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2024 Integrated Resource Plan

Modesto Irrigation District

MID Board of Directors Approval: December 5, 2023
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Modesto Irrigation District
Water and Power

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I. Executive Summary

1. Overview of MID

Modesto Irrigation District (MID), located in California's Central Valley, provides electricity, irrigation water, and treats surface water for the City of Modesto for drinking. MID is an independent, publicly owned utility founded in 1887 and has provided electric service since 1923. MID transmits and distributes electricity on more than 1,800 miles of power lines throughout its service area, providing power to the communities of Modesto, Waterford, Salida, Mountain House and parts of Ripon, Escalon, Oakdale, and Riverbank. MID provides benefits that include community ownership, control by a locally-elected Board of Directors, and business operation on a not-for-profit basis. MID is committed to providing reliable service at the lowest cost possible. MID provides reliable electric service to approximately 102,000 residential customers and more than 10,000 commercial customers.

MID's 2024 Integrated Resource Plan presents the utility's plan for reliability planning and budgeting, demonstrates compliance with MID Board policy and federal and state laws, and provides a frame of reference for development of new and revised Board policy. California Public Utilities Code - PUC Section 9622 empowers the Energy Commission to review publicly-owned utilities (POUs) Integrated Resource Plans (IRPs) to determine consistency with section 9621. The Energy Commission adopted the first IRP Guideline in 2017 which requires POUs to adopt Integrated Resource Plans by January 1, 2019, and to file the plans with the California Energy Commission by April 30, 2019. Plans must be updated at least once every five years, as fulfilled in this 2024 Integrated Resource Plan. These integrated resource plans will detail how each utility plans to meet the state's environmental and energy goals. To reflect updated standards governing renewable energy targets, MID has included the most recent SB 100 targets in this IRP.

1.1. Planning Horizon

This Integrated Resource Plan encompasses a 10-year horizon, covering the period 2021 through 2030. It details historical figures for 2021 through 2023, and MID's projected electric demand and future resource portfolio for 2024 and beyond. The plan is divided into several sections as detailed in the "Table of Contents".

1.2. 2024 Planning Assumptions

This section of the IRP provides a high-level overview of MID's 2024 IRP assumptions. The assumptions and methodology discussed in this chapter describe MID's current understanding of its customers' capacity and energy demand over the planning horizon. Later chapters in this plan present the assumptions in more detail.

1.2.1. Input Assumptions

MID's IRP utilizes a planning scenario that conforms to greenhouse gas emission reduction targets as well as renewable energy procurement and other policy goals outlined in SB 350.

Table 1-1 below shows a summary of MID's IRP planning assumptions.

Table 1-1: Input Assumptions of MID's IRP Analysis

Input	Planning Assumptions
Demand Forecast	MID's 2023 Long Term Demand and Energy Forecast
Planning Reserve	Planning reserve margin is calculated at 15% of the 1-in-10 forecasted peak demand
Natural Gas Prices	Natural gas prices are derived from ICE forward price curves; price increases beyond the price curve range are based on the EIA outlook forecast.
GHG Prices	CEC's 2021 IEPR Carbon Price Projections
CO2 Emission Rates	Gas-fired and Import resources based on California Air Resources Board (CARB) 2023 published emission rates.
Power Prices	Power prices are derived from ICE forward price curves; price increases beyond the price curve range are based on the EIA outlook forecast.
Hydro Conditions	Average hydro conditions are assumed after 2024; MID's share of generation from the Don Pedro Plant is estimated to be 175 GWh annually.
RPS Portfolio	MID's existing portfolio, plus future resources are expected to achieve 60% RPS by 2030

1.2.2. Demand-Side Forecast

MID established its "Managed Load" forecast for its IRP analysis based on the MID 2023 Long Term Demand and Energy Forecast (2023 LTDEF). MID derived its hourly net load and peak forecast by incorporating assumptions for demand-side resources including energy efficiency, solar photovoltaic, and electric vehicles. Detailed assumptions and methodology for the 2023 LTDEF are described in Chapter 7 of this IRP.

Outer Territory Cities (OTC) load represents a small portion of the MID total demand. Due to lack of historical metered data, the OTC load forecast was derived from 2018-2022 end-of-year billing data for the billed rate classes in these areas.

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

1.2.3. Supply-Side Forecast

MID's supply-side resources are used to meet net demand after adjusting for the demand side resources described above. MID provides a description of its supply-side portfolio within the standardized tables that are part of this IRP submission.

1.3. 2024 Planning Sensitivities

Sensitivity study or scenario study has been implemented as a valuable element in MID's resource planning process. Historically, MID presented a single load forecast and planning scenario in the resource plan. In the previously filed 2019 IRP, MID began to incorporate sensitivities and probability estimates in the load forecast and planning scenarios. This practice has continued and has been improved in each annual long-term load forecast. The 2023 LTDEF incorporates multiple weather scenarios to each year's forecast. Instead of providing one forecast value for each time interval, MID models weather scenarios and provides a range of forecast results covering historical extreme weather conditions. Detailed sensitivity variable utilization is described in more detail in Chapter 7 of this IRP.

1.4. 2024 Planning Processes

Figure 1-1 Overview of MID's IRP Process

Step 1

Examine Compliance Requirements
- Identify the current business and regulatory environment.
- Develop a multi-faceted matrix of required targets and consider how plan drivers may change during the planning period.

Step 2

Identify Strategic Planning Gaps
- Identify the existing portfolio and its directional gap to compliance targets.

Step 3

Consider Resource Options
- Evaluate available generation resources including conventional, renewable, and long-term market power purchases to identify the role each will play in meeting customer needs and regulatory and policy goals.

Step 4

Assess Demand
- Develop forecasts of load growth, changing load patterns, existing plant conditions, contract terms, and operational constraints to determine resource needs over the planning period.

Step 5

Develop Optimal and Reliable Portfolio
- Develop a feasible and efficient resource portfolio through least-cost optimization, followed by a quantitative and qualitative evaluation process for resource adequacy to meet reliability requirements.

Step 6

Identify Compliant and Risk Controlled Portfolio
- Use preliminary optimal resource portfolio to identify short positions to compliance targets, update supply portfolio, and repeat step 5 until the resource porfolio is fully compliant with compliance targets and the District's risk policy.

Step 7

Identify Conforming Plan
- Identify a "Conforming Plan" expected to reliably serve demand at a reasonable long-term cost while achieving compliance, and allowing for flexibility to respond to future policy changes.

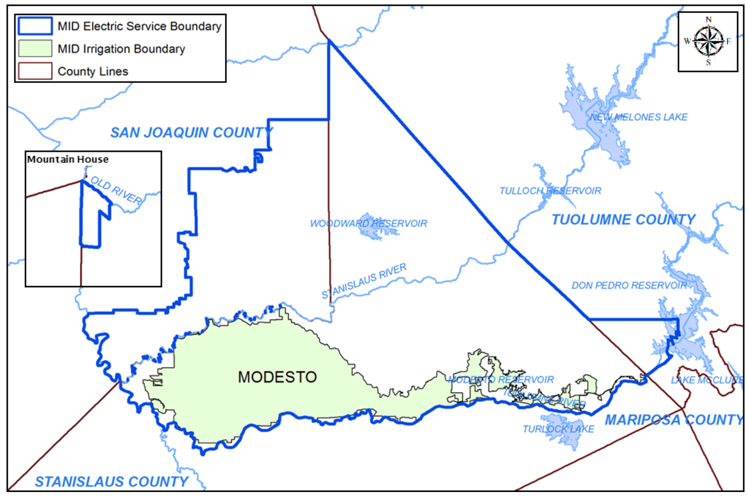
Step 8

Board to approve Conforming Plan
- Present the identified "Conforming Plan" based on the optimum resource portfolio and prepare the Integrated Resource Plan according to the CEC IRP guidelines and present the final plan for approval by the MID Board of Directors.

Step 9

Submit the IRP to CEC
- Submit the Board-approved IRP to the CEC.

II. MID Electric Service Facts



Modesto Irrigation District (MID), located in California's Central Valley, provides electricity, irrigation water, and treats surface water for the City of Modesto for drinking. MID is an independent, publicly owned utility founded in 1887 and has provided electric service to the area since 1923. MID transmits and distributes electricity using more than 1,800 miles of power lines throughout its service area, providing power to the communities of Modesto, Waterford, Salida, Mountain House and parts of Ripon, Escalon, Oakdale, and Riverbank.

Electric Service (in 2023)

Electric Accounts*		
Residential	102,774	
Commercial	13,061	
Other	143	
Total	***132,213***	

Electric Revenue
$371,845,975

Consumption
2,583,073,611 kWh

Average Residential Use
800 kWh/month

Electric Service Area
561 square miles

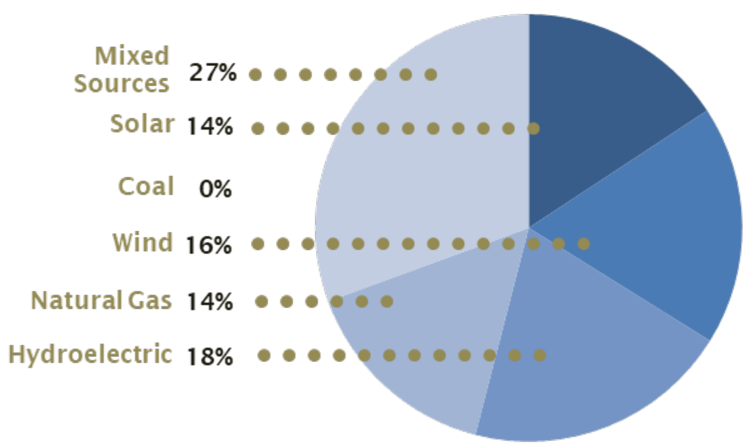
Electric Facilities

Hydropower	Capacity
Don Pedro Powerhouse	*203 MW**
New Hogan Powerhouse	*3.2 MW*

Natural Gas	Capacity
Woodland Generation 1	*50 MW*
Woodland Generation 2	*83 MW*
Woodland Generation 3	*49.2 MW*
McClure Generation	*108 MW*
Ripon Generation	*94 MW*

*MID's ownership interest in Don Pedro is 62 MW

Electric Resource Mix



III. Planning Goals

3. MID's Mission

MID will provide electric, irrigation, and domestic water treatment services for its customers, delivering the highest value at the lowest cost possible through teamwork, technology, innovation, and commitment.

3.1. System Reliability

One of MID's most important goals is to maintain a safe and reliable electric system. Through striving towards this goal, MID has achieved a system average interruption duration index (SAIDI) of 37[1], which it views as a key service differentiator. MID plans to continue the successful operational initiatives that it has put into place to maintain or improve its SAIDI score.

MID relies on the widely accepted one-day-in-ten-years (1-in-10) loss of load standard to define its resource adequacy needs. Also known as the 1-in-10 loss of load event (LOLE), the standard requires that MID maintain sufficient generation capacity and demand response resources so that system peak demand is likely to exceed available supply only once in ten years. Adequate capacity is maintained through Planning Reserve Margin (PRM), which is the amount of generation capacity available that exceeds forecasted demand by a specified percentage. MID's PRM has been established by its Board of Directors at 15% above forecasted 1-in-10 demand, with some adjustments for certain resources like hydro generation and firm imports.

MID has a relatively low load factor and experiences wide load variability during the day, particularly in high-temperature days during summer months, when the maximum demand within a day could be twice the lowest demand of the same day. This pattern is expected to become more pronounced in the future, mostly due to the continued penetration of DERs (distributed energy resources). Behind-the-meter solar resources offset part of the mid-day gross demand and then quickly ramp down when the sunlight fades in the evening. This pattern can lead to reduced demand during the day, followed by a steep increase in load as solar generation decreases. MID has not yet experienced as pronounced a reduction in net daytime demand as has been observed in other parts of the state.

MID has several measures in place to meet future demand. Throughout the next five years, capacity needs will be met with planned renewable resources and with short-term contracts delivered through existing transmission. MID maintains a 5-year capital improvement plan which identifies projects that may be needed to maintain system reliability. MID also joined the Western EIM (Energy Imbalance Market) in early 2021, which has helped improve the efficiency of MID's real time resource dispatch.

[1] SAIDI Without MED for 2021 from Annual Electric Power Industry Report, Form EIA-861

3.2. Low and Stable Rates

As a publicly owned utility, maintaining low and stable electric rates is a key MID mission criterion considered in the development of this Integrated Resource Plan. Due to rising purchase power and fuel costs, in 2022, MID raised rates for the first time since 2012 by approving a 7.4% electric service rate increase in 2023 and an additional 3.5% increase in 2024. As the 2024 budget was being built, it became apparent that purchase power costs were expected to increase 20% over 2023 figures. In 2023, the Board approved an additional 7.5% increase in 2024 (in addition to the previously approved 3.5% approved by the Board in 2022) and a 5.5% increase in 2025. In 2023, the Board also approved the implementation of a Power Cost Adjustment (PCA) to take effect on January 1st, 2025. MID has consistently maintained electric rates that are lower than adjacent Investor-Owned Utilities (IOU). Total System Average Rate (SAR), which is defined as a utility's total revenue divided by total kWh sales, is a measurement of the utility's cost to serve customer load. MID's 2022 SAR was 14.4 ¢/kWh. In 2020, SCE's year-end total electric bundled SAR was 18.5 ¢/kWh, PG&E's was 21.1 ¢/kWh and SDG&E's was 24.1 ¢/kWh. [2] MID's SAR had an annual increase of 0% for the period of 2012-2020. Over the same period, electric SARs for PG&E, SDG&E and SCE increased annually by approximately 4%, 6% and 4% respectively.

This 2024 Integrated Resource Plan serves as a guide to help MID achieve its mission. The recommended portfolio and improved capital structure are expected to help maintain stable rates throughout the planning horizon. Going forward, MID must balance affordable rates with the prospect of increasing capital expenditures, commodity costs, and costs of meeting more stringent regulatory requirements in the long-term horizon. MID must also continue to control operating and maintenance expenses and manage its energy market risks.

[2] Bundled system average. California Public Utilities Commission. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/historical-electric-cost-data/bundled-system-average

IV. Key Policy Drivers

4. Portfolio Planning Policy Drivers

MID's Integrated Resource Plan presents the utility's approach towards reliability planning and budgeting, demonstrating compliance with federal and state laws and regulations and policy set by the MID Board of Directors (MID Board), and provides a frame of reference for developing new and revised MID Board policy. This chapter outlines key policies that govern MID's planning and operations.

4.1. Planning Beyond 2030

Due to high level of policy uncertainty beyond 2030, this Integrated Resource Plan encompasses a 10 year horizon (covering the period 2021 through 2030) of MID's historical and projected demand, resource portfolio, and expected costs associated with electricity demand and supply.

4.2. MID Board Policies and Procedures

The MID Board sets policy for the District. MID Board members represent geographical divisions within the District's service area. Registered voters within each division elect a director for a four-year term of office. The following are summaries of MID Board policies governing energy procurement.

4.2.1. Long-Term Demand Capacity Procurement

Peak demand refers to the highest amount of customer electric load in any hour and is usually expressed in megawatts (MW). MID's current policy is to procure supply capacity equal to 115% of the expected peak demand, with 70% of that supply capacity sourced from long-term resources and 30% from short-term resources. A utility-owned project, or contract, is considered long-term if it has a term of 10 years or more; all other resources are considered short-term resources.

4.2.2. Renewable Portfolio Standard (RPS) Procurement

The MID Board of Directors first adopted an RPS policy through Board Resolution 2003-245 to meet the mandates of the state's first RPS bill, SB1078. That policy set a target for MID in which renewable energy procurement must meet 20% of MID's retail energy needs by 2017. Since then, SB1078 has been superseded by several newer laws, most recently by SB100, which increased the RPS targets to 60% by 2030, which are incorporated into the District's current RPS Procurement Plan.

4.2.3. Energy Efficiency (EE) Procurement

The MID Board of Directors originally adopted an EE target through Resolution 2010-50 and approved the submittal of targets to the CEC through Resolution 2013-18, and most recently adopted the District's 2022 through 2031 EE targets through Resolution 2021-77. These targets are incorporated into this Resource Plan.

4.2.4. Electric Vehicle (EV) Programs

MID's load forecast continues to include a projection of EV impacts on system demand. In December 2020 the MID Board adopted an optional time-of-use rate to incentivize off-peak charging and allow MID to join the California Air Resources Board (CARB)'s Low Carbon Fuel Standard (LCFS) Program which will allow MID to generate credits from customers' EV charging load.

4.2.5. Behind the Meter (BTM) Solar Programs

The MID Board of Directors adopted Resolution 2007-138, which offered rebate incentives for residential and commercial photovoltaic solar systems up to 30 kW and a performance-based incentive program for solar generation systems greater than 30kW and up to 1,000 kW. This policy also supported State Assembly Bills AB 58 and AB 510 by setting caps beyond which rebate incentives could be reduced and then discontinued. These caps were set at 2.5% and 5.0%, respectively, of BTM solar capacity compared to peak demand. After reaching the 5% cap in 2015, the MID Board of Directors approved a new net energy metering program, called the NEM 2.0 program, through Resolution 2016-97. NEM 2.0 was implemented on January 1, 2017 and allows customers to use their solar generating capacity to serve their own load and compensates them for any energy generated in excess of their load at a fixed rate (currently $0.076/kWh). Energy consumed when the solar system is not generating, or consumption in excess of the customer's solar generation, is purchased by the customer at the prevailing retail rate.

4.2.6. Exposure Limits

MID's Risk Management Policy implements a Value-at-Risk (VaR) limit as well as position limits. The VaR is a financial limit expressed in dollar amount that caps the amount of money that the District is willing to risk the loss of, through exposure to market pricing, over a specified time period. Position limits are put in place for both electric power and natural gas procurement, are set by the MID Board of Directors, and set boundaries for how much of the District's expected energy and natural gas needs must be hedged or "covered" in the current year and in forward years. See the Appendix for the details of MID's Risk Management Policy.

4.2.7. Energy Storage Procurement

California state bill AB2514 requires the governing boards of publicly-owned utilities to adopt energy storage procurement targets, if such targets are determined to be appropriate. The MID Board of Directors adopted a policy through Resolution 2014-72 stating that mandatory energy storage procurement targets are not appropriate for the District. It was determined that there were no operational or reliability needs that would justify mandatory procurement targets. Instead, MID will evaluate energy storage on an economic basis as opportunities arise, allowing the District to evaluate energy storage based on economics and operational fit. Using this approach, MID has executed a long-term power purchase agreement for a solar project that includes battery storage capacity.

4.2.8. Board Policy Summary

The following table lists the MID Board Resolutions relevant to power supply, and the associated state legislation.

Board Resolution	MID Policy	Description	Legislation
Board Resolution 2013-04	Planning Reserve Margin (PRM)	Established capacity planning 70/30 long-term to short-term resource ratio. Set reserve capacity level based on 1-in-10 probability.	SBx1-2, AB32, AB2514
Board Resolution 2003-245	Renewable Portfolio Standard (RPS)	Set a target for MID in which renewable energy procurement must meet 20% of MID's retail energy needs by 2017.	SB1078
Board Resolution 2011-82	Renewable Portfolio Standard (RPS)	Approved the Renewable Energy Resources Enforcement Program.	SBx1-2, PUC§399.30(e)
Board Resolution 2013-04	Renewable Portfolio Standard (RPS)	Approved the use of the allowable renewable energy credit banking mechanism and tradable renewable energy credits to meet RPS compliance goals.	SBx1-2, AB32, AB2514
Board Resolution 2013-87	Renewable Portfolio Standard (RPS)	Set a renewable energy target of 33% by 2020.	SBx1-2
Board Resolution 2018-62	Renewable Portfolio Standard (RPS)	Increased the RPS target to 50% by 2030.	SB350
Board Resolution 2022-29	Renewable Portfolio Standard (RPS)	Increased the RPS targets to 60% by 2030.	SB100
Board Resolution 2021-77	Energy Efficiency (EE) Procurement	Adopted the District's 2022 through 2031 EE targets.	AB2021
Board Resolution 2020-59	EV Programs	Adopted an optional time-of-use rate to incentivize electric vehicle off-peak charging and allowed MID to join CARB's Low Carbon Fuel Standard (LCFS) Program	---
Board Resolution 2007-138	Behind the Meter (BTM) Solar Programs	NEM 1.0 offered rebate incentives for residential and commercial photovoltaic solar systems up to 30 kW and a performance-based incentive program for solar systems greater than 30kW and up to 1,000 kW.	AB58, AB510, SB1
Board Resolution 2016-97	Behind the Meter (BTM) Solar Programs	NEM 2.0 allows customers to use their solar generating capacity to serve their own load and compensates them for any energy generated in excess of their load at a fixed rate.	
Board Resolution 2014-72	Energy Storage Procurement	Determined that there were no operational or reliability needs that justify mandatory procurement targets and that mandatory energy storage procurement targets are not appropriate for the District. Directed MID staff to instead evaluate energy storage opportunities based on economics and operational fit.	AB2514
Board Resolution 2013-48	Feed-In Tariff	Authorized the addition of a mandated renewable Feed-in Tariff obligation to the MID rate schedules for small scale renewable projects with capacity of up to 3 MW. Rate updated by Board Resolution 2019-41.	SB32, SB1332

4.3. Federal and State Laws

MID complies with federal and state laws. Below are summaries of federal and state regulations and laws that guide MID's energy planning and procurement.

4.3.1. Applicable Federal Law Passed Since 2006

Policy	Description
Greenhouse Gas Reporting (2010)	Mandatory reporting of power plant greenhouse gas (GHG) emissions to U.S. EPA for facilities located in the United States that emit 10,000 metric tons of CO_2 equivalent (MTCO2e) or greater per year. As of July 2018, the Woodland and Ripon Generation Stations continue to meet the criteria for reporting. McClure Generation Station is only operated in short periods during the year, which keeps its GHG emissions under the 10,000 $MTCO_2e$ threshold required for reporting.
National Ambient Air Quality Standards (2006)	Sets limits for six principal pollutants which are called "criteria" pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particle pollution, sulfur dioxide).
Mercury and Air Toxics Standards (2011)	Limits emissions of toxic air pollutants like mercury, arsenic, and metals from coal and oil-fired power plants.
EPA New Source Performance Standard (2012)	The Environmental Protection Agency issued a New Source Performance Standard that would require, using authority granted under the Clean Air Act, any new baseload fossil-fuel power plant to emit no more than 1,000 pounds of carbon dioxide per megawatt-hour of electricity produced, calculated over a rolling 12-month period. This compares to average coal plant emissions of about 1,800 pounds of CO2 per megawatt-hour and average natural gas plant emissions of 850 pounds of CO2 per megawatt-hour. The proposed rule does not apply to existing plants. The EPA has withdrawn this proposal but continues to seek its establishment in law. Construction of plants that do not meet the standard would likely carry some long-term risk.
Proposed Rule for Greenhouse Gas Reductions from Existing Electric Utility Generating Units (2014)	The Environmental Protection Agency proposed a rule for limiting GHG emissions from existing power plants, with the goal of achieving nation-wide electricity sector GHG reductions of 30% below 2005 emissions by 2030. The rule proposes individual emission reduction targets for each state. The 2030 California goal is to achieve a sector-wide emission factor of 537 lbs/MWh. Each state would be given the opportunity to propose its own State Implementation Plan (SIP), outlining strategies to reach the identified target. The impacts to MID would not be known until California releases its proposed SIP; however, it does not seem likely that the proposed target will be more stringent than existing emission reduction targets in California, given that California is targeting economy-wide 2050 emissions that are 80% below 1990 levels. Additionally, the California Air Resources Board (CARB) estimates that California should meet those targets with the existing state programs (RPS, cap-and-trade, energy efficiency). The EPA has withdrawn this proposal. It is very unlikely that any of these requirements would be enforced in the near term; however similar policies may be proposed again in the future.

4.3.2. State Law Passed Since 2006

Policy	Description
AB2021 Energy Efficiency (2006)	Requires all locally owned electric utilities to meet energy efficiency savings targets established by the California Energy Commission (CEC). This bill requires POUs to identify all cost-effective electricity efficiency savings and establish 10-year energy efficiency targets on a triennial basis. MID's latest 10-year targets, adopted in MID Board Resolution 2021-77, are included in this resource plan.

Policy	Description
SB1 Solar Energy Net Metering (2006)	Requires MID to have a program that adequately supports the state's efforts to install 3,000 MW of rooftop photovoltaic capacity in California. SB 1 also set a net metering cap of 2.5% of peak load. On July 31, 2007 the MID Board adopted Resolution 2007-138 which authorized the District to begin offering rebate incentives for qualifying PV systems. The District's customers have installed in excess of 50 MW of behind-the-meter solar capacity, which exceeds the District's net metering obligations, allowing the District to offer a replacement net metering program.
SB1368 Emission Performance Standard (2006)	Limits investments in baseload generation to resources that meet an emission performance standard of 1,100lbs CO2/MWh. This requirement essentially limits baseload generation options to natural gas given that the average coal plant emits 1,800 lbs. CO2/MWh while combined-cycle natural gas plants typically emit 850 lbs. CO2/MWh.
AB32 Global Warming Solutions Act of 2006	This law targets climate change by establishing a goal of reducing California's greenhouse gas emissions to 1990 levels by 2020, representing a 25% reduction statewide. In accordance with AB32, ARB adopted a mandatory reporting regulation and a cap-and-trade program in 2010 to measure and reduce statewide greenhouse gas emissions. The cap-and-trade program initially implemented an annual emissions cap starting in 2013 that decreases annually through 2020. The cap applies to utilities, large industrial facilities, and to the fuel distribution sector. To reduce cost impact to ratepayers, utilities are allocated allowances to cover a portion of their emissions and must buy compliance instruments for any remaining emissions. In 2016, SB32 expanded the statewide GHG emissions reduction goal to 40% below 1990 levels by the year 2030.
AB1613 Waste Heat and Carbon Emissions Reduction Act (2007)	This bill's goal is to advance the efficiency of the state's use of natural gas by capturing unused waste heat and to support and facilitate both customer and utility-owned Combined Heat and Power (CHP) systems. This bill requires electric utilities, including POUs, to establish a program that allows retail customers to utilize heat and power systems and for utilities to provide a market for excess electricity from CHP systems at a just and reasonable rate determined by the governing body of the utility.
AB118 Alternative Fuels and Vehicle Technologies: Funding Programs (2007)	This bill sets up funding for Alternative and Renewable Fuel and Vehicle Technology Programs to be administered by the Energy Commission. It also allows CARB to set up a Low Carbon Fuel Standard (LCFS) for transportation fuels that seeks to reduce the carbon intensity of transportation fuels by 10% by 2020.
AB920 Solar and Wind Net Metering (2009)	AB 920 requires MID to adopt a net metering rate for surplus energy from customer-generators. This rate applies to customer installations of solar or wind generators with up to 1 MW capacity. The net metering cap will remain at 2.5% of peak load as established by SB 1. Any surplus energy purchased from a customer-generator will count toward MID's RPS. The MID surplus rate has been set at the calculated annual avoided cost for the energy generated plus the annual green energy adjustment for the renewable attributes. The rate is intended to ensure that all other customers are indifferent to any surplus generation. The current MID surplus rate is $0.0567/kWh for net metering 1.0 customers and $0.076/kWh for net metering 2.0 customers.
SB32 & SB1332 Feed in Tariffs for Renewables (2009) & (2012)	SB 32 and SB 1332 require POUs to adopt standard terms for the purchase of renewable energy from eligible projects. The tariff must be made available to eligible renewable projects with a generating capacity not exceeding 3MW, on a first-come-first-served basis until MID's proportionate share of the 750 MW state cap is reached (approximately 8 MW). A tariff request can be denied only if it is determined that building or interconnection standards are not met or if the proposed installation would adversely impact the distribution system. The MID Board of Directors adopted a feed-in tariff, which became effective on July 1, 2013. The tariff offers a seasonal time-of-delivery rate to renewable projects with a generating capacity greater than 30kW but not exceeding 3MW.
AB510 Utility Net Metering (2010)	Utilities must provide meters that can read and record in both directions and must accept generation up to a cap of 5% of the total load. MID achieved its 5% obligation in 2016.
AB2514 Energy Storage (2010)	AB 2514 requires the state's publicly owned utilities to open a proceeding to determine appropriate energy storage targets (if any) by March 1, 2012 and to adopt an energy storage procurement target by October 1, 2014. The overall target is to be achieved in two parts;

Policy	Description
	the first target is to be achieved by December 31, 2016 and the second target is to be achieved by December 31, 2021. The MID Board of Directors has adopted a policy stating that energy storage targets are not appropriate for the District at this time, given the lack of reliability and operational drivers.
SBX1-2 Renewable Energy (2011)	This bill requires all California electric utilities, including publicly-owned utilities, to meet a renewable energy target of 33% of retail sales by 2020. It increases the state's previous RPS targets to 20% for 2011-2013, 25% by 2016 and 33% by 2020. MID met the 2020 target.
SB1275 Charge Ahead California Initiative (2014)	SB 1275 establishes a state goal of 1 million zero-emission and near-zero-emission vehicles in service by January 1, 2023 and to increase access for disadvantaged, low-income, and moderate-income communities and consumers to these vehicles through state-sponsored programs including rebates and vouchers.
SB350 Renewable Energy, Energy Efficiency and Vehicle Electrification (2015)	SB 350 increases the renewable energy target from 33% of retail sales in 2020 to 50% in 2030. Additionally, the bill requires the CPUC to identify cost-effective electric efficiency savings and to establish efficiency targets for gas corporations. The bill requires programs to be established to achieve a cumulative doubling of statewide energy efficiency savings in electric and natural gas end uses by January 1, 2030. This bill also requires POUs to address transportation electrification in the Integrated Resource Plans (IRPs) adopted and submitted to the Energy Commission.
SB859 (2016) Public Resources: greenhouse gas emissions and biomass.	This Bill requires IOUs and POUs that serve more than 100,000 customers, including MID, to procure through financial commitments of five years their proportionate shares (based on the ratio of the utility's peak demand to the total statewide peak demand) of 125 MW of cumulative rated capacity from existing bioenergy projects that generate energy from wood harvested from high-fire hazard zones.
SB338 Integrated Resource Plan: Peak Demand (2017)	This bill requires the commission and the governing boards of local publicly owned electric utilities to consider, as a part of the integrated resource plan process, the role of distributed energy resources and certain other energy and efficiency-related tools in helping to ensure that each load-serving entity or local publicly owned electric utility meets its energy and reliability needs while reducing the need for new generation and transmission and to achieve the state's energy goals at the least cost to ratepayers.
AB-398 California Global Warming Solutions Act of 2006: market-based compliance mechanisms; fire prevention fees; sales and use tax manufacturing exemption.	The key effect of this bill is to authorize the cap-and-trade program through 2030. It also requires CARB to implement certain changes to the cap-and-trade program, including setting a price ceiling and price containment points, limits the use of out-of-state GHG offset credits, and increase allocation of allowances to covered industrial entities. It also establishes economic policy committees that will oversee the cap-and-trade program and requests CARB to investigate certain topics such as the effects and efficacy of allowance banking on the program.
SB100 The 100 Percent Clean Energy Act of 2018.	This bill increases the renewable energy target to 60% by 2030 and requires utilities and state regulators to plan for all of the state's electricity to come from carbon-free resources by 2045 but stops short of adopting a formal zero-emission mandate.
SB1020 Clean Energy, Job, and Affordability Act of 2022	This bill revises the state policy to instead provide that eligible renewable energy resources and zero-carbon resources supply 90% of all retail sales of electricity to California end-use customers by December 31, 2035, 95% of all retail sales of electricity to California end-use customers by December 31, 2040, 100% of all retail sales of electricity to California end-use customers by December 31, 2045.

