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Form 4 Demand Forecast Methods and Models

Form 4 is for LSEs to document the electricity demand forecast methods, models, and data used to develop the submitted forecast forms. LSEs may include existing forecast model reports as an appendix to this form if this report includes the following required information.

LSEs should begin Form 4 by defining the area for which the forecast is developed identifying isolated loads and resale customers and describe how they are included or excluded from the forecast. Provide definitions of customer classes, including which rate classes are included in the categories for which forecasts are submitted.

Each of the rate classes for MID's customer consumption is described as follows:

Residential- This schedule is applicable to individual family accommodations devoted primarily to residential, household and related purposes (as distinguished from commercial, professional and industrial purposes), to general farm service on a farm, where the residence on such farm is supplied through the same meter, and to public dwelling units. Service to public dwelling units for residential occupancy is limited by special provisions described in the rate tariff.

Commercial- This schedule is applicable to general commercial customers having a demand of 1,000 kilowatts or less and multiple units for residential occupancy. Service to public dwelling units for residential occupancy is limited by special provisions described in the rate tariff. A demand rate schedule is applied to those customers that are greater than 20 kilowatts. A voluntary time of use rate schedule is also available to commercial customers with a 12-month period of an instantaneous demand of 500-1,000 kilowatts.

Industrial- This schedule is applicable to industrial customers having demands of 1,000 kilowatts or greater in any month during the previous twelve months. For customers above 25,000 kilowatts, a separate industrial rate is available.

Agriculture- This schedule is applicable to separately metered water well pumping, reclamation service, and farm use. Lighting and farm use will be provided to the extent permitted by special provisions as described in the rate tariff. This schedule does not apply to commercial food or agricultural processing operations, machine shops, or any other service not connected with the individual farm operations.

Public Lighting- This Schedule is applicable to all night lighting on the public streets, alleys, highways and parks for cities, lighting districts or other public bodies.

Following is an excerpt from MID's Long-term Demand and Energy Forecast (LTDEF) which describes MID's demand forecast used in this IEPR submittal. This narrative addresses the topics of discussions requested for the 2023 IEPR's Form 4.

Energy Demand and Peak Forecasts

1.1. Introduction

The 2023 Long-Term Demand and Energy Forecast (LTDEF) for the MID region and its outer territory cities[1] (OTC) is discussed in this chapter, including the methodology, assumptions, and data used to create the forecast. The forecast horizon for this report is from 2023 through 2032. A longer forecast through 2047 was developed, and data beyond 2032 can be provided upon request.

The forecast is based on a set of econometric models that describe the hourly load within the region as a function of several weather variables (e.g., surface temperature, solar irradiance), calendar variables (e.g., day of week, holidays), and demographic variables (e.g., population, average regional income). The LTDEF utilizes regional demographic data obtained from the U.S. Bureau of Economic Analysis and the California Department of Finance. Weather data used for the LTDEF is comprised of seventeen years of historical weather data collected by MID. The LTDEF also incorporates demand-side forecast models that include projections for customer solar, energy efficiency, and electric vehicle charging load.

