![ercot logo]

2020 ERCOT System Planning

Long-Term Hourly Peak Demand and Energy Forecast

December 31, 2019

Executive Summary

The 2020 Long-Term Demand and Energy Forecast (LTDEF) for the ERCOT region is presented in this report, which includes information about 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 (e.g., residential, business, and industrial), weather variables (e.g., temperature, heating and cooling degree days, cloud cover, and wind speed), and calendar variables (e.g., day of week and holidays). The premise forecasts that drive growth in the LTDEF are created using a set of econometric autoregressive models (AR1) and are based on certain economic (e.g., non-farm payroll employment, housing stock, and population) data. A county-level forecast of economic and demographic data was obtained from Moody's. Fifteen years of historical weather data was provided by Schneider Electric/DTN for 20 weather stations.

As shown in Figure 1, the 2020 LTDEF depicts system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.6% from 2020-2029. Historically, summer peak demand has grown at an AAGR of 1.4% from 2010-2019.

Figure 1: ERCOT Summer Peak Demand
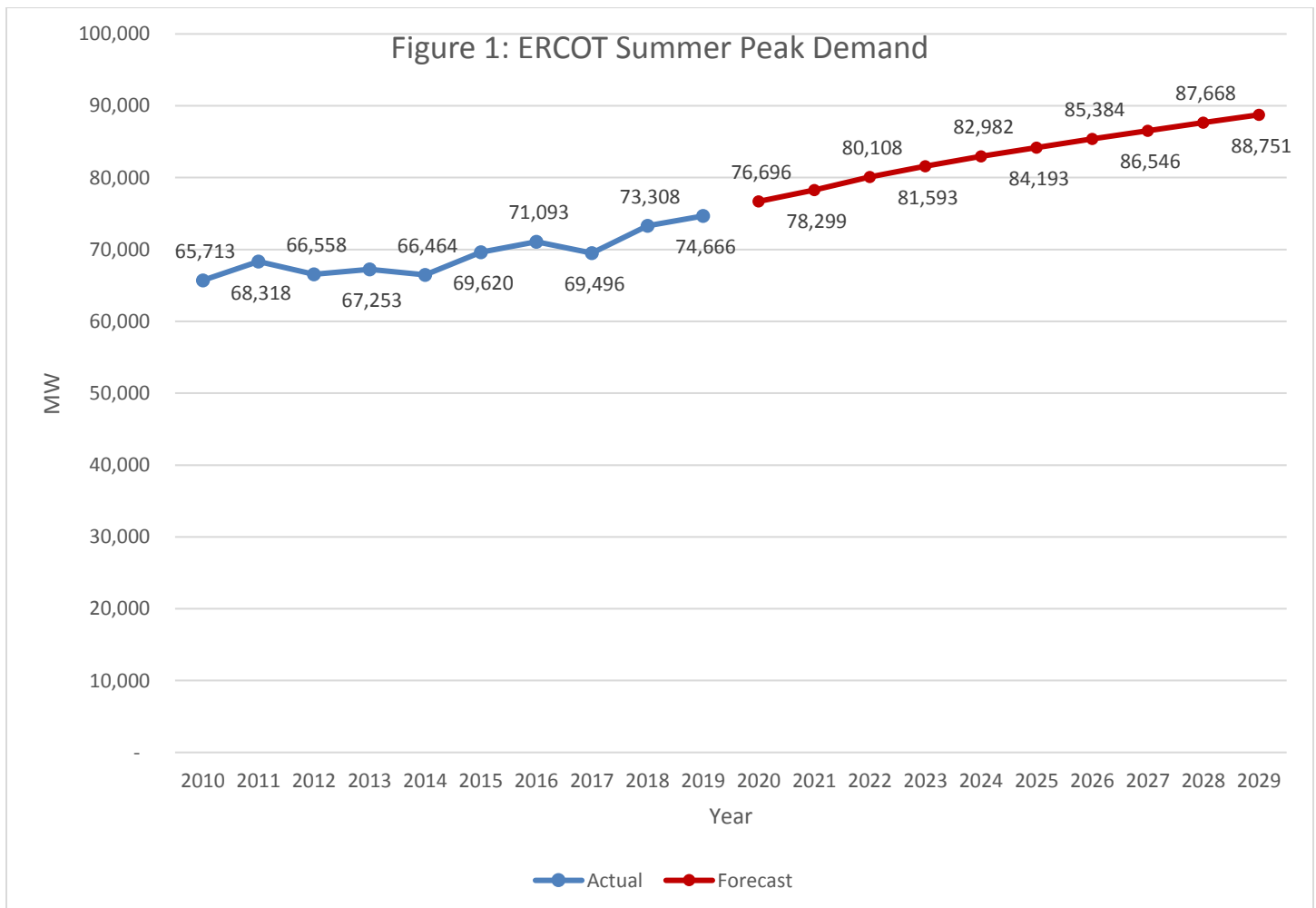
As shown in Figure 2, historical annual energy for the calendar years 2010-2019 grew at an AAGR of 2.1%. The forecasted AAGR for energy from 2020-2029 is 2.3%.