4.4. Cap-and-Trade Program

The Cap-and-Trade Program (the "Program") provides a market-based mechanism to guide the state towards its GHG reduction targets. The Program established an emissions cap by drawing a straight-line trajectory of total statewide emissions at the start of the program to the allowable quantity of emissions from entities covered under the Program under the mandated emissions reduction targets. The California

Air Resources Board (CARB), the administrator of the Program, makes available tradable compliance instruments each associated with one metric ton of CO_2 equivalent (MTCO2e) under the cap. By the end of each three-year compliance period, covered entities must surrender an amount of compliance instruments equivalent to the quantity of their GHG emissions in MTCO2e throughout the compliance period. Some of these compliance instruments are allocated directly to entities covered by the Program to assist with leakage protection and to avoid rate shock to consumers and ratepayers. Other compliance instruments are set aside by CARB as cost containment tools, such that if the price of compliance instruments reaches certain designated prices, compliance instruments will be released into the market to help mitigate price spikes caused by constriction of supply. The remaining compliance instruments are posted for sale in CARB-administered auctions, through which covered entities may purchase compliance instruments to cover their emissions. Compliance instruments can also be traded in bilateral markets. The premise of the Program is that as the cap of allowable emissions decreases each year, the price of the reduced quantity of compliance instruments will increase, and entities with the lowest cost to reduce GHG emissions will do so and sell their compliance instruments to entities with higher costs to achieve GHG reductions. Eventually, costs of compliance with the Program will increase such that all covered entities will plan to enact whatever action is available to them to reduce GHG emissions rather than continue to purchase compliance instruments that allow them to continue to emit GHGs.

Emissions from MID's Woodland Generation Station are subject to the Program, as well as all emissions associated with MID's electric energy imports. MID receives allocated allowances to help mitigate significant rate shock to its customers by covering a portion of the District's emissions. The current Cap-and-Trade regulation authorizes a schedule of allocated allowances to MID through 2030. MID's policy strives to ensure compliance at the lowest cost and considers GHG costs in its dispatch and procurement decisions.

V. Renewable Energy Procurement Plan

5. MID Renewable Energy Procurement Overview

MID relies on a diverse, balanced power resource mix to meet customer needs. This chapter presents the District's plan for adding renewable energy to its electric resource portfolio to meet the state's mandates while maintaining a balanced resource mix and meeting the utility's reliability needs.

On November 13, 2018, the MID Board of Directors approved[1] the revised Renewable Portfolio Standard (RPS) Procurement Plan and Enforcement Program. The updates to the RPS Procurement Plan and Enforcement Program, and this Integrated Resource Plan, focus on implementing the requirement to meet 60% of MID's electric retail sales with renewable energy by 2030 in accordance with Senate Bill 100[2]. More recently, on June 7, 2022 the MID Board of Directors adopted the second revision to the RPS Procurement Plan and Enforcement Program[3]. The revision incorporates the requirement commencing in 2021 to meet 65% of MID's RPS procurement from contracts of 10 or more year duration, ownership, or ownership agreements in accordance with the regulations adopted by the California Energy Commission (CEC) governing publicly owned utilities (POUs) for compliance with the RPS[4]. In this Integrated Resource Plan, MID projects that it is well-positioned to meet the requirements of its RPS Procurement Plan and Enforcement Program. MID plans on meeting its RPS requirements by continuing to apply current-year renewable energy credits (RECs) combined with previous volumes of excess procurement (also known as "banked" RECs) and purchases of tradable renewable energy credits (TRECs) to supplement the ongoing layering in of new, long-term RPS assets.

This chapter lists the policies, assumptions, and plans that inform MID's renewable resource planning.

5.1. RPS Targets by 2030

This Integrated Resource Plan describes MID's plan to comply with the SB100 RPS targets as a percentage of retail load as listed below:

- 33% by December 31, 2020;
- 44% by December 31, 2024;
- 52% by December 31, 2027;
- 60% by December 31, 2030.

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[1] MID Board Resolution 2018-62.

[2] Senate Bill 100 (De León, Chapter 312, Statutes of 2018). The pertinent provisions of SB 100 are codified in Public Utilities Code Sections 399.15, and 399.30, and added Section 454.53 to the Public Utilities Code.

[3] MID Board Resolution 2022-29.

[4] The CEC updated its regulations specifying Enforcement Procedures for the RPS for Local Publicly Owned Electric Utilities on July 12, 2021 to adopt a long-term procurement requirement as codified in Senate Bill 350 (De León, Chapter 547, Statutes of 2015). The most recent update to the MID RPS Procurement plan incorporated the requirement to meet 65% of MID's RPS procurement from long-term contracts leaving the ability for MID to procure 35% of its RPS procurement from short-term contracts. The CEC has specific requirements for procurement to make distinctions between short and long-term contracts, but the REC products will continue to be treated the same as the original corresponding portfolio content category.

Table 5-1 below provides a summary of RPS requirements through 2020. Table 5-2 shows post-2020 compliance periods.

Table 5-1: RPS Portfolio Content Categories

		Compliance Periods	**1** 1/1/11-12/31/13	**2** 1/1/14-12/31/16	**3** 1/1/17-12/31/20
		RPS % as a percentage of retail energy sales by end of Compliance Period	Average 20%	25%	33%
Commonly known as Buckets	Portfolio Content Category (PCC) 1	Minimum portion of RPS required to be either: 1) Physically within CA, or 2) Adjacent and interconnected to CA, or 3) Dynamically scheduled into CA	50%	65%	75%
	PCC2	Firmed and Shaped	No minimum or maximum	No minimum or maximum	No minimum or maximum
	PCC3	Tradeable Renewable Energy Credits Maximums	25%	15%	10%
	PCC0	Grandfathered contracts executed before 6/1/2010	Count in full	Count in full	Count in full

Table 5-2: Post-2020 Compliance Periods

Compliance Periods	**4** 1/1/21-12/31/24	**5** 1/1/25-12/31/27	**6** 1/1/28-12/31/30
RPS % as a percentage of retail energy sales by end of Compliance Period	44%	52%	60%

The CEC's updated regulations governing POU compliance with the RPS laws clarify that the RPS portfolio content category structure described for Compliance Period 3 in Table 4-1 continue to apply beyond 2020.

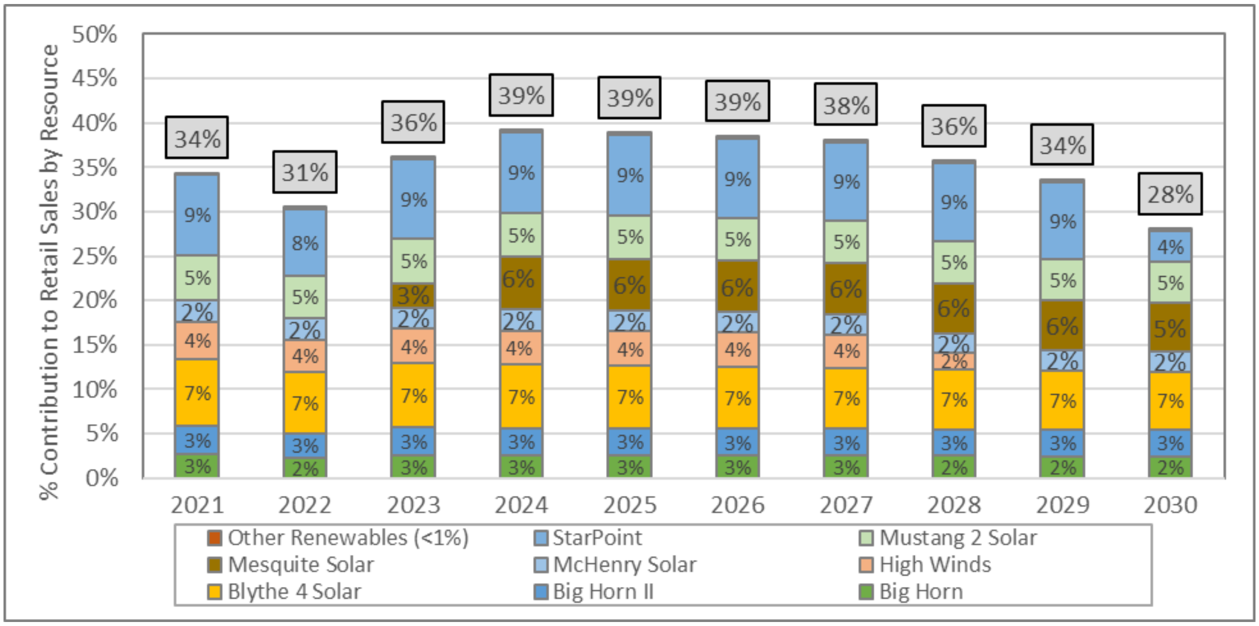
5.2. MID Current and Future RPS Mix

MID's RPS portfolio currently includes power purchases from four wind generation projects: the Big Horn I and Big Horn II projects purchased as part of the M-S-R Public Power Agency; and the Star Point Wind Project and High Winds Project both for which MID is the sole off-taker. The Big Horn I and Big Horn II projects are located in Klickitat County, Washington. The Star Point and High Winds projects are located respectively in Sherman County, Oregon and Solano County, California. MID has also procured the output from two solar photovoltaic projects located outside its service area. The Mustang Two Barbaro and Blythe Solar IV projects are located respectively in Kings County and Riverside County, California. MID's renewable energy mix also includes the New Hogan and Stone Drop small hydro projects, the locally situated McHenry Solar Farm, and surplus energy from behind-the-meter solar photovoltaic systems. Through its base resource contract with the Western Area Power Administration (WAPA), the District also receives a small amount of RECs from Central Valley Project hydro generation.

MID has also executed a power purchase agreement with RWE Clean Energy for the purchase of the energy output, capacity, and associated environmental attributes from a 52.5 MW share of its 105 MW Mesquite Solar 4 Project with 10 MW of lithium-ion battery energy storage capacity. The project is located south of Tonopah, within Maricopa County, Arizona and commenced commercial operation in February 2024. The project is directly connected to the California Independent System Operator system.

Figure 5-1 illustrates MID's procured RPS resources. In 2022, 31% of the energy required to serve MID's retail load was sourced from eligible renewable energy resources. As previously described, banked RECs and TRECs will be used to meet any differences between what is generated and the RPS targets to ensure that MID has sufficient REC products to meet its compliance period obligations.

Figure 5-1: MID's Procured RPS Resources (for illustrative purposes)



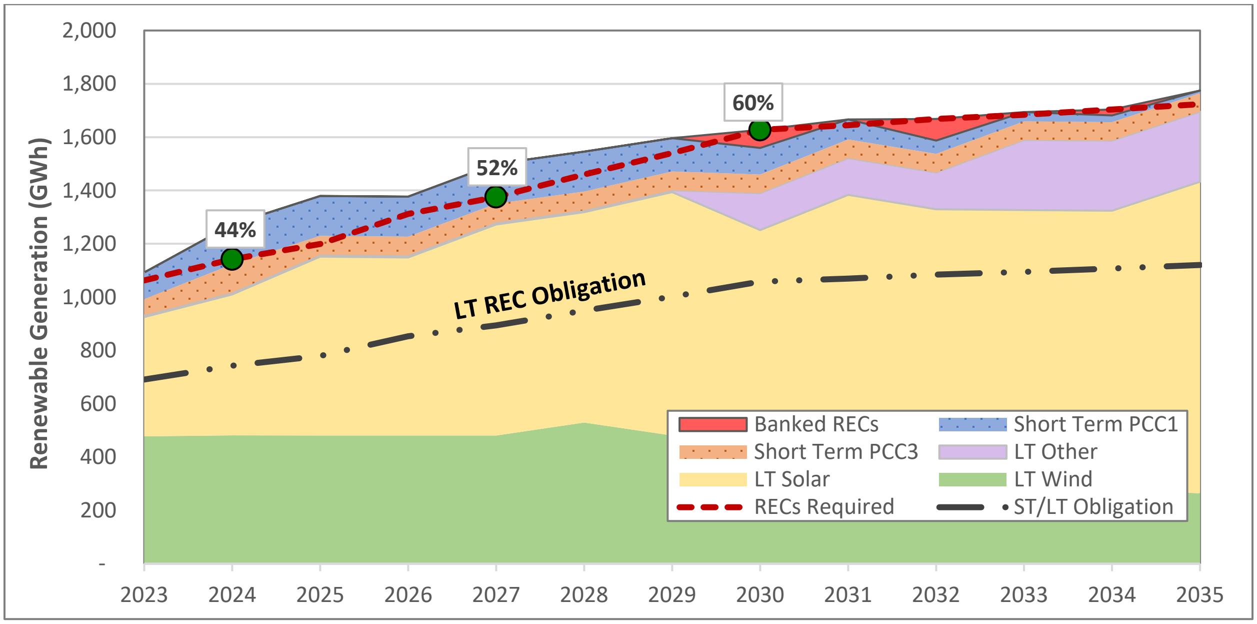
5.2.1. <u>Use of REC Banking and TRECs for RPS Compliance</u>

The current RPS law allows for RECs to be retired up to 36 months after the corresponding energy was generated. In addition, SBX1-2 provided that contracts that were approved by the governing boards of electric utilities prior to June 1, 2010 count in full towards POUs' RPS obligations. Further, the CEC regulation allows POUs that took early action (i.e. procured renewable resources prior to the adoption of mandatory POU RPS targets) to carryover excess renewable generation measured from 2004 through 2010 and use it for RPS compliance in future years.

Except for tradable RECs that must be retired at the end of each compliance period, excess RECs that are not used to meet an RPS goal in a specific year will roll over to a future year and be used for RPS compliance instead of RECs that will be generated in that future year. The RECs generated during that future year and not used for compliance at that time will roll over to the next year, and so forth.

Banking RECs in this fashion is consistent with the most recent RPS regulation. Figure 4-2 shows MID's planned application of tradeable and banked RECs towards its RPS compliance through 2035.

Figure 5-2: MID RPS Procurement (for illustrative purposes)



5.2.2. Renewable Portfolio Standard (RPS) MID Procurement Policy

The MID Board of Directors originally adopted an RPS policy through Board Resolution 2003-245 to meet the mandates of the state's RPS bill (SB 1078). SB 1078 set a target that 20% of the statewide energy mix be supplied by renewable resources by 2017. The most recent RPS law, SB100, increased the RPS targets to 60% by 2030. The MID RPS Policy is periodically updated to incorporate the latest state RPS goals and other requirements.

5.3. Items for Further Consideration

5.3.1. Energy Storage

AB 2514 required the state's publicly owned utilities to open a proceeding to determine appropriate energy storage targets (if any) by March 1, 2012 and to adopt an energy storage procurement target by October 1, 2014. The target was to be achieved in two parts; the first portion of the target was to be achieved by December 31, 2016 and the second part of the target by December 31, 2021. The MID Board of Directors adopted a policy in 2014 that declared that energy storage targets were not appropriate for the District in the near-term.

5.3.1.1. Energy Storage Procurement

Although MID did not adopt mandatory energy storage procurement targets under AB 2514, MID pursues energy storage opportunities in its RPS procurement solicitations with the goal of increasing the economic efficiency of new RPS assets. With increasing targets for emissions reductions and renewable energy procurement, MID has begun to actively encourage project developers and power merchants to offer hybrid (PV plus storage) and stand-alone energy storage systems in all recent and upcoming resource solicitations to fill a growing need for new dispatchable resources to support increased renewables penetration and load growth. MID applies competitive solicitation and robust economic analysis to each potential resource to ensure technical and cost portfolio fit. Given the reliability benefits of energy storage dispatchability and the reduced pool of alternatives as emitting generating resources are phased out, along with the proliferation and maturation of the battery energy storage industry, MID expects that energy storage will be a meaningful component of capacity procurement in the planning horizon.

VI. Transportation Electrification

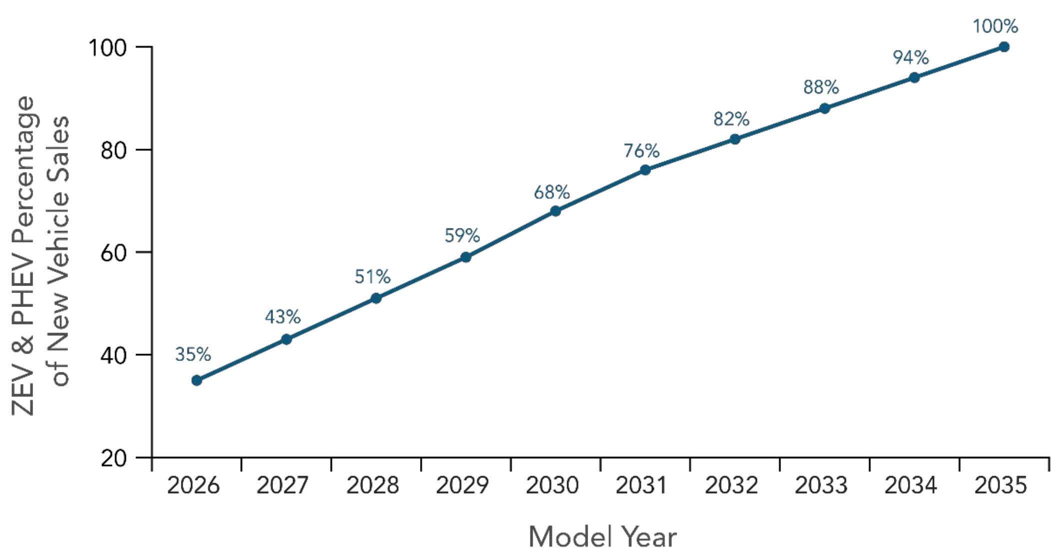
6. MID Transportation Electrification Overview

POUs are required to address Transportation Electrification in Integrated Resource Plans adopted and submitted to the Energy Commission pursuant to SB 350. This chapter considers the effects of increasing deployment of both Light-Duty Electric Vehicles and Heavy-Duty Electric Vehicles in MID territory.

6.1. Electric Vehicle Methodology and Assumptions

In December 2018, California Energy Commission staff developed a spreadsheet-based tool called the “Light-Duty Plug-in Electric Vehicle Energy and Emission Calculator”. The calculator was designed to assist POUs in estimating and reporting on the energy and emissions impact of light-duty plug-in electric vehicle (LD PEV) deployment in their service territories. The calculator was used to help fill a significant gap in data available to identify existing and forecast LD PEVs within the MID service area, along with an updated assumption estimating that there will be approximately 6 million electric vehicles in California by 2030. This projected increase in electric vehicles is largely driven by the “Advanced Clean Cars II Regulation” standard adopted in 2022 by the California Air Resources Board[1], as represented in Figure 6-1. Additionally, MID used data from the “Zero Emission Vehicle and Infrastructure Statistics” portal to inform the 2024 Integrated Resource Plan. Based on this data, the share of electric vehicles within California that are located in the MID service territory is estimated to be 0.56% in 2030, or approximately 33,000 PEVs.

Figure 6-1: Advanced Clean Cars II Regulations New Sale Adoption Rate

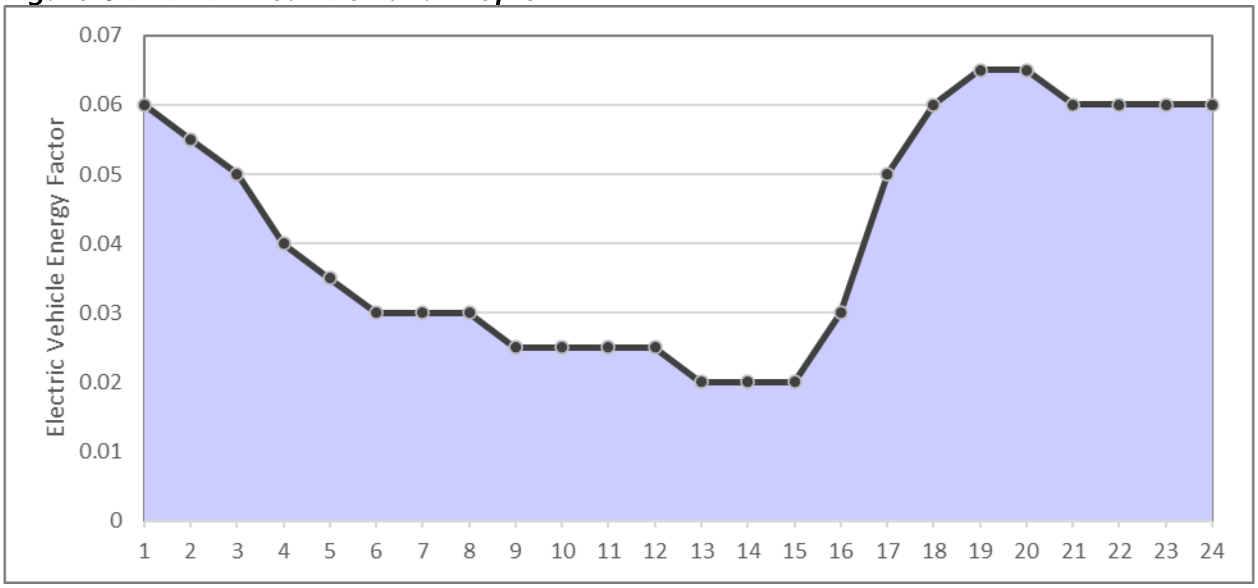


[1] California Air Resources Board. California moves to accelerate to 100% new zero-emission vehicle sales by 2035 | California Air Resources Board. (n.d.). Retrieved January 23, 2023, from https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035

6.1.1. Electric Vehicle Charging Profile

MID estimates an hourly profile of PEV energy consumption based on the profile developed from a study by the Rocky Mountain Institute[2] and historical rate class data from MID customers on the EV-D electric vehicle time of use rate. The estimated typical PEV hourly charging profile for an average electric vehicle on a peak summer day in 2024 is shown in Figure 6-2.

Figure 6-2: EV 24 Hour Demand Profile



It is estimated that the annual demand from electric vehicles will have an average annual growth rate of 24.2% for 2024-2030. A detailed projection of demand in GWh is listed in Table 6-1.

Table 6-1: EV Annual Energy Estimate (GWh)

	2024	2025	2026	2027	2028	2029	2030
2023 LTDEF	32.1	40.5	50.2	62.1	76.3	92.7	111.6

As transportation electrification increases in MID system territory, it is expected that the system coincident peak will increase correspondingly. This impact on net peak demand is estimated and reported in the Standardized IRP Tables.

6.1.2. Heavy-Duty Transportation Electrification

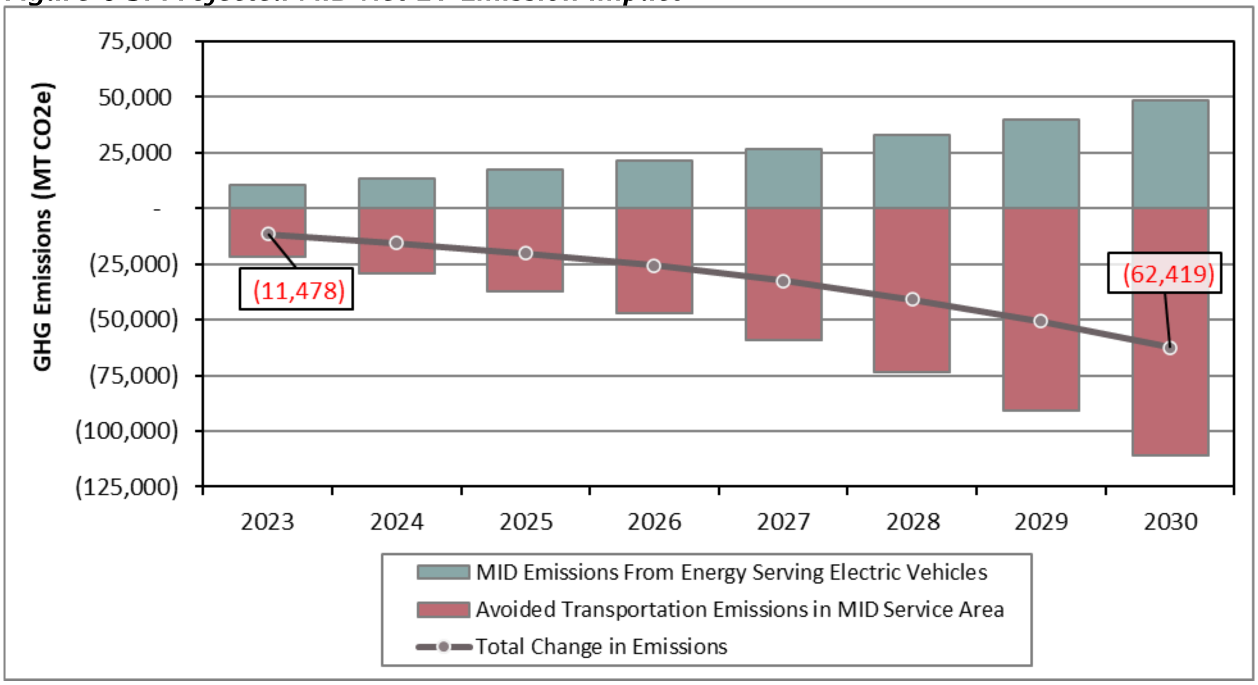
MID works closely with local businesses to determine heavy-duty transportation electrification that has already occurred, as well as projected electrification of heavy-duty vehicles in commercial and industrial sectors. Currently, electric buses and semi-trucks have begun to be electrified from local public and commercial diesel and natural gas fleets. Going forward, MID will continue to collaborate with customers regarding infrastructure needs and demand impacts as customer fleets continue to convert to heavy duty electric vehicles.

