2023 ERCOT System Planning

Long-Term Hourly Peak Demand and Energy Forecast

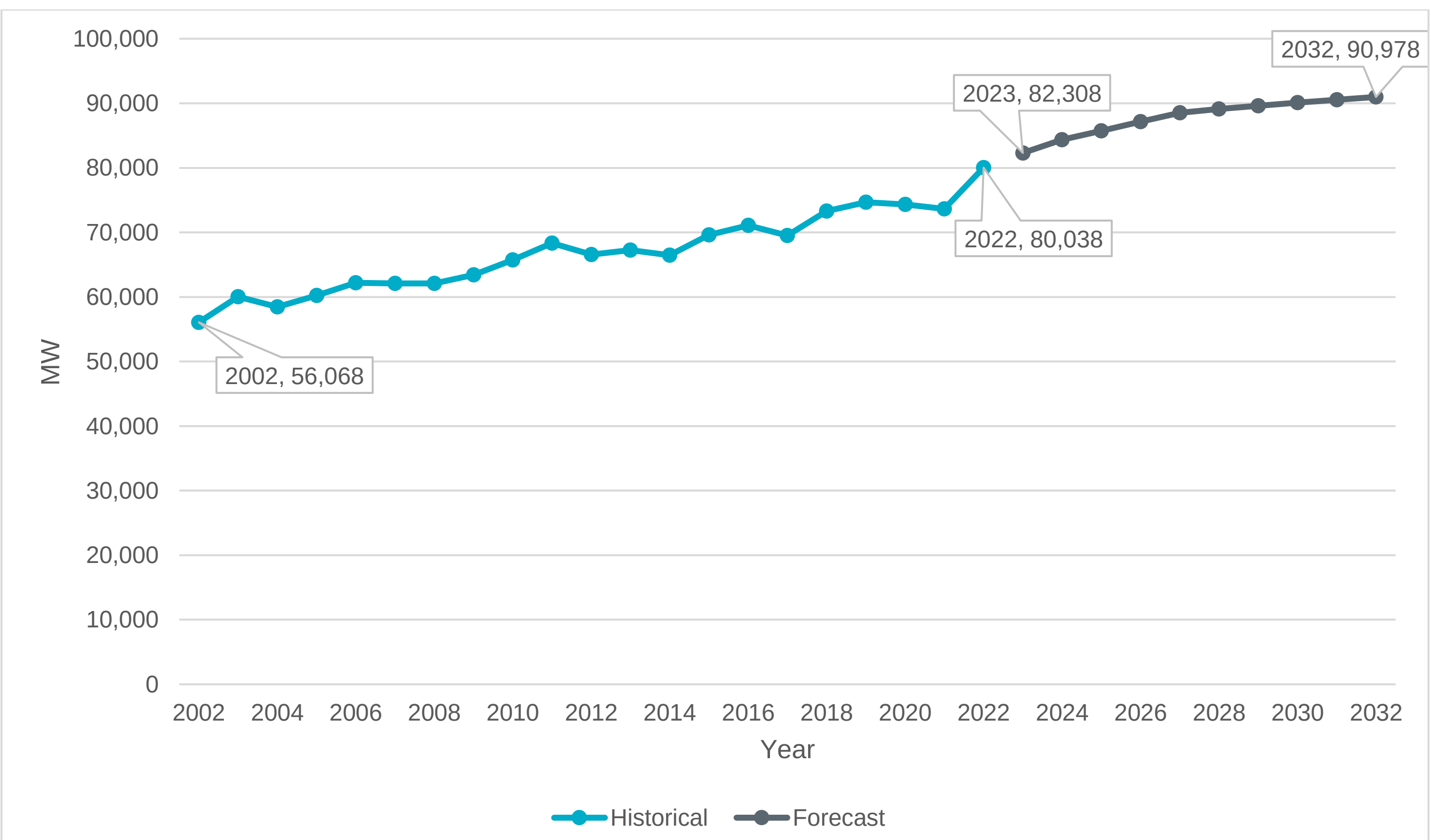
January 18, 2023

Executive Summary

The 2023 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., various temperature values), 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.

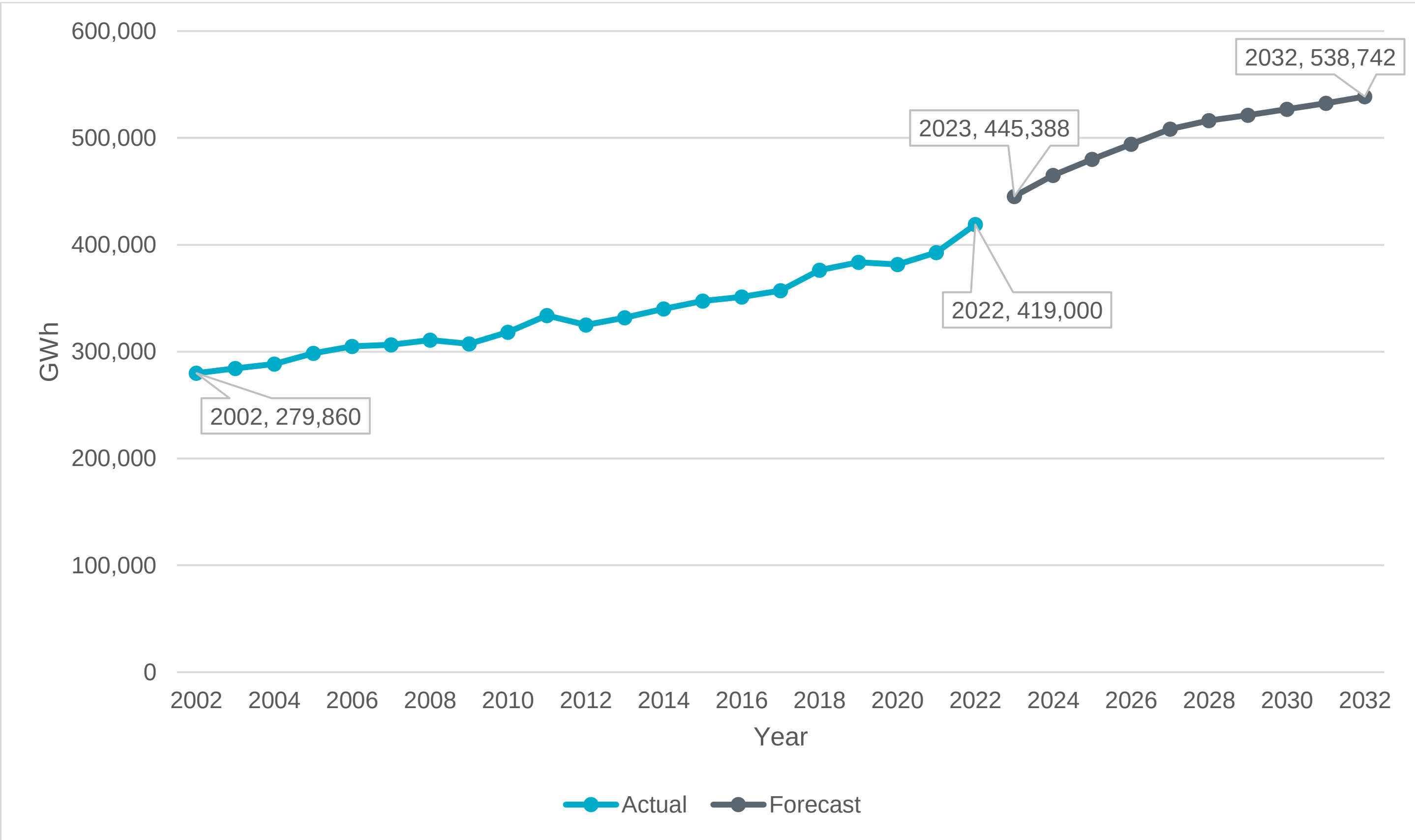
As shown in Figure 1, the 2023 LTDEF depicts system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.1% from 2023-2032. Historically, summer peak demand has grown at an AAGR of 2.0% from 2013-2022.