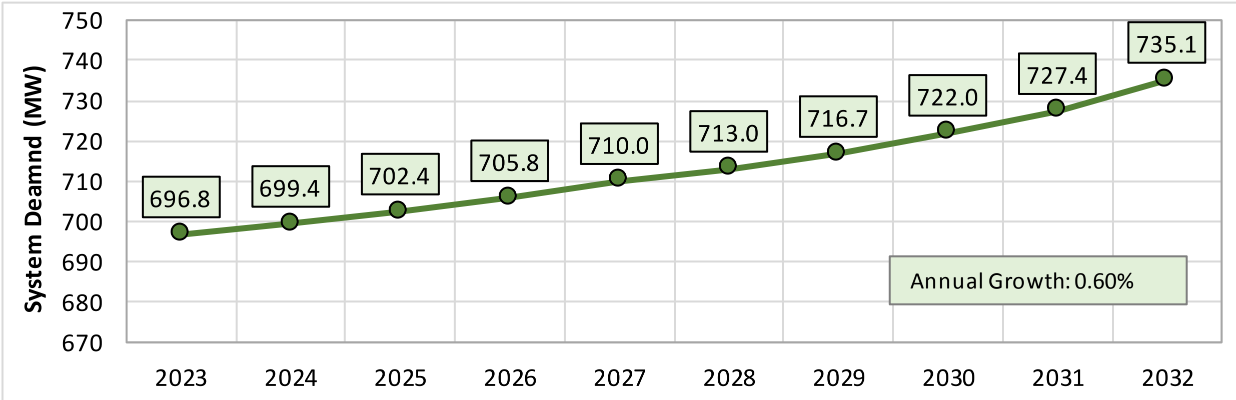
1.2. Overview of Forecast Results

As shown in Figure 1-1, the 2023 LTDEF projects that system 1-in-2 peak[2] demand will increase at an average annual rate of approximately 0.60% from 2023 to 2032. Historically, peak demand annual growth increased at a rate of 1.8% from 2013-2022.

[1] Since 1996, MID has served load in competition with PG&E in the northern expansion area, defined as "a 400 square mile area in Southern San Joaquin County, Northern Stanislaus County, and Western Tuolumne County", often referred to as the "four-city area" "including Ripon, Escalon, Oakdale and Riverbank". Additionally, MID has been the sole load serving entity in the city of Mountain House since 2001. MID is also the non-exclusive load serving entity for new load in the northern expansion area, referred as "Greenfield load", since 2007.

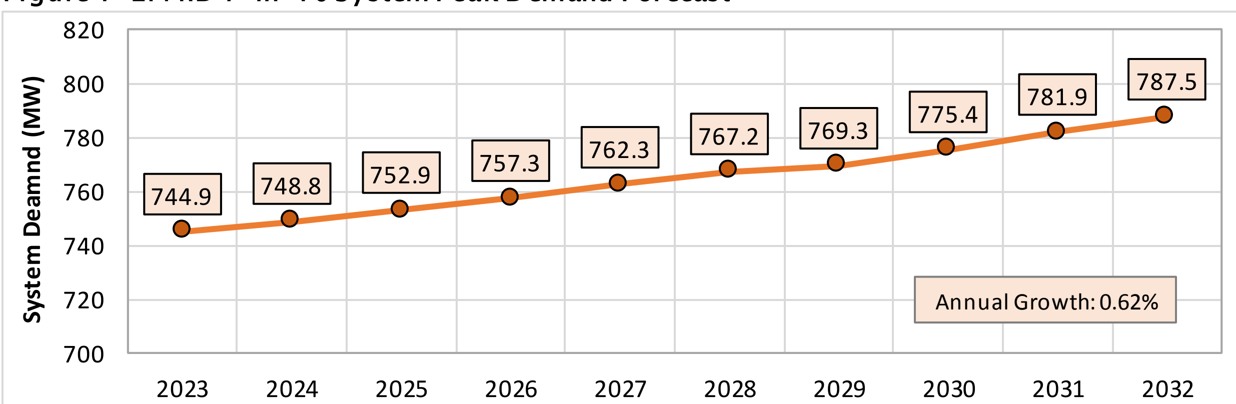
[2] Non-coincident peak: MID's regional peak demand usually does not coincide with the statewide peak demand, so MID only forecasts regional non-coincident peak.

Figure 1-1: MID 1-in-2 System Peak Demand Forecast



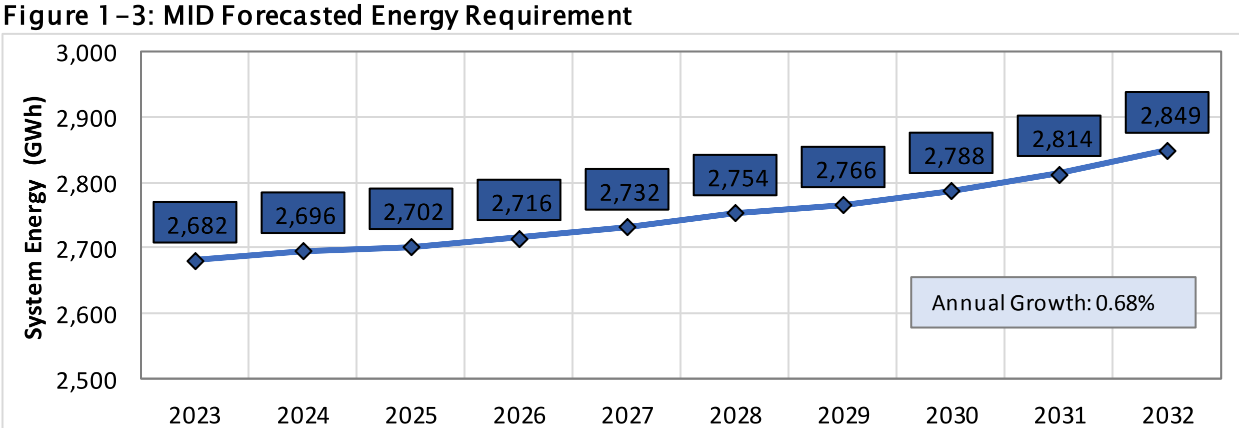
As shown in Figure 1-2, the 2023 LTDEF projects that system 1-in-10 peak demand will increase at an average annual rate of approximately 0.62% from 2022 to 2032.