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

6.2. Transportation Electrification Impacts

MID estimates that PEV charging demand has an increasingly considerable impact to the MID emission profile as more electric vehicles are adopted within system territory. Emissions increases from electric generation for PEV charging and the avoided emissions associated with transportation electrification are estimated and reported on the Standardized IRP Tables. The estimated comparative impact on emissions is shown below in Figure 6-3.

Figure 6-3: Projected MID Net EV Emission Impact



6.3. Transportation Electrification Infrastructure

MID is currently evaluating PEV charging station installation standards for single-family dwellings, multi-family dwellings, and workplaces. MID recently began participating in the Low Carbon Fuel Standard (LCFS) program administered by the California Air Resources Board and is researching programs using the associated funding to decrease the barrier for consumers to enter the PEV market and support the adoption of PEVs more broadly by increasing their practical appeal. To support transportation electrification, MID is in the process of installing electric vehicle DC fast chargers at its downtown Modesto office for public use. Furthermore, MID is seeking partners and investigating the feasibility of installing electric vehicle chargers throughout its service area, which has to date received little investment from PEV charging companies for public charging stations. MID utilizes a web browser-based tool[3] to assist customers with locating public EV chargers near them.

[3] https://mid.chooseev.com/chargers/

6.3.1. Rebates and Other Financial EV Incentives

MID does not offer a specific rebate for EV purchases. However, MID currently offers a $500 rebate to customers who purchase a level 2 EV charger for their residence or business. On MID's EV portal[4], MID displays a list of rebates that customers may be eligible for. Low-income consumers will benefit from larger rebates dependent upon the number of persons in the household and total household income. MID offers a time-of-use rate, designated "EV-D" for residential customers who own a registered plug-in battery electric vehicle or plug-in hybrid electric vehicle. The EV-D rate is structured to incentivize EV charging during off-peak hours for customers who choose to enroll in this rate program.

[4] https://mid.chooseev.com/promos/

VII. Peak Demand and Energy Forecasts

7. Overview of IRP Energy and Peak Forecasts

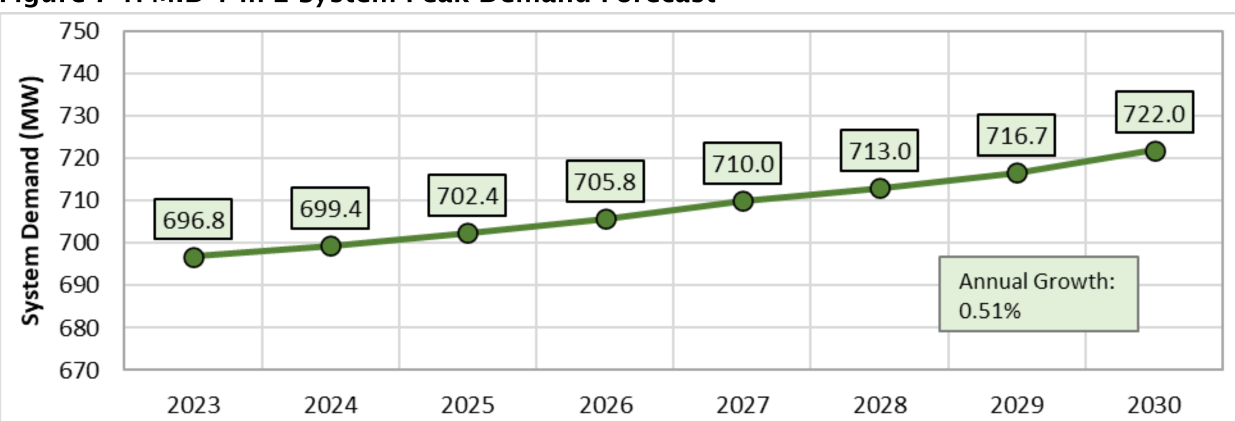
POUs are required to address Peak Demand and Energy Forecasts in the IRPs adopted and submitted to the Energy Commission pursuant to SB 350. The 2023 Long-Term Demand and Energy Forecast (LTDEF) for the MID region and its outer territory cities[1] (OTC) is discussed in this chapter, including the methodology, assumptions, and data used to create the forecast. The forecast horizon for this report is 2023 through 2030.

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.

7.1. Overview of Forecast Results

As shown in Figure 7-1, the 2023 LTDEF projects that system 1-in-2 peak[2] demand will increase at an average annual rate of approximately 0.51% from 2023 to 2030. Historically, peak demand annual growth increased at a rate of 1.6% from 2013-2022.

Figure 7-1: MID 1-in-2 System Peak Demand Forecast



[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.

As shown in Figure 7-2, the 2023 LTDEF projects that system 1-in-10 peak demand will increase at an average annual rate of approximately 0.57% from 2022 to 2030.

Figure 7-2: MID 1-in-10 System Peak Demand Forecast

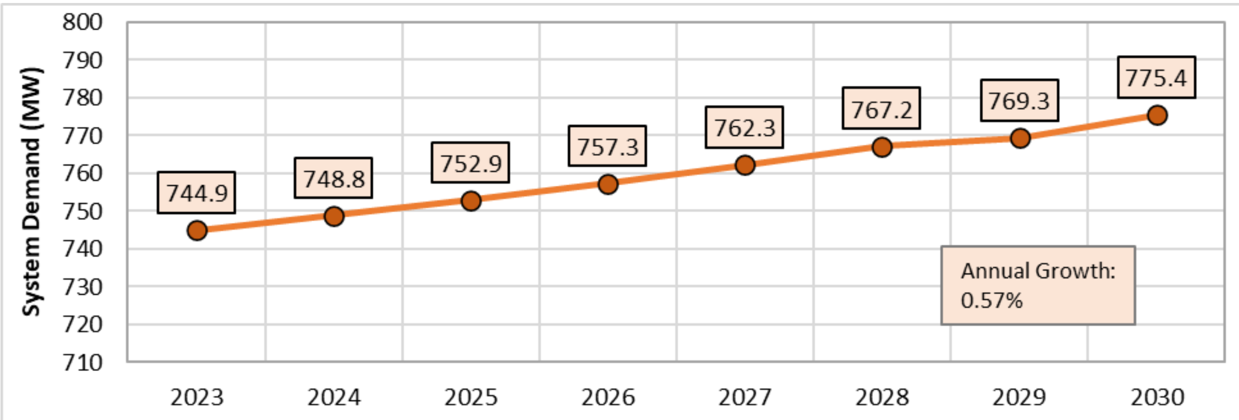
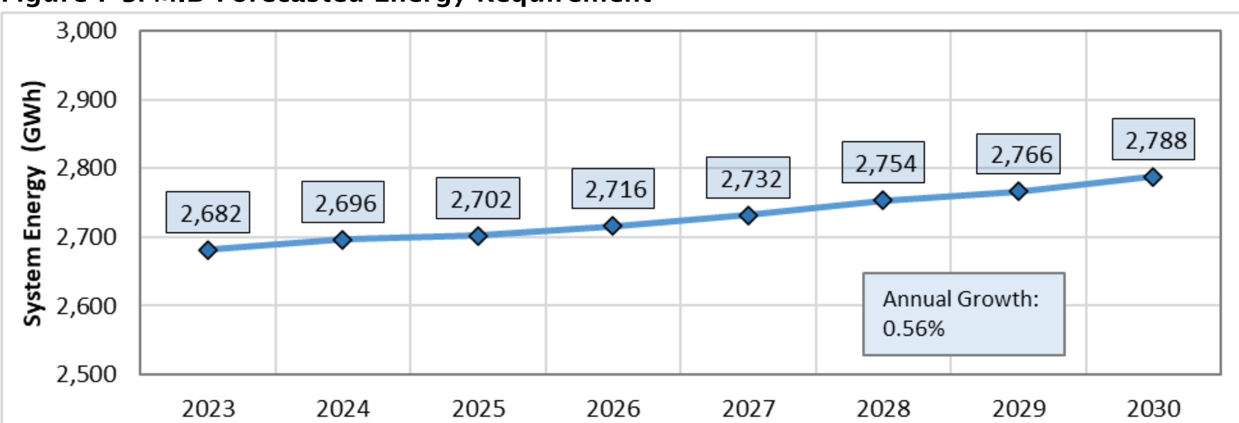


Figure 7-3 depicts that the 2023 LTDEF projects system energy requirements will increase at an average annual rate of approximately 0.56% from 2023-2030. Historically, the average annual energy growth rate was 0.43% from 2013-2022.

Figure 7-3: MID Forecasted Energy Requirement



7.2. 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.

7.2.1. 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 Integrated 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

7.2.1.1. 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

7.2.1.2. Econometric Model Building Process

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 Section7.2.1.1 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.

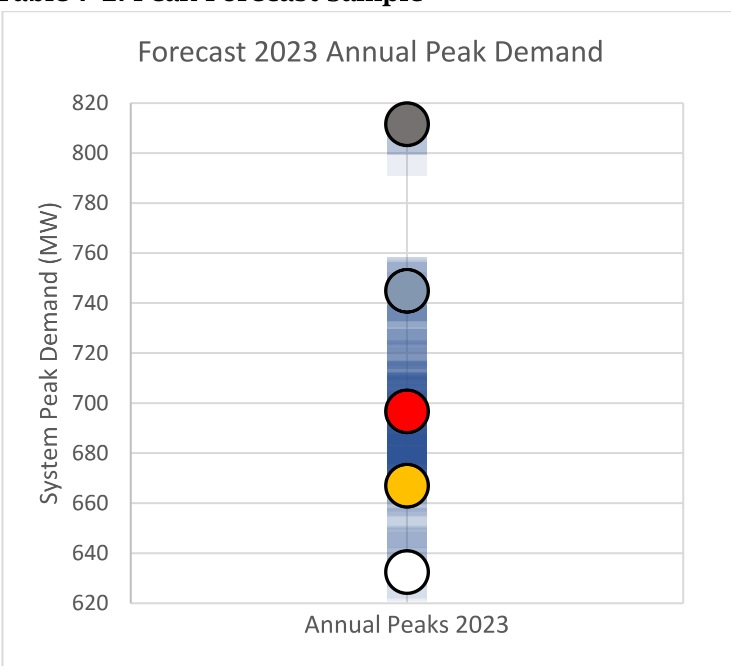
7.2.1.3. Weather Scenarios Building

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 (2023-2030), the 119 historical weather patterned scenarios were entered into the econometric regression model to generate approximately 952 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 7-2 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 7-2: Peak Forecast Sample



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

7.2.2. 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.

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.

7.2.3. 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.

7.2.4. Retail Sales Forecast and Retail Class Forecast

The retail sales forecast is derived from the total system forecast and is used primarily for energy accounting and rate-making decisions. The retail sales forecast was developed from historical net retail energy and received behind-the-meter (BTM) generation collected from customer meters and assumes 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 4.4%.

Energy received by MID from retail customers' BTM generation was projected using a monthly factor calculated using historical received BTM generation divided by total BTM generation and this factor ranged from 36% to 55% depending on the month. The received energy is added to the retail sales forecast to account for energy purchased by MID from customer supplied generation.

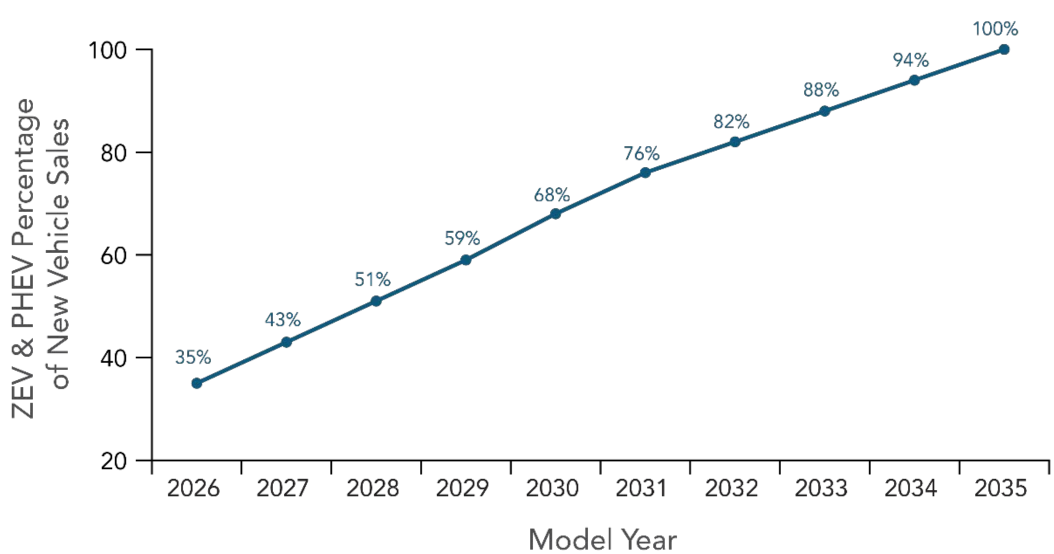
The retail class forecasts were derived from historical retail class ratios, which are the ratios of historical metered retail sales in each retail class to total retail sales. The set of average historical retail class ratios was applied to the 2023 LTDEF total retail sales forecast to derive a retail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

7.2.5. 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. 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 known EV projects occurring in MID's territory: The City of Modesto's bus electrification, Modesto City Schools (MCS) conversion to an all-electric bus fleet, and industrial customer 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 7-3.

Figure 7-3: Advanced Clean Cars II Regulations New Sale Adoption Rates



By the end of 2030, the projected EV contribution to MID's load is expected to be 110.6 GWh.

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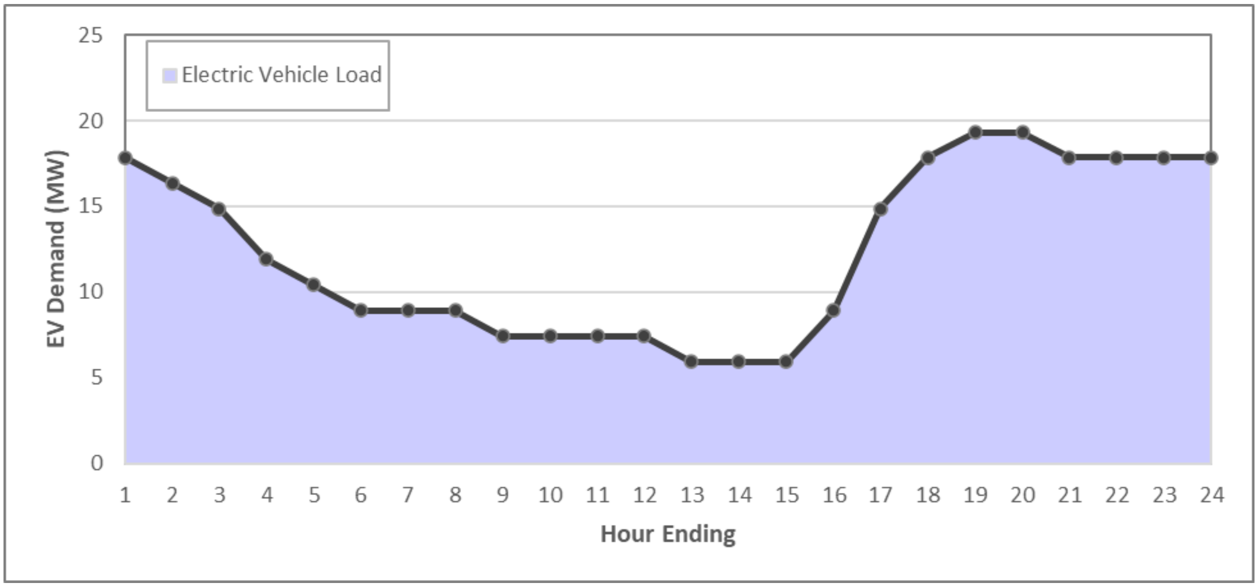
[3] California Air Resources Board. California moves to accelerate to 100% new zero-emission vehicle sales by 2035 | California Air Resources Board. (n.d.). Retrieved January 23, 2023, from https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035

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 known 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 7-4 is an example of the 24-hour charging load.

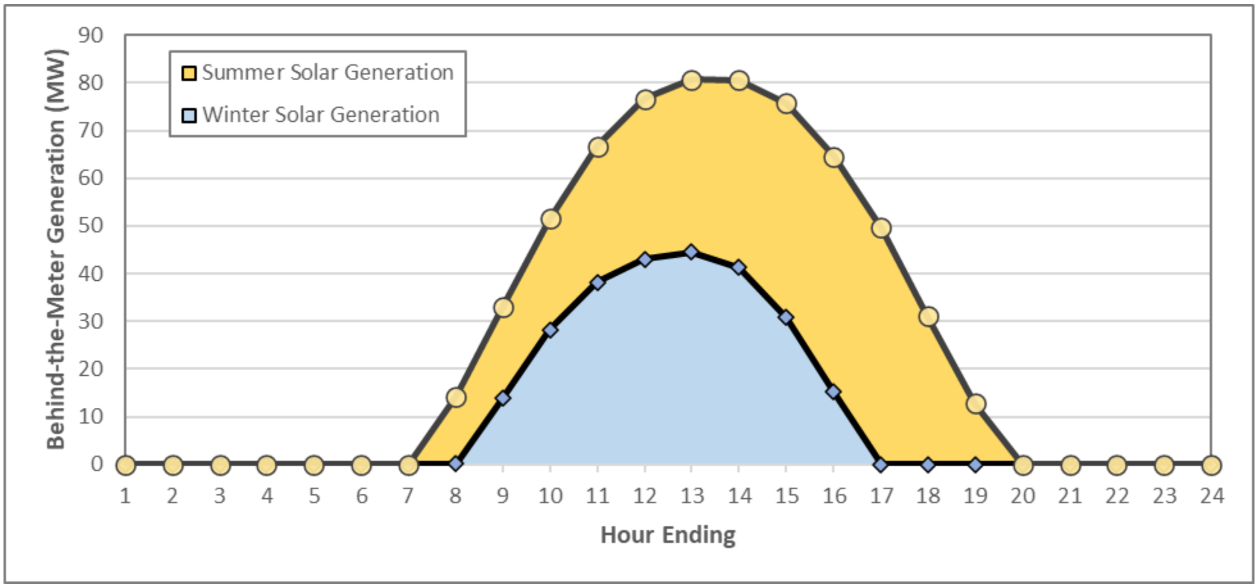
Figure 7-4: August 2030 Electric Vehicle Charging Pattern



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 191.7 GWh of system energy consumption annually by the end of 2030. Figure 7-5 shows a comparison of the average modeled distributed solar generation profile for MID's system in the winter and summer of 2030.

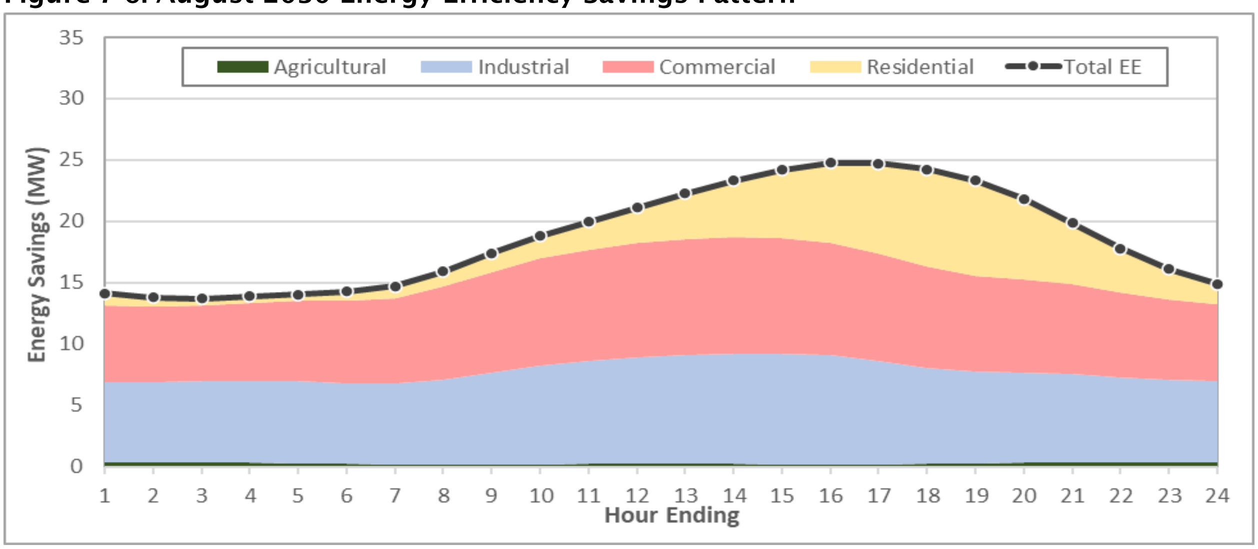
[4] Rocky Mountain Institute, 2016, "Electric Vehicles as Distributed Energy Resources".

Figure 7-5: 2030 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). Historical energy efficiency is based on incremental gross energy savings from energy efficiency programs implemented from 2015 to 2022. Forecasted savings for the next ten years are the energy efficiency 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 measure-specific 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 7-6.

Figure 7-6: August 2030 Energy Efficiency Savings Pattern



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

VIII. Portfolio Planning and Evaluation

8. Overview of Portfolio Planning and Evaluation

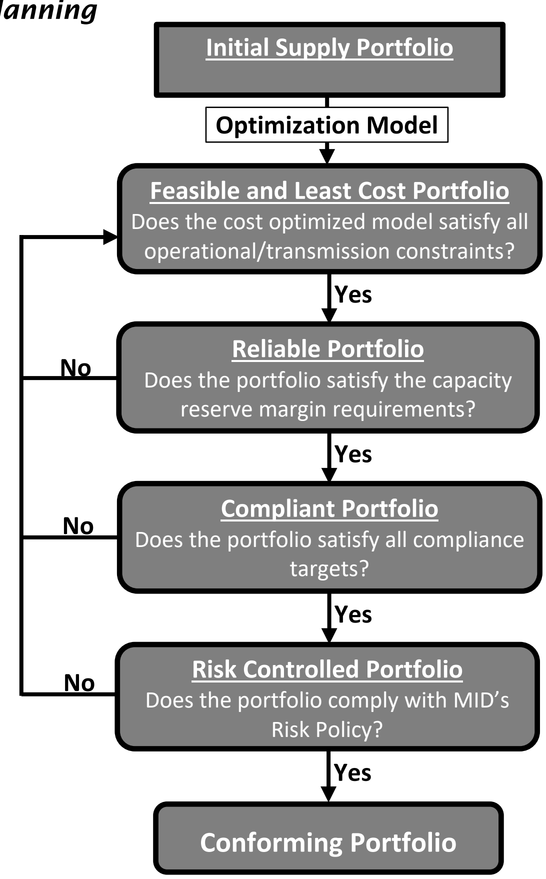
The primary objective of the resource planning process is to build a supply portfolio that satisfies compliance requirements, maintains reliability, and is economical. This chapter discusses how MID plans a feasible portfolio and examines the economics of the portfolio.

8.1. Portfolio Planning

MID uses production cost simulations to validate the operational feasibility and performance of different portfolio options. Production cost simulation is used to simulate the least-cost dispatch of generation resources to meet demand and ancillary service requirements of the system on an hourly basis, while satisfying all generator operational constraints, transmission constraints, and other system reliability requirements. The production cost simulation model, which considers detailed generator characteristics, ramping capabilities, and balancing load on an hourly basis, is used to assess the operational feasibility of resource portfolios in MID's power system.

Figure 8-1 illustrates the series of checks that MID runs on portfolio iterations through the optimization process to ensure that a long-term portfolio is reliable, follows compliance requirements, and minimizes risk at the least possible cost.

Figure 8-1: Portfolio Planning



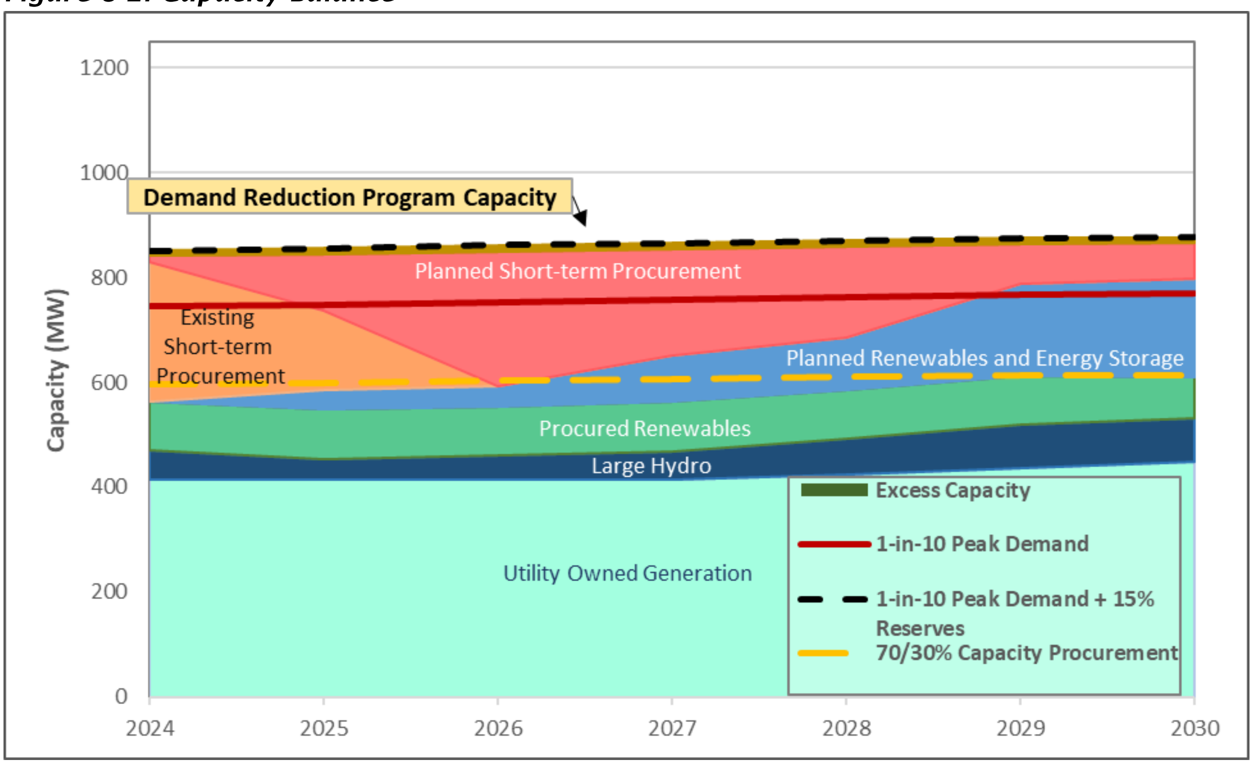
8.2. Capacity Requirement Evaluation

MID evaluates its resource adequacy based on the sum of the probability-adjusted 1-in-10 peak demand and a Planning Reserve Margin (PRM) of 15% of forecasted 1-in-10 peak demand, with adjustments for resources such as hydro and firm energy imports.

In 2013, MID's Board adopted Resolution 2013-04 which requires MID to plan on covering seventy percent of its total demand and PRM needs through long-term capacity commitments which can include owned resources and purchases with terms lasting at least 10 years, and thirty percent through short-term commitments of less than 10 years. While MID staff aims to meet the 70/30 ratio, mandatory procurement to meet certain targets, such as renewable portfolio standards and greenhouse gas standards, have made it increasingly difficult to maintain this ratio.

