2022 ERCOT System Planning

Long-Term Hourly Peak Demand and Energy Forecast

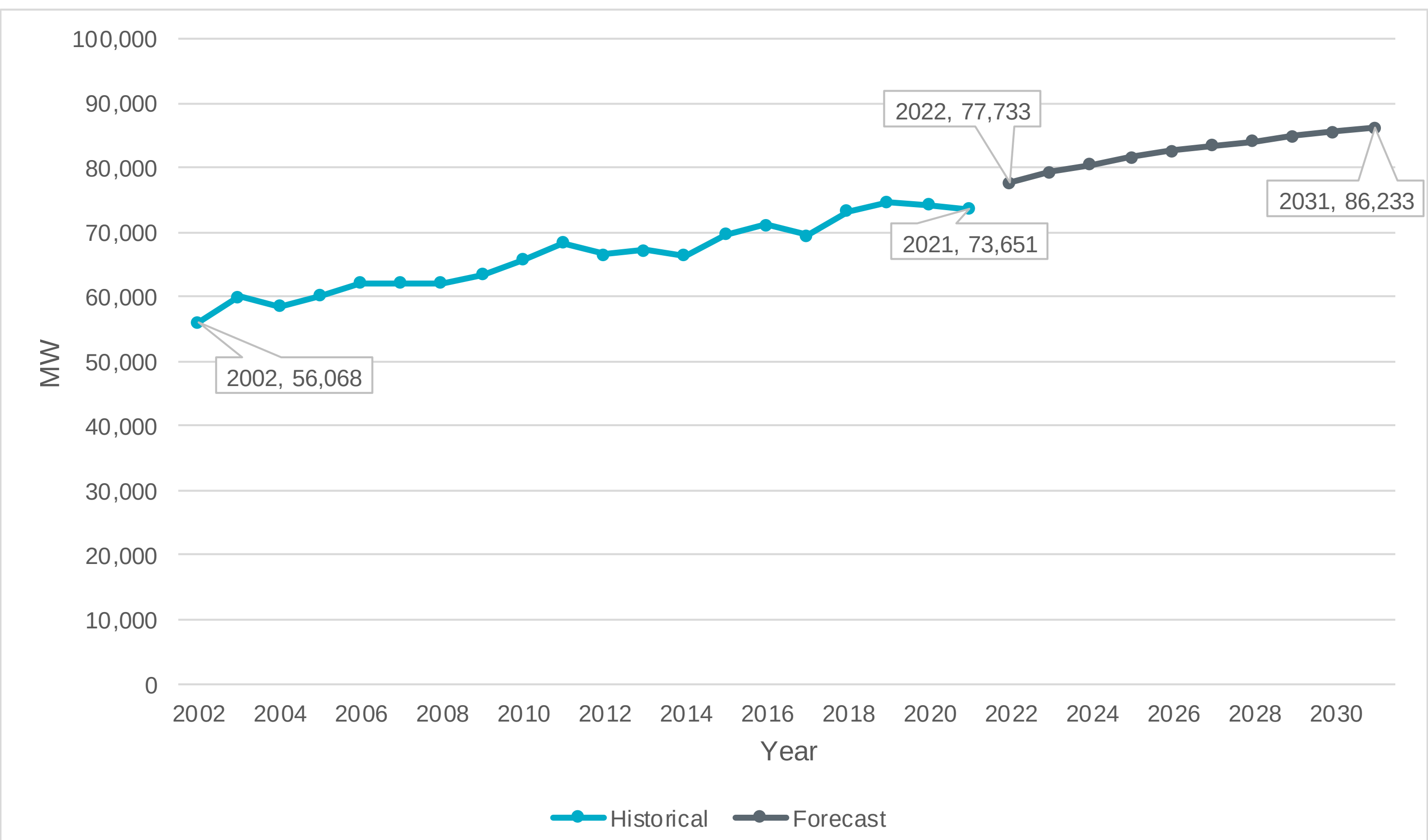
January 18, 2022

Executive Summary

The 2022 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.

