# MORENO VALLEY ELECTRIC UTILITY 2018 INTEGRATED RESOURCE PLAN

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# ATTACHMENTS

Attachment 1: MVU IRP Analysis Workbook

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- California Public Utilities Commission (CPUC) Order Instituting Rulemaking Proceeding to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements and the associated Reference System Plan, R1602007
- The California Air Resources Board (CARB) Greenhouse Gas (GHG) Cap and Trade Regulation and SB 350 related guidance, including the Scoping Plan Update
- California Independent System Operator (CAISO) tariff, business practice manuals and various related initiatives
  - CAISO 2018 Final Net Qualifying Capacity (NQC) Report
  - CAISO 2018 Final Effective Capacity List
  - CAISO Transmission Planning Process
- North American Electric Reliability Corporation (NERC)
- Western Electricity Coordinating Council (WECC)
- California Public Utilities Commission (CPUC) website, including:
  - Integrated Resource Plan and Long-Term Procurement Plan (IRP and LTPP)
  - CPUC Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans, D1802018, Proceeding R1602007, February 13, 2018
  - CPUC Standard Load Serving Entity (LSE) Plan Template
  - CPUC Guide to Production Cost Modeling in IRP Proceeding
  - CPUC Net Qualifying Capacity List (to be used by all LSEs)

- RESOLVE Model with 2017 IEPR
- CPUC Reference System Plan
- RESOLVE Inputs and Assumptions
- Summary of RESOLVE Model Inputs and Outputs

# 1 EXECUTIVE SUMMARY

## 1.1 IRP PROCESS

The Power Integrated Resource Plan (IRP) is Moreno Valley Utility's (MVU) 20-year blueprint for ensuring reliable and environmentally-responsible energy at affordable rates. It is MVU's commitment to a sustainable energy future. This IRP endeavors to substantially conform to the requirements of the California Clean Energy and Pollution Reduction Act of 2015 (SB 350), which was signed into law October 2015, and the Publicly-Owned Utility IRP Guidelines issued by the California Energy Commission (CEC) on August 9, 2017. SB 350 requires utilities with load greater than 700 GWh, to develop an IRP by January 1, 2019 and update the IRP at least every five years. As a smaller utility, MVU is not required by SB 350 to develop an IRP but does so voluntarily. For more information about IRP requirements, please see Section 18 – Legislative and Regulatory Mandates and/or visit the IRP page of the CEC website.

This IRP identifies a diverse and balanced portfolio of resources needed to ensure that MVU has reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner. The portfolio relies upon zero carbon-emitting resources to the maximum extent reasonable to achieve any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) or any successor legislation. The proposed procurement plan includes a strategy for procuring best-fit and least-cost resources to satisfy these portfolio needs.

Building an IRP is a multi-variate exercise that must fulfill many different objectives, as specified in applicable legislation, regulations and the utility's own local planning priorities. Some of these many objectives are illustrated in *Figure 1-1*.

Consistent with good utility practice and the default standard of the California Independent System Operator (CAISO), this IRP includes a capacity planning reserve margin of at least 15% above the expected annual and monthly peak demands. MVU's procurement plan includes a renewable energy procurement compliance margin of 5% per compliance period to address the risks of load variations, renewable resource performance and potential contract failure. The IRP ensures that MVU meets, by 2030, its share of the California greenhouse gas (GHG) emissions reduction target established by the California Air Resources Board (CARB).

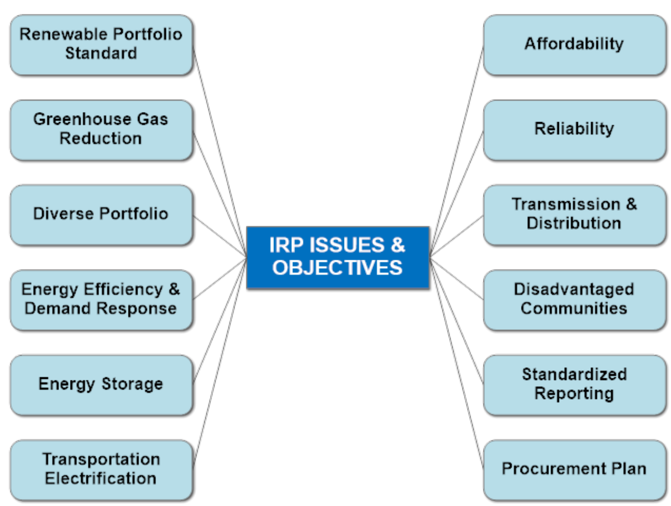



*Figure 1-1 - IRP Issues and Objectives*

### 1.1.1 IRP Modeling Approach

To the extent reasonable, the IRP utilizes publicly available analysis and work products of the CAISO, the CEC's 2017 Integrated Energy Policy Report (IEPR) and the California Public Utility Commission (CPUC)'s Integrated Resource Planning proceeding, together with the associated Reference System Plan developed using the E3 RESOLVE Model. The IRP also used Excel spreadsheets to model MVU-specific information.

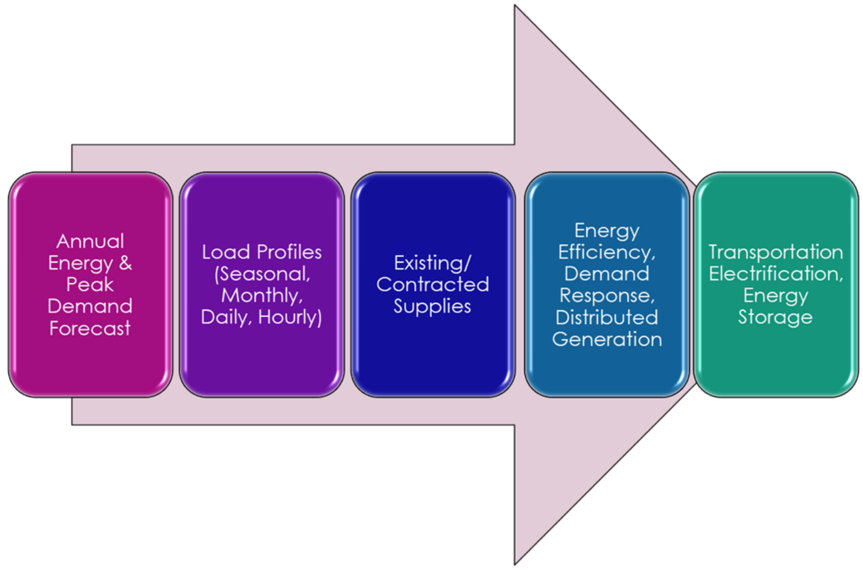



*Figure 1-2 - IRP Process Inputs*

The IRP produces analysis and recommendations based on a standard utility IRP methodology using scenarios, portfolios, and sensitivities (See *Figure 1-3*).

The IRP considered a number of potential renewable, distributed and conventional generation resources to meet load in excess of MVU's existing contracts. Energy storage was generally considered primarily as a potential capacity or shaping resource. Cost, operational characteristics and availability of these potential resources is based on the E3 Resolve Model and summarized in Section 9.

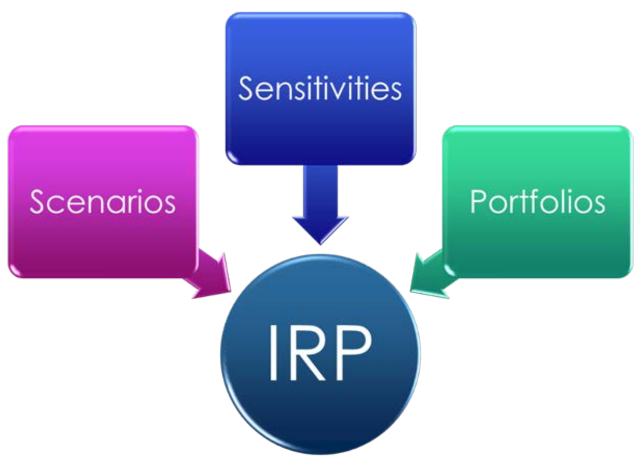



*Figure 1-3 - IRP Modeling Methodology*

On February 21, 2017, the Moreno Valley City Council approved energy efficiency targets for MVU. According to this policy, annual energy efficiency savings will be targeted at 0.65% of retail electric sales through 2027. The IRP assumes all existing and committed energy efficiency and demand response programs are in place, and additional achievable energy efficiency is set at 0.65% annually throughout the planning horizon. MVU will strive to procure all reasonably cost-effective energy efficiency and demand response, and all new construction is expected to meet the current energy efficiency standards. Any additional energy efficiency or demand response that might be procured will reduce MVU's net load and/or peak demand. These topics are addressed in Section 10.

### 1.1.2 Load Forecast

The annual load forecast is explicitly represented as a forecast of "Baseline Consumption" with a series of "demand-side modifiers." These modifiers include:

- Electric vehicles;
- Behind-the-meter PV; and
- Energy efficiency.

The load forecast was developed by projecting MVU's annual energy (MWh) and peak capacity demand (MW) using historical data and projected growth rates provided by MVU. Historical data was also used to model MVU's seasonal, monthly, daily and hourly load profiles. Using MVU's proportion of the CEC's state-wide load forecast, MVU-specific forecasts were derived for bulk transmission and distribution system losses, behind-the-meter solar PV installations, and electric vehicle charging load. The forecasted unadjusted net peak estimates MVU demand at "traditional" peak hours. The MVU peak demand forecast was adapted based on the E3/CPUC RESOLVE model results to reflect anticipated shift of utility peaks occurring later in the day due to modifiers such as rooftop solar photovoltaic production.

MVU's load forecast results are provided in Section 8.

### 1.1.3 Scenarios, Portfolios and Sensitivities

As described in Section 7, the IRP strives to achieve the "least-cost, best-fit" plan for meeting future electric system needs while maintaining regulatory compliance, high reliability, and flexibility to respond to future changes in the industry, the economy, and customer preferences. Standard industry practice for developing IRPs includes the use of 1) Scenarios, 2) Sensitivities, and 3) Portfolios.

Scenarios are defined as core sets of alternative policies, assumptions, and conditions. Portfolios are different combinations of supply and demand side resources. Sensitivities test the importance of individual variables on results. MVU included the following scenarios, portfolios and sensitivities in its 2018 IRP analysis.

#### *1.1.3.1 Scenarios*

| SCENARIO A | SCENARIO B | SCENARIO C |
|---|---|---|
| • 50% RPS by 2030<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• GHG 52 MMT $CO_2e$ | • 60% RPS by 2030<br>• 100% Clean by 2045<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• GHG 42 MMT $CO_2e$ | • 75% RPS by 2025<br>• 100% Clean by 2035<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• GHG 30 MMT $CO_2e$ |

*Figure 1-4 - MVU IRP Scenarios*

Each of the MVU IRP scenarios assume that energy efficiency consists of existing programs in place with additional achievable energy efficiency (AAEE) set at the City Council approved target of 0.65%. MVU will procure all viable and cost-effective energy efficiency and demand response. New construction is expected to be built to current energy efficiency standards.

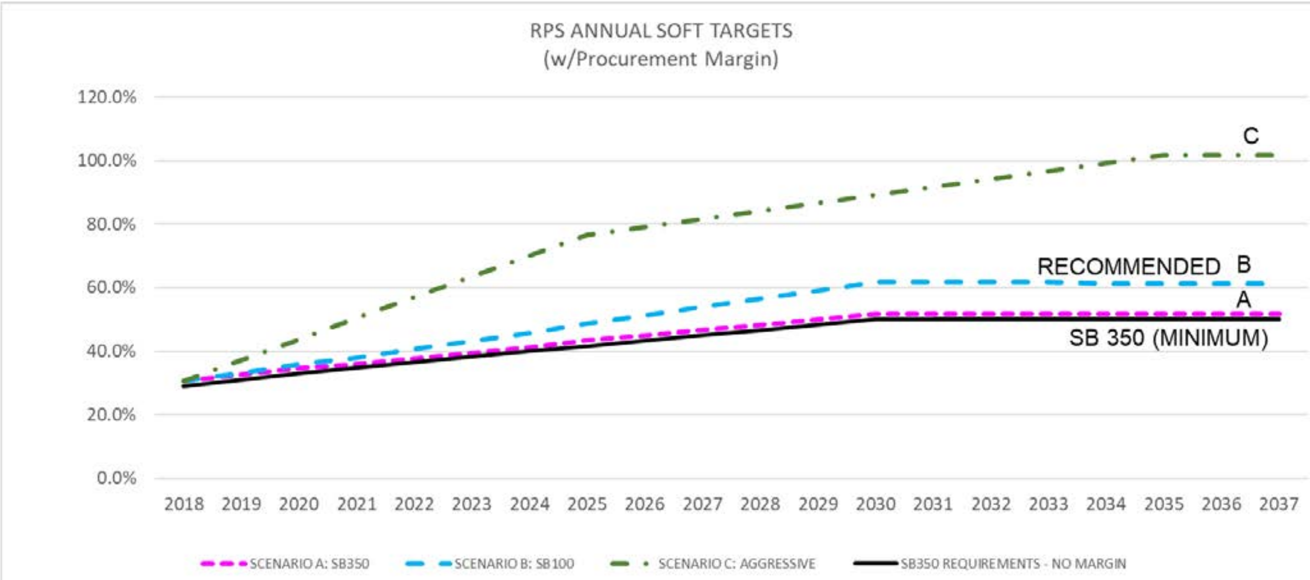
**SCENARIO A** is the base case or default scenario (the status quo). It includes meeting the requirements of SB 350 (e.g., 50% RPS by 2030) plus a procurement margin of 5% in each compliance period, with GHG emissions on current trajectory. This reflects statewide electricity sector GHG emissions of approximately 52 MMT $CO_2e$ by 2030.

**SCENARIO B** includes more progressive environmental goals, including a 60% RPS by 2030 plus a procurement margin of 5% in each compliance period and 100% "clean" (i.e., non-carbon emitting) resources by 2045. MVU's GHG emissions target is based on its share of a state-wide electricity sector goal of 42 MMT $CO_2e$ by 2030. Scenario B is intended to comply with pending California legislation (Senate Bill "SB" 100) that may increase the existing RPS.

**SCENARIO C** provides even more ambitious goals, including a 75% RPS by 2025 plus a procurement margin of 5% in each compliance period, 100% "clean energy" (non-carbon emitting, which includes large hydro in addition to renewables) by 2035, and a state-wide electricity sector GHG emissions target of 30 MMT $CO_2e$.

Figure 1-5 below compares the RPS targets in each Scenario against the current California minimum RPS.

*Figure 1-5 - Scenario RPS Targets*




### *1.1.3.2 Portfolios*

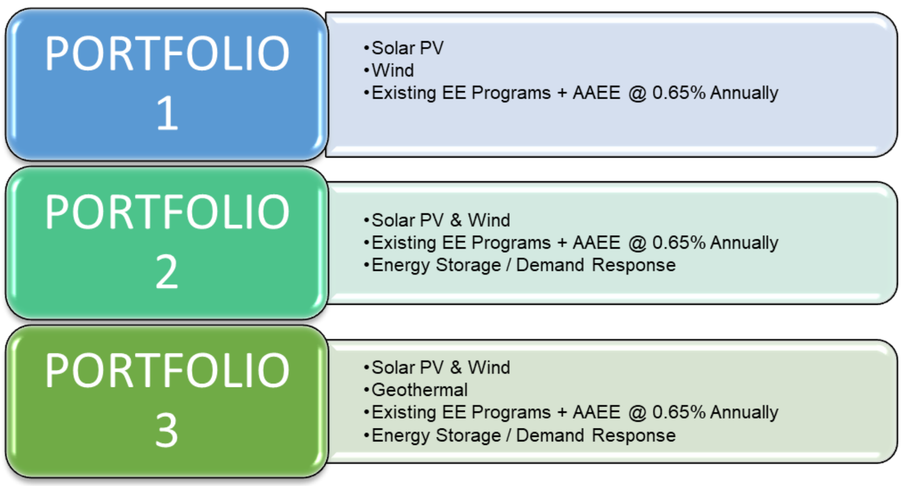



*Figure 1-6 - MVU IRP Portfolios*

Three energy resource portfolios are modeled, including:

**PORTFOLIO 1** includes existing contracts/resources and:

- Existing EE Programs + AAEE @ 0.65% Annually
- RPS Net Short is met with a mix of:
  - 70% solar PV, and
  - 30% wind.

- Any remaining need may be met with in the most cost-effective manner, including with non-renewable resources and/or capacity.

**PORTFOLIO 2** includes existing contracts/resources and:

- Existing EE Programs + AAEE @ 0.65% Annually
- One (1) MW of energy storage and/or demand response beginning in 2018-2019, then matching the expected capacity of solar resource additions thereafter
- RPS Net Short is met with a mix of:
  - 70% solar PV, and
  - 30% wind.
- Any remaining energy and/or capacity need is met in the most cost-effective manner, including with non-renewable resources and/or capacity. However, beginning in **2035**, these additional resources must be "clean," which includes resources that are not carbon-emitting, but not necessarily defined as "renewable" in California (e.g., large hydro).

**PORTFOLIO 3** includes existing contracts/resources and:

- Existing EE Programs + AAEE @ 0.65% Annually
- One (1) MW of energy storage and/or demand response beginning in 2018-2019, then matching the expected capacity of solar resource additions thereafter
- RPS Net Short is met with a mix of:
  - 55% solar PV,
  - 30% wind, and
  - 15% geothermal.
- Any remaining energy and/or capacity need is met in the most cost-effective manner, including with non-renewable resources and/or capacity. However, beginning in ***2025***, these additional resources must be "clean," which includes resources that are not carbon-emitting, but not necessarily defined as "renewable" in California (e.g., large hydro).

#### *1.1.3.3 Sensitivities*

For sensitivity analysis, the MVU IRP relied on the analysis performed to develop the CPUC Energy Division's Reference System Plan. Several sensitivities were run to test the resiliency of the preferred portfolio. These sensitivities included:

- Higher and Lower levels of energy efficiency
- Higher and lower levels of behind-the-meter solar PV
- Flexible electric vehicle charging profiles
- Higher and lower installed cost of PV solar
- Higher and lower costs of batteries for energy storage
- No Federal investment or production tax credits for renewable energy
- Accelerated retirement of natural gas-fired resources
- Lower load growth, based on the CEC IEPR projected rates

- Lower demand growth, based on the CEC IEPR projected rates

### 1.1.4 GHG Targets

The IRP incorporates MVU's share of the California 2030 GHG emissions reduction targets established by CARB. The three scenarios modeled MVU's share of different levels of projected statewide electricity sector GHG emissions. Additional information is available in Section 5.

*Figure 1-7 - GHG Emission Targets*

**MVU Share of Statewide GHG Targets (MMT $CO_2e$)**

| MVU Mid Demand Case | 2030 |
|---|---|
| Scenario A: 51 MMT $CO_2e$ | 0.0596 |
| Scenario B: 42 MMT $CO_2e$ | 0.0481 |
| Scenario C: 30 MMT $CO_2e$ | 0.0344 |

| MVU High Demand Case | 2030 |
|---|---|
| Scenario A: 51 MMT $CO_2e$ | 0.0817 |
| Scenario B: 42 MMT $CO_2e$ | 0.0660 |
| Scenario C: 30 MMT $CO_2e$ | 0.0472 |

| MVU Low Demand Case | 2030 |
|---|---|
| Scenario A: 51 MMT $CO_2e$ | 0.0431 |
| Scenario B: 42 MMT $CO_2e$ | 0.0348 |
| Scenario C: 30 MMT $CO_2e$ | 0.0249 |

## 1.2 Challenges and Critical Issues

### 1.2.1 Load Volatility

There are a number of factors that can cause actual loads to vary. Variations may include but not be limited to: the rate of growth (or decline), load shape (seasonally, daily, hourly, etc.) and capacity factor. Differences between load and planning assumptions complicate the procurement strategy. It may be challenging to secure the right amount and types of power supplies to match uncertain future loads. To ensure reliable and low-cost service, MVU strives to timely secure adequate power supplies to meet future load growth without procuring so much as to unnecessarily burden customers with the cost and risk of excess or stranded resources. There may be a mismatch in timing and commitment obligations between MVU, which must secure much of its future power supply under long-term multi-year contracts, and customer loads that are typically not under any long-term obligation to the utility.

### 1.2.2 Distributed Generation

Roof top solar and other forms of behind-the-meter (BTM) distributed generation are considerably more expensive, both to customers and to MVU, than utility scale renewable energy. Utility scale projects can be sited in areas of optimal insolation, can use solar tracking mechanisms to increase efficiency, and take advantage of significantly lower soft costs and economies of scale. MVU does not control the decision of a customer to install BTM distributed generation but may be able to influence it by modifying net metering rates to more accurately reflect the value to the utility's other customers, and by offering lower cost alternatives such as a green tariff and/or community solar project(s).

### 1.2.3 Fundamental Market Shifts

Significant increases in solar generation (both utility scale and BTM) in California have had an interesting impact on grid operations. The net load decreases significantly during the middle of the day as solar generation peaks and ramps up steeply in the evening as the sun sets. This phenomenon is commonly known as the "Duck Curve." As a consequence, some "must run" generation (including renewables) is at greater risk of potential curtailment during certain hours and seasons, while large amounts of flexible ramping capacity must be available to meet the evening peak. The daytime hours once known as "on-peak" may include a relatively "off-peak" period in the middle of the day, and a "super-peak" in the evening as solar generation declines. This fundamental change in net load affects the market value and associated prices of energy. Higher penetration of renewable energy can flood the market with "take-or-pay" energy during certain periods, resulting in historically low or even negative energy market prices, and the need for flexible peaking capacity can significantly increase prices in the early evening. These shifts can impact the value of energy received by MVU under its power sales contracts. Any time-of-use and other rates MVU may have should reflect this evolving change in its cost-of-service.

The CAISO automatically balances electricity supply and demand every five minutes by choosing the least-cost resource to meet the needs of the grid. External to the CAISO, however, utilities still manually balance supply and demand. A broader and more precise system helps with the transformation to a more diverse energy mix. Renewable resources introduce new operating dynamics best met by modernized grid dispatching. The regional Energy Imbalance Market (EIM) was formed for these reasons. EIM technology increases visibility of interconnected systems and uses automated tools to more accurately balance resources using market mechanisms. The increasing regional footprint of the EIM may help mitigate some of the operational and market price impacts of California's increasing renewable energy targets.

### 1.2.4 Changing Utility Environment

The IRP is based on legislation, regulations and market conditions at the time it is written. These frequently change. An example of change in legislation and regulations is the evolution in recent years from the requirements in Senate Bill (SB)1 X2, which included a California-wide RPS change from 20% by 2020 to 33% by 2020. Subsequently, SB 350 increased the RPS to 50% by 2030 and incorporated other electric utility resource planning obligations. Further legislation has been proposed (e.g., SB 100) that could advance the RPS even further.

An example of electric utility structural change that may materially impact electricity market conditions is the shift of substantial load to community choice aggregators (CCAs) from historical service provided by California's three large investor-owned utilities (IOUs, namely Southern California Edison, Pacific Gas and Electric and San Diego Gas and Electric). It is estimated that the majority of the customers served by CPUC regulated IOUs in the past may be served by CCAs in the future. This may have major implications on the power contracts being secured to serve future load, and consequently on energy and capacity markets.

In addition, several of California's natural-gas fired power plants may retire early due to the lack of long-term contracts necessary to keep them financially solvent, and/or newly proposed legislation. While retirement of the aging natural gas fleet may be a attractive ultimate goal, premature loss of these resources could have undesirable impacts on reliability and/or market prices.

MVU addresses these risks by: (i) using a reasonable range of IRP scenarios, portfolios and sensitivities, (ii) attempting to preserve resource flexibility and diversity to the extent practical, and (iii) frequently updating its IRP.

### 1.2.5 Energy Storage

Potential electricity generation and the demand for it by end-use consumers does not always match up. The electric grid must constantly balance the amount of energy produced with the amount consumed down to the fraction of a second. To avoid periods of overgeneration and/or resource curtailment, and to effectively utilize high levels of intermittent renewable resources such as wind and solar, the grid must have access to balancing resources such as fast response natural gas-fired generation and resources for storing peak energy production and releasing it on demand.

The IRP proposes future procurement of energy storage to the extent it is viable and cost-effective to support MVU's resource mix. One barrier to wider adoption of energy storage technologies by public utilities is the lack of market price signals for some of the services energy storage could potentially provide, and the misalignment of costs incurred with benefits derived. Many of energy storage's benefits accrue to the bulk transmission system as a whole and to the CAISO balancing authority, rather than to individual utility participants that incur the cost of owning or contracting for energy storage.

This IRP proposes modest procurement of capacity from energy storage to support the integration of variable output renewable resources (primarily solar) and to increase the resource adequacy capacity value of these resources to reduce reliance on capacity purchases from the market. To the extent it is cost-effective, the IRP recommends the procurement of energy storage capacity coupled with solar resources (i.e., "behind the fence") so that the solar output can be shaped to match optimum market prices and provide increased resource adequacy capacity from the renewable resource. Energy Storage assumptions are provided in Section 11.

### 1.2.6 Transportation Electrification

According to the CEC 2018 Integrated Energy Policy Report, the transportation sector is the largest source of greenhouse gases in California, responsible for 50 percent of emissions, as well as 80 percent of smog-forming pollutants. However, transportation markets and services are evolving quickly, and California is at the forefront of the transition. The state has outlined a vision to power California's cars, public transportation, and freight systems with clean electricity and low carbon fuels in the decades ahead and to promote active modes of transportation, including walking and cycling. Though this shift will take time, California has begun laying the groundwork necessary to make this vision a reality.

Governor Edmund G. Brown Jr. signed an executive order calling for at least five million zero emission vehicles (ZEV) on California roads by 2030 and an extensive expansion of charging and refueling infrastructure. This goal will boost the ZEV market from just over 1 percent of California's fleet today to nearly 20 percent by 2030.

Because of its location near major freeways in the greater Los Angeles area, efforts to reduce emissions from automobiles through electrification are likely to have a positive impact on the citizens of Moreno Valley. MVU can support these efforts by facilitating the installation of additional electric vehicle charging infrastructure in its service territory.

The amount, type (for example, Level 1, Level 2, DC fast charge), and location of electric vehicle charging infrastructure in the MVU service territory can have a material impact on future MVU loads. Appropriate rate structures can incentivize charging when the cost of power to MVU is lowest and may reduce potential overgeneration or curtailment of renewable energy resources during peak production. Transportation Electrification is addressed in Section 12.

### 1.2.7 Disadvantaged Communities

The California Environmental Protection Agency (CalEPA) currently identifies "disadvantaged communities" using the California Communities Environmental Health Screening Tool, available on its website[1] (CalEnviroScreen). Indicators in CalEnviroScreen are measures of either environmental conditions, in the case of pollution burden indicators, or health and vulnerability factors for population characteristics. The results are depicted on maps so that different communities can be compared to one another. A census tract with a high score is one that experiences higher pollution burden and vulnerability than census tracts with low scores. Disadvantaged communities are defined as those census tracts scoring above the 75th percentile using the CalEnviroScreen tool.