To develop a valid resource mix, MID staff calculates the capacity shortage and adjusts the supply stack until the capacity requirements are met. Once the adjustment process is complete, the production cost model is used to check the feasibility of the adjusted supply stack. As seen in Figure 8-2, long-term capacity procurement is expected to meet the 70% long-term capacity requirement in 2024.

Figure 8-2: Capacity Balance



8.2.1. Winter and Summer Peak Supply

MID's ability to serve load 24-hours a day is crucial to reliability and customer satisfaction. Each year MID analyzes its summer and winter supply stack under 1-in-10 conditions plus 15% planning reserves to ensure the resource portfolio's ability to serve load. As seen in Figure 8-3, demand through hour ending 16 will be met with MID's current supply portfolio. A small amount of additional reserve capacity will be needed to meet demand during peak hours, which will be met with short-term power purchases.

Figure 8-3: 2024 – 1-in-10 Summer Peak Demand

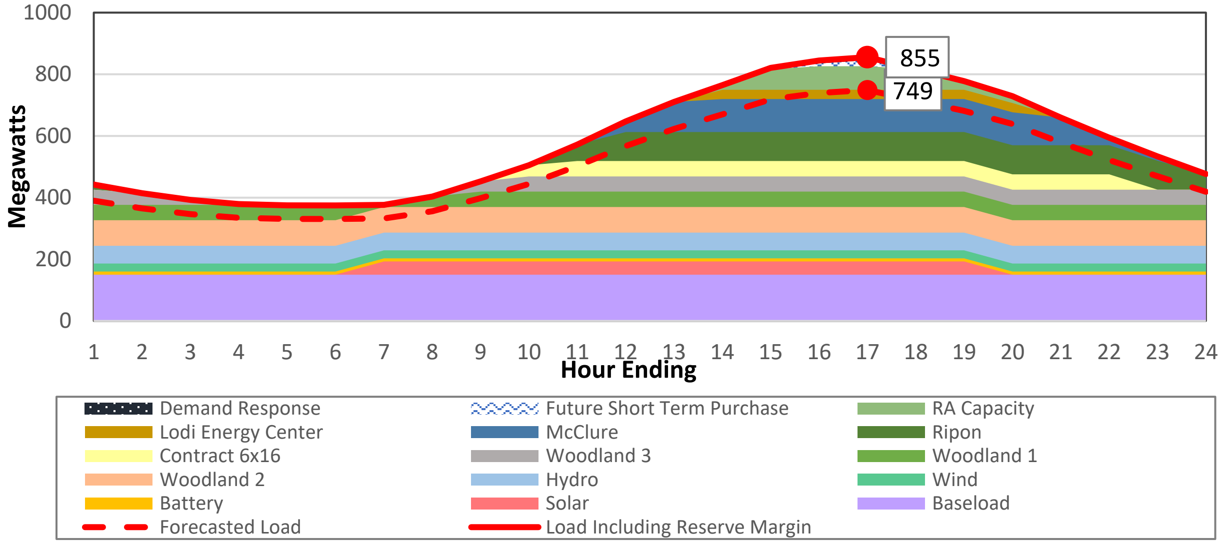
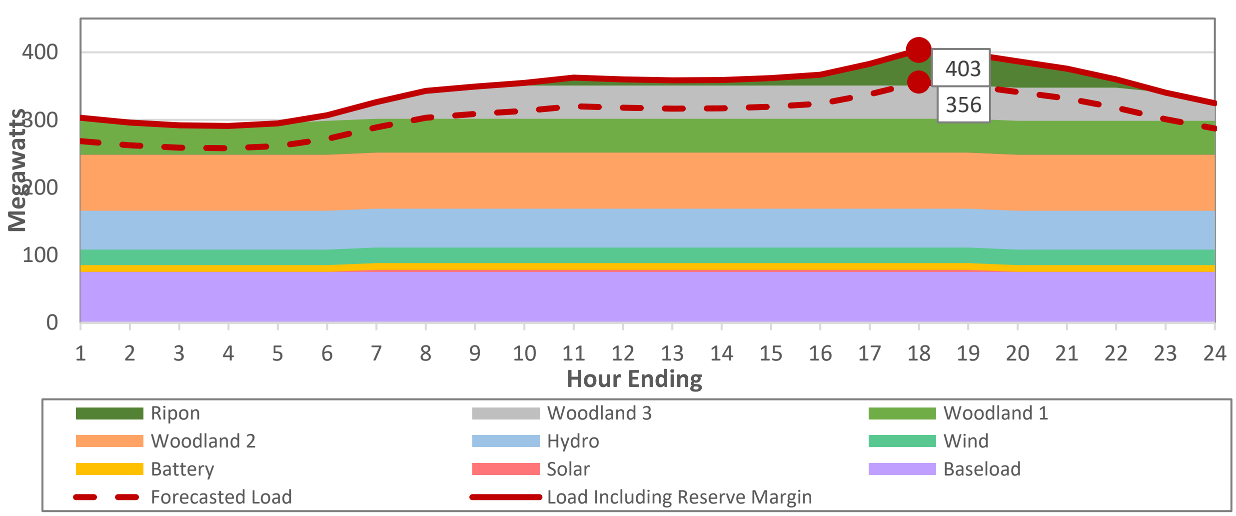


Figure 8-4 is an example of the supply stack under winter 1-in-10 peak conditions. MID's current supply of utility owned generation (UOG) and baseload contracts provide adequate supply to meet winter demand needs.

Figure 8-4: 2024 – 1-in-10 Winter Peak Demand

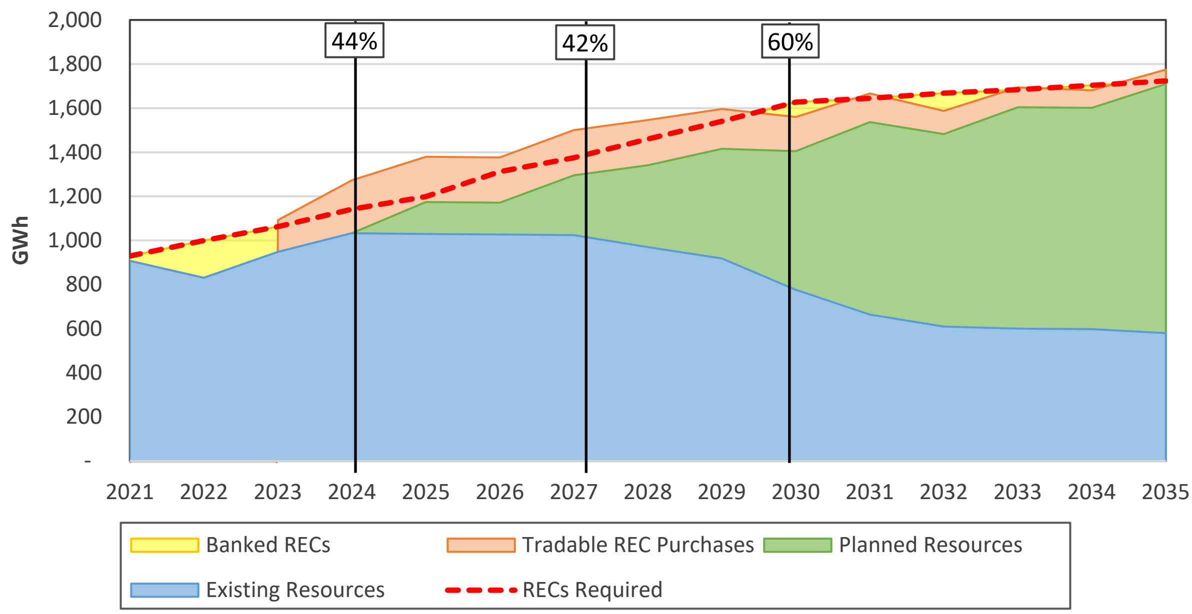


8.3. RPS Target Compliance

Meeting RPS compliance targets is a key focus of MID's portfolio planning process. As discussed in Chapter 5, by banking excess RECs from existing RPS-eligible renewable energy projects, purchasing short-term PCC1 RECs, and purchasing TRECs, MID could meet its SB 100 RPS targets through 2024 without adding any new resources. Generic renewable resources with projected energy prices are added in the planning process to account for future procurement of eligible projects that will be needed for RPS compliance. These generic resources will be replaced with specific projects as they are procured.

Figure 8-5 shows an illustrative depiction of MID's current RPS compliance trajectory.

Figure 8-5: RPS Trajectory



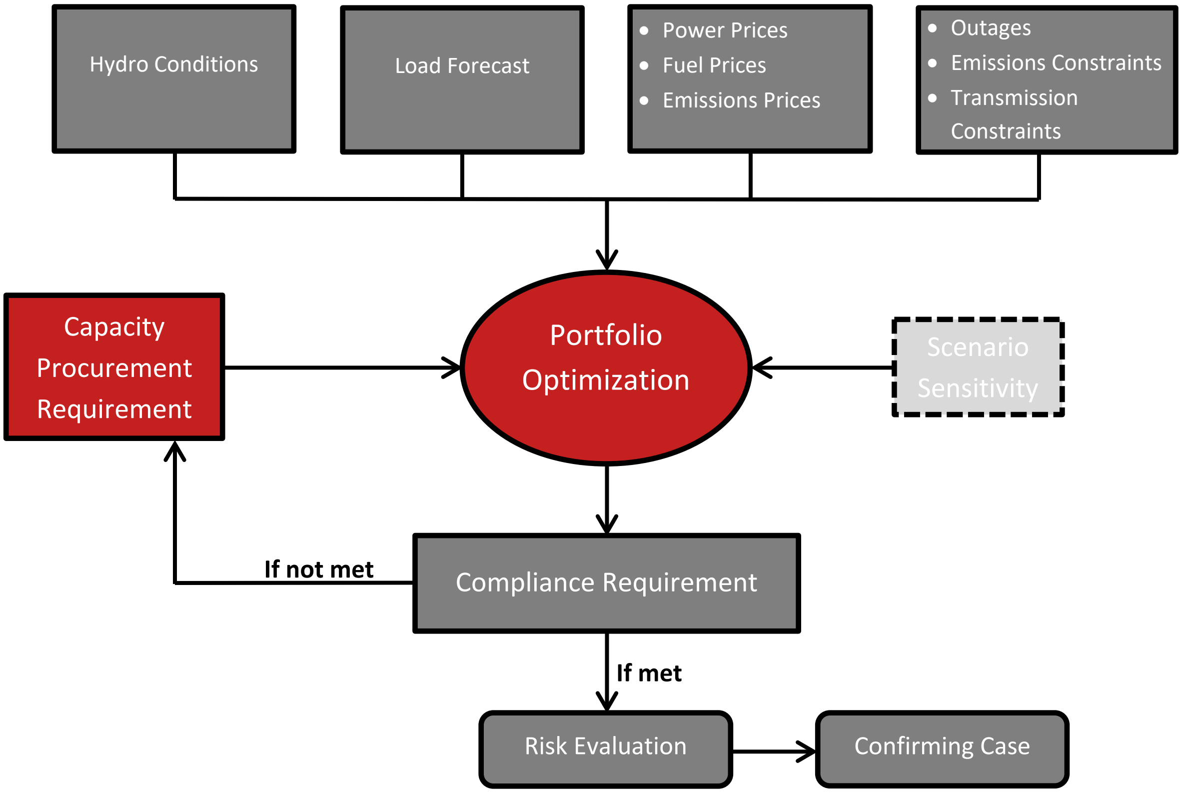
8.4. Production Cost Model

MID establishes its future energy supply planning portfolio based on three major supply categories: utility-owned generation, renewable portfolio, and market purchases.

MID builds the production cost model for its utility owned generation portfolio according to the physical characteristics and historical operating patterns of each plant. The market portfolio represents procurement from either bilateral contracts that have a negotiated pricing scheme, or short-term purchases either through financial hedges, or day-ahead energy transactions. Future renewable energy supply is expected to be procured from long-term bilateral arrangements to purchase the output from a qualifying renewable project over a defined term.

The production cost simulation model considers generator characteristics and forecasted market and load conditions on an hourly basis to simulate future operations. Figure 8-6 below depicts the inputs, outputs, and subsequent processes associated with the production cost model.

Figure 8-6: Portfolio Planning



8.4.1. Production Cost Model Input Assumptions

The following details the major input assumptions included in the 2024 production cost model.

8.4.1.1. Generator and Power Supply

The production cost model simulates the dispatch of MID's generator supply. Table 8-1 lists MID's owned generation assets and key unit characteristics that are included in the production cost model's generation portfolio.

Table 8-1: Utility Owned Generation Supply

Generation Units	Service Start Year	Plant Type	Fuel	Max Capacity-Summer (MW)	Max Capacity-Winter (MW)
Woodland 1	1993	Gas Turbine	Natural Gas	50	50
Woodland 2 (CTG:50 MW) (STC:33 MMW)	2003	Combined Cycle Gas Turbine	Natural Gas	83	83
Woodland 3 (6 Units Total)	2011	Reciprocating	Natural Gas	49	49
McClure 1	1980	Gas Turbine	Natural Gas/Diesel	53.5	53.5
McClure 2	1981	Gas Turbine	Natural Gas/Diesel	53.5	53.5
Ripon 1	2006	Gas Turbine	Natural Gas	48	48
Ripon 2	2006	Gas Turbine	Natural Gas	46	46
Lodi Energy Center	2012	Combined Cycle Gas Turbine	Natural Gas	30	30
*Claribel Generation**	2028	-	Natural Gas	48	48
Don Pedro	1973	Francis Type	Hydro	57	57
Power Smart	2023	DR	N/A	3	0
Interruptible	-	DR	N/A	10	0

* Capacity increases from 12MW in 2028 to 48MW in 2031

‘Power Smart’ and ‘Interruptible’ are demand response programs that do not deliver physical energy. Instead, these programs are called upon to reduce load, typically only during periods of high demand where other resources have already reached their maximum output. Because the Power Smart & Interruptible programs can be called upon, they are considered supply resources for capacity planning purposes.

In addition to MID’s thermal and hydro generation, the production cost model also considers energy generated or received through power purchase agreements (PPAs). Some of these resources are interconnected to and deliver their output to the CAISO system, while the output from others is delivered to MID’s system. Table 8-2 provides a list of resources under contract that were modeled in the 2024 Integrated Resource Plan.

Table 8-2: Purchase Power Contracts

Purchase Power Contracts				
Contract/Resource	**Contract Capacity (MW)**	**Fuel Type**	**Start Date**	**End Date**
WAPA	5	Hydro	2005	2024
Big Horn I	25	Wind	10/4/2006	9/30/2031
Big Horn II	33	Wind	11/1/2010	11/30/2035
Star Point	98.7	Wind	6/1/2010	5/31/2030
McHenry Solar	25	Solar	7/1/2012	6/30/2037
Stone Drop	0.26	Hydro	-------	-------
High Winds	50	Wind	6/1/2015	3/30/2028
New Hogan	5	Hydro	5/23/1983	5/23/2033
Mustang2	50	Solar	12/31/2019	12/30/2039
Blythe4	62.5	Solar	12/31/2020	12/31/2040
Mesquite Solar	52.5 (Solar) 10 (Battery)	Solar/Battery	7/31/2023	7/31/2043
Future Solar*	50-450	Solar	2025-2043	-
Future Batteries*	25-325	Battery	2025-2043	-
Future Baseload Renewable*	15-45	TBD	2030-2043	-
Future Wind*	50-150	Wind	2028-2043	-
Existing Market RA Purchases	77	Purchase	2024	-
Existing Market Purchases	75-200	Purchase	2024	2025
Planned Market Purchases	175	Purchase	2026	2043

* Contract capacity varies by year

8.5. Risk Controlled Portfolio

To minimize exposure to market volatility, MID follows a risk policy for energy procurement. MID's Risk Management Policy implements a Value-at-Risk (VaR) limit as well as position limits. The VaR is a financial limit expressed in dollar amount that caps the amount of money that the District is willing to risk the loss of, through exposure to market pricing, over a specified time period. Position limits for both electric power and natural gas procurement are set by the MID Board of Directors, and set boundaries for how much of the District's expected energy and natural gas needs must be hedged or "covered" in the current year and in forward years. This step in the production cost model includes checking planned procurement results against the Risk Management Policy, which is included in the Appendix.

8.5.1. Energy Position Limits

MID's Risk Management Policy sets a boundary limit on the amount of energy that MID must have procured for the following year. The policy sets this limit between 75 and 100 percent of forecasted system load. While compliance with the Risk Management Policy is managed by MID's Risk Oversight Committee, the Integrated Resource Plan must capture a resource procurement strategy that will facilitate compliance with the policy.

8.6. Greenhouse Gas

The State's cap-and-trade program is a market-based greenhouse gas (GHG) emissions reduction program covering approximately 80% of the state's economy-wide emissions in primarily the electric, industrial, and fuels sectors, and is currently authorized through 2030.

Entities with enough annual GHG emissions to qualify to be covered by the program must acquire and surrender a number of compliance instruments sufficient to cover their GHG emissions on an annual basis and per three-year compliance period. One compliance instrument is used to cover one metric ton of carbon dioxide-equivalent GHG emissions. This can be an allowance, or an offset representing GHG emissions avoided through various types of qualifying projects. The statewide emissions target is to achieve 40% below 1990 GHG levels by 2030.

MID receives an annual direct allocation of allowances to help reduce significant rate shock to electric customers. To maintain compliance with the cap-and-trade program, MID may use a combination of its allocated allowances, allowances purchased in quarterly auctions or bilateral markets, and offsets. MID's utility-specific GHG emission target is incorporated in this Integrated Resource Plan.

Compliance needs for the cap-and-trade program are considered with MID's RPS obligations to develop a resource acquisition strategy that meets compliance with both policies.

8.7. 2024 Conforming Case

A final conforming portfolio is generated after validating its feasibility, economics, reliability, compliance and risk. This conforming plan is the basis for the 2024 IRP. All current projections show compliance with state goals.

IX. Electric Transmission and Distribution (T&D) System

9. Overview of MID T&D System

MID provides electrical service to an area of approximately 568 square miles in portions of San Joaquin, Stanislaus, and Tuolumne counties. MID is the exclusive provider of electric services within its traditional service area of approximately 160 square miles and within the Mountain House Community Service District in San Joaquin County, which covers approximately 8 square miles. MID was authorized to become the sole provider in the Mountain House Community Service District under Public Utilities Code Section 9610. MID was authorized by AB 2638 to compete with PG&E to provide service to customers in a 400 square mile joint electric distribution service area.

Each year, MID performs an evaluation and study of the electric transmission system to assess its compliance with NERC/WECC Standards and to evaluate its general reliability and operational flexibility.

9.1. Transmission and Distribution System

This section provides an overview of MID's transmission and distribution assets. Each year MID updates its five-year plan, which provides a system assessment for the next five calendar years with the focus primarily on summer peak demand. The five-year plan includes analysis for both the transmission system (69 kV – 230 kV) and distribution system (6.9 kV – 21 kV).

9.1.1. Bulk Transmission System

The MID transmission system consists of 142.5 miles of 230 kV and 37.7 miles of 115 kV transmission lines that route power through three intertie stations to step power down from 230 kV and 115 kV to 69 kV. There are 203.73 miles of 69 kV lines that serve the thirty-eight (38) substations within MID's system. Figure 9-1 illustrates how MID is situated relative to the other agencies within the Balancing Authority of Northern California ("BANC") balancing authority area along with some key high-voltage transmission lines and substations.

MID's Bulk Electric System (BES) transmission facilities are listed below:

1. Westley Switching Station – 230 kV Station jointly owned with TID
2. Rosemore – 230 kV Transmission Substation
3. Parker – 230 kV Transmission Substation
4. Standiford – 115 kV Transmission Substation
5. Santa Cruz – 115 kV Transmission Substation
6. Claus – 115 kV Transmission Substation

Import capability is critical for MID's operations, and as such MID together with other northern California cities and utilities, is a member of a California joint powers agency known as the Transmission Agency of Northern California ("TANC"). TANC, together with the Western Area Power Administration ("WAPA"), the Department of Water Resources, the City of Shasta Lake, Carmichael Water District, the City of Vernon, San Juan Suburban Water District, and PG&E own the California-Oregon Transmission Project

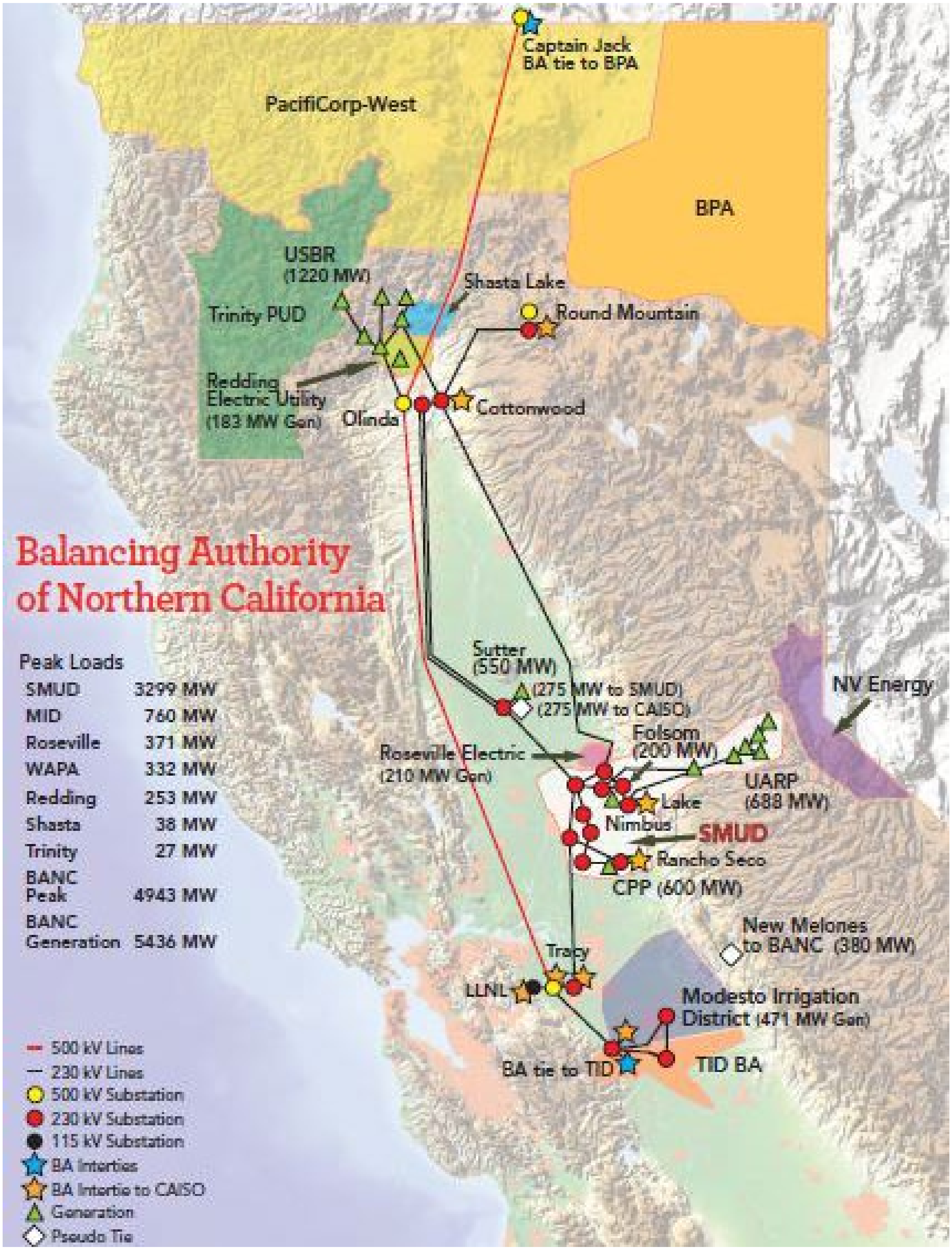
("COTP"), a 339-mile, 1,600 MW, 500 kV transmission project between southern Oregon and central California. The southern physical terminus of the COTP is near PG&E's Tesla substation. MID's connection to the COTP is through MID's 230 kV Westley-Tracy transmission line, via WAPA's 500 kV Tracy substation.

To the south of MID's system, PG&E provides TANC and certain other entities with approximately 300 MW of firm, bi-directional transmission service on its transmission system from the Midway substation near Buttonwillow, California (the "Tesla-Midway Service") under a long-term agreement known as the South of Tesla Principles ("SOT"). MID's share of Tesla-Midway service is 102 MW. Table 9-1 lists MID's transmission rights on these transmission paths.

Table 9-1: Transmission Rights on Bulk System

MID Tramsmission Rights	Paths	Direction	Capacity (MW)	Firmness	Notes
COTP	Captain Jack to Tracy	Southbound	320	Firm	MID COTP rights will step down to 311 MW by end of 2024, and 286 MW by end of 2039
SOT	Westley to Midway	Southbound	102	Firm	
COTP	Tracy to Captain Jack	Northbound	314	Firm	MID COTP rights will step down to 305 MW by end of 2024, and 280 MW by end of 2039
SOT	Midway to Westley	Northbound	102	Firm	

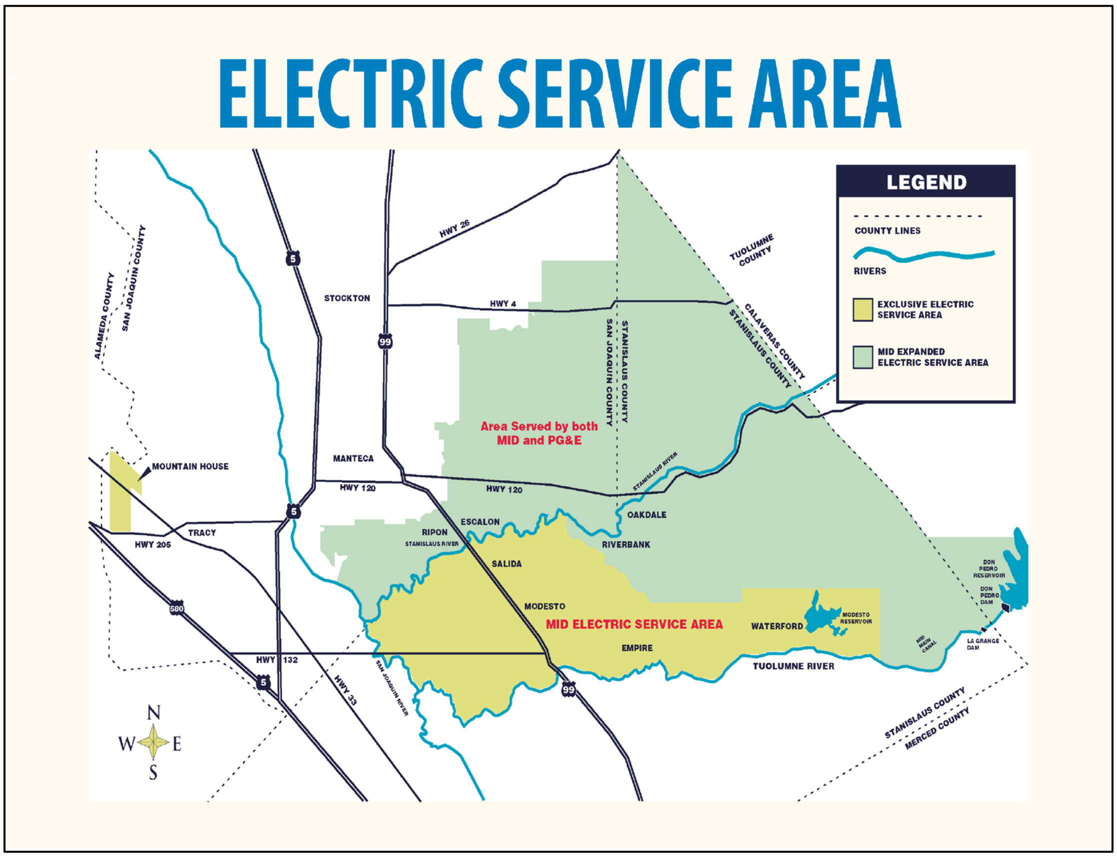
Figure 9-1: Balancing Authority of Northern California



9.1.2. Distribution System

MID's distribution system consists of over 1,000 miles of distribution lines and 35 distribution substations over the 160 square mile territory shown in Figure 9-2. The traditional 12 kV distribution system currently includes all of Modesto and its surrounding communities (Empire, Waterford, and Salida). In addition, MID also serves portions of the cities of Riverbank at 12 kV, and Ripon, Escalon, and Oakdale at 17 kV (together, the "Four Cities"). Further, MID also serves the community of Mountain House at 21 kV. The MID traditional distribution service territory is divided into six (6) planning areas with two (2) additional areas for the Four Cities and Mountain House. The planning areas are defined by electric boundaries, which limit load transfers. The substations within each planning area are electrically adjacent to each other. This means that each substation has the ability to back-up others in the area.