Figure 1-2: MID 1-in-10 System Peak Demand Forecast



As shown in Figure 1-3, the 2023 LTDEF projects system energy requirements will increase at an average annual rate of approximately 0.68% from 2023-2032. Historically, the average annual energy growth rate was 0.50% from 2013-2022.

Figure 1-3: MID Forecasted Energy Requirement



1.3. 2023 LTDEF Methodology and Assumptions

The assumptions and methodology discussed in this chapter reflect MID's current understanding and best estimation of the region, applicable regulations, and technological developments and their impact on energy consumption. All assumptions are subject to change. The annual load forecast update process is designed to capture changes in load conditions due to material changes to any of the several major underlying assumptions in subsequent LTDEF reports. This chapter focuses on the methodology, assumptions, and inputs.

1.3.1. Modeling Framework

The 2023 LTDEF model is a linear regression model. The model accounts for impacts from weather, economics, demographics, and seasonal trends on energy demand and consumption, and incorporates demand-side forecasts for photovoltaic generation, energy efficiency, and electric vehicle charging load. Historical impacts of interruptible and demand response program events are accounted for on the demand side in the LTDEF, future impacts of these programs are accounted for on the supply side in the MID Resource Plan.

The MID LTDEF is comprised of load from two geographic regions: MID base territory and MID OTC. Forecasts for both territories share a similar methodology.

The LTDEF model building process consists of three steps:

- Model variables selection
- Econometric model building process
- Weather scenarios building

1.3.1.1. Model Variables Selection

The input variables listed below were considered during development of the LTDEF; however, the final model is based only on statistically relevant variables.

- Weather Variables
  - Surface Temperature
  - Solar Irradiance (not used in the final model)
  - Lagged Temperature (1-3 & 24 hours)
  - 24 & 36-Hour Temperature Moving Average
- Economic and Demographic Variables
  - Population
  - Average Regional Income

    - Labor Force Data (not used in the final model)
    - Inflation (not used in the final model)
    - Seasonal Employment (not used in the final model)
    - New Housing Builds (not used in the final model)
- Categorical Variables
    - Month
    - Day Type (day of week, holiday)
    - Hour
- Interaction Variables
    - Population and Month
    - Population and Hour
    - Population and Day Type
    - Average Regional Income and Month
    - Average Regional Income and Hour
    - Average Regional Income and Day Type
    - Temperature and Hour
    - Temperature and Month
    - Lagged Temperature and Hour
    - Lagged Temperature and Month
    - Temperature Moving Average and Hour
    - Temperature Moving Average and Month
    - Hour and Day Type
    - Hour and Month

1.3.1.2. <u>Econometric Model Building Process</u>

During the econometric model building process, historical hourly demand, temperature, economic and demographic data from 1/1/2015 – 12/31/2022 were used. Only the statistically significant variables listed in Section 1.3.1.1. above were selected to build the econometric model.

The initial stage of building the forecast model involved developing a set of regressions using historical data. All variables were regressed with actual values that functioned as either independent variables or interaction variables (X variables). Load from years 2015 to 2022 functioned as the dependent variable (Y variables). Each variable's significance was tested by using a range of data that excluded the test year. By benchmarking the regression's projected Y variable to the actual load of the year, the X variables that had material impact to the resulting projections were identified. Any immaterial X variables were excluded from the model. For example, new construction data was determined to be an immaterial variable in the econometric model and was excluded. After multiple models and additional testing, the statistically relevant variables were used to build a preliminary econometric model.

The final forecast was developed by using the econometric model and the associated coefficients that were derived from the most recent seven-year period. Using the most recent historical data is consistent with the intuitive hypothesis that the current year's electricity consumption pattern will have the most similarities with its most recent historical years.