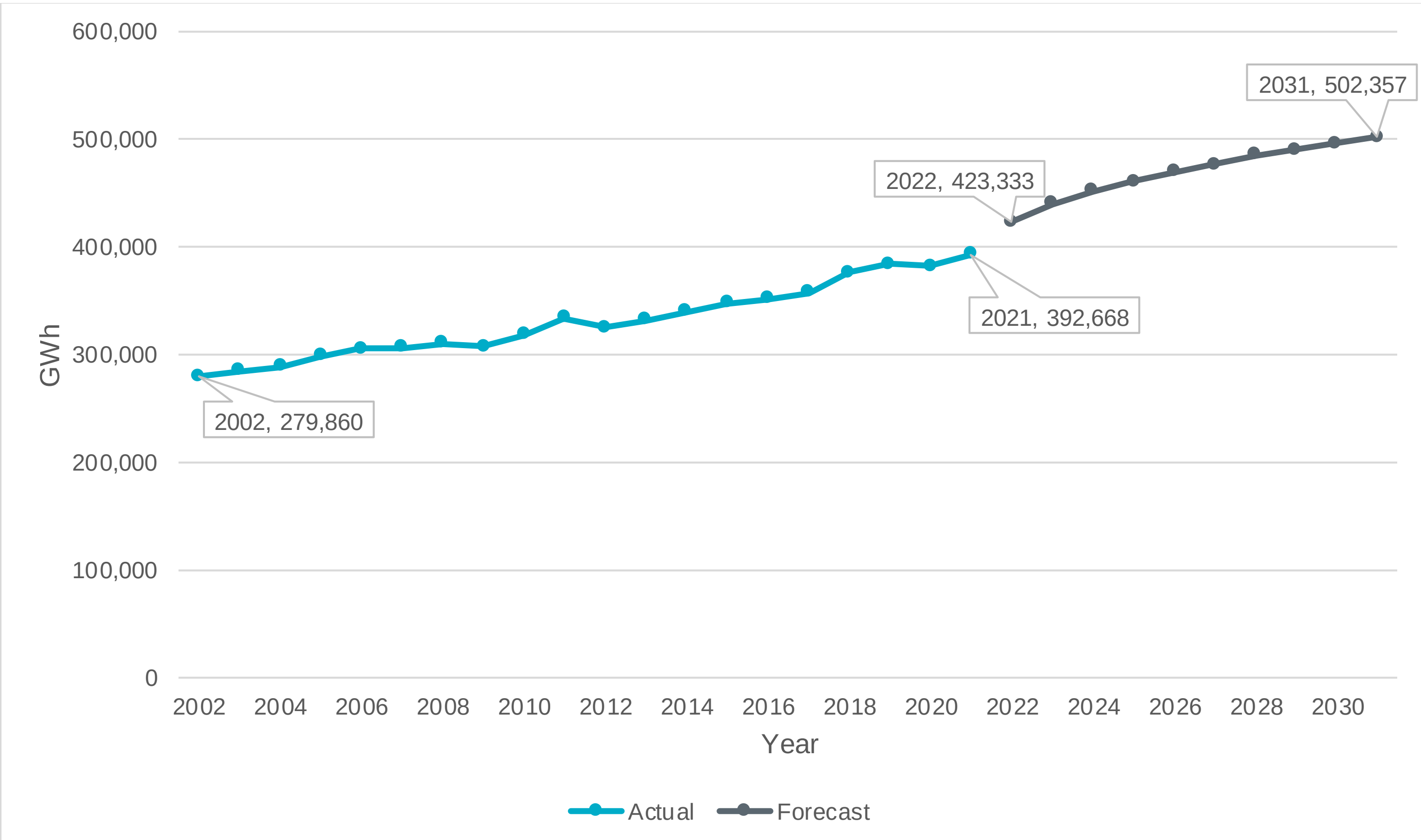
As shown in Figure 1, the 2022 LTDEF depicts system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.2% from 2022-2031. Historically, summer peak demand has grown at an AAGR of 1.1% from 2012-2021.

Figure 1: ERCOT Summer Peak Demand Forecast



As shown in Figure 2, historical annual energy for the calendar years 2012-2021 grew at an AAGR of 2.1%. The forecasted AAGR for energy from 2022-2031 is 1.9%.

Figure 2: ERCOT Annual Energy Forecast



Introduction

This report gives a high-level overview of the 2022 LTDEF. The forecast methodology is described, highlighting its major conceptual and statistical underpinnings. The 2022 forecast results are presented in a manner comparing them to the 2021 LTDEF to allow for a direct comparison of results. This year ERCOT created an hourly rooftop PV forecast. The rooftop PV forecast methodology is also 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 2021 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).

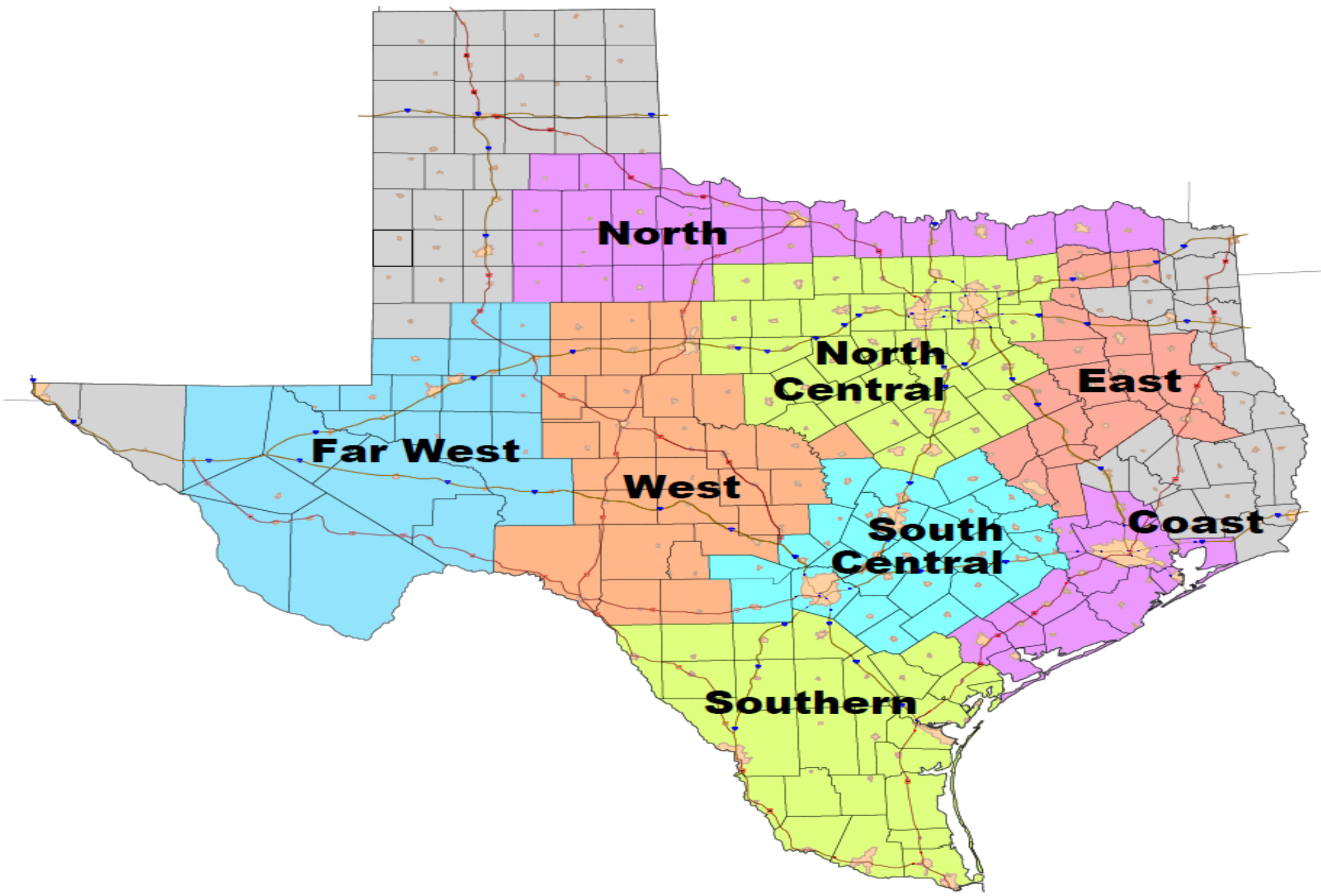
Premises were separated into three different customer classes for modeling purposes:

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

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

All premise models were developed using historical data from January 2016 through September 2021. An autoregressive model (AR1) was used for all premise models.

