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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.

MID annually produces a report projecting long term electric load growth for its 160 square mile service territory, which includes the major portion of Stanislaus County. Additionally, since 1996, the District has provided electric services to the 7.5 square mile area of the Mountain House Community Services District and to portions a 400 square mile competitive service territory (previously exclusive PG&E territory) located in southern San Joaquin County, northern Stanislaus County and western Tuolumne County. These additional service territory loads are referred to as Mountain House and Expansion Territories.

The MID forecast of customers and energy consumption are broken into five separate rate class categories – residential, commercial, industrial, agriculture and public lighting. For each of the rate classes, loads for Mountain House and Expansion Territories are separated from the original base MID accounts and forecasted separately.

Each of the rate classes for MID customers 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 operation

*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.

Each of the rate class categories are calibrated by applying the corresponding historical independent variable data to the regression equation and comparing those results to the actual outcomes. The R-square value provides a mechanism to measure how accurately the regression replicates historical data. Many of the models in the MID forecast have R-squared values of 0.93 or higher. When the back-casted values are superimposed graphically with historical values, the results are somewhat similar.

Form 2 identifies the key independent variables used in the various regressions of the load forecast. The variables are utilized as follows:

<u>Customer Forecasts:</u>

- **Residential**-This customer forecast is an engineering model that uses the Stanislaus County housing forecast developed by Woods & Poole Economics (Washington DC) to estimate future MID housing growth.

- **Commercial**-This customer forecast is an econometric regression model that uses the number of commercial customers lagged one year, number of residential customers and the consumer price index as independent variables.

- **Industrial**-This customer forecast is an engineering model that uses the historical customer growth rate to estimate future growth.

- **Agriculture**-This customer forecast is an engineering model that uses the historical growth rate to estimate future growth.

- **Lighting**-This customer forecast is an engineering model that uses the growth rate of the lighting energy forecast to estimate the number of future customers.

<u>Energy Forecasts:</u>

- **Residential**-This energy forecast is an econometric regression model that uses the number of residential customers, cooling degree days and the residential marginal cost of electricity as independent variables.

- **Commercial**-This energy forecast is an econometric regression model that uses the number of commercial customers, commercial marginal cost of electricity and cooling degree days as independent variables.

- **Industrial**-This energy forecast is broken into three separate models, each representing distinct customer groupings. One model is used to estimate seasonal industrial loads, another to estimate a single large industrial customer with unique operations and a third is used to estimate loads for the remaining industrial customers.

The single industrial customer regression uses a simple trending analysis for future energy consumption.

The seasonal load model consists of customers with high consumption during the months of June-September and much lower consumption during the rest of the year. This model uses Woods & Poole forecasts of Stanislaus County manufacturing employment and manufacturing earnings as independent variables.

The model for the remaining industrial load uses Woods & Poole forecasts of Stanislaus County manufacturing employment and the number of industrial customers as independent variables.

- **Agriculture**-This is an econometric regression model that uses the Tuolumne river full natural flow at La Grange and the number of agriculture customers as independent variables.

The results of all of the individual models are summed to derive the total system consumption forecast. The system input forecast is derived by applying a loss factor of 2.5% to the estimated consumption. This loss rate is estimated from recent historical data.

After defining the forecast area and included customers, describe the methodology for forecasting electricity demand components such as end-uses, fuel types, or structure types. Include key forecast model structural equations, for example, econometric models, behavioral equations, or identities. For sector models developed using aggregate econometric methods, provide data for all dependent and independent variables, reporting all standard statistical parameters for econometric models. Algebraic variables and variable mnemonics should be clearly defined.

MID's peak demand is projected on a total system-wide basis encompassing all MID served territories. The peak demand forecast uses two separate regression models: base and weather sensitive. The sum of the two models represents the total peak demand projection.

The base portion of the model is the portion of load that is non-sensitive to variable weather conditions. Historically, the months of March and April are the mildest months of the year in the central valley and are used to help estimate this portion of peak demand. For each year of historical data, the daily peak load for all Tuesdays, Wednesdays and Thursdays, with a maximum temperature between 65$^o$ and 75$^o$ is averaged for the months of March and April. This average is assumed to represent the portion of demand that does not include any cooling or heating loads.

A regression is performed using total consumption and the residential marginal cost of electricity as independent variables. Estimates of electric vehicle charging demand for the MID territory, which are provided by the CEC, are removed from the historical data in order to normalize the data set. The CEC estimates for future electric vehicle demand is then added to the regression results to account for its effects on future peak demand. Because electric vehicle charging is expected to occur mostly off-peak, it does not add much to peak demand.