Figure 1: ERCOT Summer Peak Demand Forecast



As shown in Figure 2, historical annual energy for the calendar years 2013-2022 grew at an AAGR of 2.6%. The forecasted AAGR for energy from 2023-2032 is 2.1%.

Figure 2: ERCOT Annual Energy Forecast



Introduction

This report gives a high-level overview of the 2023 LTDEF. The forecast methodology is described, highlighting its major conceptual and statistical underpinnings. The 2023 forecast results are presented in a manner comparing them to the 2022 LTDEF to allow for a direct comparison of results. The impacts of rooftop PV are also included. The rooftop PV forecast methodology is described. Finally, an examination is presented describing the seven major sources of forecast uncertainty: weather, economics, energy efficiency, price responsive loads, electric vehicles, large industrial loads, and changes in the ERCOT service territory.

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. To reflect the unique weather and load characteristics of each zone, separate load forecasting models were developed for each of the weather zones.

The 2022 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 model descriptions included in this document should be understood as referring to weather zones. The ERCOT forecast is calculated as the sum of all weather zone forecasts.

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 2017 through September 2022. An autoregressive model (AR1) was used for all premise forecasts.

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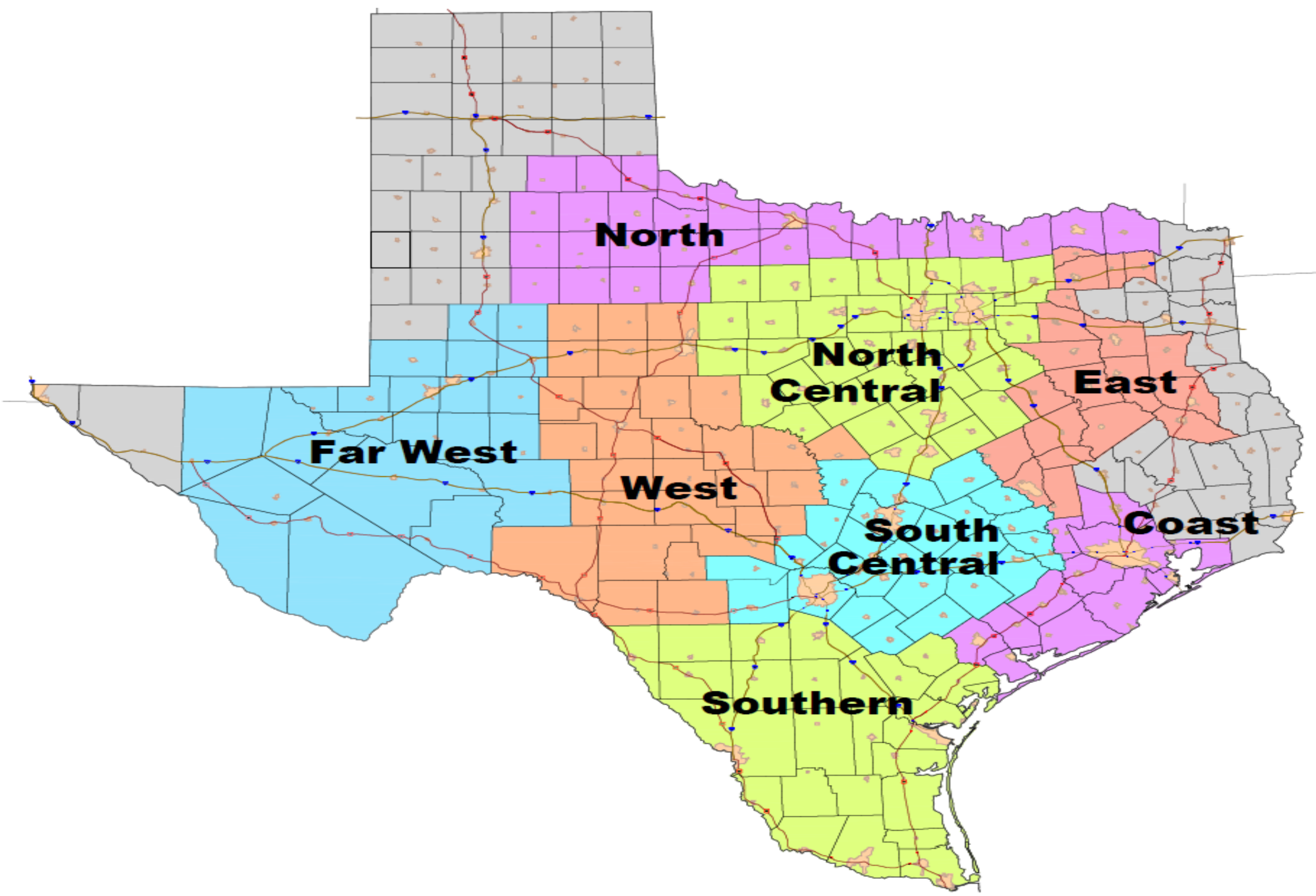
[1] *See ERCOT Nodal Protocols, Section 2.*
[2] *See ERCOT Nodal Protocols, Section 18.6.1.*

Figure 3: ERCOT Weather Zones



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.

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 including various lagged values,
    b. Temperature squared including various lagged values,
    c. Temperature cubed including various lagged values,
5. Interactions,
    a. Day of Week and Temperature variables,
    b. Hour and Day of Week,
    c. Hour and Temperature variables,
    d. Month and Temperature variables, and
6. Number of premises.

All 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, 2017 through September 30, 2022, 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.

The validation data set consisted of a randomly selected 30% of data from January 1, 2017 through September 30, 2022 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, 2017 through September 30, 2022 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 seen.

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 2007 through 2021 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 2007 as weather input into the model for all forecasted years (2023-2032). The actual weather data from all days in 2007 was copied into the same day and hour for each of the forecasted years (2023-2032). For example, the actual weather data for 1/1/2007 was copied into 1/1/2023, 1/1/2024, …, and 1/1/2032. Using 2007's weather as input into each weather zone's forecast model results in what is referred to as the 2007 weather load forecast scenario. The 2007 weather load forecast scenario is a forecast that assumes 2007's weather would occur for each forecasted calendar year (2023-2032). This process was completed for each of the historical weather years (2007-2021) individually and resulted in fifteen weather load forecast scenarios for each weather zone for each of the forecasted years 2023-2032. 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, $HF_{(West,\ 7/24/2008\ 1700,\ 7/24/2023\ 1700)}$, would denote the forecast for 7/24/2023 at 5:00 pm, based on weather from 7/24/2008 at 5:00 pm, for the West weather zone.