Portions of Moreno Valley as among the top 25% of communities that are considered "disadvantaged" for purposes of IRP planning. There are also disadvantaged communities near Moreno Valley, but outside of the MVU service territory. Consequently, efforts by MVU to increase the use of renewable energy resources and reduce localized pollution and GHG emissions should have a positive impact on disadvantaged communities. The IRP strives to ensure that Moreno Valley achieves the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities. In addition, the City of Moreno Valley has issued a broader Request for Proposals for "Professional Services to Prepare an Outreach Toolbox for Disadvantaged Communities – Engage Moval."

For more on disadvantaged communities, please refer to Section 13.

## 1.3 Proposed Policy Guidelines & Recommendations

### 1.3.1 Procurement and Risk Management

MVU will continue to procure resources consistent with approved policies and delegation of authority as detailed in the 2015 IRP (See details in Section 16).

[1] https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30

MVU will:

- Maintain competitive electric rates and increase control over energy costs through management of a diversified resource mix.
- Promote local economic development through the availability of special incentives within MVU's service territory, investment in local energy infrastructure and related programs.
- Help customers reduce energy consumption and electric bills through investment in and administration of locally-focused cost-effective conservation and energy efficiency programs, cost effective distributed generation and other demand-side programs.
- Enhance system reliability through investment in local distribution infrastructure, use of qualified energy suppliers/contractors, implementation of demand-side resources and focused investment in locally situated generation resources when appropriate.
- Seek utility ownership options in its renewable power supply procurement. Typically, it will not make sense for the utility to own its renewable power supplies until the investment tax credit has been fully realized by tax equity investors (generally somewhere between five and seven years after commercial operation).

### 1.3.2 Rates

MVU will review and update, if necessary, pertinent terms and conditions of its incentive programs and rates, as well as MVU's related Net Energy Metering (NEM) program to ensure that MVU-funded customer incentives are appropriately aligned with evolving industry trends and market considerations. On a going forward basis, MVU will periodically review these programs to ensure that utility costs, benefits and overarching policy objectives are appropriately reflected.

In its next cost-of-service study, MVU should review any time-of-use (TOU) rates and adjust to evolving market conditions and potentially expand their application. It may be appropriate to peg credit under the NEM program to market values for wholesale power at the time delivered. Market changes may also call for some rates to include capacity charges for standby service.

MVU will also want to review its electric vehicle charging rates to align with wholesale electric market prices. Ideally, load growth for EV charging can be incentivized through rates to complement MVU's load profile and to improve its capacity factor. These changes should be clearly communicated to customers if they are to be effective in modifying behavior.

### 1.3.3 Green Tariff/Community Solar

In order to offer its customers additional options for incorporating renewable energy into their power supply, MVU is considering offering a) a Green Tariff to allow customers to select and pay for higher proportions of renewable energy supply, and b) a Community Solar Project, which would allow customers interested in rooftop or parking lot solar the opportunity to participate in a more economical manner. These options may be particularly attractive to customers who would install behind-the-meter solar but can't because they don't own their property or the property is not well suited for solar due to the age of the roof, shading, orientation, etc.

#### 1.3.4 Resource Adequacy

Based on past practice, this IRP addresses the procurement of system resource adequacy capacity only. MVU should consider developing a policy for procurement of local and flexible resource adequacy capacity, together with a methodology for estimating its potential allocation of liability in the event of a CAISO shortfall.

## 1.4 Results and Preferred Portfolio

Scorecards were prepared for each scenario/portfolio combination, and for the mid-, low- and high-load forecasts. The name of each case includes the scenario (A, B or C), the Portfolio (1, 2 or 3), and the load forecast (Mid, Low, or High). These summary result scorecards are provided in Section 14.1. Details are in Attachment 1: MVU IRP Analysis Workbook.

- **Case A1** has been identified as MVU's base case, or minimum procurement portfolio.
- **Case B2** is the preferred portfolio, as it targets MVU's share of CARB's recommended statewide electricity section greenhouse gas emission reductions, primarily with a higher level of renewable energy procurement. The GHG reductions embodied in Case B2 are based on the same targets as the CPUC established for its jurisdictional entities, including Southern California Edison. It also reflects RPS targets that are included in proposed legislation (SB 100), positioning MVU to more easily meet these standards without changing its IRP if the legislation is passed.
- **Case C3** represents a stretch goal but is not recommended for adoption at this point in time.

## 1.5 Cost and Rate Impacts

Table 1-1 summarizes the estimated relative cost of incremental power supplies as reflected in the Portfolio Scorecards. Numbers in this table reflect the estimated net present value over the 20-year planning horizon for new resource acquisition. In its IRP proceeding, the CPUC Energy Division staff estimated that the reference system portfolio, on which preferred Scenario/Portfolio B2 was based, would result in an increase in retail rates of approximately 1% by 2030.

*Table 1-1 - Cost Comparison*

| Scenario/Portfolio | Low Demand Case | Mid Demand Case | High Demand Case |
|---|---|---|---|
| **A1** | $256,359,860 | $334,502,704 | $436,610,440 |
| **B2** | $248,027,817 | $297,699,746 | $427,734,313 |
| **C3** | $225,657,461 | $291,744,104 | $437,491,534 |

*Table 1-2 - Anticipated Additional Annual Cost for Recommended (Preferred) MVU Portfolio*

| MVU PORTFOLIO ADDITIONAL COST | |
|---|---|
| **2017 NPV** | **$297,699,746** |
| **2018** | $3,711,978 |
| **2019** | $3,257,168 |
| **2020** | $6,222,986 |
| **2021** | $8,180,498 |
| **2022** | $8,715,031 |
| **2023** | $10,506,904 |
| **2024** | $12,170,437 |
| **2025** | $14,056,550 |
| **2026** | $15,217,625 |
| **2027** | $16,392,491 |
| **2028** | $17,604,062 |
| **2029** | $18,873,611 |
| **2030** | $20,206,374 |
| **2031** | $21,602,875 |
| **2032** | $23,102,454 |
| **2033** | $24,722,555 |
| **2034** | $26,404,209 |
| **2035** | $28,292,919 |
| **2036** | $30,339,364 |
| **2037** | $34,109,779 |

# 2 BACKGROUND

## 2.1 SENATE BILL 350

On October 7, 2015, Governor Edmund G. Brown, Jr. signed the California Clean Energy and Pollution Reduction Act of 2015 – SB 350[2] into law. Among other things, SB 350 increased the Renewables Portfolio Standard (RPS) procurement target from 33 percent to 50 percent of retail sales by 2030 and requires the doubling of energy efficiency savings in retail end uses by 2030, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety. These requirements apply to all load-serving entities, including MVU.

Also pursuant to SB 350, Section 9621 of the Public Utilities Code (PUC) requires local publicly owned electric utilities (POUs) with an average electrical demand exceeding 700 gigawatt-hours, as determined on a three-year average commencing January 1, 2013 to adopt Integrated Resource Plans (IRPs). This requirement is not applicable to MVU, which has developed its IRP voluntarily.

SB 350 includes a number of provisions specifying issues to be addressed in IRPs, including adverse impacts on disadvantaged communities, transportation electrification, the adoption of renewable energy procurement plans, energy storage systems, resource adequacy, reliability, portfolio diversity and balance, and cost effectiveness.

SB 350 requires that the IRPs include strategies to achieve greenhouse gas (GHG) emissions reduction targets. Those targets are to be established by the California Air Resources Board (CARB), in coordination with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). For the electricity sector, the targets reflect the sector's percentage share in achieving the economy wide GHG emissions reductions of 40 percent from 1990 levels by 2030.

In order to establish energy efficiency targets that achieve a statewide cumulative doubling of energy efficiency savings in electricity and natural gas end uses by 2030, SB 350 requires the CEC to conduct a public process that engages with stakeholders. This public process is carried out separately through the Integrated Energy Policy Report (IEPR) process.

In addition, the CEC is tasked with reviewing POU IRPs and making recommendations to correct any deficiencies. Pursuant to PUC Section 9622 the CEC has adopted guidelines[3] to govern the submission of information, data, and reports needed to support CEC review of POU IRPs.

## 2.2 ABOUT MORENO VALLEY UTILITY

The City of Moreno Valley, California is home to approximately 200,000 residents. It was incorporated as a General Law City on December 3, 1984, merging the communities of Moreno, Sunnymead and Edgemont. It includes an area of 51.5 square miles, located in Southern

[2] Senate Bill 350, De León, Chapter 547, Statutes of 2015
[3] California Energy Commission Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines, July 2017 (CEC-200-2017-004-CMF)

California's "Inland Empire" in the western portion of Riverside County, surrounded by Riverside, Perris, March Air Reserve Base, Lake Perris and the Badlands. Moreno Valley's elevation is 1,650 Ft.

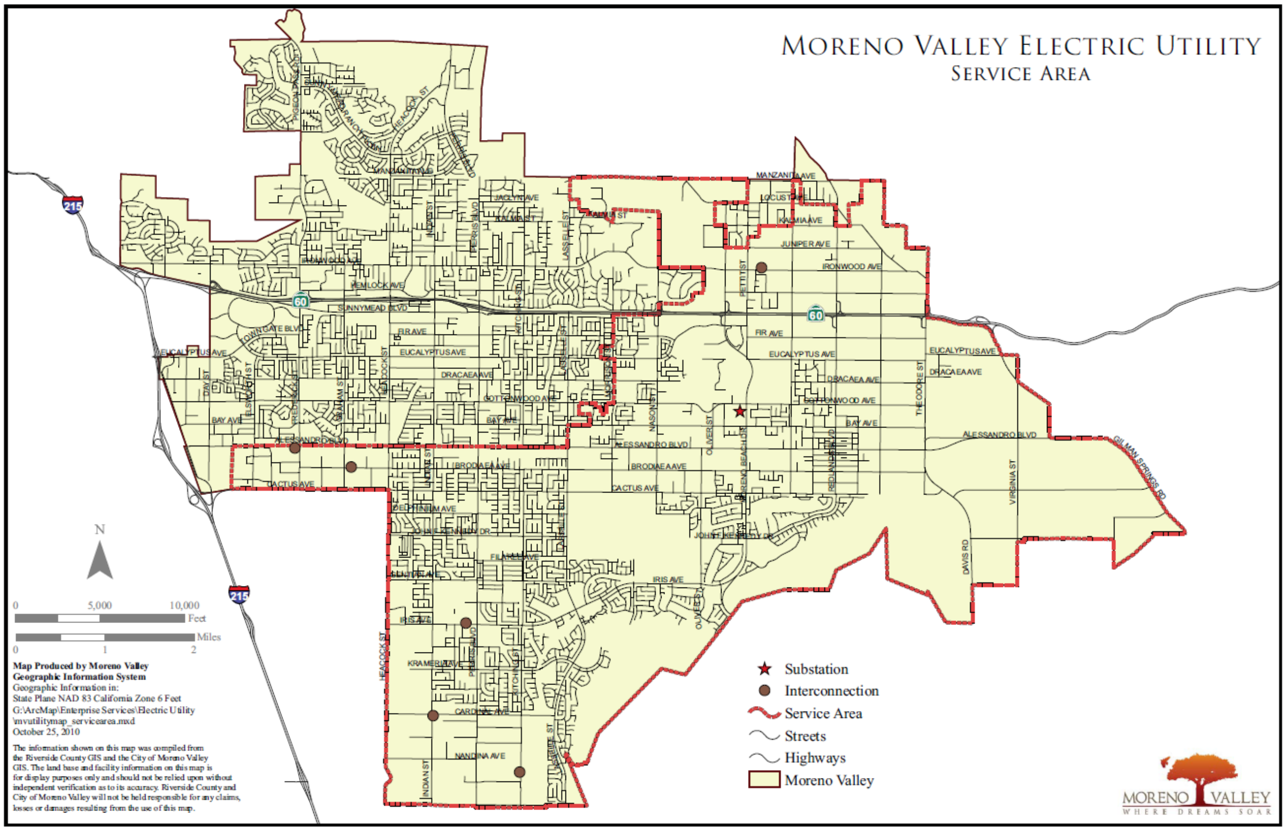



*Figure 2-1 - Moreno Valley Electric Utility Service Area*

Moreno Valley is among California's fastest growing cities. It is the second most populous city in Riverside County. Projected growth can be attributed to the large areas of undeveloped property for commercial enterprises and the addition of energy-intensive commercial accounts focused in the logistics, e-commerce and fulfillment industries. The City is a favorable location for large-scale distribution centers. Moreno Valley hosts economic development programs; a range of quality housing options including high-end executive homes, affordable single-family homes, and condominiums; a family-friendly lifestyle; good schools, impressive quality-of-life amenities and growing job centers. Moreno Valley's amenities include: more than 38 parks and/or joint-use facilities (531 maintained acres) and 6,000 acres of open space at Lake Perris; recreational facilities, major medical, and educational facilities; quality housing at affordable prices, open spaces, abundant retail centers, industrial developments, social and cultural activities.

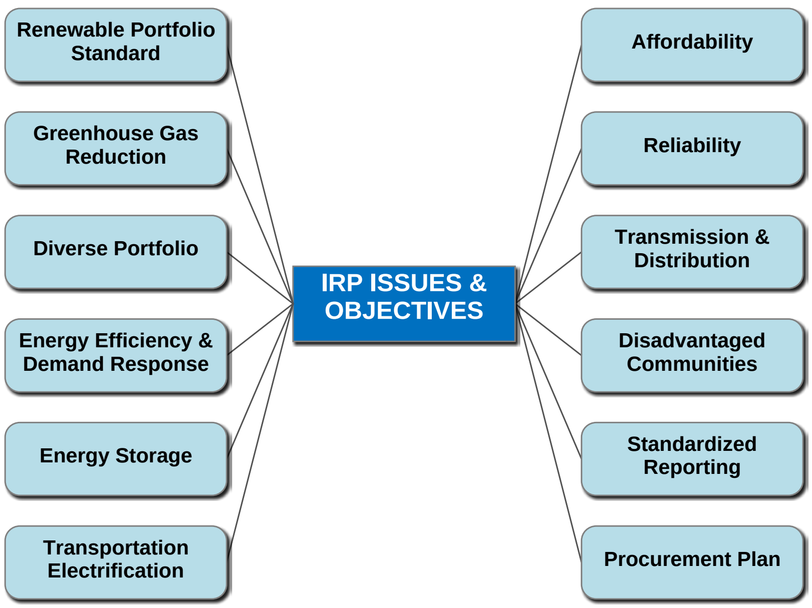
The mission of the Moreno Valley Electric Utility (MVU) is to provide safe, reliable, and economical public electric service with a focus on innovative customer solutions, infrastructure enhancement, community development, and environmentally responsible resource management. MVU is a fairly young utility, celebrating 14 years of service in 2018. MVU was established with the purpose of enhancing economic development in the City. As a "greenfield" utility, MVU provides electric service to new housing and business development. With fairly new utility infrastructure and 100%

underground service, MVU boasts an impressive record of reliability. MVU fully supports a diversified, sustainable power supply that includes renewables, energy efficiency, demand response, energy storage, electric vehicles, and cost-effective and clean distributed generation.

## 2.3 IRP OBJECTIVES

Building an IRP is a multi-variate exercise that must fulfill many different objectives, as specified in applicable legislation, regulations and the utility's own local planning priorities. Some of these many objectives are illustrated in *Figure 2-2* below, and further described in the following text.

*Figure 2-2 - IRP Issues & Objectives*




- Renewable Portfolio Standard – The IRP plans for the procurement of sufficient eligible renewable energy resources to serve at least 50 percent of annual retail load by 2030, plus a reasonable margin of procurement to manage the risk of load uncertainty, renewable resource performance variations and potential contract failures. There are four compliance periods covering the period between 2017 and 2030. Calculation of the forecasted procurement target for each compliance period is based on annual retail sales, and the procurement plan demonstrates reasonable progress toward "soft targets" in each individual year. The mix of renewables

| COMPLIANCE PERIOD | YEARS | RPS TARGET (% of Retail Load) |
|---|---|---|
| **3** | Jan 1, 2017 through Dec 31, 2020 | 33% |
| **4** | Jan 1, 2021 through Dec 31, 2024 | 40% |
| **5** | Jan 1, 2025 Through Dec 31, 2027 | 45% |
| **6** | Jan 1, 2028 Through Dec 31, 2030+ | 50% |

*Table 2-1 - RPS Targets by Compliance Period* must meet portfolio content category requirements. Beginning in 2021, at least 65% of renewable energy resources must be supplied through utility ownership or long-term (10+ year) contracts. See *Table 2-1* and *Table 2-2* for a summary of these requirements.

*Table 2-2 - RPS Portfolio Content Categories*

| Portfolio Content Category (PCC) | Description | Requirement |
|---|---|---|
| **0** | Any contract or ownership agreement originally executed prior to June 1, 2010, shall "count in full" toward the RPS procurement requirements.[4] | N/A |
| **1** | Eligible renewable energy resource electricity products that:<br>(A) Have a first point of interconnection with a California balancing authority;<br>(B) Are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source; or<br>(C) Have an agreement to dynamically transfer electricity to a California balancing authority. | =>75% |
| **2** | Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority. | Up to 15% |
| **3** | Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify as PCC 1 or 2. | <=10% |

- Greenhouse Gas Reduction - The IRP includes a strategy for MVU to meet the 2030 GHG emissions reduction targets established by the California Air Resources Board (CARB). The GHG targets in this IRP reflect the electricity sector's share of California's ambitious goal of reducing statewide GHG emissions to 80% below 1990 levels by 2050. *Figure 2-3* below illustrates the planned trajectory of the emission reductions. The IRP details assumptions on net emissions impacts from MVU's existing and planned programs expected to reduce net GHG emissions. The IRP reports estimated emissions intensities in metric tons of carbon dioxide equivalent per megawatt-hour (MT $CO_2e$/MWh) for each supply resource.

[4] if all of the following conditions are met:
(1) The renewable energy resource was eligible under the rules in place as of the date when the contract was executed, and
(2) Any contract amendments or modifications occurring after June 1, 2010, do not increase the nameplate capacity or expected quantities of annual generation, or substitute a different renewable energy resource. The duration of the contract may be extended if the original contract specified a procurement commitment of 15 or more years.

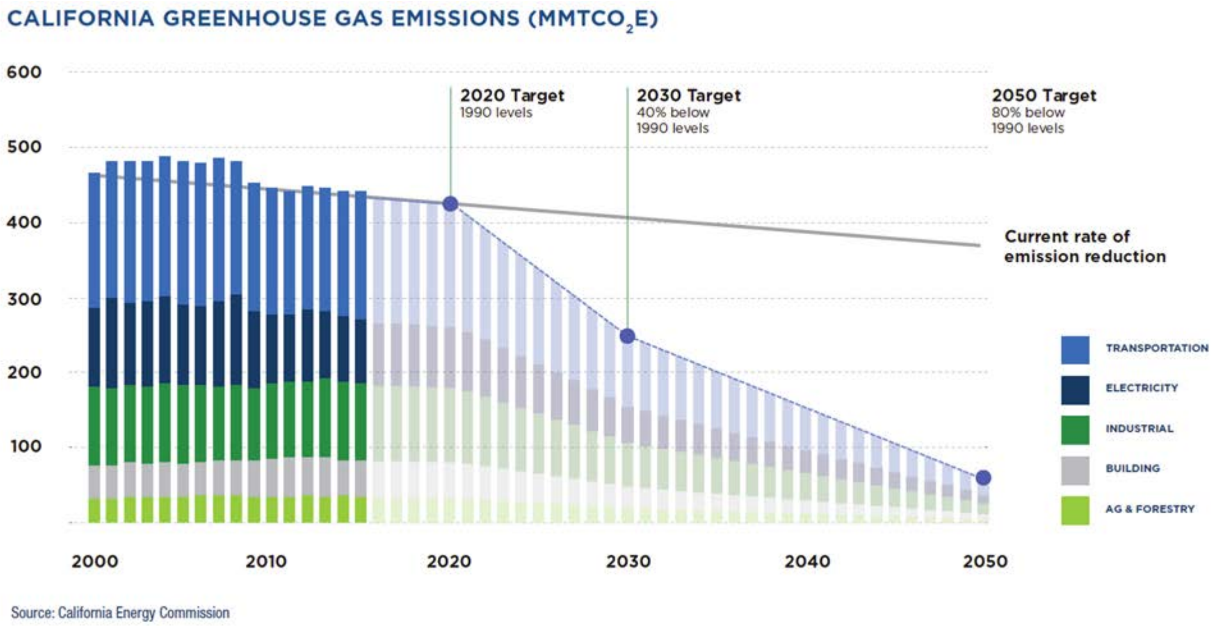



*Figure 2-3 - California Greenhouse Gas Emissions*

- Diverse Portfolio – The IRP recommends procurement of a diversified power supply portfolio consisting of both short-term and long-term electricity, electricity-related, and demand response products. Beginning January 1, 2021, at least 65 percent of the procurement that counts toward the renewables portfolio standard requirement in each compliance period must be from contracts of 10 years or more in duration or utility ownership of eligible renewable energy resources.

- Energy Efficiency/Demand Response – SB 350 requires the CEC to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. These statewide targets are to be based on a doubling of the mid-case estimate of additional achievable energy efficiency (AAEE) savings, as contained in the *California Energy Demand Updated Forecast,* extended to 2030. The IRP recommends programs and measures that will contribute toward the SB 350 goal, address procurement of energy efficiency and demand response resources and include the impacts of these programs. Because Moreno Valley is a relatively new utility, there are fewer opportunities to procure energy efficiency. Load growth is expected to come primarily from new construction, which will be built to current energy efficiency standards. The utility's goal is to procure all cost effective and viable energy efficiency and demand response, with specific City Council approved energy efficiency measures targeted at 0.65% annually.

- Energy Storage – The IRP addresses procurement of viable and cost-effective energy storage pursuant to California Public Utilities Code (PUC) Chapter 7.7, commencing with

PUC Section 2835. To the extent possible, the energy storage analysis describes (1) the possible role that storage can play to address overgeneration concerns and reduce the need for generation from specific gas-fired generation or market sources, and (2) any quantitative analyses that evaluates the cost-effectiveness of multi-hour storage compared to other resources that meet evening ramping needs.

- Transportation Electrification – The IRP addresses procurement of resources to support transportation electrification. The transportation sector accounts for nearly 40 percent of statewide greenhouse gas (GHG) emissions. Transportation electrification is an important strategy for meeting the state's long-term GHG emission reduction goals.

- Affordability – The IRP ensures the goal of serving customers at just and reasonable rates and minimizing impacts on ratepayer bills. The IRP includes estimates of rate impacts under the recommended IRP scenario for consideration by the City Council as the local governing authority.

- Reliability – MVU must prudently plan for and procure adequate resources to meet its planning reserve margin, peak demand and operating reserves in order to provide reliable electric service to its customers. The IRP specifies (i) how the utility will meet the goal of ensuring system and local reliability and (ii) the procurement plan to meet resource adequacy requirements.

- Transmission & Distribution System – The IRP supports the goal of strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and of local communities. Transmission into MVU is relatively new and robust, with no current system reliability concerns. There are no plans for material upgrades or enhancements to the distribution system, or to transmission and distribution communications and information technology to reliably integrate distributed generation and demand-side energy management.

- Disadvantaged Communities - IRPs must ensure achievement of the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities. The California Environmental Protection Agency (CalEPA) has identified disadvantaged communities based on geographic, socioeconomic, public health, and environmental hazard criteria using the California Communities Environmental Health Screening Tool, available on its website.[5] The IRP includes a discussion of current programs and policies in place to address local air pollution, new and existing emissions reductions programs focused on disadvantaged communities, and efforts to identify disadvantaged communities in the utility's service territory, if applicable.

- Standardized Reporting – The IRP includes annual data through the planning horizon in the following four Standardized Tables developed by the CEC:

[5] https://www.calepa.ca.gov/files/2017/04/SB-535-Designation-Final.pdf

- *Capacity Resource Accounting Table (CRAT)*: Annual peak capacity demand in each year and the capacity contribution of each energy resource in the utility's portfolio to meet that demand.
- *Energy Balance Table (EBT)*: Annual total energy demand and annual estimates for energy supply from various resources.
- *RPS Procurement Table (RPT)*: A summary of the utility's resource plan to meet the RPS requirements.
- *GHG Emissions Accounting Table (GEAT)*: Annual GHG emissions associated with each resource in the utility's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.

- Procurement Plan – The ultimate goal of the IRP is to identify the mix of resources to be used by MVU to meet all of its obligations over the planning horizon, and to develop a short-term (2-3 year) action plan. The procurement plan includes all inputs, assumptions, and methodologies.

## 2.4 COORDINATION WITH ENERGY POLICY AGENCIES

In preparing this IRP, MVU has monitored and to the extent practicable, incorporated information (in some cases, verbatim) from:

- The CEC's SB 350 proceedings, IRP Guidelines and Integrated Energy Policy Report development;
- The CPUC's R1602007 Order Instituting Rulemaking Proceeding to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements and the associated Reference System Plan;
- The CARB GHG Cap and Trade Regulation and SB 350 related guidance, including the Scoping Plan Update;
- The relevant CAISO tariff provisions, business practice manuals and various related initiatives.

# 3 SYSTEM PLANNING REQUIREMENTS

PUC section 9620 requires each local publicly owned electric utility serving end-use customers to prudently plan for and procure adequate resources to meet its planning reserve margin and peak demand and operating reserves, sufficient to provide reliable electric service to its customers.

## 3.1 Reliability Planning – Reserve Margin

As required by national (NERC) and regional (WECC) reliability criteria and the CAISO Tariff, MVU must adopt a planning reserve margin for use in its annual and monthly resource adequacy plans, if applicable. The reserve margin is a percentage of the coincident peak demand forecasts.

Consistent with good utility practice and the default standard of the CAISO, this IRP includes a **planning reserve margin of at least 15%** above the expected annual and monthly peak demands.

## 3.2 Resource Adequacy (RA)

MVU is required to provide the CAISO with annual and monthly resource adequacy plans to demonstrate compliance with the reliability requirements of CAISO Tariff Section 40. In these plans, CAISO scheduling coordinators demonstrate that they have procured sufficient capacity resources to meet their coincident peak load plus reserve margin. Failure to demonstrate sufficient resource adequacy resources in the annual or monthly resource plans may trigger the CAISO's capacity procurement mechanism pursuant to CAISO Tariff Section 43, and the City may be responsible for its share of the associated costs.

A resource providing resource adequacy capacity is generally subject to an availability assessment by the CAISO. The availability standard is 96.5 percent each month. If the monthly availability calculation is below the lower bound (94.5 percent) of the CAISO's monthly availability standard, the resource may be subject to a non-availability charge for the month. RA resources whose availability calculation is above the CAISO's upper bound (98.5 percent) of the monthly availability standard may be eligible for an availability incentive payment for the month.

