the ABWR severe accident release sequences that might be expected to involve core-concrete interactions have frequencies of less than 1 x 10^{-8} Ryr^{-1}. On this basis, the NRC staff believes that a basemat melt-through probability of 1 x 10^{-7} Ryr^{-1} is reasonable and still conservative.

The groundwater pathway is more tortuous and affords more time for implementing protective actions than the air pathway and, therefore, results in a lower risk to the public. As a result, the NRC staff concludes that the risks associated with releases to groundwater are sufficiently small that they would not have a significant effect on determination of suitability of the STP site.

5.11.2.4 Summary

The NRC staff reviewed the risk analyses in the ER, FSAR, and DCD for the purpose of determining the potential environmental impacts of severe accidents. Based on this review, the NRC staff concludes that the overall severe accident risk for proposed STP Units 3 and 4 is low. The NRC staff is currently reviewing the risk analyses presented in the FSAR to confirm this conclusion and determine compliance with the NRC's safety regulations (10 CFR 52.79) and the Commission's safety goals. The results of that review will be presented in the Safety Evaluation Report prepared by the staff regarding the COL application. The NRC staff also conducted a confirmatory analysis of the probability-weighted consequences of severe accidents for proposed STP Units 3 and 4 using the MACCS2 code. The results of both the STPNOC analysis and the NRC staff analysis indicate that the environmental risks associated with severe accidents if two ABWR reactors were to be located at the STP site would be small compared to risks associated with operation of the current-generation reactors at the STP and other sites. On these bases, the NRC staff concludes that the environmental impact of the probability-weighted consequences of severe accidents at the STP site would be SMALL for the proposed ABWRs.

5.11.3 Severe Accident Mitigation Alternatives

STPNOC has applied for a license to construct and operate two ABWRs at the STP site. The ABWR design (see Appendix A to Part 52–Design Certification Rule for the U.S. Advanced Boiling Water Reactor) incorporates many features intended to reduce severe accident CDFs and the risks associated with severe accidents. The effectiveness of the ABWR design features is evident in Table 5-18 and Table 5-19, which compare CDFs and severe accident risks for the ABWR with CDFs and risks for current-generation reactors including existing STP Units 1 and 2. CDFs and risks have generally been reduced by a factor of 100 or more when compared to the existing units.

The purpose of the evaluation of severe accident mitigation alternatives (SAMAs) is to determine whether there are severe accident mitigation design alternatives (SAMDAs) or procedural modifications or training activities that can be justified to further reduce the risks of severe accidents (NRC 2000b). Consistent with the direction from the Commission to consider the SAMDAs at the time of certification, the ABWR vendor (GE 1994) and the NRC staff, in its environmental assessment (EA) accompanying the rule (NRC 1996b), have considered a design alternatives for a ABWR at a generic site. The NRC staff incorporates that EA into this EIS by reference.

On these bases, the NRC staff concluded (NRC 1996b):

> Because the ABWR design already includes numerous plant features designed to reduce core-damage frequency and risk, additional plant improvements would be unable to significantly reduce the risk of either internally or externally initiated events.... Moreover, with the features already incorporated in the ABWR design, the ability to estimate core-damage frequency and risk approaches the limitations of probabilistic techniques. ... Although improvements in these areas may introduce additional contributors to core-damage frequency and risk estimates, the NRC staff does not expect that they would be significant in absolute terms.

Further, 10 CFR Part 52 Appendix A Section VI(B)(7) provides resolution for:

> All environmental issues concerning severe accident mitigation design alternatives associated with the information in the NRC's final environmental assessment for the ABWR design and Revision 1 of the technical support document for the ABWR, dated December 1994, for plants referencing this appendix whose site parameters are within those specified in the technical support document.

In its ER, STPNOC reasserted the reactor vendor's claim that there were no SAMDAs that would be cost beneficial. STPNOC did not do a STP site-specific evaluation of design alternatives. STPNOC did assess the maximum benefit that would accrue if a single procedural or training alternative could eliminate all remaining risk associated with the ABWR design by updating the analysis submitted for design certification (GE 1994) with STP site specific information and procedures set forth in NUREG/BR-0184 (NRC 1997b). STPNOC determined that the maximum benefit at the STP site would be less than $20,000. A more realistic assessment would show that the potential benefit would be substantially less than the maximum because no alternative can reduce the remaining risk to zero.

The NRC staff has limited its review to determination of whether or not the STP site characteristics are within the site parameters specified in the ABWR technical support document (GE 1994). The technical support document does not contain a specific list of site parameters. However, the population dose risk is given as 4.5×10^{-3} person-rem per year. The population dose risk is based on release characteristics including amount and probability, meteorological conditions, and population distribution and is, therefore, the appropriate site parameter for purposes of comparison.

STPNOC evaluated the population dose risk for the STP site using the MACCS2 code with site specific meteorological and population distribution. The population dose risk derived from the site-specific analysis discussed in the ER and shown in Table 5-18 is 4.1×10^{-3} person-rem per year. Independent review by the NRC staff confirmed this value. On this basis, the NRC staff concludes that the STP site characteristics are bounded by the site parameters considered during the ABWR design certification, and that the environmental issues related to the SAMDAs have been resolved by rule.

SAMDAs are a subset of SAMAs. SAMAs also include procedural and training alternatives. STPNOC did not develop procedural and training alternatives. In its ER, STPNOC (2009a) states that "[e]valuation of specific administrative controls would occur when the proposed Units 3 and 4 design is finalized and plant administrative processes and procedures are being developed." Pursuant to regulatory requirements, procedures must be in place and training must be completed prior to loading fuel.

5.11.4 Summary of Postulated Accident Impacts

The NRC staff evaluated the environmental impacts from DBAs and severe accidents for an ABWR at the STP site. Based on the information provided by STPNOC and NRC's own independent review, the staff concludes that the potential environmental impacts (risks) from a postulated accident from the operation of the proposed Units 3 and 4 would be SMALL and additional mitigation would not be warranted.

5.12 Measures and Controls to Limit Adverse Impacts During Operation

In its evaluation of environmental impacts during operation of proposed Units 3 and 4, the review team relied on STPNOC's compliance with the following measures and controls that would limit adverse environmental impacts:

- Compliance with applicable Federal, State, and local laws; ordinances, and regulations intended to prevent or minimize adverse environmental impacts,
- Compliance with applicable requirements of permits or licenses required for operation of the new unit (e.g., Corps' Section 404 Permit, NPDES),
- Compliance with existing STP Unit 1 and 2 processes and/or procedures applicable to proposed Unit 3 and 4 environmental compliance activities for the STP site,
- Compliance with STPNOC procedures applicable to environmental control and management, and
- Implementation of BMPs.

8.0 Need for Power

Chapter 8 of the U.S. Nuclear Regulatory Commission's (NRC) *Environmental Standard Review Plan* (ESRP) (NRC 2000) guides the NRC staff's review and analysis of the need for power from a proposed nuclear power plant. In addition to the ESRP guidance, the NRC addressed need for power in a 2003 response to a petition for rulemaking (68 FR 55910). In the 2003 response, the NRC reviewed whether or not need for power should be considered in NRC environmental impact statements (EISs) prepared in conjunction with applications that could result in construction of a new nuclear power plant. The NRC (68 FR 55910) concluded that:

> The need for power must be addressed in connection with new power plant construction so that the NRC may weigh the likely benefits (e.g., electrical power) against the environmental impacts of constructing and operating a nuclear power reactor. The Commission emphasizes, however, that such an assessment should not involve burdensome attempts to precisely identify future conditions. Rather, it should be sufficient to reasonably characterize the costs and benefits associated with proposed licensing actions.

While the NRC will perform a need for power analysis in its EIS, the NRC also stated in its response to the petition that (1) the NRC does not supplant the states, which have traditionally been responsible for assessing the need for power-generating facilities, for their economic feasibility and for regulating rates and services; and (2) the NRC has acknowledged the primacy of state regulatory decisions regarding future energy options (68 FR 55910).

8.1 Description of Power System

8.1.1 Description of STPNOC

The purpose of proposed Units 3 and 4 at the South Texas Plant Electric Generating Station (STP) site is to provide baseload generation for use by the owners and/or for eventual sale on the wholesale market. As discussed in Chapter 1, it is planned that Unit 3 would be owned by Nuclear Innovation North America (NINA) South Texas 3 LLC and the City of San Antonio, Texas, through the City Public Services Board (CPS Energy), and that Unit 4 would be owned by NINA South Texas 4 LLC and CPS Energy. Both proposed units would be baseload merchant generator plants. NINA South Texas 3 LLC and NINA South Texas 4 LLC intend to sell their share of the power from Units 3 and 4 on the wholesale market. CPS Energy may either use its share of Units 3 and 4 to supply the needs of its service area and/or sell the power on the wholesale market (STPNOC 2009).

