2022	6.73	11.73	1.64	2.74	0.94
2023	7.05	12.05	1.71	2.81	0.94
2024	7.38	12.38	1.79	2.89	0.94
2025	7.70	12.70	1.87	2.97	0.94
2026	8.00	13.00	1.95	3.05	0.94
2027	8.32	13.32	2.02	3.12	0.94
2028	8.60	13.60	2.09	3.19	0.94
2029	8.86	13.86	2.18	3.28	0.94
2030	9.14	14.14	2.26	3.36	0.94

*High Natural Gas price is the EIA Reference Case forecast plus $5/MMBtu

†PRB and Lignite costs do not include transportation costs (i.e., rail costs to deliver from the mine to the power plant)

Appendix E: Generation Siting Requirements

Generation Type	Gas Pipeline Density/Capacity	Railroad Density	Urban Density	Non-Attainment Zone	Amount of Significant Environmental Constraint	Wind Conditions	Solar Thermal Conditions	Surface Water Density	Solar PV Conditions
	High (H); Medium (M); Low (L); Very Low (VL)	High (H); Medium (M); Low (L); Very Low (VL)	Very High (VH); Medium/Low (L)	Yes (Y); Potential (P); No (N)	High (H); Medium (M); Low (L)	1-7	Good (G); Average (A); Below Average (BA); Poor (P)	High (H); Medium (M); Low (L);	Very High (VH); High (H); Medium (M)
Wind good			L		M or L	3-4			
Wind Average			L		M or L	2			
Solar Thermal Good			L		M or L		G	H	
Solar Thermal Average			L		M or L		G or A	H or M	
Natural Gas Combustion Turbine Good	H		L	N	M or L				
Natural Gas Combustion Turbine Average	H or M		L	N	M or L				
Natural Gas Combined Cycle Good	H		L	P or N	M or L			H or M	
Natural Gas Combined Cycle Average	H or M		L	P or N	M or L			H or M	
Coal		H or M	L	N	L			H or M	
Biomass		H or M or L	L		M or L				
Nuclear			L					H	
Geo-Thermal			L		M or L				
Solar PV Good									VH or H
Solar PV Average									