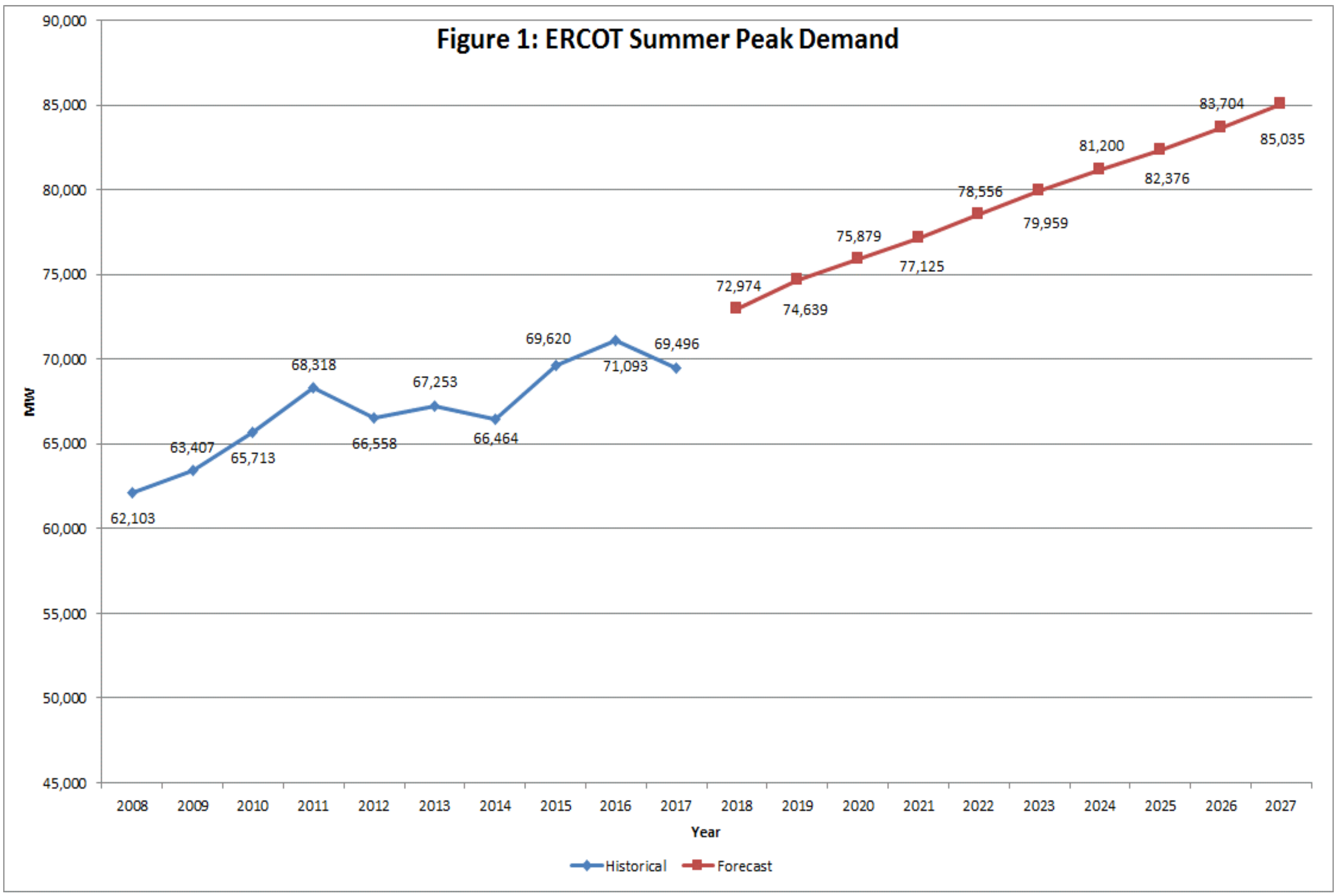
2018 ERCOT System Planning

Long-Term Hourly Peak Demand and Energy Forecast

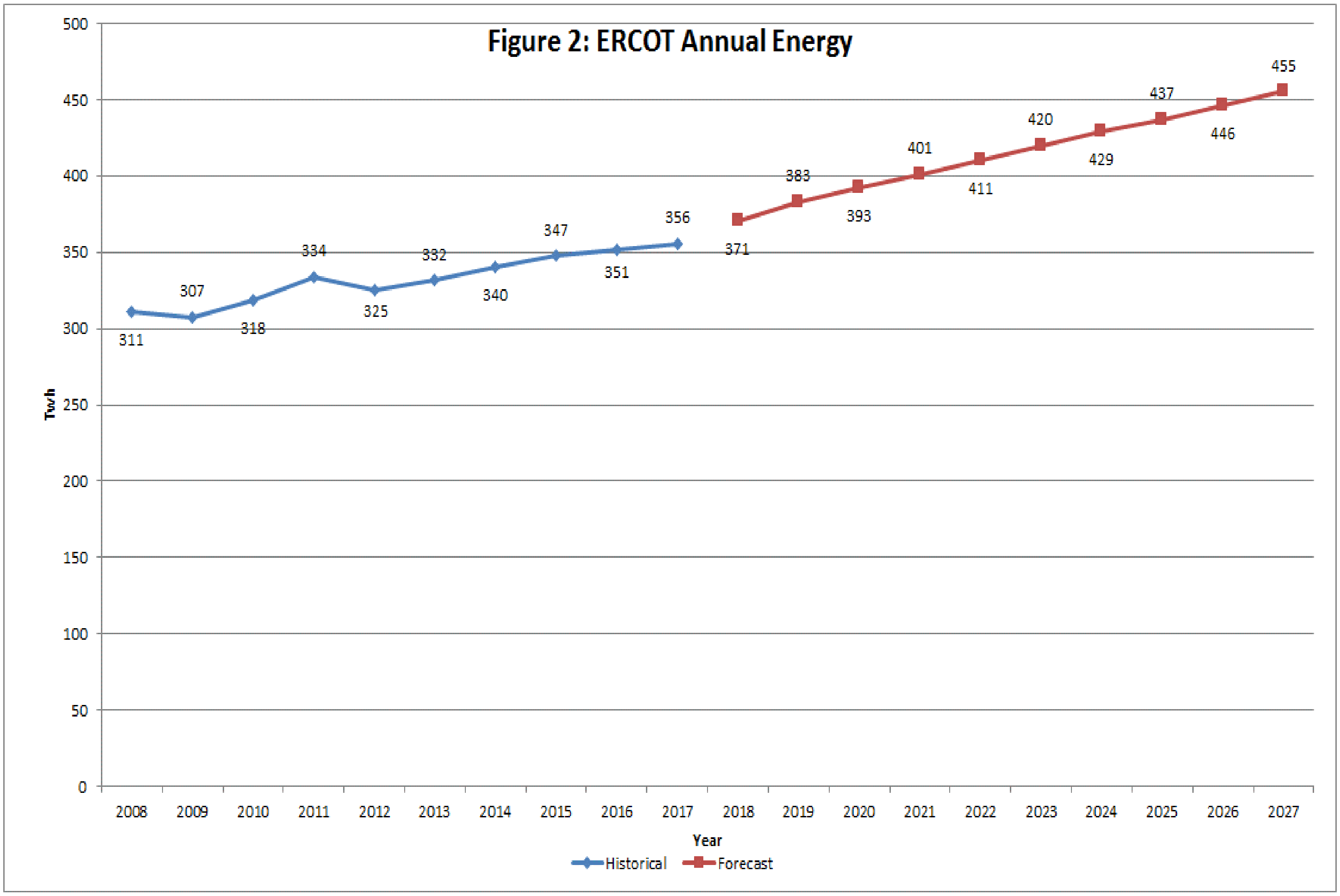
December 15, 2017

Executive Summary

The 2018 Long-Term Demand and Energy Forecast (LTDEF) for the ERCOT region is presented in this report, and includes the methodology, assumptions, and data used to create the forecast. This forecast is based on a set of econometric models describing the hourly load in the region as a function of the number of premises in various customer classes (residential, business, and industrial), weather variables (e.g., heating and cooling degree days, temperature, cloud cover, wind speed) and calendar variables (day of week, holiday). Premise forecasts are based on a set of econometric autoregressive models (AR1) and are based on certain economic (e.g., nonfarm payroll employment, housing stock, population) data. A county level forecast of economic and demographic data was obtained from Moody's. Fifteen years of historical weather were provided by Schneider Electric/DTN for 20 weather stations.



As shown in Figure 1, the 2018 LTDEF depicts system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.7% from 2018-2027. Historically, summer peak demand has grown at AAGR of 1.3% from the 2008-2017.



As shown in Figure 2, historical annual energy for the calendar years 2008-2017 grew at an AAGR of 1.5%. The forecasted AAGR for energy for 2018-2027 is 2.3%.

Introduction