Figure 2: ERCOT Annual Energy
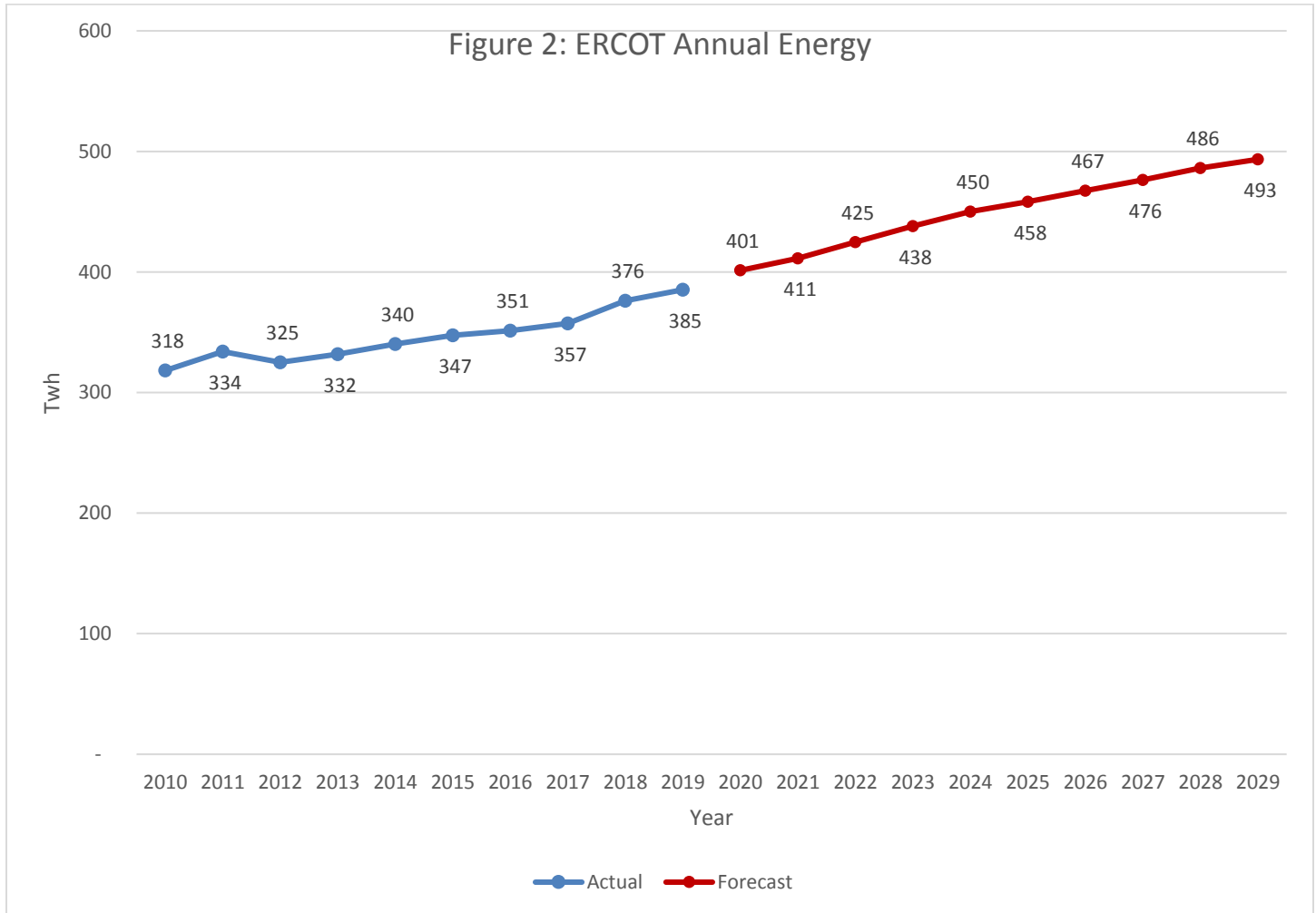
Introduction

This report gives a high-level overview of the 2020 LTDEF. The forecast methodology is described, highlighting its major conceptual and statistical underpinnings. The 2020 forecast results are presented in a manner comparing them to the 2019 LTDEF to allow for a direct comparison of results. Finally, an examination is presented describing the six major sources of forecast uncertainty: weather, economics, energy efficiency, demand response, on-site distributed generation, and electric vehicles.

2020 Modeling Framework

ERCOT consists of eight distinct weather zones (Figure 3). Weather zones[1] represent a geographic region in which climatological characteristics are similar. Each weather zone has 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.