There are three types of resource adequacy capacity that must be designated. There may be some overlap. For example, a local RA resource can also qualify as a system RA resource, but not all system RA resources qualify as local RA resources. RA resources must be available during the five-consecutive peak availability assessment hours each month as designated by the CAISO.

### 3.2.1 System RA

MVU must demonstrate it owns, controls or has contractual rights to system resource adequacy resources with sufficient CAISO verified net qualifying capacity to meet MVU's monthly coincident peak demand, plus the planning reserve margin of 15%.

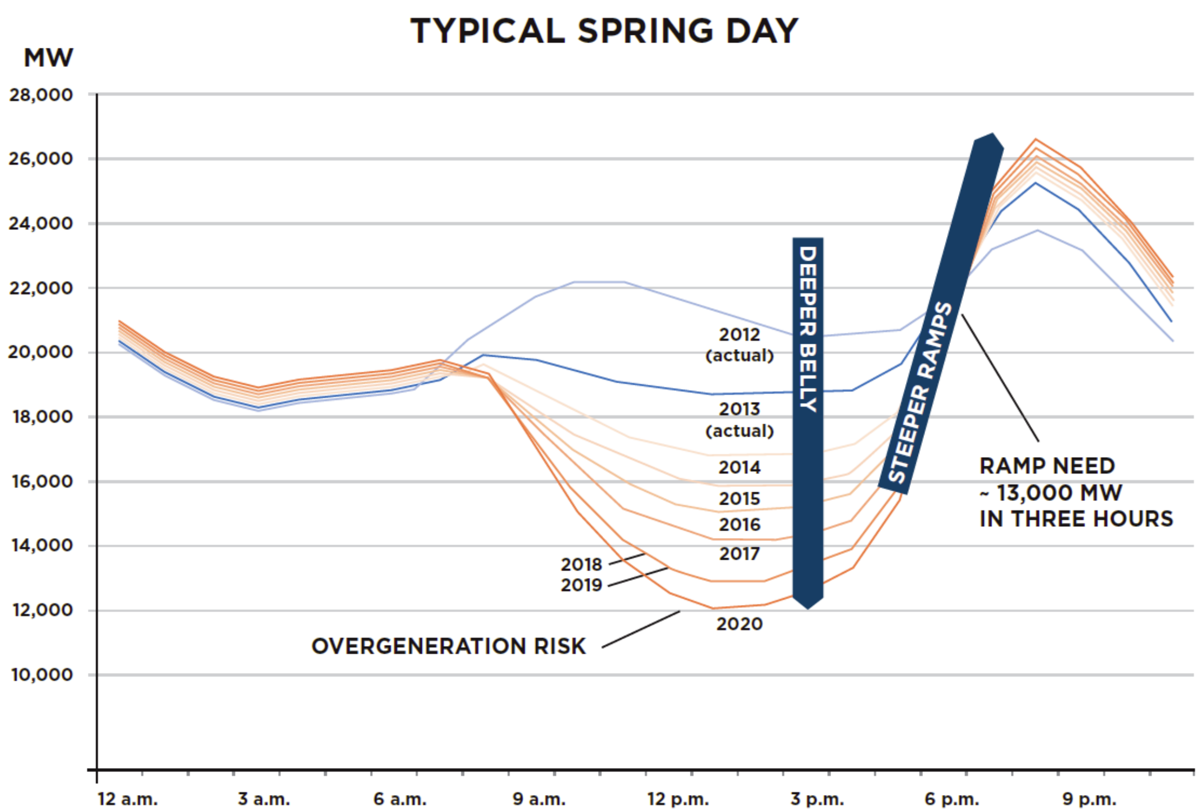
### 3.2.2 Local – LA Basin

Local capacity area resources are needed to address certain contingencies in areas of the CAISO grid where bulk transmission limitations or other conditions may constrain the electrical supply available to serve load. The cost responsibility for these local resources is allocated to the scheduling coordinators for load serving entities within the constrained local area in proportion to their annual coincident peak load share. MVU is in the CAISO's East Central Transmission Access Charge (TAC) area and can procure local capacity area resources from the LA Basin and/or Big Creek Ventura local capacity subareas. Changes in the available natural gas storage at Aliso Canyon have impacted (increased) the local capacity requirements in the LA Basin.

### 3.2.3 Flexibility

The CAISO has identified a need for sufficient capacity that is operationally flexible enough to respond to dispatch instructions necessary to address the uncertainty and variability of changing load profiles and of intermittent energy resources such as wind and solar. The CAISO's "Duck Curve" is the most well-known tool for illustrating this growing need.

*Figure 3-1 - Duck Curve Equals Electricity Demand Minus Wind and Solar Generation (Net Load)*




Source: California ISO, presentation by Mark Rothleder at May 12, 2017, IEPR workshop

Flexible resource adequacy capacity (FRAC) is a subset of resource adequacy capacity with specific operating characteristics, as defined in Section 40.10 of the CAISO Tariff, to address these needs. Each year, the CAISO conducts a flexible capacity needs assessment to specifically identify the largest forecasted three-hour net load ramps within a given month for the upcoming year and determine each local regulatory authority's contribution to this ramp in MW. The allocation is based on the average of the sum of the load serving entities' change in load, minus the change in wind output, minus the change in solar PV output, minus the change in solar thermal output during the five highest three-hour net-load changes in the month.

There are three categories of flexible resource adequacy capacity resources with increasingly stringent operating characteristics: base ramping, peak ramping, and super peak ramping. A resource that meets the qualifications of the flexible capacity category for base ramping resources also qualifies as a peak ramping resource. A resource that meets the qualifications of the flexible capacity category for base ramping resources or peak ramping resources also qualifies as a super-peak ramping resource. The primary characteristics of each category of flexible ramping resource adequacy resources are illustrated in Table 3-1.

*Table 3-1 - Flexible RA Categories*

| | BASE | PEAK | SUPER-PEAK |
|---|---|---|---|
| **DAYS AVAILABLE** | 7 days/week | 7 days/week | Every non-holiday weekday |
| **HOURS AVAILABLE** | 17 hours/day<br>5 AM to 10 PM | 5 hours/day<br>specific hours vary by season | 5 hours/day<br>specific hours vary by season |
| **MIN. HOURS AT FULL EFFECTIVE FLEXIBLE CAPACITY** | 6 | 3 | 3 |
| **MINIMUM STARTUPS** | 2 per day<br>60 per month | 1 per day | 1 per day<br>5 CAISO dispatches per month |

## 3.3 Net Qualifying Capacity

The contribution of each type of generation resource to this requirement depends on its performance characteristics and availability to produce power during the most constrained periods of the year. This contribution is referred to as Net Qualifying Capacity (NQC). For most thermal generation, these Net Qualifying Capacity percentages are relatively close to 100% as shown in *Table 3-2*.

*Table 3-2 - Thermal Resource NQC*

| RESOURCE CLASS | NQC (% of max) |
|---|---|
| CHP* | 100% |
| Nuclear | 99% |
| CCGT1 | 95% |
| CCGT2 | 98% |
| Peaker1 | 98% |
| Peaker2 | 98% |
| Advanced_CCGT | 95% |
| Aero_CT | 95% |
| Reciprocating_Engine | 100% |
| ST | 100% |

The contribution of demand response resources to the resource adequacy requirement, including new shed DR resources, is assumed to be equal to the 1-in-2 ex ante peak load impact. Shift demand response resources are not currently assumed to have an impact on the planning reserve margin.

Renewable resources with full deliverability capacity status (FCDS) are assumed to contribute to system resource adequacy requirements. These resources fall into two categories: (1) baseload, which includes all biomass, geothermal, and small hydro; and (2) variable resources, which includes both solar and wind resources. The treatment of each category reflects the differences in their intermittency.

For baseload renewables, each resources' contribution to resource adequacy is assumed to be equivalent to its average annual capacity factor (i.e., a geothermal resource with an 80% capacity factor is also assumed to have an 80% net qualifying capacity). This assumption reflects the characteristic of baseload resources that they tend to produce energy throughout the year with a relatively flat profile, and thereby their contribution to peak needs is not materially different from their average levels of production throughout the year.

*Table 3-3 - Geothermal NQC*

| Geothermal | |
|---|---|
| **Month** | **CY 2018 Geothermal Factor** |
| JAN | 79.17% |
| FEB | 79.19% |
| MAR | 78.96% |
| APR | 75.19% |
| MAY | 78.50% |
| JUN | 76.03% |
| JUL | 77.10% |
| AUG | 77.18% |
| SEP | 74.03% |
| OCT | 75.60% |
| NOV | 78.36% |
| DEC | 78.18% |

The contribution of variable renewable resources to system resource adequacy needs is based on the concept of "Effective Load Carrying Capability" (ELCC), defined as the incremental flat load that may be met when that resource is added to a system while preserving the same level of reliability. The contribution of wind and solar PV resources to resource adequacy needs depends not only on the coincidence of the resource production with peak loads, but also on the characteristics of the other variable resources on the system as well. This relationship is perhaps best illustrated by the phenomenon of the declining marginal capacity value of solar resources as the "net" peak demand shifts away from periods of peak solar production. For the sake of simplicity, the capacity contribution of variable renewable resources in this IRP is based on the CAISO's 2018 ELCC Values and Technology Factors, as shown in *Table 3-5* - Solar ELCC/NQC and *Table 3-4* - Wind ELCC/NQC.

*Table 3-5 - Solar ELCC/NQC*

| Solar PV | |
|---|---|
| **Month** | **CY 2018 Solar ELCC** |
| JAN | 0.0% |
| FEB | 2.4% |
| MAR | 10.4% |
| APR | 33.2% |
| MAY | 30.5% |
| JUN | 44.8% |
| JUL | 41.7% |
| AUG | 41.0% |
| SEP | 33.4% |
| OCT | 29.4% |
| NOV | 4.1% |
| DEC | 0.0% |

*Table 3-4 - Wind ELCC/NQC*

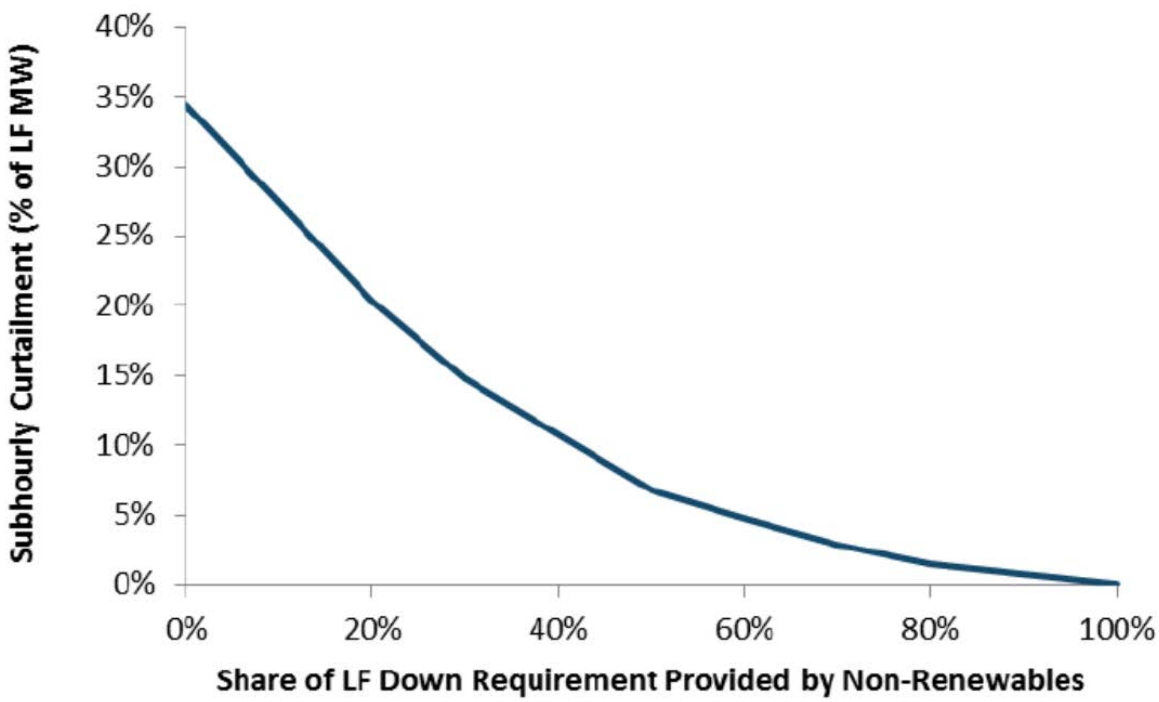
| Wind | |
|---|---|
| **Month** | **CY 2018 Wind ELCC** |
| JAN | 11.3% |
| FEB | 17.3% |
| MAR | 18.3% |
| APR | 31.4% |
| MAY | 30.6% |
| JUN | 47.5% |
| JUL | 29.7% |
| AUG | 26.5% |
| SEP | 26.5% |
| OCT | 8.8% |
| NOV | 8.4% |
| DEC | 15.2% |

For energy storage, a use-limited resource, the contribution to the planning reserve margin is a function of both the capacity and the duration of the storage device. To align with resource adequacy accounting protocols, a resource with four hours of duration may count its full capacity towards the planning reserve margin. For resources with durations under four hours, the capacity contribution is de-rated in proportion to the duration relative to a four-hour storage device (e.g. a 2-hour energy storage resource receives half the capacity credit of a 4-hour resource).

## 3.4 Renewable Curtailment

The RESOLVE model allows renewables to provide load following down. This allows renewables to be curtailed on the sub-hourly level to provide reserves. The amount of sub-hourly curtailment (i.e. the deployment) is parametrized by a "Reflex Surface" in the SYS_Reserves worksheet of the RESOLVE model. *Figure 3-2* below shows the amount of sub-hourly curtailment this results in. For instance, when all load following down is met by renewables, this surface indicates that the amount of sub-hourly curtailment that would occur would be equal to 34% of the hourly downward load following requirement across the hour (i.e. “deployed”).

*Figure 3-2 - Anticipated Sub-Hourly Renewable Curtailment as a Function of Load Following (LF) Met by Renewables*




## 3.5 Transmission and Distribution System

MVU is a CAISO participating load. Accordingly, its transmission needs, including any reliability or economic system upgrades, are addressed through the CAISO’s transmission planning process.

The RESOLVE model includes assumptions regarding the assumed transmission costs to import energy from resources in various other balancing authorities to the CAISO, as shown in *Table 3-6 - Assumed Transmission Costs (Hurdle Rates) in RESOLVE ($/MWh)*[6]. In addition to these cost-based hurdle rates, an additional cost is attributed to all imports to California reflecting the cost to import unspecified power into California under CARB’s cap and trade program; this cost is calculated based on the relevant year’s carbon cost and a deemed rate of 0.428 tons/MWh.

*Table 3-6 - Assumed Transmission Costs (Hurdle Rates) in RESOLVE ($/MWh)*

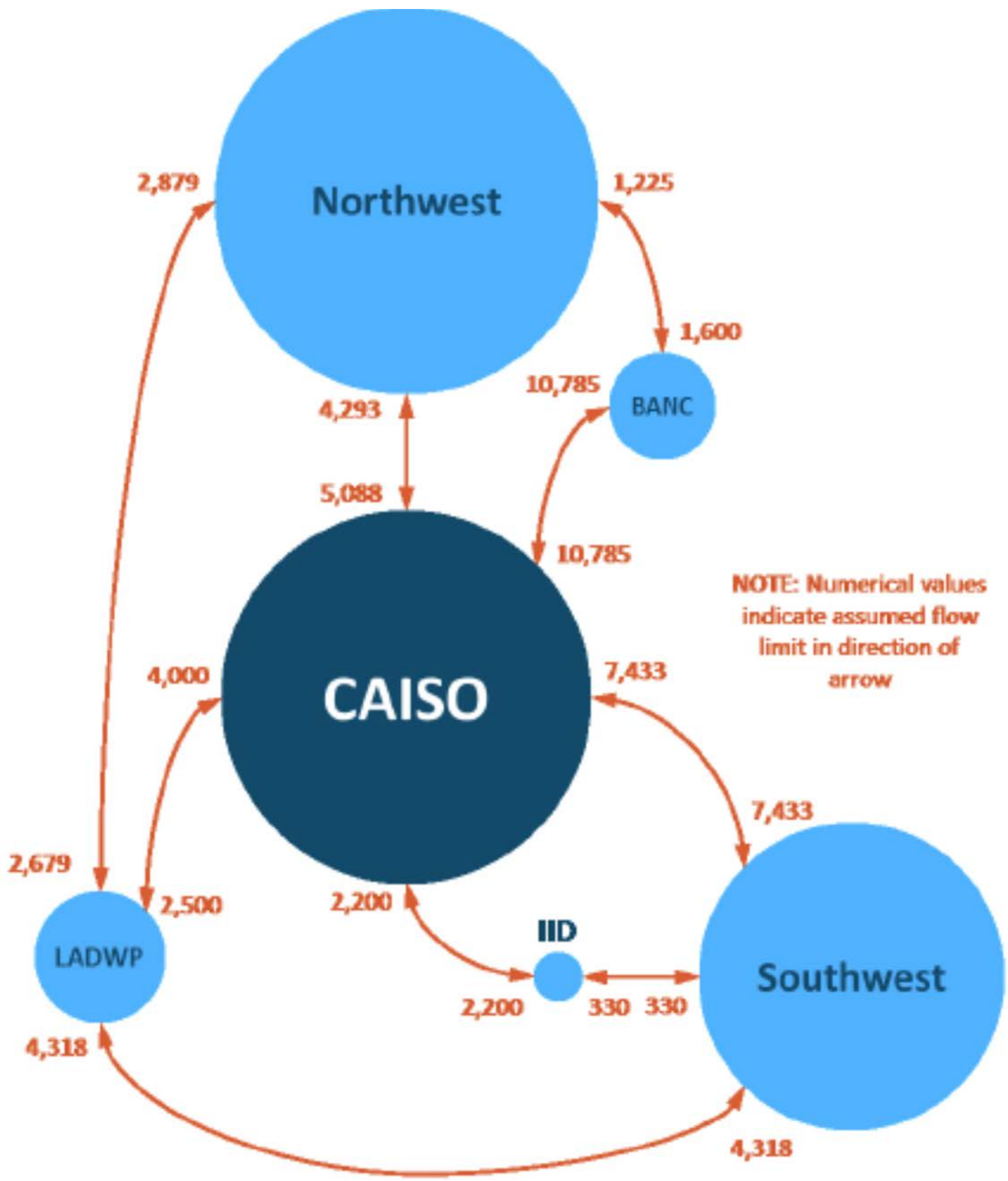
| Export Zone | Hurdle Rate ($/MWh) |
|---|---|
| From BANC | $2.47 |
| From CAISO | $9.96 |
| From IID | $4.07 |
| From LDWP | $5.71 |
| From NW | $3.89 |
| From SW | $3.86 |

[6] Source: CPUC 2017 RESOLVE Documentation, Inputs and Assumptions, 9/15/2017, pages 66-69

Although the costs in *Table 3-6 - Assumed Transmission Costs (Hurdle Rates) in RESOLVE ($/MWh)* are shown as variable costs ($/MWh) for modeling simplicity, it is worth noting that many of these transmission providers offer service on a capacity basis only, which significantly increases the effective transmission rate for low-capacity factor resources such as wind and solar.

The MVU service territory does not have any local transmission constrained areas (i.e., where loads can be reliably served only if there is sufficient local dispatchable generation capacity that provides operating reserves and associated energy under high-load conditions).

*Figure 3-3 - Transmission Topology Used in RESOLVE (Transfer Limits Shown in MW)*



# 4 RENEWABLE PORTFOLIO STANDARDS

## 4.1 RPS REQUIREMENTS

MVU is required to procure eligible renewable energy resources equivalent to at least 50 percent of its retail load by 2030, consistent with California Public Utilities Code (PUC) Article 16, commencing with Section 399.11. MVU reports the following data in the attached CEC Energy Balance and RPS Procurement Tables:

- Forecasted RPS Procurement Targets (% and MWh)
- Forecasted Renewable Resource Procurement (MWh)
- The RPS Procurement Plan

*Table 4-1 - RPS Requirements by Compliance Period*

| COMPLIANCE PERIOD | YEARS | SB 350[1] RPS TARGET (% of Retail Load) |
|---|---|---|
| 3 | January 1, 2017 through December 31, 2020 | 33% |
| 4 | January 1, 2021 through December 31, 2024 | 40% |
| 5 | January 1, 2025 Through December 31, 2027 | 45% |
| 6 | January 1, 2028 Through Dec 31, 2030+ | 50% |

*At least 65% of RPS contracts must have a duration 10+ years beginning Jan. 1, 2021.*

*[1] Existing California Golden State Standard (SB 350) RPS Minimum Targets.*

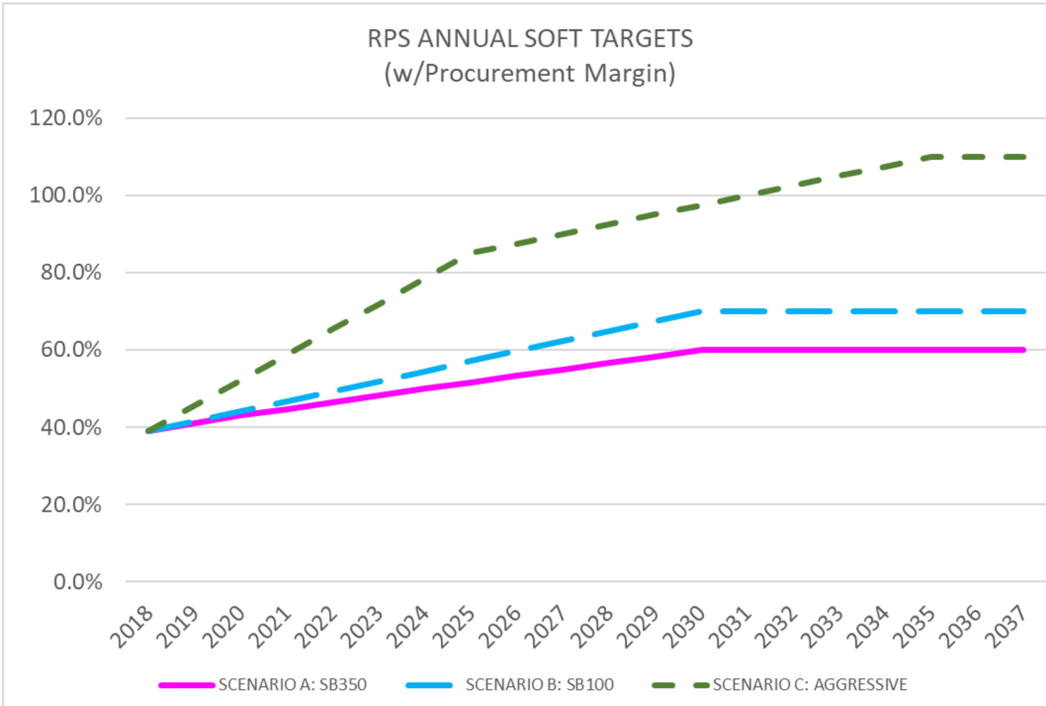
This IRP defines the minimum procurement needed to meet the requirements for each compliance period pursuant to PUC Section 399.30(c) (2). There are four compliance periods covering 2017 through 2030, as illustrated in *Table 4-1* - RPS Requirements by Compliance Period. Calculation of the forecasted procurement target for each compliance period is based on annual retail sales (as reported in the Energy Balance Table) and the City's established RPS annual soft targets as shown in *Figure 4-1* - RPS Annual Soft Targets, plus a reasonable procurement margin. The forecasted procurement targets for each compliance period may also be adjusted to reflect specific RPS provisions, such as voluntary green pricing programs.

The forecast of RPS procurement assumed to be available to meet the RPS planning requirement may include:

- Historical carryover from pre-2011 procurement.
- Excess procurement from previous compliance periods.
- Utility-owned and contracted resources (as identified in the Energy Balance Table).
- A forecast of additional procurement needed in each compliance period. This forecast may include:
  - Utility-owned resources or contracts for energy (as identified in the Energy Balance Table).
  - Purchase of limited unbundled RECs, not to exceed 10% of the RPS requirement.

For RPS procurement purposes, MVU's procurement plan includes a **procurement compliance margin of 5%** to address the risks of load variations, renewable resource performance and potential contract failure.

*Figure 4-1 - RPS Annual Soft Targets*




This IRP does not rely on any exemptions or optional compliance measures that affect the City's forecasted procurement requirements. The City's RPS procurement plan is incorporated into the IRP. The IRP includes the plan to meet the portfolio balance and long-term contracting requirements as shown in *Figure 4-2 - RPS Portfolio Content Categories*. No issues have been identified that have the potential to prevent the City from procuring sufficient renewable resources.

*Figure 4-2 - RPS Portfolio Content Categories*

| Portfolio Content Category (PCC) [1] | Description | Requirement |
|---|---|---|
| 0 | Any contract or ownership agreement originally executed prior to June 1, 2010, shall "count in full" toward the RPS procurement requirements. [2] | N/A |
| 1 | Eligible renewable energy resource electricity products that: (A) Have a first point of interconnection with a California balancing authority; (B) Are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source; or (C) Have an agreement to dynamically transfer electricity to a California balancing authority. | =>75% |
| 2 | Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority. | Up to 15% |
| 3 | Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify as PCC 1 or 2. | <=10% |

*At least 65% of RPS contracts must have a duration 10+ years beginning Jan. 1, 2021.*
*[1] From Public Utilities Code Section 399.16*

*[2] Only if all of the following conditions are met:*

*(A) The renewable energy resource was eligible under the rules in place as of the date when the contract was executed, and*

*(B) Any contract amendments or modifications occurring after June 1, 2010, do not increase the nameplate capacity or expected quantities of annual generation, or substitute a different renewable energy resource.*

## 4.2 LOCAL RENEWABLE RESOURCE DEVELOPMENT

As part of its renewable energy procurement strategy, MVU may choose to independently develop locally situated, customer-sited renewable energy projects. City leadership has expressed an interest in developing these smaller-scale projects to the greatest extent practical. However, prices available in the current wholesale market for utility-scale renewable energy continue to decrease, resulting in price comparisons (relative to smaller-scale distributed generation) that place locally situated renewable generating capacity at a competitive disadvantage. Depending on project-specific details, pricing associated with certain locally-situated renewable capacity may exceed utility-scale alternatives by 50-100%. In some instances, the local economic and political benefits associated with local capacity installation(s) may outweigh the noted cost premium. However, as the operator of a relatively new utility, the City must remain cautious when evaluating these tradeoffs to avoid imposing disproportionate rate impacts on its customers. Looking forward, the City may choose to pursue development of select, locally-situated renewable project opportunities to supplement purchases from utility-scale project alternatives.