The applicant, STP Nuclear Operating Company (STPNOC), stated in its application for combined licenses (COLs) that proposed Units 3 and 4 at the STP site would be unregulated entities. The electric utility industry in the State of Texas was deregulated in 2002. One of the principal owners of proposed Units 3 and 4 (NINA) is a merchant generator that does not have a specific service area. The other principal owner, CPS Energy, is a municipal utility that sells capacity in excess of its own retail service needs in the San Antonio area into the Electric Reliability Council of Texas (ERCOT) wholesale market (STPNOC 2009). Currently, CPS Energy has several wholesale contracts, for which it is seeking renewal, that amount to firm power obligations. In addition, CPS Energy's native retail service area of Bexar County and the San Antonio vicinity also is growing in population and represents additional potential demand. However, in estimating the need for power for proposed Units 3 and 4, STPNOC is relying on ERCOT's forecast of the overall demand for power in the ERCOT region rather than CPS Energy's specific service and contract obligations (STPNOC 2009).

8.1.2 Description of ERCOT

STPNOC has defined the region of interest for evaluating the need for power as the entire area served by ERCOT, the independent system operator (ISO) for the electric grid for most of the State of Texas (Figure 8-1).

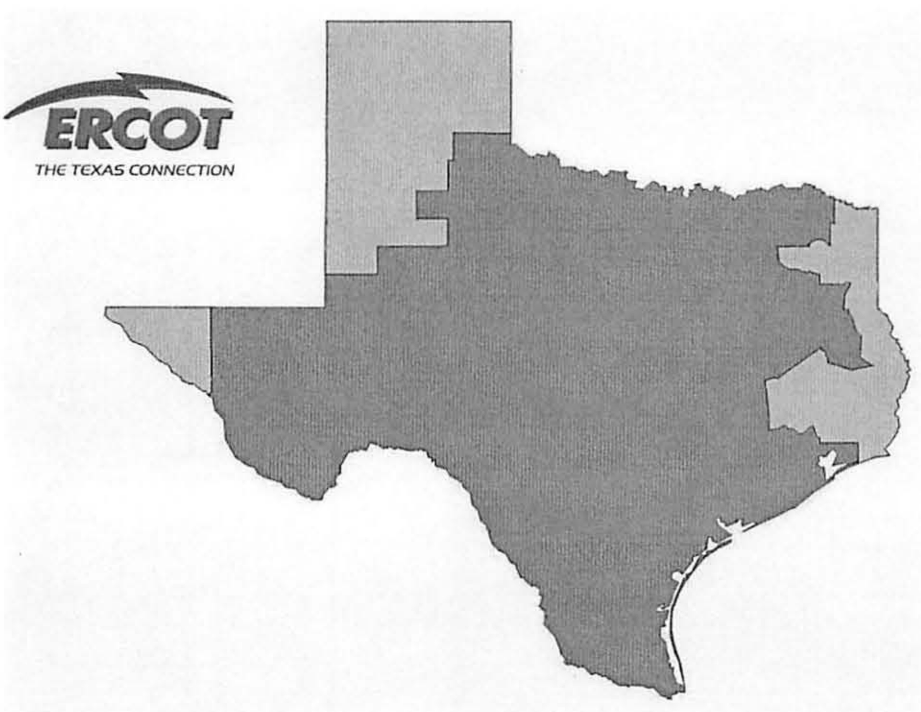

Figure 8-1. Map of the ERCOT ISO Service Area (STPNOC 2009)

ERCOT is a membership-based nonprofit corporation formed under 26 USC 501(c)(6) of the Internal Revenue Code. It is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas (PUCT) and the Texas Legislature. ERCOT's members include retail consumers, investor-owned and municipally-owned utilities, rural electric cooperatives, river authorities, independent generators, power marketers, and retail electric providers (ERCOT 2008a). The ERCOT board of directors is made up of independent members, consumers, and representatives from each of ERCOT's electric market segments. The board of directors appoints ERCOT's officers, who direct and manage day-to-day operations (ERCOT 2008b). ERCOT's responsibilities include:

- managing the flow of electric power to approximately 22 million Texas customers, representing 85 percent of the State's electric load,
- scheduling power on an electric grid with 40,000 mi of high-voltage transmission lines and more than 550 generation units,
- managing financial settlements for the Texas competitive wholesale bulk-power market, and
- administering of customer switching for 6.5 million Texans in competitive choice areas (ERCOT 2008c).

As explained in STPNOC's environmental report (ER), the history of the deregulation of the previously regulated electric supply market in the ERCOT region began in 1995, when the Texas Legislature passed Senate Bill 373, introducing wholesale competition into Texas' intrastate market. PUCT adopted rules requiring all transmission system owners to make their transmission systems available for use by others at prices and on terms comparable to each respective owner's use of its system for its own wholesale transactions. In 1999, by terms of Senate Bill 7, choice was further broadened by allowing retail customers of investor owned utilities (IOUs) to choose their electric energy supplier (electric cooperatives and municipally owned utilities such as CPS Energy had the option not to allow their retail customers to join this arrangement and CPS Energy has not allowed this). Formerly, vertically integrated IOUs had to separate their retail energy service activities from regulated utility activities and to unbundle their generation, transmission/ distribution, and retail electric sales functions into separate units, which could be sold off or else operated as independent entities at arm's length from each other. Transmission and distribution entities (including electric cooperatives and integrated municipally owned utilities) are fully regulated by the PUCT and must make their facilities available on an open and non-discriminatory basis. IOUs and independent power producers owning generation assets must be registered as power generation companies with the PUCT and must comply with certain rules that are intended to protect consumers, but they are otherwise unregulated and may sell electricity in private bilateral transactions and at market prices (STPNOC 2009).

As explained in the ER and confirmed in the references below, under deregulation in Texas, utilities no longer perform the comprehensive analysis and planning functions that they once did. The central planning organization under the new Texas market is the ERCOT ISO. State law assigns these obligations to ERCOT, under the oversight of the PUCT. The analyses, reports, system planning processes, and criteria development from ERCOT are the key measures for determining resource needs in the State [see e.g., Texas Utility Code Ann. §§ 39.155(b) and 39.904(k)] (Texas Utilities Code 2009). STPNOC is relying upon several studies performed for or by ERCOT on need for power in ERCOT's capacity as a regional transmission organization. Regional transmission organizations were created as a result of Order No. 2000 issued by the Federal Energy Regulatory Commission (FERC), which encouraged the voluntary formation of such organizations to administer the transmission grid on a regional basis throughout North America (FERC 1999, 2008).

The ERCOT ISO region is also the geographic territory of the Texas Regional Entity (Texas RE) (ERCOT 2008g). Texas RE is one of the eight approved regional entities in North America under the North American Electric Reliability Corporation (NERC). NERC's mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces reliability standards, monitors the bulk power system, assesses and reports on future transmission and generation adequacy, and offers education and certification programs to utility industry personnel (NERC 2008a). Texas RE is a functionally independent division of ERCOT and is independent of all users, owners, and operators of the bulk power system in the State of Texas. As mandated by the delegation agreement with NERC approved by FERC, Texas RE performs the regional entity functions described in the Energy Policy Act of 2005 for the ERCOT region. Texas RE develops, monitors, assesses, and enforces NERC reliability standards within the ERCOT region. In addition, Texas RE has been authorized by the PUCT and is permitted by NERC to investigate compliance with the ERCOT protocols and operating guides, working with PUCT staff regarding any potential protocol violations (ERCOT 2008g).

The ERCOT region is almost entirely isolated from other NERC regions, electrically speaking. The formation of what is now the ERCOT region dates from the beginning of World War II, when several Texas utilities banded together and interconnected to support the war effort as the Texas Interconnected System (STPNOC 2009). Texas Interconnected System formed ERCOT in 1970 to comply with NERC requirements (ERCOT 2008d). Since the goals of these entities over the years have been to ensure the reliability of the Texas grid rather than to interconnect with the rest of the country, importing electric power into, or exporting electric power out of the ERCOT region effectively is not practicable. As a practical matter this means that electricity demand in the ERCOT region must be served from generation within ERCOT and that power generated in excess of demand within ERCOT cannot effectively reach other markets (STPNOC 2009).

8.1.3 Description of the ERCOT Analytical Process

NRC guidance provides that additional independent review by the NRC may not be needed when need for power analyses prepared by an independent third party such as an affected state, NERC reliability council, or regional transmission organization is sufficiently (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty (NRC 2000). Taken in aggregate, the staff determined that the studies and reports summarized in Section 8.4 satisfy the four tests .

8.1.3.1 Systematic Test

The review team determined ERCOT has a systematic and iterative process for load forecasting and reliability assessment that is updated annually. ERCOT is required by the PUCT to provide extensive studies, issue reports, make recommendations for transmission system needs and resource adequacy, and even make legislative recommendations to further those objectives (STPNOC 2009). The essence of ERCOT is that it is a neutral and independent source of information on electricity issues for policymakers. The development of these reports is subject to a vigorous stakeholder input process.

Membership in ERCOT is open to any entity that meets any of the segment definitions as set forth in the ERCOT bylaws. Members must be in an organization that either operates in the ERCOT region or represents consumers within the ERCOT region. The members are organized by the following market segments: consumers, cooperatives, independent generators, independent power marketers, independent retail electric providers, investor owned utilities, and municipal utilities (ERCOT 2005b, 2008l). ERCOT uses industry best practices and methodological approaches to determine future system reliability and the need for new generating capacity. The forecasts and methods are vetted by ERCOT membership. Moreover, the analyses and actions of ERCOT based on these analyses are overseen by the PUCT.