Figure 9-2: MID Electric Service Area



9.2. Transmission Assessment 2022

MID's most recent NERC/WECC Annual Electric Transmission System Assessment study completed in 2022 demonstrated that MID's transmission system is currently designed and operated in compliance with the NERC/WECC Reliability Standards. However, actions to address the requirements of several new NERC standards must be implemented by 2026 in order to comply with the new standards once they become effective in 2029. MID is currently investigating projects to address the associated corrective action plans.

MID also conducts its own general evaluation study of its transmission system to determine that it will be able to deliver customer loads in a safe, reliable, operationally flexible, and cost-effective manner while maintaining compliance with NERC/WECC planning criteria. Approximately 11,000 steady state simulations were studied and over 300 stability simulations were performed per case to ensure reliablilty. Also, contingency definitions were further reviewed and refined. The use of a criteria screener for dynamic simulations increased accuracy for stability simulations.

Both the NERC/WECC and general transmission assessments demonstrated the capability of the MID transmission system to meet our customers' and NERC/WECC expectations; however, they did identify some areas of the system where improvements could be made. The following are projects that have been identified to address the improvement areas found in the assessments:

In-Progress Projects

- Clough - Stockton 69kV Line Re-route
- Westley 230kV Bus Differential Relays

Near Term Projects

- Mountain House Substation Expansion and 69kV Lines (local system capacity and redundancy upgrade)
- Spare Claus Transformer (reliability upgrade)
- Hershey Tap Upgrade (reliability upgrade)
- Standiford 115kV Bus and Transformer Upgrade (address affecting generator interconnection overloads)

Future Potential Projects (Beyond 2024-2028 Plan)

- A Second Source for the Hershey Substation

9.3. Distribution Assessment 2022

MID's distribution planning process includes a five-year distribution system plan that is refreshed annually and is built on careful evaluation of past, present, and future-forecasted system conditions to identify deficiencies and strategize optimal infrastructure investments anticipated over the five-year horizon to address capacity and reliability requirements. The distribution planning goal is to plan for safe and reliable electric service for all MID customers at the lowest possible cost. The approach towards achieving this goal is described by:

1. Distribution System Evaluation
    - Monitoring and analyzing distribution system configurations and performance
    - Forecasting distribution system loads
    - Monitoring community development plans and issues
    - Reviewing and analyzing the implications of land-use proposals
    - Analyzing and developing solutions for distribution operating and reliability issues

2. Distribution System Design
    - Developing long range plans for system design and configuration
3. Primary circuit designs for residential and commercial plans
4. Distribution System Planning
    - Developing project proposals to construct or modify distribution system facilities including feeders and substations
    - Establishing project priorities
    - Budgeting and scheduling projects based upon system requirements, customer needs, and available resources
    - Reliability
    - Monitor system performance and develop mitigation recommendations
    - Develop and right-size programs to meet system reliability limits
    - Establish project priorities
    - Participate in equipment root-cause investigations

Multiple capital projects are scheduled every year to improve the system. These projects may include constructing new substations, reconductoring underground feeder getaways, and protective relay replacements. A short list of some of the major capital projects scheduled from 2023-2028 are:

- Mariposa B54 Line Extension (2023)
- Claribel B46 Reconductor (2024)
- New Claribel Transformer (2024-2025)
- Enslen B62 Reconductor (2025)
- New Claribel Feeder (2025)
- Stoddard B46 Line Extension (2028)
- Briggsmore B48 Line Extension (2028)

MID distribution network reliability indices show that MID's distribution network has not experienced material stress caused by Distributed Energy Resources (DERs). A review of MID outage data shows that the top 5 outage causes are not directly related to DERs (vehicle/pole collisions, distribution transformer failures, overhead fuse failure, birds, balloons, and unclassified are the top outage causes).

The System Average Interruption Duration Index (SAIDI) is a statistical representation of the amount of time the average electric utility customer was without electric power in a year and is a commonly used metric by utilities. The SAIDI is calculated by taking all of MID's customer outage minutes and dividing by the total number of MID customers. MID's SAIDI for 2021 was 37 minutes compared to the average SAIDI of 121 for reporting California utilities and 138 nationwide. MID expects to improve its SAIDI value further due to initiatives in underground cable installations, avian protection, tree trimming, overhead #6 copper replacement, transformer load management, and small mammal protection.

9.4. Grid Impact of Load Growth and Renewable Resources

Among the eight geographic MID distribution areas, two are expected to experience significant load growth through the next five years. One of the area's expected growth is driven by commercial and industrial load additions, and the other is driven by residential load additions. MID continues to monitor, research, and evaluate the forecasted load impact of electrification of the vehicle sector and the transition of other fossil fuel equipment like water heaters and boilers and sees the impact of these load additions as a much larger driver for distribution planning and upgrade solutions than the continuing integration of customer distributed energy resources (DER). While MID's distribution system has not experienced material adverse impacts from DERs, MID continues to monitor its system for impacts and necessary upgrades.

X. Disadvantaged Communities

10. Overview of MID Facts

Approximately 35%[1] of MID electric service area residents live within the disadvantaged communities shown in Figure 10-2.

10.1. Retail Rate Assistance Programs

MID offers a discounted rate for qualifying low-income customers. The MID CARES (Community Alternative Rate for Electric Service) program reduces the fixed monthly charge from $30.00 to $12.00 and applies a 23% discount on the first 850kWh used each month for a period of up to three years, or as long as the household qualifies. At the end of 2023, there were 8,113 customers enrolled in the CARES program. On average, customers in the CARES program saved $36.83 each month in 2023. The total benefits realized by CARES customers in 2023 was approximately $3.4 million. This program comprises a substantial portion of MID's annual public benefits funding allocation.

MID also offers a Medical Life Support (DLS) Rate for customers who need electricity for life-sustaining devices or who have a condition or disease that requires special heating or air conditioning. The DLS rate reduces the energy rate of the customer's first 500 kWh by 50% for each billing cycle. There were 1,054 customers enrolled in the DLS rate at the end of 2023. Customers on the DLS rate saved $25.53 on average for each month in 2023. The total discount realized by DLS customers in 2023 was approximately $326,000.

Additionally, MID's Good Neighbor Program is available for customers who seek emergency assistance with their electric bills. MID partners with the Salvation Army to receive donations and enables a designated fund to be applied to customers who experience hardship.

10.2. Barriers to Investment in Energy Efficiency

Studies have shown that the typical low-income household in the United States spends upward of 15 to 20 percent of their total monthly income on energy costs. This expense often competes with other necessities such as groceries, utilities, education, and health care.

Cash flow concerns and a lack of available credit are major barriers that limit the ability of low-income customers to invest in energy efficiency. Most energy efficiency retrofits require available cash or credit upfront. Low-income households that own their home find it challenging to come up with the short-term cash investment even though there is likely a long-term return. Low-income households that rent have

[1] The number of residents in disadvantaged communities within MID's service territory was calculated by summing the number of residents living within the disadvantage areas defined by CalEPA methodology (as listed in https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40) and then divided by total residents in the census tracts serviced by the District.

limited incentive to make improvements to dwellings that are not their own. Also, low-income households tend to have less available credit for purchases, including those that reduce their utility bills.

Most low-income households are renters. Whether it be a multifamily or single-family dwelling, most energy efficiency improvements depend on the willingness of the landlord to make the investments. In the MID service territory, the affordable home inventory is very low and even most affordable multifamily residences have a long waiting list. The minimal supply of affordable housing and high customer demand does not provide any incentives for the landlord to make energy efficiency improvements.

10.2.1. Energy Efficiency in Disadvantaged Communities

MID's Weatherization Program provides energy efficient measures to rental or owner-occupied low-income customer homes. The program's scope may include replacement of broken windows, refrigerator, microwave, swamp coolers, or installation of insulation, sunscreens, weather stripping, and some types of home repairs. Customer eligibility is determined by the same income qualifications as the MID CARES Program. Customer demand for the program typically exceeds its annual budget amount. Energy savings from the Weatherization Program are included in the results for the annual SB1037 report to the CEC.

MID observes that the locations of the Weatherization Program service points show significant overlap with the location of local disadvantaged communities. A visual comparison of the weatherization projects map (Figure 10-1), and the local disadvantaged communities map (Figure 10-2) illustrates the correlation.

Figure 10-1: MID Service Area Weatherization Projects

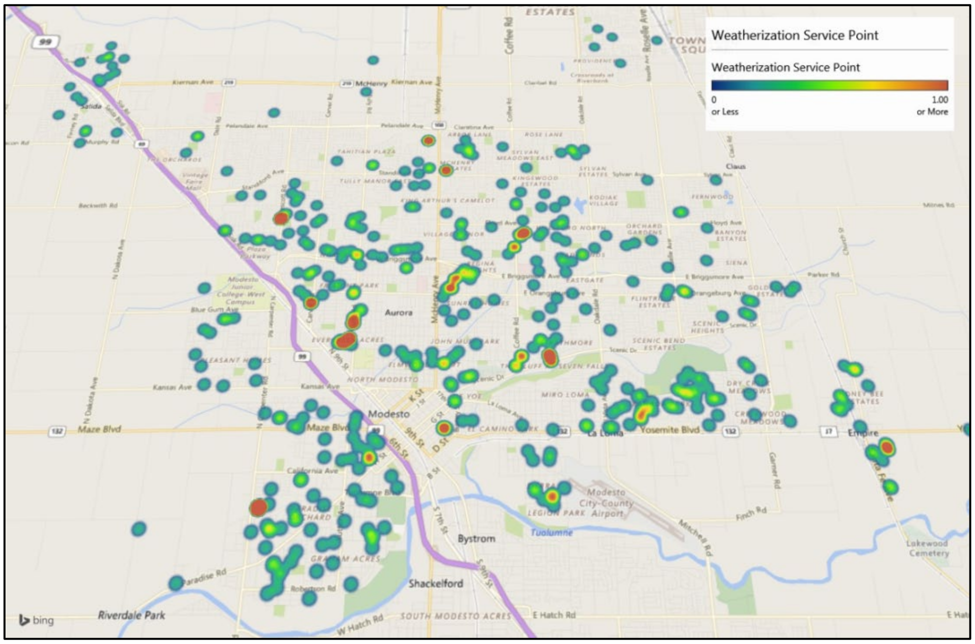
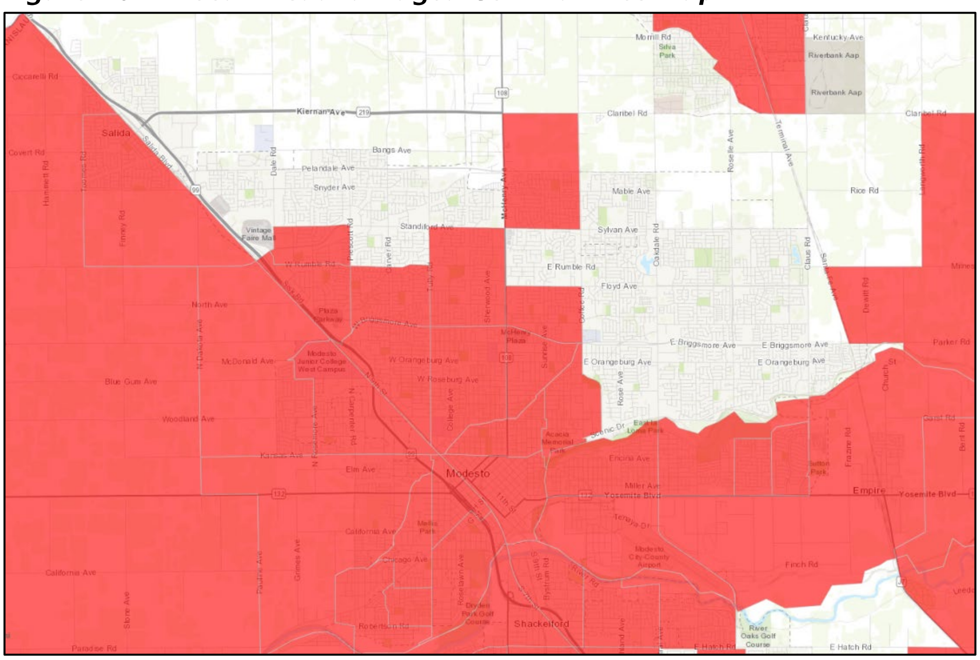


Figure 10-2: Local Disadvantaged Communities Map[2]



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[2] https://oehha.ca.gov/calenviroscreen/sb535

XI. Rate Impact Analysis

11. Major Risk Components

As a publicly owned utility, Modesto Irrigation District strives to provide its customers with just and reasonable rates, while achieving its compliance obligations for increased renewables and lower GHG emissions.

Properly managing energy supply costs is key to MID maintaining consistently low retail rates. This chapter covers MID's major risk components that could affect customer retail rates in the future. The three risk components that MID identifies are: energy supply costs, capital expenditures, and market volatility.

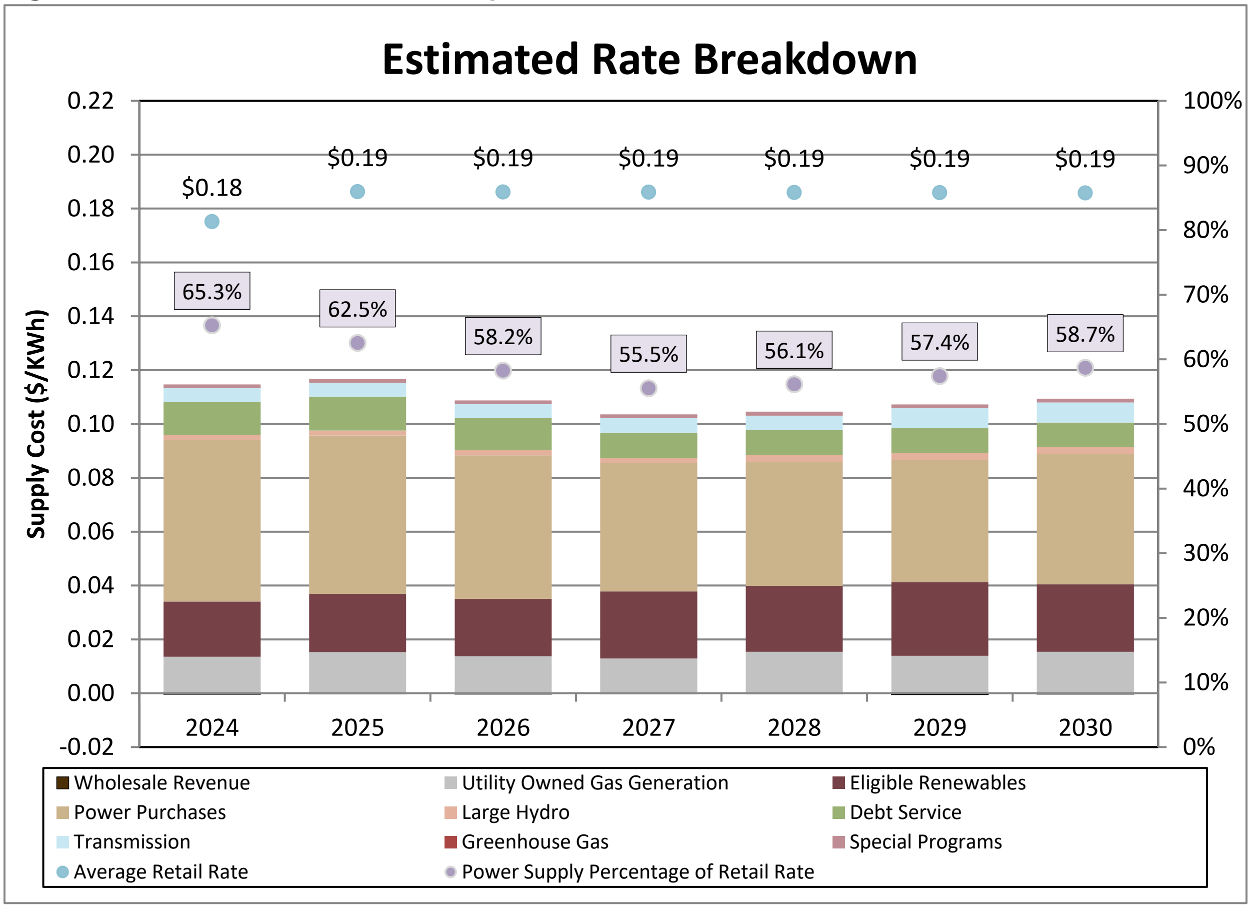
11.1. Energy Supply Costs

Costs related to energy supply make up approximately 56 to 65 percent of MID's electricity retail rates. MID has identified 7 cost components that have the largest impact on energy supply costs:

- Eligible Renewables Procurement
- Debt service
- Power Purchases
- Utility Owned Gas Generation
- Transmission
- Greenhouse Gas
- Special Programs

Under the current policy and portfolio assumptions, MID expects relatively minor changes in overall power supply costs from 2024 to 2030. The estimated energy supply cost for 2024 is $115.40/MWh. By 2030, the supply costs are expected to be approximately $110.00/MWh. However, energy supply costs are subject to volatility and could increase due to the uncertainty of statewide renewable requirements, GHG costs, or changes in market conditions; this IRP presents a snapshot of current projections.

Figure 11-1: MID Estimated Rate Impacts Breakdown



11.1.1. Eligible Renewable Resources

Eligible Renewable Resources are expected to be MID's second-largest supply expense in 2024 with an estimated cost of $54 million. This makes up roughly 12% of MID's retail rates. The current eligible renewables costs do not include potential resources that have not yet been studied in detail. For example, energy storage and additional resources or tools to integrate increasing amounts of renewable energy by responding to generation variability are not considered. Eligible renewable resources costs are estimated to be $69 million in 2030 and to make up 14% of retail rates.

11.1.2. Power Supply Debt Service

Debt service expenses are projected to be $32 million in 2024, accounting for 7% of MID's retail rates. MID has made significant progress in both reducing its electric debt and shortening its debt maturity through the refinancing of bonds. As a result of this effort, supply-related debt is expected to decrease to an estimated $25 million by 2030, reducing its contribution to retail rates to 5%. However, this projection does not account for new financing that may be needed for future resources.

11.1.3. Power Purchases

Costs for power purchases are costs to procure non-renewable power from other parties. Power purchases are currently MID's largest energy supply expense at an estimated $158 million in 2024 and will represent 34% of 2024 retail rates. Power Purchase costs are expected to be $133 million by 2030, making up 26% of retail rates. The decrease in power purchase costs from 2024 – 2030 is mostly attributed to normalization of energy market prices. The current energy price is relatively high along with the current economic environment which has seen higher-than-normal inflation and lingering supply chain issues driving up costs economy-wide. MID expects that macroeconomic conditions will eventually regress to normal along with increased investment in transmission and generation capacity in the western United States should result in some downward pressure on this category in the mid-to-long term; however, power purchase cost has significant exposure to market risk.

11.1.4. Utility Owned Gas Generation

MID owns eight gas burning generation plants. They are projected to stay in service throughout the IRP planning horizon. The utility owned generation (UOG) expenses are costs associated with fuel and operating and maintenance costs. The UOG costs are estimated to be $36 million in 2024, making up 7% of retail rates. Due to increased natural gas transportation rates on the PG&E system, MID expects UOG costs to increase by an average 2.2% annually from 2024 - 2030. As a result, UOG expenses are expected to be $42 million in 2030, making up 8% of retail rates.

11.1.5. Energy Supply Related Transmission Expense

Energy supply related transmission expenses in 2024 are expected to make up 3% of retail rates at a total expected cost of $14 million. This category cost is expected to be $21 million in 2030, making up 4% of retail rates. Increased transmission expenses are driven by increasing costs associated with CAISO's Transmission Access Charge.

11.1.6. Greenhouse Gas

Greenhouse gas emission compliance is one of MID's compliance goals. Thanks to MID's divesture of its share of the San Juan coal plant, MID's annual emissions have substantially decreased from 2017, which was the last year in which coal-fired generation was included in MID's supply portfolio. Allocated cap-and-trade allowances provided to MID to reduce significant rate impacts to electric customers are expected to continue to protect MID rate customers from major cost impacts through the IRP horizon; however, this assumption is based on current regulations and cap-and-trade allocation schedule and could change if the regulations are revised.

11.1.7. Special Programs

Special programs are programs MID has sponsored to promote renewable energy, energy efficiency, or demand response. The programs are mainly customer programs, such as the SB1 solar rebate program, lighting rebate programs, and demand response programs. These programs are expected to cost $3 million in 2024. Costs associated with existing committed special programs are expected to remain steady throughout the IRP Planning horizon.

11.2. Capital Expenditure Impact to Rate

Electric utilities rank among the most capital intensive of businesses. Thus, cost of capital and access to capital are central concerns of the District as it seeks to maintain affordable rates while de-carbonizing its generation portfolio and building infrastructure to enable the electrification of economic sectors currently dependent on fossil fuels.

Traditionally, utilities recover costs of supply and costs of capital through retail sales revenues. Developments such as energy efficiency, distributed generation, and distributed storage make cost recovery less certain. This creates downward pressure on borrowing capacity and upward pressure on borrowing cost. Besides energy supply costs, the cost of capital will likely be an increasingly impactful component to future retail rates and will be greatly affected by rising interest rates.

11.2.1. Market Volatility

Energy markets are very active and volatile markets. Energy prices vary by location, and the supply of the energy is constrained by multiple factors including transmission capabilities.

A strong argument can be made that the direction of alternative energy sources (e.g., nuclear, renewables, storage, energy efficiency, and demand response) will have a significant impact on regional gas and electricity prices.

To safeguard customers' exposure to market volatility, the MID Board of Directors maintains a Risk Management Program most recently revised on May 24, 2016, which provides controls for the operational, price, and credit risks of MID's power trading and natural gas acquisition operations. The Risk Management Program policy addresses roles and responsibilities, authorized and prohibited transactions, exposure limits, transaction and market data collection procedures, and reporting requirements. Day-to-day risk management activities are carried out by a Risk Management Oversight Committee and a Pricing/Risk Management Administrator. MID uses a number of methods to mitigate market risk and credit risk using short-term and long-term contracts in addition to local generation which provides a long-term hedge against market volatility.

Standardized Reporting Tables
for Publicly Owned Utility IRP Filing
California Energy Commission
Energy Assessment Division

POUs must submit the following four Standardized Tables to the Energy Commission as part of the IRP Filing. The Energy Commission encourages POUs to submit data for multiple scenarios, though POUs are only required to submit data for one scenario that meets the requirements of PUC Section 9621. Annual data must be reported in the Standardized Tables through the planning horizon.

Instructions for filling out the tables are in Appendix B Standardized Reporting Tables

Description of Worksheet Tabs

Admin Info: A listing of contact information of the tables' preparer with information for any back-up personnel.

CRAT: Capacity Resource Accounting Table (CRAT): Annual peak capacity demand in each year and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.

EBT: Energy Balance Table (EBT): Annual total energy demand and annual estimates for energy supply from various resources.

GEAT: GHG Emissions Accounting Table (GEAT): Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.

RPT: Resource Procurement Table (RPT): A detailed summary of a POU resource plan to meet the RPS requirements.

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Administrative Information
Form CEC 113 (May 2017)

Name of Publicly Owned Utility ("POU")	Modesto Irrigation District
Name of Resource Planning Coordinator	Brock Costalupes
Name of Scenario	2024IRP

Persons who prepared Tables	**CRAT**	**Energy Balance Table**	**Emissions Table**	**RPS Table**	**Application for**
Name:	Samuel Arellano	Samuel Arellano	Noah Wells	Noah Wells	
Title:	Resource Planner	Resource Planner	Resource Planner	Resource Planner	
E-mail:	samuel.arellano@mid.org	samuel.arellano@mid.org	noah.wells@mid.org	noah.wells@mid.org	
Telephone:	(209) 557-1335	(209) 557-1335	(209) 526-7415	(209) 526-7415	
Address:	1231 11th Street	1231 11th Street	1231 11th Street	1231 11th Street	
Address 2:					
City:	Modesto	Modesto	Modesto	Modesto	
State:	CA	CA	CA	CA	
Zip:	95354	95354	95354	95354	
Date Completed:	11/3/2023	11/3/2023	11/3/2023	11/3/2023	
Date Updated:	2/29/2024	2/29/2024	2/29/2024	2/29/2024	

Back-up / Additional Contact Persons for Questions about these Tables (Optional):

Name:	Brock Costalupes				
Title:	Interim Resource Planning & Development Manager				
E-mail:	Brock.Costalupes@mid.org				
Telephone:	(209) 526-7397				
Address:	1231 11th Street				
Address 2:					
City:	Modesto				
State:	CA				
Zip:	95354				

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Capacity Resource Accounting Table
Form CEC 109 (May 2017)

Scenario Name:

Yellow fill relates to an application for confidentiality.
Data input by User are in dark green font.