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,
6. Number of premises[3], and
7. Non-Farm Employment / Housing Stock / Population[4]

[3] *For Coast, East, North Central, South, and South Central weather zones.*
[4] *For Far West, North, and West weather zones.*

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, 2016 through September 30, 2021, 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, 2016 through September 30, 2021 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, 2016 through September 30, 2021 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 2006 through 2020 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 2006 as weather input into the model for all forecasted years (2022-2031). The actual weather data from all days in 2006 was copied into the same day and hour for each of the forecasted years (2022-2031). For example, the actual weather data for 1/1/2006 was copied into 1/1/2022, 1/1/2023, …, and 1/1/2031. Using 2006's weather as input into each weather zone's forecast model results in what is referred to as the 2006 weather load forecast scenario. The 2006 weather load forecast scenario is a forecast that assumes 2006's weather would occur for each forecasted calendar year (2022-2031). This process was completed for each of the historical weather years (2006-2020) individually and resulted in fifteen weather load forecast scenarios for each weather zone for each of the forecasted years 2022-2031. 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, $HF_{(West,\ 7/24/2008\ 1700,\ 7/24/2022\ 1700)}$, would denote the forecast for 7/24/2022 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 2022-2031). 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 2022, take the highest forecasted value from each of the fifteen weather load forecast scenarios for August 2022 and average them. To determine the second highest value for August 2022, take the second highest forecasted value for each of the fifteen weather load forecast scenarios for August 2022 and average them. Repeat this process for all hours in August 2022. See Table 1 (below) 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 2022-2031). 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 2022, take the highest forecasted value in months June through September from each of the fifteen weather load forecast scenarios for calendar year 2022 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.

Table 1: Coast Weather Zone August 2022 Forecast Scenarios

	Historical Weather Year															
Rank	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Average**
1	21,339	21,841	21,379	21,538	21,601	22,363	21,666	21,388	21,411	21,954	21,429	20,920	21,352	21,746	21,582	21,567
2	21,097	21,821	21,027	21,357	21,583	22,147	21,436	21,371	21,346	21,902	21,415	20,865	21,288	21,718	21,386	21,451
3	21,045	21,723	20,996	21,306	21,536	22,145	21,362	21,366	21,181	21,708	21,402	20,859	21,200	21,694	21,386	21,394
4	20,886	21,686	20,996	21,295	21,534	21,944	21,359	21,288	21,046	21,701	21,357	20,760	21,045	21,639	21,379	21,328
5	20,832	21,674	20,926	21,274	21,504	21,908	21,315	21,285	21,003	21,607	21,326	20,756	21,039	21,627	21,311	21,292
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740	12,552	12,366	12,189	12,514	12,506	13,253	12,450	12,197	11,949	11,945	12,225	11,742	12,438	13,043	12,305	12,378
741	12,320	12,364	12,117	12,477	12,502	13,245	12,449	11,988	11,836	11,907	12,176	11,720	12,320	13,042	12,294	12,317
742	12,134	12,295	12,106	12,438	12,459	13,190	12,410	11,880	11,823	11,787	12,130	11,694	12,316	13,028	12,250	12,263
743	11,799	12,180	12,055	12,428	12,428	13,134	12,319	11,792	11,777	11,770	12,101	11,692	12,247	12,952	12,215	12,193
744	11,798	12,147	12,010	12,410	12,279	12,981	12,252	11,772	11,751	11,721	12,072	11,573	12,209	12,938	12,180	12,139

Example:
Table 2 (below) shows the forecasted summer peak demand for the Coast weather zone for 2022 based on the historical weather years of 2006-2020. The forecasted gross summer peak demand for Coast is 21,567 MW.

Weather Zone Normal Weather Winter Peak Demand Forecast

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 2022-2031). 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.

Table 2: Coast Weather Zone 2021 Summer Peak Forecast Scenarios

	Historical Weather Year																
Rank	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Average**	**90th**
1	21,339	21,841	21,379	21,538	21,601	22,363	21,666	21,388	21,411	21,954	21,429	20,920	21,352	21,746	21,582	21,567	22,117
2	21,097	21,821	21,027	21,357	21,583	22,147	21,436	21,371	21,346	21,902	21,415	20,865	21,288	21,718	21,386	21,451	22,000
3	21,045	21,723	20,996	21,306	21,536	22,145	21,362	21,366	21,181	21,708	21,402	20,859	21,200	21,694	21,386	21,394	21,892
4	20,886	21,686	20,996	21,295	21,534	21,944	21,359	21,288	21,046	21,701	21,357	20,760	21,045	21,639	21,379	21,328	21,798
5	20,832	21,674	20,926	21,274	21,504	21,908	21,315	21,285	21,003	21,607	21,326	20,756	21,039	21,627	21,311	21,292	21,767
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740	12,552	12,366	12,189	12,514	12,506	13,253	12,450	12,197	11,949	11,945	12,225	11,742	12,438	13,043	12,305	12,378	13,127
741	12,320	12,364	12,117	12,477	12,502	13,245	12,449	11,988	11,836	11,907	12,176	11,720	12,320	13,042	12,294	12,317	13,123
742	12,134	12,295	12,106	12,438	12,459	13,190	12,410	11,880	11,823	11,787	12,130	11,694	12,316	13,028	12,250	12,263	13,093
743	11,799	12,180	12,055	12,428	12,428	13,134	12,319	11,792	11,777	11,770	12,101	11,692	12,247	12,952	12,215	12,193	13,025
744	11,798	12,147	12,010	12,410	12,279	12,981	12,252	11,772	11,751	11,721	12,072	11,573	12,209	12,938	12,180	12,139	12,955

Example:
Table 3 (below) shows the forecasted winter peak demand for the Coast weather zone for the winter of 2023 based on the historical weather years of 2006-2020. The forecasted gross winter peak demand for Coast is 16,152 MW.