8.1.3.2 Comprehensive Test

The review team finds that, in aggregate, the ERCOT studies and reports discussed in Section 8.4 are comprehensive. ERCOT (ERCOT 2008e) takes account of trends in customer demand (including the underlying factors of population, income, and employment growth and impacts of both normal and extreme weather conditions. The electricity supply analysis takes into account changes in generation profile and potential generation additions; new generating resources planned for construction in Texas; trends in electric power generation by fuel source; trends in consumption by class of consumer; forecasts of future electricity sales; transmission congestion in Texas; demand side management (DSM), demand response, and distributed generation; and electric reliability assessments. The demand forecasts are fed into the generation and transmission planning process. ERCOT uses industry best practices and methodological approaches to determine system reliability and the need for new generating capacity (ERCOT 2008f, i, j, k). Moreover, the forecasts are subject to a vigorous participatory process.

The model developers recognize that they have not been successful in the past in including electricity prices as valid predictive variables in the electricity demand model (ERCOT 2008e, 2009a):

> In regard to prices, which are considered an important driver for inclusion in a demand equation, it is not clear as to whether or not the wholesale prices that ERCOT collects are really the most relevant for a forecasting application, in terms of being the prices ultimately faced by the consumer. Since the wholesale prices are collected on an hourly basis, and retail prices are better reflected by an average over a longer time period, such as a month, wholesale hourly prices do not capture the correlation with the MWh consumption correctly. Several attempts to include market clearing prices of energy in the forecasting models were made but were unsuccessful. The models obtained showed price to be insignificant or to indicate a nonsensical relationship regarding the direction of the effect of price (wrong sign on the coefficient) and thus should not be included in a long-term demand equation. To make matters more challenging in this respect, an objective and credible forecast of these prices would represent a major accomplishment in itself. Inclusion of a price variable in the forecasting models could potentially provide a means to calculate an unbiased and credible forecast of the price effect on the long-term load response.

However, reportedly, the constraints have been overcome and all future versions of the demand forecast will include the effects of energy prices (PNNL 2009).

8.1.3.3 Subject to Confirmation Test

The review team finds that, in aggregate, the studies and reports discussed in Section 8.4 are subject to confirmation. ERCOT's forecasts are independently prepared. These forecasts are then independently reviewed, confirmed, and consolidated by PUCT and NERC. Both the Long-Term Peak Demand study (ERCOT 2008e) and the Capacity, Demand, and Resources Report (CDR) look at historical information as a check on past forecasting performance and these results are published. For example, in 2008 to validate the forecast model, an out-of-sample prediction was performed by estimating the model with data up to December 2005 and a forecast was produced for January 2006 to December 2006 using the actual temperatures. A forecast for the summer season only was also produced using the actual temperatures. The system peak that occurred on August 17, 2006, was forecasted for the year 2006 with a 0.78 percent error and a 0.45 percent error for the summer alone (ERCOT 2008e). Forecast comparisons for 2008 show a -0.5 percent error for annual energy (with monthly errors from -7.6

percent to plus 6.0 percent). Maximum hourly demand at the August peak had a -1.0 percent error and the forecast for annual peak had a -4.2 percent error (ERCOT 2008c)

Over a longer term, from 1999 to 2006, the ERCOT peak demand and energy consumption forecasts were within ± 5 percent of the actual values (STPNOC 2009). ERCOT publishes its methodology, key input data, forecast errors, methodological uncertainties and limitations, and conclusions.

8.1.3.4 Responsive to Forecasting Uncertainty Test

In preparing its load forecasts and reliability assessments, ERCOT takes account of forecasting uncertainty. It also takes into account of the fact that not all proposed new generating units will be built and that some existing generating units may be taken off line for various reasons.

8.1.3.5 Summary of ERCOT Analytical Process

Based on its review of ERCOT documents, the review team determined that, in aggregate, the ERCOT forecasts and documents are sufficiently (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty to serve the needs of the review team in complying with Section 102 of the National Environmental Policy Act. In keeping with the ESRP (NRC 2000) and the Commission statements at 68 FR 55910, the review team gave particular credence to:

- ERCOT's 2009 long-term demand forecast (ERCOT 2009a),
- ERCOT's 2009 CDR (ERCOT 2009b),
- ERCOT's examination of long-term generation issues associated with wind energy in the 2008 Long-Term System Assessment (ERCOT 2008f), and
- NERC's evaluation of long term system adequacy (NERC 2008b).

8.2 Power Demand

The review team initially relied on the 2007 ERCOT Long-Term Peak Demand and Energy Forecast as its basis for understanding the need for power (ERCOT 2007). Since then, review team also has reviewed the 2008 and 2009 long-term demand studies (ERCOT 2008e, 2009a), ERCOT's 2008 Long Term System Assessment Study (ERCOT 2008f), ERCOT's latest CDR (ERCOT 2009b), and the summary of ERCOT findings from the 2008 studies in NERC's 2008 Long-Term Reliability Assessment as bases for comparison with the STPNOC's need for power assessment (NERC 2008b). ERCOT's demand forecasting model is described in detail in the 2009 demand forecast report and is summarized below (ERCOT 2009a).

The ERCOT long-term load forecast covers a period from 1 to 15 years using a process and tools developed internally by ERCOT. The forecast is used for a variety of operating and planning purposes, the most important of which for the EIS is system planning. The forecasting model is a set of equations that describes the historical load as a function of independent variables, where the coefficients are estimated by multiple regression methods. The long-term forecast was produced with a set of econometric models that use weather and economic and demographic data to capture and project the long-term trends from the past 5 years of historical data. Twelve years of weather data were available from 20 ERCOT weather stations. These weather stations were used to develop weighted hourly weather profiles for each of eight weather zones in the ERCOT region. These data were used in the load shape models. Monthly cooling degree days and heating degree days were used in the monthly energy models. Uncertainty in weather effects (especially that of extreme weather) on load was investigated in a number of ways, including the running of Monte Carlo simulations, to assess the impact of extreme temperatures on the peak demands. Economic and demographic changes can affect the characteristics of electrical demand in the medium- to the long-run. Economic and demographic data at the county level were obtained on a monthly basis from Moody's Economy.com. Three of the key economic and demographic variables that drive the forecast are per capita income, population, and employment. The growth rates in these variables have declined during the last three forecasts, but still show largely the same picture for need for power over the next 10 to 15 years.

Because the proposed Units 3 and 4 at the STP site would be baseload merchant power plants that are expected to operate more than 90 percent of the time to obtain best cost-effectiveness, the most important part of the ERCOT forecast for purposes of the this review is the growth in annual energy demand and the growth in demand at the near-minimum demand hours, since Units 3 and 4 would address this lowest part of the annual load duration curve. ERCOT, on the other hand, needs to emphasize peak load demand because of its institutional responsibility for meeting peak demand and reserve margin. During the period from 1997 to 2007 the compound growth rates for peak demand and annual energy were 2.3 percent per year and 1.5 percent per year, respectively (ERCOT 2009a). Assuming normal weather, ERCOT projects that peak energy demand would increase at a compounded rate of 2.0 percent per year (13,923 MW total) between 2009 and 2019 and that annual energy (average demand) would grow at a compounded growth rate of 2.04 percent per year (7965 average MW total) (ERCOT 2009a). Figure 8-2 shows the ERCOT 2009 peak and annual average load forecasts for the period 2009-2019.

Figure 8-3 shows the 8760-hour load duration curve for the ERCOT region for 2007, the last full year for which data were available. Ninety percent of the hours in the year equals 7884, corresponding to a demand of about 26,000 MW. This is approximately the portion of demand that is addressed by existing nuclear power plants at STP and Comanche Peak (as well as some hydroelectric, coal, and natural gas combined cycle baseload). If minimum annual hourly