Weather Zone Normal Weather Hourly Forecast

The fifteen weather zone load forecast scenarios are used as the basis for creating the weather zone normal weather hourly forecast. Each of the fifteen hourly weather zone load forecast scenarios were separated into individual calendar year forecasts (covering calendar years 2023-2032). 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 forecasted peak value for August 2023, take the highest forecasted value from each of the fifteen weather load forecast scenarios for August 2023 and average them. To determine the second highest value for August 2023, take the second highest forecasted value for each of the fifteen weather load forecast scenarios for August 2023 and average them. Repeat this process for all hours in August 2023. See Table 1 (page 9) for a summary of these calculations.

After this process has been completed for all hours in August, a forecast will have been created 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 Summer Peak Demand Forecast

The fifteen weather load forecast scenarios are used as the basis for creating the weather zone normal weather summer peak forecast. Each of the fifteen hourly weather load forecast scenarios are separated into individual calendar year forecasts (covering calendar years 2023-2032). 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 the fifteen weather scenarios for a particular calendar year are averaged to determine the normal weather forecasted summer peak value. For example, to determine the normal weather forecasted summer peak value for calendar year 2023, take the highest forecasted value in months June through September from each of the fifteen weather load forecast scenarios for calendar year 2023 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 1 (page 9) shows the forecasted summer peak demand for the Coast weather zone for 2023 based on the historical weather years of 2007-2021. The forecasted gross summer peak demand for Coast is 22,554 MW.

<u>Table 1: Coast Weather Zone August 2023 Forecast Scenarios</u>

	Historical Weather Year														
Rank	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Average**
1	22,768	22,383	22,956	22,542	23,276	23,583	22,813	22,209	22,972	22,214	21,656	21,922	22,511	22,316	22,192	22,554
2	22,709	21,921	22,264	22,515	23,146	22,465	22,129	22,109	22,733	22,182	21,574	21,902	22,454	22,045	21,903	22,270
3	22,699	21,867	22,161	22,456	22,888	22,241	22,123	22,063	22,586	22,119	21,525	21,852	22,399	22,024	21,874	22,192
4	22,684	21,863	22,160	22,381	22,793	22,229	22,111	21,951	22,473	21,982	21,494	21,836	22,311	21,966	21,829	22,138
5	22,499	21,746	22,108	22,327	22,740	22,186	22,046	21,930	22,430	21,976	21,443	21,771	22,307	21,926	21,760	22,080
	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
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	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
740	12,761	12,517	12,838	12,809	13,632	12,811	12,604	12,396	12,335	12,620	12,197	12,791	13,350	12,700	13,074	12,762
741	12,715	12,514	12,792	12,793	13,629	12,737	12,393	12,283	12,275	12,590	12,179	12,744	13,335	12,668	13,005	12,710
742	12,643	12,482	12,770	12,790	13,567	12,697	12,234	12,265	12,244	12,569	12,162	12,544	13,314	12,589	12,920	12,653
743	12,581	12,415	12,749	12,783	13,515	12,483	12,183	12,216	12,201	12,478	12,152	12,472	13,308	12,568	12,907	12,601
744	12,495	12,389	12,718	12,678	13,330	12,461	12,149	12,158	12,164	12,478	12,052	12,464	13,208	12,545	12,881	12,545

<u>Weather Zone Normal Weather Winter Peak Demand Forecast</u>

The fifteen weather load forecast scenarios are used as the basis for creating the weather zone normal weather winter peak forecast. Each of the fifteen hourly weather load forecast scenarios are separated into individual calendar year forecasts (covering calendar years 2023-2032). 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 forecasted winter peak value. For example, to determine the normal weather forecasted winter peak value for 2023, take the highest forecasted value from each of the fifteen weather load forecast scenarios for December 2022 – March 2023 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 (page 10) shows the forecasted winter peak demand for the Coast weather zone for the winter of 2023 based on the historical weather years of 2007-2021. The forecasted gross winter peak demand for Coast is 17,543 MW.

<u>Weather Zone Normal Weather Hourly Forecast Mapping to Calendar</u>

The next step is to map the weather zone average hourly forecasts into a representative calendar. Remember that the average 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 2007-2021. 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 average hourly values were mapped to the day and hour from the historical year with the same month and the same rank.

Example:
The Coast Gross Summer Peak Forecast for 2023 is 22,554 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 ranking, the Coast Summer Peak value is assigned to 8/09 @ 1600 for all forecasted years (2023-2032). This means that the Coast Summer Peak will always occur on 8/09 @ 1600 for all forecasted years that are mapped to 2016.

Example:
In 2015, Coast's Summer Peak occurred on 8/11/2015 @ 1600. Using the 2015 mapping ranking, the Coast Summer Peak value is assigned to 8/11 @ 1600 for all forecasted years (2023-2032). This means that the Coast Summer Peak will always occur on 8/11 @ 1600 for all forecasted years that are mapped to 2015.

Table 2: Coast Weather Zone 2023 Summer Peak Forecast Scenarios

Historical Weather Year

Rank	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average	90th
1	22,768	22,383	22,956	22,542	23,276	23,583	22,813	22,209	22,972	22,214	21,656	21,922	22,511	22,316	22,192	22,554	23,398
2	22,709	21,921	22,264	22,515	23,146	22,465	22,129	22,109	22,733	22,182	21,574	21,902	22,454	22,045	21,903	22,270	22,898
3	22,699	21,867	22,161	22,456	22,888	22,241	22,123	22,063	22,586	22,119	21,525	21,852	22,399	22,024	21,874	22,192	22,775
4	22,684	21,863	22,160	22,381	22,793	22,229	22,111	21,951	22,473	21,982	21,494	21,836	22,311	21,966	21,829	22,138	22,728
5	22,499	21,746	22,108	22,327	22,740	22,186	22,046	21,930	22,430	21,976	21,443	21,771	22,307	21,926	21,760	22,080	22,595
	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
740	12,761	12,517	12,838	12,809	13,632	12,811	12,604	12,396	12,335	12,620	12,197	12,791	13,350	12,700	13,074	12,762	13,462
741	12,715	12,514	12,792	12,793	13,629	12,737	12,393	12,283	12,275	12,590	12,179	12,744	13,335	12,668	13,005	12,710	13,453
742	12,643	12,482	12,770	12,790	13,567	12,697	12,234	12,265	12,244	12,569	12,162	12,544	13,314	12,589	12,920	12,653	13,415
743	12,581	12,415	12,749	12,783	13,515	12,483	12,183	12,216	12,201	12,478	12,152	12,472	13,308	12,568	12,907	12,601	13,391
744	12,495	12,389	12,718	12,678	13,330	12,461	12,149	12,158	12,164	12,478	12,052	12,464	13,208	12,545	12,881	12,545	13,257

Table 3: Coast Weather Zone 2023 Winter Peak Forecast Scenarios

Historical Weather Year

Rank	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average
1	18,359	16,780	16,264	18,561	19,588	16,492	16,451	17,830	16,942	15,672	17,300	19,148	16,056	15,827	21,878	17,543

This mapping process was completed using calendar years 2007-2021. This produced fifteen different hourly forecasts one based on each calendar year. Note, though, that the monthly peak demand and monthly energy values are the same in each of the fifteen hourly weather zone 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) 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 2020, and August 2021. 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.