# 5 GHG REDUCTION GOALS

This IRP ensures that MVU meets, by 2030, its share of the GHG emissions reduction target established by CARB. The three scenarios modeled in this IRP address the City's share of different levels of statewide electricity sector GHG emissions. For each supply resource included in its Energy Balance Table, the City reports to the CEC its estimated emissions intensities (in metric tons of carbon dioxide equivalent per megawatt hour (MT $CO_2e$/MWh) using the Greenhouse Gas Emissions Accounting Table. The IRP assumptions on net emissions impacts from existing and planned programs expected to reduce net GHG emissions are based on CARB emissions summary data and the GHG planning prices specified in the CPUC IRP filing requirements decision template issued in February 2018 (*Table 5-1* - IRP GHG Planning Prices). The GHG Planning Price is equivalent to the marginal cost of GHG abatement associated with the 42 MMT Scenario for the years 2018 to 2026 (i.e., a curve that slopes upward from ~$15/ton to ~$23/ton), followed by a straight-line increase from ~$23/ton in 2026 to $150/ton in 2030. The straight-line increase is intended to fill the gap for the years for which the CPUC's RESOLVE model does not produce GHG abatement cost values (i.e., 2027, 2028, and 2029).

*Table 5-1 - IRP GHG Planning Prices*

| GHG Planning Prices for Use in IRP | |
|---|---|
| **Year** | **Price per metric ton of CO2e emissions** |
| **2018** | $15.17 |
| **2019** | $16.05 |
| **2020** | $16.94 |
| **2021** | $17.88 |
| **2022** | $18.86 |
| **2023** | $19.91 |
| **2024** | $21.02 |
| **2025** | $22.19 |
| **2026** | $23.44 |
| **2027** | $55.08 |
| **2028** | $86.72 |
| **2029** | $118.36 |
| **2030** | $150.00 |
| **SOURCE: CPUC Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans, Rulemaking 16 02 007, Decision 18-02-018, February 8, 2018, Pg. 115, Table 5** | |

An alternative to the GHG Planning Price is the GHG Emissions Benchmark. The GHG Emissions Benchmark for MVU is a percentage of the GHG emissions target based on MVU's 2030 proportionate share of the state electrical load using the "mid Baseline mid AAEE mid AAPV" version of Form 1.1c of the CEC's adopted 2017 IEPR demand forecast. See *Table 5-2* - MVU GHG Emissions Benchmarks. MVU's 2030 projected load share used to determine these benchmarks is provided below in *Table 5-3* - Moreno Valley Forecasted 2030 Load Share.

*Table 5-2 - MVU GHG Emissions Benchmarks*

## MVU Share of Statewide GHG Targets (MMT $CO_2e$)

| CEC Mid-Demand | **2030** |
|---|---|
| Scenario A: 51 MMT $CO_2e$ | 0.0389 |
| Scenario B: 42 MMT $CO_2e$ | 0.0314 |
| Scenario C: 30 MMT $CO_2e$ | 0.0224 |

| MVU Mid Case | **2030** |
|---|---|
| Scenario A: 51 MMT $CO_2e$ | 0.0596 |
| Scenario B: 42 MMT $CO_2e$ | 0.0481 |
| Scenario C: 30 MMT $CO_2e$ | 0.0344 |

| MVU High Case | **2030** |
|---|---|
| Scenario A: 51 MMT $CO_2e$ | 0.0817 |
| Scenario B: 42 MMT $CO_2e$ | 0.0660 |
| Scenario C: 30 MMT $CO_2e$ | 0.0472 |

| **MVU Low Case** | **2030** |
|---|---|
| Scenario A: 51 MMT $CO_2e$ | 0.0431 |
| Scenario B: 42 MMT $CO_2e$ | 0.0348 |
| Scenario C: 30 MMT $CO_2e$ | 0.0249 |

*Table 5-3 - Moreno Valley Forecasted 2030 Load Share*

| Load Forecasts | |
|---|---|
| CEC Statewide Mid-Demand Load Forecast (GWh) [2] | 248,293 |
| CEC MVU Mid-Demand Load Forecast (GWh) [2] | 186 |
| MVU Mid Case Load Forecast (GWh) [3] | 285 |
| MVU High Case Load Forecast (GWh) [3] | 390 |
| MVU Low Case Load Forecast (GWh) [3] | 206 |

| MVU Load as % of Statewide Load | |
|---|---|
| CEC Mid-Demand (%) | 0.075% |
| MVU Mid Case (%) | 0.115% |
| MVU High Case (%) | 0.157% |
| MVU Low Case (%) | 0.083% |

[1] SOURCE: CPUC Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans, Rulemaking 16 02 007, Decision 18-02-018; February 8, 2018, Page 115 Table 5

[2] SOURCE: CEC 2017 IEPR Form 1.1c - Statewide California Energy Demand Forecast 2018 - 2030, Mid Demand Baseline Case, Mid AAEE and AAPV Savings - Electricity Deliveries to End Users by Agency (GWh)

[3] SOURCE: MVU Forecast from Budget

# 6 STUDY DESIGN

## 6.1 OBJECTIVES

This IRP identifies a diverse and balanced portfolio of resources needed to ensure that MVU has reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner. The portfolio relies upon zero carbon-emitting resources to the maximum extent reasonable to achieve any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) or any successor legislation. The proposed procurement plan includes a strategy for procuring best-fit and least-cost resources to satisfy these portfolio needs.

Some of the specific objectives include:

- **Reliability**: Ensuring resource adequacy to support system and local electric service reliability.
- **Cost**: Fulfilling MVU's obligation to serve its customers at just and reasonable rates and minimizing impacts on ratepayers' bills.
- **Compliance**: Meeting the requirements of any laws, rules and regulations applicable to MVU's power supply and resources.
- **GHG Reduction**: Meeting MVU's proportionate share of the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the CPUC and the CEC, for the electricity sector and each load-serving entity. These targets reflect the electricity sector's percentage in achieving the economywide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.
- **Renewable Portfolio Standard**: Procuring at least 50 percent eligible renewable energy resources by December 31, 2030.
- **Diversity and Sustainability**: Strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and the local community.
- **Demand-Side**: Enhancing distribution systems and demand-side energy management.
- **Transportation Electrification**: Addressing the electrical system needs and promoting the adoption of transportation electrification as a means of reducing GHG.
- **Energy Storage**: Procuring cost effective and viable energy storage to support electrical system reliability, renewable resource integration, and changing load profile impacts on market prices and flexible resource requirements.
- **Disadvantaged Communities**: Minimizing localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

## 6.2 METHODOLOGY

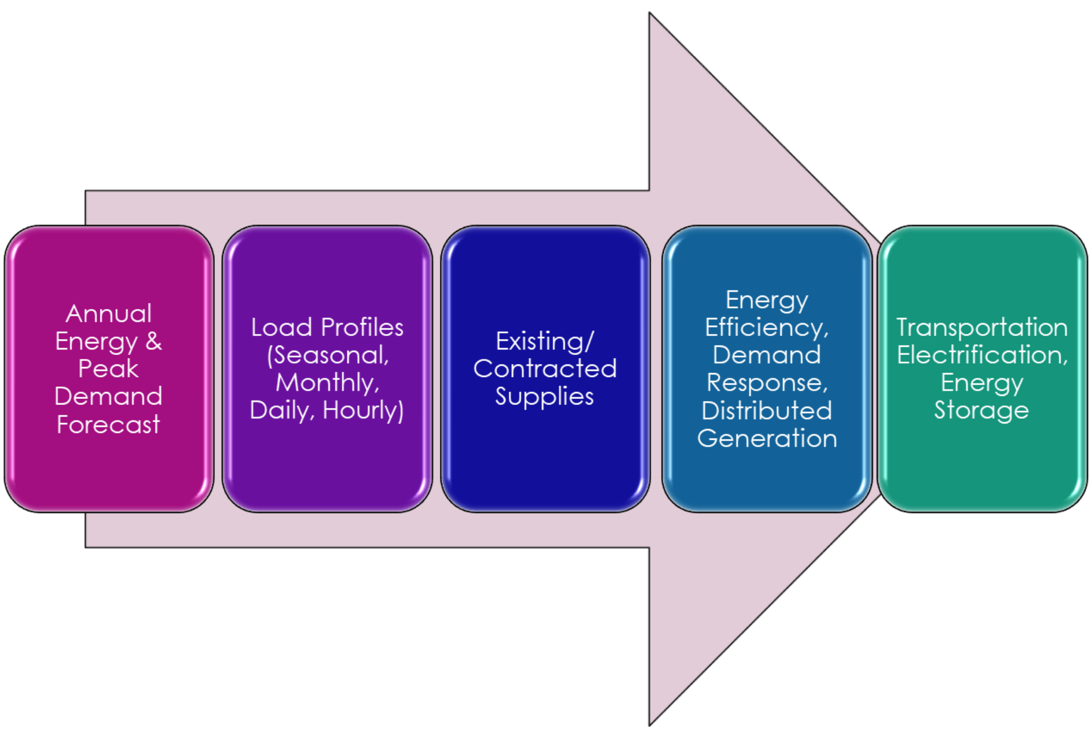
### 6.2.1 Modeling Tools

To the extent reasonable, this IRP utilizes the publicly available analysis and work products of the CAISO, the CEC's 2017 Integrated Energy Policy Report (IEPR) and the CPUC's Integrated Resource Planning proceeding, together with the associated Reference System Plan developed using the E3 RESOLVE Model. This IRP also used Excel spreadsheets to model MVU-specific information.

### 6.2.2 Modeling Approach

The IRP was developed by forecasting MVU's annual energy (MWh) and peak demand (MW) forecast using historical data and projected growth rates provided by MVU. Historical data was also used to model MVU's seasonal, monthly, daily and hourly load profiles. For context, the load forecast was compared to the CEC's IEPR load forecast for MVU, and ratios of state and CAISO load were derived from the CEC forecasts. Using MVU's proportion of the CEC's state-wide load forecast, MVU-specific forecasts were derived for bulk transmission and distribution system losses, behind-the-meter solar PV installations, and electric vehicle charging load. The forecasted unadjusted net peak projects MVU demand at "traditional" peak hours. The MVU peak demand forecast was adapted based on the E3/CPUC RESOLVE model results to reflect anticipated shift of utility peaks occurring later in the day compared to the traditional end use peak due to demand modifiers such as solar photovoltaic production.

Figure 6-1 - MVU IRP Inputs



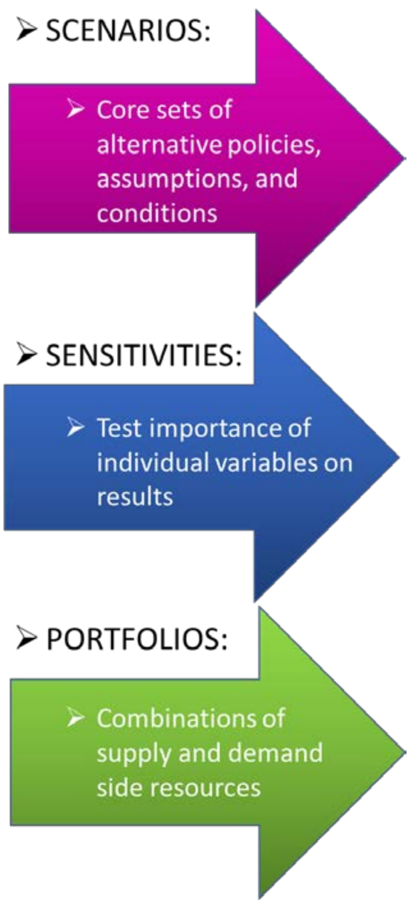
MVU provided contracts and associated data for modeling the energy production and resource adequacy capacity of its existing and contracted power supplies. Where available, historical and or contractually-specified data was used. Where not available, generic generation profiles from the RESOLVE Model and resource adequacy net qualifying capacity (NQC) from the CAISO's 2018 NQC Technology Factors were used. Expected cost, operational characteristics and load levels for potential new resources, energy storage and transportation electrification were taken from the results of the RESOLVE model.

MVU's proportionate share of greenhouse gas emissions and emission reduction targets (i.e., 51, 42 and 30 MMT $CO_2e$ in 2030) were calculated from the CARB data and RESOLVE model results. 42 MMT is equivalent to a 46 MMT assumption when compared with the 30-53 MMT range identified for the electric sector in the most recent Scoping Plan Update adopted by CARB. GHG planning prices were taken from the "CPUC Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans," Rulemaking 16 02 007, Decision 18-02-018, dated February 8, 2018, Pg. 115, Table 5.

MVU's projected electric vehicle transportation charging load was forecast using the RESOLVE model, adapted to MVU's proportionate share of California load.

### 6.2.3 Methodology

*Figure 6-2 - IRP Modeling Methodology*





The IRP produces analysis and recommendations based on a standard utility IRP methodology using scenarios, portfolios, and sensitivities (see *Figure 6-2* - IRP Modeling Methodology). Specifics regarding this modeling construct are provided in Section 7 - *SCENARIOS & SENSITIVITIES.*

# 7 SCENARIOS & SENSITIVITIES

The IRP strives to achieve the "least-cost, best-fit" plan for meeting future electric system needs while maintaining regulatory compliance, high reliability, and flexibility to respond to future changes in the industry, the economy, and customer preferences. Standard industry practice for developing IRPs includes the use of 1) Scenarios, 2) Sensitivities, and 3) Portfolios. Scenarios are defined as core sets of alternative policies, assumptions, and conditions. Sensitivities test the importance of individual variables on results. Portfolios are different combinations of supply and demand side resources. MVU included the following scenarios, portfolios and sensitivities in its 2018 IRP analysis.

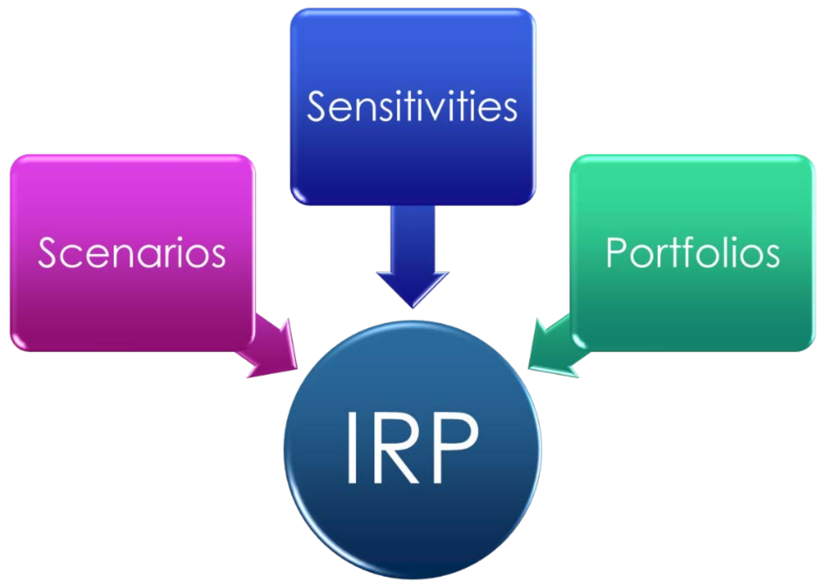



*Figure 7-1 - Scenarios, Sensitivities & Portfolios*

## 7.1 Scenarios

**SCENARIO A** is the base case or default scenario (the status quo). It includes meeting the requirements of SB350 (e.g., a 50% RPS by 2030), with the existing energy efficiency programs in place plus additional achievable energy efficiency at the City Council approved target of 0.65% annually. GHG emissions are on the current trajectory. It reflects statewide electricity sector GHG emissions of approximately 52 MMT $CO_2e$ by 2030.

**SCENARIO B** includes more progressive environmental goals, including a 60% RPS by 2030 and 100% "clean" (i.e., non-carbon emitting) resources by 2045. Energy efficiency consists of existing programs in place plus additional achievable energy efficiency at the City Council approved target of 0.65% annually. GHG emissions are based on a state-wide electricity sector goal of 42 MMT $CO_2e$ by 2030.

**SCENARIO C** provides even more ambitious goals, including a 75% RPS by 2025, 100% clean energy by 2035, and a state-wide electricity sector GHG emissions target of 30 MMT $CO_2e$. Energy efficiency consists of existing programs in place plus additional achievable energy efficiency at the City Council approved target of 0.65% annually.

| SCENARIO A | SCENARIO B | SCENARIO C |
|---|---|---|
| • 50% RPS by 2030<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• GHG 52 MMT $CO_2e$ | • 60% RPS by 2030<br>• 100% Clean by 2045<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• GHG 42 MMT $CO_2e$ | • 75% RPS by 2025<br>• 100% Clean by 2035<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• GHG 30 MMT $CO_2e$ |

*Figure 7-2 - IRP Scenarios*

## 7.2 PORTFOLIOS

| | |
|---|---|
| PORTFOLIO 1 | • Solar PV<br>• Wind<br>• Existing EE Programs + AAEE @ 0.65% Annually |
| PORTFOLIO 2 | • Solar PV & Wind<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• Energy Storage / Demand Response |
| PORTFOLIO 3 | • Solar PV & Wind<br>• Geothermal<br>• Existing EE Programs + AAEE @ 0.65% Annually<br>• Energy Storage / Demand Response |

*Figure 7-3 - IRP Portfolios*

Three energy resource portfolios are modeled, including:

**PORTFOLIO 1** includes existing contracts/resources and:

- RPS Net Short is met with a mix of:
    - 70% solar PV, and
    - 30% wind.
- Non-Renewable Energy: Any remaining need is met with non-renewable resources and/or capacity.
- AAEE at the City Council approved target of 0.65% annually.

**PORTFOLIO 2** includes existing contracts/resources and:

- AAEE at the City Council approved target of 0.65% annually
- Energy Storage/Demand Response: one (1) MW of energy storage and/or demand response beginning in 2018-2019, then matching the expected capacity of solar resource additions thereafter
- RPS Net Short is met with a mix of:
    - 70% solar PV, and
    - 30% wind.
- Non-Renewable Energy: Any remaining need is met with non-renewable resources and/or capacity, with the constraint that, beginning in **2035**, such non-renewable energy must be "clean," which includes non-renewables that are not carbon-emitting, such as large hydro and nuclear.

**PORTFOLIO 3** includes existing contracts/resources and:

- AAEE at the City Council approved target of 0.65% annually
- Energy Storage/Demand Response: one (1) MW of energy storage and/or demand response beginning in 2018-2019, then matching the expected capacity of solar resource additions thereafter
- RPS Net Short is met with a mix of:
    - 55% solar PV,
    - 30% wind, and
    - 15% geothermal.
- Non-Renewable Energy: Any remaining need is met with non-renewable resources and/or capacity, with the constraint that, beginning in ***2025***, such non-renewable energy must be "clean," which includes non-renewables that are not carbon-emitting, such as large hydro.

## 7.3 SENSITIVITIES

For sensitivity analysis, the MVU IRP relied on the analysis performed to develop the CPUC Energy Division's Reference System Plan. Several sensitivities were run to test the resiliency of the preferred portfolio. These sensitivities included:

- Higher and Lower levels of energy efficiency
- Higher and lower levels of behind-the-meter solar PV
- Flexible electric vehicle charging profiles

- Higher and lower installed cost of PV solar
- Higher and lower costs of batteries for energy storage
- No Federal investment or production tax credits for renewable energy
- Accelerated retirement of natural gas-fired resources
- Lower load growth, based on the CEC IEPR projected rates
- Lower demand growth, based on the CEC IEPR projected rates

The following were among the findings of the sensitivity analysis:

- With some exceptions, the least-cost portfolio composition for meeting different GHG targets and reliability constraints does not change much under different assumptions about the future.
- Generally, model results indicate that part of the least-cost solution for 2030 is to procure utility-scale solar PV and wind within the next 1-3 years to take advantage of federal tax credits. Procuring refers to entering into power purchase agreements. These agreements may include deliveries that begin many years in the future. No costs would be incurred until deliveries begin.
- Future conditions modeled that tend to increase total resource costs include:
  - High levels of behind-the-meter solar PV
  - Zero curtailment of renewables (requires additional battery storage)
  - No tax credits
  - Early and/or high levels of natural gas plant retirements
  - High loads
  - High technology (e.g., PV and battery) costs

# 8 LOAD FORECAST

MVU anticipates significant load growth over the planning horizon. However, the timing of load increases is subject to significant uncertainty and is unlikely to reflect the smoothed growth curve generally reflected in resource plans. Going forward, MVU will perform annual reviews of these customer and electric load projections to ensure that such projections accurately build upon observed historical trends and incorporate any changes to planned development activities that may impact future projections.

The annual load forecast is explicitly represented as a forecast of “Baseline Consumption” with a series of “demand-side modifiers.” These modifiers include:

- Electric vehicles;
- Behind-the-meter PV; and
- Energy efficiency.

“Baseline Consumption” refers to a forecast of the consumption of electricity derived from projected retail sales, capturing forecast economic and demographic changes in the absence of load modifiers.

MVU’s load forecast was developed using a simple annual load growth model. MVU acknowledges that load growth is often more “lumpy” than the forecast would indicate but using a wide range of forecasts, along with planning reserve and procurement compliance margins, will allow MVU to adapt to changes as they occur.

As a relatively young utility in a rapidly growing community with strong economic development goals, the MVU budget includes forecasted annual load growth far greater than the average projections utilized by the CEC in its IEPR. MVU’s internal load forecasts include net growth of 1% in the low case, 3.5% in the mid case and 6% in the high case. By contrast, the CEC’s projected annual average growth rates for low, mid and high case scenarios are -1.14%, -0.24% and 1.33% respectively. These MVU and CEC forecasts are illustrated in *Figure 8-1* - MVU Energy Load Forecast vs. CEC below. Details are provided in Attachment 1: MVU IRP Analysis Workbook, and Attachment 2: CEC Standardized Tables (EBT – Energy Balance Table).

In the absence of aggressive demand side management, MVU anticipates that its peak capacity demand will grow even faster than its energy load. Peak demand is forecasted to grow at rates of 3% (low case), 6% (mid case) and 9% (high case), as illustrated in *Figure 8-2* - MVU Annual Peak Demand Forecast below and in Attachment 1: MVU IRP Analysis Workbook, and Attachment 2: CEC Standardized Tables (CRAT – Capacity Resource Accounting Table).

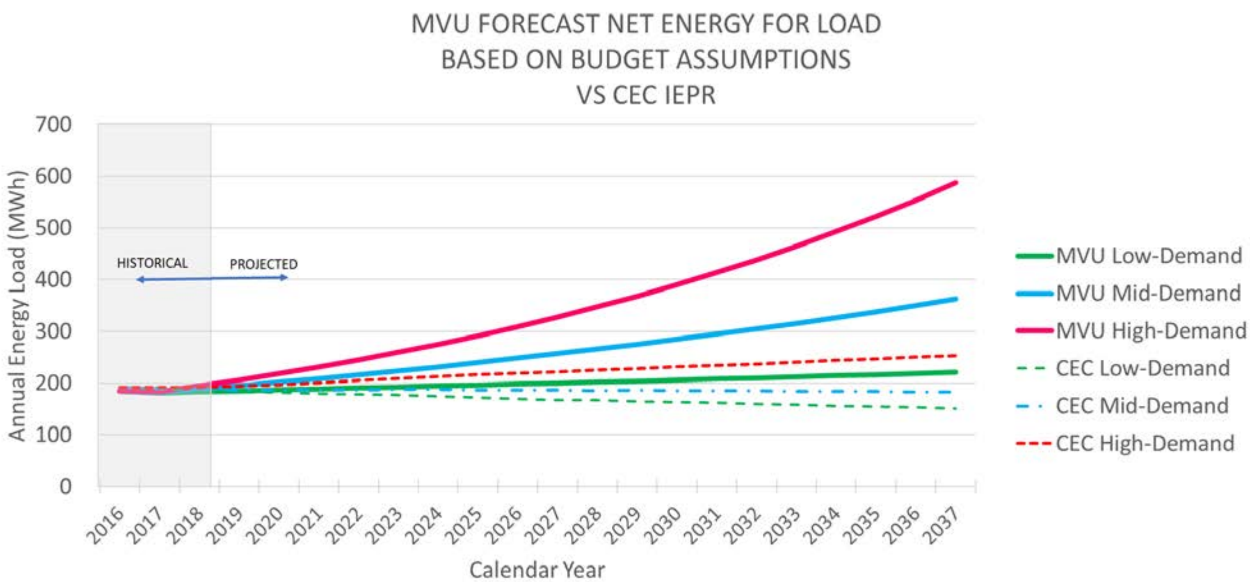



*Figure 8-1 - MVU Energy Load Forecast vs. CEC*

*Figure 8-2 - MVU Annual Peak Demand Forecast*

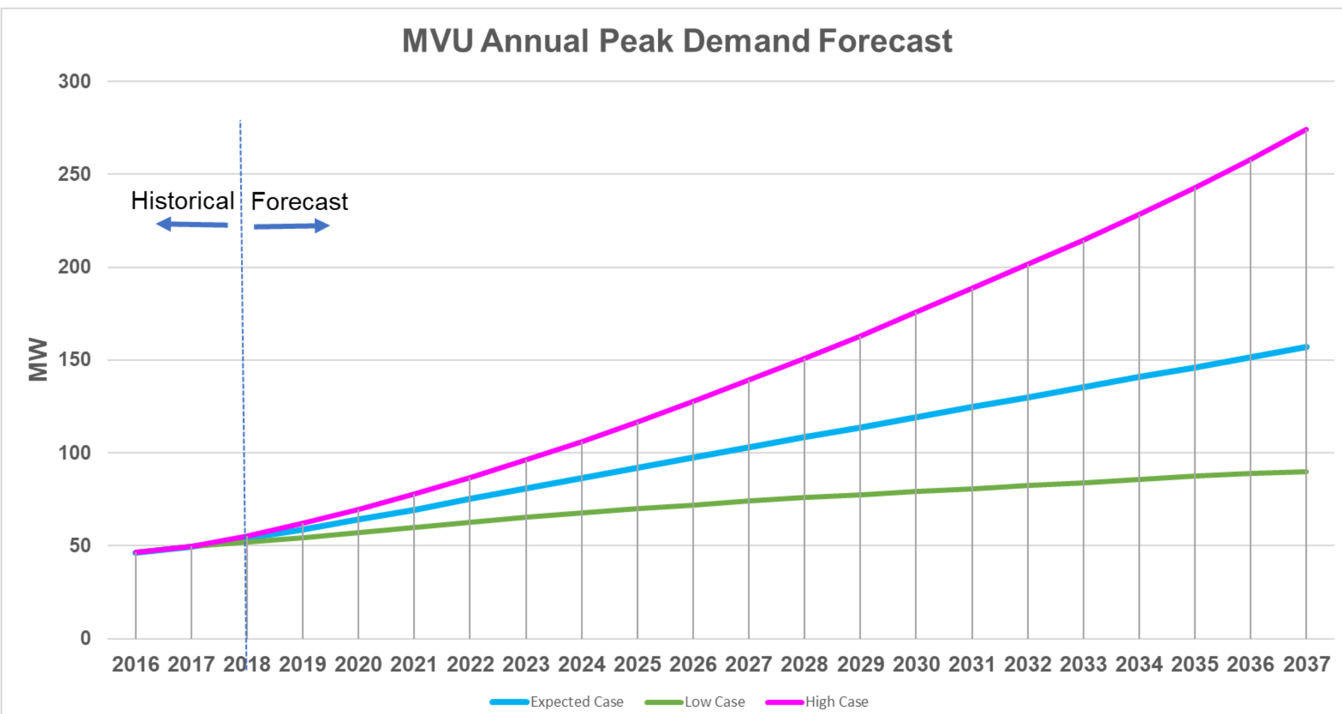



*Table 8-1* and *Figure 8-3* illustrate MVU's load duration based on historical data from October 2016 through September 2017. Approximately 2/3 of the year, MVU's load was between 20 and 30 MWh per hour. Only 3% of the year was MVU's load peak between 40 and 50 MWh per hour. Based on the same data, *Figure 8-4* illustrates MVU's hourly and monthly load profile.