This report gives a high level overview of the 2018 LTDEF. The forecast methodology is described, highlighting its major conceptual and statistical underpinnings. The 2018 forecast results are presented in a manner comparing them to the 2017 LTDEF. This allows for a direct comparison of results and also facilitates an explanation for the changes. Finally, an examination is presented describing the six major sources of forecast uncertainty: weather, economics, energy efficiency, demand response, onsite distributed generation, and electric vehicles.

2018 Modeling Framework

ERCOT consists of eight distinct weather zones (Figure 3). Weather zones[1] represent a geographic region in which climatological characteristics are similar for all areas in the region. Each weather zone has either two or three weather stations that provide data for the assigned weather zone. In order to reflect the unique weather and load characteristics of each zone, separate load forecasting models were developed for each of the weather zones.

The 2018 LTDEF was produced with a set of linear regression models that combine weather, premise data, and calendar variables to capture and project the long-term trends extracted from the historical load data. Premise forecasts were also developed.

All of the model descriptions included in this document should be understood as referring to weather zones. The ERCOT forecast is calculated as a sum of all of the weather zone forecasts.

Premise Forecast Models

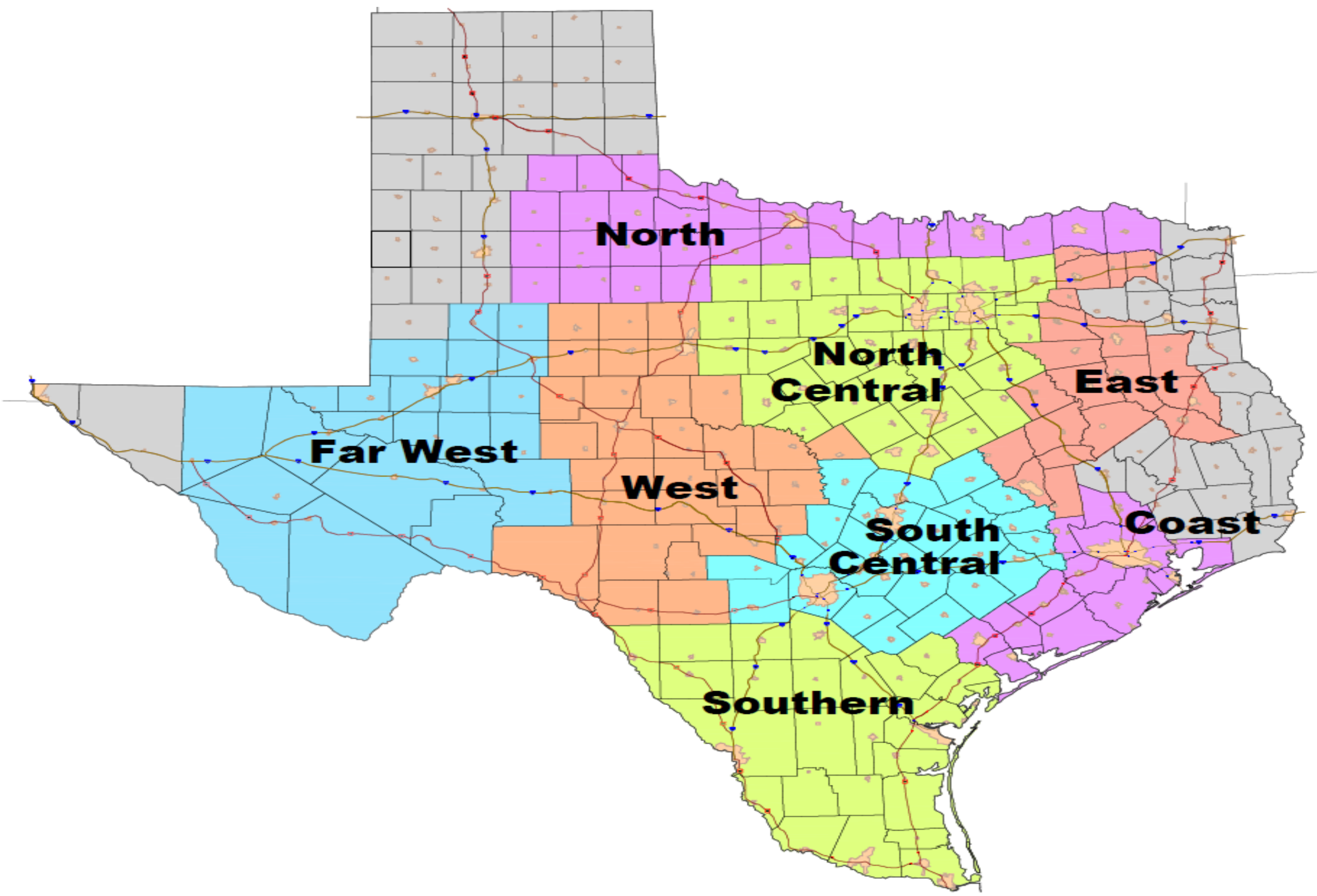
The key driver in the forecasted growth of demand and energy is the number of premises. County-level economic data was used to capture and project the long-term trends extracted from the historical premise data. Counties are mapped into a unique weather zone (Figure 3).