<u>ERCOT Zone Normal Weather (P50) Hourly Forecast</u>

Each of the fifteen different mapped hourly forecasts based on the historical calendar years of 2007-2021 for each weather zone are summed for each forecasted year, month, day, and hour. This results in fifteen different ERCOT 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.

To determine which hourly ERCOT coincident forecast to use as our primary and official ERCOT coincident forecast, an analysis was performed on these fifteen different 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 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. Figure 4 (page 12) shows the ranges of ERCOT Summer Peak demands based on using different historical diversity factors.

<u>Load Forecast Scenarios (ERCOT system)</u>

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.

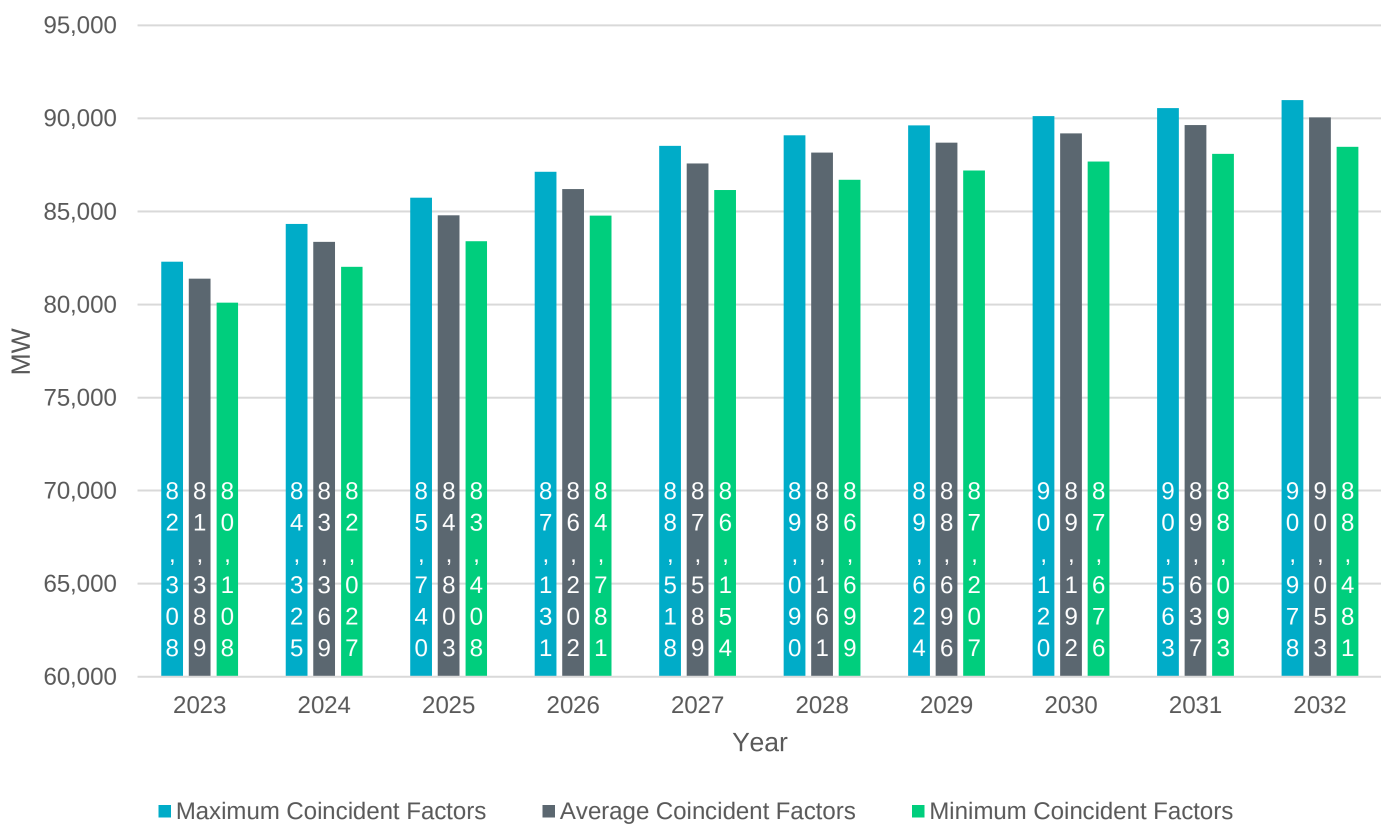
The following notation can be used to denote ERCOT system weather load forecast scenarios:

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

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

For example, $HF_{(7/24/2008\ 1700,\ 7/24/2023\ 1700)}$, would denote the forecast for 7/24/2023 at 5:00 pm, which was based on weather from 7/24/2008 at 5:00 pm, for the ERCOT system.

Figure 4: ERCOT Summer Peak Forecasts



<u>Weather Zone 90th Percentile Summer Peak Demand Forecast</u>

Another forecast of interest is the 90th percentile (denoted as 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 base 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 (page 10) shows the forecasted summer peak demand for the Coast weather zone for 2023 based on historical weather years of 2007-2021. The 90th column is the 90th percentile of the fifteen forecasts. The P90 forecasted gross summer peak demand for the Coast weather zone in 2021 is 23,398 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 most weather zones where load is highly dependent on weather, using weather to derive percentiles does not work well for Far West, where the load is consistent across weather variations. Instead, economic variation, in particular the Moody's high economic scenario, was used to derive a 90th Percentile forecast for Far West.

Forecast Adjustments

Forecast Adjustments for Industrial Facilities

Adjustments were made to reflect large industrial facilities projected to be operational in various weather zones. The assumptions regarding these loads are:

1. The loads will be served by ERCOT (i.e., these loads will not be self-served).
2. The loads will not be price responsive (i.e., these loads will not actively be reduced to avoid transmission charges as part of ERCOT's four Coincident Peak calculations, high price intervals, etc.).
3. The loads will come online on the currently projected integration dates.

Figure 5 (page 14) shows the Summer Peak forecast adjustments that were applied to the ERCOT system.

Forecast Adjustments for Large Flexible Loads (LFLs)

A new type of load has been growing in the ERCOT service territory. This load commonly includes cryptocurrency miners. This load can come online quickly and is very responsive to real time prices. Large flexible loads are categorized as:

1. Co-located, meaning that the load is behind the meter of existing generation or
2. Non co-located, meaning that the load is not behind the meter of existing generation.