The resulting regression for the base portion of the peak demand is as follows:
(BASE_PK_NO_EV_(MW) + EVD) = + 30.9913 + (0.1150 TOT_SALES_NO_EV_(MWh)) + (-0.9361 XMCR_(¢/kWh)) + (EVD)

Where:
BASE_PK_NO_EV_(MW) = weather insensitive portion of peak demand
EVD = electric vehicle demand
TOT_SALES_NO_EV_(MWh) = system energy consumption minus EV charging
XMCR_(¢/kWh) = residential marginal cost of electricity

Related Statistics:
R Square = 0.9947

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| t Stat (XMCR) = -2.5670 | P-value (XMCR) = 0.0148 |
| t Stat (TOT_SALES_NO_EV) = 46.1548 | P-value (TOT_SALES_NO_EV) = 2.9589E-32 |

The weather sensitive portion of peak demand is determined by subtracting the base peak from the total system peak in each historical year. The weather sensitive demand forecast regression uses three independent variables: residential marginal cost of electricity, temperature build-up, and residential air-conditioning stock.

Adjustments are made to normalize the historical data for the effects of energy conservation programs, demand-side management (DSM) programs, day of the week of peak occurrence and seasonal food processing loads. Future conservation and DSM impacts are estimated separately and added to the regression results.

A Monday or Friday peak has been found to produce a peak that is several Megawatts lower than one that occurs on Tuesday through Thursday when all other conditions are the same due to extended weekends and traditional business patterns. The Monday/Friday effect is estimated to produce a peak that is approximately fifteen Megawatts less than a midweek peak with the same characteristics.

The resulting regression for the weather sensitive portion of peak demand is as follows:
"WEATH_SEN_PK_(MW) = -520.5577 + (0.0048 CENT_AC_STOCK) + (5.7150 1_in_2_MID_TEMP_BU_(°F)) - (2.9223 XMCR (¢/kWh))

Where:
WEATH_SEN_PK = weather sensitive portion of the peak demand
CENT_AC_STOCK = residential air-conditioning stock
1_in_2_MID_TEMP_BU = 1in2 temperature build-up
XMCR = residential marginal cost of electricity

Related Statistics:
R Square = 0.9593

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| t Stat (CENT_AC_STOCK) = -11.6808 | P-value (CENT_AC_STOCK) = 2.8853E-13 |
| t Stat (1in2_TEMP_BU) = 5.6681 | P-value (1in2_TEMP_BU) = 2.5662E-06 |

t Stat (XMCR) = 1.4560 P-value (XMCR) = 0.1549

The Temperature Build-Up (TBU) variable is a weighted 3-day average which is calculated by averaging the high temperature for a peak day multiplied by 10/17 plus the high temperature of the previous day multiplied by 5/17 plus the highest temperature of the day previous to that multiplied by 2/17. This TBU weighting method is used to capture the residual effects of prolonged hot weather. Future weather sensitive demand is estimated using a 106$^{o}$ TBU for the 1-in-2 demand and 109$^{o}$ for the 1-in-10 demand. The difference between the two cases is estimated to be approximately 18MW. Temperature measurements are taken from the MID weather station, which is located at the District's downtown Modesto office. Temperature readings from 1985 to the present are used to determine the probability of occurrence for different TBU values.

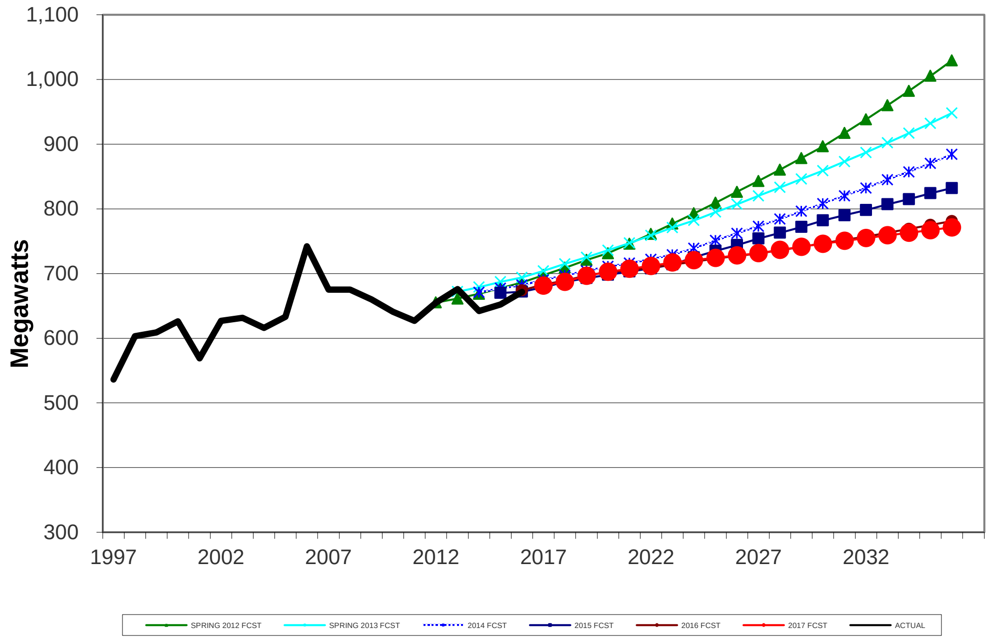
Historical customer generation data provided in forms 1.7a,b,c are tracked internally by MID. Future customer solar generation for each customer class is estimated based on historical adoption rates.