Figure 3: ERCOT Weather Zones
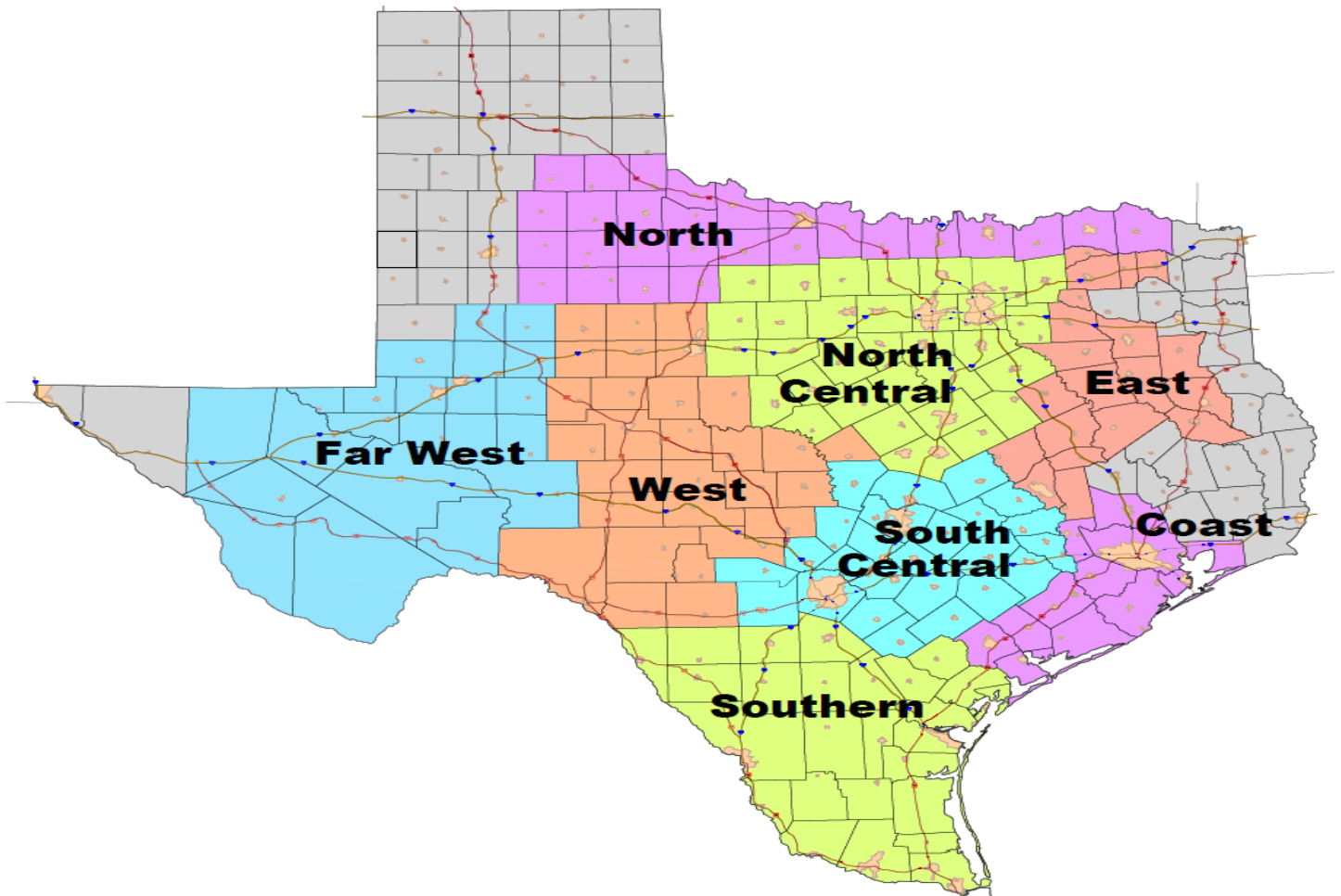
The 2020 LTDEF was produced with a set of linear regression models that combine weather, premise data, and calendar variables to capture and project the long-term trends extracted from the historical load data. Premise forecasts were also developed.

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

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

Premise Forecast Models

The key driver of 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. County-level data was mapped into the weather zones (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]).

All premise models were developed using historical data from January 2014 through August 2019. 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.

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

Premise Model Issues

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

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

As a result of this, it was problematic to create accurate premise forecast models for the Far West and West weather zones. These two weather zones instead used economic variables as the key driver of forecasted growth of demand and energy.

Hourly Demand Models

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

1. Month,
2. Day of Week,
3. Hour,
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,
    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 models and to provide details on the types of variables that were evaluated in the creation of the models. 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 of each area.

Model Building Process

The model building data set was comprised of a randomly selected 60% of the data from January 1, 2014 through August 31, 2019, with the remaining 40% of the data 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.

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[3] *All Degree Day variables are calculated versus 65 degrees F.*
[4] *For Coast, East, North, North Central, South, and South Central weather zones.*
[5] *For Far West and West weather zones.*

The validation data set consisted of a randomly selected 30% of data from January 1, 2014 through August 31, 2019 timeframe. The data in the validation data set was withheld from the model building data set. After model building was complete, the validation data set was used to determine the accuracy of the various forecast models. Each model's performance was calculated based on its forecasting performance on the validation data set. The most accurate models were selected based on their performance. The remaining randomly selected 10% of the data from January 1, 2014 through August 31, 2019 made up the test data set. After the most accurate models were selected based on their performance on the validation dataset, those models were run on the test data set to verify that the models performed well at predicting data they had not been built or selected based on.

Using only five years of historical data and as much of the current year's data as possible enables the model to reflect recent appliance stock, energy efficiency measures, price responsive load impacts, etc.

Weather Zone Load Forecast Scenarios

Actual weather data from calendar years 2004 through 2018 was used to create each weather zone's forecast by applying the weather data from each historical year one-by-one to the load forecasting model. The process began by using actual weather data from 2004 as weather input into the model for all forecasted years (2020-2029). The actual weather data from all days in 2004 was copied into the same day and hour for each of the forecasted years (2020-2029). For example, the actual weather data for 1/1/2004 was copied into 1/1/2020, 1/1/2021, … , 1/1/2029. Using 2004's weather as input into each weather zone's forecast model results in what is referred to as the 2004 weather load forecast scenario. The 2004 weather load forecast scenario is a forecast that assumes 2004's weather would occur for each forecasted calendar year (2020-2029). This process was completed for each of the historical weather years (2004-2018) individually and resulted in fifteen weather load forecast scenarios for each weather zone for the forecasted years 2020-2029. It should be noted that the premise and economic forecasts are the same in each of these fifteen weather scenarios.

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

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

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

For example, $HF_{(West,\ 7/24/2008\ 1700,\ 7/24/2020\ 1700)}$, would denote the forecast for 7/24/2020 at 5:00 pm, 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 50th 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 2020-2029). 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 2020, take the highest forecasted value from each of the fifteen weather load forecast scenarios for August 2020 and average them. To determine the second highest value for August 2020, take the second highest forecasted value for each of the fifteen weather load forecast scenarios for August 2020 and average them. Repeat this process for all hours in August 2020. See Table 1 below for a summary of these calculations.