The final econometric regression model was then fitted and adjusted for data abnormalities. For example, in this version of the econometric model, manual adjustments were necessary to properly account for holidays and for major industrial outages, and to remove time-related forecast errors.

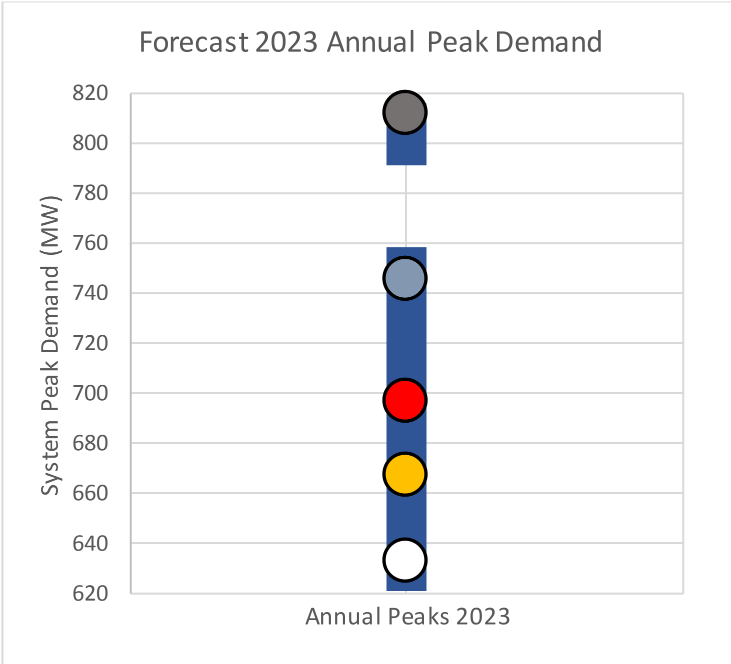
1.3.1.3. Weather Scenarios Building

Once the final econometric regression model was constructed, weather scenarios were used to derive the final energy and peak load forecasts. The weather scenarios used in MID's LTDEF model are based on 17 years of historical weather data (1/1/2006-12/31/2022) which was used to create 119 independent weather scenarios. The weather scenarios were created by shifting the base 17-year hourly weather data by daily intervals (24-hours) per scenario set. In addition to the original scenario set, a total of three lagging and three leading scenario sets were used. This "weather shifting" was used to capture more variation between weather events and time-series variables such as: day of the week, holidays, and month.

For each forecast year (2023-2032), the 119 historical weather patterned scenarios were entered into the econometric regression model to generate approximately 1,190 annual sets of load forecasts. The resulting load forecasts were then fitted and adjusted for special days (holidays, leap days) and combined with demographic growth to derive each forecast year's final energy and peak demand projection. Each year's 1-in-2 peak demand forecast is the 50th percentile value of that year's weather patterned peak demand model results and the 1-in-10 peak demand forecast is the 90th percentile value of that year's weather patterned peak demand model results. Similarly, the result that represents the 50th percentile value of that year's weather patterned model results was selected as the final energy forecast.

Table 1-2 uses the 2023 annual peak demand results as an example that shows how the annual peak demand forecast was derived. After ranking the forecast results from the 119-weather scenario sets from highest to lowest, the annual peak value of 697 MW was shown to represent the 50th percentile result.

Table 1-2: Peak Forecast Sample



Percentile	Peak (MW)
Maximum	812
90th Percentile	745
50th Percentile	697
10th Percentile	667
Minimum	632

1.3.2. OTC Load Forecast Scenarios

OTC (Outer Territory Cities) load represents a small portion of MID's total demand. Due to lack of historical metered data by territory, the OTC load forecast was derived from 2018-2022 end-of-year billing data for individual cities and their billed rate classes.

Historically, the northern expansion area represents 8.8% of MID's total retail sales and Mountain House represents 2.8% of MID's total retail sales. The ratio of OTC load to the system total load changes over time, but the difference is considered negligible and is not varied in this forecast. Later chapters of this report present detailed monthly and yearly forecasts for the OTC load.

Greenfield load is also considered in the forecast at the same growth rate of the entire system. It accounts for approximately 2.5% of MID retail load.