Table 3: Coast Weather Zone 2023 Winter Peak Forecast Scenarios

	Historical Weather Year															
Rank	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Average**
1	15,303	16,258	15,810	15,652	17,231	17,780	15,192	15,870	17,218	16,117	14,915	16,813	18,214	15,222	14,682	16,152

Weather Zone Normal Weather Hourly Forecast Mapping to Calendar

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 2007-2020. 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 2022 is 21,567 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 (2022-2031). 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 (2022-2031). This means that the Coast Summer Peak will always occur on 8/11 @ 1600 for all forecasted years that are mapped to 2015.

This mapping process was completed using calendar years 2007-2020. This produced fourteen different hourly forecasts based on calendar years 2007-2020. Note, though, that the monthly peak demand and monthly energy values are the same in each of the fourteen 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 2019, and August 2020. 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 fourteen different mapped hourly forecasts based on the historical calendar years of 2007-2020 for each weather zone are summed for each forecasted year, month, day, and hour. This results in fourteen 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 fourteen 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 2015 was deemed the ERCOT official forecast. Using the 2015 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 2015 historical factors resulted in the highest ERCOT coincident summer peak forecast. Figure 4 (below) shows the ranges of ERCOT Summer Peak demands based on using different historical diversity factors.

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, $HF_{(7/24/2008\ 1700,\ 7/24/2022\ 1700)}$, would denote the forecast for 7/24/2022 at 5:00 pm, which was based on weather from 7/24/2008 at 5:00 pm, for the ERCOT system.

Weather Zone 90th Percentile Summer Peak Demand Forecast

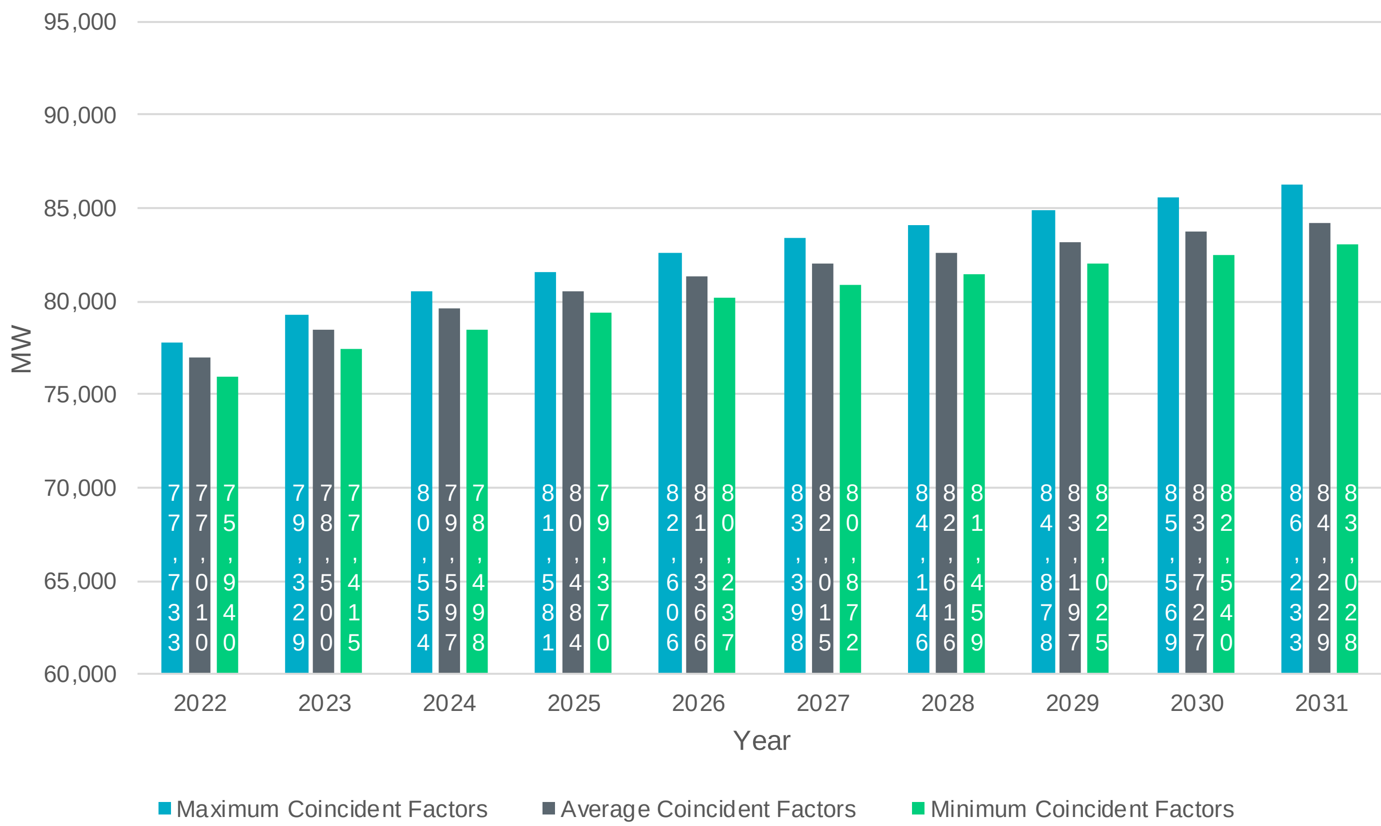
Another forecast of interest is the 90th percentile (denoted as P90) weather zone summer peak demand forecast. The process for determining the 90th percentile weather zone summer peak demand forecast is identical to the process used for calculating the base forecast, except that instead of using the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

Example:
Table 2 (page 10 above) shows the forecasted summer peak demand for the Coast weather zone for 2022 based on historical weather years of 2006-2020. 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 22,117 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.