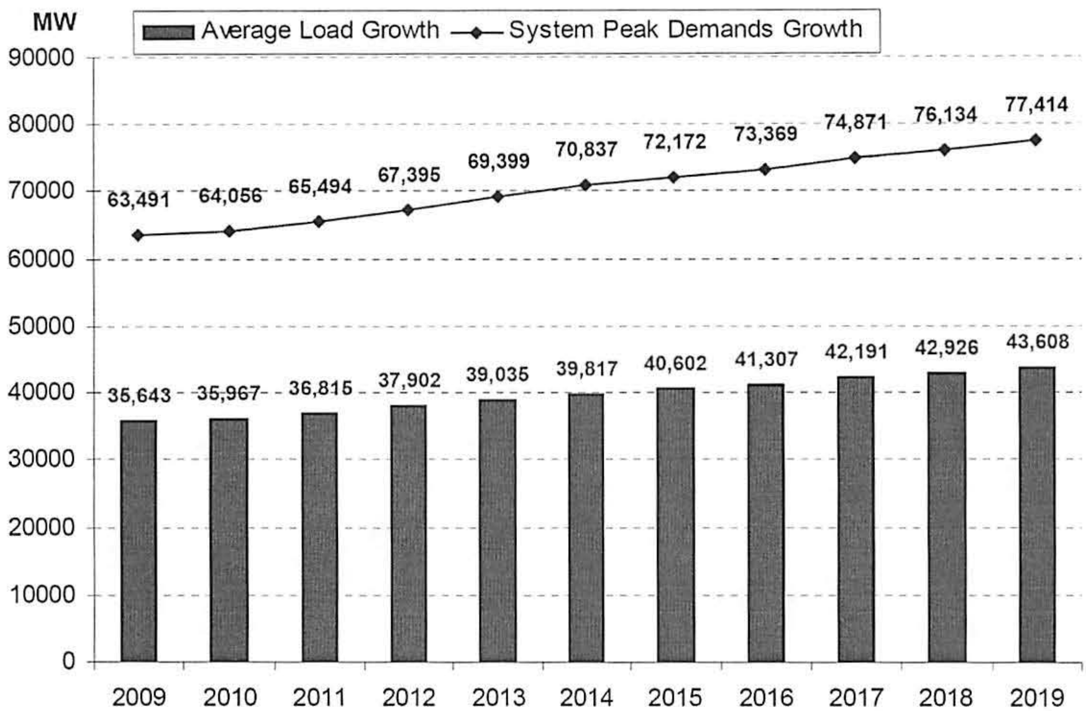

Figure 8-2. Peak Demand and Average Demand in the ERCOT Region 2009-2019 (ERCOT 2009a) (Note: figures are projected totals, not annual growth.)

demand (equal to 21,817 MW in 2007) and 90th percentile hourly demand both grew at approximately the rate of annual average hourly demand in the ERCOT region shown in Figure 8-3, they both would grow by about 27.4 percent by 2019, or by amounts of 5978 MW and 7124 MW, respectively. These increases exceed the increase of high-availability baseload capacity represented by proposed Units 3 and 4 at STP. This simple calculation provides an initial indication that the growth in baseload demand in the ERCOT region would be enough to support additions of two units at both STP and Comanche Peak.

In the 2008 annual NERC report (NERC 2008b) "2008 Long-Term Reliability Assessment 2008-2017, October 2008," it is noted that forecasts of the demand for power declined between the 2007 and 2008 forecasts (after having risen between 2006 and 2007). The decline continued from 2008 to 2009. Figure 8-4 shows the last four summer peak load forecasts compiled by ERCOT. Figure 8-5 shows the difference between annual energy forecasts in 2008 and 2009. The actual 2008 values are below the forecast largely because the peak forecast assumes normal summer weather, and weather was relatively cool on the peak day in 2007.

The NERC report for ERCOT (NERC 2008b) states that the lower 2008 forecast takes into account the slowing of the Texas economy:

- The lower peak demands reflect the expected state of the economy as represented by economic indicators that have been found to drive electricity use in the ERCOT region's eight weather zones, including real per-capita personal income, population, gross domestic product, and various employment measures including non-farm employment and total employment.
- In the long-term, real personal per-capita income is expected to level-off or decline in a slight to medium fashion due to wage rates experiencing modest growth, only slightly faster than inflation, due to lower productivity growth. Texas non-farm employment continues to grow faster than the U.S. rate. The gross domestic product also shows a lower level and growth rate from 2008 to 2018 when compared to last year's forecast.
- Given the net effects of the economic indicators used in the 2008 Long Term Demand Forecast, they indicate slowdown of the economy in the long run. The long-run impact on the forecast due to economic slowdown is projected to start around 2010. Its effects are projected to translate into a 4.50 percent decline in energy and a 3.31 percent decline in peak demand by 2018, when compared to last year's forecast [Note: "last year" refers to the 2007 forecast].

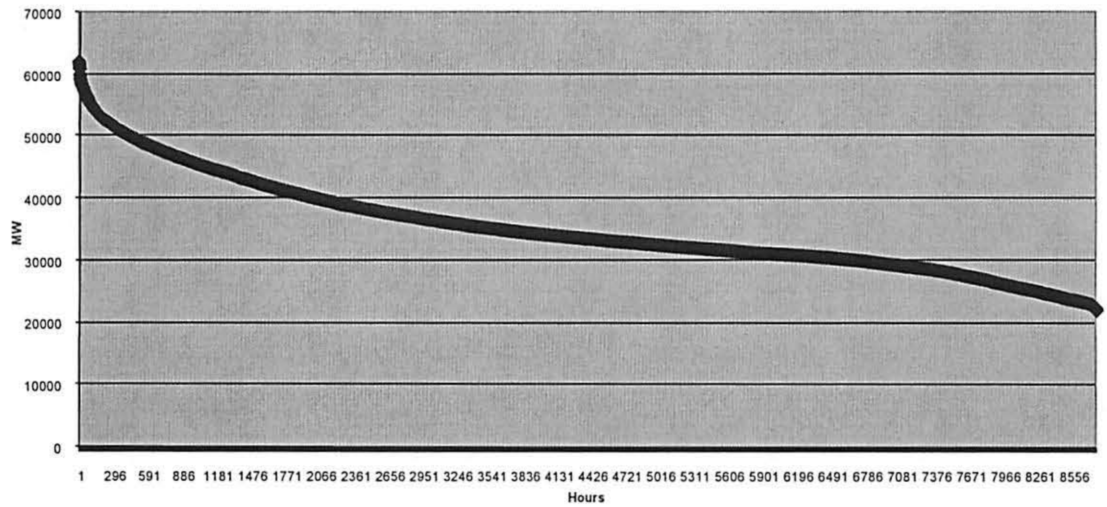

Figure 8-3. ERCOT 2007 Load Duration Curve. (Compiled by review team from ERCOT 2008h)

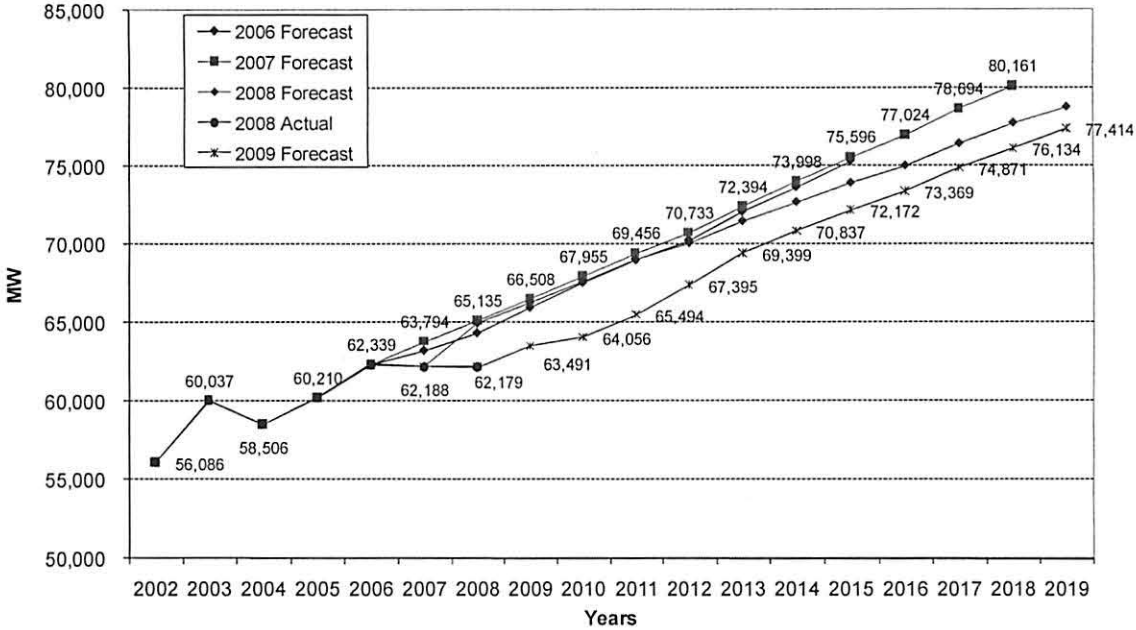

Figure 8-4. ERCOT 2006, 2007, 2008, and 2009 Peak Load Forecasts. (Compiled from 2007, 2008, and 2009 ERCOT Long-Term Demand Forecast reports data by review team from ERCOT 2007; ERCOT 2008e; and ERCOT 2009a)

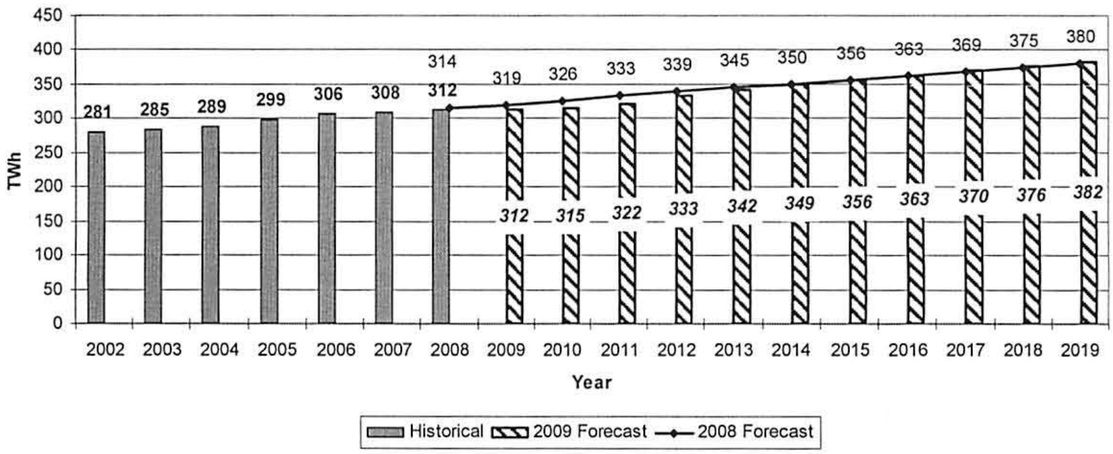

Figure 8-5. ERCOT 2008 and 2009 Energy Demand Forecasts (ERCOT 2009a)