Premises were separated into three different customer classes for modeling purposes:

1. Residential (including lighting),
2. Business (small commercial), and
3. Industrial (premises which are required to have an IDR meter[2]).

[1] *See ERCOT Nodal Protocols, Section 2.*
[2] *See ERCOT Nodal Protocols, Section 18.6.1.*

Figure 3: ERCOT Weather Zones



All premise models were developed using historical data from January 2012 through August 2017. An autoregressive model (AR1) was used for all premise models.

Residential Premise Forecast

Residential premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (residential premises) and the following:

1. Housing Stock,
2. Population, and
3. Non-farm employment.

Business Premise Forecast

Business premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (business premises) and the following:

1. Housing Stock,

2. Population, and
3. Non-Farm employment.

Industrial Premise Forecast

Industrial premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (industrial premises), and the following:

1. Housing Stock,
2. Population, and
3. Non-Farm employment.

Premise Model Issues

During the review process for the previously mentioned premise models, a problem was identified that impacted two weather zones.

In the Far West and West weather zones, during the historical timeframe used to create the models, there was a significant increase in the number of premises in the middle of 2014. This increase was due to an entity opting in to ERCOT's competitive market and due to an expansion of ERCOT's service territory.

As a result of this problem, premise forecast models were not able to be created for the Far West and West weather zones. These two weather zones used economic variables as the key driver in the forecasted growth of demand and energy.

Hourly Energy Models

The long-term trend in hourly energy was modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable, hourly energy and the following:

1. Month,
2. Season,
3. Day Type (day of week, holiday),
4. Weather Variables,
    a. Temperature,
    b. Temperature Squared,
    c. Temperature Cubed,
    d. Dew Point,
    e. Cloud Cover,
    f. Wind Speed,
    g. Cooling Degree Days[3] (base 65),
    h. Heating Degree Days[3] (base 65),
    i. Lag Cooling Degree Days[3] (1,2, or 3 previous days),
    j. Lag Heating Degree Days[3] (1,2, or 3 previous days), and
    k. Lag Temperature (1, 2, 3, 24, 48, or 72 previous hours).
5. Interactions

---

[3] *All Degree Day variables are calculated versus 65 deg F.*

   a. Hour and Day of Week,
   b. Hour and Temperature,
   c. Hour and Dew Point,
   d. Temperature and Dew Point, and
   e. Hour and Temperature and Dew Point,
6. Number of premises[4], and
7. Non-Farm Employment/Housing Stock/Population[5]

All of the variables listed above are used to identify the best candidates for inclusion in the forecast model and to provide details on the types of variables that were evaluated in the creation of the model. Not every variable listed above was included in each model. Unique models were created for each weather zone to account for the different load characteristics for each area.

<u>Model Building Process</u>
Historical data (January 2012 – August 2017) [6] was divided into three different data sets:

1. Model Building,
2. Model Validation, and
3. Model Testing.

The model building data set was comprised of data from January 2012 through December 2016 with 30% of the data randomly withheld. The model building data set was used to create various forecast models. The model building process was an iterative process that was conducted multiple times.

After model building was complete, the validation data set was used to determine the accuracy of the various forecast models. The validation data set consisted of the 30% of data from the January 2012 through December 2016 timeframe that was withheld from the model building data set. Each model's performance was calculated based on the forecasting performance for data contained in the validation data set. Based on the results of the forecast for the validation data set, the model was updated appropriately.

After model validation was complete, the model testing data set was used to determine the accuracy of the various forecast models. The model testing data set contained data from January 2017 through August 2017. The model testing data was not included in model building or model validation. Model testing data was used to determine the accuracy of the model after model validation had been completed. The most accurate models were selected based on their performance on the model testing data set.

The last step in the model building process was to update the selected model for each weather zone by using data from January 2012 through August 2017 in order to update the variable coefficients. Typically only five years of historical data are used to develop models. Using only five years of historical data enables the model to be created

[4] *For Coast, East, North, North Central, South, and South Central weather zones.*
[5] *For Far West and West weather zones.*
[6] *Far West, South, and South Central models used less than five historical years*

based on data that better reflects the current appliance stock, energy efficiency measures, price responsive load impacts, etc.

Weather Zone Load Forecast Scenarios

Actual weather data from calendar years 2002 through 2016 was used as input for each weather zone's forecast model. The process began by using actual weather data from 2002 as weather input for all forecasted years (2018-2027). The actual weather data from all days in 2002 was copied into the same day and hour for each of the forecasted years (2018-2027). For example, the actual weather data for 1/1/2002 was copied into 1/1/2018, 1/1/2019, etc. …, and 1/1/2027. Using 2002's weather as input into each weather zone's forecast model results in what is referred to as the 2002 weather load forecast scenario. The 2002 weather load forecast scenario is a forecast that assumes 2002's weather would occur for each forecasted calendar year (2018-2027). This process was completed for each of the historical weather years (2002-2016) and resulted in fifteen weather load forecast scenarios for each weather zone for 2018-2027. It should be noted that the premise and economic forecasts are the same in each of these scenarios.

The following notation can be used to denote the weather load forecast scenarios:

$HF_{(z,x,y)}$

Where:
HF = hourly demand forecast,
x = historical weather date and time,
y = forecast date and time, and
z = weather zone (Coast, East, Far West, North, North Central, South, South Central, and West).

For example, $HF_{(West,\ 7/24/2008\ 1700,\ 7/24/2019\ 1700)}$, would denote the forecast for 7/24/2019 at 5:00 pm, which was based on weather from 7/24/2008 at 5:00 pm, for the West weather zone.

Weather Zone Normal Weather (P50) Hourly Forecast

The fifteen weather zone load forecast scenarios are used as the basis for creating the weather zone normal weather 50^{th} percentile (denoted as the P50) hourly forecast. Each of the fifteen hourly weather zone load forecast scenarios were separated into individual calendar year forecasts (covering calendar years 2018-2027). The calendar year forecasts were then divided by calendar month. Forecasted hourly values for each individual calendar month were ordered from the highest value to the lowest value. Then, for each ordered value, the average was calculated. This process is commonly referred to as the Rank and Average methodology.