Table 1: Coast Weather Zone August 2020 Forecast Scenarios

	Historical Weather Year															
Rank	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	P50
1	21,257	21,208	21,081	21,499	21,099	21,858	21,485	22,220	22,656	21,458	21,172	22,031	21,660	21,074	21,290	21,536
2	21,166	20,502	20,895	21,413	20,756	21,384	21,266	22,151	21,250	21,244	21,132	21,947	21,406	21,025	21,257	21,253
3	21,083	20,421	20,883	21,358	20,716	21,277	21,254	22,128	21,236	21,211	21,099	21,589	21,356	20,902	21,153	21,178
4	20,996	20,404	20,603	21,225	20,641	21,250	21,170	22,096	21,152	21,210	21,001	21,555	21,348	20,841	21,131	21,108
5	20,834	20,382	20,495	21,131	20,591	21,156	21,170	22,040	21,119	21,188	20,972	21,545	21,299	20,792	21,062	21,052
.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
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740	10,358	11,734	11,610	11,512	11,271	11,727	11,760	13,131	11,655	11,323	11,079	11,111	11,355	10,693	11,689	11,467
741	10,315	11,713	11,597	11,509	11,241	11,702	11,710	13,124	11,653	11,192	11,019	11,073	11,329	10,643	11,488	11,421
742	10,266	11,707	11,265	11,481	11,199	11,682	11,699	13,097	11,552	11,125	10,915	10,993	11,300	10,618	11,479	11,359
743	10,245	11,661	11,051	11,447	11,104	11,596	11,597	13,083	11,545	10,975	10,889	10,984	11,247	10,611	11,440	11,298
744	10,095	11,614	11,035	11,360	11,087	11,580	11,506	12,968	11,454	10,956	10,867	10,924	11,230	10,537	11,395	11,240

After this process has been completed for all hours in August, a P50 forecast will have been calculated for all 744 hours of August. At this point, the forecast 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 monthly forecasted peak demand values. The forecasted monthly peak values for August and January, however, are 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 2020-2029). The

maximum forecasted hourly value occurring during the summer season (defined as June through September) is determined for each individual calendar year. The summer peak demand values from all of the fifteen weather scenarios 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 2020, take the highest forecasted value in months June through September from each of the fifteen weather load forecast scenarios for calendar year 2020 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 2020 based on the historical weather years of 2004-2018. The P50 column is the average of the fifteen forecasts in the row. The P50 forecasted summer peak demand for Coast is 21,536 MW.

Table 2: Coast Weather Zone 2020 Summer Peak Forecast Scenarios

							Historical Weather Year										
Rank	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	P50	P90
1	21,257	21,208	21,081	21,499	21,099	21,858	21,485	22,220	22,656	21,458	21,172	22,031	21,660	21,074	21,290	21,536	22,394

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 2020-2029). The maximum forecasted hourly value occurring during the winter season (defined as December through March) is determined for each 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 2021, take the highest forecasted value from each of the fifteen weather load forecast scenarios for December 2020 – March 2021 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 2021 based on the historical weather years of 2004-2018. The P50 column is the average of the fifteen forecasts in the row. The P50 forecasted winter peak demand for Coast is 16,552 MW.

Table 3: Coast Weather Zone 2021 Winter Peak Forecast Scenarios

							Historical Weather Year									
Rank	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	P50
1	16,753	16,465	15,303	16,186	16,601	16,404	17,542	17,621	15,203	15,988	16,992	16,334	15,816	16,754	18,317	16,552

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 was accomplished by looking at historical load data from calendar years 2007-2018. For each month in each historical year, the rank of all of the observations for each day and hour was determined. Then, the corresponding forecasted P50 hourly values were mapped to the day and hour from the historical year with the same month and the same rank.

Example:
The Coast P50 Summer Peak Forecast for 2020 is 21,536 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 (2020-2029). 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 (2020-2029). 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 was completed using calendar years 2007-2018. This produced twelve different hourly P50 forecasts based on each of the twelve calendar years 2007-2018. Note, though, that the monthly peak demand and monthly energy values are exactly the same in each of the twelve hourly weather zone P50 forecasts. The only difference is the day and time that the forecasted hourly values occur when mapped to the different historical years.

Example:
There are 744 (31 days times 24 hours per day) P50 hourly forecasted demand values for the Coast weather zone for August. They are mapped into a day and time (in August) based on the historical ranking of actual load values from August 2007, August 2008, August 2009, ... , August 2017, and August 2018. Each forecasted value was assigned a day and hour based on the historical ranking. But the monthly peak demand and monthly energy values are the same no matter which historical mapping year is used.

ERCOT Zone Normal Weather (P50) Hourly Forecast

Each of the twelve different mapped hourly P50 forecasts based on the historical calendar years of 2007-2018 for each weather zone are summed for each forecasted year, month, day, and hour. This results in twelve different ERCOT P50 hourly coincident forecasts. The differences among these forecasts are 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 which hourly P50 ERCOT coincident forecast to use as our primary and official P50 ERCOT coincident forecast, an analysis was performed on these twelve 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 2008 was deemed the ERCOT official P50 forecast. Using the 2008 historical factors resulted in the least amount of diversity between weather zone demand and ERCOT-wide demand at the time of ERCOT's summer peak. Stated differently, using the 2008 historical factors resulted in the highest ERCOT coincident summer peak forecast.