Units = MW

	PEAK LOAD CALCULATIONS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Forecast Total Peak-Hour 1-in-2 Demand	680	760	705	699	702	706	710	713	717	722
2	[Customer-side solar: nameplate capacity]	59	69	78	84	91	98	105	111	118	124
2a	[Customer-side solar: peak hour output]	16	19	20	35	38	42	49	48	50	45
3	[Peak load reduction due to thermal energy storage]	0	0	0	0	0	0	0	0	0	0
4	[Light Duty PEV consumption in peak hour]	2	2	3	5	6	7	10	10	15	18
5	Additional Achievable Energy Efficiency Savings on Peak	13	13	16	16	17	19	21	22	23	24
6	Demand Response / Interruptible Programs on Peak	0	15	0	7	7	7	7	7	7	7
7	**Peak Demand (accounting for demand response and AAEE) (1-5-6)**	667	732	690	677	679	680	683	685	688	692
8	Planning Reserve Margin	100	110	103	106	107	109	109	109	108	107
9	Firm Sales Obligations	0	0	0	0	0	0	0	0	0	0
10	**Total Peak Procurement Requirement (7+8+9)**	767	842	793	783	786	789	792	794	796	799

EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES

Utility-Owned Generation and Storage (not RPS-eligible):

For fuel type, choose from list or enter value

	[list resource by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11a	Woodland1	Natural Gas	43	43	50	50	50	50	50	50	50	50
11b	Woodland2	Natural Gas	83	83	83	83	83	83	83	83	83	83
11c	Woodland3	Natural Gas	49	49	49	49	49	49	49	49	49	49
11d	Ripon1	Natural Gas	48	48	48	48	48	48	48	48	48	48
11e	Ripon2	Natural Gas	46	46	46	46	46	46	46	46	46	46
11f	McClure1	Natural Gas	54	54	54	54	54	54	54	54	54	54
11g	McClure2	Natural Gas	54	54	54	54	54	54	54	54	54	54
11h	DON PEDRO	Large Hydroelectric	62	62	58	58	42	48	56	68	83	83
11i	Lodi Energy Center	Natural Gas	30	30	30	30	30	30	30	30	30	30
11j	Claribel	Natural Gas	0	0	0	0	0	0	0	12	24	36
11k												

Long-Term Contracts (not RPS-eligible):

	[list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11l	WAPA CVP	Large Hydroelectric	1	2	5	0	0	0	0	0	0	0
11m	CCSF	Large Hydroelectric	0	0	0	0	0	0	0	0	0	0
11n	ACS Specified Energy	Unspecified/System	100	25	0	0	0	0	0	0	0	0
11o	Non-Specified Energy	Unspecified/System	126	225	275	200	150	0	0	0	0	0
11p	Capacity Contracts	Unspecified/System	0	0	0	67	0	0	0	0	0	0
11q												
11	**Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a…11n)**		695	720	751	738	605	461	469	493	520	532

Utility-Owned RPS-eligible Resources:

	[list resource by plant or unit]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12a	Stone Drop	Small Hydroelectric	0	0	0	0	0	0	0	0	0	0
12b												

Long-Term Contracts (RPS-eligible):

	[list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12c	BigHorn	Wind	8	7	4	7	7	7	7	7	7	7
12d	BigHornII	Wind	3	3	3	3	3	3	3	3	3	3
12e	Fiscalini	Biofuels	0.75	0	0	0	0	0	0	0	0	0
12f	McHenry Solar	Solar PV	14.5	10.1	16.2	13	13	13	13	13	13	13
12g	StarPoint	Wind	17	17	15	16	16	16	16	16	16	0
12h	Blythe4	Solar PV	30	38	28	17	17	17	17	17	17	17
12i	High Winds	Wind	0	0	0	0	0	0	0	0	0	0
12j	Mustang2	Solar PV	15	33	40	14	14	14	14	14	14	14
12k	New Hogan	Small Hydroelectric	0	0	0	0	0	0	0	0	0	0
12l	SB859 Biomass	Biofuels	0.555	0	0	0	0	0	0	0	0	0
12m	Mesquite Solar	Solar PV	0	0	0	24	24	24	24	24	24	24
12n												
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a…12t)**		89	108	106	93	93	93	93	93	93	77
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		784	829	857	831	698	555	563	586	613	609

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	[list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
14a	Generic ACS Specified Resource	Unspecified/System	0	0	0	0	0	75	75	75	75	75
14b	Generic Unspecified Resource	Unspecified/System	0	0	0	0	50	100	100	100	100	100
14c	Generic Standalone MID Battery	Storage	0	0	0	0	0	0	0	0	25	25
14d												
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		0	0	0	0	50	175	175	175	200	200

RPS-ELIGIBLE RESOURCES:

	[list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
15a	NewSolarMID	Solar PV	0	0	0	0	0	0	50	50	100	100
15b	NewSolar CalSO	Solar PV	0	0	0	0	39	39	39	39	39	39
15c	NewWind CalSO	Wind	0	0	0	0	0	0	0	11	11	11
15d	NewBaseRenewCalSO	Biofuels	0	0	0	0	0	0	0	0	0	15
15e												
15	**Total peak dependable capacity of generic RPS-eligible resources**		0	0	0	0	39	39	89	99	149	164
16	**Total peak dependable capacity of generic supply resources (14+15)**		0	0	0	0	89	214	264	274	349	364

CAPACITY BALANCE SUMMARY

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
17	**Total peak procurement requirement (from line 10)**	767	842	793	783	786	789	792	794	796	799
18	**Total peak dependable capacity of existing and planned supply resources (from line 13)**	784	829	857	831	698	555	563	586	613	609
19	**Current capacity surplus (shortfall) (18-17)**	17	(13)	64	48	(87)	(234)	(229)	(208)	(183)	(190)
20	**Total peak dependable capacity of generic supply resources (from line 16)**	0	0	0	0	89	214	264	274	349	364
21	**Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)**	17	(13)	64	48	1	(21)	35	67	167	175

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
Form CEC 110 (May 2017)

Scenario Name:

Units = MWh

Yellow fill relates to an application for confidentiality.

Historical Data

NET ENERGY FOR LOAD CALCULATIONS

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Retail sales to end-use customers	2,640,606	2,637,109	2,583,074	2,634,401	2,645,185	2,663,236	2,683,711	2,709,494	2,725,834	2,751,000
2	Other loads	0	0	0	0	0	0	0	0	0	0
3	Net energy for load	2,676,774	2,695,949	2,658,170	2,696,031	2,702,025	2,715,608	2,731,861	2,753,594	2,765,978	2,787,517
4	Retail sales to end-use customers (accounting for AAEE impacts)	2,640,606	2,637,109	2,583,074	2,736,364	2,754,451	2,780,101	2,808,101	2,841,541	2,864,790	2,896,745
5	Net energy for load (accounting for AAEE impacts)	2,676,774	2,695,949	2,658,170	2,797,994	2,811,291	2,832,474	2,856,251	2,885,640	2,904,935	2,933,262
6	Firm Sales Obligations	0	0	0	0	0	0	0	0	0	0
7	**Total net energy for load (accounting for AAEE impacts) (5+6)**	**2,676,774**	**2,695,949**	**2,658,170**	**2,797,994**	**2,811,291**	**2,832,474**	**2,856,251**	**2,885,640**	**2,904,935**	**2,933,262**
8	[Customer-side solar generation]	84,999	112,984	108,552	127,461	138,643	149,799	160,676	171,637	181,622	191,703
9	[Light Duty PEV electricity consumption/procurement requirement]	12,002	17,355	23,528	31,101	39,581	49,230	61,152	75,337	91,735	110,582
10	[Other transportation electricity consumption/procurement requirement]	0	0	0	0	0	0	0	0	0	0
11	[Other electrification/fuel substitution; consumption/procurement requirement]	0	0	0	0	0	0	0	0	0	0

EXISTING AND PLANNED GENERATION RESOURCES

Utility-Owned Generation Resources (not RPS-eligible):

	[list resource by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12a	Woodland1	Natural Gas	71,520	94,400	14,805	37,467	49,883	43,900	31,238	74,433	17,916	29,932
12b	Woodland2	Natural Gas	243,621	197,858	255,078	286,929	293,038	295,045	293,260	261,981	314,894	327,032
12c	Woodland3	Natural Gas	42,705	40,289	50,860	53,586	45,767	50,454	57,595	56,980	51,583	65,914
12d	Ripon1	Natural Gas	18,127	13,812	8,197	13,824	15,705	16,414	11,443	14,924	9,899	15,895
12e	Ripon2	Natural Gas	15,553	8,387	3,747	12,593	12,004	13,616	13,935	13,805	11,068	13,602
12f	McClure1	Natural Gas	1,372	1,400	900	1,500	1,557	1,520	1,500	1,580	1,540	1,540
12g	McClure2	Natural Gas	2,012	1,513	1,145	2,040	2,120	2,040	2,040	2,040	2,330	2,120
12h	DON PEDRO	Large Hydroelectric	82,947	86,627	238,925	230,000	175,000	175,000	175,000	175,000	175,000	175,000
12i	Lodi Energy Center	Natural Gas	184,731	90,032	119,167	153,048	134,788	151,934	156,211	152,278	126,736	117,056
12j	Claribel	Natural Gas	0	0	0	0	0	0	0	0	0	0
12k												

Long-Term Contracts (not RPS-eligible):

	[list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12l	WAPA CVP	Large Hydroelectric	9,163	3,755	12,729	13,400	13,400	13,400	13,400	13,400	13,400	13,400
12m	CCSF	Large Hydroelectric	0	0	0	0	0	0	0	0	0	0
12n	ACS Specified Energy	Unspecified/System	356,483	30,579	108,122	0	0	0	0	0	0	0
12o	Non-Specified Energy	Unspecified/System	516,266	933,471	1,290,437	942,600	811,800	0	0	0	0	0
12p	Capacity Contracts	Unspecified/System	0	0	0	0	0	0	0	0	0	0
12q												
12r												
12	**Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a…12n)**		**1,544,500**	**1,502,122**	**2,104,111**	**1,746,987**	**1,555,061**	**763,323**	**755,621**	**766,421**	**724,366**	**761,490**

Utility-Owned RPS-eligible Generation Resources:

	[list resource by plant or unit]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
13a	Stone Drop	Small Hydroelectric	248	172	363	700	700	700	700	700	700	700
13b												

Long-Term Contracts (RPS-eligible):

	[list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
13c	BigHorn	Wind	69,872	70,169	59,103	66,624	66,480	66,480	66,480	66,624	66,480	66,480
13d	BigHornII	Wind	83,014	75,051	61,417	79,908	79,788	79,788	79,788	79,908	79,788	79,788
13e	Fiscalini	Biofuels	649	0	0	0	0	0	0	0	0	0
13f	McHenry Solar	Solar PV	62,259	62,040	53,739	61,491	61,184	60,878	60,573	60,270	59,969	59,669
13g	StarPoint	Wind	253,458	212,052	194,947	234,844	234,604	234,604	234,604	234,844	234,604	95,016
13h	Blythe4	Solar PV	193,519	180,565	171,011	185,070	184,145	183,224	182,308	181,396	180,489	179,587
13i	High Winds	Wind	109,854	94,101	73,318	99,900	99,900	99,900	99,900	48,200		
13j	Mustang2	Solar PV	131,538	123,915	126,303	128,255	127,614	126,976	126,341	125,710	125,081	124,456
13k	New Hogan	Small Hydroelectric	4,438	5,626	10,871	6,600	6,600	6,600	6,600	6,600	6,600	6,600
13l	SB859 Biomass	Biofuels	0	0	0	0	0	0	0	0	0	0
13m	Mesquite Solar	Solar PV	0	0	21,923	153,628	152,860	152,096	151,335	150,578	149,826	149,076
13n												
13o												
13	**Total energy from RPS-eligible resources (sum of 13a…13t)**		**908,849**	**823,691**	**772,995**	**1,017,020**	**1,013,874**	**1,011,245**	**1,008,629**	**954,831**	**903,537**	**761,372**
13z	**Undelivered RPS energy**		**439,349**	**404,207**	**403,426**	**573,453**	**571,119**	**568,796**	**566,484**	**512,484**	**461,996**	**459,719**
14	**Total energy from existing and planned supply resources (12+13)**		**2,453,349**	**2,325,812**	**2,877,107**	**2,764,007**	**2,568,936**	**1,774,568**	**1,764,251**	**1,721,251**	**1,627,903**	**1,522,862**

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	[list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
15a	Generic ACS Specified Resource	Unspecified/System Power	0	0	0	0	0	511,200	511,200	512,400	511,200	511,200
15b	Generic Unspecified Resource	Unspecified/System Power	0	0	0	0	400,152	716,421	645,661	636,467	621,600	621,600
15c	Generic Standalone MID Battery	Storage	0	0	0	0	0	0	0	0	0	0
15d												
15e												
15	**Total energy from generic supply resources (not RPS-eligible)**		0	0	0	**0**	**400,152**	**1,227,621**	**1,156,861**	**1,148,867**	**1,132,800**	**1,132,800**

RPS-ELIGIBLE RESOURCES:

	[list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
16a	NewSolarMID	Solar PV	0	0	0	0	0	0	126,400	126,112	251,536	250,272
16b	NewSolar CalSO	Solar PV	0	0	0	0	144,750	144,026	143,302	142,579	141,884	141,160
16c	NewWind CalSO	Wind	0	0	0	0	0	0	0	99,745	99,655	99,655
16d	NewBaseRenewCalSO	Biofuels	0	0	0	0	0	0	0	0	0	131,400
16e												
16f												
16g												
16h												
16i												
16j												
16k												
16l												
16m												
16n												
16	**Total energy from generic RPS-eligible resources**		0	0	0	**0**	**144,750**	**144,026**	**269,702**	**368,436**	**493,075**	**622,487**
17	**Total energy from generic supply resources (15+16)**		0	0	0	**0**	**544,902**	**1,371,647**	**1,426,563**	**1,517,304**	**1,625,875**	**1,755,287**
17z	**Total energy from RPS-eligible short-term contracts**											

ENERGY FROM SHORT-TERM PURCHASES

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
18	**Short term and spot market purchases:**	1,944,959	1,955,719	1,361,137	1,323,727	1,080,594	1,077,206	1,050,801	1,063,684	1,021,013	1,118,359
18a	**Short term and spot market sales:**	**976,585**	**1,087,230**	**986,436**	**665,202**	**641,752**	**643,058**	**641,952**	**639,686**	**678,544**	**660,001**

ENERGY BALANCE SUMMARY

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
19	**Total energy from supply resources (14+17+17z)**	**2,453,349**	**2,325,812**	**2,877,107**	**2,764,007**	**3,113,838**	**3,146,215**	**3,190,814**	**3,238,555**	**3,253,778**	**3,278,149**
19a	**Undelivered RPS energy (from 13z)**	**439,349**	**404,207**	**403,426**	**573,453**	**571,119**	**568,796**	**566,484**	**512,484**	**461,996**	**459,719**
20	**Net Short term and spot market purchases (18 - 18a)**	**968,374**	**868,489**	**374,701**	**658,525**	**438,842**	**434,149**	**408,849**	**423,999**	**342,469**	**458,358**
21	**Total delivered energy (19-19a+20)**	**2,982,374**	**2,790,094**	**2,848,381**	**2,849,079**	**2,981,561**	**3,011,568**	**3,033,179**	**3,150,069**	**3,134,251**	**3,276,788**
22	**Total net energy for load (from 7)**	**2,676,774**	**2,695,949**	**2,658,170**	**2,797,994**	**2,811,291**	**2,832,474**	**2,856,251**	**2,885,640**	**2,904,935**	**2,933,262**
23	**Surplus/Shortfall (21-22)**	**305,600**	**94,146**	**190,211**	**51,086**	**170,270**	**179,095**	**176,928**	**264,429**	**229,317**	**343,526**

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
GHG Emissions Accounting Table
Form CEC 111 (May 2017)

Scenario Name:

Yellow fill relates to an application for confidentiality.

Emissions Intensity Units = mt CO2e/MWh
Yearly Emissions Total Units = Mmt CO2e

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY

Utility-Owned Generation (not RPS-eligible):

	[list resource by name]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1a	Woodland1	0.4842	0.0346	0.0457	0.0072	0.0181	0.0242	0.0213	0.0151	0.0360	0.0087	0.0145
1b	**Woodland2**	0.4641	**0.1131**	**0.0918**	**0.1184**	**0.1332**	**0.1360**	**0.1369**	**0.1361**	**0.1216**	**0.1461**	**0.1518**
1c	**Woodland3**	0.4379	**0.0187**	**0.0176**	**0.0223**	**0.0235**	**0.0200**	**0.0221**	**0.0252**	**0.0250**	**0.0226**	**0.0289**
1d	Ripon1	0.5726	0.0104	0.0079	0.0047	0.0079	0.0090	0.0094	0.0066	0.0085	0.0057	0.0091
1e	Ripon2	0.5686	0.0088	0.0048	0.0021	0.0072	0.0068	0.0077	0.0079	0.0078	0.0063	0.0077
1f	McClure1	1.0668	0.0015	0.0015	0.0010	0.0016	0.0017	0.0016	0.0016	0.0017	0.0016	0.0016
1g	McClure2	0.7632	0.0015	0.0012	0.0009	0.0016	0.0016	0.0016	0.0016	0.0016	0.0018	0.0016
1h	Lodi Energy Center	0.3945	0.0327	0.0342	0.0943	0.0907	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690
1i	Claribel	n/a	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Long-Term Contracts (not RPS-eligible):

	[list contracts by name]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1j	ACS Specified Energy	0.0163	0.006	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1n)**		**0.227**	**0.205**	**0.252**	**0.284**	**0.268**	**0.270**	**0.263**	**0.271**	**0.262**	**0.284**

Utility-Owned RPS-eligible Generation Resources:

	[list resource by plant or unit]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2a												

Long-Term Contracts (RPS-eligible):

	[list contracts by name]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2b												
2	**Total GHG emissions from RPS-eligible resources (sum of 2a…2t)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
3	**Total GHG emissions from existing and planned supply resources (1+2)**		**0.227**	**0.205**	**0.252**	**0.284**	**0.268**	**0.270**	**0.263**	**0.271**	**0.262**	**0.284**

EMISSIONS FROM GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	[list resource by name or description]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
4a	Future ACS Specified Resource	0.0163	0.000	0.000	0.000	0.000	0.000	0.008	0.008	0.008	0.008	0.008
4b	Future Unspecified Resource	0.428	0.000	0.000	0.000	0.000	0.171	0.307	0.276	0.272	0.266	0.266
4	**Total GHG emissions from generic supply resources (not RPS-eligible)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.171**	**0.315**	**0.285**	**0.281**	**0.274**	**0.274**

RPS-ELIGIBLE RESOURCES:

	[list resource by name or description]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
5a												
5	**Total GHG emissions from generic RPS-eligible resources**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
6	**Total GHG emissions from generic supply resources (4+5)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.171**	**0.315**	**0.285**	**0.281**	**0.274**	**0.274**

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
7	**Net spot market/short-term purchases:**	0.428	**0.414**	**0.372**	**0.160**	**0.282**	**0.188**	**0.186**	**0.175**	**0.181**	**0.147**	**0.196**

TOTAL GHG EMISSIONS

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8	**Total GHG emissions to meet net energy for load (3+6+7)**	**0.642**	**0.577**	**0.413**	**0.566**	**0.627**	**0.770**	**0.723**	**0.733**	**0.683**	**0.755**

EMISSIONS ADJUSTMENTS

8a	**Undelivered RPS energy (MWh from EBT)**	439,349	404,207	403,426	573,453	571,119	568,796	566,484	512,484	461,996	459,719
8b	**Firm Sales Obligations (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0
8c	**Total energy for emissions adjustment (8a+8b)**	439,349	404,207	403,426	573,453	571,119	568,796	566,484	512,484	461,996	459,719
8d	**Emissions intensity (portfolio gas/short-term and spot market purchases)**	0.428	0.428	0.428	0.428	0.428	0.428	0.428	0.428	0.428	0.428
8e	**Emissions adjustment (8Cx8D)**	0.188	0.173	0.173	0.245	0.244	0.243	0.242	0.219	0.198	0.197

PORTFOLIO GHG EMISSIONS

8f	**Adjusted Portfolio emissions (8-8e)**	0.45	0.40	0.24	0.32	0.38	0.53	0.48	0.51	0.49	0.56

GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
9	**GHG emissions reduction due to gasoline vehicle displacement by LD PEVs**	**0.013**	**0.016**	**0.022**	**0.029**	**0.037**	**0.047**	**0.059**	**0.074**	**0.091**	**0.111**
10	**GHG emissions increase due to LD PEV electricity loads**	**0.007**	**0.008**	**0.010**	**0.014**	**0.017**	**0.022**	**0.027**	**0.033**	**0.040**	**0.048**
11	**GHG emissions reduction due to fuel displacement - other transportation electrification**										
12	**GHG emissions increase due to increased electricity loads - other transportation electrification**										

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
RPS Procurement Table
Form CEC 112 (May 2017)

Scenario Name:

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	**Beginning Start of 2017**	**Compliance Period 4**					**Compliance Period 5**				**Compliance Period 6**			
			2021	**2022**	**2023**	**2024**		**2025**	**2026**	**2027**		**2028**	**2029**	**2030**	
1	Annual Retail sales to end-use customers (accounting for AAEE impacts) (From EBT)		2,640,606	#####	#####	2,736,364		2,754,451	2,780,101	2,808,101		2,841,541	2,864,790	2,896,745	
2	Green pricing program Exclusion, (may include other exclusions like self generation exclusion)		40,746	40,046	39,202	39,202		39,202	39,202	39,202		39202.1001	39,202	39,202	
3	Soft target (%)		35.75%	38.50%	41.25%	44.00%		46.00%	50.00%	52.00%		54.67%	57.33%	60.00%	
4	Required procurement for compliance period		4165417					4,059,292				4,866,475			
	Category 0, 1 and 2 Resources (bundled with RECs)														
5	Excess balance at beginning/end of compliance period	178364					(314,497)				(331,561)				(719,298)
6	RPS-eligible energy procured (copied from EBT)		908,849	823,691	772,995	1,017,020		1,158,624	1,155,271	1,278,332		1,323,267	1,396,612	1,383,859	
6A	Amount of energy applied to procurement obligation														
7	Net purchases of Category 0, 1 and 2 RECs					150,000		150,000	150,000	150,000		150,000	125,000	100,000	
7A	Excess balance and REC purchases applied to procurement obligation		929,450	999,869	#####	1,186,751		1,249,015	1,370,450	1,439,827		1,531,945	1,620,004	1,714,526	
8	Net change in balance/carryover (RECs and RPS-eligible energy) (6+7-6A-7A)		(20,601)	(176,178)	(276,352)	(19,731)		59,610	(65,178)	(11,496)		(58,678)	(98,392)	(230,666)	
	Category 3 Resources (unbundled RECs)														
9	Excess balance at beginning/end of compliance period						0				0				0
10	Net purchases of Category 3 RECs		**15,298**	**15,985**	**59,825**	**105,667**		**70,510**	**70,355**	**70,202**		**70,050**	**69,899**	**69,750**	
11	Excess balance and REC purchases applied to procurement obligation		15,298	15,985	59,825	105,667		70,510	70,355	70,202		70,050	69,899	69,750	
12	Net change in REC balance		0	0	0	0		0	0	0		0	0	0	
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		4,362,192					4,270,359				5,076,174			
14	Over/under procurement for compliance period (13 - 4)		196775.0485					211,067				209,699			

A-A. Acronyms

ACRONYMS

AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
AB 2021	2006 California Assembly Bill 2021 (set energy efficiency targets)
AB 32	2006 California Assembly Bill 32 (set greenhouse gas reduction targets)
BA	Balancing Authority
BANC	Balancing Area of Northern California
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
COB	California/Oregon Border
COI	California/Oregon Intertie
COTP	California/Oregon Transmission Project
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIM	Energy Imbalance Market
EPA	U.S. Environmental Protection Agency
ETC	Existing Transmission Contract
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GMC	Grid Management Charge
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
ISO	Independent System Operator
LEC	Lodi Energy Center
LOLE	1-in-10 Loss of Load Event
LSE	Load Serving Entities
MID	Modesto Irrigation District
MMBtu	One Million British Thermal Units
MRTU	CAISO Market Redesign & Technology Upgrade (implemented in 2009)
MSR	Modesto, Santa Clara, Redding Public Power Agency

MSSC	Most Severe Single Contingency
MTCO2e	Metric Tons of Carbon Dioxide Equivalent
NCPA	Northern California Power Agency
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NP15	North of Path 15 Transmission
OATT	Open Access Transmission Tariff
OFT	Out-of-Territory
PB	Public Benefit
PEV	Plug-in Electric Vehicle
PEVC	Plug-in Electric Vehicle Collaborative
PNM	Public Service Company of New Mexico
POU	Publicly Owned Utility
PRM	Planning Reserve Margin
PV	Photovoltaics
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SAIDI	System Average Interruption Duration Index
SAR	System Average Rate
SB1	2006 California Senate Bill 1 (set statewide rooftop solar installation targets)
SBX1-2	2011 California Senate Bill 2 (33% renewable requirement)
SC	Scheduling Coordinator
SCADA	Supervisory Control and Data Acquisition
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SOT	South of Tesla Transmission
SWTP	Southwest Transmission Project
TAC	Transmission Access Charge
TANC	Transmission Agency of Northern California
WALC	WAPA (Lower Colorado Region)
WAPA	Western Area Power Administration
WASN	WAPA (Sierra Nevada Region)
WECC	Western Electricity Coordinating Council
ZEV	Zero Emissions Vehicle

Photograph provided by: Avangrid Renewables

Renewable Portfolio Standard Procurement Plan & Enforcement Program

Photograph provided by: Axium Infrastructure

June 7, 2022
Revision 2

SECTION 1: INTRODUCTION

Senate Bill (SB) X1-2 (SBX1-2)[1], enacted in the 2011-2012 First Extraordinary Session of the Legislature, modified the State's Renewable Portfolio Standard (RPS) program and set forth new RPS requirements applicable to publicly owned utilities (POUs). Among other things, SBX1-2 codified an RPS target for electric service providers of 33 percent of electric retail sales coming from eligible renewable resources by 2020. SBX1-2 also required that the POUs adopt a program of enforcement[2] and also directed the California Energy Commission (CEC), in consultation with the POUs, to adopt regulations for enforcement of the POU RPS programs. On June 12, 2013, the CEC adopted the *"Enforcement Procedures for the Renewable Portfolio Standard for Local Publicly-Owned Utilities"* (CEC RPS Regulations).[3] The CEC RPS Regulations first became effective on October 1, 2013, and were subsequently modified, with amendments effective April 12, 2016, and July 12, 2021.

The Clean Energy and Pollution Reduction Act of 2015, SB 350[4], signed by the Governor in October 2015, increased the statewide RPS mandate to 50 percent by December 31, 2030. These targets were updated by SB 100[5], the 100 Percent Clean Energy Act of 2018, which was signed into law in September 2018. The most recent RPS targets require that MID meet the SBX1-2 targets through 2020 and that MID reach 44 percent RPS by the end of 2024, 52 percent RPS by the end of 2027, and 60 percent RPS by the end of 2030.

MID has combined the RPS Procurement Plan with its RPS Enforcement Program in order to facilitate implementation, administration, and compliance with SBX1-2, SB 100, and the CEC RPS Regulations. As MID first adopted its MID RPS Enforcement Program outlining specific elements to be included in its RPS Procurement Plan, and the previous version of the RPS Procurement Plan[6] incorporated the critical elements of the MID RPS Enforcement Program, this latest revision combines both the MID RPS Enforcement Program and the MID RPS Procurement Plan into one document.

SECTION 2: MID'S RPS PROCUREMENT HISTORY

In accordance with the MID RPS procurement strategy, as it has been updated from time to time, MID made the following renewable energy procurement investments:

<u>Procurement Prior to 2003</u>

- Stone Drop Mini-Hydroelectric Project
    - Located in Waterford, Stanislaus County, CA
    - Built and operated by MID
    - 260 kW
    - 700 MWhs of renewable energy annually
    - Delivery commenced April 1984

1 SBX1-2 (Chapter 1, Statutes of 2011, First Extraordinary Session) amends pertinent provisions in Public Resources Code Sections 25740 through 25751 and amends and/or adds Public Utilities Code Sections 399.11 through 399.31.

2 MID adopted its "*Renewable Energy Resources Enforcement Program*" (MID RPS Enforcement Program) during its regularly scheduled meeting on December 13, 2011 via Board Resolution No. 2011-82.

3 The CEC RPS Regulations are set forth in Title 20, Division 2 of the California Code of Regulations.

4 Senate Bill 350 (De León, Chapter 547, Statutes of 2015). The pertinent provisions of SB 350 are codified in Public Utilities Code Sections 399.15 through 399.30, and added Section 9021 to the Public Utilities Code.

5 Senate Bill 100 (De León, Chapter 312, Statutes of 2018). The pertinent provisions of SB 100 are codified in Public Utilities Code Sections 399.15, and 399.30, and added Section 454.53 to the Public Utilities Code.

6 The first version of this procurement plan was adopted by the MID Board of Directors on November 12, 2013 via Board Resolution 2013-87.

2004

- High Winds Wind Project
  - Located in Solano County, CA
  - 10-year contract
  - 25 megawatt (MW) share
  - 65 GWhs of renewable energy annually
  - Delivery commenced June 2004

2005

- Shiloh Wind Project
  - Located in Solano County, CA
  - 10-year contract
  - 50 MW share
  - 140 GWhs of renewable energy annually
  - Delivery commenced June 2006

2006

- Big Horn Wind Project 1
  - Located in Klickitat County, WA
  - Through the Modesto-Santa Clara-Redding Public Power Agency (MSRPPA)
  - 20-year duration and an extension right of 5 years
  - Approximately a 25MW share
  - 65 GWhs of renewable energy annually
  - Delivery commenced October 2006

2009

- Star Point Wind Project
  - Located in Sherman County, OR
  - 20-year contract
  - 99.7 MW
  - 235 GWhs of renewable energy annually
  - Delivery commenced June 2010
- High Winds Project extension and increased share
  - Contract extension of 1 year at the original 25 MW level through May 2015
  - Additional 13 year contract extension starting June, 2015
  - Increased from 25 MW to 50 MW share
  - 110 GWhs of renewable energy annually
- Fiscalini Biodigester
  - Located in Stanislaus County, CA
  - 750 kW
  - 4 GWhs of renewable energy annually
  - Delivery commenced October 2009
  - Contract was extended for 15 years starting April 2012

2010

- McHenry Solar Farm
  - Located in Stanislaus County, CA
  - 25-year contract

    - 25 MW solar photovoltaic power plant
    - 65 GWhs of renewable energy annually
    - Commercial operation was declared in December 2012
- Big Horn Wind Project 2
    - Located in Klickitat County, WA
    - Executed through the MSRPPA
    - 25-year contract
    - 33 MW wind project share
    - 80 GWhs of renewable energy annually
    - Deliveries commenced November 2010
- New Hogan Hydro Electric Project
    - Located in Calaveras County
    - 3.3 MW small hydroelectric project
    - Built and operated by MID
    - 10 GWhs of renewable energy annually
    - Deliveries commenced in 1986
    - Prior to 2010 output was sold to PG&E
    - MID's rights end upon expiration of the FERC license in 2032.