*Table 8-1 - MVU Load Duration*

| | 1 | 2 | 3 | 4 | TOTAL |
|---|---|---|---|---|---|
| Load (MWh) | 40-50 | 30-40 | 20-30 | <20 | |
| Hours/year | 273 | 1056 | 5817 | 1614 | 8760 |
| % | 3% | 12% | 66% | 18% | 100% |

*Figure 8-3 - MVU Load Duration Curve*

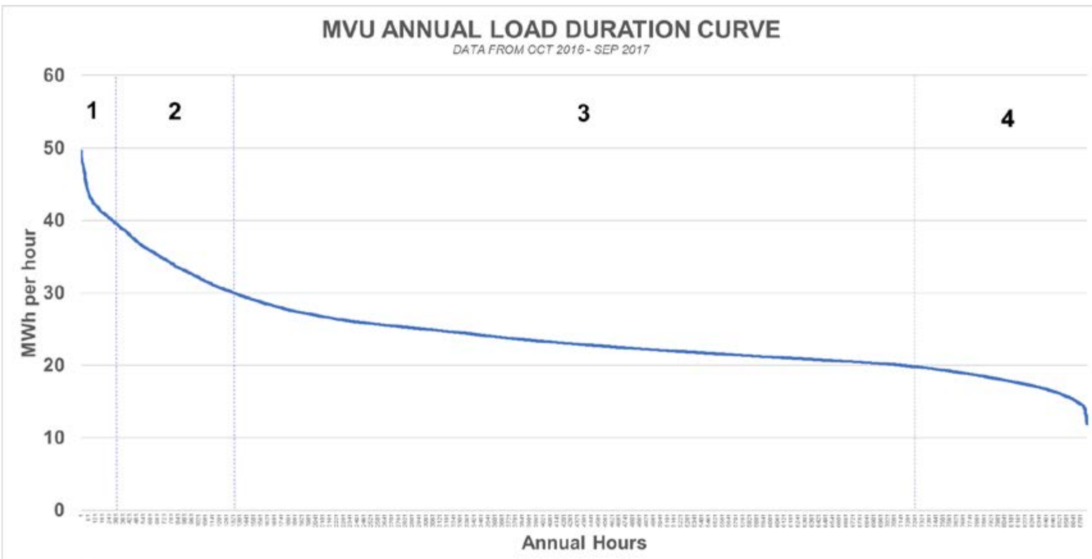
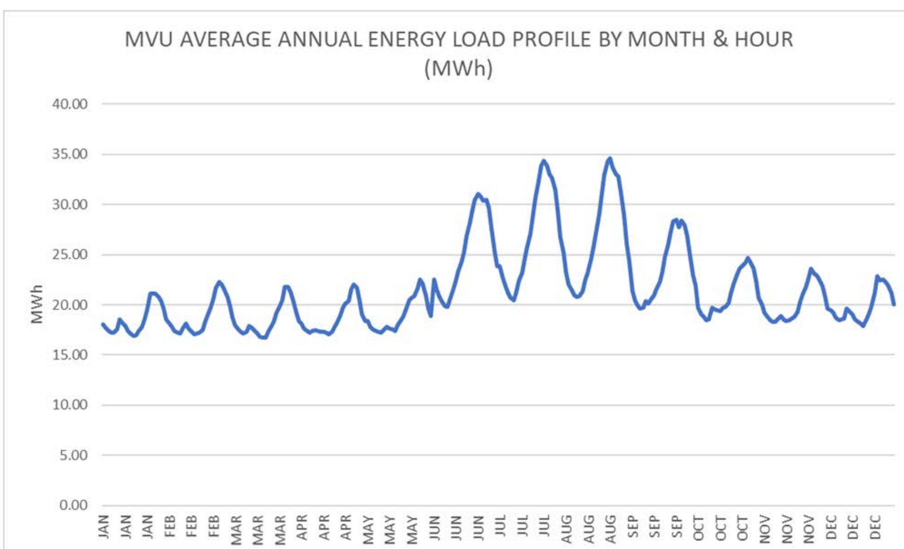



*Figure 8-4 - MVU Annual Energy Load Profile*



# 9 CANDIDATE RESOURCES

This IRP considered a number of potential renewable, distributed and conventional generation resources to meet load in excess of MVU's existing contracts. Energy storage was generally considered primarily as a potential capacity or shaping resource. The tables below provide the comparative pricing assumptions used for modeling purposes and were taken from the RESOLVE model. Highlighted in yellow are the resources selected for inclusion in MVU's IRP portfolios.

Pumped hydro storage, geothermal, and out of state wind resources all require, to varying degrees, long lead times and/or large capital investments. They may also require a large amount of load and/or aggregated purchases by multiple load-serving entities to be considered economic. Depending on the progress of California's GHG mitigation strategies and renewable integration needs, all three of these resources may prove necessary for reliability and/or economic reasons by 2030. Out of state wind may be generalized to include all out of state renewables, though wind adds a specific diversity benefit relative to in state wind and solar resources. Pumped hydro storage can also be generalized to include bulk storage of other types.

*Table 9-1 - Candidate Utility Scale Renewable Resources Levelized Cost of Energy (LCOE)*

**Levelized Cost**
($/MWh)

| | 2018 | 2022 | 2025 | 2030 |
|---|---|---|---|---|
| **Average All-In LCOE** | | | | |
| Solar PV - Tracking - 20MW+ | $ 52 | $ 51 | $ 63 | $ 60 |
| Solar PV - Tracking - 10MW | $ 54 | $ 53 | $ 65 | $ 62 |
| Solar PV - Tracking - 5MW | $ 58 | $ 56 | $ 69 | $ 66 |
| Solar PV - Fixed Tilt - 20MW+ | $ 60 | $ 59 | $ 73 | $ 70 |
| Solar PV - Tracking - 1MW | $ 62 | $ 60 | $ 74 | $ 71 |
| Solar PV - Fixed Tilt - 10MW | $ 62 | $ 61 | $ 75 | $ 72 |
| Wind | $ 67 | $ 79 | $ 87 | $ 86 |
| Solar PV - Fixed Tilt - 5MW | $ 68 | $ 66 | $ 82 | $ 78 |
| Solar PV - Fixed Tilt - 1MW | $ 73 | $ 71 | $ 88 | $ 84 |
| Geothermal | $ 88 | $ 88 | $ 88 | $ 88 |
| Biomass - Large | $ 158 | $ 158 | $ 158 | $ 158 |
| Hydro - Small | $ 163 | $ 163 | $ 163 | $ 163 |
| Solar Thermal - Storage | $ 190 | $ 185 | $ 232 | $ 222 |
| Solar Thermal - No Storage | $ 205 | $ 199 | $ 249 | $ 240 |

*Table 9-2 - Candidate Distributed Renewable Resources*

**Levelized Cost**
($/MWh)

| Average All-In LCOE | 2018 | 2022 | 2025 | 2030 |
|---|---|---|---|---|
| Wind - Distributed | $ 94 | $ 106 | $ 113 | $ 112 |
| Solar PV - Parking Lot | $ 95 | $ 90 | $ 110 | $ 104 |
| Biogas - Distributed | $ 146 | $ 146 | $ 146 | $ 146 |
| Solar PV - Commercial Rooftop | $ 148 | $ 139 | $ 171 | $ 162 |
| Solar PV - Commercial Rooftop BTM | $ 148 | $ 139 | $ 171 | $ 162 |
| Biomass - Large | $ 158 | $ 158 | $ 158 | $ 158 |
| Solar PV - Residential Rooftop BTM | $ 161 | $ 152 | $ 187 | $ 177 |
| Biomass - Distributed | $ 200 | $ 200 | $ 200 | $ 200 |

*Table 9-3 - Candidate Conventional Resources*

**Levelized Cost**
($/MWh)

| Average All-In LCOE | 2018 | 2022 | 2025 | 2030 |
|---|---|---|---|---|
| Gas - CCGT | $ 85 | $ 85 | $ 85 | $ 85 |
| Gas - CT - Frame | $ 261 | $ 261 | $ 261 | $ 261 |
| Gas - CT - Aero | $ 296 | $ 296 | $ 296 | $ 296 |
| Gas - ICE | $ 296 | $ 296 | $ 296 | $ 296 |

*NOTE: CCGT = Combined Cycle Gas Turbine & ICE = Internal Combustion Engine*

*Table 9-4 - Candidate Energy Storage Resources*

**Levelized Cost**
($/MWh)

| Average All-In LCOE | 2018 | 2022 | 2025 | 2030 |
|---|---|---|---|---|
| Battery - Li | $ 91 | $ 64 | $ 54 | $ 50 |
| Pumped Storage | $ 115 | $ 115 | $ 115 | $ 115 |
| Battery - Flow | $ 232 | $ 188 | $ 170 | $ 161 |
| | | | | |
| Battery - Li [Capacity] | $ 38 | $ 27 | $ 23 | $ 21 |
| Battery - Li [Energy] | $ 53 | $ 37 | $ 31 | $ 29 |
| | | | | |
| Battery - Flow [Capacity] | $ 208 | $ 169 | $ 153 | $ 145 |
| Battery - Flow [Energy] | $ 23 | $ 19 | $ 17 | $ 16 |
| | | | | |
| Pumped Storage [Capacity] | $ 106 | $ 106 | $ 106 | $ 106 |
| Pumped Storage [Energy] | $ 9 | $ 9 | $ 9 | $ 9 |

Once procurement activities are undertaken, MVU will procure the most effective resources to meet cost, reliability, diversity and other needs. The ultimate resource mix may look different from the proposed plan in this IRP.

There could be cost savings to MVU ratepayers by procuring additional renewable energy earlier than required by the RPS, in order to take advantage of expiring ITC and PTC. However, the cost savings that could flow from capturing the federal tax credits are highly uncertain. ITC and PTC eligibility rules have different timing requirements, declining benefits, and expiration dates. It is also a possibility, though remote, that the federal tax credits may be extended. International solar tariff actions will likely result in an increase in costs. For solar PV, improving operational efficiencies may also mitigate against price increases even in the absence of tax benefits.

# 10 ENERGY EFFICIENCY, DEMAND RESPONSE AND DISTRIBUTED GENERATION

## 10.1 ENERGY EFFICIENCY

On February 21, 2017, the City Council approved energy efficiency targets for MVU. According to this policy, annual energy efficiency and demand reduction savings will be targeted at 0.65% of retail electric sales through 2027.

All three scenarios included in this IRP are based on the same level of energy efficiency, i.e., all existing and committed energy efficiency programs are in place, and energy efficiency will be targeted at 0.65% of retail electric sales over the planning horizon. MVU will strive to procure all cost-effective energy efficiency, and all new construction is expected to meeting the current energy efficiency standards. Any additional cost-effective energy efficiency that might be procured would reduce MVU's net load. The incremental efficiency savings included in the CEC's forecasts is derived from the RPS Calculator v.6.2, which includes load scenarios that reflect both the Mid AAEE and its doubling. To date, no analysis has identified the specific programs or measures that might be included in this wedge or whether such programs and measures might be cost-effective for MVU.

The EE profiles used by RESOLVE roughly follow the load profile. These profiles are based on the hourly profiles developed by the CEC to represent the load impact of Additional Achievable Energy Efficiency in the IEPR Demand Forecast, using linear interpolation for years beyond the forecast.

## 10.2 DEMAND RESPONSE


*Figure 10-1 - Categories of Demand Response (DR)*

This IRP adopts the demand response program assumptions from the Lawrence Berkeley National Laboratory's (LBNL) final report on the 2025 California DR Potential Study (March 1, 2017) as described in the RESOLVE model documentation. DR resources identified are included in some of the RESOLVE analyses, with cost, performance, and potential data based on the findings in the LBNL report.

There are four categories of demand response resources:

- New "Shed" DR:
  - DR loads that can occasionally be curtailed to provide peak capacity and support the system in emergency or contingency events.
  - Treated as a candidate resource by RESOLVE in all cases; when selected by the model, the impact of the new shed is incremental to the baseline shed DR from existing programs.
- "Shift" DR:
  - DR that encourages the diurnal movement of energy consumption from hours of high demand to hours with surplus renewable generation.
  - Not included in RESOLVE core cases due to lack of certainty on viability of resource but made available as a candidate resource in the "Shift DR" sensitivity.
- "Shimmy" DR
  - DR that provides load-following and regulation type of ancillary services.
  - Not included in RESOLVE modeling but recognized as possible substitute for short-duration storage resources.
- "Shape" DR
  - DR that reflects "load-modifying" resources like time-of-use (TOU) and critical peak pricing (CPP) rates, and behavioral DR programs that do not have direct automation tie-ins to load control equipment.
  - TOU and existing load-modifying DR (e.g., CPP) included as part of baseline assumptions in RESOLVE modeling, including sensitivities; no additional shape DR was included

See RESOLVE Inputs and Assumptions document for details.

## 10.3 Distributed Generation

The IRP assumes that most MVU distributed generation will be in the form of customer-owned or leased "behind-the-meter" (BTM) solar PV. Although there are arguably benefits to having generation in the utility service territory, the variability and cost (both to the customer and to other utility ratepayers) of these distributed systems makes them unlikely to be part of a "least-cost, best fit" recommendation. As shown in

*Table* 10-1 - Average All-In Levelized Cost of Energy, distributed generation technologies (highlighted in yellow) are significantly more expensive than other alternatives. This is partly due to the economies of scale associated with large utility projects, the fact that utility scale projects generally use solar tracking mechanisms that allow them to produce more energy than fixed-tilt rooftop or parking lot facilities, and the higher soft costs associated with distributed generation.

*Table 10-1 - Average All-In Levelized Cost of Energy*

| | | 2018 | 2022 | 2025 | 2030 |
|---|---|---|---|---|---|
| **Average All-In LCOE** | | | | | |
| **Levelized Cost** | Solar PV - Tracking - 20MW+ | $ 52 | $ 51 | $ 63 | $ 60 |
| ($/MWh) | Solar PV - Tracking - 10MW | $ 54 | $ 53 | $ 65 | $ 62 |
| | Solar PV - Tracking - 5MW | $ 58 | $ 56 | $ 69 | $ 66 |
| | Solar PV - Fixed Tilt - 20MW+ | $ 60 | $ 59 | $ 73 | $ 70 |
| | Solar PV - Tracking - 1MW | $ 62 | $ 60 | $ 74 | $ 71 |
| | Solar PV - Fixed Tilt - 10MW | $ 62 | $ 61 | $ 75 | $ 72 |
| | Wind | $ 67 | $ 79 | $ 87 | $ 86 |
| | Solar PV - Fixed Tilt - 5MW | $ 68 | $ 66 | $ 82 | $ 78 |
| | Solar PV - Fixed Tilt - 1MW | $ 73 | $ 71 | $ 88 | $ 84 |
| | Gas - CCGT | $ 85 | $ 85 | $ 85 | $ 85 |
| | Geothermal | $ 88 | $ 88 | $ 88 | $ 88 |
| | Wind - Distributed | $ 94 | $ 106 | $ 113 | $ 112 |
| | Solar PV - Parking Lot | $ 95 | $ 90 | $ 110 | $ 104 |
| | Biogas - Distributed | $ 146 | $ 146 | $ 146 | $ 146 |
| | Solar PV - Commercial Rooftop | $ 148 | $ 139 | $ 171 | $ 162 |
| | Solar PV - Commercial Rooftop BTM | $ 148 | $ 139 | $ 171 | $ 162 |
| | Biomass - Large | $ 158 | $ 158 | $ 158 | $ 158 |
| | Solar PV - Residential Rooftop BTM | $ 161 | $ 152 | $ 187 | $ 177 |
| | Hydro - Small | $ 163 | $ 163 | $ 163 | $ 163 |
| | Solar Thermal - Storage | $ 190 | $ 185 | $ 232 | $ 222 |
| | Biomass - Distributed | $ 200 | $ 200 | $ 200 | $ 200 |
| | Solar Thermal - No Storage | $ 205 | $ 199 | $ 249 | $ 240 |
| | Gas - CT - Frame | $ 261 | $ 261 | $ 261 | $ 261 |
| | Gas - CT - Aero | $ 296 | $ 296 | $ 296 | $ 296 |
| | Gas - ICE | $ 296 | $ 296 | $ 296 | $ 296 |

MVU does not control whether or not its customers elect to install BTM solar, but since it has exceeded the mandatory "net metering" threshold, MVU may want to consider a couple of policy options to preserve customer choice while reducing the cost incurred by non-participating customers.

As part of a cost-of-service analysis, MVU may wish to restructure the credit it offers to new net metered customers to more accurately reflect MVU's avoided costs associated with BTM generation. Crediting such customers with the full retail rate, which includes a significant portion of MVU's fixed, unavoidable costs, shifts a higher share of these costs to remaining customers who cannot or choose not to participate in distributed generation. It also credits them for the renewable resource attributes associated with the customer's system, but MVU is not able to claim these attributes toward its RPS[7]. A more appropriate credit might be tied to MVU's avoided cost (i.e., the CAISO locational marginal price) at the time of generation, plus any avoided distribution and/or transmission losses.

Another policy to consider would be the offer of green tariff pricing that would allow customers to subscribe to varying levels of renewable portfolio content, up to 100% of their retail load. Power supply to support the green tariff offering could be sourced from larger, more cost-effective utility-scale projects. Another benefit of such a program would be its

[7] BTM generation reduces the retail load upon which MVU's RPS is based, but MVU does not receive RPS credit for BTM resources.

accessibility for renters and others that do not have suitable rooftops or parking lots for their own BTM solar installations.

# 11 ENERGY STORAGE

This IRP includes the proposed future procurement of energy storage to the extent it is viable and cost-effective to support MVU's resource mix. One barrier to wider adoption of energy storage technologies by public utilities is the lack of market price signals for the services potentially provided, and the misalignment of costs incurred with benefits derived. Many of energy storage's benefits accrue to the bulk transmission system as a whole and the CAISO balancing authority, rather than to individual utility participants that incur the cost of owning or contracting for energy storage.

This IRP proposes the procurement of capacity from energy storage to support the integration of variable output renewable resources (primarily solar) and to increase the resource adequacy capacity value of these resources to reduce reliance on capacity purchases from the market. To the extent it is cost-effective, the IRP recommends the procurement of energy storage capacity coupled with solar resources (i.e., "behind the fence") so that the solar output can be shaped to match optimum market prices and provide increased resource adequacy capacity from the renewable resource. This structure is expected to provide greater benefits to MVU than energy storage connected directly to the grid, which would rely on system energy rather than specified source renewables for charging.

The table below, taken from the RESOLVE model, provides indicative pricing assumptions for the three most viable energy storage technologies. The IRP assumes that MVU would incur the capacity cost of lithium ion batteries, with energy provided from separately procured renewable resources. The forecasted price curve indicates that energy storage will likely be more cost-effective for MVU towards the middle of the planning horizon or later.

*Table 11-1 - Energy Storage Price Assumptions*

| **Levelized Cost** ($/MWh) | | 2018 | 2022 | 2025 | 2030 |
|---|---|---|---|---|---|
| **Average All-In LCOE** | | | | | |
| | Battery - Li | $ 91 | $ 64 | $ 54 | $ 50 |
| | Pumped Storage | $ 115 | $ 115 | $ 115 | $ 115 |
| | Battery - Flow | $ 232 | $ 188 | $ 170 | $ 161 |
| | | | | | |
| | Battery - Li [Capacity] | $ 38 | $ 27 | $ 23 | $ 21 |
| | Battery - Li [Energy] | $ 53 | $ 37 | $ 31 | $ 29 |
| | | | | | |
| | Battery - Flow [Capacity] | $ 208 | $ 169 | $ 153 | $ 145 |
| | Battery - Flow [Energy] | $ 23 | $ 19 | $ 17 | $ 16 |
| | | | | | |
| | Pumped Storage [Capacity] | $ 106 | $ 106 | $ 106 | $ 106 |
| | Pumped Storage [Energy] | $ 9 | $ 9 | $ 9 | $ 9 |

# 12 TRANSPORTATION ELECTRIFICATION

The transportation sector accounts for 50 percent of statewide GHG emissions[8]. Transportation electrification is an important strategy for meeting the state's long-term GHG emission reduction goals. In assessing procurement for transportation electrification, MVU considered the following information, to the extent possible, in the IRP analysis:

- Charging profiles (for example, monthly, daily, or hourly load profiles) assumed for light duty plug-in electric vehicle (LD PEV) forecasted through 2030. The IRP utilized the E3/CPUC RESOLVE model "EV Work Charging" profile data for this purpose.
- The IRP does not reflect any assumed new EV charging tariff(s) designed to influence the charging profile. However, the issue may be considered in future Cost of Service Studies.
- Current amount, type (for example, Level 1, Level 2, DC fast charge), and location of charging infrastructure in the service territory, to the extent incorporated into the E3/CPUC RESOLVE model.
- Due to the location and nature of its service territory, any programs to promote transportation electrification Moreno Valley would positively impact disadvantaged communities.
- MVU has accounted for increased electrical load from transportation electrification through 2030 in the Capacity Resource Accounting and Energy Balance Tables.

[8] CEC 2018 Integrated Energy Policy Report

# 13 DISADVANTAGED COMMUNITIES

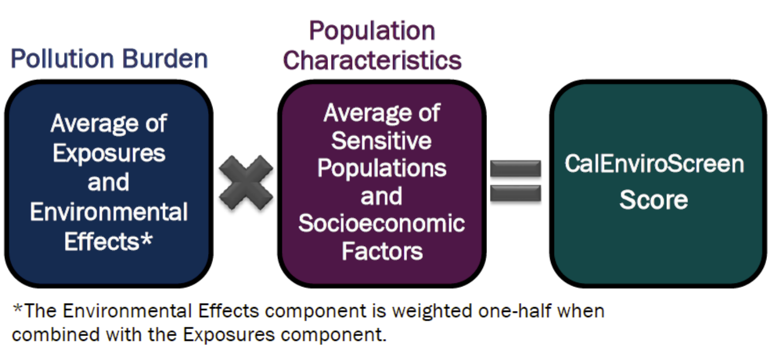
Section 454.52 of the Public Utilities Code requires that IRPs "strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities…" and "minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code." CalEPA designates census tracts as "disadvantaged communities" for investing cap-and-trade proceeds.

*Some census tracts in Moreno Valley are identified by the CalEPA as "disadvantaged communities." Designation as a "disadvantaged community" is a comparison of one census tract against others in the state with respect to pollution burden and population characteristics. It is used to target specific communities to receive investment proceeds from the state's GHG cap & trade program, for allocation of grants, and other environmental justice decisions. It is not necessarily an indicator of health risk or community desirability.*

This IRP ensures that the City achieves the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code (HSC)[9].

The California Environmental Protection Agency (CalEPA) currently identifies disadvantaged communities using the California Communities Environmental Health Screening Tool, available on its website.[10] The CalEnviroScreen was developed by the Office of Environmental Health Hazard Assessment (OEHHA) and CalEPA. It is a science-based mapping tool that helps identify California communities that are most affected by many sources of pollution, and that are often especially vulnerable to pollution's effects. CalEnviroScreen uses environmental, health, and socioeconomic information to produce a numerical score for each census tract in the state. Census tracts from the US Census Bureau (2010 census) are used to represent the locations of communities across California. The average size of a census tract is around 4,000 people and represents a relatively fine scale of analysis.

*Figure 13-1 - CalEnviroScreen Model Formula*




The Model:

- Is made up of a suite of 20 statewide indicators of pollution

[9] PUC Section 9621
[10] https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30

burden and population characteristics associated with increased vulnerability to pollution's health effects.

- Uses a weighted scoring system to derive average pollution burden and population characteristics scores for each census tract.
- Calculates a final CalEnviroScreen score for a given census tract relative to the other tracts in the state by multiplying the pollution burden and population characteristics components together.
- The score measures the relative pollution burdens and vulnerabilities in one census tract compared to others and is not a measure of health risk.
- Is used to:
    - Identify California's most environmentally burdened and vulnerable communities.
    - Assist CalEPA's boards and departments with decisions, such as prioritizing resources and cleanup activities.
    - Target California communities for investment of proceeds from the State's cap-and-trade program.
    - Provide guidance to CalEPA's Environmental Justice Task Force and other state entities in allocating grants and in other decisions.

Indicators in CalEnviroScreen are measures of either environmental conditions, in the case of pollution burden indicators, or health and vulnerability factors for population characteristic indicators.

CalEnviroScreen indicators fall into four broad groups, as illustrated below.

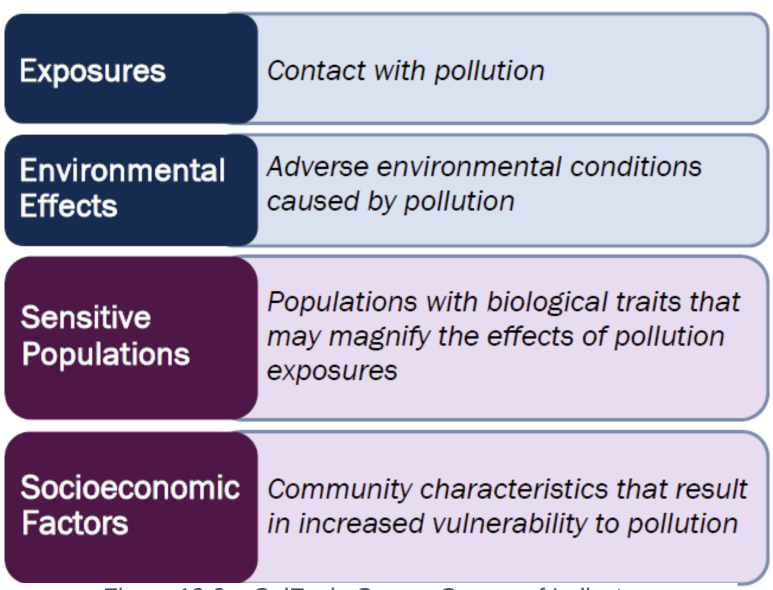



*Figure 13-2 – CalEnviroScreen Groups of Indicators*

The results are depicted on maps so that different communities can be compared to one another. A census tract with a high score is one that experiences higher pollution burden and vulnerability than census tracts with low scores. CalEnviroScreen ranks census tracts based on data that are available from state and federal government sources.