For example, to determine the normal weather (P50) forecasted peak value for August 2018, take the highest forecasted value for each of the fifteen weather load forecast scenarios for August 2018 and average them. To determine the second highest peak value for August 2018, take the second highest forecasted value for each of the fifteen weather load forecast scenarios for August 2018 and average them. Repeat this process for all hours in August 2018. See Table 1 below for a summary of these calculations.

Table 1: Coast Weather Zone
August 2018 Peak Forecast Scenarios

	Historical Weather Year															
Rank	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	P50
1	19,859	21,001	20,391	19,820	20,313	21,004	20,025	20,908	21,005	21,323	20,504	20,619	20,568	21,156	20,932	20,629
2	19,819	20,887	20,338	19,805	20,177	20,884	20,013	20,705	20,906	21,249	20,463	20,533	20,487	20,930	20,727	20,528
3	19,743	20,794	20,295	19,794	20,147	20,760	19,991	20,556	20,633	21,093	20,432	20,506	20,364	20,844	20,669	20,441
4	19,509	20,767	20,257	19,743	19,976	20,678	19,853	20,503	20,631	21,074	20,427	20,493	20,329	20,832	20,619	20,379
5	19,481	20,707	20,125	19,741	19,968	20,642	19,772	20,467	20,584	21,071	20,414	20,439	20,304	20,803	20,606	20,342
.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
740	11,153	10,681	10,329	11,527	11,554	11,297	10,862	11,452	11,556	12,464	11,395	11,067	10,812	10,839	11,013	11,200
741	11,151	10,555	10,315	11,515	11,420	11,279	10,808	11,421	11,550	12,460	11,388	10,967	10,722	10,828	10,857	11,149
742	11,140	10,539	10,169	11,454	11,260	11,253	10,757	11,409	11,385	12,436	11,349	10,803	10,643	10,777	10,824	11,080
743	11,124	10,520	10,100	11,413	11,044	11,205	10,746	11,389	11,338	12,225	11,323	10,727	10,562	10,736	10,761	11,014
744	11,037	10,474	10,074	11,403	11,011	11,155	10,685	11,211	11,238	12,160	11,272	10,681	10,556	10,722	10,729	10,960

After this process has been completed for all hours in August, a P50 forecast will have been calculated for all 744 hours of August. The forecast at this point is ordered from the highest value (indicated as rank 1) to the lowest value (indicated as rank 744). Note that the forecasted values have not yet been assigned to a day or hour. The values associated with a rank of 1 are the initial monthly forecasted peak demand values. The forecasted monthly peak values for August and January though will be subject to an adjustment which is covered in the two sections immediately below.

Weather Zone Normal Weather (P50) Summer Peak Demand Forecast

The fifteen weather load forecast scenarios are used as the basis for creating the weather zone normal weather 50th percentile (denoted as the P50) summer peak forecast. Each of the fifteen hourly weather load forecast scenarios are separated into individual calendar year forecasts (covering calendar years 2018-2027). The maximum forecasted hourly value occurring during the summer season (defined as June 1 through September 30) is determined for each individual calendar year. The summer peak demand values from each weather scenario for a particular calendar year are averaged to determine the normal weather P50 forecasted summer peak value. For example, to determine the normal weather (P50) forecasted summer peak value for calendar year 2018, take the highest forecasted value from each of the fifteen weather load forecast scenarios for calendar year 2018 and average them. The forecasted summer peak demand is then assigned to August and replaces the previously calculated peak (rank 1) forecasted value for the month of August.

Example:
Table 2 (below) shows the forecasted summer peak demand for the Coast weather zone for 2018 based on the historical weather years of 2002-2016. The P50 column is the average of the fifteen forecasts in the row. The P50 forecasted summer peak demand for Coast is 20,733 MW.

Table 2: Coast Weather Zone
2018 Summer Peak Forecast Scenarios

	Historical Weather Year																
Rank	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**P50**	**P90**
1	19,859	21,001	20,391	20,775	20,313	21,004	20,025	20,908	21,005	21,323	21,119	20,619	20,568	21,156	20,932	20,733	21,223

Weather Zone Normal Weather (P50) Winter Peak Demand Forecast

The fifteen weather load forecast scenarios are used as the basis for creating the weather zone normal weather 50th percentile (denoted as the P50) winter peak forecast. Each of the fifteen hourly weather load forecast scenarios are separated into individual calendar year forecasts (covering calendar years 2018-2027). The maximum forecasted hourly value occurring during the winter season (defined as December 1 through March 31) is determined for each individual year. The winter peak demand values from each weather scenario for a particular year are averaged to determine the normal weather P50 forecasted winter peak value. For example, to determine the normal weather (P50) forecasted winter peak value for 2018, take the highest forecasted value from each of the fifteen weather load forecast scenarios for December 1, 2017 – March 31, 2018 and average them. The forecasted winter peak demand is then assigned to January and replaces the previously calculated peak (rank 1) forecasted value for the month of January.

Example:
Table 3 (below) shows the forecasted winter peak demand for the Coast weather zone for the winter of 2018 based on the historical weather years of 2002-2016. The P50 column is the average of the fifteen forecasts in the row. The P50 forecasted winter peak demand for Coast is 14,554 MW.

Table 3: Coast Weather Zone
2018 Winter Peak Forecast Scenarios

	Historical Weather Year															
Rank	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**P50**
1	15,015	14,680	13,653	13,634	13,479	14,714	14,341	13,800	15,866	15,967	14,033	14,977	15,504	14,498	14,144	14,554

Weather Zone Normal Weather (P50) Hourly Forecast Mapping to Calendar
The next step is to map the weather zone P50 hourly forecasts into a representative calendar. Remember that the P50 hourly forecast is ranked from highest to lowest value within each forecasted month. The sorted hourly forecasted values need to be mapped into a representative time sequenced shape. This is accomplished by looking at historical load data from calendar years 2007-2016. For each month in each historical year, determine the rank of all of the observations for each day and hour. Then map the corresponding forecasted P50 hourly values to the day and hour from the historical year with the same month and the same rank.

Example:
The Coast P50 Summer Peak Forecast is 20,733 MW. Also remember that the forecasted summer peak value is assigned to the month of August. In 2016, Coast's Summer Peak occurred on 8/09/2016 @ 1600. Using the 2016 mapping factors, the Coast P50 Summer Peak value is assigned to 8/09 @ 1600 for all forecasted years (2018-

2027). This means that the Coast P50 Summer Peak will always occur on 8/09 @ 1600 for all forecasted years when mapped to 2016.