1.3.3. Economic Assumptions and Demographic Data

During variable testing, several economic and demographic variables were evaluated: population, labor force, average regional income, and seasonal employment. The most significant variables were determined to be population and average regional income, which were reported respectively by the California Department of Finance and the U.S. Bureau of Economic Analysis (BEA). The population data is comprised of population statistics from cities located within the MID region and OTC area. Population data forecasts are not available for MID's region, so it is assumed that population will grow at a rate equal to the past 7 years (2016-2022). Regional income forecasts are not available, so it assumed that income beyond 2022 will increase at the 10-year average growth rate from 2010 to 2019.

1.3.4. Retail Sales Forecast and Retail Class Forecast

The retail sales forecast was developed from historical net retail energy and received BTM generation collected from customer meters. The net retail energy forecast was projected by assuming a fixed average transmission loss factor in MID's electric system. The loss factor used in the 2023 LTDEF was based on the average historical loss factor calculated as the percent difference between the system total input energy and net retail energy. This method results in a loss factor of approximately 4.3%.

The received retail energy was projected using a monthly factor calculated using the historical received BTM generation divided by the total behind-the-meter generation. This factor ranged from 36% to 55% depending on the month.

The retail class forecasts were derived from historical retail class ratios, which are the ratios of historical metered retail sales in each retail class to total retail sales. The set of average historical retail class ratios was applied to the 2023 LTDEF total retail sales forecast to derive a retail sales forecast for each class. The monthly and annual ratios vary, but overall, each retail class maintains a consistent ratio over time.

1.3.5. Forecast for Electric Vehicles, Customer Solar, and Energy Efficiency

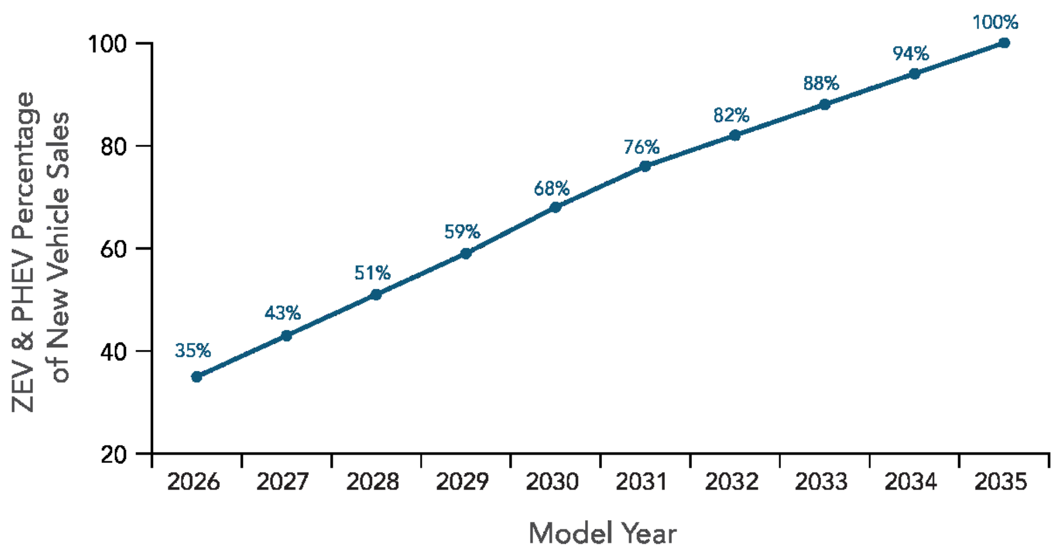
The 2023 LTDEF incorporates two Electric Vehicle (EV) forecasts: light-duty and heavy-duty EVs. The light-duty electric vehicle forecast was developed from methods used in the California Energy Commission's electric vehicle forecast and assumptions, which were published in December 2018 in the "Light-Duty Plug-in Electric Vehicle Energy and Emission Calculator". The forecast is derived from a set of base assumptions such as MID's share of California's electric vehicles and the "Advanced Clean Cars II Regulation" standards set by the California Air Resource Board's (CARB)[3]. The forecast assumes that 0.42% of the state's electric vehicles were located within MID's territory in 2022; that share is forecast to increase linearly to 0.74% by 2040 and remain there through the forecast horizon. The 2023 LTDEF predicts that there will be 6.0 million electric vehicles in California by 2030 and 11.0 million by the end of 2035. The heavy-duty EV forecast includes energy from EV projects occurring in MID's territory: The City of Modesto's bus

[3] California Air Resources Board. California moves to accelerate to 100% new zero-emission vehicle sales by 2035 | California Air Resources Board. (n.d.). Retrieved January 23, 2023, from https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035

electrification, Modesto City Schools (MCS) conversion to an all-electric bus fleet, and Frito Lay's conversion to electric semi-trucks.