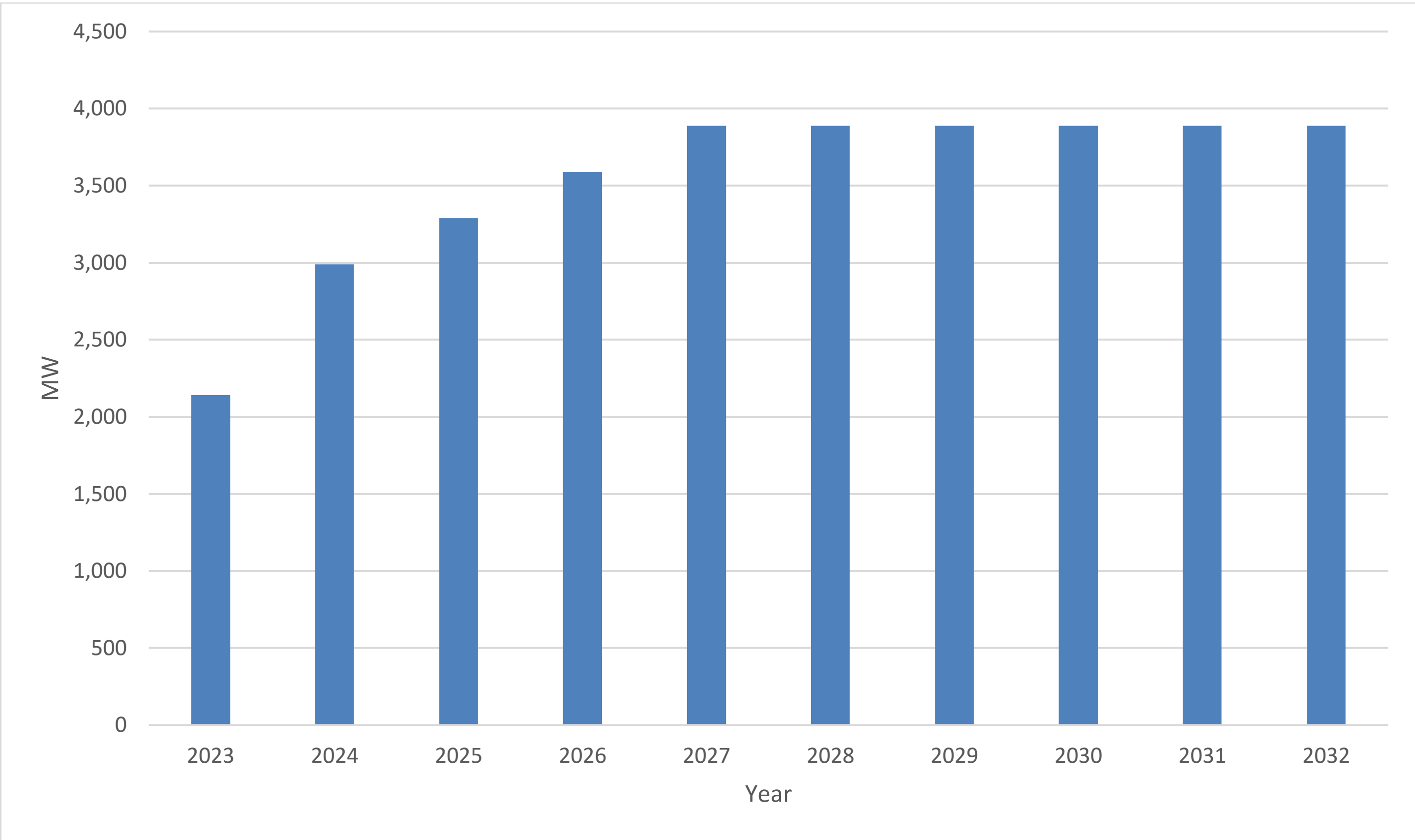
At the end of 2022, ERCOT was tracking approximately 1,500 MWs of LFLs consuming energy on the ERCOT system. The 2022 LTDEF increases the demand of LFLs by 700 MW per year from 2023 through 2027 resulting in approximately 5,000 MW total LFL load in 2027. The demand contribution of LFLs at the time of ERCOT's Summer Peak is forecasted to be 10% of their total demand based on the observed behavior of ERCOT-tracked LFLs during 2022 Summer Peak conditions. For example, LFLs are forecasted to increase ERCOT's 2027 Summer Peak by 500 MW.

Forecast Adjustments for Entities joining the ERCOT Region

The first phase of Lubbock Power and Light (LP&L) joining ERCOT occurred in 2021. This phase included approximately 75% of LP&L's total load (~500 MW). The remaining part of LP&L's load (representing approximately 25% Lubbock's current load) will be transferred to ERCOT in 2023. An hourly forecast was created for Lubbock based on Lubbock's Peak Forecast of its own growth. This separate forecast for Lubbock was added to the ERCOT forecast from Lubbock's projected integration date onward. Lubbock's forecasted load was added to the North weather zone.

In January, 2020, additional Rayburn load of approximately 150 MW was added to the East weather zone. A forecast was created based on data included from their PUCT filing.

Figure 5: ERCOT Summer Peak Forecast Adjustments for Industrial Facilities



Load Forecast Comparison

Figure 6 (page 15) presents the ERCOT summer peak demand forecasts for 2023-2031 from the 2020 LTDEF, 2021 LTDEF, and the 2021 LTDEF. Similarly, Figure 7 (page 16) presents the ERCOT annual energy forecasts for 2022-2031 from the same historical forecasts.

Figure 6: ERCOT Summer Peak Forecasts Comparison

<u>Rooftop PV Forecast</u>

Seeing that rooftop PV is expected to grow much faster in the future as compared to the amount that is present in the historical data that was used to create the load forecasting models, separate models were developed for a PV forecast. The PV forecast is then applied to the load forecast in order to better reflect the likely future impact of rooftop PV on the load forecast.

For each weather zone, Residential ESIIDs were separated into two groups, those with rooftop PV and those without PV based on their load profile. The average usage per ESIID was calculated for each hour for data in the historical data set for ESIIDs with and without rooftop PV. Figure 8 (page 18) shows a graph comparing the average usage per ESIID for those with and without PV on a summer day.

Figure 7: ERCOT Annual Energy Forecasts Comparison

<u>Weather Zone Average Usage Models</u>

Models were estimated for each of the eight ERCOT weather zones for both groups (ESIIDs with rooftop PV and ESIIDs without rooftop PV) between the dependent variable (hourly average usage) and the following:

1. Month,
2. Day of Week,
3. Hour,
4. Weather Variables,
    a. Temperature including various lagged values,
    b. Temperature squared including various lagged values,
    c. Temperature cubed including various lagged values,
    d. Cloud Cover,
5. Interactions,
    a. Hour and Day of Week,
    b. Hour and Temperature variables, and
    c. Month and Temperature variables.

Weather Zone Average Usage Forecasts

Actual weather data from calendar years 2007 through 2021 was used by applying the weather data from each historical year one-by-one to both hourly average usage models (those with PV and those without). The process began by using actual weather data from 2007 as weather input into the average usage models for all forecasted years (2023-2032). The actual weather data from all days in 2007 was copied into the same day and hour for each of the forecasted years (2023-2032). For example, the actual weather data for 1/1/2007 was copied into 1/1/2023, 1/1/2024, …, and 1/1/2032. This process was completed for each of the historical weather years (2007-2021) individually and resulted in fifteen average usage weather forecast scenarios for both groups (those with PV and those without) for each weather zone for each of the forecasted years 2023-2032.