The review team notes that the ERCOT 2009 forecast features still further reduced economic growth in the short term as a result of the 2008-2009 economic downturn. However, some of the decline in underlying long-term economic conditions discussed by NERC between 2007 and 2008 took a more optimistic turn in the ERCOT 2009 forecast. Figure 8-6 through Figure 8-8 show the change in key long-term growth variables used as the primary economic drivers for the 2009 ERCOT forecasts: population, employment, and per-capita income. ERCOT determined population growth rate would be relatively unchanged due to the economic downturn following an initial drop in numbers, but that employment and per-capita income would suffer an initial slump, followed by a faster growth rate than expected in 2008 and which would overtake the 2008 forecasted values by about 2013.

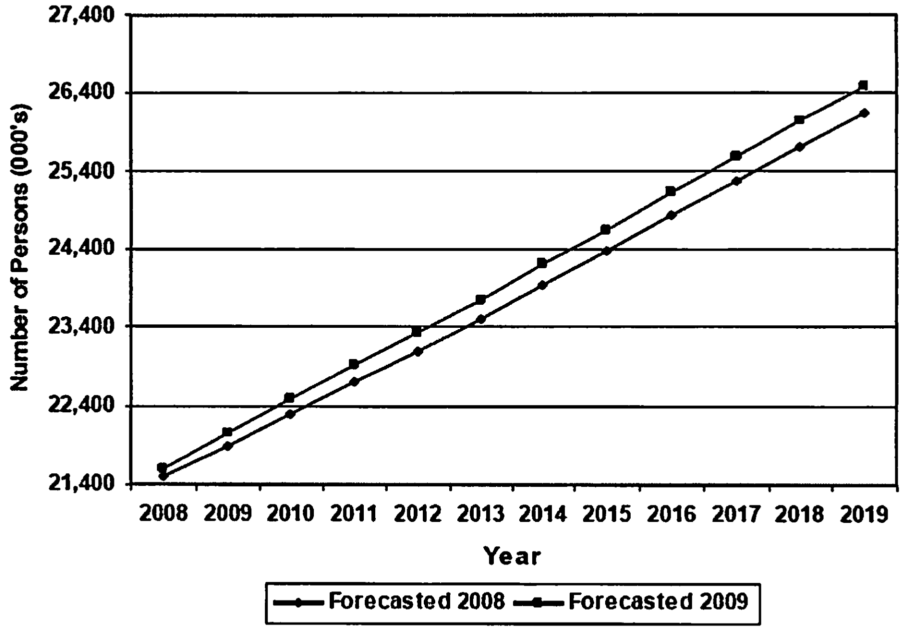

Figure 8-6. Population in the ERCOT Region (ERCOT 2009a)

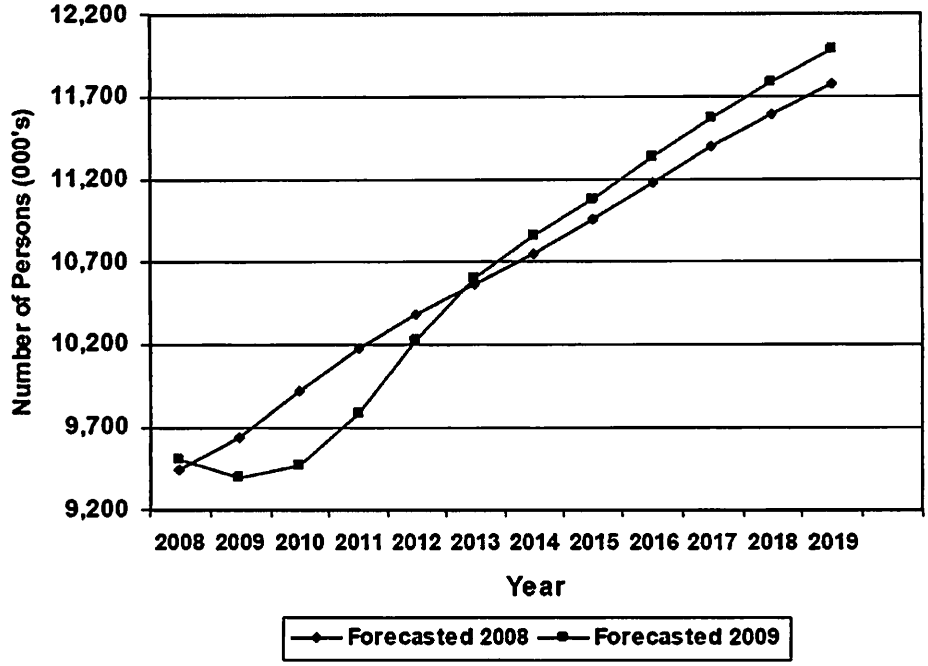

Figure 8-7. Total Non-Farm Employment in the ERCOT Region (ERCOT 2009a)

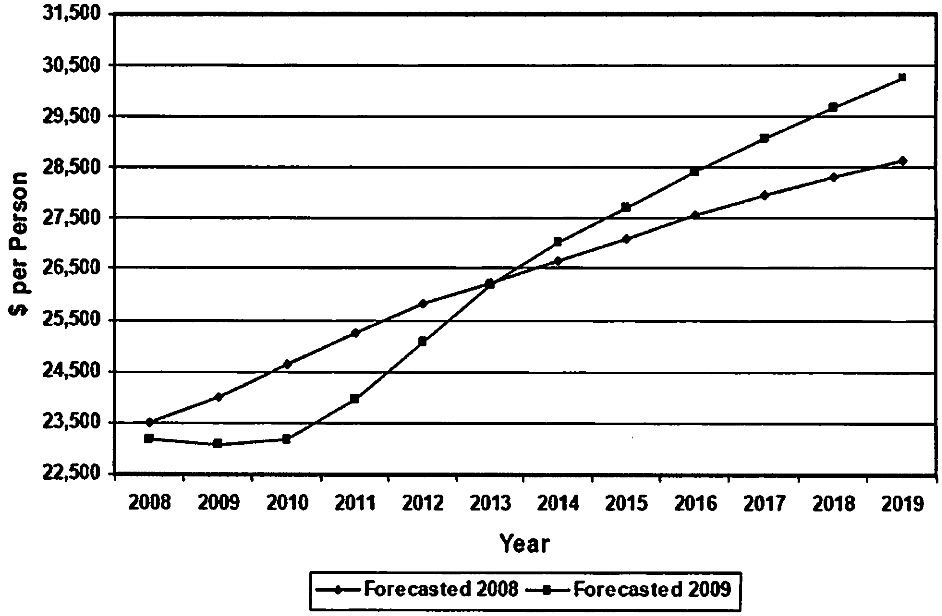

Figure 8-8. Per Capita Income in the ERCOT Region (ERCOT 2009a)

Because it is involved in meeting the maximum demand conditions in its territory, ERCOT pays considerable attention to the summer peak demand and the margin of safety in meeting that peak. The current generation reserve margin requirement for the ERCOT region is 12.5 percent, as approved by the ERCOT Board in August 2002. The following is a brief summary of the methodology for the reserve margin calculation (ERCOT 2005a). The terms used here are defined below.

Firm Load equals:

- long-term forecast model total summer peak demand
- minus loads acting as resources serving as responsive reserve
- minus loads acting as resources serving as non-spinning reserve
- minus balancing up loads.

Available Resources equals:

- installed capacity using the summer net dependable capability pursuant to ERCOT testing requirements (excluding wind generation)
- plus capacity from private networks
- plus effective load carrying capability of wind (determined in a study for ERCOT in 2006 by Global Energy to be 8.7 percent of name plate generation (GED 2007)
- plus reliability must run units under contract
- plus 50 percent of non-synchronous ties
- plus summer net dependable capability of available switchable capacity as reported by the owners
- plus available "mothballed" generation
- plus planned generation with a signed generation interconnection agreement (SGIA) and a Texas Commission on Environmental Quality air permit, if required
- plus effective load carrying capability of planned wind generation with SGIA
- minus retiring units.

Reserve margin is then defined as (Available Resources - Firm Load Forecast/Firm Load Forecast).

In the ERCOT methodology, loads acting as resources are capable of reducing or increasing the need for electrical energy or providing ancillary services such as responsive reserve service or non-spinning reserve service. Loads acting as resources must be registered and qualified by ERCOT, and they will be scheduled by a qualified scheduling entity (STPNOC 2009).