<u>2017</u>

- Mustang II Barbaro Solar Project
    - Located in Kings County, CA
    - 50 MW
    - 20-year contract
    - 150 GWhs of renewable energy annually
    - Deliveries commence Decembercommenced November 2020
- Blythe Solar IV Project
    - Located in Riverside County, CA
    - 62.5 MW
    - 20-year contract
    - 190 GWhs of renewable energy annually
    - Deliveries commence Decembercommenced November 2020

<u>2018</u>

- Loyalton Biomass Project
    - Located in Sierra County, CA
    - 1 MW
    - 5-year contract
    - 7GWhs of renewable energy annually
    - Delivery commenced April 2018
    - Procured to meet the requirements of SB859; requires that the state's electric utilities acquire their load ratio share of capacity from biomass facilities that burn woody biomass from high hazard fire zones.

<u>2020</u>

- Mesquite Solar 4 Project
    - Located in Maricopa County, AZ

- 52.5 MW
- 20-year contract
- 155 GWhs of renewable energy annually
- Deliveries commence in July 2023

SECTION 3: MID'S RPS PROCUREMENT PLAN

In order to comply with Public Utilities Code (PUC) § 399.30(a) and CEC RPS Regulation §§ 3205(a) and (b), and fulfill its renewable energy resource generation procurement targets, MID adopts and implements this RPS Procurement Plan and Enforcement Program incorporating the compliance periods and targets specified in PUC § 399.30. MID shall procure energy from eligible renewable resources as set forth in PUC § 399.12(e) and that have been certified by the CEC as an eligible renewable energy resource. The General Manager shall take all necessary or appropriate actions to implement this MID RPS Procurement Plan and Enforcement Program.

PUC § 399.30(m) provides that MID shall retain discretion over both of the following:

- The mix of eligible renewable energy resources procured by MID and those additional generation resources procured by MID for purposes of ensuring resource adequacy and reliability.
- The reasonable costs incurred by MID for eligible renewable energy resources owned by MID.

In compliance with SBX1-2, the CEC RPS Regulations, and the requirements of SB 100, including the discretion expressly reserved to MID, MID will endeavor to procure energy from eligible renewable energy resources in a manner that complies with the procurement targets and the portfolio balance percentages for portfolio content categories (PCC). The sections and table below summarize those requirements. The procurement compliance targets listed below are minimum requirements established in SBX1-2, and SB 100, as set forth in the CEC RPS Regulation § 3204. ATTACHMENT 1 shows an illustrative summary of MID's plan for compliance with the current RPS mandate.

A. Compliance Periods

PUC § 399.30(b) defines compliance periods as follows (*see also* CEC RPS Regulations §3204):

1. Compliance Period 1: January 1, 2011, to December 31, 2013, inclusive.
2. Compliance Period 2: January 1, 2014, to December 31, 2016, inclusive.
3. Compliance Period 3: January 1, 2017, to December 31, 2020, inclusive.
4. Compliance Period 4: January 1, 2021 to December 31, 2024, inclusive.
5. Compliance Period 5: January 1, 2025 to December 31, 2027, inclusive.
6. Compliance Period 6: January 1, 2028 to December 31, 2030, inclusive.
7. Compliance Periods beginning on or after January 1, 2031, shall be for three years in length starting on January 1 and ending on December 31.

B. Procurement Requirements within Each Compliance Period

1. PUC §§ 399.30 (c)(1) and (2) establish the quantities of energy from eligible renewable energy resources to be procured for each compliance period and calls for reasonable

progress toward compliance period soft targets during intervening years (*see also* CEC RPS Regulations § 3204(a)).

The following targets are established:

Table 1. RPS Compliance Period Targets

Compliance Periods	Years	RPS Target As a Percentage of Retail Energy Sales
Compliance Period 1	2011 - 2013	Average of 20%
Compliance Period 2	2014	20%
	2015	20%
	2016	25%
Compliance Period 3	2017	27%
	2018	29%
	2019	31%
	2020	33%
Compliance Period 4	2021	35.75%
	2022	38.50%
	2023	41.25%
	2024	44%
Compliance Period 5	2025	46%
	2026	50%
	2027	52%
Compliance Period 6	2028	54.67%
	2029	57.33%
	2030	60%
Future Compliance Periods	2031 - Onward	60%

2. For each compliance period beginning on or after January 1, 2031, MID shall demonstrate that it has procured enough electricity products within the compliance period sufficient to meet or exceed an average of 60.00 percent of MID's retail sales over the three calendar years of the compliance period.
3. In accordance with CEC RPS Regulation § 3204(e), RPS procurement requirement deficits incurred by MID in any compliance period shall not be added to the RPS procurement requirements of MID in a future compliance period.

C. Defining Portfolio Content Categories (PCCs)

PUC §§ 399.30(c)(3) and 399.16 establish PCCs specifying the electricity products that may be procured for RPS compliance during each compliance period (*see also* CEC RPS Regulations § 3203).

The following are general descriptions of each PCC:

1. PCC 1: refer to PUC § 399.16(b)(1), CEC RPS Regulations 3203(a) for a full description of requirements.

   Overview:

   - PCC 1 electricity products must be procured together with associated renewable energy credits (RECs) to be classified as PCC 1.
   - The electricity products must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the Western Electricity Coordinating Council (WECC) region, and must meet one of the following criteria:
     - Must have its first point of interconnection within the metered boundaries of a California balancing authority area (CABAA), or
     - Must have its first point of interconnection to an electricity distribution system used to serve end users within the metered boundaries of a CABAA, or
     - Must be scheduled on an hourly or sub-hourly basis into a CABAA without substituting electricity from another source. If there is a difference between the amount of electricity generated within an hour and the amount of electricity scheduled into a CABAA within that same hour, only the lesser of the two amounts shall be classified as PCC 1, or
     - The electricity from the eligible renewable energy resource can be dynamically transferred into the CABAA.

     Maintaining PCC 1 Status in a Resale Transaction:

     - The original contract for procurement of the electricity products meets one of the criteria above (*see also* CEC RPS Regulations § 3203(a)(1)(A) – (D)). In this case, only the real time transfer of energy and associated RECs to the ultimate buyer that have not been generated prior to the effective date of the resale contract with the ultimate buyer are allowed; or
     - The transaction meets the scheduling condition above while maintaining the original hourly and sub-hourly schedule and the real time transfer of energy and associated RECs to the ultimate buyer that have not been generated prior to the effective date of the resale contract with the ultimate buyer. *See also* CEC RPS Regulations § 3203(a)(2)(D).
   - Electricity products originally qualifying as PCC 1 and resold that do not meet the criteria above shall not be counted as PCC 1 electricity products.

2. PCC 2: refer to PUC § 399.16(b)(2), and CEC RPS Regulations 3203(b) for a full description of requirements.

   Overview:

   - PCC 2 electricity products (sometime also referred to as "firmed-and-shaped") must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the WECC region, and the electricity must be matched with incremental electricity that is scheduled into a CABAA.

- The following criteria for bundled PCC 2 electricity products must be met:
    - The first point of interconnection in the WECC region for both the eligible renewable energy resource and the resource providing the incremental or firming energy must be located outside the metered boundaries of a CABAA.
    - The firming energy used to match the electricity from the eligible renewable energy resource must be incremental to MID[7].
    - The contract or ownership agreement for the firming energy is executed at the same time or after the contract or ownership agreement for the electricity products from the eligible renewable energy resource is executed.
    - The firming energy must be scheduled into the CABAA within the same calendar year as the electricity from the eligible renewable energy resource is generated.
    - The electricity from the eligible renewable energy resource must be available to be procured by the MID and may not be sold back to that resource.
- Electricity products originally qualifying as PCC 2 and resold must meet the following criteria to remain PCC 2:
    - The original contract for procurement of the electricity products meets the PCC 2 criteria above *(see also* CEC RPS Regulations § 3203(b)(2)(A) – (E)).
    - The resale contract transfers only electricity and RECs that have not yet been generated prior to the effective date of the resale contract.
    - The resale contract transfers the original arrangement for firming energy, including the source and quantity for the firming energy.
    - The resale contract retains the scheduling of the firming energy into the CABAA as set out in the original transaction.
    - The transaction provides firming energy for the MID in its claim of the transaction for RPS compliance.
    - The firmed energy is scheduled into the CABAA.
- Electricity products originally qualifying in PCC 2 and resold that do not meet the criteria requirements of either PCC 1 or PCC 2 fall within PCC 3.

3. PCC 3: refer to PUC § 399.16(b)(3), CEC RPS Regulations § 3203(c) for a full description of requirements.
   Overview:
    - All unbundled RECs and other electricity products procured from eligible renewable energy resources located within the WECC region that do not meet the requirements of either PCC 1 or PCC 2 fall within PCC 3.

[7] For purposes of this Section (*see also* CEC RPS Regulations § 3203), "incremental electricity" means electricity that is generated by a resource located outside the metered boundaries of a CABAA and that is not in the portfolio of MID claiming the electricity products for RPS compliance prior to the date the contract or ownership agreement for the electricity products from the eligible renewable energy resource, with which the incremental electricity is being matched, is executed by MID or other authority, as delegated by the MID governing board.

- Electricity products that fall under the PCC 3 electricity product category that were procured and under contract prior to June 1, 2010 can be used under the optional compliance measure described in the CEC RPS Regulation § 3206 (a)(1)(A), and will be designated by the label "GR3" for MID's internal tracking.

4. PCC 0: refer to PUC § 399.16(d), CEC RPS Regulations § 3202(a)(2) for a full description of requirements.

   Overview:

   - Contracts or ownership agreements originally executed prior to June 1, 2010 (PCC 0), count in full towards the RPS procurement targets set forth in Section 3.B above and the long-term procurement requirements in Section 3.E below if the renewable resource met the CEC's RPS eligibility requirements that were in effect when the procurement or ownership agreement was executed by MID and the associated RECs are retired within 36 months of the date the electricity product is generated. The contracts or ownership agreements will continue to count in full if any contract amendments or modifications that occurred after June 1, 2010, do not increase the nameplate capacity or expected quantities of annual generation, or substitute of a different renewable energy resource to meet the terms of the original agreement. An amendment to increase the duration of the contract beyond its original term is acceptable if the original term was at least 15 years.
   - PCC 0 resources are not subject to the portfolio balancing requirements defined in Section 3.D below but will automatically qualify for the long-term procurement requirement in section 3.E below (*see also* CEC RPS Regulations §§ 3204(c) and 3204(d)(2)(J)).
   - If contract amendments or modifications after June 1, 2010 increase nameplate capacity or expected quantities of annual generation, increase the term of the contract as outlined above, or substitute a different renewable energy resource, only the MWhs or resources procured prior to June 1, 2010, shall count in full toward the RPS procurement targets. The remaining procurement must be classified into PCC 1, 2, or 3, and must meet the portfolio balance requirement of Section 3.D as well as classified as long-term or short-term in accordance with Sections 3.E below (*see also* CEC RPS Regulations § 3202(a)(2)(B), §§ 3204(c) and (d)).

5. Historic Carryover: refer to CEC RPS Regulations § 3206(a)(5) for a full description of requirements.

   Overview:

   - MID procurement generated before January 1, 2011, that met the PCC 0 criteria above (*see also* CEC RPS Regulations § 3202(a)(2)), that was in excess of the sum of the 2004 – 2010 annual procurement targets defined in CEC RPS Regulations Section 3206(a)(5)(D), have been credited to MID by CEC for use in MID's RPS procurement targets during any of the compliance periods.

D. Portfolio Balancing Requirements- Quantities for PCCs

Refer to PUC §§ 399.30(c)(3) and 399.16(c), and CEC RPS Regulations § 3204(c) for a for a full description of requirements.

Table 2 provides a summary of the RPS requirements that are applicable to POUs in the CEC RPS Regulations.

Table 2. Portfolio Content Category Requirements

Compliance Periods	Years	Balancing Requirements For Portfolio	
		PCC 1	PCC 3
Compliance Period 1	2011 - 2013	≥50%	≤25%
Compliance Period 2	2014 - 2016	≥65%	≤15%
Compliance Period 3	2017 - 2020	≥75%	≤10%
Future Compliance Periods	2021 - Onward	≥75%	≤10%

As PCC 0 products count in full, they are not subject to the portfolio balancing requirement but do count toward MID's total RPS procurement requirements.

E. Long-Term Procurement Requirement

Refer to PUC §§ 399.13 (b)(1) and 399.30(d)(1).

Beginning January 1, 2021, and for each compliance period thereafeter, at least 65 percent of procurement counted toward the RPS requirement of each compliance period shall be from contracts of 10 years or more in duration or ownership or ownership agreements for eligible renewable energy resources. For purpsoes of this section 3.E contracts shall be measured from the contract start date.

MID will classify electricity products as long-term or short-term based on the contracts, ownership, or ownership agreements through which they are procured and subject to the provisions of the CEC RPS Regulations § 3204(d).

SECTION 4: OPTIONAL COMPLIANCE MEASURES

Both PUC § 399.30 and CEC RPS Regulations § 3206 authorize the use of additional flexible measures for compliance. MID incorporates each of optional compliance measures into this RPS Procurement Plan and Enforcement Program as follows:

A. Banking Mechanism

MID may apply excess procurement from one compliance period to subsequent compliance periods, including compliance years following 2020, using the criteria outlined in CEC RPS Regulations § 3206(a)(1). MID may count any excess procurement accrued beginning January 1, 2011 and in subsequent compliance periods.

B. Delay of Timely Compliance

MID may waive or delay timely compliance with an RPS requirement if MID demonstrates that any of the conditions beyond the control of MID, as set forth in CEC RPS Regulations § 3206(a)(2), exist and MID would have met its RPS procurement requirements but for the cause of delay.

C. Cost Limitations

Refer to PUC §§ 399.30(d)(2) and 399.15(c), and CEC RPS Regulations § 3206(a)(3) for a full description of requirements.

1. At the discretion of the MID Board of Directors, the following cost limitation rules may be applied to MID's expenditures for procurement under this RPS Procurement Plan and Enforcement Program, consistent with CEC RPS Regulations Section 3206(a)(3).

   In implementing a cost limitation for procurement expenditures under this RPS Procurement Plan and Enforcement Program, MID will consider the following:

   a. The extent to which the RPS procurement expenditures may result in disproportionate rate impacts.

   b. In its efforts to diversify its RPS, MID will examine the cost-effectiveness of new opportunities while taking into consideration the impacts on rates and protecting its customers from an excessive rate increase(s). When compared to the cost to purchase non-renewable energy of comparable volume and delivery profile, if incorporating the annual expenditure of new eligible renewable resources into MID's current RPS Procurement Plan and Enforcement Program would result in rate increases of more than 2 percent per year at any time during the life of the considered RPS procurement, cost limitation may be applied at the discretion of the MID Board of Directors.

2. In the event that procurement of electric products to satisfy this RPS Procurement Plan and Enforcement Program result in an exceedance of the cost limitation:

   a. MID shall consider taking actions which may include, but are not limited to, refraining from entering into new contracts or constructing facilities for eligible renewable energy resources beyond the quantity that can be procured within the cost limitation.

   b. MID shall take reasonable action to evaluate feasible options that may otherwise allow MID to meet its procurement requirements in a cost effective manner, including, but not limited to, re-evaluation of current procurement commitments, planned procurements, and the availability of alternative electric products in other portfolio content categories.

D. Portfolio Balance Requirement Reduction

MID may reduce the portfolio balance requirement for PCC 1 for a specific compliance period. The need to reduce portfolio balance requirements for PCC 1 must have resulted from conditions beyond the control of MID as set forth in CEC RPS Regulations § 3206 (a)(4) . If MID reduces its portfolio balance requirements for PCC 1, it must adopt such changes at a publicly noticed meeting (with advance notice to the CEC) and must include this information in the updated RPS Procurement Plan and Enforcement Program submitted to the CEC.

E. **MID Authority**

PUC § 399.30, and other relevant laws and regulations.

In endeavoring to procure adequate supplies of renewable energy to meet the targets set forth in this RPS Procurement Plan and Enforcement Program, MID shall at all times maintain system reliability and safety. The District retains all authority and flexibility granted under PUC Section 399.30 and other relevant authorities in meeting its obligations under PUC Section 399.30 in accordance with this RPS Procurement Plan and Enforcement Program and retains the ability to modify this document at any time in order to maintain system reliability and safety.

SECTION 5: REVIEW, UPDATES, AND ENFORCEMENT

Refer to PUC § 399.30(e), § 399.30(f), CEC RPS Regulations §§ 3205(a) and (b) for a full description of requirements.

This RPS Procurement Plan and Enforcement Program will be updated as appropriate for consistency with RPS requirements, as they may change from time to time.

A. MID will provide the following notice as it pertains to RPS procurement regarding a new or updated RPS Procurement Plan and Enforcement Program:

- MID shall post notice in accordance with Chapter 9 (commencing with Section 54950) of Part 1 of Division 2 of Title 5 of the Government Code whenever the Board of Directors will deliberate in public on the RPS Procurement Plan and Enforcement Program.

B. If the Enforcement Program is modified or amended, MID shall provide no less than 10 calendar days notice to the public before any meeting is held to make a substantive change to the Enforcement Program.

C. Other enforcement actions by MID that will assist MID's efforts in in the RPS procurement process as part of this RPS Procurement Plan and Enforcement Program shall inlcude, but not be limited to the following:

1. Staff shall inform the Board of Directors in the event that MID will not meet the renewable energy resource procurement requirements set forth in MID's RPS Procurement Plan and Enforcement Program.
2. As soon as reasonably practicable following informing the Board of Directors of a noncompliance issue, staff shall develop and present to the Board a plan to bring the District into compliance.

SECTION 6: COMPLIANCE AND REPORTING

MID shall comply with and utilize, as warranted, the provisions of CEC RPS Regulation § 3207.

ATTACHMENT 1

1. EXISTING ELIGIBLE RENEWABLE ENERGY RESOURCES

MID currently has the following energy resources under contract and/or ownership that meet the eligible renewable energy requirements set forth in PUC Section 399.11, *et seq.* and the CEC RPS Regulations:

Table 1: MID Current Eligible Renewable Energy Resources

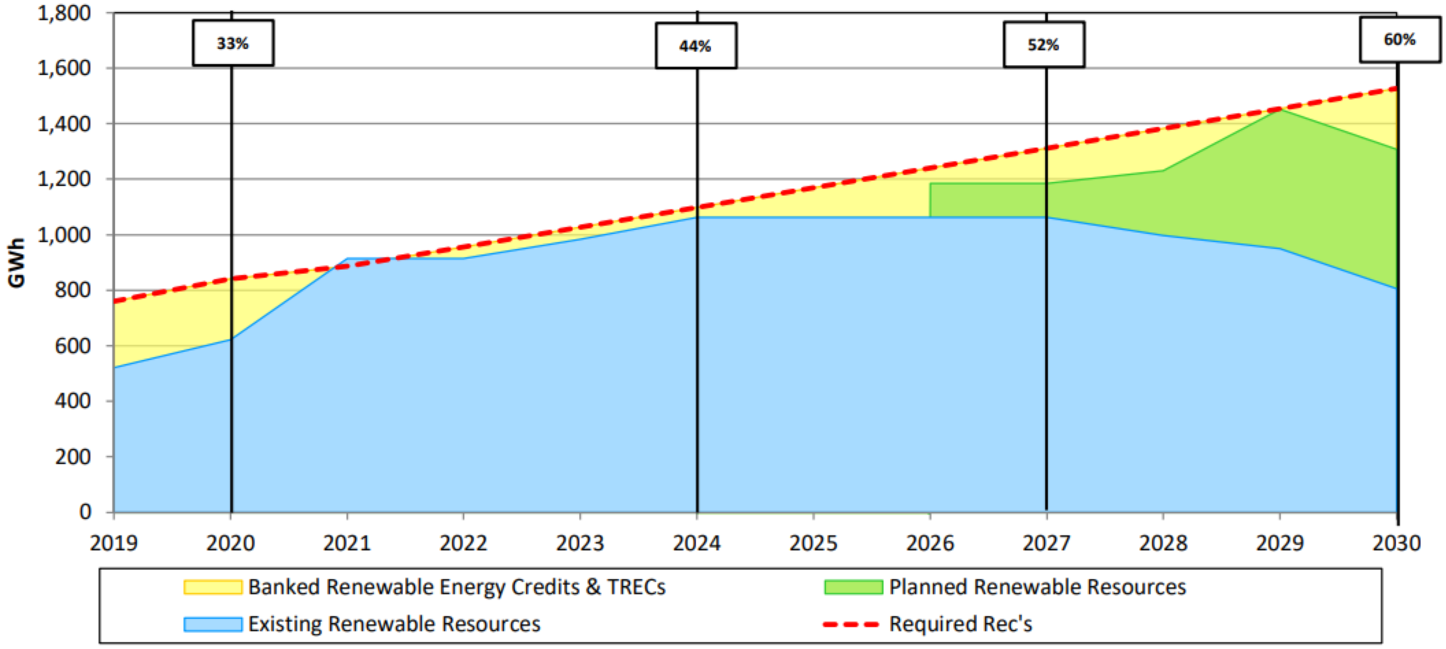
Technology/Projects	PCC Category	MW	Annual GWh
Small Hydroelectric			
• Stone Drop Mini Hydro	PCC 0	0.260	1
• New Hogan	PCC 0	3.3	10
Wind			
• High Winds Wind Project	PCC 0	50	110
• Big Horn Wind Project 1	PCC 0	25	65
• Big Horn Wind Project 2	PCC 0	32.5	80
• Star Point Wind Project	PCC 0	99.7	235
Digester Gas			
• Fiscalini Farms	PCC 1	0.750	4
Biomass			
• ARP-Loyalton	PCC 1	1	7
Solar			
• McHenry Solar Farm	PCC 0	25	65
• Small Solar Photovoltaic Systems	GR3/PCC 3	10	17
• Solar: Mustang Two Barbaro	PCC 1	50	147
• Solar: Blythe IV	PCC 1	62.5	190
Procured			
• Solar: Mesquite Solar 4	PCC 1	52.5	155

2. PROCUREMENT PLAN FOR FUTURE RENEWABLE ENERGY RESOURCES

In order to meet the requirements of SB 100 and the CEC RPS Regulations, MID plans to carry forward excess procurement from one compliance period to the next whenever possible. As existing contracts near expiration, MID will negotiate an extension or replace those resources with other eligible renewable energy resources as necessary to maintain RPS compliance. MID will also use its available historic carryover and prior excess procurement in years where there may otherwise be a shortfall through the banking mechanism described in Section 4.A of this RPS Procurement Plan and Enforcement Program.

The following example illustrates the banking approach described in Section 4.A of this RPS Procurement Plan and Enforcement Program.

RPS Procurement Plan Example
(for illustrative purposes)



3. REVISION HISTORY

Revision Number	Revision Date	Summary of Changes
1	November 13, 2018	Updated title to combine the MID Renewable Energy Resources Enforcement Program with the RPS Procurement Plan, cleanup, and implementation of updates associated with SB 100.
2	June 7, 2022	Updated to include the December 22, 2020 amendments to the CEC RPS Regulation approved by the California Office of Administrative Law on July 12, 2021.

Modesto Irrigation District

Risk Management Policy

Version 5.0, Approved

May 24, 2016

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I. Organizational Structure and Responsibilities

A. Firm-Wide Responsibilities

All personnel involved in procurement, trading, marketing, and risk management activities for energy and related attributes shall conduct business in accordance with all applicable laws, regulations, tariffs and rules. These include MID policies regarding ethics and conflicts of interest. Personnel shall deal honestly and in good faith.

B. Management Responsibilities

1. Board of Directors

The Board has oversight responsibility for the organization including business strategies and the risks involved. The Board:

- Approves and oversees business objectives, plans, strategies and policies.

- Defines the risk tolerance of the organization and the goals, scope and time horizon of the Risk Management Program.

- Designates Qualified Independent Representative(s) (see below, QIR) pursuant to the rules of the Commodity Futures Trading Commission (CFTC), and obligates such QIR(s) to comply with section 23.450(b) (1) of the CFTC rules. The Board will designate each QIR by special purpose resolution after a case-by-case evaluation of a candidate's satisfaction of the CFTC requirements.

- Through the adoption of the Risk Management Policy:

    - Establishes risk exposure limits.

    - Grants authority to Operations to enter into transactions of the types, within the terms, and for the purposes that are explicitly listed as approved in this document.

    - Installs a reporting structure that communicates the risks assumed by MID and shows the results of risk management activities.

    - Grants authority to the Risk Oversight Committee (ROC) to set and approve procedures to enhance the management and control of risk within the constraints of this Policy.

2. Risk Oversight Committee

The ROCshall ensure the implementation and serve as the policy interpretation authority of this policy. Within the constraints of the Board-adopted *policies* herein, the ROC may adopt *procedures* it deems necessary to further define and enhance the risk management and control environment. The ROC includes the Assistant General Manager of Finance, Assistant General Manager Transmission and Distribution, and Assistant General Manager Electric Resources, and such others as the General Manager may designate This body will:

- Implement the Risk Management Policy and ensure the adequacy and functioning of the system of controls over market, credit and operational risks.
- Communicate the results of risk management activities to the Board.
- Adopt procedures to ensure that each Qualified Independent Representative (see below, QIR) meets the requirements of CFTC Regulation 23.450, procedures to monitor QIRs, procedures for QIRs to use in evaluating swaps, and such other procedures necessary to enhance the risk management and control environment.
- Provide adequate staffing and resources (e.g., number, level and experience of staff; computer support; etc.) for risk management activities.
- Approve counterparties and counterparty credit limits.
- Determine business level strategies and their effect on the risk position of MID.
- Propose changes to risk tolerance for approval by the Board based on strategic direction and business opportunities.
- Establish a standard for effective communications among management and staff to maintain timely information on the risks faced by the firm.
- Meet on a regular basis to monitor compliance with policy and procedures and the performance of risk management activities.
- Monitor the performance of risk management personnel.

- Monitor each QIR for performance and for ongoing satisfaction of the requirements of CFTC Regulation 23.450.
- Consider and recommend appropriate risk management actions and/or practices to incorporate into the Risk Management Policy and/or Procedures.

- Monitor for breakdowns in segregation of duties especially in light of potential changes in personnel, organizational structure and information systems.
- Ensure that appropriate action is taken if risk limits are exceeded.

3. Operations

In general, execution of risk management activities (i.e., trading and hedging) will be performed by operating personnel (traders, schedulers, analysts, etc.) who are responsible to:

- Develop physical and financial transaction trading expertise.
- Execute trades (physical or financial) within the limits specified herein.
- Use only recorded lines when transacting by telephone.
- Report all trades to Risk Management and provide copies of deal confirmations.
- Identify areas where the financial markets and/or risk management expertise can be used to increase business opportunities.
- Provide a first line of defense against credit risk by helping to identify and avoid counterparties which are not creditworthy or which lack integrity.
- Provide notice to Risk Management (RM) of concerns regarding conduct of counterparties that may be inconsistent with market rules.
- Maintain communications with the ROC as to the status of all risk taking and risk management activities.
- The Assistant General Manager for Electric Resources will approve a list of authorized traders.

4. Risk Management

To maintain segregation of duties, Risk Management (RM) will be functionally and organizationally independent from the line management of Divisions that execute energy transactions. Risk Management will be responsible to:

- Organize and conduct meetings of the ROC, engaging the ROC in discussions regarding developments in energy markets that could expose MID to losses.
- Measure and communicate the financial exposure of MID's energy portfolio by applying accepted risk measurement and valuation standards.