Figure 4: ERCOT Summer Peak Forecasts



<u>Forecast Adjustments</u>

There are multiple large industrial facilities projected to be operational in the South weather zone during the forecasted years 2022 – 2031. Additions of 75 - 930 MW were made to the South load forecast based on the estimated loads of these facilities. 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.

There are multiple large industrial facilities projected to be operational in the South Central weather zone during the forecasted years of 2022 – 2031. Additions of 24 - 480 MW were made to the load forecast based on the estimated loads of these facilities. The assumptions regarding these loads are:

1. The load will be served by ERCOT (i.e., load will not be self-served).

2. The load may be price responsive (i.e., load could actively be reduced to avoid transmission charges as part of ERCOT's four Coincident Peak calculations, high price intervals, etc.).
3. The load will come online on the currently projected integration dates.

There are multiple large industrial facilities projected to be operational in the Far West weather zone during the forecasted years of 2022 – 2031. Additions of 200 – 1,000 MW were made to the load forecast based on the estimated loads of these facilities. The assumptions regarding these loads are:

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

Lubbock joined ERCOT in 2021. 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.

Additional Rayburn load was included in the East weather zone. This load was initially added to the East weather zone in January 2020. A forecast was created based on data included from their PUCT filing.

Load Forecast Comparison

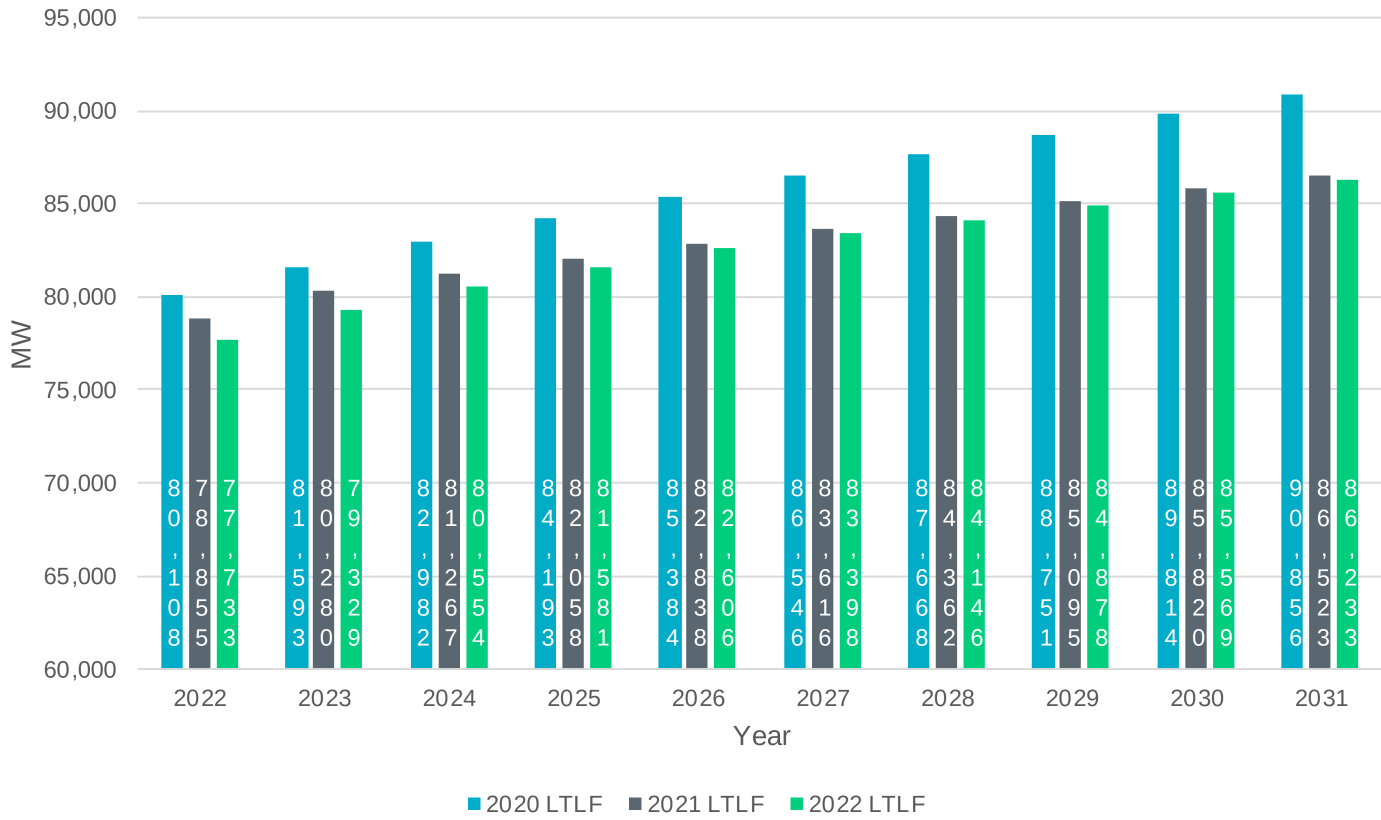
Figure 5 (below) presents the ERCOT summer peak demand forecasts for 2022-2031 from the 2020 LTDEF, 2021 LTDEF, and the 2021 LTDEF. Similarly, Figure 6 (below) presents the ERCOT annual energy forecasts for 2022-2031 from the same historical forecasts.

Rooftop PV Forecast

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 7 (below) shows a graph comparing the average usage per ESIID for those with and without PV on a summer day.