STPNOC discussed the need for power in the context of declining reserve margins in the ERCOT region (STPNOC 2009). As recently as May 2008, forecasted reserve margin in the ERCOT Demand and Reserves report was expected to fall below the required reserve margin of 12.5 percent by 2013. However, the May 2009 update to this report now shows a better capability to meet firm load at least through 2014 (see Table 8-1). ERCOT produces a "top-down" forecast for its major subareas, but does not include separate demand estimates for different end-use sectors. Thus, forecasts do not contain separate forecasts for residential, commercial, and industrial demand.

As shown in Table 8-1, the ERCOT 2009 forecasts take into account DSM programs and efficiency programs. As stated in the 2008 Texas State Energy Plan, DSM can be divided into (1) demand-response programs, which are designed to encourage customers to reduce usage during peak times or to shift that usage to other times; and (2) energy efficiency programs, which provide a reduction in the overall quantity of electricity consumed over the year, but may not necessarily reduce the electricity demanded at the hour of system peak (Governor's Competitiveness Council 2008). Under Texas House Bill 3693 (signed into law in 2007), regulated utilities (transmission and distribution utilities [TDUs]) in ERCOT, and the integrated utilities outside of ERCOT, are required by law to offer DSM programs sufficient to offset 15 percent of the growth in demand by December 31, 2008, and 20 percent of the growth in demand by December 31, 2009 (Governor's Competitiveness Council 2008). Although only regulated utilities are affected inside of ERCOT, success of such programs could affect the overall demand for electricity in the ERCOT region.

Table 8-2 is a less-detailed extension of Table 8-1 to the year 2024 that shows the ERCOT 2009 forecast of demand, reserve margin (ERCOT calculates long-term required resources to meet peak demand plus 12.5 percent). Total resources estimates and the need for baseload power are calculated in Section 8.3. The total resources estimate does not include STP Units 3 and 4 or other units projected for completion after 2014.

Table 8-1. ERCOT Peak Demand and Calculated Reserve Margin, 2009-2014

	2009	2010	2011	2012	2013	2014
Total Summer Peak Demand (MW)	63,491	64,056	65,494	67,394	69,399	70,837
Less: LAARS Serving as Response Reserve and Spinning Reserve, Balancing–Up Loads	1115	1115	1115	1115	1115	1115
Less Energy Efficiency Program (per HB36693)	110	242	242	242	242	242
Firm Load Forecast (MW)	62,266	62,699	64,137	66,037	68,042	69,480
Required Reserve Margin (12.5%)	7783	7837	8017	8255	8505	8685
Required Resources	70,049	70,536	72,154	74,292	76,547	78,165
Estimated Total Resources (MW) (Table 8-3)	72,712	75,314	76,215	77,287	79,122	79,123
Reserve Margin (Resources - Firm Load Forecast)/Firm Load Forecast)	16.8%	20.1%	18.8%	17.0%	16.3%	13.9%

Source: ERCOT 2009b

Table 8-2. ERCOT Calculated Reserve Margin, 2009-2024

	2009	2010	2014	2019	2024
Peak Summer Demand, MW	63,491	64,056	70,837	77,414	82,778
Less: LAAR Spinning and Non Spinning reserve and Balancing-up Loads	1115	1357	1357	1357	1357
Firm Load, MW	62,266	62,699	69,480	76,057	81,421
Plus Reserve Requirements (Peak +12.5%)	7936	8007	8855	9677	10,347
Total Resource Requirements, MW	71,427	72,063	76,692	87,091	93,125
Total Resources, No Retirements	72,712	75,314	79,122	79,123	79,123
Reserve Margin Based on Firm Load	16.8%	20.1%	13.9%	4.0%	-2.8%

Source: Calculated by the review team from tables and figures in ERCOT 2009b.

8.3 Power Supply

ERCOT prepares an annual CDR (ERCOT 2009b) on the supply capacity, demand, and reserves in the ERCOT region. It is developed from data provided by the market participants as part of the annual load data request, the generation asset registrations, and from data collected for the annual U.S. Department of Energy Coordinated Bulk Power Supply Program Report.

The working paper calculates the generation resources reported to be available by market participants (STPNOC 2009).

The CDR considers all of the generation resources in the ERCOT region meeting the list in the previous section. There are several constraints on which resources are listed as available in the CDR.

- Only those new generating resources for which the owners have initiated full transmission interconnection study requests through ERCOT are included as planned generation.
- If an air permit is required for a new generating unit, the unit must have received that permit before it is included as planned generation.
- Some mothballed resources may be counted, but the probability of these resources being able to be returned to service varies by generating technology and declines as the length of time they are mothballed increases (ERCOT 2005b).
- Retiring and retired units are not counted.

Wind Energy in Texas

Large amounts of wind energy have or are about to enter the ERCOT region. In the Interim Order on Reconsideration in Docket 33672 (Interim Order), the PUCT designated five zones as Competitive Renewable Energy Zones (CREZ), primarily for wind power, in the western and Panhandle areas of Texas. By Texas law this amount of power would have to be accepted by the market, if offered to the market, in preference to thermal generation. Installed wind capacity could grow from around 6900 MW to as much as 24,400 MW over the next few years, with a planning value of 18,456 MW in 2018. In response, ERCOT performed a CREZ Transmission Optimization Study (ERCOT 2008j), an extensive study of intrastate transmission bottlenecks that might arise and solutions that might be needed to absorb this new power source.

The wind generation development scenarios used in the CREZ Transmission Optimization Study were also used to evaluate resource needs in the ERCOT system in the December, 2008 Long-Term System Assessment (ERCOT 2008f). The Long-Term System Assessment evaluated the need for other types of generation capacity under the assumption that the projected 2018 load duration curve would be lowered by the maximum possible use of 18,456 MW of wind energy. Figure 8-9 shows that at approximately the 80^{th} percentile (a rule-of-thumb definition of baseload generation) there would still be a demand for up to 30,852 MW of baseload with 18,456 MW of wind generation installed in the system if natural gas prices remained at about $7 per million Btu. However, there would be little need for additional baseload generation beyond current levels (nuclear could still substitute for retiring coal and natural gas, if needed).

Current U.S. Energy Information Administration forecasts of natural gas prices favor a natural gas price to the electricity sector of about $7 per million Btu through much of the next 20 years, as many new resources come on line, even as economic recovery increases demand (EIA 2009). This indicates that the demand in 2018 for baseload capacity (80th percentile of the wind-altered load duration curve) would be close to the 30,852 MW forecast in Figure 8-9. The demand for baseload at the 90th percentile of the wind-altered load duration curve would be about 28,000 MW, an increase of about 2000 MW from current levels. That would not be enough on its own to fully absorb STP Units 3 and 4, but substitution for retiring coal or natural gas-fired plants would still be possible.

ERCOT's 2009 Supply Forecast

Table 8-3 provides ERCOT's May 2009 projection of the generating resources of various types that that would be available to serve the ERCOT region between 2009 and 2024. The 2009-2014 ERCOT projections anticipate substantial development of wind resources during the 2009-2014 period, and the review team adopted the view that these resources would be developed and would meet the State's goal of 18,564 MW of installed wind capacity by 2018. If the State falls short of its goal for wind, the demand for STP Units 3 and 4 would be larger than calculated in this section.

There is uncertainty as to the timing, type, number, and capacity of generating units that may be retired during the forecast period, which affects the need for replacement generating plants. The age of the power plant being considered for retirement is a factor in the decision to retire the plant. Based on ERCOT's May 2009 CDR, Figure 8-10 shows how the summer capacity of generating resources may be affected by the need of some participants to retire older, less efficient, or polluting power plants. Under any retirement scenario, the replacement of such power plants in the ERCOT region further adds to the need for new generating capacity.

The ERCOT forecast of generating resources shown in Table 8-3 begins with installed capacity of existing generating stations. To that is added generating capacity of private networks (connected to the ERCOT grid, but not directly metered by ERCOT), the effective load carrying capability of existing wind generators (at 8.7 percent of installed capacity), and reliability must-run (RMR) units that are required for local grid stability. The remaining group of resources includes (1) 50 percent of so-called "switchable" resources that could either operate in ERCOT or in the Southwest Power Pool; (2) a protected estimate of mothballed resources that could be brought back on line in each year (the actual estimate is an expected value based on detailed computations that involve the age of the unit and the length of time it has been shut down), and (3) planned resources, whose inclusion depends on the phase that each resource is in the required interconnection studies (STPNOC 2009). This resulting estimate is then adjusted downward to account for switchable units known to be unavailable to ERCOT and retiring units. However, because there is also considerable uncertainty concerning whether existing power plants would be retired, the review team calculated available resources both with and without retirements, as shown in Table 8-3.