Disadvantaged communities are defined as those census tracts scoring above the 75th percentile using the CalEnviroScreen tool based on geographic, socioeconomic, public health, and environmental hazard criteria.

The CalEnviroScreen Model:

- Is made up of a suite of 20 statewide indicators of pollution burden and population characteristics associated with increased vulnerability to pollution's health effects.
- Uses a weighted scoring system to derive average pollution burden and population characteristics scores for each census tract.
- Calculates a final CalEnviroScreen score for a given census tract relative to the other tracts in the state by multiplying the pollution burden and population characteristics components together. The score measures the relative pollution burdens and vulnerabilities in one census tract compared to others and is not a measure of health risk.

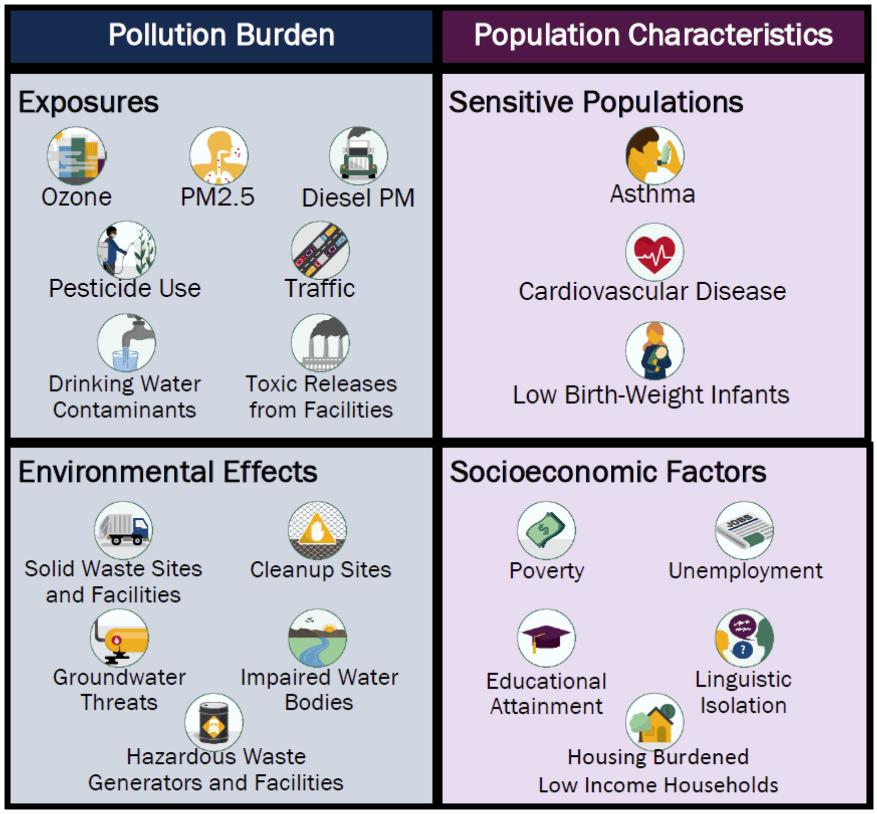
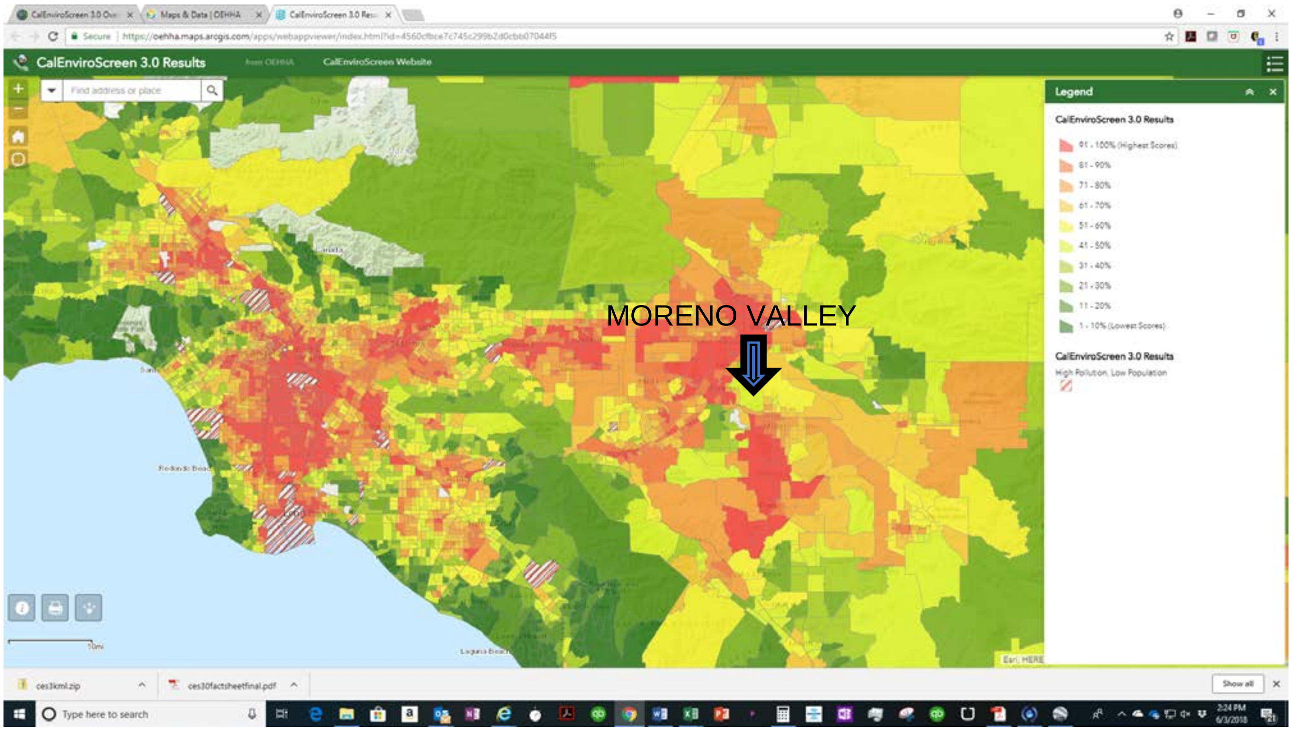



*Figure 13-3 - Specific Indicators for CalEnviroScreen*

The results are depicted on maps so that different communities can be compared to one another based on data that are available from state and federal government sources.

CalEnviroScreen 3.0 was released in January 2017. *Figure 13-4* - CalEnviroScreen for Greater Los Angeles Area shows the communities in the greater Los Angeles area that have been identified by the CalEnviroScreen tool as disadvantaged communities.

*Figure 13-4 - CalEnviroScreen for Greater Los Angeles Area*



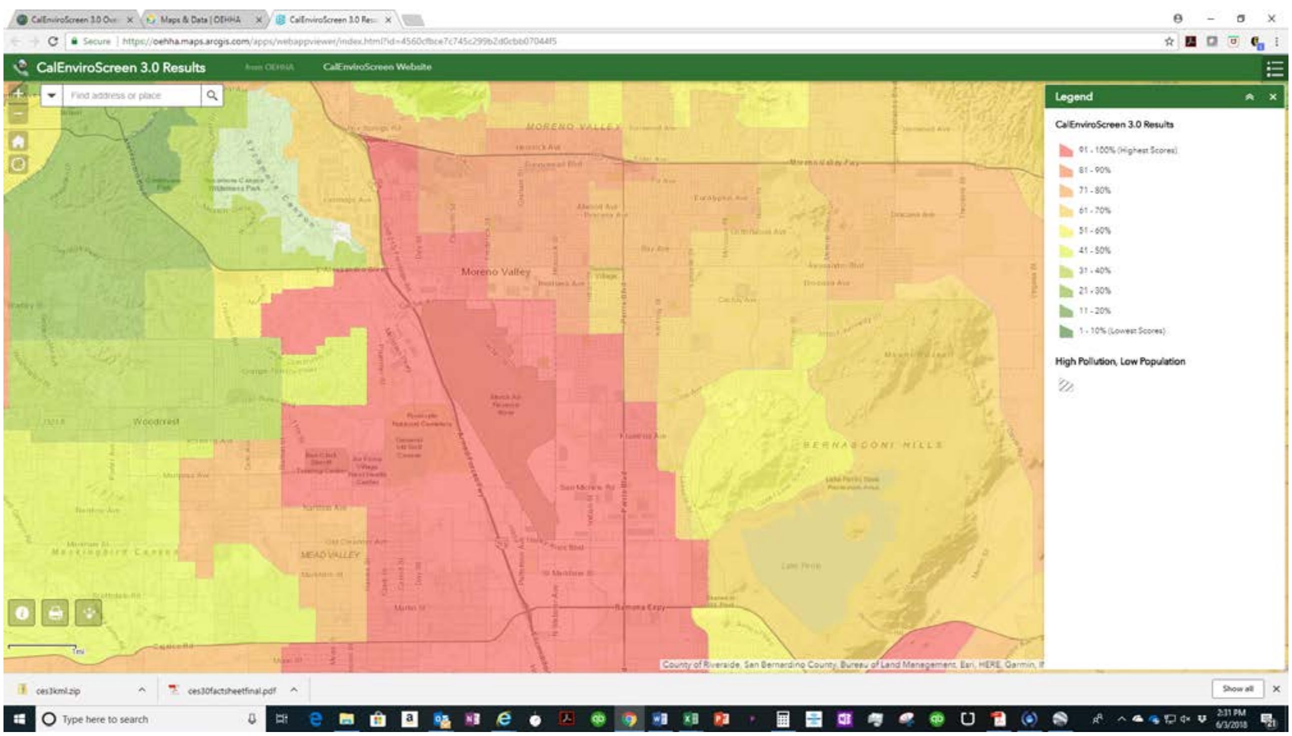




*Figure 13-5 - CalEnviroScreen Results for Moreno Valley*

As indicated in *Figure 13-5* - CalEnviroScreen Results for Moreno Valley, the CalEnviroScreen Tool identifies portions of Moreno Valley as among the top 25% of communities that are considered "disadvantaged" for purposes of IRP planning. There are also disadvantaged communities near Moreno Valley, but outside of the MVU service territory. Consequently, efforts by MVU to increase the use of renewable energy resources and reduce localized pollution and GHG emissions should have a positive impact on disadvantaged communities. These potentially positive actions include specifically:

- Reducing or replacing generation from natural gas-fired generation and non-specified system resources;
- Developing community solar offerings for customers within the service territory;
- Developing or expanding programs that provide local solar and energy efficiency in the community;
- Transportation electrification investments;
- Coordination with local municipal authorities and air quality management or pollution control districts;
- Labor, workforce, and training programs that provide benefits to low-income customers, including those that live in the surrounding disadvantaged communities;
- Financing mechanisms to improve access and participation of customers in clean energy programs;
- Efforts to increase contracting opportunities for small businesses; and
- Strategies to maximize education and participation in clean energy and transportation programs, including engagement with local community-based organizations for outreach activities.

Because existing natural gas plants are located disproportionately in disadvantaged communities, there is a nexus between analysis of natural gas resources and disadvantaged community impacts. The results of analysis by CPUC Energy Division staff suggests that the choice of the GHG Scenario (e.g., 42 MMT vs. 30 MMT) has a greater impact on the air pollution emissions in disadvantaged communities overall than any of the sensitivities containing changes to individual variables. This is generally because reducing the emissions from the electricity generation sector requires more reliance on renewables and less on natural gas, with combined cycle natural gas turbines being the most prevalent and largest emitters in the sector, since they run more hours than the peaking class of natural gas plants.

On June 7, 2018, the Moreno Valley Planning Department issued a Request for Proposals for "Professional Services to Prepare an Outreach Toolbox for Disadvantaged Communities: Engage Moval." The RFP and additional information are available on the City's procurement website on Planetbids.

# 14 STUDY RESULTS

## 14.1 PORTFOLIO RESULTS

Scorecards were prepared for each scenario/portfolio combination, and for the mid-, low- and high-load forecasts. The name of each case includes the scenario (A, B or C), the Portfolio (1, 2 or 3), and the load forecast (Mid, Low, or High). These summary result scorecards are provided below. Details are in Attachment 1: MVU IRP Analysis Workbook.

*Table 14-1 - MVU IRP Results - Mid Demand Case Scorecard*

| MORENO VALLEY UTILITY 2018 IRP PLANNING CASE COMPARISON | | | |
|---|---|---|---|
| | MID DEMAND | | |
| METRIC | A1 | B2 | C3 |
| 2030 Forecast Net Energy for Load (MWh) | 284,640 | 284,640 | 284,640 |
| 2030 Forecast Peak Demand (MW) | 137 | 137 | 137 |
| Planning Reserve Margin | 15.0% | 15.0% | 15.0% |
| **2030 RPS Target (%)** | **50.0%** | **60.0%** | **87.5%** |
| RPS Procurement Margin | 5.0% | 5.0% | 5.0% |
| | | | |
| 2030 Projected EV Charging Load (MWh) | 11,140 | 11,140 | 11,140 |
| | | | |
| MVU 2030 Projected GHG Target (MMT $CO_2$e) | 0.0596 | 0.0481 | 0.0344 |
| 2030 MVU Projected GHG Emissions (MMT $CO_2$e) | 0.0589 | 0.0467 | 0.0132 |
| Comparable State 2030 GHG Target (MMT $CO_2$e) | **51** | **42** | **30** |
| | | | |
| RPS Target Met? | ☑ | ☑ | ☑ |
| GHG Target Met? | ☑ | ☑ | ☑ |
| Resource Adequacy Target(s) Met? | ☑ | ☑ | ☑ |
| | | | |
| 2020 Energy Portfolio Diversity (%): | | | |
| **Losses** (% of gross load) | 6.74% | 6.74% | 6.74% |
| **AAEE** (% of gross load) | 0.5% | 0.5% | 0.5% |
| **BTM Solar** (% of gross load) | 9.0% | 9.0% | 9.0% |
| **Solar** (% of net energy) | 31.4% | 31.4% | 31.4% |
| **Wind** (% of net energy) | 7.4% | 7.4% | 7.4% |
| **Geothermal** (% of net energy) | 0.0% | 0.0% | 0.0% |
| **Clean Non-Renewable** (% of net energy) | 0.0% | 0.0% | 0.0% |
| **System/Other Resources** | 46.3% | 46.3% | 46.3% |
| | | | |
| 2030 Energy Portfolio Diversity (%): | | | |
| **Losses** (% of gross load) | 6.4% | 6.4% | 6.4% |
| **AAEE** (% of gross load) | 0.5% | 0.5% | 0.5% |
| **BTM Solar** (% of gross load) | 9.0% | 9.0% | 9.0% |
| **Solar** | 42.6% | 49.6% | 68.9% |
| **Wind** | 9.1% | 12.1% | 20.3% |
| **Geothermal** | 0.0% | 0.0% | 0.0% |
| **Clean Non-Renewable** | 0.0% | 0.0% | 10.8% |
| **System/Other Resources** | 48.3% | 38.3% | 0.0% |
| | | | |
| 2030 Energy Storage/Demand Response (MW) | 0.0 | 9.3 | 15.6 |
| | | | |
| Additional Cost of New Resources (NPV) | $334,502,704 | $297,699,746 | $291,744,104 |
| Cost Deviation from Base Case (A1) | **0** | **($36,802,958)** | **($42,758,600)** |

*Table 14-2 - MVU IRP Results - Low Demand Case Scorecard*

| MORENO VALLEY UTILITY 2018 IRP PLANNING CASE COMPARISON | | | |
|---|---|---|---|
| | LOW DEMAND | | |
| **METRIC** | **A1** | **B2** | **C3** |
| **2030 Forecast Net Energy for Load (MWh)** | 205,995 | 205,995 | 205,995 |
| **2030 Forecast Peak Demand (MW)** | 91 | 91 | 91 |
| **Planning Reserve Margin** | 15.0% | 15.0% | 15.0% |
| **2030 RPS Target (%)** | **50.0%** | **60.0%** | **87.5%** |
| **RPS Procurement Margin** | 5.0% | 5.0% | 5.0% |
| | | | |
| **2030 Projected EV Charging Load (MWh)** | 11,140 | 11,140 | 11,140 |
| | | | |
| **MVU 2030 Projected GHG Target (MMT $CO_2e$)** | 0.0596 | 0.0481 | 0.0344 |
| **2030 MVU Projected GHG Emissions (MMT $CO_2e$)** | 0.0426 | 0.0338 | 0.0096 |
| **Comparable State 2030 GHG Target (MMT $CO_2e$)** | **51** | **42** | **30** |
| | | | |
| **RPS Target Met?** | ☑ | ☑ | ☑ |
| **GHG Target Met?** | ☑ | ☑ | ☑ |
| **Resource Adequacy Target(s) Met?** | ☑ | ☑ | ☑ |
| | | | |
| **2020 Energy Portfolio Diversity (%):** | | | |
| **Losses** (% of gross load) | 6.67% | 6.67% | 6.67% |
| **AAEE** (% of gross load) | 0.5% | 0.5% | 0.5% |
| **BTM Solar** (% of gross load) | 13.2% | 13.2% | 13.2% |
| **Solar** (% of net energy) | 33.9% | 33.9% | 33.9% |
| **Wind** (% of net energy) | 8.0% | 8.0% | 8.0% |
| **Geothermal** (% of net energy) | 0.0% | 0.0% | 0.0% |
| **Clean Non-Renewable** (% of net energy) | 0.0% | 0.0% | 0.0% |
| **System/Other Resources** | 41.9% | 41.9% | 41.9% |
| | | | |
| **2030 Energy Portfolio Diversity (%):** | | | |
| **Losses** (% of gross load) | 6.1% | 6.1% | 6.1% |
| **AAEE** (% of gross load) | 0.5% | 0.5% | 0.5% |
| **BTM Solar** (% of gross load) | 13.2% | 13.2% | 13.2% |
| **Solar** | 44.3% | 52.1% | 71.3% |
| **Wind** | 7.3% | 10.2% | 22.3% |
| **Geothermal** | 0.0% | 0.0% | 0.0% |
| **Clean Non-Renewable** | 0.0% | 0.0% | 10.8% |
| **System/Other Resources** | 48.3% | 38.8% | 0.0% |
| | | | |
| **2030 Energy Storage/Demand Response (MW)** | 0.0 | 7.1 | 10.0 |
| | | | |
| **Additional Cost of New Resources (NPV)** | $256,359,860 | $248,027,817 | $225,657,461 |
| **Cost Deviation from Base Case (A1)** | **0** | **($8,332,043)** | **($30,702,398)** |

*Table 14-3 - MVU IRP Results - High Demand Case Scorecard*

| MORENO VALLEY UTILITY 2018 IRP PLANNING CASE COMPARISON | | | |
|---|---|---|---|
| | HIGH DEMAND | | |
| METRIC | A1 | B2 | C3 |
| **2030 Forecast Net Energy for Load (MWh)** | 390,326 | 390,326 | 390,326 |
| **2030 Forecast Peak Demand (MW)** | 202 | 202 | 202 |
| **Planning Reserve Margin** | 15.0% | 15.0% | 15.0% |
| **2030 RPS Target (%)** | **50.0%** | **60.0%** | **87.5%** |
| **RPS Procurement Margin** | 5.0% | 5.0% | 5.0% |
| | | | |
| **2030 Projected EV Charging Load (MWh)** | 11,140 | 11,140 | 11,140 |
| | | | |
| **MVU 2030 Projected GHG Target (MMT $CO_2$e)** | 0.0596 | 0.0481 | 0.0344 |
| **2030 MVU Projected GHG Emissions (MMT $CO_2$e)** | 0.0807 | 0.0640 | 0.0181 |
| **Comparable State 2030 GHG Target (MMT $CO_2$e)** | **51** | **42** | **30** |
| | | | |
| **RPS Target Met?** | ☑ | ☑ | ☑ |
| **GHG Target Met?** | ☑ | ☑ | ☑ |
| **Resource Adequacy Target(s) Met?** | ☑ | ☑ | ☑ |
| | | | |
| **2020 Energy Portfolio Diversity (%):** | | | |
| **Losses** (% of gross load) | 6.81% | 6.81% | 6.30% |
| **AAEE** (% of gross load) | 0.5% | 0.5% | 0.5% |
| **BTM Solar** (% of gross load) | 5.1% | 5.1% | 6.8% |
| **Solar** (% of net energy) | 29.0% | 29.0% | 29.0% |
| **Wind** (% of net energy) | 6.9% | 6.9% | 6.9% |
| **Geothermal** (% of net energy) | 0.0% | 0.0% | 0.0% |
| **Clean Non-Renewable** (% of net energy) | 0.0% | 0.0% | 0.0% |
| **System/Other Resources** | 50.3% | 50.3% | 50.3% |
| | | | |
| **2030 Energy Portfolio Diversity (%):** | | | |
| **Losses** (% of gross load) | 6.7% | 6.7% | 4.9% |
| **AAEE** (% of gross load) | 0.5% | 0.5% | 0.5% |
| **BTM Solar** (% of gross load) | 5.1% | 5.1% | 6.8% |
| **Solar** | 0.0% | 47.9% | 67.1% |
| **Wind** | 0.0% | 0.0% | 0.0% |
| **Geothermal** | 0.0% | 0.0% | 0.0% |
| **Clean Non-Renewable** | 0.0% | 0.0% | 10.8% |
| **System/Other Resources** | 0.0% | 0.0% | 0.0% |
| | | | |
| **2030 Energy Storage/Demand Response (MW)** | 0.0 | 14.6 | -7.1 |
| | | | |
| **Additional Cost of New Resources (NPV)** | $436,610,440 | $427,734,313 | $437,491,534 |
| **Cost Deviation from Base Case (A1)** | **0** | **($8,876,127)** | **$881,094** |

## 14.2 Preferred Portfolio

Case A1 has been identified as MVU's base case, or minimum procurement portfolio. Case B2 is the preferred portfolio, as it targets MVU's share of CARB's recommended statewide electricity section greenhouse gas emission reductions, primarily with a higher level of renewable energy procurement. The GHG reductions embodied in Case B2 are based on the same targets as the CPUC established for its jurisdictional entities, including Southern California Edison. It also reflects

RPS targets that are included in proposed legislation (SB 100), positioning MVU to more easily meet these standards without changing its IRP if the legislation is passed. Case C3 represents a stretch goal but is not recommended for adoption at this point in time.

### 14.2.1 Cost and Rate Analysis

*Table 14-4* summarizes the estimated relative cost of incremental power supplies as reflected in the Portfolio Scorecards. Numbers in this table reflect the estimated net present value over the 20-year planning horizon for new resource acquisition. In its IRP proceeding, the CPUC Energy Division staff estimated that the reference system portfolio, on which preferred Scenario/Portfolio B2 was based, would result in an increase in retail rates of approximately 1% by 2030.

*Table 14-4 - Cost Comparison*

| Scenario/Portfolio | Low Demand Case | Mid Demand Case | High Demand Case |
|---|---|---|---|
| **A1** | $256,359,860 | $334,502,704 | $436,610,440 |
| **B2** | $248,027,817 | $297,699,746 | $427,734,313 |
| **C3** | $225,657,461 | $291,744,104 | $437,491,534 |

### 14.2.2 Local Air Pollutant Minimization

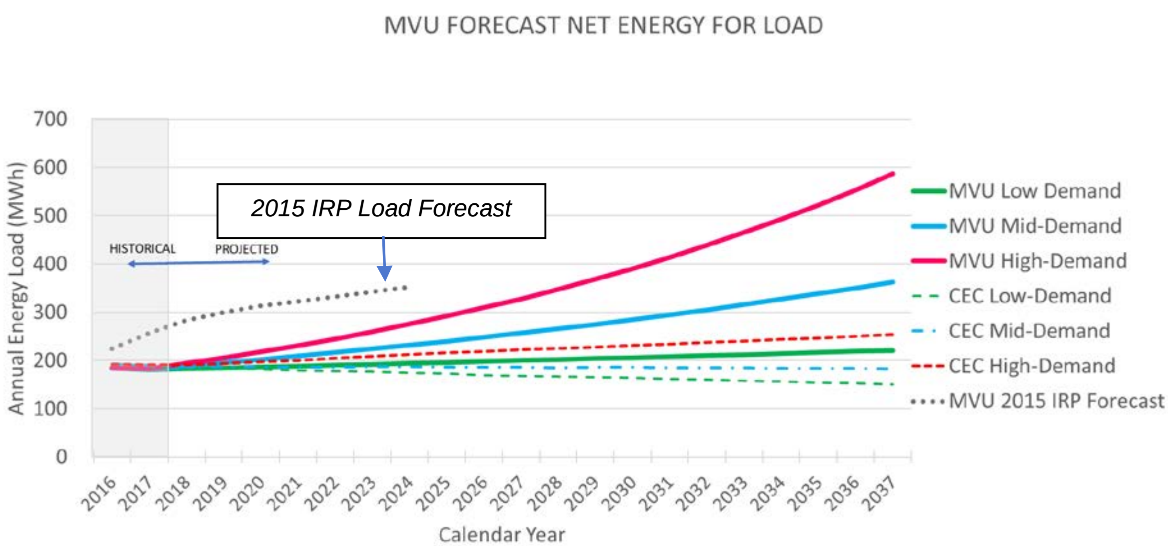
By targeting higher levels of renewable energy, and avoiding contracts with new conventional (e.g., natural-gas fired) generation, MVU is doing its part to minimize GHG emissions and local air pollutants. These efforts can be augmented through facilitation of transportation electrification, such as supporting customers who wish to purchase electric vehicles and install charging devices in their homes, and the installation of public charging stations by employers and retail establishments in Moreno Valley.

## 14.3 Deviations From Current Resource Plans

This IRP builds upon the work in MVU's 2015 IRP and includes some portions of the 2015 IRP verbatim. Material deviations from MVU's 2015 IRP in the following ways:

- The 2018 IRP includes a range of load forecasts for both energy and demand, including high, low and expected (base) cases.
- Net energy for load is initially lower and is projected to grow at a rate that is initially more gradual, than in the 2015 IRP. *Figure 14-1* below illustrates the comparison of the 2015 IRP load forecast with the 2018 IRP forecast cases.