The changes made to the 2023 LTDEF indicate much more growth in the light-EV sector than expected in previous forecasts. This is driven by an increase in the expected number of new EV sales in California due to the adoption rates set by CARB standards as shown below in figure 1-4.

Figure 1-4: Advanced Clean Cars II Regulations New Sale Adoption Rates

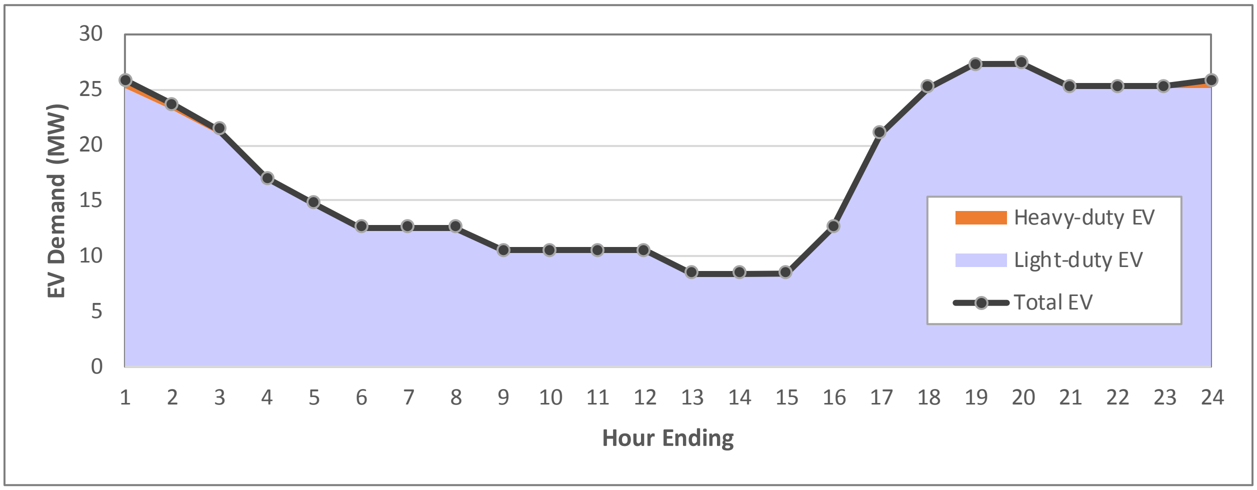


By the end of 2032, the projected EV contribution to MID's load is expected to be 156.3 GWh, a 46.8 GWh increase over the 2022 LTDEF.

To incorporate the light-duty EV energy into the load forecast, light-duty charging was shaped into an hourly pattern developed from a study by the Rocky Mountain Institute[4] and historical rate class data from MID's EV customers. Heavy-duty charging from semi-trucks was applied equally across all hours. City-bus charging was based on the City of Modesto's historical charging data while MCS buses are expected to charge during low-cost hours set by time-of-use rates. Figure 1-5 is an example of the 24-hour pattern used.

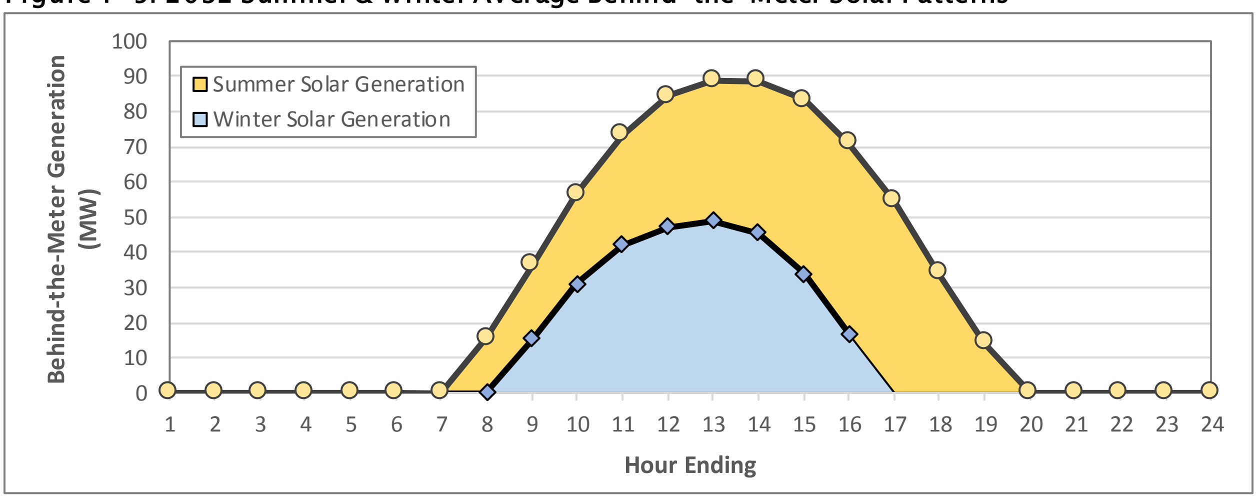
[4] Rocky Mountain Institute, 2016, "Electric Vehicles as Distributed Energy Resources".