The following notation can be used to denote the average usage scenarios for residential ESIIDs with PV:

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

Where:
ResPV = hourly PV average usage,
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.

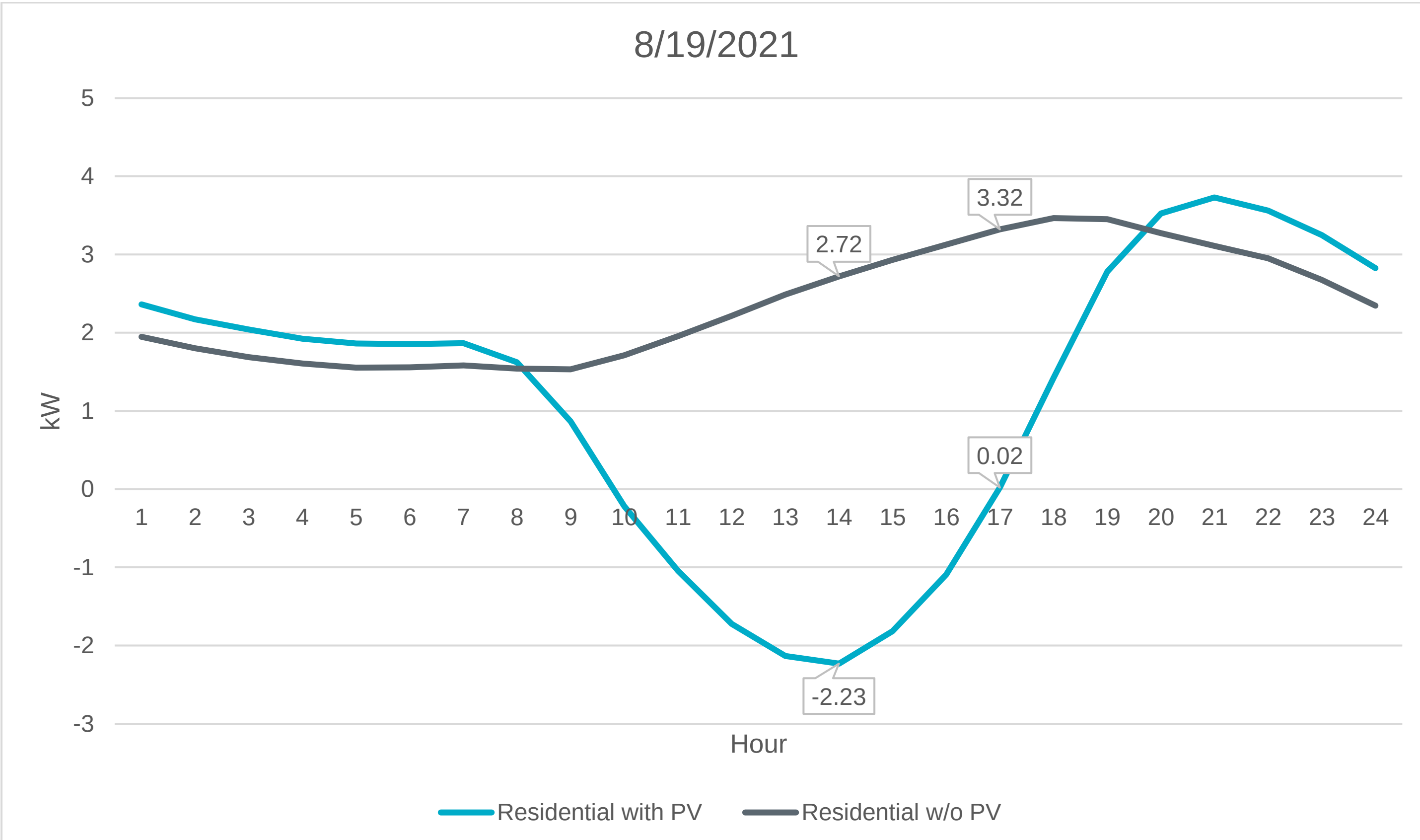
For example, $ResPV_{(West,\ 7/24/2008\ 1700,\ 7/24/2023\ 1700)}$, would denote the average usage for ESIIDs with PV on 7/24/2023 at 5:00 pm, based on weather from 7/24/2008 at 5:00 pm, for the West weather zone.

Similarly, the following notation can be used to denote average usage scenarios for residential ESIIDs without PV:

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

Where:
ResNoPV = hourly average usage,
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.

Figure 8 – Comparison of Average Usage for Residential ESIIDs with and without Rooftop PV



For example, $ResNoPV_{(West,\ 7/24/2008\ 1700,\ 7/24/2023\ 1700)}$, would denote the average usage of residential ESIIDs without PV for 7/24/2023 at 5:00 pm, based on weather from 7/24/2008 at 5:00 pm, for the West weather zone.

<u>Weather Zone PV Forecasts</u>

To determine the average PV load reduction for each weather zone, take the average usage for ESIIDs with PV and subtract the average usage for ESIIDs without PV for each forecast date and time for each weather forecast scenario. This can be expressed as