Example:
In 2015, Coast's Summer Peak occurred on 8/11/2015 @ 1600. Using the 2015 mapping factors, the Coast P50 Summer Peak value is assigned to 8/11 @ 1600 for all forecasted years (2018-2027). This means that the Coast Summer Peak will always occur on 8/11 @ 1600 for all forecasted years when mapped to 2015.

This mapping process is completed using calendar years 2007-2016. When this is completed, there will be ten different hourly P50 forecasts. Note though that the monthly peak demand and monthly energy values will be exactly the same in each of the ten hourly weather zone P50 forecasts. The only difference is the day and time that the forecasted hourly values occur.

Example:
There are 744 (31 days times 24 hours per day) P50 hourly forecasted demand values for Coast for August. They will be mapped into a day and time (in August) based on the historical ranking from August 2007, August 2008, August 2009, ..., August 2015, and August 2016. Each forecasted value is assigned a day and hour based on the historical ranking. But the monthly peak demand and monthly energy values are the same no matter what historical mapping year is used.

<u>ERCOT Zone Normal Weather (P50) Hourly Forecast</u>
Each of the ten different mapped hourly P50 forecasts based on the historical calendar years of 2007-2016 for each weather zone are summed for each forecasted year, month, day, and hour. This results in ten different ERCOT P50 hourly coincident forecasts. The difference in these forecasts is caused by the different timing of weather conditions across the ERCOT region. It bears repeating that all of the underlying weather zone load forecasts have the same exact monthly peak demand and energy values.

In order to determine the single hourly P50 ERCOT forecast, an analysis was performed on these ten different P50 hourly coincident forecasts. The distribution of ERCOT summer peak demand was determined. Seeing that it is very difficult to determine how weather conditions will align or not at the time of ERCOT's summer peak, the forecast using historical factors from 2007 was deemed as the ERCOT official P50 forecast. Using the 2007 historical factors resulted in the least amount of diversity of weather zone demand at the time of ERCOT's summer peak. Stated differently, using the 2007 historical factors resulted in the highest ERCOT summer peak forecast.

<u>Load Forecast Scenarios (ERCOT system)</u>
The fifteen weather zone load forecast scenarios are used as the basis for creating load forecast scenarios for the ERCOT system. The hourly values from each weather zone are summed for each year, month, day, and hour to get the ERCOT total forecasted hourly demand. This process was completed for each of the historical weather years (2002-2016) and resulted in fifteen ERCOT load forecast scenarios for 2018-2027.

The following notation can be used to denote ERCOT system weather load forecast scenarios:

$$\sum_{z=1}^{8} HF_{(z,x,y)}$$

Where:
HF = hourly demand forecast,
x = historical weather date and time,
y = forecast date and time, and
z = weather zone (Coast, East, Far West, North, North Central, South, South Central, and West).

For example, $HF_{(\text{7/24/2008 1700, 7/24/2019 1700})}$, would denote the forecast for 7/24/2019 at 5:00 pm, which was based on weather from 7/24/2008 at 5:00 pm, for the ERCOT system.

Weather Zone (P90) Summer Peak Demand Forecast

Another forecast of interest is the 90th (P90) percentile weather zone summer peak demand forecast. The process for determining the 90th percentile weather zone summer peak demand forecast is identical to the process used for calculating the P50 forecast except that instead of using the average of the fifteen weather zone load forecast scenarios, the 90th percentile of the values is used.

Example:
Table 2 (above) shows the forecasted summer peak demand for the Coast weather zone for 2018 based on historical weather years of 2002-2016. The P90 column is the 90th percentile of the fifteen forecasts. The P90 forecasted summer peak demand for Coast is 21,223 MW.

Forecast Adjustments
A large liquefied natural gas (LNG) facility started construction in Freeport in November 2014. This facility expects to begin operations of the first liquefaction train in September 2018. The second liquefaction train has an in-service date of February 2019 followed by the third liquefaction train with an in-service date of August 2019. The Freeport LNG facility is located in the Coast weather zone. This facility will have an estimated load of 655 MW once all three trains are in-service. This load will be served by ERCOT (i.e., this load will not be self-served).

To account for this large load addition, the Coast forecast was increased by the estimated load for each train (approx. 218 MW). The assumptions regarding this load are as follows:

1) The load will be served by ERCOT (i.e., this load will not be self-served).
2) The load will not be price responsive (i.e., this load will not actively be reduced to avoid transmission charges as part of ERCOT's four Coincident Peak calculations, high price intervals, etc.).
3) The first train will be operational on 7/1/2018.
4) All three trains will be operational on 7/1/2019.

Change Made Since 2017 LTDEF

1. Calendar year 2007 was used as the basis for estimating the impacts of weather diversity at the time of ERCOT's System Peaks
   In the 2017 LTDEF, calendar year 2003 was used.

   The reasons for changing from using the 2003 historical factors were:
   1) The factors were 14 years old,
   2) The Weather Zone Normal Weather (P50) Hourly Forecast methodology depends on having the same number of hours in each month. Daylight Savings changes were made in 2007. Using years from 2007 forward allowed for each month to have the same number of hours.

Load Forecast Comparison
Figure 4 presents the ERCOT summer peak demand forecasts for 2018-2026 from the 2017 LTDEF and the 2018 LTDEF.