Historical energy efficiency conservation figures are estimated internally by MID staff. Historical information is then decayed using an s-curve decay method applied to actual measures installed as of 2016 over their individual estimated lifecycles. Future Energy efficiency conservation is forecasted internally for each rate class.

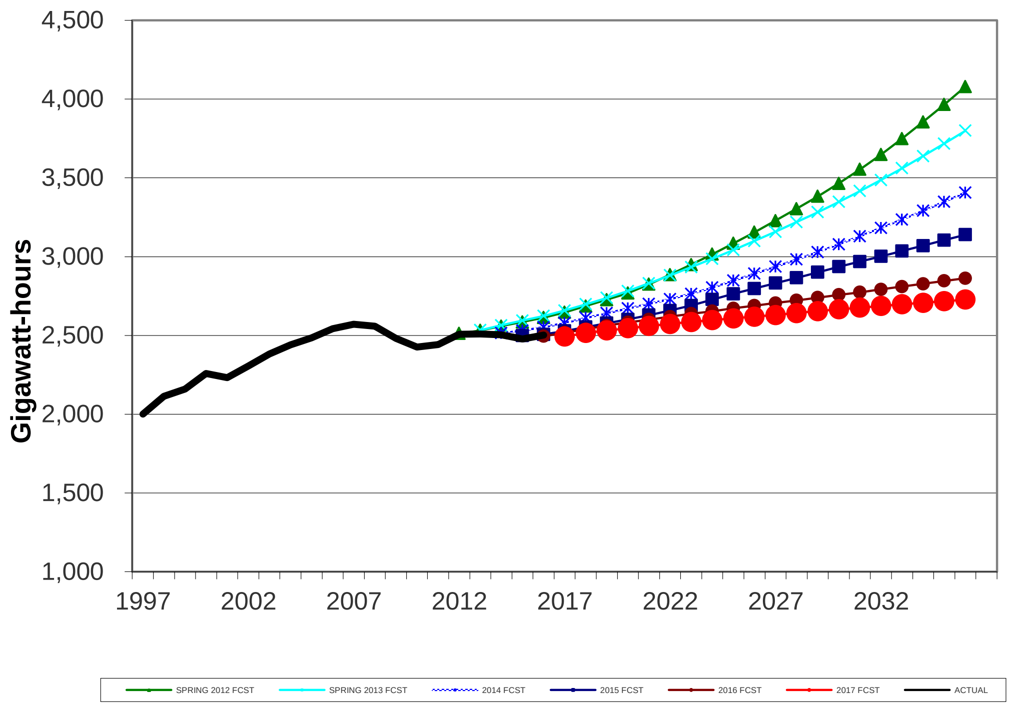
Last, discuss the reasonableness of differences between historical and forecasted growth patterns. Report the past performance of the forecasting method, including comparison of previous forecasts to actual annual weather-adjusted peak and energy demand; then discuss how the submitted forecast is reasonable in light of economic and demographic data, energy prices, demand-side-management technology and programs, state policy trends, and climate change.

A graph of previous demand and energy forecasts are as follows:

## Graph S-9
## Peak Demand Forecast Comparison




## Graph S-7
## Energy Sales Forecast Comparison



As shown in the graphs, previous peak demand and consumption forecasts have a hyperbolic growth shape, reflecting the higher historical growth observed at that time. Growth has been more modest since the 2008 recession, resulting in flatter demand and consumption projections.

**Additional Forecast Detail**

The following are additional topics that should be addressed in forecast methodology discussion:

**Forecast Calibration Procedures**

Most forecasts are calibrated to historical energy consumption and peak demand. Provide a comprehensive description of the method of forecast calibration.

**Economic and Demographic Data**

UDCs are required to provide documentation of the methods used to develop the economic and demographic projections reported in Form 2 and a discussion of the plausibility of those projections. They may include an economic and demographic methodology report as an appendix to this form. Documentation should include historical data sources, projected data sources, and reasoning of these sources for the forecast.