- Recommend portfolio hedging strategies.
- Deliver risk reports per Sections IV and V below.
- Monitor for violations of Risk Management Policies and Procedures and report such to the ROC.
- Review the adequacy of risk management activities, controls, reports, and policies; and recommend updates and improvements,
- Review and evaluate proposed energy market activities and transactions to ensure that adequate analysis and risk assessment has been performed.
- Recommend counterparties and credit limits for ROC approval.
- Monitor credit exposures compared to limits, prepare and issue credit risk management reports, and analyze the credit exposure impact of new transactions.
- Accept credit enhancement (e.g., guarantees) from trading counterparties.
- Provide back-up of risk books and records and plan for business continuity (in conjunction with Information Technology).
- Immediately notify ROC of any breakdown in risk management functionality (e.g., risk management software systems).

5. Qualified Independent Representative

The implementing regulations of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Act) require MID to have a Qualified Independent Representative (QIR) in order to trade products the Act defines as “swaps” with entities defined as “swap dealers.” Many of the products approved herein for trading meet the definition of “swaps” and many of MID’s counterparties are “swap dealers.” Note: this Policy uses the term QIR to be consistent with the Act. The Act defines the QIR to be independent of the swap dealer, not MID. MID may have more than one QIR and each QIR can be an MID employee or a consultant. Each QIR will:

- Demonstrate knowledge of the laws and regulations applicable to QIRs.
- Advise MID with respect to swaps, swap transactions and trading strategies involving swaps.
- Meet the requirements of CFTC Regulation 23.450(b) (1) and such additional requirements as the ROC may specify.

6. Risk Management Responsibilities of Other Functional Areas

These responsibilities shall be carried out by individuals within MID to assure corporate policies are followed.

a. Accounting and Controller

- Develop and apply accounting policies to financial transactions.
- Participate in the settlement of transactions (including accounts payable/receivable).
- Follow accounting standards for energy transactions.
- Prepare financial statement disclosures.

b. Finance

- Provide proper types and levels of capital to fund the operation.
- Maintain controls over cash or other assets in custody (including investment decisions on funds in trading and broker accounts).
- Evaluate cash flow implications of stress testing scenarios.

c. Legal

- Review Board-level policies.
- Review trading agreements with counterparties.
- Assess legal enforceability of contracts with applicable laws and regulations.

d. Information Technology

- Specify, develop, manage, and maintain risk management computer systems.
- Data archival, back-up, and recovery planning.

II. Authorized and Prohibited Transactions

This section describes the ethical standards, purposes, parameters, and types of transactions that may be executed by authorized traders under the authority granted via this Risk Management Policy. Traders may execute only those transactions that meet the tests of ethics and purpose, are within allowed parameters, and are of a type explicitly listed as approved. For the sake of clarity and comparison, this section also contains examples of prohibited transactions that shall not be executed. In addition, the Federal Energy Regulatory Commission has characterized certain activities as "gaming" and/or "anomalous market behavior". Traders shall not engage in gaming or anomalous behavior. Potential transactions must affirmatively meet all criteria (ethics, purpose, parameter, and type) before being executed: actions not specifically prohibited are not necessarily allowed.

A. Ethical Standards

- MID will deal honestly and in good faith.
- Trading and risk management personnel have a duty to know and comply with the laws, rules, regulations, and tariffs of the markets in which they participate.
- Trading and risk management personnel shall not engage in fraudulent behavior or make false representations.
- MID will honor the terms and conditions of its contracts.
- Trading and risk management personnel shall not collude with other companies to affect the price or supply of power, allocate markets, "blackball" counterparties, or otherwise restrain competition. (In addition to being unethical, such behavior could subject individuals to civil and criminal penalties.)

B. Purpose of Transactions

1. Approved Purposes

- Transactions must have a legitimate business purpose. Legitimate purposes include generating revenues, managing risks, balancing loads and resources, providing for reliability. Legitimate purposes also include ensuring that MID holds sufficient energy-related attributes (e.g., emission allowances, renewable energy credits) to meet regulatory/legislative mandates and progress towards environmental goals.
- Customer supply activities are allowed. These activities seek to ensure reliable supplies to meet MID's obligations to its customers at low and stable rates.

- Sales of surplus capacity, energy, fuel, and environmental attributes are allowed. Such sales can occur in spot or forward markets.

- Spread and Arbitrage trading activities are allowed. These activities seek to generate revenue or reduce costs by capturing pricing inconsistencies or capitalizing on non-random trends. Spreads may be locational (e.g., California-Oregon Border versus Palo Verde), temporal (e.g., spot or next-day markets versus forward markets), or cross-commodity (e.g., capacity versus energy or gas versus power). “Convergence bidding” in California Independent System Operator (CASIO) markets is allowed.

- Portfolio positioning activities are allowed. MID’s portfolio of energy and associated attributes may be positioned long or short within the limits of this policy for the purpose of attempting to reduce net purchased power costs.

2. Prohibited Purposes

- Dealing/Market making is not allowed. This involves (large numbers of) transactions to try and capture the (small) bid/ask spread for a commodity. A market maker stands ready to both buy and sell a commodity at market price. MID will be either a buyer or seller depending on its needs.

- Positioning the portfolio to be long or short outside the exposure limits of this Policy is prohibited.

- Wash trades are prohibited. Wash trading is simultaneous or near-simultaneous trades and offsetting trades done to affect reported trading volumes, revenues or prices.

- Sale of fictitious reliability services or congestion relief. MID shall not offer to sell services that it has no way of providing.

- False scheduling is prohibited. MID shall not falsely represent its projected loads and resources to a scheduling authority.

C. Parameters of Allowed Transactions

1. Commodity

Only transactions involving electrical energy, natural gas, and fuel oil are allowed. Transactions involving attributes associated with electrical energy are also allowed. These associated attributes include, but are not limited to: capacity, resource adequacy, emission allowances, and renewable energy credits. Trading in other commodities (e.g., corn, crude oil, etc.) are prohibited. The delegations of authority to transact contained in this policy do not extend to weather derivatives, credit derivatives, and coal; any transactions involving these products must go to the Board for approval.

2. Term and Tenure

For the purposes of this Policy, “term” means the duration of a transaction; “tenure” means the maximum time into the future that deliveries extend. The maximum allowed term of transactions is four years. For example, a transaction for deliveries starting on 1/1/2013 and ending on 12/31/2016 would have an allowable term. The maximum allowed tenure is the end of the fourth calendar year forward. For example, on March 1, 2013 a purchase of power for the summer of 2017 would have an allowable tenure because deliveries conclude before the end of calendar year 2017 (2013 + 4).

3. Location

Power and natural gas shall be transacted only at delivery points and index locations where MID controls assets or has price exposure. Power is confined to the Western Electricity Coordinating Council (WECC) region. MID has commodity gas exposure at Henry Hub and gas basis exposure at PG&E citygate. To the extent that the Board makes special authorization (outside this Policy) for gas pipeline capacity or purchase power contracts indexed to, for example, Alberta gas, the applicable locations are allowable. Locations unrelated to MID assets and/or prices exposures (e.g., Pennsylvania-Jersey-Maryland power or Chicago citygate gas) are prohibited.

D. Transaction Types

To execute a transaction, traders agree on the commodity, the term, the location, the quantity, the price, the contract type, and any clarifying terms. This section has addressed which commodities, terms, and locations are allowed. Quantities are controlled by Section IV, Exposure Limits. Below are the allowed and prohibited pricing structures, contract types, and clarifications.

1. Pricing Structure

a. Approved

- Both fixed and indexed pricing are allowable within the following limits. Index pricing can reference production costs or a price publication. Any published price used for indexing shall be from a reputable organization for a liquid trading hub. Questions on the suitability of indexes shall be resolved by Risk Management.

b. Prohibited

- Index pricing where an index from a disreputable publisher or illiquid trading hub is employed.

2. Settlement (physical versus financial)

a. Approved

- Both physical and financial settlements are allowable within the following limits. Physical transactions involve the delivery of actual electrical energy/capacity or gas molecules. Financial transactions are settled in cash instead of via physical delivery. Transactions must be specific as to whether they are physical or financial and the conditions for alternative settlement (e.g., financial settlement when physical settlement is impossible).

b. Prohibited

- Traders are not allowed to agree to transaction terms that alter the settlement features of master trading contracts (e.g., Western Systems Power Pool, Edison Electric Institute, International Swap Dealers Association, and North American Energy Standards Board). Examples of prohibited behavior would include altering liquidated damages clauses or giving the counterparty additional discretion to dictate financial versus physical settlement.

3. Contract Type

a. Approved

- Forward contracts
- Futures contracts
- “Simple” put and call options (“simple” as opposed to complex and multiplier structures, see prohibited list).
- “Plain vanilla” swaps (“plain vanilla” refers to fixed-floating and floating-fixed swaps with a pre-determined and constant notional quantity).
- Basis swaps where both indices float, but where a fixed differential is established (e.g., a transaction locking in the PG&E citygate index at 30 cents above the NYMEX settlement).

- First-order combinations of approved types including options-on-futures and swaptions.
- Gas tolling and gas tolling options where one party supplies (physically or financially) natural gas and receives from the other party a quantity of electricity based on a contractual heat rate.

b. Prohibited

- Uncovered written options (i.e., a written option with no physical resource or existing portfolio resources to offset the risk).
- Complex options (e.g., an option on an option).
- Options with a multiplier structure (e.g., option contracts with a variable quantity tied to an index with a multiplier – a put option with a strike price of $20/MWh and a quantity equal to 1,000 MWh multiplied by the COB index divided by the strike price).
- Swaps where the notional amount is not a pre-determined quantity .
- Higher-order combinations of approved types such as extendable swaps.

4. Other Terms

a. Approved

- With respect to regulatory reporting requirements (e.g., of the Dodd-Frank Act), traders are authorized to specify which party will report transactions.
- Traders are authorized to represent that MID is hedging and to specify regulatory categories that MID falls into (e.g., special entity and end user).
- Traders may sign transaction confirmations that repeat terms found in approved enabling agreements.

b. Prohibited

- Long form confirmations in lieu of a valid enabling agreement.
- Granting more credit than is done via the enabling agreement with a party (e.g., waiving a requirement that the counterparty post collateral).

E. Practices Discussed in FERC Market Behavior Documents

Investigations of trading activities in California's Power Exchange (PX) and Independent System Operator (CAISO) markets resulted in a list of activities that the Federal Energy Regulatory Commission (FERC) considers "gaming" or "anomalous market behavior". All of these activities are banned under this Policy. Note that there are also certain activities that FERC does not prosecute, but that are still prohibited at MID.

1. Activities Prohibited by FERC Market Rules

- **False import, also known as Ricochet or Megawatt Laundering**. This is described by FERC as a "fictional export-import parking transaction" where no power actually leaves the state of California. This Policy prohibits false representations and false scheduling, therefore false import schemes are prohibited by MID.

- **Cutting non-firm exports**. In this practice, a market participant schedules a non-firm counter flow on a congested transmission path. Then, after collecting a congestion payment, the schedule is cut. This Policy prohibits transactions that MID cannot perform on or does not intend to perform on.

- **Death Star**. This was a scheme to collect congestion payments without doing anything to relieve congestion. A congestion counter flow would be scheduled along with a series of imports/exports and a transaction with another control area to effectively send the same amount of power back to the point of origin, but no congestion relief would occur. The schedules would book out, but the CAISO still paid for congestion relief. This Policy prohibits the sale of false congestion relief.

- **Scheduling counter flows on out-of-service transmission**. Scheduling counter flows on out-of-service transmission is prohibited at MID. This Policy prohibits transactions that MID cannot perform on or does not intend to perform on.

- **Load Shift**. This is another form of false scheduling to create congestion and get paid to relieve it. The participant overschedules load in one zone and under schedules in another, thus creating apparent congestion in the direction of the overscheduled zone. The participant later adjusts schedules and receives a congestion payment. This Policy prohibits false representations and false scheduling.

- **Paper trading of ancillary services**. In this practice, a participant trades ancillary services even though they do not have the resources to provide the services they sell. This Policy prohibits the sale of fictitious reliability services and sales of ancillary services beyond what the District, in good faith, believes it can provide at the time when the sale is made. This Policy allows legitimate arbitrage of ancillary services markets as described in the following section.

- **Double selling of ancillary services**. This involves selling a resource as reserves in one market and selling it as energy in another. Again, this Policy prohibits transactions that MID cannot perform on or does not intend to perform on.

- **Selling non-firm energy as firm**. Firm energy requires operating reserves; non-firm does not. If a market participant acquires non-firm energy and sells it as firm, an unjust profit can be made because the participant avoids the expense of buying reserves. This is a false representation and is prohibited under this Policy.

2. Activities not Prosecuted by FERC

- **Under scheduling of load**. Utilities may attempt to influence market prices by altering load schedules. Although FERC did not prosecute this behavior, it involves false representations and is prohibited by this Policy.

- **Export of California power**. This issue was debated when California was attempting to cap power prices at a lower level than surrounding states. However, selling power that is produced in California and actually exported (unlike the false practices discussed above) is not illegal, does not violate rules or tariffs, and is not prosecutable by FERC. MID relies on purchases from out-of-state when it needs power and this Policy allows out-of-state sales when MID is surplus (in the absence of any legitimate emergency orders or superseding MID policies to the contrary). When selling power, operating personnel shall seek to maximize value for MID's customer-owners.

- **Ancillary services arbitrage**. Unlike the false paper trading of ancillary services discussed above, FERC has found that ancillary services markets can be legitimately arbitraged provided the market participant is buying and selling real, not fictitious, services. For example, reserves can be sold in a day-ahead market and bought back in an hour-ahead market to take advantage of systematic price discrepancies to the extent that the market participant has bona fide reserves available to make good on the transactions. This Policy allows the arbitrage of ancillary services markets to the extent that operating personnel have bone fide resources to cover the transactions and provided that applicable tariff provisions are followed (e.g., CAISO protocols for Convergence Bidding).

III. Exposure Limits

Exposure limits guide hedging activities so that energy price risk remains within MID's tolerance. MID's limit structure includes a Value-at-Risk (VaR) limit and position limits.

A. Value-at-Risk (VaR)

VaR measures risk across commodities, markets, and time frames. Total portfolio risk is rolled up into a single number, making it simple to monitor.

MID's VaR limit is as follows:

- VaR limit = $3,330,000 * Adjustor. The Adjustor is 1.0 as of 5/10/16 and thereafter changes with the year-on-year change in budgeted retail revenue with the adjustment becoming effective on the date that a new budget is adopted.
- 10-day holding period
- 95% one-tailed confidence interval
- (This specification means that one can say with a confidence level of 95% that, over the next 10 days, MID's energy portfolio will not experience a loss in value in excess of the VaR amount.)

VaR is based on *value* rather than *cash*. VaR encompasses gains and losses on positions for future time periods; those gains and losses may or may not be realized. Neither does VaR indicate the maximum amount that could be lost. VaR also requires a computer model for calculation. To mitigate these disadvantages, MID includes cash-based stress testing as part of its risk management program, which highlights extreme loss possibilities, and position limits, which are simpler to calculate.

B. Position Limits

Position limits are straightforward to understand and calculate, and also provide a bridge to long-term resource planning. MID's position limits are specified in terms of "percent covered". Percent covered is on a forecast energy-volume basis. Thus, if the resource plan projects that MID will have an energy need (wholesale and retail obligations) of 200,000 MWh for a given month and MID has 180,000 MWh covered for that month, the coverage would be 90%. Covered means that MID has locked in the pricing for a volume of energy. Fixed-price forward contracts or futures contracts are ways of covering. Projected energy volumes from MID's long-term contracts with Hetch Hetchy, MSR/San Juan, and Western Area Power Administration, while not perfectly fixed in price, are deemed covered for the purposes of the position limits. Resource planning assumed energy volumes from hydro and renewable resources are also deemed covered (MID's stress testing model captures the variability of these resources).

Gas tolling purchases (where MID receives power, but pays based on a gas price) are considered to provide coverage for the power volume, but create a corresponding amount of natural gas need. Call options are considered to provide coverage at 100% of the contract quantity if the option strike price is within 50% of the underlying market price at the time of the transaction.

When MID financially hedges its natural gas exposure, the New York Mercantile Exchange (NYMEX) component is considered to provide coverage at 75% of the contract quantity, while a corresponding basis swap provides coverage at 25%. Buy/re-sells or "one-to-ones" do not count in the percent covered calculations. For example, in the above 180,000/200,000 = 90% covered case, if MID contracted to buy 10,000 MWh at COB and sell 10,000 MWh at Palo Verde, the 10,000 would not be included in either the numerator or the denominator.

Wind resources are intermittent. Historically, there has been negative correlation between wind production and market price (i.e., when prices are high, there tends to be less production). To account for this effect, wind energy will provide coverage at 95% of projected volume.

The table below gives MID's acceptable coverage ranges (these levels must be achieved by the end of January each year and progress must continue throughout the year). No more than 15% of the coverage may be supplied with options.

	Power		Natural Gas	
	Year	**Any Month**	**Year**	**Any Month**
Current Calendar Year (CCY)	-	70%-105%	-	50%-105%
Next Calendar Year (CCY + 1)	75%-100%	60%-100%	40%-80%	30%-90%
Current Year plus Two (CCY + 2)	65%-95%	-	20%-60%	-
Current Year plus Three (CCY + 3)	-	-	0%-40%	-
Current Year plus Four (CCY + 4)	-	-	0%-20%	-

C. Exceeding Limits

If a limit has been exceeded, Risk Management will notify the Risk Oversight Committee and the personnel responsible for the area in which the limit has been exceeded. Such notification shall take place as soon as practicable after the limit violation is detected. In addition, Risk Management shall prepare a recommendation regarding hedging or liquidation possibilities. The Risk Oversight Team will determine a response.

IV. Transaction and Market Data Collection

Trading and risk management are data-intensive activities. Market data are used to evaluate deals, value transactions and estimate risks. A key feature of this Policy is the requirement that MID's energy portfolio be marked-to-market as part of VaR. Mark-to-market is not generally required for financial reporting purposes; rather, it is used to create a disciplined environment where losing transactions are recognized immediately. This section lists the data requirements for the risk management program.

A. Market Data Responsibilities

Risk Management is responsible for gathering market price, yield curve, volatility, and correlation data. This data must come directly from market sources, not MID's traders.

B. Data Sources

Whenever possible, the publicly available sources listed below shall be used. If such data is not publicly available, Risk Management will attempt to obtain bona fide dealer quotes.

Product	Source
Spot Power	Bloomberg, InterContinental Exchange (ICE), Dow Jones Indices, CAISO
Forward Power	Bloomberg, ICE, NYMEX
Spot Gas	Bloomberg, ICE, Gas Daily
Forward Gas	Bloomberg, ICE, NYMEX

C. Forward Curves

The forward curve is the term structure of forward prices. These are prices that could be locked in today for delivery during various periods in the future. Although the prices may be quoted with a bid/ask spread, risk analysis will generally use "mid" curves, which average the bid and ask prices.

A variety of forward curves are needed to value MID's energy portfolio. MID has exposure to power and gas prices in several locations. In addition, there are both on-peak and off-peak products in the power market. A forward curve must be produced for each product-location combination. Risk Management and IT shall develop and maintain software applications for processing data, generating the forward curves, and transferring the forward curves into the risk management system database.

D. Transaction Data Responsibilities

All energy transactions must be accounted for by Risk Management. The data capture requirements for each contract type are shown in the table below. It shall be the responsibility of Operations to provide this data to Risk Management.

Transaction Data Requirements		
Products	**Contract Types**	**Data Requirements**
All		• Settlement (Physical or financial) • Trade date • Delivery term • Counterparty • Buyer and seller • Product/underlying • Quantity (MWh, etc.) • Contract pricing • Broker and fee (if applicable) • Location • Enabling agreement (e.g., WSPP, NAESB)
Additional Data for Swaps	• Fixed/floating • Basis	• Principal or Notional amount • Rates (fixed, floating) • Day-count convention (if applicable)
Additional Data for Options	• Calls, puts • Physical/real asset	• Option type (call/put) • Strike price ($) • Strike date(s) • Exercise Type (American/European) • Premium amount ($)

E. Data Required for Value-at-Risk Analysis

Volatilities, correlations, and yield curves are also required to calculate VaR.

1. Volatility

Volatility is the annualized standard deviation of price changes. This parameter is used to model how far prices can move from their current levels. There are two methods for estimating volatility:

- Historical. Statistical calculations are applied to a time series of historical data (e.g., daily gas prices).
- Implied. Option prices are observed in the market, plugged into an option pricing model, and used to back-solve for volatility (volatility being a determinate of the option price).

Implied volatility is considered to be a purer market measure. However, there is currently not enough trading in electricity options to get representative figures using the implied method. Thus, Risk Management shall calculate volatilities using the historical technique. Risk Management shall use high quality, consistent data and shall consider tenure (near-by months will be more volatile than far-away months) in these calculations. If MID’s risk system uses price models that incorporate additional parameters for price modeling (e.g., mean reversion coefficients), then Risk Management shall calculate those as well.

2. Correlations

Correlation measures the tendency of two prices to move together. For example, when natural gas prices rise, there is a strong tendency for power prices to rise. Correlations are used in risk management to quantify the value of diversification.

Calculating correlations presents some challenges. The source data must be gathered contemporaneously. If gas prices were sampled at 8 a.m. and power prices were sampled at 10 a.m., the correlations would be invalid. There is also a large amount of data involved. MID’s portfolio encompasses several gas and power locations; on-peak and off-peak products; and the trading authorizations herein extend many months into the future. A correlation coefficient is needed for every combination of location, product, and month. There are well over 10,000 combinations in MID’s case. MID shall use high quality, contemporaneous data to calculate correlations.

3. Yield curves

Yield curves are required for present value calculations and valuing swap transactions. The zero coupon yield curve shall be used for these purposes. Developing the zero coupon yield curve is an involved process involving bootstrapping and interpolation. However, it is part of the Bloomberg Professional Service to which MID subscribes. Risk Management shall use the zero curves from Bloomberg. In the event that Bloomberg becomes unavailable, Risk Management shall perform these calculations or determine a replacement data source.

V. Management Reporting

A. Objective

The objectives of risk management reporting are to communicate the market and credit risks assumed by MID and to show the results of trading and risk management activities.

B. Reporting Requirements

The following reports will be prepared by Risk Management:

1. Market Price Reports

a. Energy Market Updates

Energy Market Updates consist of general pricing information and market commentary from a non-technical perspective. These updates are prepared at the discretion of the General Manager.

b. Price Data

Pricing information, consisting of tabular data in electronic form, shall be collected on a regular basis. The data shall cover electricity and natural gas products at locations where MID has market positions. Prices from spot and forward markets are included. The data shall be maintained so that price reports can be produced as needed.

2. Position and Risk Reports

a. Portfolio Analysis Report

The analytic package in MID's Contango risk management system is called the Portfolio Analysis Module (PAM). The output results of PAM include the size of MID's market positions (reported in terms of "delta", the first derivative of value with respect to price), the mark-to-market value, and the value-at-risk.

b. Limit Tracking Report

The Limit Tracking Report is a comparison of actual positions and value-at-risk versus limits. This report shall be presented in graphical or tabular format.

3. Credit Reports

a. Credit Exposure by Rating Report

This report details credit exposure (the potential realized and unrealized losses that could be incurred by MID if a counterparty defaults in payment and/or delivery). Exposures are sorted by counterparty rating.

b. Credit Limit and Concentration Report

The Credit Limit and Concentration Report show credit exposure by counterparty. The percentage of MID's total credit exposure is also shown for each counterparty.

4. Stress Testing Report

MID's stress testing uses Monte Carlo simulation. Energy prices are modeled as stochastic processes where prices evolve randomly over time. The randomness is described mathematically and calibrated to observed market parameters. MID's portfolio is also modeled including statistical uncertainties in load, hydro and wind conditions. A simulation engine runs the model many times, each time sampling the probability distributions that describe MID's market positions and the market prices. Cash flow results are captured for each run. The results are presented in the form of a probability distribution for cash flow, which directly yields the risk at various levels of statistical confidence.

5. Operational Reports

a. Violations/Exceptions

Violations of and exceptions to these Policies shall be reported to the Risk Oversight Team as soon as practical. The Risk Oversight Team shall determine the appropriate course of action.

b. Collateral and Margin

Risk Management shall track collateral and margin outlays. Information shall be reported to Finance & Accounting as required.

c. Energy Derivative Assessment Report

Accounting standards require that certain derivative transactions be reported on MID's financial statements using fair value accounting, rather than accrual accounting. Transactions pursuant to this Policy must be evaluated for applicability and their fair values determined as of the end of the fiscal year. Risk Management shall produce a report for Finance & Accounting and MID's auditors for this purpose.

6. Hedge Performance Report

Hedge performance is benchmarked against the daily price indices for North Path 15 (power) and PG&E citygate (gas). The Hedge Performance Report is a comparison of the costs with and without risk management transactions. The cost with the transactions is the actual cost realized over a period. The cost without the transactions pulls out all the energy and costs of the risk management transactions and assumes the energy was bought at the index price. This is known as a "ratable" comparison.

C. Reporting Requirement Summary

The table below summarizes the reports including the intended audience, the frequency, and the contents.

Risk Reports

Report	Frequency	User	Details
		Risk Oversight Committee	•
Price Report	Weekly	Operations	• Power and gas prices • Spot and forward markets
Portfolio Analysis Report	Weekly	Operations	• Position delta values • Portfolio mark-to-market • Value-at-Risk
Limit Tracking Report	Bi-Monthly	Risk Oversight Committee	• Graph of VaR and position size versus limits
Credit Exposure by Rating	Quarterly	Risk Oversight Committee	• Graph of credit exposures by credit rating categories
Credit Limit and Concentration Report	Quarterly	Risk Oversight Committee	• Credit exposures versus limits for each counterparty • Percentage concentration
Stress Testing Report	Annual	Board of Directors Risk Oversight Committee Finance & Accounting	• Results of stress testing • Simulation and scenario analysis
Violation/Exception	As Needed	Risk Oversight Committee	• Violations of and exceptions to Policies
Collateral and Margin	As Needed	Finance & Accounting	• Cash flows into and out of collateral and margin accounts
GASB #53 Derivative Assessment	Annual	Finance & Accounting	• Fair values and GASB #53 applicability for energy deals
Hedge Performance Report	Annual	Risk Oversight Committee	• P&L, compare hedging to buying spot market energy

VI. Appendix: Board Resolutions Approving Risk Management Policy

Version 2.0 approved June 21, 2005

Version 2.1 approved December 12, 2006

Version 2.2 approved January 22, 2008

Version 3.0 approved January 26, 2010

Version 4.0 approved April 23, 2013

Version 5.0 approved May 24, 2016

RESOLUTION 2023-57
APPROVING THE ADOPTION OF THE 2024 MODESTO IRRIGATION DISTRICT INTEGRATED RESOURCE PLAN

WHEREAS, Senate Bill 350 (2015) requires MID to adopt an Integrated Resource Plan, and to submit the adopted report to the California Energy Commission (CEC); and

WHEREAS, MID staff annually develops a load forecast and a resource plan, whose results are presented to the Board of Directors through budget workshops, and whose results are relied upon to develop the purchase power & fuel budgets; and

WHEREAS, MID staff developed an Integrated Resource Plan based on the results of the 2023 load forecast and 2023 resource plan, and incorporated additional information as necessary to meet the requirements of Senate Bill 350 and the CEC's reporting guidelines.

BE IT RESOLVED, That the Modesto Irrigation District Board of Directors hereby adopts the 2024 MID Integrated Resource Plan and, pending updates to add 2023 calendar-year data once it becomes available, authorizes submission of the Integrated Resource Plan to the CEC for compliance with the requirements of Senate Bill 350 and with the CEC's reporting guidelines.

Moved by Vice President Blom, seconded by Director Keating, that the foregoing resolution be adopted.

The following roll call vote was had:
Ayes: Directors Blom, Boer, Byrd, Frobose and Keating
Noes: Director None
Absent: Director None
President Byrd declared the resolution adopted.

oOo

I, Angela Cartisano, Board Secretary of the Modesto Irrigation District, do hereby CERTIFY that the foregoing is a full, true and correct copy of a resolution duly adopted at a regular meeting of said Board of Directors held the fifth day of December 2023.

Board Secretary of the
Modesto Irrigation District