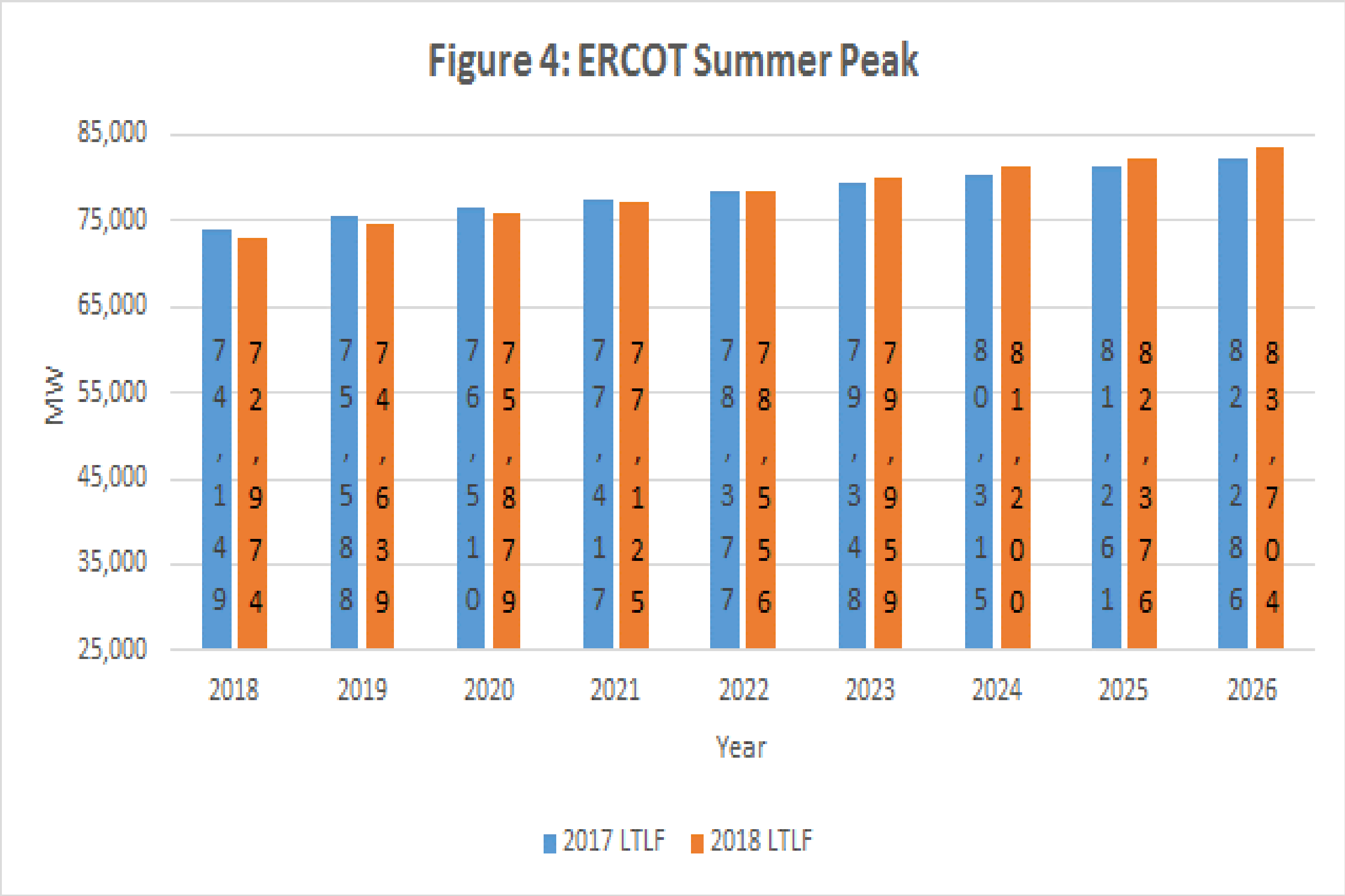


Figure 5 presents the ERCOT annual energy forecast for 2018-2026 from the 2017 LTDEF and the 2018 LTDEF.

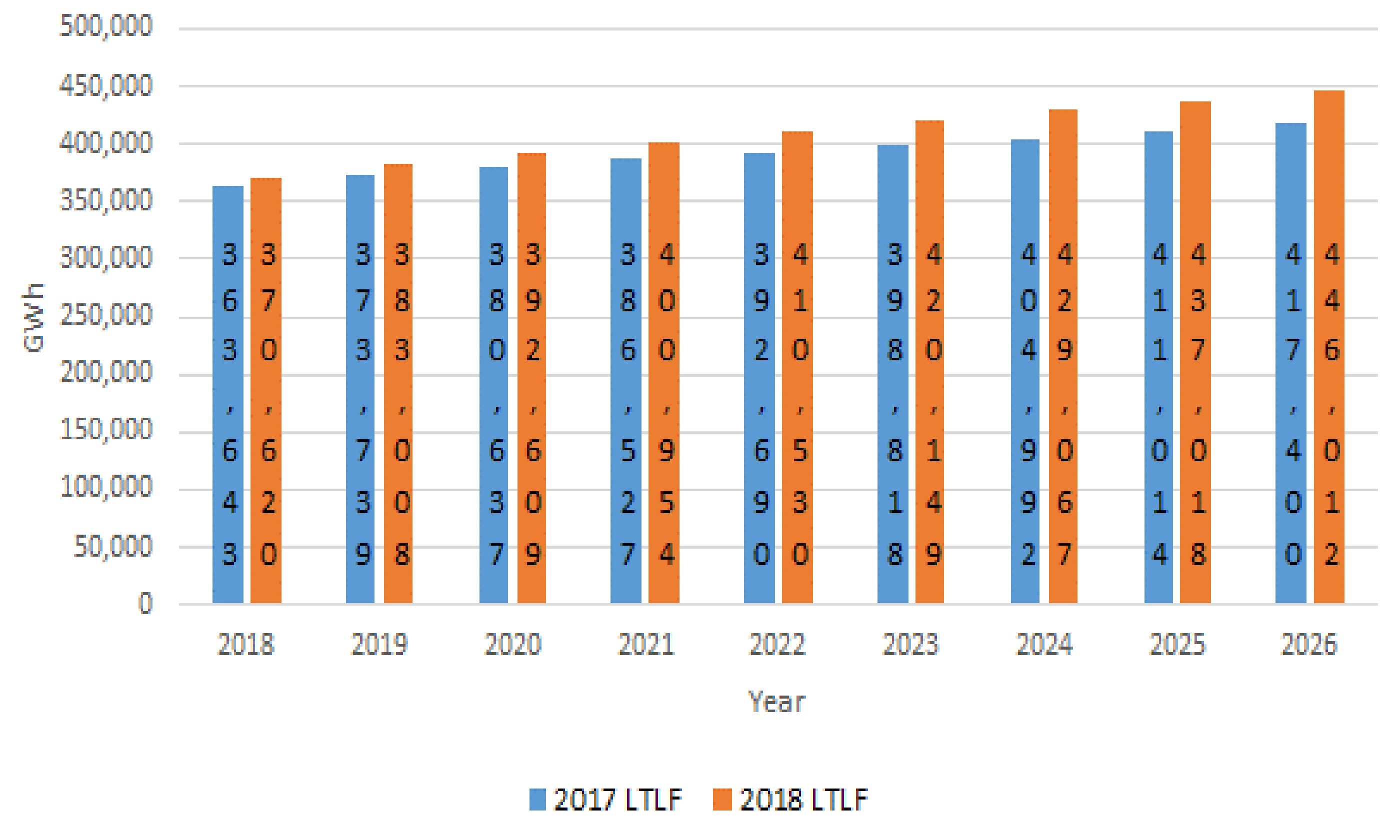


Figure 5: ERCOT Annual Energy Forecast

Load Forecast Uncertainty

A long-term load forecast can be influenced by a number of factors. The volatility of these factors can have a major impact on the accuracy of the forecast. This document will cover the following eight areas.

1. Weather,
2. Economics,
3. Energy Efficiency,
4. Price Responsive Loads,
5. Onsite Distributed Generation,
6. Electric Vehicles.
7. Large Industrial Loads, and
8. Change in ERCOT's Service Territory.