**Historical Peak and Projected Peak Loads**

Describe the methods and data used to develop the historical and projected peak loads of sectors or customer classes reported in Form 1.3.

**Energy and Peak Loss Estimates**

Forms 1.2, 1.3, and 1.4 include estimates of energy losses. Describe fully the method and data sources used to develop historical and forecast energy and peak losses. If the method uses a loss factor, specify what that factor is and discuss if that factor varies by year or by customer sector.

**Estimates of Direct Access, Community Choice Aggregation, and Other Departed Load**

UDCs should describe the methods, assumptions, and data used to forecast direct access, community choice aggregation, and other departed load reported in Forms 1.2 and 1.4. These should include a list of current and projected ESP and CCA entities in the distribution utility's planning area.

IOUs should describe the methods and data used to account for expected migrating municipal load in their forecasts. Data used to account for migrating or newly departed municipal load should be reported on Form 1 or 2, as appropriate.

POUs and CCAs that anticipate load growth from newly acquired load should identify the areas in which they are acquiring load and describe the data sources used to account for that load growth.

**Weather Adjustment Procedures**

Describe the process for adjusting the forecast to normal weather conditions and the sources of the meteorological data, including:

- Names and locations of the weather stations
- Weights used for each weather station
- Temperature variables used, such as daily maximum, heating and cooling degree days, or apparent temperature values
- Base values of the temperature variables used and annual data used in the adjustment process

UDCs should also describe the methods and assumptions used to develop the high temperature cases (1-in-5, 1-in-10, 1-in-20, and 1-in-40) reported in Form 1.5. Provide a narrative discussion of the baseline peak temperature assumptions, how the high temperature scenarios were developed, sources for the weather data, and the methods used to develop the temperature probability distributions. Include any climate change considerations used to adjust the expected relationship between these scenarios.

**Hourly Loads by Subarea**

If an LSE is submitting hourly loads for subareas of their service area in Form 1.6b, provide definitions of the reported subareas. Attach a file with geographic identifiers, such as ZIP Codes, that define the region covered by each zone. Also, describe the source of the data, if from metered load, or the methods used to develop estimates of the subarea loads.

**Local Private Supply Estimates**

Describe fully the methods, assumptions, and data sources used to develop the estimates provided in Forms 1.7a through 1.7c. Because these are expected energy and on-peak effects, they require estimates of how facilities will actually be operated. Indicate the degree to which conservation efforts, financial incentives, and interruptible programs and negotiated rates have been incorporated into the self-generation forecast. Separate reports may be attached as long as these demand forms include a summary.

**Energy Efficiency and Demand Side Management**

Explicitly discuss how energy efficiency and other demand-side impacts are incorporated into the final forecast for each sector. The description of how this is accomplished should be explicit for each sector, for energy and peak demand. Methods might include:

- Direct inclusion of use of end-use models and appropriate inputs characterizing the impacts of standards or programs.
- Calculation of the difference from an unmitigated forecast without program savings in the historical or forecast period and a forecast with both historical and forecast program savings included.
- Separately computed savings for programs from other analytic techniques with some or all of these savings subtracted from a “raw model output” to produce the final forecast.

**Climate Change and Electrification**

The IEPR forecast includes the potential impacts of climate change and electrification that may cause forecasted demand to deviate from historical trends. UDCs are required to document any such considerations embedded within their own demand forecast, including references to studies, plans, and other sources that support their assumptions.

**Form 6 Incremental Demand-Side Program Methodology**

Form 6 is for providing a narrative description of the methodology used to determine DSM program impacts from Form 3, Demand-Side Program Impacts.

**Efficiency Program Impacts**

Discuss how estimates for potential efficiency program impacts were derived in Form 3.2. List and provide documented studies or sources used to support these assumptions. Additionally, describe the method by which potential load impacts are reconciled with the UDC's demand forecast as reported in Form 1.

**Demand Response Program Impacts**

Discuss how the estimates of peak impacts were derived for each program in Form 3.3. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections. Describe the method used to develop estimates of non-dispatchable program impacts and the extent to which the forecast is consistent with recent program performance. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak. For example, will the dispatch signal be sent each year to all or most customers, or only during emergencies, or on days when peak load passes a critical value?

**Renewable and Distributed Generation Program Impacts**

Discuss how the estimates of energy and peak impacts for each program were derived in Form 3.4. In particular, detail the method and data used to project impacts of solar programs. Describe assumptions about eligible population, participation rates, price elasticities, fuel prices, wholesale market conditions, and prices used to develop the projections. Last, describe criteria used in deciding how to model customer decisions to use these facilities in peak shaving or baseload modes.