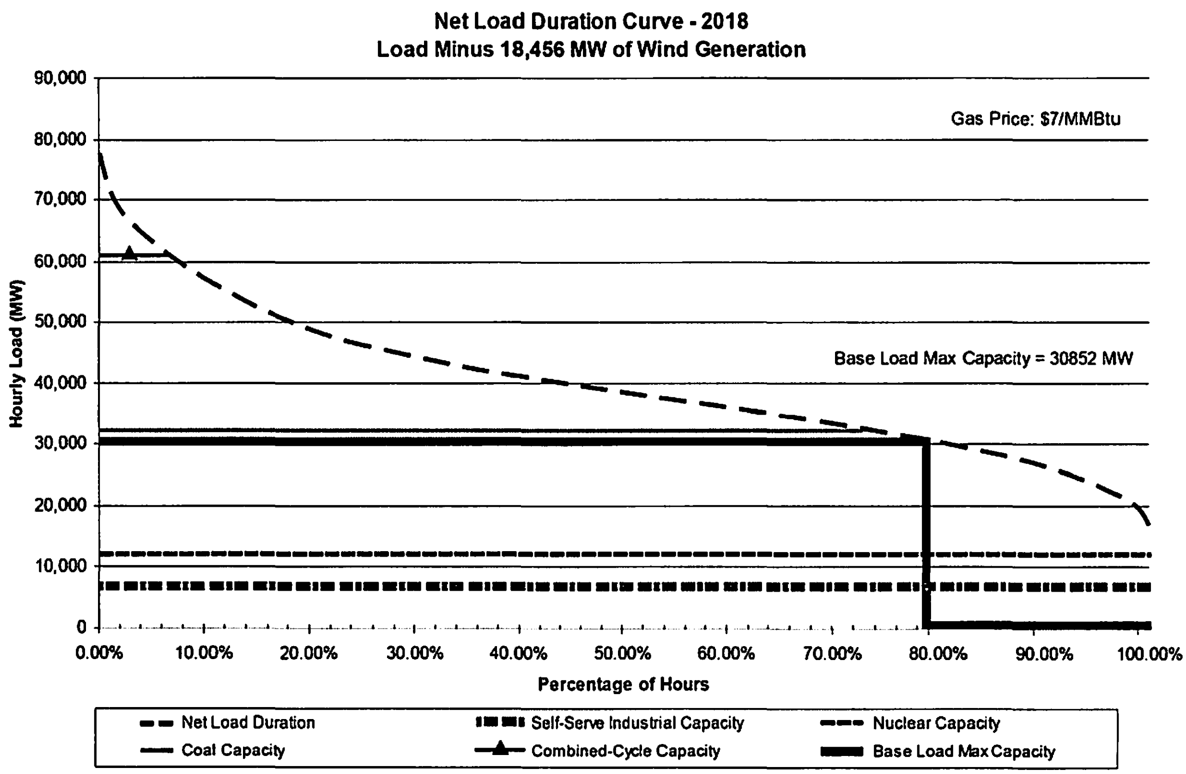

Figure 8-9. ERCOT Net Load Duration Curve in 2018 with 18,456 MW of Wind Generation Capacity (ERCOT 2008f)

Table 8-3. 2009 ERCOT Forecasted Summer Resources, 2009-2024

	2009	2010	2011	2012	2013	2014	2019	2024
Installed Capacity, MW	63,492	61,800	61,800	61,800	61,800	61,800	61,800	61,800
Capacity from Private Networks, MW	5313	5318	5318	5318	5318	5318	5318	5318
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	708	708	708	708	708	708	708	708
RMR Units to be under Contract, MW	115	0	0	0	0	0	0	0
Operational Generation, MW	69,628	67,826	67,826	67,826	67,826	67,826	67,826	67,826
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553	553	553
Switchable Units, MW	2848	2848	2848	2848	2848	2848	2848	2848
Available Mothballed Generation , MW	0	401	479	479	479	479	479	479
Planned Units (not wind) with Signed IA and Air Permit, MW	0	3,769	4389	5414	7206	7206	7206	7206
ELCC of Planned Wind Units with Signed IA, MW	0	76	121	168	211	211	1606	1606
Total Resources, MW	73,029	75,472	76,215	77,287	79,122	79,123	80,518	80,518
less Switchable Units Unavailable to ERCOT, MW	317	158	0	0	0	0	0	0
less Retiring Units, MW (None through 2014, Based on >50 yrs after 2014	0	0	0	0	0	0		0
Retirements in Based of age >50 yrs after 2014	0	0	0	0	0	0	9289	25,274
Resources, MW (no retirements)	72,712	75,314	76,215	77,287	79,122	79,123	80,518	80,518
Reserve Margin Above Firm Load, No retirements	16.8%	20.1%	18.8%	17..0%	16.3%	13.9%	5.86%	-1.11%
Resources, MW (with retirements)	72,712	75,314	76,215	77,287	79,122	79,122	71,229	55,244
Reserve Margin Above Firm Load, With retirements	16.8%	20.1%	18.8%	17.0%	16.3%	13.9%	-6.4%	-32.2%

Source: ERCOT 2009b and review team calculations based on the expanded wind resource availability of 18,564 installed MW by 2018, and the >50-year old generation retirement scenarios in Figure 8-10.

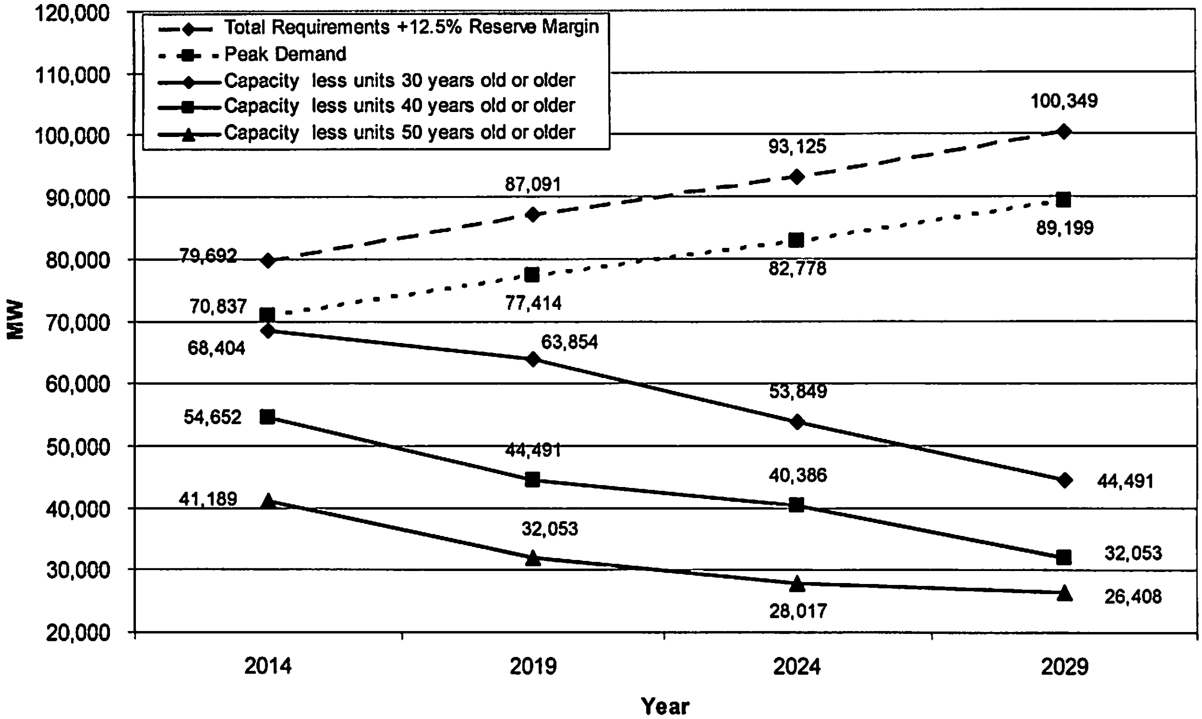

Figure 8-10. Alternative ERCOT Generation Capacity Reduction Scenarios vs. Projected Demand (ERCOT 2009b)

In Table 8-3, the ERCOT forecast shows that by 2014, the amount of summer resources would be about 79,100 MW and 80,500 MW by 2019. Reserve requirements would be met in 2014, but not by 2019. The reserve margin would fall from 13.9 percent in 2014 to 5.9 percent in 2019. With retirements of older power plants after 2014, the demand and supply would be further out of balance, because the resources needed just to meet firm load would be 76,100 MW. The resources available, accounting for wind generation and retirements, would be only 71,200 MW if only power plants older than 50 years old were retired — an absolute shortage of 5000 MW and a shortage of 15,900 MW relative to the amount needed to cover the reserve margin. The reserve margin would be below zero. If retirements of power plants increase, the prospective shortage of generation in the 2014-2019 period would grow still larger

STPNOC concluded in its ER (STPNOC 2009), based on the ERCOT 2007 forecasts and before the 2008-2009 economic recession, which the generation shortage in 2016 could be between 20,000 and 50,000 MW. The shortage in Table 8-3 is 15,900 MW, still substantial.