*Figure 14-1 - MVU Forecast of Net Energy for Load*




- The planning horizon in this IRP is 20 years, compared to the 10-year planning horizon in 2015. For CEC reporting purposes, the planning horizon is through 2030.
- RPS goals in the 2015 IRP were based on legislation existing at the time (SB2 1-X) and the targets incorporated therein, specifically 33% by 2020. This 2018 IRP is based on new legislation that passed in the interim (SB 350), and the requirements therein. RPS targets in SB 350 include an increase to 50% by 2030, along with other measures. This IRP incorporates the SB 350 targets as minimums in its base case, and also models higher levels of renewables and clean energy that will likely be needed to achieve the California's GHG emission reduction targets and, if passed, SB 100.
- The 2018 IRP includes specific GHG reduction objectives based on goals established by regulatory agencies for the electricity sector's share of the statewide target of 80% reduction from 1990 levels by 2050. This target was established after the drafting of MVU's 2015 IRP.
- The organization and level of this IRP is intended to conform substantially with the information requirements in the newly released California Energy Commission Publicly-Owned Utility Integrated Resource Plan Submission and Review Guidelines (IRP Guidelines) (August 9, 2017), CEC-200-2017-004-CMF. These guidelines are not strictly applicable to MVU due to its small size and did not exist at the time of 2015 IRP. However,

MVU has made an effort to follow the guidelines as a best practice and for consistency with the larger utilities and load serving entities in California.

# 15 ACTION PLAN

The following actions are recommended in the medium-term (next one to three years):

## 15.1 Resource Procurement

Begin to procure renewable and resource adequacy capacity resources pursuant to the Resource Procurement Plan, with the goal of securing 100% of the resources projected to be needed over the next one to three years. MVU may also take advantage of a favorable market to secure coverage for a longer period of time, to the extent consistent with its risk management strategy.

## 15.2 Reliability

Develop methodology for estimating MVU's share of and/or liability for local area resource adequacy capacity and flexible resource adequacy capacity pursuant to CAISO tariff and associated business practices, and incorporate such resources into the procurement plan.

## 15.3 Energy Efficiency

Procure the most cost-effective energy efficiency available in the MVU service territory at the City Council approved rate of 0.65% of retail sales annually.

## 15.4 Demand-Side Management and/or Energy Storage

Procure cost-effective demand-side management and/or energy storage, specifically targeting measures that reduce peak load and improve capacity factor and/or shift generation from periods of low market prices to periods of higher value to MVU customers. The most likely form of cost-effective energy storage is likely to be located behind-the-fence storage at utility-scale renewable energy projects, which would maximize the value of renewable power procurement.

## 15.5 Distributed Generation

Encourage development of the most cost-effective and operationally beneficial distributed generation (DG) for all MVU customers by offering a green power tariff tied to specific utility scale renewable energy projects and consider development of a community solar project.

## 15.6 Transportation Electrification

Support the development of transportation electrification by encouraging installation of electric vehicle charging stations in public areas such as shopping centers, and by large employers in the MVU service territory. Continue efforts to provide customers with information about electric vehicles and charging infrastructure.

## 15.7 Rates and Policies

Consider the impacts of rate design and public policies in encouraging customer behavior that is consistent with MVU goals of minimizing rates. Attempt to align rates with cost drivers, such as time of use, and ensure that programs such as net metering reflect realistic costs and value to other MVU customers. Consider capping net metered DG and developing a small local generation feed-in tariff.

## 15.8 Disadvantaged Communities

Support efforts by the Moreno Valley Planning Department to identify disadvantaged communities in Moreno Valley, and create an Outreach Toolbox to engage members of these communities.

# 16 RESOURCE PROCUREMENT PLAN

## 16.1 ASSUMPTIONS

This procurement plan is based on the following assumptions:

- Preferred Scenario/Portfolio: B2 – Mid Demand Case (same data for additional cases provided in Attachment 1)
    - 2030 GHG Target = 0.0481 MMT $CO_2e$ (estimated proportionate share of 42 MMT statewide electricity sector target)
    - RPS Goal of 60% by 2030; 100% clean energy by 2045
    - Minimum RPS margin of procurement: 5% above goal
    - At least 65% of RPS met through utility ownership or long-term (10+ year) power purchase agreements (Note: Utility ownership not practical until full capture of Investment Tax Credits for solar; not practical for wind due to Production Tax Credit)
    - Assumes all RPS procurement is for Portfolio Content Category (PCC) 1 eligible resources. To reduce costs, some of these PCC 1 purchases could be replaced by PCC 2 and/or PCC 3 up to stated maximums.
- New renewable resource mix will be approximately 70% solar and 30% wind.
    - Actual procurement will be based on market response and may differ from these initial targets.
- New renewable resources are assumed to have full capacity delivery status in order for the associated net qualifying capacity to count toward MVU's resource adequacy requirements. If a new renewable resource has energy only deliverability status, it will not count for RA, and should be discounted from the price of fully deliverable products by at least the value of the RA capacity.
- Capacity Planning Reserve: 15%
- Targeted energy storage procurement (if cost effective) assumed to be within the fence of a renewable energy project, and capacity only (energy to be provided from the renewable energy project).

## 16.2 MVU ENERGY PROCUREMENT PLAN

Many of the following paragraphs are taken directly from the 2015 IRP with only minor edits, as the general approach to procurement has not materially changed.

MVU will continue to use a portfolio risk management approach in its power purchasing program, seeking low cost supply as well as diversity among technologies, production profiles, generation project sizes, project locations, counterparty, length of contract, and timing of market purchases. Any existing resources are considered in the determination of additional purchases of energy. The design of the resource portfolio will also consider the financial requirements of the utility and honor existing policies to maintain rate competitiveness with Southern California Edison and promote economic development in the City.

MVU will manage its energy requirements and supply commitments with the objective of balancing cost stability and cost minimization, while leaving some flexibility to take advantage of market opportunities or technological improvements that may arise. MVU has identified its open position separately for renewable resources and capacity resources. MVU endeavors to maintain portfolio coverage targets of up to 100% in the near-term (0 to 5 years) and leaves a greater portion open in the mid to long term, consistent with generally accepted industry practice.

MVU will procure its energy needs through various appropriate methods, including bilaterally negotiated agreements and formal solicitation processes, such as requests for proposals and/or requests for offers. MVU transacts with energy suppliers which have executed Master Agreements with the City and/or are members of the Western Systems Power Pool ("WSPP"). The MVU Risk Management Policy addresses the various criteria for counterparties with which MVU may transact, including key considerations such as the creditworthiness of energy product suppliers.

Specific authorities for entering into energy procurement contracts are allocated to the Electric Utility Manager, consistent with the adoption of the 2013 Resource Plan – the 2013 Plan established appropriate procurement authorities for MVU, which balanced a variety of important considerations, including the time-sensitive nature of market pricing, the anticipated term and financial commitment associated with specific energy transactions, administrative practicalities, and Council oversight of such transactions among other considerations.

Actual resource procurement may vary from this plan, and may depend upon revised load projections, market conditions and resource availability, as well as the application of MVU's cost containment policy related to renewable energy, at the time MVU engages in additional energy procurement.

MVU will procure its net open positions using a combination of power purchase agreements of various terms (short, medium, long) and demand-side programs. The potential for MVU owned generation projects is not specifically addressed in this Plan, as there is no imminent timetable for the development of such resources. Such discussion may be added in future updates to this Plan based on specific development opportunities that are being considered by the Utility. In addition, when considering future long-term power purchase agreements, MVU will consider facilities that offer the option to purchase the project at the end of investment tax credit recovery period (typically 5-10 years).

In order to meet the portion of MVU load that is not served by bundled renewable energy contracts, MVU may engage in purchases of unspecified system energy or unit specific purchases from natural gas-fueled generation or additional renewable energy projects when they are able to satisfy MVU requirements competitively. Energy products may include block peak (and/or super-peak) and off-peak, baseload, and shaped energy. MVU may purchase energy and/or capacity at fixed prices, indexed prices or through tolling agreements. Under a tolling agreement, MVU would obtain the right to electricity produced by a natural gas generation facility, and MVU would deliver the natural gas to the facility for conversion into electrical energy. Purchases of system energy will typically be for short and medium terms (< 5 years). Unit-specific and tolling agreements may be for short, medium and long terms. Natural gas purchases associated with tolling agreements, if applicable, will typically be for short to medium terms.

MVU expects to contract with additional counterparties for supply of system energy and capacity in anticipation of the expiration of the Exelon agreements in 2019. Execution of master power purchase and sale agreements with multiple, credit-worthy counterparties in the near term will enable energy purchases through execution of transaction-specific confirmations at the appropriate time.

MVU may engage in purchases or sales of resource adequacy capacity from generation resources that qualify to meet resource adequacy requirements in accordance with CAISO rules. Terms may range from 1 month up to ten years. Capacity is also often bundled with energy and RECs under long-term renewable energy power purchase agreements, which may be pursued by MVU consistent with its RPS Procurement Plan.

MVU will use a portfolio risk management approach in its power purchasing program, seeking low cost supply as well as diversity among technologies, production profiles, generation project sizes, project locations, counterparty, length of contract, and timing of market purchases. These factors are taken into consideration when MVU engages the market.

MVU will manage its forward load obligations and supply commitments with the objective of balancing cost stability and cost minimization, while leaving some flexibility to take advantage of market opportunities or technological improvements that may arise. MVU has identified its open position separately for renewable resources (by compliance category), conventional resources, capacity resources, and on a total portfolio basis. MVU endeavors to maintain portfolio coverage targets of up to 100% in the near-term (0 to 5 years) and leaves a greater portion open in the mid to long term, consistent with generally accepted industry practice.

With respect to MVU's total supply and load obligations, MVU will manage exposure to market price risk by executing forward electric supply commitments for its projected energy sales obligations. MVU considers a variety of factors including the desire to maintain cost stability for MVU customers and cost minimization for MVU customers. MVU's budgeting and rate setting processes benefit from maximizing cost certainty within the budgetary fiscal year and avoiding significant year-to-year changes caused by energy market volatility. However, it is appropriate to maintain flexibility for incorporation of new, but as yet unplanned, resources or load reducing programs and to maintain limited exposure to market pricing in order to maintain relative cost parity with the local investor owned utility. In light of these considerations, the following market price contracting guidelines shall be maintained during operation of the MVU program.

*Table 16-1 - MVU Power Supply Contracting Guidelines*

| Time Horizon | Contracting Guideline (Contracts/Total Energy Need) |
|---|---|
| **Current Year** | 80% to 105% |
| **Year 2** | 70% to 100% |
| **Year 3** | 60% to 95% |
| **Year 4 and Beyond** | Up to 85% |

As MVU continues to contract with additional counterparties for supply of system energy and capacity, observing the contracting guidelines reflected in *Table 16-1* - MVU Power Supply Contracting Guidelines will help to mitigate forward price risk. Execution of master power purchase and sale agreements with multiple, credit-worthy counterparties in the near term will enable energy purchases through execution of transaction specific confirmations at the appropriate time.

Generally, the renewable portion of the portfolio is met with longer term contracts, providing cost stability for the supply portfolio. MVU's guidelines for long term, bundled renewable energy purchases are shown in *Table 16-2*. Note that such guidelines reflect the percentage of the Utility's renewable energy requirements that may be placed under contract during each of the identified time horizons; such percentages may be adjusted in consideration of cost limitation principles referenced in MVU's RPS Procurement Plan.

*Table 16-2 - MVU Renewable Energy Contracting Guidelines*

| Time Horizon | Contracting Guideline (Contracts/Total Energy Need) |
|---|---|
| **Current Year** | 90% to 105% |
| **Year 2 – 3** | 70% to 90% |
| **Year 4 – 5** | 50% to 75% |
| **Beyond Year 5** | 40% to 60% |

MVU's supply preference is for a mix of renewable energy technologies that will deliver energy in a pattern that is generally consistent with MVU's load shape (See Section 8, *Figure 8-3 - MVU Load Duration Curve* and *Figure 8-4 - MVU Annual Energy Load Profile)*. Preferred purchase volumes should be in rough proportion to the Utility's load profile, subject to adjustments for market conditions and technology price differentials that exist at the time of purchase. Recent market data suggests that peaking resources are likely to comprise a larger proportion of the renewable supply portfolio due to the recent rapid declines in prices for solar PV generation projects and the abundance of such projects in development. The actual renewable portfolio during the planning period will likely be more heavily weighted toward peaking energy production due to the prevalence of competitively priced solar projects. MVU may also engage in purchases from as-available renewable generation (e.g., wind) to the extent that energy prices reflect a lower value due to their intermittency.

## 16.3 Procurement Methods

For long term purchase commitments, MVU will typically use competitive solicitations which may take the form of an RFP or a similar process where a comparative analysis of proposals is made at a single point in time. An RFP may be used where a specific resource need has been identified, some degree of urgency exists in fulfilling the identified need, sufficient time exists to conduct an RFP, and management believes that an RFP would yield the most competitive outcome.

Bilaterally negotiated agreements in response to unsolicited proposals may be used for unique opportunities that are fleeting in nature such that timelines associated with an RFP would prevent MVU from engaging in beneficial procurement opportunities. Short- and medium-term power purchases will typically be negotiated on a bilateral basis or via independent energy brokers, particularly in markets with sufficient market price transparency to ensure competitive procurement outcomes. These markets include 1) system energy at a defined CAISO trading hub for peak, off-peak, or baseload products; 2) unbundled RECs; and 3) short term resource adequacy capacity. This process allows for maximum operational flexibility to manage supply and demand imbalances in an efficient manner.

The Utility may also utilize ongoing, “seasonal” procurement processes and/or standard offer tariffs/contracts, as alternatives to the aforementioned procurement mechanisms. In the case of seasonal procurement processes, these mechanisms may be administered on an annual basis to address less urgent, longer term resource requirements in an opportunistic manner. Such processes also provide a good source of market intelligence while imposing moderate administrative burdens. Ongoing renewable energy and resource adequacy capacity needs tend be well suited for such processes, as the Utility will want to regularly engage the market to determine pricing trends and product availability.

With regard to stand offer tariffs/contracts, such as renewable energy feed-in tariffs, these procurement options allow the Utility to develop narrowly defined product and contracting requirements which must be agreed to by all interested counterparties. Standard offer tariffs/contracts provide a useful mechanism for addressing select resource needs of the utility, particularly locally-situated renewable energy projects/products. Through a feed-in tariff the Utility will be able to specify applicable pricing, product quantities and project locations that will apply to all interested projects. In the event that the feed-in tariff is not fully subscribed (i.e., the specified energy or capacity limit has not been reached/achieved), additional qualifying projects will be able to engage the Utility through an expedited application and contracting process (which would require the acceptance of all specified terms, without modification) that minimizes the need for administrative approvals. Such procurement options may be well suited to advance locally developed renewable generating capacity without exposing the Utility to various project development risks and financing costs.

## 16.4 Procurement Authorities

Energy procurement authority varies depending upon the nature of the energy product being procured and the financial commitment associated with related agreements. MVU has adopted guidelines related to such purchases that balance the need for time-sensitive action and fiscal oversight. The appropriate procurement method and procurement authority are generally defined by the term of the energy product purchase, consistency with an approved resource plan, and whether capital financing is required.

The Moreno Valley City Council establishes procurement policies and objectives through adoption of the resource plan and related procedures. The Electric Utility Manager is authorized to execute certain contracts for energy products that are consistent with the approved resource plan, while other resource commitments require City Manager or City Council pre-approval prior to execution.

For shorter term power purchases, it is appropriate for the Electric Utility Manager to have discretion in contracting, consistent with its responsibilities and expertise in efficiently operating the Electric Utility. Time is often of the essence in such transactions, and these transactions are unlikely to raise policy considerations that require Council input. For long-term commitments, it is appropriate for the City Council to exercise a greater degree of oversight. The various energy procurement authorities are as follows:

### 16.4.1 Short-Term Contracts

Power purchase agreements (energy, capacity, RECs) with terms of 12 months or less may be entered into on MVU’s behalf by the Electric Utility Manager, subject to approval by the

Chief Financial Officer/City Treasurer, City Attorney, and City Manager. The Electric Utility Manager will report all such contracts to the City Council.

### 16.4.2 Medium-Term Contracts

Power purchase agreements (energy, capacity, RECs) with terms of greater than 12 months and less than or equal to 5 years and which are made pursuant to a Council approved resource plan may be entered into by the City Manager. The Electric Utility Manager and/or City Manager will report all such contracts to the City Council.

### 16.4.3 Long-Term Contracts

Power purchase agreements (energy, capacity, RECs) with terms of greater than 5 years shall require City Council approval prior to execution.

### 16.4.4 Capital Projects and Debt

Contracts associated with MVU ownership of generation assets or the assumption of debt by MVU in support of generation projects or power purchase agreements require City Council pre-approval.

### 16.4.5 Other Energy Procurement

Any procurement of energy products that is inconsistent with or that is not addressed in the adopted resource plan requires City Council pre-approval.

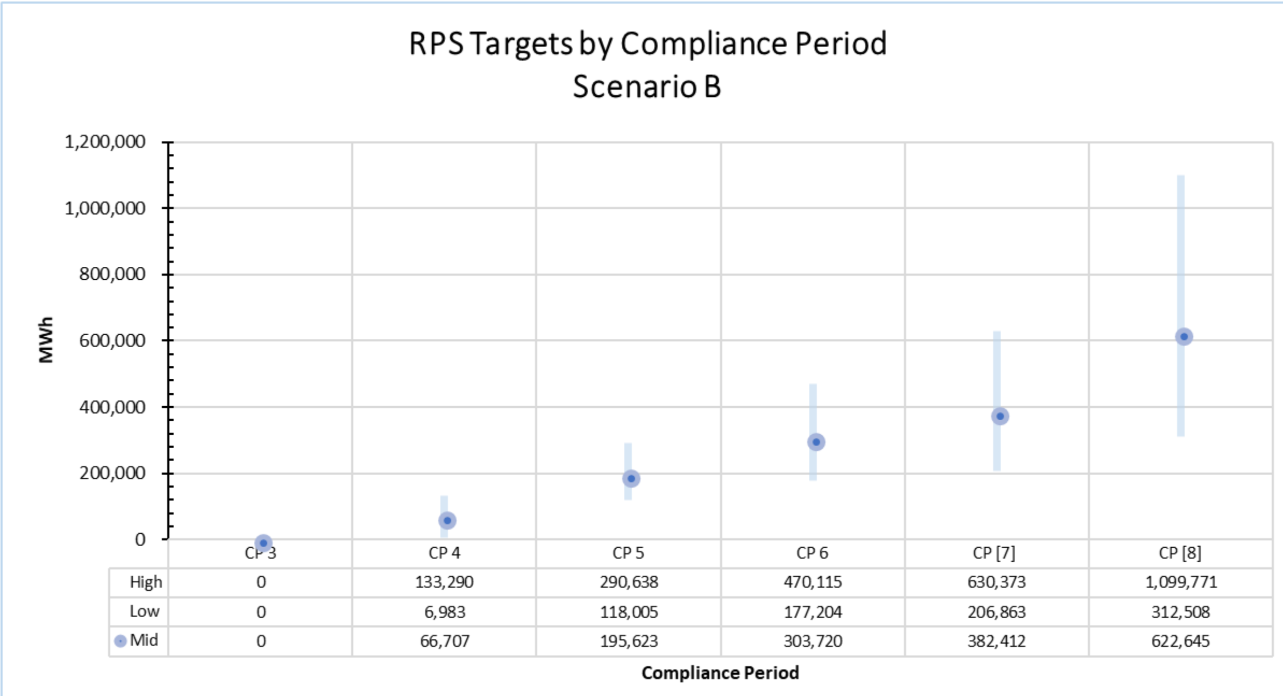
## 16.5 RPS Procurement Targets

Table 16-3 below shows the MVU RPS Procurement Targets for Recommended Scenario B. The targets include a 5% procurement margin in each compliance period. The last two compliance periods have not officially been established by the State but are assumed to follow the previously established structure of 3 to 4-year periods. It is recommended that MVU procure resources pursuant to the recommended Scenario and the mid-load case unless and until it becomes aware of circumstances that would dictate otherwise. Figure 16-1 shows the potential range of procurement targets from high load to low load, including the mid-load case.

*Table 16-3 - Recommended Scenario RPS Procurement Targets by Compliance Period*

| RPS Procurement Targets by Compliance Period (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| | 2018-2020 | 2021-2024 | 2025-2027 | 2028-2030 | 2031-2033 | 2034-2037 |
| Scenario B | CP 3 | CP 4 | CP 5 | CP 6 | CP [7] | CP [8] |
| Mid | 0 | 66,707 | 195,623 | 303,720 | 382,412 | 622,645 |

*Figure 16-1 Range of RPS Targets by Compliance Period*




| | CP 3 | CP 4 | CP 5 | CP 6 | CP [7] | CP [8] |
|---|---|---|---|---|---|---|
| High | 0 | 133,290 | 290,638 | 470,115 | 630,373 | 1,099,771 |
| Low | 0 | 6,983 | 118,005 | 177,204 | 206,863 | 312,508 |
| Mid | 0 | 66,707 | 195,623 | 303,720 | 382,412 | 622,645 |

Table 16-4 below breaks down the compliance period RPS procurement amounts shown in Table 16-3 into annual soft targets. A carryover account utilizes any excess procurement in one year to meet the targets for the next or subsequent years. The first column (after the years) is MVU's RPS target in MWh minus its existing RPS-eligible resources. Positive numbers indicate that additional procurement is needed; negative numbers indicate that MVU has a surplus. The column highlighted in yellow is the amount of RPS-eligible resources that must be procured, after carryover adjustment, to meet the RPS annual soft targets. The sum of the amounts in this highlighted column for each year of the compliance period is equal to the compliance period targets in Table 16-3 above.

Also shown are recommended proportions of different renewable technologies (in this Scenario, limited to solar and wind) to ensure portfolio diversity, provided that these resources are available at competitive costs. The table assumes all RPS procurement is Portfolio Content Category (PCC) 1 but also shows optional amounts of procurement in PCC 2 and 3 that, if reasonably available to MVU, may substitute for equivalent amounts of PCC 1 purchases to reduce total costs. Finally, Table 16-4 shows the minimum quantity of RPS procurement that must be under utility ownership or long-term (10+ year) contracts pursuant to SB 350.

*Table 16-4 - RPS Procurement Plan - Annual Detail*

| B2 MID: SCENARIO B, PORTFOLIO 2, MID DEMAND CASE RPS PROCUREMENT PLAN | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MVU RPS (NET SHORT)/ SURPLUS (MWh) | CARRY OVER (MWh) | CARRY OVER BALANCE (MWh) | RPS TARGET TO BE PROCURED (MWh) | TOTAL PCC 1 (MWh) | PCC 1 SOLAR 70% (MWh) | PCC 1 WIND 30% (MWh) | OPTIONAL: PCC 2 (MWh) | OPTIONAL: PCC 3 (MWh) | LONG TERM CONTRACTS (10+ YRS) (MWh) | |
| 2018 | (10,757) | 10,757 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2019 | (3,632) | 3,632 | (14,389) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | CP 3 |
| 2020 | (35,965) | 35,965 | (50,353) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2021 | 16,407 | (16,407) | (33,946) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2022 | 24,248 | (33,946) | (9,698) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | CP 4 |
| 2023 | 33,389 | (9,698) | 0 | 23,691 | 23,691 | 16,584 | 7,107 | 14,486 | 9,657 | 0 | |
| 2024 | 43,016 | 0 | 0 | 43,016 | 43,016 | 30,111 | 12,905 | 15,890 | 10,594 | 5,938 | |
| 2025 | 54,226 | 0 | 0 | 54,226 | 54,226 | 37,958 | 16,268 | 17,525 | 11,683 | 13,335 | |
| 2026 | 65,011 | 0 | 0 | 65,011 | 65,011 | 45,508 | 19,503 | 19,100 | 12,733 | 20,445 | CP 5 |
| 2027 | 76,386 | 0 | 0 | 76,386 | 76,386 | 53,470 | 22,916 | 20,763 | 13,842 | 27,939 | |
| 2028 | 88,355 | 0 | 0 | 88,355 | 88,355 | 61,849 | 26,507 | 22,519 | 15,013 | 35,810 | |
| 2029 | 101,022 | 0 | 0 | 101,022 | 101,022 | 70,715 | 30,306 | 24,373 | 16,249 | 44,151 | CP 6 |
| 2030 | 114,343 | 0 | 0 | 114,343 | 114,343 | 80,040 | 34,303 | 26,329 | 17,553 | 52,909 | |
| 2031 | 120,767 | 0 | 0 | 120,767 | 120,767 | 84,537 | 36,230 | 27,251 | 18,167 | 57,182 | |
| 2032 | 127,381 | 0 | 0 | 127,381 | 127,381 | 89,167 | 38,214 | 28,204 | 18,803 | 61,571 | CP [7] |
| 2033 | 134,264 | 0 | 0 | 134,264 | 134,264 | 93,985 | 40,279 | 29,192 | 19,461 | 66,150 | |
| 2034 | 139,991 | 0 | 0 | 139,991 | 139,991 | 97,994 | 41,997 | 30,009 | 20,006 | 69,969 | |
| 2035 | 147,268 | 0 | 0 | 147,268 | 147,268 | 103,088 | 44,180 | 31,060 | 20,706 | 74,796 | CP [8] |
| 2036 | 154,765 | 0 | 0 | 154,765 | 154,765 | 108,336 | 46,430 | 32,147 | 21,431 | 79,757 | |
| 2037 | 180,621 | 0 | 0 | 180,621 | 180,621 | 126,434 | 54,186 | 33,272 | 22,181 | 102,987 | |

## 16.6 MVU ADDITIONAL ENERGY PROCUREMENT PLAN

Beyond the renewables required to meet the RPS, MVU will need to procure additional energy to meet its projected loads. Table 16-5 shows MVU's projected additional energy procurement targets. This additional energy can be renewable or non-renewable, whichever is most cost-effective. However, this plan calls for these additional energy resources to all be non-carbon emitting no later than 2035.

*Table 16-5 - MVU Additional Energy Procurement Plan*

| B2 MID: SCENARIO B, PORTFOLIO 2, MID DEMAND CASE ADDITIONAL ENERGY PROCUREMENT PLAN | |
|---|---|
| | MVU NON-RPS (ADDITIONAL) ENERGY PROCUREMENT TARGET (MWh) |
| 2018 | 63,905 |
| 2019 | 16,753 |
| 2020 | 93,515 |
| 2021 | 145,894 |
| 2022 | 152,682 |
| 2023 | 136,848 |
| 2024 | 125,618 |
| 2025 | 122,825 |
| 2026 | 120,716 |
| 2027 | 118,309 |
| 2028 | 115,586 |
| 2029 | 112,527 |
| 2030 | 109,112 |
| 2031 | 112,931 |
| 2032 | 116,884 |
| 2033 | 120,974 |
| 2034 | 126,569 |
| 2035 | 130,999 |
| 2036 | 135,584 |
| 2037 | 140,330 |

## 16.7 MVU Capacity/Resource Adequacy Procurement Plan

In addition to its energy resources, MVU must ensure that it has access to sufficient capacity to meet its resource adequacy requirements. Some of the resources MVU procures to meet its RPS and/or additional energy requirements may also include capacity attributes. Table 16-6 below summarizes MVU's annual capacity procurement plan. The amounts in this table equal MVU's projected capacity demand minus the net qualifying capacity of its existing resources. A positive number indicates a procurement need. Table 16-7 provides greater detail.