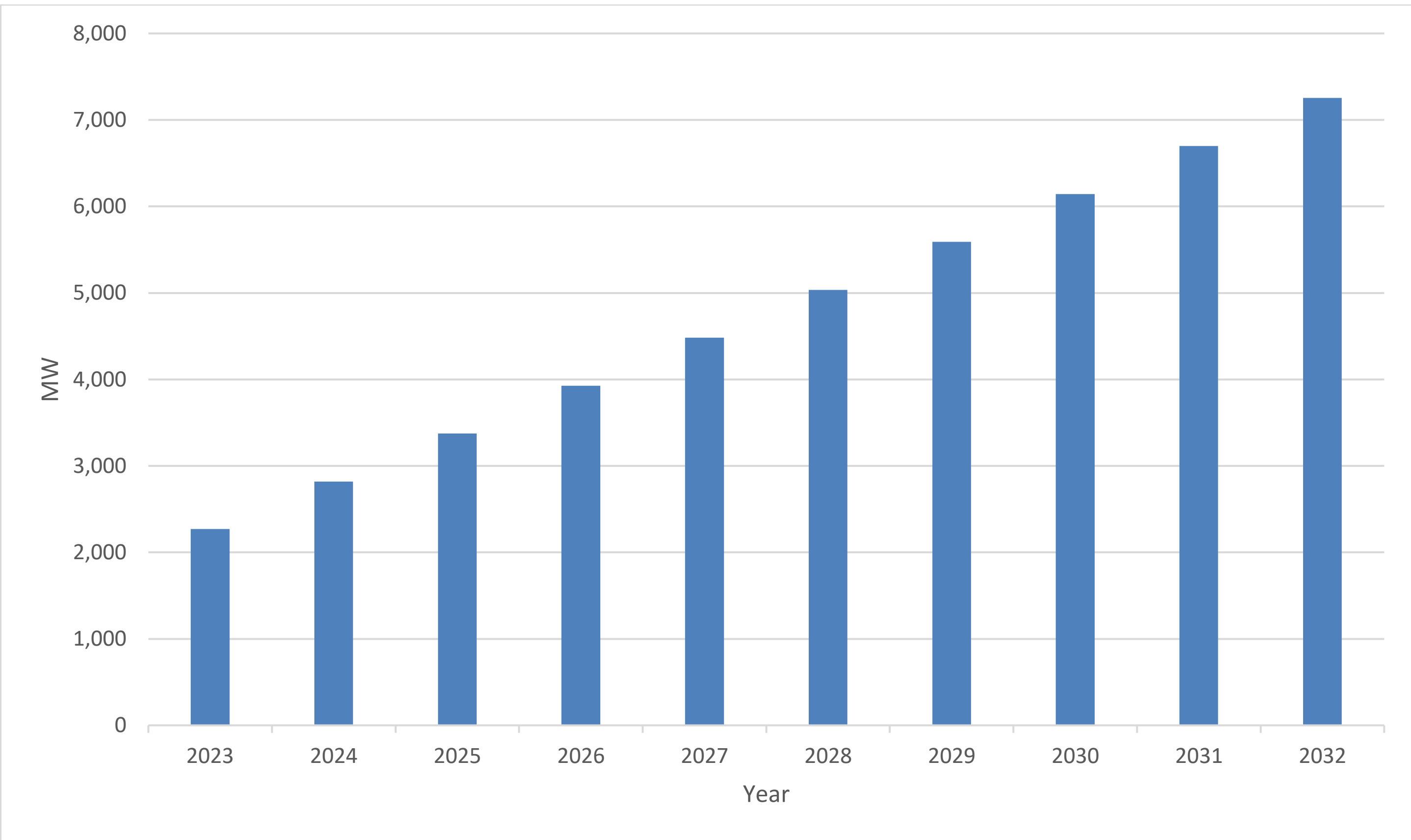
$$\forall x \forall y \forall z\ ResPV_{(x,y,z)} - ResNoPV_{(x,y,z)}$$

Where:
ResPV = hourly average usage for Residential ESIIDs with PV,
ResNoPV = hourly average usage for Residential ESIIDs without PV,
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.

The final step is to multiply the forecasted average PV load reduction by the forecasted number of ESIIDs with PV.

As of the third quarter of 2022, there was approximately 1,500 MW of Rooftop PV capacity installed in ERCOT. This forecast projects Rooftop PV capacity to increase to approximately 7,000 MW by 2032.

Figure 9 – ERCOT System Total Rooftop PV net to Grid



<u>Load Forecast Uncertainty</u>

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 seven areas:

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

Weather Uncertainty

Figure 10 (page 21) suggests the significant impact of weather in forecasting. This figure shows what the 2023 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 77,428 MW using 2021's weather to 85,696 MW using 2011's weather. This equates to approximately a 10% difference in the forecast based on historical weather volatility. This variation due to differences in weather and calendar factors between the fifteen historical weather years.

Figure 11 (page 22) depicts weather volatility out to 2032. Assuming 2021 weather (identified as the mild weather scenario) in 2032, we would expect a peak of 86,563 MW. Assuming 2011 weather (identified as the extreme weather scenario) in 2031, results in a forecasted peak demand of 93,966 MW. This equates to approximately a 10% difference in the forecast based on weather extremes.

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. A recent example was the impact COVID-19 had on economic forecasts. Premise forecasts were created using the base economic scenario from Moody's Analytics.

Energy Efficiency

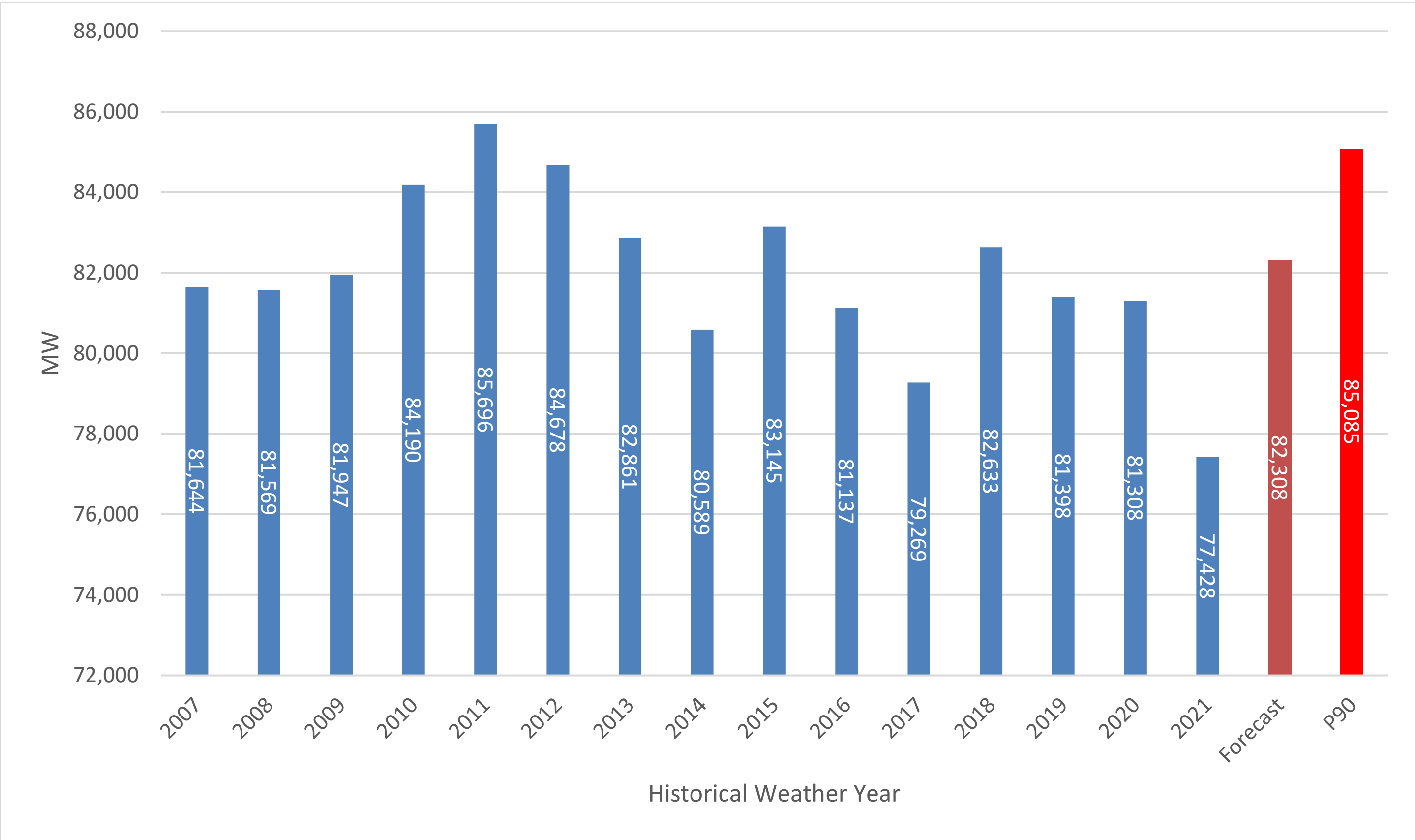
Energy efficiency is another source of uncertainty. First, it must be recognized that the 2023 LTDEF was a "frozen efficiency" forecast. That means the forecast model employs statistical techniques that estimate the relationships between load, weather, and economics based on historical data from January 2017 through September 2022. 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.