In the ERCOT region, STPNOC estimated about 24.5 percent of current generating capacity is currently considered to be baseload and that this percentage would rise to 30.1 percent by 2012 (STPNOC 2009) In its ER, STPNOC estimated the combined capacity of baseload generation that addresses ERCOT through the year 2012 based on the ERCOT criteria (Table 8-4). The percentage of baseload may be increasing (STPNOC 2009). STP Units 1 and 2 and Comanche Peak Units 1 and 2 would represent 4892 MW of the 22,178 MW of total summer baseload generating capacity needed in the ERCOT region in 2012 (STPNOC 2009). The growth in need for baseload generation in Table 8-4 from 2007 to 2012 is 4557 MW, of which only 2100 MW of new coal and gas had been added to the ERCOT forecast. In the longer term, plant retirements and further increases in demand for power allowed STPNOC (STPNOC 2009) to conclude that:

> Thus, the need for new capacity in ERCOT in 2015-2016 is substantially greater than the new capacity to be provided by STP 3 & 4. As a result, not only will there be a need for power from STP 3 & 4, there will be a need for a substantial amount of other new generating capacity.

Table 8-4. STPNOC Forecasted Summer Capacity, Baseload Generation Units Only

	2007	2008	2009	2010	2011	2012
Resources, MW	71,812	72,048	71,960	72,394	72,939	73,703
Baseload Generation, MW	17,621	17,621	19,057	19,998	21,378	22,178
Percent of Resources that are Baseload Generation	24.50%	24.50%	26.50%	27.60%	29.30%	30.10%

Source: STPNOC 2009

Table 8-5 shows an estimate made by the review team of the need for baseload power in 2009-2024 with and without retirement of older power plants. For purposes of this estimate it was assumed that baseload power would represent about 27.5 percent of the identified generating needs in Table 8-3. This percentage is midway between today's 24.5 percent and the 30.1 percent calculated by STONOC for the year 2102. Without any retirements, Table 8-5 shows that the demand for new baseload is about 1808 MW, a reflection of much higher planned non-wind resources and wind power penetration into the Texas market than assumed in 2007, combined with lower load growth than assumed by STPNOC in their forecast. With only plants greater than 50 yr old retiring, the demand for new baseload plants not currently in the ERCOT forecast grows to 4362 MW, more than enough for two new nuclear units.

Table 8-5. ERCOT/Review Team Forecasted Summer Capacity, Baseload Generation Units Only[a]

	2009	2010	2014	2019	2024
Power Requirements, Including 12.5% Reserves (MW)	71,427	72,063	79,692	87,091	93,125
Current ERCOT Planned New Generation: No Retirements (MW)					
Generating Resources	73,029	75,472	79,123	80,518	80,518
Baseload Needed (27.5%)	19,643	19,817	21,915	23,950	25,609
Baseload Needed After 2009	(353)	(894)	156	1808	3467
Current ERCOT Planned New Generation: Retire Only Plants >50 Yr Old (MW)					
Generating Resources	73,029	75,472	79,123	71,229	55,244
Baseload Needed (27.5%)	19,643	19,817	21,915	23,950	25,609
Baseload Needed After 2009	(353)	(894)	156	4362	10,417

(a) Excludes proposed STP Units 3 and 4

8.4 Assessment of Need for Power

The review team reviewed reports prepared by ERCOT regional ISO in conjunction with its assessment of the need for power from STPNOC's proposed Units 3 and 4 at the STP site. STPNOC relied on the 2007 versions of these reports, which show a slightly higher need for power than the 2008 and 2009 reports; however, all versions provide essentially the same picture. The review team's key findings from the reports are summarized as follows:

- The demand for power at the summer peak and the annual demand for energy in the ERCOT region are both projected to rise over the period 2009 through 2019 at approximately 2.0 percent per year compounded. Total demand would be 77,400 MW at peak in 2019, and including a 12.5 percent reserve requirement, resources would need to be about 87,100 MW in that year. If minimum-hour demand and 90th percentile hourly demand also increases at the 2.0 percent rate, by 2019 the ERCOT region would need an additional 6000 MW to 7100 MW of baseload generation due to load growth alone. This estimate, however, does not account for other supply plans.

- As noted in Section 8.3, retiring generating units were not counted in the 2009 forecast of ERCOT region available resources (they are shown as zero in forecasted resources). Thus, depending on the rate of retirement of older generating units, the ERCOT region may need substantial additional generating capacity by 2019. The analysis in Table 8-3 shows that if only the oldest (greater than 50 years old) are retired after 2014, amount of additional demand for new generation would be about 9300 MW relative to a case with no retirements. About 25 to 30 percent of that growth likely would be baseload generation.

- The 2009 ERCOT resource forecast contains 8137 MW of current installed capacity in 2009 (with 708 MW of average Effective Load Carrying Capability) plus 2425 MW of planned installed capacity (average Effective Load Carrying Capability of 211 MW). However, larger amounts of additional wind generation capacity may be built in the CREZ areas of Texas, ranging up to 24,000 MW installed (average Effective Load Carrying Capability of 2088 MW). Large amounts of wind generation would require major investments in transmission resources and improved system controls to manage wind resources, but they could reduce the demand for power during the off-peak portions of the year and may limit the demand for additional intermediate and baseload thermal generating resources. More modest market penetration of wind energy leaves a market for increased baseload generation. The discussion of the CREZ study in Section 8.3 favors a lower wind penetration rate with up to 18,546 MW installed capacity, given very aggressive wind development, which still leaves room for 10,000 MW of growth in baseload demand by 2018, and 2000 MW of demand growth at the 90^{th} percentile. Because there is uncertainty in the success of very aggressive wind generation and because nuclear plants can substitute for other potential baseload generation, the review team believes there is a need for the amount of electrical generation represented by STP Units 3 and 4.

The State of Texas has funded an ambitious DSM program that is designed to reduce electricity demand by 15 to 20 percent in the service areas of regulated utilities within ERCOT and integrated Texas utilities outside of ERCOT (Governor's Competitiveness Council 2008). This program is included in the ERCOT forecasts and is part of the 2009 calculation of need for new generating resources.

If the Texas DSM program were completely successful, a 15 to 20 percent reduction in load growth in the regulated portion of the ERCOT region would reduce the need for power, but not eliminate it.

Table 8-6 summarizes the results of the review team's analysis of the ERCOT electricity demand and supply forecasts that have occurred since STPNOC used the ERCOT 2007 forecasts to estimate unmet need for power from STP Units 3 and 4. The staff reviewed the ERCOT 2008 and 2009 demand forecasts, noted the changes since 2007, and decided that while ERCOT's short-term forecast of peak summer demand was heavily influenced by the 2008 to 2009 recession, the longer-term estimate of demand is only slightly lower than in the 2007 forecast. A more important issue is that the 2007 supply forecast did not include either the impact of Texas's energy conservation plan or the full impact of an ambitious program to significantly expand the scope of wind power in Texas. The review team added these elements to the ERCOT 2009 long-term supply forecast. Finally, the review team examined directly the impact of power plant retirements, a factor not specifically included in ERCOT's detailed forecasts. Based on information available in STPNOC's need for power analysis, the review team translated the modified ERCOT 2009 demand and supply forecasts into an estimate of the unmet need for baseload power in ERCOT in the years 2014-2019, which spans the potential completion dates for proposed Units 3 and 4.

Table 8-6. ERCOT/Review Team Forecasted Unmet Need for Baseload Generation Compared with STPNOC Estimated Need for Baseload Power

	Review Team/ERCOT 2009 (2014 and 2019), MW	**STPNOC/ERCOT 2007 (2017) MW**	**Difference (Review Team/STPNOC) (Smallest to Largest)**
Estimated Baseload Demand	21,900 to 24,000[(a)]	26,600[(b)]	-4700 to -4500
Estimated Baseload Supply	21,800 to 19,600[(c)]	9900 to 20,100[(d)]	-500 to +11,900
Unmet Net Need for Baseload Power	100 to 4400[(e)]	6500 to 16,700[(f)]	-2100 to -16,600
Proposed Capacity	2740	2740	0

(a) Table 8-35, 2014 and 2019 power requirements times 27.5%.
(b) STPNOC 2009, Figure 8.4-2, 2017 "Total Requirement:, times 30.1%.
(c) Table 8-3, 2014 and 2019 resources with retirements, times 27.5%.
(d) STPNOC 2009, Figure 8.4-2, 2017 "Capacity less units 50 years old or older," "Capacity less units 30 years old or older," times 30.1%..
(e) Difference between demand and supply.
(f) Difference between demand and supply.

Table 8-6 shows that although the demand for baseload power in 2016-2017 has not changed much since the 2007 analysis, the combination of conservation and wind power may have significantly reduced the need for baseload power. However, even though the potential unmet need for power in the review team's alternative estimate is much smaller than STPNOC's estimate, it still shows an unmet need large enough to accommodate proposed Units 3 and 4. In addition, because Units 3 and 4 are merchant plants, they do not need to show an absolute shortage of power. The marketplace would decide whether Units 3 and 4 would be able to compete successfully with other potential suppliers of baseload electricity.

8.4.1 Conclusion

The review team concludes that there is an expected future shortage of baseload power in the ERCOT region that could be at least partially addressed by construction of proposed Units 3 and 4 at the STP site. The review team determined that the STPNOC assessment of its need for power in its ER is not unreasonable. Building of the two new units could address (1) growth in demand for baseload power and (2) replacement of retiring baseload generating units elsewhere in ERCOT. Based on its analysis, the review team concludes that there is a justified need for new baseload generating capacity in the ERCOT region in excess of the planned 2740 MW capacity output of proposed Units 3 and 4 at STP.

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