Figure 5: ERCOT Summer Peak Forecasts Comparison

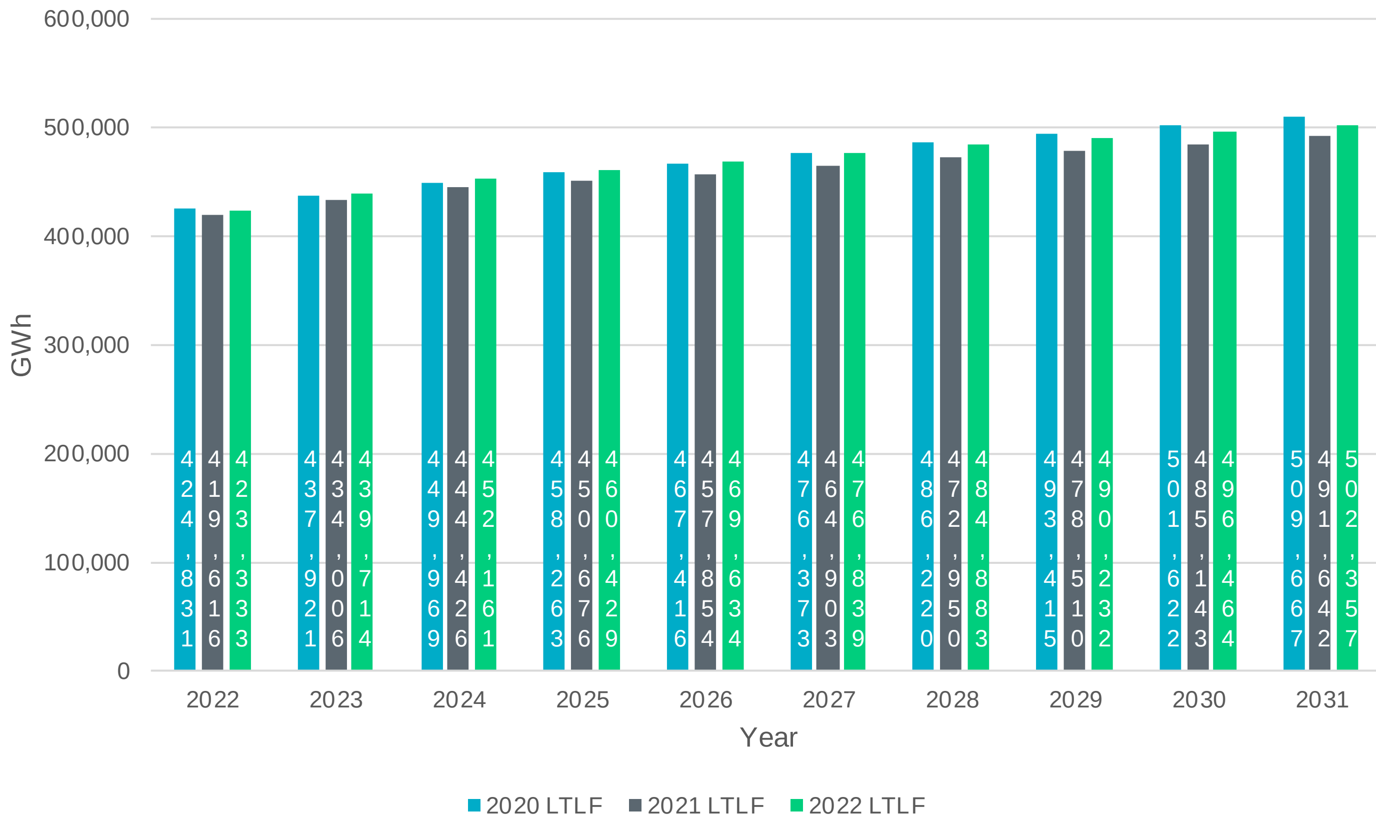


<u>Weather Zone Average Usage Models</u>

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.

Figure 6: ERCOT Annual Energy Forecasts Comparison



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

Actual weather data from calendar years 2006 through 2020 was used by applying the weather data from each historical year one-by-one to both of the hourly average usage models (those with PV and those without). The process began by using actual weather data from 2006 as weather input into the average usage models for all forecasted years (2022-2031). The actual weather data from all days in 2006 was copied into the same day and hour for each of the forecasted years (2022-2031). For example, the actual weather data for 1/1/2006 was copied into 1/1/2022, 1/1/2023, …, and 1/1/2031. This process was completed for each of the historical weather years (2006-2020) 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 2022-2031.

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.