Price Responsive Loads

Price responsive load programs are another area of uncertainty. Determining the impact of these programs is challenging, especially when you consider that ERCOT's price caps have increased from $1,000/MWh to $9,000/MWh followed by a cut to $5,000/MWh. There have typically been few times with very high prices. This makes forecasting their impacts difficult due to a scarcity of data. There remains much uncertainty as to what future levels these programs may achieve.

Like Energy Efficiency, it must be recognized that the 2022 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 2016 – September 2021. In the future, ERCOT may create price responsive load scenarios, which would adjust the forecasted peak demands.

Figure 10 - 2023 Summer Peak Demand Scenarios



Electric Vehicles (EV)

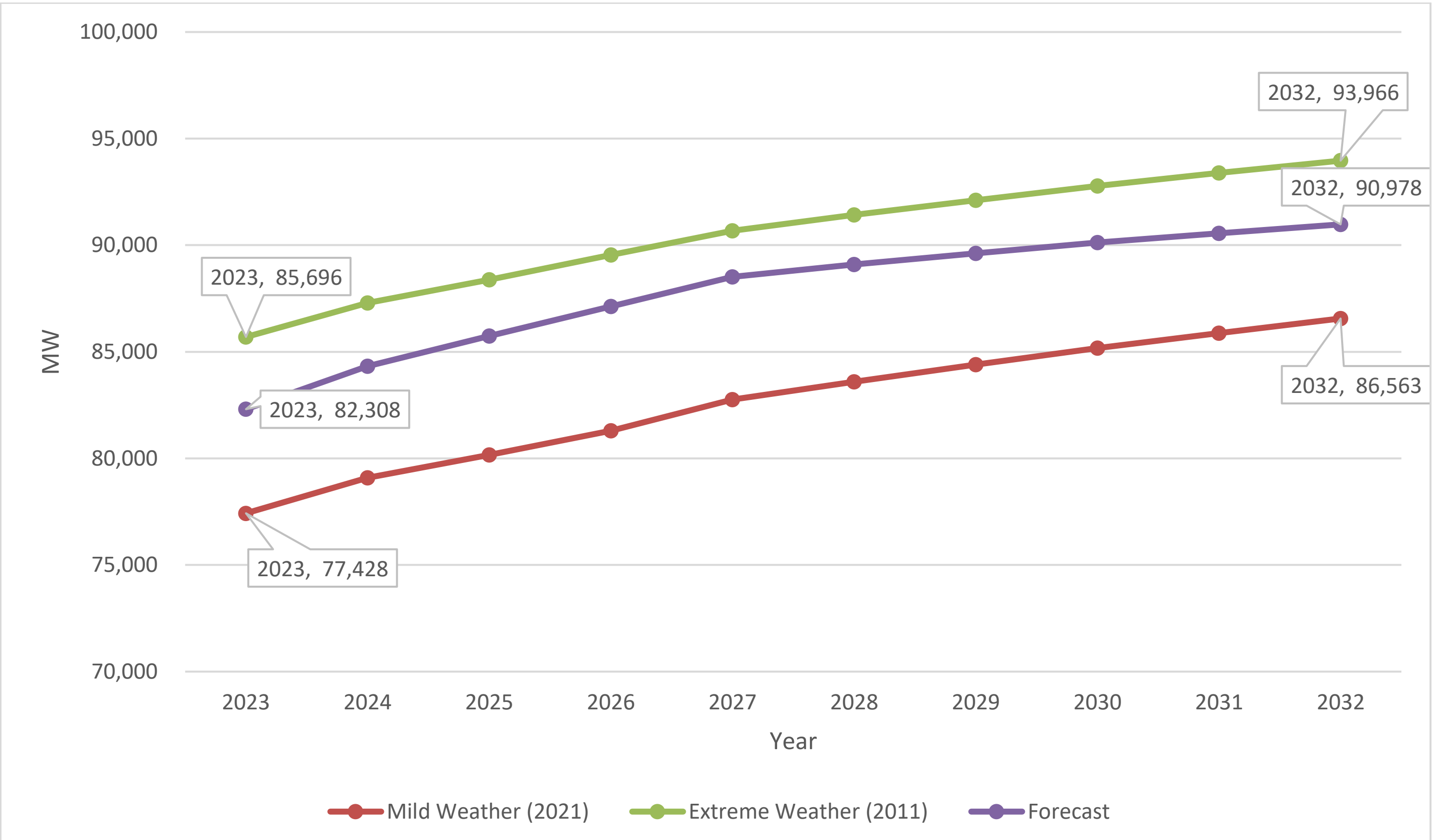
In 2022, ERCOT contracted with the Brattle Group to create an EV load forecast methodology[3]. The results from applying this forecast methodology include:

1. Approximately 770,000 Light Duty Vehicles (LDVs) and 160,000 Medium/Heavy Duty Vehicles (MHDVs) are projected to be electric by 2029 in Texas, representing about 4% of the LDV stock and 4% of MHDV stock and therefore 4% of all vehicles on the road. Approximately 96% of electrified LDVs and 93% of MHDVs will be registered in ERCOT's region.
2. The total EV charging load in 2029 is projected to be approximately 6 TWh, adding 1.25% of load to ERCOT's electric load forecast in 2029 up from 0.2% in 2022. The projected peak hour demand from EVs in 2029 is 900 MW.

[3] https://www.ercot.com/files/docs/2022/10/13/2022.10.13%20Brattle%20EV-ERCOT%20RPG%20Presentation.pptx

ERCOT will continue to refine the EV forecasting process in 2024.

Figure 11 – Summer Peak Forecast Uncertainty Due to Weather



<u>Large Industrial Loads</u>

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, etc. 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.

<u>Large Flexible Loads (LFLs)</u>

A new type of load has been growing in the ERCOT service territory. This load commonly includes cryptocurrency miners. This load can come online quickly and is very responsive to real time prices. ERCOT will be monitoring the growth of LFLs closely.

Change in ERCOT's region

Another challenge in creating a load forecast is the potential for ERCOT's region to change. Recent examples include the addition of the City of Lubbock and part of Rayburn Electric Co-Op joining ERCOT.

Looking Ahead

As more information becomes available and additional analysis is performed on each of these highlighted areas of forecast uncertainty, ERCOT may begin developing models which quantify their impacts on future long-term demand and energy forecasts. These themes will likely be revisited in the 2024 LTDEF.

Appendix A
Peak Demand and Energy Forecast Summary

Year	Summer Peak Demand (MW)	Energy (TWh)
2023	82,308	445
2024	84,325	465
2025	85,740	480
2026	87,131	494
2027	88,518	508
2028	89,090	516
2029	89,624	521
2030	90,120	527
2031	90,563	532
2032	90,978	539