Figure 1-5: August 2032 Electric Vehicle Charging Pattern



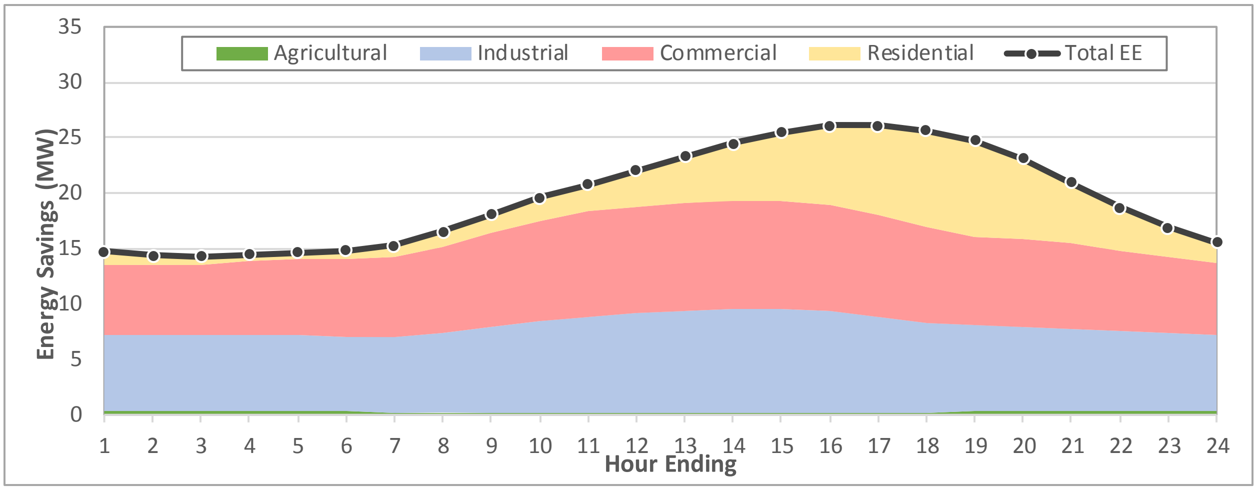
The 2023 LTDEF incorporates a machine learning solar forecast model based on hourly historical solar generation from MID's customers. The model projects that distributed solar generation will offset 211.6 GWh of system energy consumption annually by the end of 2032. This is approximately a 51.3 GWh increase from the 2022 LTDEF. Figure 1-5 shows a comparison of the average modeled distributed solar generation profile for MID's system in the winter and summer of 2032.

Figure 1-5: 2032 Summer & Winter Average Behind-the-Meter Solar Patterns



The 2023 LTDEF uses the latest gross energy efficiency program forecast approved by the MID Board of Directors (10-Year Targets). The historical energy efficiency is based on incremental gross energy savings from energy efficiency programs implemented from 2015 to 2022. Energy efficiency savings for the next ten years are the targets approved by the board of directors. Incremental savings beyond the 10-Year Targets are expected to decrease slowly over the remainder of the forecast horizon. Hourly energy efficiency savings are based on measurespecific load shapes developed for CMUA members for state energy efficiency reporting by ESPLabs[5]. An example of the hourly energy efficiency savings pattern is shown in Figure 1-6.

Figure 1-6: August 2032 Energy Efficiency Savings Pattern



[5] ESPLabs, https://www.esplabs.com/