Load Forecast Scenarios (ERCOT system)

The 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.

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

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

Where:
HF = hourly demand forecast,
y = historical weather date and time, and
z = forecast date and time.

For example, $HF_{(7/24/2008\ 1700,\ 7/24/2020\ 1700)}$, would denote the forecast for 7/24/2020 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 percentile (P90) 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 year 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 2020 based on historical weather years of 2004-2018. The P90 column is the 90th percentile of the fifteen forecasts. The P90 forecasted summer peak demand for the Coast weather zone in 2020 is 22,394 MW.

Weather Zone (P90) Summer Peak Demand Forecast for Far West

Although using weather variation from fifteen historical weather years to derive percentiles works well for all other Weather Zones where load is highly dependent on weather, using weather to derive percentiles does not work so well for Far West, where the load is fairly consistent across weather variations. Instead, economic variation, in particular Moody's high economic scenario, was used to derive a 90th Percentile forecast for Far West.

Forecast Adjustments

Coast
A large liquefied natural gas (LNG) facility is under construction in the Coast weather zone. This facility expects to begin operations of its third liquefaction train on February 1, 2020. The facility will have an estimated load of 655 MW once all three trains are in-service.

South
There are multiple large industrial facilities projected to be operational in the South weather zone during the forecasted timeframe (2020-2029). Additions of 75 - 930 MW were made to the forecast based on the estimated loads of these facilities.

Far West
Strong load growth due to oil and gas operations continues in the Far West weather zone. To account for this, 400 MW were added to the forecast.

North
Lubbock is expected to join ERCOT in June, 2021. An hourly forecast was created for Lubbock based on Lubbock's Peak Forecast. This forecast for Lubbock was added beginning on Lubbock's projected integration date.

East
Rayburn is transferring load to ERCOT in January, 2020. An hourly forecast was built for Rayburn using Rayburn's Actual Summer and Winter Peaks from 2019. The forecast was added starting on January 6, 2020.