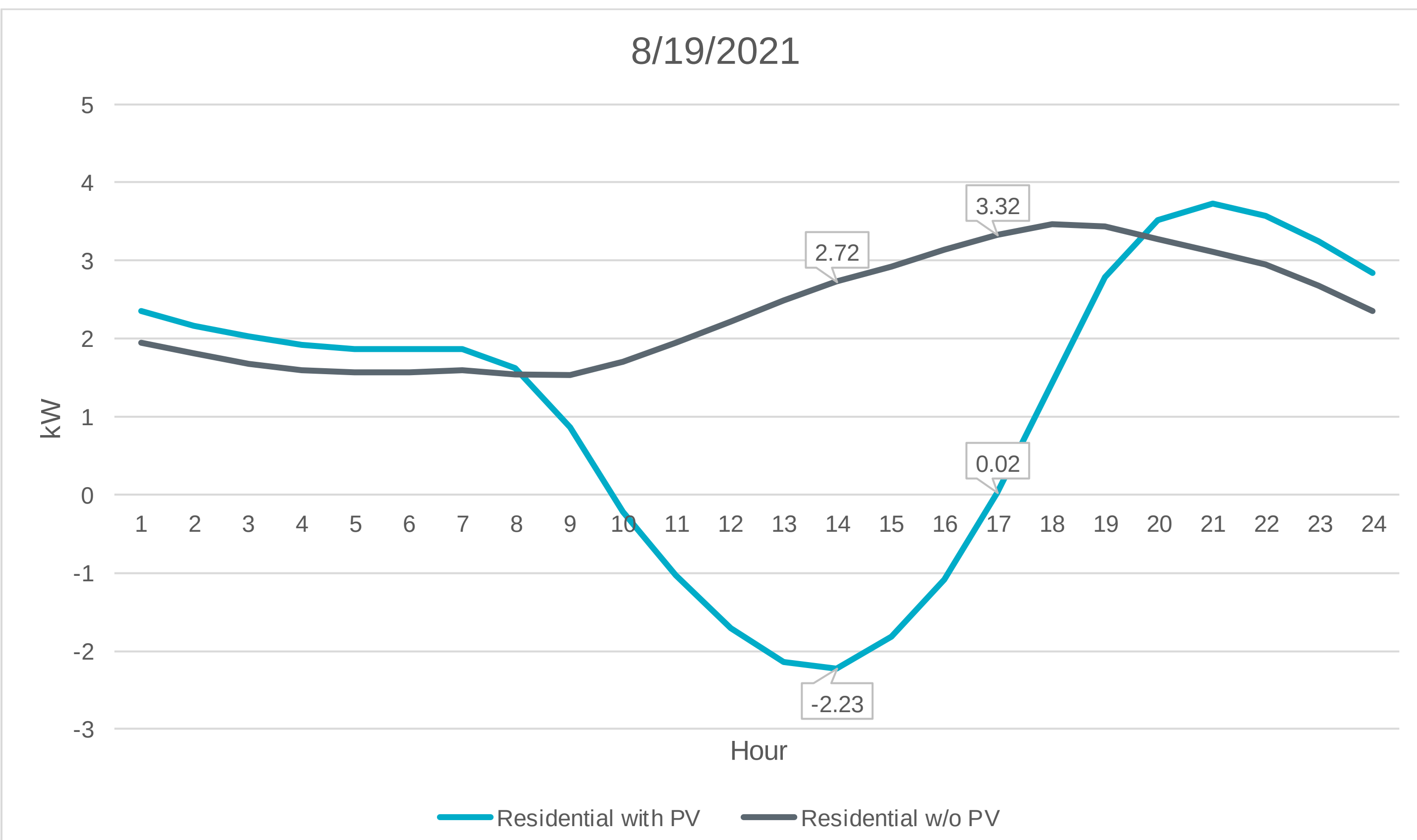
For example, $ResPV_{(West,\ 7/24/2008\ 1700,\ 7/24/2022\ 1700)}$, would denote the average usage for ESIIDs with PV on 7/24/2022 at 5:00 pm, based on weather from 7/24/2008 at 5:00 pm, for the West weather zone.

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



For example, $ResNoPV_{(West,\ 7/24/2008\ 1700,\ 7/24/2022\ 1700)}$, would denote the average usage of residential ESIIDs without PV for 7/24/2022 at 5:00 pm, based on weather from 7/24/2008 at 5:00 pm, for the West weather zone.

Weather Zone PV Forecasts

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 2021, there was approximately 1,030 MW of Rooftop PV capacity installed in ERCOT. This forecast projects Rooftop PV capacity to increase to approximately 6,000 MW by 2031.

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 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 8 suggests the significant impact of weather in forecasting. This figure shows what the 2022 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 75,566 MW using 2017's weather to 80,382 MW using 2011's weather. This equates to approximately a 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 8 - 2022 Summer Peak Demand Scenarios