Weather Uncertainty

Figure 6 suggests the significant impact of weather in forecasting any specific year. This figure shows what the 2018 forecasted peak demand would be using the actual weather from each of the past fifteen years as input in the model. As shown, there is considerable variability ranging from 70,455 MW using 2004's weather to 76,176

MW using 2011's weather. This equates to approximately an 8% difference in the forecast based on historical weather volatility.

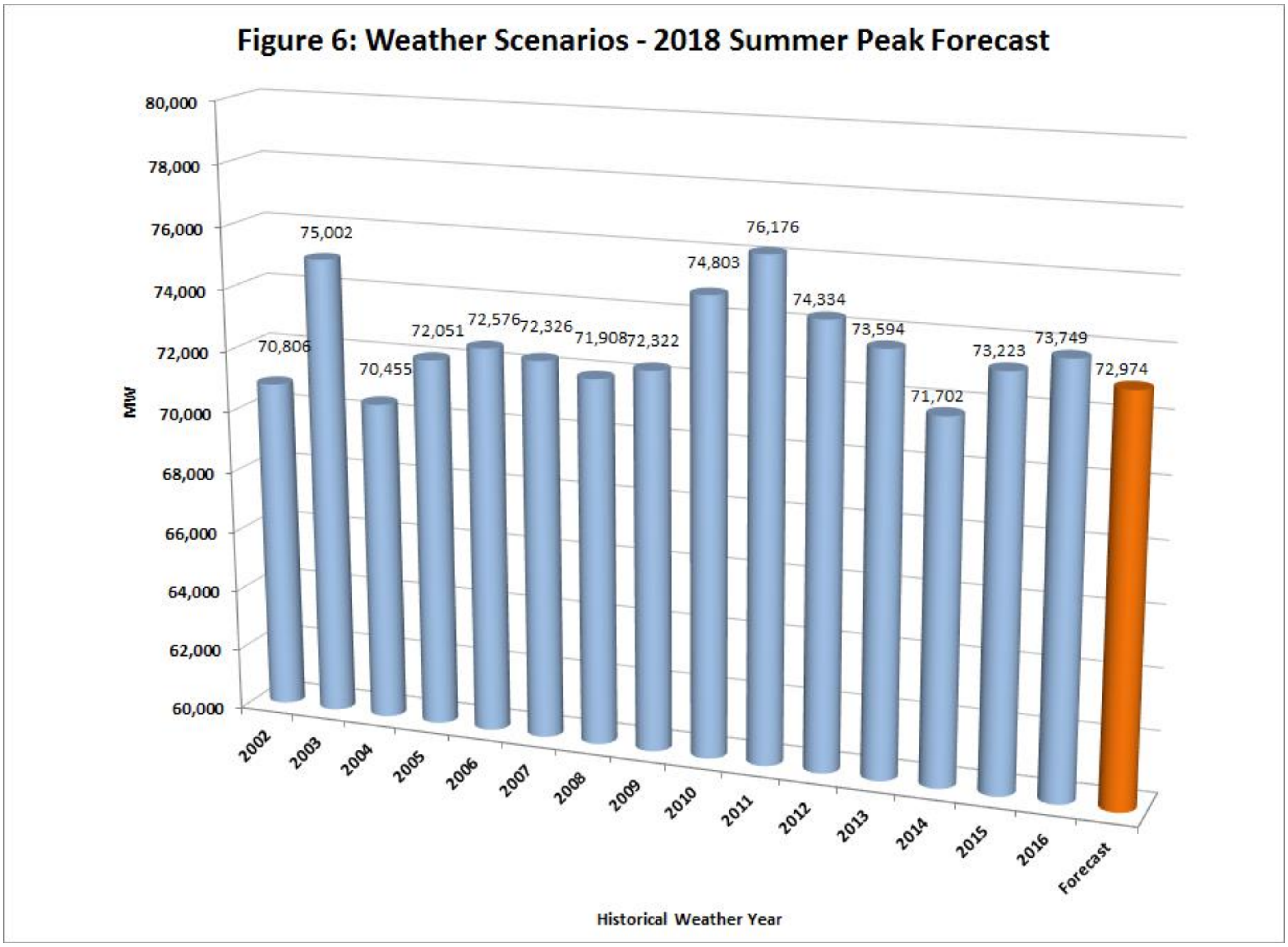
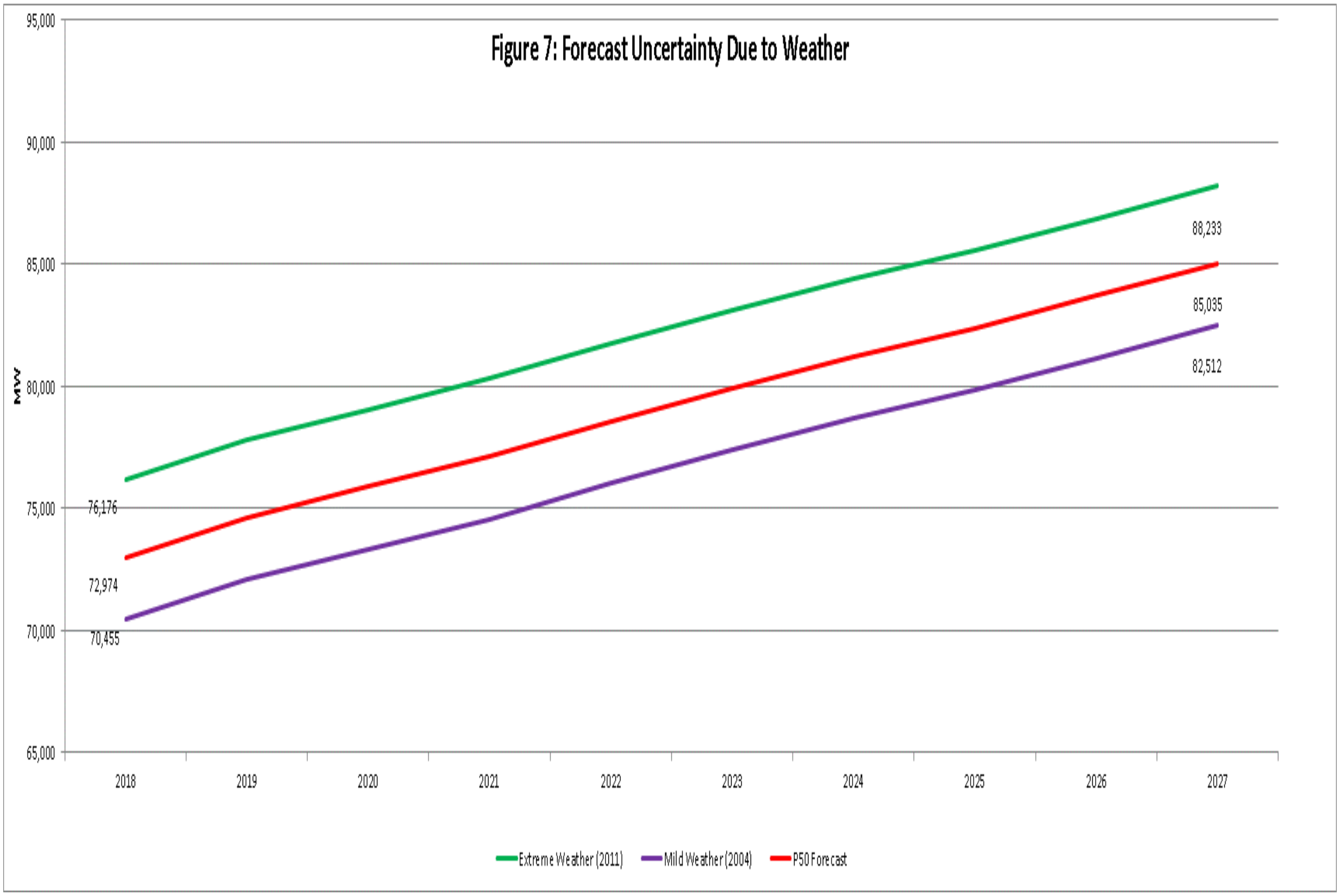