Load Forecast Comparison

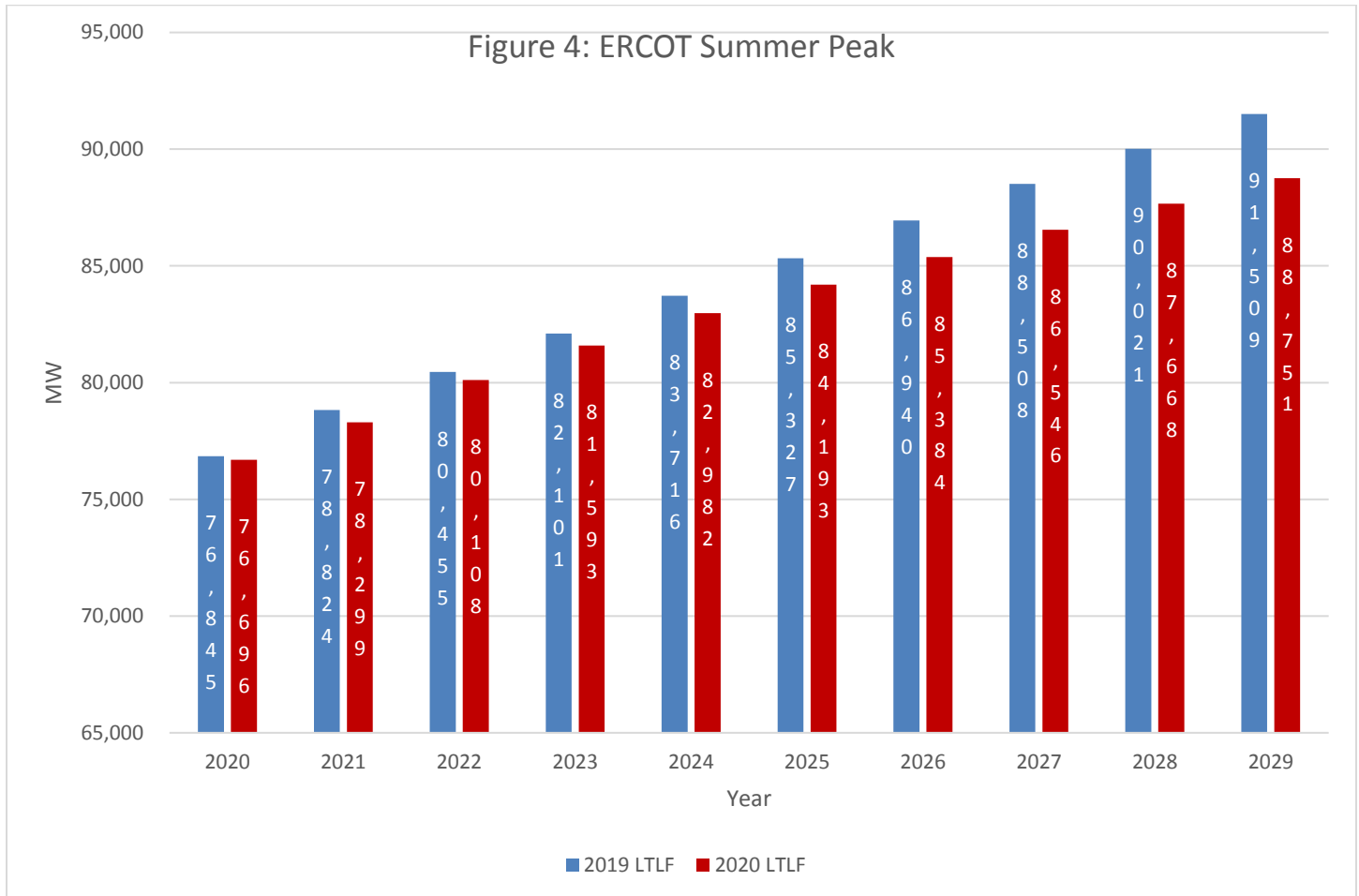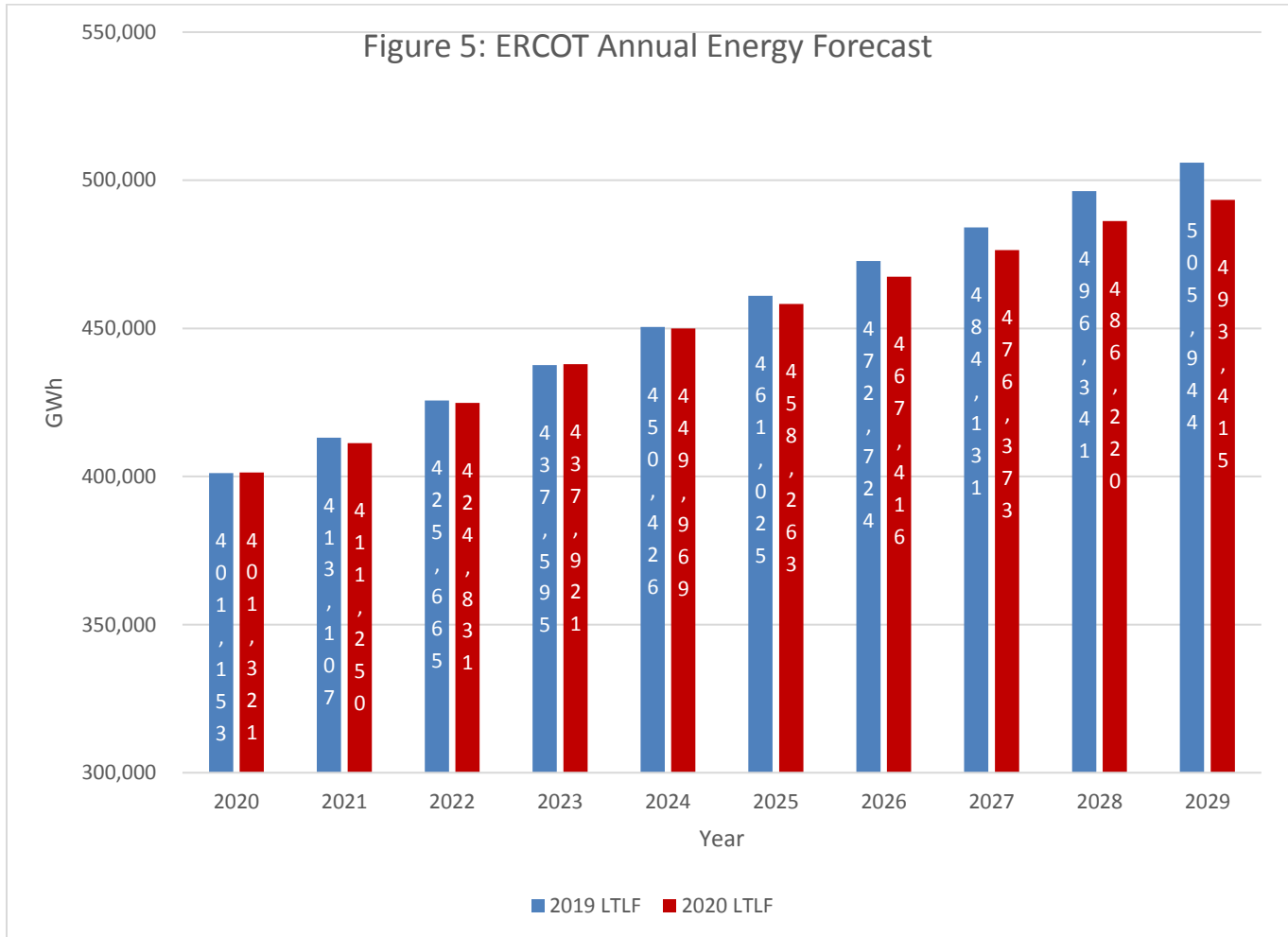Figure 4 presents the ERCOT summer peak demand forecasts for 2020-2029 from the 2019 LTDEF and the 2020 LTDEF.

Figure 4: ERCOT Summer Peak

Year	2019 LTLF	2020 LTLF
2020	76,845	76,696
2021	78,824	78,299
2022	80,455	80,108
2023	82,101	81,593
2024	83,716	82,982
2025	85,327	84,193
2026	86,940	85,384
2027	88,508	86,546
2028	90,021	87,668
2029	91,509	88,751

Figure 5 presents the ERCOT annual energy forecast for 2020-2029 from the 2019 LTDEF and the 2020 LTDEF.

Figure 5: ERCOT Annual Energy Forecast

Year	2019 LTLF	2020 LTLF
2020	401,153	401,321
2021	413,107	411,250
2022	425,665	424,831
2023	437,595	437,921
2024	450,426	449,969
2025	461,025	458,263
2026	472,724	467,416
2027	484,131	476,373
2028	496,341	486,220
2029	505,944	493,415

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:

1. Weather,
2. Economics,
3. Energy Efficiency,
4. Price Responsive Loads,
5. On-site 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. This figure shows what the 2020 forecasted peak demand would be using the actual weather from each of the past fifteen years as input into the model. As shown, there is considerable variability ranging from 74,280 MW using 2004's weather to 79,947 MW using 2011's weather. This equates to approximately a 7.6% difference in the forecast based on historical weather volatility. The variation seen in the figure below is due to differences in weather and calendar factors between the fifteen historical weather years.