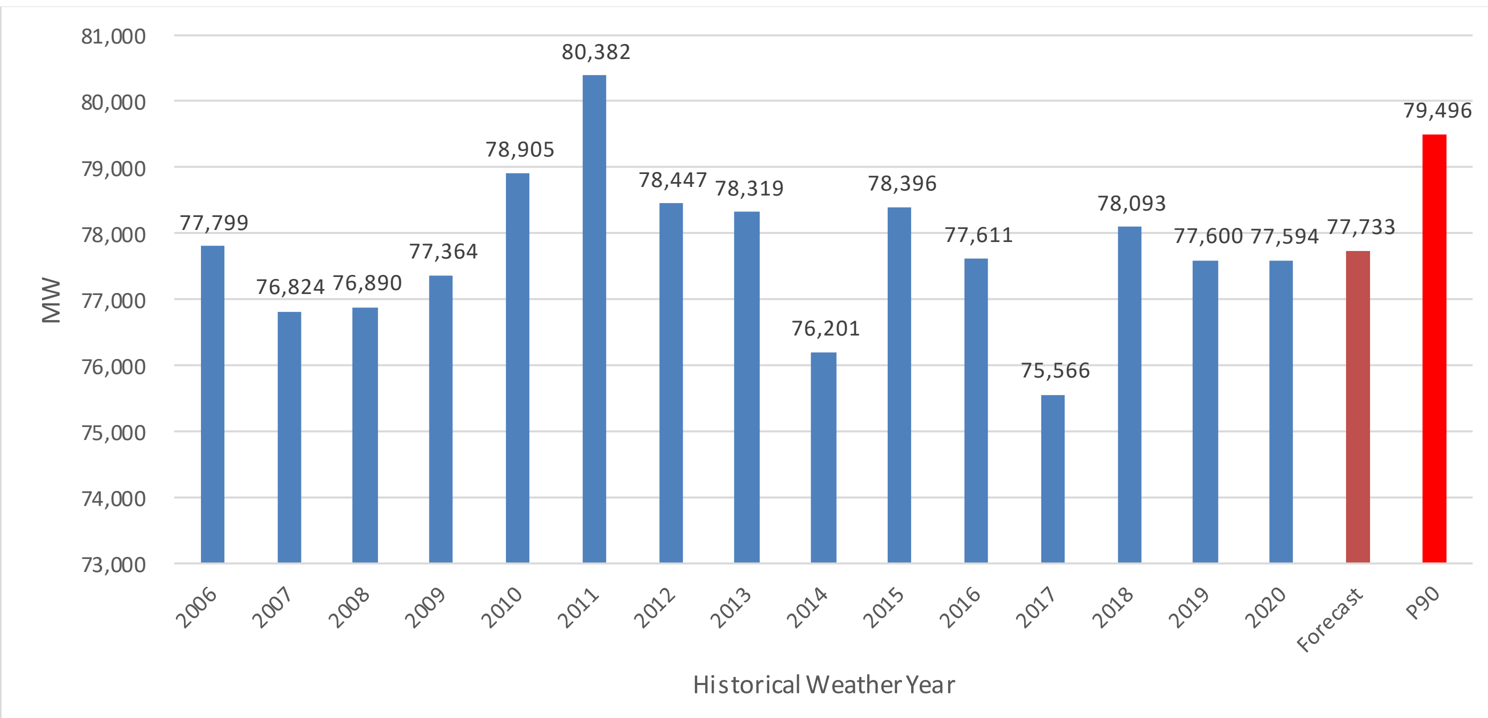


Figure 9 (below) depicts weather volatility out to 2031. Assuming 2017 weather (identified as the mild weather scenario) in 2031, we would expect a peak of 83,934 MW. Assuming 2011 weather (identified as the extreme weather scenario) in 2031, results in a forecasted peak demand of 89,196 MW. This equates to approximately a 6% difference in the forecast based on weather extremes.

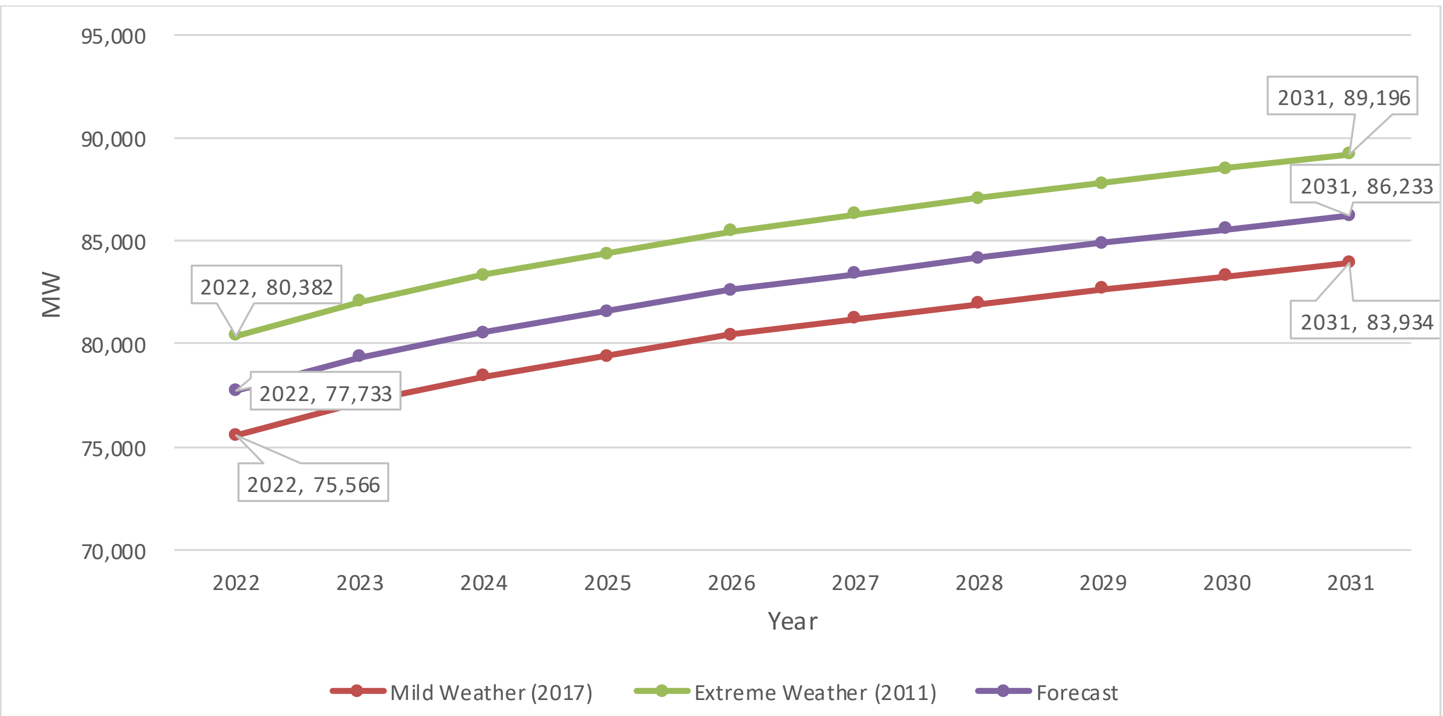
Economic Uncertainty

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 2022 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 2016 through September 2021. 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.

Figure 9 – Summer Peak Forecast Uncertainty Due to Weather



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 over the last few years, ERCOT's price caps have increased from $1,000/MWh to $9,000/MWh. Another recent change is the reduction in the ERCOT price cap 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.

Electric Vehicles Uncertainty

The growth of Electric Vehicles (EVs) has been accelerating. ERCOT has posted an RFP for creating an EV forecast. The expectation is for ERCOT to incorporate the impacts of EVs in their 2023 LTLF.

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, 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 2022 LTDEF was adjusted for large industrial loads as follows:

1. 650 MW was added to the Coast weather zone,
2. 200 MW – 1,000 MW was added to the Far West weather zone,
3. 75 MW – 930 MW was added to the South weather zone, and
4. 190 MW – 480 MW was added to the South Central weather zone.

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 joined ERCOT in 2021. Lubbock's peak load is approximately 500 MW. The 2022 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 2022 LTDEF and it was added to the East weather zone forecast.

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 2023 LTDEF.

Appendix A
Peak Demand and Energy Forecast Summary

Year	Summer Peak Demand (MW)	Energy (TWh)
2022	77,733	423
2023	79,329	440
2024	80,554	452
2025	81,581	460
2026	82,606	470
2027	83,398	477
2028	84,146	485
2029	84,878	490
2030	85,569	496
2031	86,233	502