Figure 7 depicts weather volatility out to 2027. Assuming 2004 weather (identified as the mild weather scenario) in 2027, we would expect a peak of 82,512 MW. Assuming 2011 weather (identified as the extreme weather scenario) in 2027, results in a forecasted peak demand of 88,233 MW. This equates to approximately a 7% difference in the forecast based on weather extremes.

<u>Economic Uncertainty</u>

Economic uncertainty impacts the premise forecasts. Stated differently, significant changes in economic forecasts will have impacts on the premise forecasts, which in turn, will be reflected in the peak demand and energy forecasts. Premise forecasts were based on Moody's Analytics base economic scenario.



<u>Energy Efficiency</u>

Energy efficiency is a much more difficult uncertainty to quantify. First, it must be recognized that the 2018 LTDEF was a "frozen efficiency" forecast. That means the forecast model employs statistical techniques that estimate the relationships between load, weather, and economics based on historical data from January 2012 through August 2017. The implicit assumption in the forecast is that there will be no significant change in the level of energy efficiency during the forecasted timeframe when compared to what occurred during the historical period used in the model building process. Such an assumption has significant implications. Among other things, it means that the models assume the thermal characteristics of the housing stock and the characteristics of the mix of appliances will remain relatively the same. If thirty percent of the residential central air conditioners in the South Central weather zone have Seasonal Energy Efficiency Ratios (SEER—a measure of heat extraction efficiency) of twelve during the historical time period, then the model assumes the same proportion in all forecasted years. In the future, ERCOT will create energy efficiency scenarios which adjust the load forecast based on data from the Energy Information Administration (EIA)[7]. It is somewhat likely that an Energy Efficiency adjustment will be applied in the 2019 LTDEF.

[8] *For a discussion of the EIA scenarios, see the "Buildings Sector Case" at* <u>http://www.eia.gov/forecasts/aeo/appendixe.cfm</u>

Price Responsive Loads

Price responsive load programs are in their infancy for much of ERCOT. Determining the impact of these programs is challenging, especially when you consider that over the last few years, ERCOT's price caps have increased from $1,000/MWh to $9,000/MWh. Discussions are underway to explore ways to enable loads to participate in ERCOT's real-time energy market by submitting demand response offers to be deployed by the Security Constrained Economic Dispatch. There remains much uncertainty as to what future levels these programs may achieve. Similarly to Energy Efficiency, it must be recognized that the 2018 LTDEF was a "frozen" forecast with respect to price responsive loads. Price responsive loads are reflected in the forecast at the level that was observed during the historical period. In the future, ERCOT may create price responsive load scenarios, which will adjust the forecasted peak demands.

Onsite Distributed Generation (DG)

Another area of uncertainty is due to onsite distributed generation. Included are technologies such as the following:

1. Distributed Generation (non-renewable),
2. Distributed Onsite Wind,
3. Photovoltaic (PV), and
4. Solar Water Heating.

Onsite distributed generation technologies are also characterized by much uncertainty as to what future levels may be achieved. The 2018 LTDEF was a "frozen" forecast with respect to onsite renewable generation technologies. Onsite renewable generation technologies are reflected in the forecast at the level that was observed during the historical period. In the future, ERCOT may create scenarios for Onsite Renewable Energy Technologies.

Electric Vehicles Uncertainty

The growth of Electric Vehicles (EVs) has been accelerating. As an example, industry forecasts indicate that the number of electric vehicles in Texas will grow from 5,000 to approximately 100,000 by 2023. Still, the number of electric vehicles represents a very small percentage of the new car market in the United States. The 2018 LTDEF was a "frozen" forecast with respect to EVs. EVs are reflected in the forecast at the level that was observed during the historical period. ERCOT will continue to monitor the growth of electric vehicles in order to monitor their impact on the load forecast.

Large Industrial Loads

A key challenge in creating a load forecast is to determine if the model is adequately capturing the impact of future large industrial loads. Examples include liquefied natural gas facilities, oil and gas exploration, chemical processing plants, Tesla battery plants, etc. In addition, ERCOT had discussions with Transmission Service Providers (TSPs) and gathered information on the expected growth of industrial load within their service territories. ERCOT carefully reviews the historical performance of their long-term load forecasts to determine how well large industrial growth has been captured. Based on the results of this evaluation and on data gathered from the TSPs, ERCOT may use this information to adjust their forecast. As an example, the 2018 LTDEF was adjusted for the Freeport LNG facility.

Change in ERCOT's Service Territory

Another challenge in creating a load forecast is the potential for ERCOT's service territory to change. As an example, discussions are underway to determine if the City of Lubbock should join ERCOT. Lubbock's peak load is approximately 600 MW. The 2018 LTDEF does not include any changes to ERCOT's service territory.

Looking Ahead

As more information becomes available and additional data analysis is performed for each of these highlighted areas of forecast uncertainty, ERCOT will begin developing models which quantify their impacts on future long-term demand and energy forecasts. These themes will likely be revisited in the 2019 LTDEF.

Appendix A
Peak Demand and Energy Forecast Summary

Year	Summer Peak Demand (MW)	Energy (TWh)
2018	72,974	371
2019	74,639	383
2020	75,879	393
2021	77,125	401
2022	78,556	411
2023	79,959	420
2024	81,200	429
2025	82,376	437
2026	83,704	446
2027	85,035	455