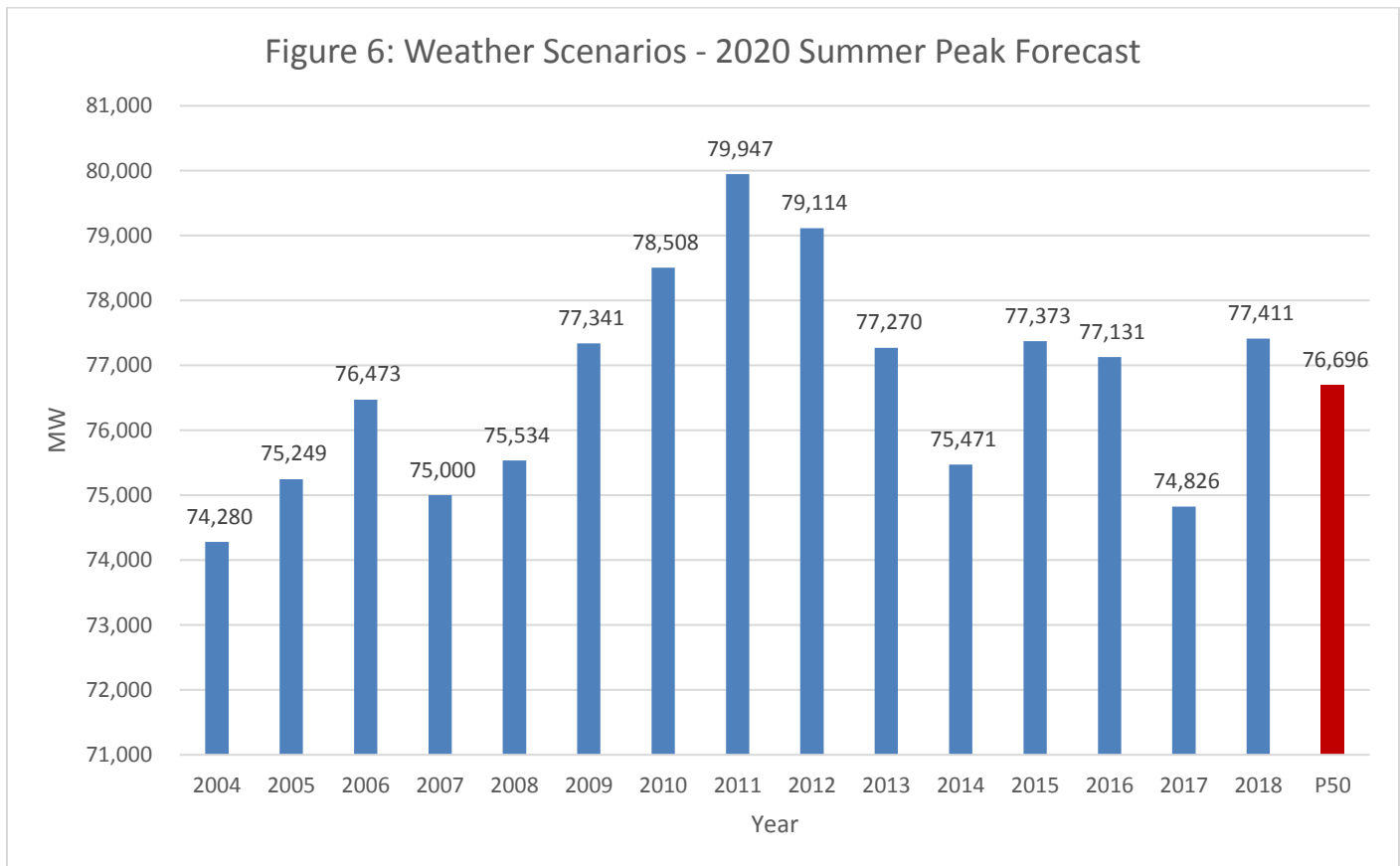Figure 6: Weather Scenarios - 2020 Summer Peak Forecast

Figure 7 depicts weather volatility out to 2029. Assuming 2004 weather (identified as the mild weather scenario) in 2029, we would expect a peak of 86,346 MW. Assuming 2011 weather (identified as the extreme weather scenario) in 2029, results in a forecasted peak demand of 92,007 MW. This equates to approximately a 6.6% difference in the forecast based on weather extremes.

Figure 7: Forecast Uncertainty Due to Weather
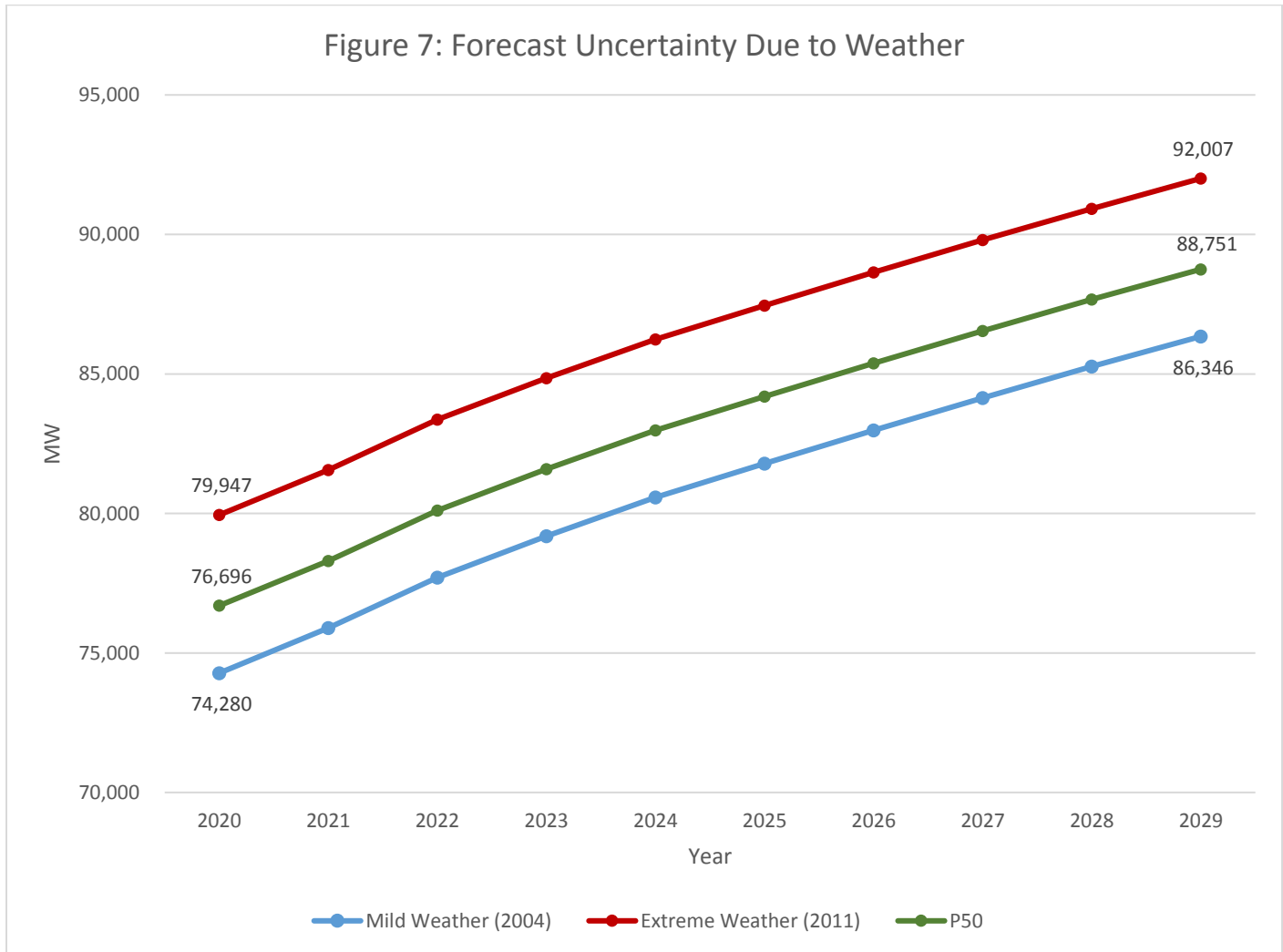
Economic Uncertainty

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 the base economic scenario from Moody's Analytics.

Energy Efficiency

Energy efficiency is a much more difficult uncertainty to quantify. First, it must be recognized that the 2020 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 2014 through August 2019. 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 had Seasonal Energy Efficiency Ratios (SEER—a measure of heat extraction efficiency) of twelve during the historical time period, then the model assumes that same proportion in all forecasted years. In the future, ERCOT may create energy efficiency scenarios which adjust the load forecast based on data from the Energy Information Administration (EIA)[6].

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. Similar to Energy Efficiency, it must be recognized that the 2020 LTDEF is 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 of January 2014 – August 2019. In the future, ERCOT may create price responsive load scenarios, which would adjust the forecasted peak demands.

On-site Distributed Generation (DG)

Another area of uncertainty is on-site distributed generation. Included are technologies such as the following:
1. Distributed Generation (non-renewable),
2. Distributed On-site Wind,
3. Photovoltaic (PV), and
4. Solar Water Heating.

On-site distributed generation technologies are also characterized by much uncertainty about what future levels may be achieved. The 2020 LTDEF was a "frozen" forecast with respect to on-site renewable generation technologies. On-site renewable generation technologies are reflected in the forecast at the level that was observed during the historical period of January 2014 – August 2019. In the future, ERCOT may create scenarios for On-site Renewable Energy Technologies.

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

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 2020 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 of January 2014 - August 2019 which was used to build the 2020 LTDEF models. ERCOT will continue to monitor the growth of electric vehicles in order to quantify 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 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 the long-term load forecast. The 2020 LTDEF was adjusted for large industrial loads in the Coast, South, and Far West weather zones.

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, the City of Lubbock is joining ERCOT in 2021. Lubbock's peak load is approximately 500 MW. The 2020 LTDEF includes an hourly forecast for Lubbock (based on the City of Lubbock's forecast of its growth) which was added to the North weather zone forecast. The addition of Rayburn to ERCOT's service territory also necessitated an adjustment to the 2020 LTDEF and it was added to the East weather zone forecast.

Looking Ahead

As more information becomes available and additional data analysis is performed on 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 2021 LTDEF.

Appendix A
Peak Demand and Energy Forecast Summary

Year	Summer Peak Demand (MW)	Energy (TWh)
2020	76,696	401
2021	78,299	411
2022	80,108	425
2023	81,593	438
2024	82,982	450
2025	84,193	458
2026	85,384	467
2027	86,546	476
2028	87,668	486
2029	88,751	493