*Table 16-6 - MVU Capacity Procurement Plan*

| B2 MID: SCENARIO B, PORTFOLIO 2, MID DEMAND CASE CAPACITY PROCUREMENT PLAN | |
|---|---|
| | MVU CAPACITY/SYSTEM RESOURCE ADEQUACY NET SHORT - PROCUREMENT TARGET (MW) |
| 2018 | 4 |
| 2019 | 64 |
| 2020 | 63 |
| 2021 | 72 |
| 2022 | 79 |
| 2023 | 81 |
| 2024 | 83 |
| 2025 | 88 |
| 2026 | 92 |
| 2027 | 96 |
| 2028 | 100 |
| 2029 | 103 |
| 2030 | 107 |
| 2031 | 112 |
| 2032 | 117 |
| 2033 | 122 |
| 2034 | 127 |
| 2035 | 132 |
| 2036 | 136 |
| 2037 | 138 |

*Table 16-7 - MVU Resource Adequacy Procurement Plan*

| MVU CAPACITY/RESOURCE ADEQUACY PROCUREMENT PLAN | | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| **MVU NET ANNUAL PEAK DEMAND - MID CASE + PLANNING RESERVE MARGIN (MW)** | | **62.1** | **67.6** | **73.8** | **80.0** | **86.4** |
| **MVU EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC (MW)** | **RA STATUS** | | | | | |
| TGEN-MVU-RA1 TGP Energy Management LLC (Tenaska) Pool | FCDS | 2.0 | 2.0 | 2.0 | 0.0 | 0.0 |
| ASTORA_2_SOLAR2, AST2-MVU-RA1 RE Astoria 2 LLC (Recurrent via SCPPA) | FCDS | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| Antelope Expansion 3A, LLC (Sustainable Power Group, or SPower) | FCDS | 0.0 | 0.0 | 6.7 | 6.7 | 6.7 |
| WHITNY_6_SOLAR Whitney Point Solar, LLC (NextEra) | EO | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| INLDEM_5_UNIT1 Direct Energy Business Marketing, LLC - Inland Empire Energy Center Unit 1 | FCDS | 55.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ***TOTAL: EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC*** | | **57.9** | **2.9** | **9.6** | **7.6** | **7.6** |
| **ASSUMED CAPACITY OF RENEWABLE PROCUREMENT ADDITIONS (MW)** | **CF:** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |
| *Solar* | 30% | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| *Wind* | 31% | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **RA CAPACITY FROM GENERIC ENERGY RESOURCE ADDITIONS (ASSUMES FCDS - MW)** | **NQC (JUN)** | **0.0** | **1.0** | **1.0** | **0.0** | **0.0** |
| *90% Energy Storage/Demand Response* | | 0.0 | 1.0 | 1.0 | 0.0 | 0.0 |
| *31% Solar* | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| *31% Wind* | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **MVU CAPACITY/SYSTEM RESOURCE ADEQUACY NET SHORT - PROCUREMENT TARGET (MW)** | | **(4.2)** | **(63.7)** | **(63.1)** | **(72.4)** | **(78.8)** |

| MVU CAPACITY/RESOURCE ADEQUACY PROCUREMENT PLAN | | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| **MVU NET ANNUAL PEAK DEMAND - MID CASE + PLANNING RESERVE MARGIN (MW)** | | **92.9** | **99.4** | **105.9** | **112.2** | **118.5** |
| **MVU EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC (MW)** | **RA STATUS** | | | | | |
| TGEN-MVU-RA1 TGP Energy Management LLC (Tenaska) Pool | FCDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ASTORA_2_SOLAR2, AST2-MVU-RA1 RE Astoria 2 LLC (Recurrent via SCPPA) | FCDS | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| Antelope Expansion 3A, LLC (Sustainable Power Group, or SPower) | FCDS | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 |
| WHITNY_6_SOLAR Whitney Point Solar, LLC (NextEra) | EO | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| INLDEM_5_UNIT1 Direct Energy Business Marketing, LLC - Inland Empire Energy Center Unit 1 | FCDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ***TOTAL: EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC*** | | **7.6** | **7.6** | **7.6** | **7.6** | **7.6** |
| **ASSUMED CAPACITY OF RENEWABLE PROCUREMENT ADDITIONS (MW)** | **CF:** | **8.9** | **16.2** | **20.4** | **24.5** | **28.8** |
| *Solar* | 30% | 6.3 | 11.5 | 14.4 | 17.3 | 20.3 |
| *Wind* | 31% | 2.6 | 4.8 | 6.0 | 7.2 | 8.4 |
| **RA CAPACITY FROM GENERIC ENERGY RESOURCE ADDITIONS (ASSUMES FCDS - MW)** | **NQC (JUN)** | **4.7** | **8.4** | **10.6** | **12.8** | **15.0** |
| *90% Energy Storage/Demand Response* | | 1.9 | 3.5 | 4.4 | 5.3 | 6.2 |
| *31% Solar* | | 1.9 | 3.5 | 4.4 | 5.3 | 6.2 |
| *31% Wind* | | 0.8 | 1.5 | 1.8 | 2.2 | 2.6 |
| **MVU CAPACITY/SYSTEM RESOURCE ADEQUACY NET SHORT - PROCUREMENT TARGET (MW)** | | **(80.6)** | **(83.4)** | **(87.6)** | **(91.9)** | **(95.8)** |

| MVU CAPACITY/RESOURCE ADEQUACY PROCUREMENT PLAN | | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|
| **MVU NET ANNUAL PEAK DEMAND - MID CASE + PLANNING RESERVE MARGIN (MW)** | | **124.7** | **130.9** | **137.1** | **143.3** | **149.5** |
| **MVU EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC (MW)** | **RA STATUS** | | | | | |
| TGEN-MVU-RA1 TGP Energy Management LLC (Tenaska) Pool | FCDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ASTORA_2_SOLAR2, AST2-MVU-RA1 RE Astoria 2 LLC (Recurrent via SCPPA) | FCDS | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| Antelope Expansion 3A, LLC (Sustainable Power Group, or SPower) | FCDS | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 |
| WHITNY_6_SOLAR Whitney Point Solar, LLC (NextEra) | EO | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| INLDEM_5_UNIT1 Direct Energy Business Marketing, LLC - Inland Empire Energy Center Unit 1 | FCDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ***TOTAL: EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC*** | | **7.6** | **7.6** | **7.6** | **7.6** | **7.6** |
| **ASSUMED CAPACITY OF RENEWABLE PROCUREMENT ADDITIONS (MW)** | **CF:** | **33.3** | **38.1** | **43.1** | **45.5** | **48.0** |
| *Solar* | 30% | 23.5 | 26.9 | 30.5 | 32.2 | 33.9 |
| *Wind* | 31% | 9.8 | 11.2 | 12.6 | 13.3 | 14.1 |
| **RA CAPACITY FROM GENERIC ENERGY RESOURCE ADDITIONS (ASSUMES FCDS - MW)** | **NQC (JUN)** | **17.3** | **19.8** | **22.4** | **23.7** | **25.0** |
| *90% Energy Storage/Demand Response* | | 7.2 | 8.2 | 9.3 | 9.8 | 10.3 |
| *31% Solar* | | 7.2 | 8.2 | 9.3 | 9.8 | 10.3 |
| *31% Wind* | | 3.0 | 3.4 | 3.9 | 4.1 | 4.3 |
| **MVU CAPACITY/SYSTEM RESOURCE ADEQUACY NET SHORT - PROCUREMENT TARGET (MW)** | | **(99.7)** | **(103.4)** | **(107.0)** | **(112.0)** | **(116.9)** |

| MVU CAPACITY/RESOURCE ADEQUACY PROCUREMENT PLAN | | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| **MVU NET ANNUAL PEAK DEMAND - MID CASE + PLANNING RESERVE MARGIN (MW)** | | **155.7** | **161.9** | **168.2** | **174.4** | **180.6** |
| **MVU EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC (MW)** | **RA STATUS** | | | | | |
| TGEN-MVU-RA1 TGP Energy Management LLC (Tenaska) Pool | FCDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ASTORA_2_SOLAR2, AST2-MVU-RA1 RE Astoria 2 LLC (Recurrent via SCPPA) | FCDS | 0.9 | 0.9 | 0.9 | 0.9 | 0.0 |
| Antelope Expansion 3A, LLC (Sustainable Power Group, or SPower) | FCDS | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 |
| WHITNY_6_SOLAR Whitney Point Solar, LLC (NextEra) | EO | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| INLDEM_5_UNIT1 Direct Energy Business Marketing, LLC - Inland Empire Energy Center Unit 1 | FCDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ***TOTAL: EXISTING CAPACITY RESOURCES - ANNUAL PEAK NQC*** | | **7.6** | **7.6** | **7.6** | **7.6** | **6.7** |
| **ASSUMED CAPACITY OF RENEWABLE PROCUREMENT ADDITIONS (MW)** | **CF:** | **50.6** | **52.8** | **55.5** | **58.3** | **68.1** |
| *Solar* | 30% | 35.8 | 37.3 | 39.2 | 41.2 | 48.1 |
| *Wind* | 31% | 14.8 | 15.5 | 16.3 | 17.1 | 20.0 |
| **RA CAPACITY FROM GENERIC ENERGY RESOURCE ADDITIONS (ASSUMES FCDS - MW)** | **NQC (JUN)** | **26.4** | **27.5** | **28.9** | **30.4** | **35.5** |
| *90% Energy Storage/Demand Response* | | 10.9 | 11.4 | 12.0 | 12.6 | 14.7 |
| *31% Solar* | | 10.9 | 11.4 | 12.0 | 12.6 | 14.7 |
| *31% Wind* | | 4.5 | 4.7 | 5.0 | 5.2 | 6.1 |
| **MVU CAPACITY/SYSTEM RESOURCE ADEQUACY NET SHORT - PROCUREMENT TARGET (MW)** | | **(121.8)** | **(126.8)** | **(131.6)** | **(136.4)** | **(138.4)** |

## 16.8 PROJECTED MVU GHG EMISSIONS

| MVU PORTFOLIO GHG EMISSIONS (MT $CO_2e$) | GHG Factor (MT $CO_2e$ per MWh) | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| Excelon (contract through 6/30/19) | 0.428 | 23,943 | 46,974 | 0 | 0 | 0 |
| GENERIC NON-RPS (NON-CARBON EMITTING AFTER 2035) | 0.428 | 27,352 | 7,170 | 40,025 | 62,442 | 65,348 |
| **TOTAL MVU PORTFOLIO GHG EMISSIONS** | | 51,294 | 54,144 | 40,025 | 62,442 | 65,348 |
| | | | | | | |
| GHG PLANNING PRICE ($ per metric ton of $CO_2e$ emissions) | 2017 NPV | $15.17 | $16.05 | $16.94 | $17.88 | $18.86 |
| **PLANNING COST OF MVU GHG EMISSIONS** | **$29,616,359** | $778,134 | $869,018 | $678,015 | $1,116,472 | $1,232,465 |

| MVU PORTFOLIO GHG EMISSIONS (MT $CO_2e$) | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Excelon (contract through 6/30/19) | 0 | 0 | 0 | 0 | 0 |
| GENERIC NON-RPS (NON-CARBON EMITTING AFTER 2035) | 58,571 | 53,765 | 52,569 | 51,667 | 50,636 |
| **TOTAL MVU PORTFOLIO GHG EMISSIONS** | 58,571 | 53,765 | 52,569 | 51,667 | 50,636 |
| | | | | | |
| GHG PLANNING PRICE ($ per metric ton of $CO_2e$ emissions) | $19.91 | $21.02 | $22.19 | $23.44 | $55.08 |
| **PLANNING COST OF MVU GHG EMISSIONS** | $1,166,150 | $1,130,134 | $1,166,512 | $1,211,065 | $2,789,051 |

| | GHG 2030 Target = | | 48,148 | MT $CO_2e$ | |
|---|---|---|---|---|---|
| **MVU PORTFOLIO GHG EMISSIONS (MT $CO_2e$)** | **2028** | **2029** | **2030** | **2031** | **2032** |
| Excelon (contract through 6/30/19) | 0 | 0 | 0 | 0 | 0 |
| GENERIC NON-RPS (NON-CARBON EMITTING AFTER 2035) | 49,471 | 48,161 | 46,700 | 48,334 | 50,026 |
| **TOTAL MVU PORTFOLIO GHG EMISSIONS** | 49,471 | 48,161 | 46,700 | 48,334 | 50,026 |
| | | | | | |
| GHG PLANNING PRICE ($ per metric ton of $CO_2e$ emissions) | $86.72 | $118.36 | $150.00 | $150.00 | $150.00 |
| **PLANNING COST OF MVU GHG EMISSIONS** | $4,290,101 | $5,700,390 | $7,004,990 | $7,250,165 | $7,503,921 |

| MVU PORTFOLIO GHG EMISSIONS (MT $CO_2e$) | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|
| Excelon (contract through 6/30/19) | 0 | 0 | 0 | 0 | 0 |
| GENERIC NON-RPS (NON-CARBON EMITTING AFTER 2035) | 51,777 | 54,172 | 56,068 | 58,030 | 60,061 |
| **TOTAL MVU PORTFOLIO GHG EMISSIONS** | 51,777 | 54,172 | 56,068 | 58,030 | 60,061 |
| | | | | | |
| GHG PLANNING PRICE ($ per metric ton of $CO_2e$ emissions) | $150.00 | $150.00 | $150.00 | $150.00 | $150.00 |
| **PLANNING COST OF MVU GHG EMISSIONS** | $7,766,558 | $8,125,761 | $8,410,163 | $8,704,519 | $9,009,177 |

## 16.9 ANTICIPATED COST OF MVU PORTFOLIO ADDITIONS

The following estimated costs for MVU portfolio additions are derived from the levelized cost of energy ($/MWh) unit cost planning assumptions for candidate resources in the CPUC Reference System Portfolio. MVU's actual costs will depend on market conditions at the time of procurement and may be higher or lower than these estimates. Table 16-8 provides a summary of the anticipated annual costs, and Table 16-9 provides more detail.

*Table 16-8 - MVU Portfolio Additions - Anticipated Cost Summary*

| MVU PORTFOLIO ADDITIONAL COST | |
|---|---|
| 2017 NPV | **$234,643,728** |
| 2018 | $3,711,978 |
| 2019 | $3,257,168 |
| 2020 | $6,222,986 |
| 2021 | $8,180,498 |
| 2022 | $8,715,031 |
| 2023 | $10,506,904 |
| 2024 | $12,170,437 |
| 2025 | $14,056,550 |
| 2026 | $15,217,625 |
| 2027 | $16,392,491 |
| 2028 | $17,604,062 |
| 2029 | $18,873,611 |
| 2030 | $20,206,374 |
| 2031 | $21,602,875 |
| 2032 | $23,102,454 |
| 2033 | $24,722,555 |
| 2034 | $26,404,209 |
| 2035 | $28,292,919 |
| 2036 | $30,339,364 |
| 2037 | $34,109,779 |

*Table 16-9 - MVU Portfolio Estimated Additional Cost Detail*

| MVU PORTFOLIO ADDITIONAL COST | 2017 NPV | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| GENERIC BTM DISTRIBUTED SOLAR | **$36,452,558** | $1,325,946 | $1,543,764 | $1,741,372 | $1,949,131 | $2,155,864 |
| GENERIC SOLAR | **$24,483,733** | $0 | $0 | $0 | $0 | $0 |
| GENERIC WIND | **$40,760,785** | $0 | $0 | $0 | $0 | $0 |
| GENERIC NON-RPS | **$84,672,949** | $2,333,800 | $611,799 | $3,415,135 | $5,327,975 | $5,575,898 |
| GENERIC ENERGY STORAGE/DR (CAPACITY) | **$24,374,628** | $0 | $306,298 | $278,732 | $0 | $0 |
| GENERIC RESOURCE ADEQUACY (CAPACITY) | **$23,899,075** | $52,232 | $795,307 | $787,746 | $903,393 | $983,270 |
| AAEE | **$0** | $0 | $0 | $0 | $0 | $0 |
| **TOTAL** | **$234,643,728** | $3,711,978 | $3,257,168 | $6,222,986 | $8,180,498 | $8,715,031 |

| MVU PORTFOLIO ADDITIONAL COST | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| GENERIC BTM DISTRIBUTED SOLAR | $2,483,147 | $2,846,158 | $3,546,332 | $3,815,920 | $4,078,051 |
| GENERIC SOLAR | $971,268 | $1,836,263 | $2,629,966 | $3,128,568 | $3,639,229 |
| GENERIC WIND | $620,022 | $1,124,170 | $1,415,107 | $1,694,113 | $1,987,673 |
| GENERIC NON-RPS | $4,997,639 | $4,587,533 | $4,485,529 | $4,408,509 | $4,320,603 |
| GENERIC ENERGY STORAGE/DR (CAPACITY) | $428,698 | $736,361 | $886,492 | $1,024,541 | $1,171,304 |
| GENERIC RESOURCE ADEQUACY (CAPACITY) | $1,006,131 | $1,039,953 | $1,093,124 | $1,145,974 | $1,195,631 |
| AAEE | $0 | $0 | $0 | $0 | $0 |
| **TOTAL** | $10,506,904 | $12,170,437 | $14,056,550 | $15,217,625 | $16,392,491 |

| MVU PORTFOLIO ADDITIONAL COST | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|
| GENERIC BTM DISTRIBUTED SOLAR | $4,342,853 | $4,619,650 | $4,913,645 | $5,548,641 | $6,265,697 |
| GENERIC SOLAR | $4,169,952 | $4,725,547 | $5,303,959 | $5,601,929 | $5,908,728 |
| GENERIC WIND | $2,295,824 | $2,621,164 | $2,962,540 | $3,128,972 | $3,300,335 |
| GENERIC NON-RPS | $4,221,144 | $4,109,429 | $3,984,723 | $4,124,188 | $4,268,535 |
| GENERIC ENERGY STORAGE/DR (CAPACITY) | $1,330,455 | $1,507,494 | $1,706,289 | $1,802,146 | $1,900,844 |
| GENERIC RESOURCE ADEQUACY (CAPACITY) | $1,243,833 | $1,290,328 | $1,335,218 | $1,396,999 | $1,458,315 |
| AAEE | $0 | $0 | $0 | $0 | $0 |
| **TOTAL** | $17,604,062 | $18,873,611 | $20,206,374 | $21,602,875 | $23,102,454 |

| MVU PORTFOLIO ADDITIONAL COST | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|
| GENERIC BTM DISTRIBUTED SOLAR | $7,075,420 | $7,989,784 | $9,022,312 | $10,188,274 | $11,504,916 |
| GENERIC SOLAR | $6,228,005 | $6,493,646 | $6,831,213 | $7,178,979 | $8,378,309 |
| GENERIC WIND | $3,478,668 | $3,627,043 | $3,815,592 | $4,009,837 | $4,679,726 |
| GENERIC NON-RPS | $4,417,934 | $4,622,263 | $4,784,042 | $4,951,484 | $5,124,786 |
| GENERIC ENERGY STORAGE/DR (CAPACITY) | $2,003,556 | $2,089,013 | $2,197,609 | $2,309,485 | $2,695,311 |
| GENERIC RESOURCE ADEQUACY (CAPACITY) | $1,518,972 | $1,582,460 | $1,642,152 | $1,701,305 | $1,726,731 |
| AAEE | $0 | $0 | $0 | $0 | $0 |
| **TOTAL** | $24,722,555 | $26,404,209 | $28,292,919 | $30,339,364 | $34,109,779 |

## 16.10 ANTICIPATED MVU PORTFOLIO MIX (MWH)

| PROPOSED PORTFOLIO CONTENTS SUMMARY (MWh) | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Gross Consumption Forecast (MWh)** | 211,891 | 220,640 | 229,533 | 238,759 | 248,264 |
| Line Losses | 14,536 | 15,031 | 15,550 | 16,082 | 16,633 |
| AAEE | 0 | 0 | 0 | 0 | 0 |
| BTM Solar | 8,985 | 10,645 | 12,196 | 13,827 | 15,473 |
| **Net Energy for Load (MWh)** | 188,370 | 194,963 | 201,787 | 208,849 | 216,159 |
| | | | | | |
| **Renewable Energy (MWh)** | | | | | |
| Existing Solar | 18,524 | 18,457 | 63,271 | 62,955 | 63,476 |
| Existing Wind | 20,000 | 20,000 | 15,000 | 0 | 0 |
| New Generic (Solar) | 24,459 | 29,830 | 7,596 | 24,277 | 30,213 |
| New Generic (Wind) | 10,482 | 12,784 | 3,255 | 10,404 | 12,949 |
| New Generic (Geothermal) | 0 | 0 | 0 | 0 | 0 |
| **TOTAL RENEWABLE ENERGY** | 73,464 | 81,072 | 89,122 | 97,637 | 106,638 |
| Solar | *42,982* | *48,288* | *70,867* | *87,233* | *93,690* |
| Wind | *30,482* | *32,784* | *18,255* | *10,404* | *12,949* |
| Geothermal | *0* | *0* | *0* | *0* | *0* |
| | | | | | |
| **Non-Renewable Resources (MWh)** | | | | | |
| Existing | 55,941 | 109,753 | 0 | 0 | 0 |
| New Generic | 58,965 | 4,138 | 112,664 | 111,212 | 109,521 |
| TOTAL NON-RENEWABLE ENERGY | 114,906 | 113,891 | 112,664 | 111,212 | 109,521 |
| | | | | | |
| **TOTAL RESOURCES TO SERVE LOAD (MWh)** | **188,370** | **194,963** | **201,787** | **208,849** | **216,159** |
| Surplus/(Deficit) | 0 | 0 | 0 | 0 | 0 |

| PROPOSED PORTFOLIO CONTENTS SUMMARY (MWh) | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Gross Consumption Forecast (MWh)** | 258,072 | 268,258 | 278,754 | 289,602 | 300,780 |
| Line Losses | 17,192 | 17,780 | 18,388 | 19,023 | 19,673 |
| AAEE | 0 | 0 | 0 | 0 | 0 |
| BTM Solar | 17,155 | 18,923 | 20,707 | 22,532 | 24,379 |
| **Net Energy for Load (MWh)** | 223,724 | 231,555 | 239,659 | 248,047 | 256,729 |
| **Renewable Energy (MWh)** | | | | | |
| Existing Solar | 63,185 | 62,920 | 62,608 | 62,320 | 62,034 |
| Existing Wind | 0 | 0 | 0 | 0 | 0 |
| New Generic (Solar) | 37,076 | 44,294 | 51,939 | 59,977 | 68,446 |
| New Generic (Wind) | 15,890 | 18,983 | 22,259 | 25,704 | 29,334 |
| New Generic (Geothermal) | 0 | 0 | 0 | 0 | 0 |
| **TOTAL RENEWABLE ENERGY** | 116,150 | 126,197 | 136,805 | 148,002 | 159,814 |
| Solar | *100,261* | *107,214* | *114,546* | *122,297* | *130,480* |
| Wind | *15,890* | *18,983* | *22,259* | *25,704* | *29,334* |
| Geothermal | *0* | *0* | *0* | *0* | *0* |
| **Non-Renewable Resources (MWh)** | | | | | |
| Existing | 0 | 0 | 0 | 0 | 0 |
| New Generic | 107,574 | 105,357 | 102,854 | 100,046 | 96,915 |
| TOTAL NON-RENEWABLE ENERGY | 107,574 | 105,357 | 102,854 | 100,046 | 96,915 |
| **TOTAL RESOURCES TO SERVE LOAD (MWh)** | **223,724** | **231,555** | **239,659** | **248,047** | **256,729** |
| Surplus/(Deficit) | 0 | 0 | 0 | 0 | 0 |

| PROPOSED PORTFOLIO CONTENTS SUMMARY (MWh) | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|
| **Gross Consumption Forecast (MWh)** | 312,321 | 324,291 | 336,737 | 350,383 | 365,877 |
| Line Losses | 20,342 | 21,030 | 21,739 | 21,500 | 22,252 |
| AAEE | 0 | 0 | 0 | 0 | 0 |
| BTM Solar | 26,265 | 28,247 | 30,358 | 34,281 | 38,711 |
| **Net Energy for Load (MWh)** | 265,714 | 275,014 | 284,640 | 294,602 | 304,913 |
| **Renewable Energy (MWh)** | | | | | |
| Existing Solar | 61,773 | 61,466 | 61,185 | 60,904 | 60,649 |
| Existing Wind | 0 | 0 | 0 | 0 | 0 |
| New Generic (Solar) | 77,349 | 86,758 | 96,644 | 101,722 | 106,953 |
| New Generic (Wind) | 33,149 | 37,182 | 41,419 | 43,595 | 45,837 |
| New Generic (Geothermal) | 0 | 0 | 0 | 0 | 0 |
| **TOTAL RENEWABLE ENERGY** | 172,272 | 185,406 | 199,248 | 206,222 | 213,439 |
| Solar | *139,122* | *148,224* | *157,829* | *162,626* | *167,602* |
| Wind | *33,149* | *37,182* | *41,419* | *43,595* | *45,837* |
| Geothermal | *0* | *0* | *0* | *0* | *0* |
| **Non-Renewable Resources (MWh)** | | | | | |
| Existing | 0 | 0 | 0 | 0 | 0 |
| New Generic | 93,443 | 89,609 | 85,392 | 88,381 | 91,474 |
| TOTAL NON-RENEWABLE ENERGY | 93,443 | 89,609 | 85,392 | 88,381 | 91,474 |
| **TOTAL RESOURCES TO SERVE LOAD (MWh)** | **265,714** | **275,014** | **284,640** | **294,602** | **304,913** |
| Surplus/(Deficit) | 0 | 0 | 0 | 0 | 0 |

| PROPOSED PORTFOLIO CONTENTS SUMMARY (MWh) | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|
| **Gross Consumption Forecast (MWh)** | 382,331 | 399,831 | 418,477 | 438,376 | 459,651 |
| Line Losses | 23,031 | 23,837 | 24,672 | 25,535 | 26,429 |
| AAEE | 0 | 0 | 0 | 0 | 0 |
| BTM Solar | 43,714 | 49,363 | 55,742 | 62,946 | 71,081 |
| **Net Energy for Load (MWh)** | 315,585 | 326,631 | 338,063 | 349,895 | 362,142 |
| **Renewable Energy (MWh)** | | | | | |
| Existing Solar | 60,347 | 60,071 | 59,795 | 59,545 | 41,191 |
| Existing Wind | 0 | 0 | 0 | 0 | 0 |
| New Generic (Solar) | 112,394 | 118,000 | 123,794 | 129,767 | 148,616 |
| New Generic (Wind) | 48,169 | 50,571 | 53,055 | 55,614 | 63,692 |
| New Generic (Geothermal) | 0 | 0 | 0 | 0 | 0 |
| **TOTAL RENEWABLE ENERGY** | 220,910 | 228,642 | 236,644 | 244,927 | 253,499 |
| Solar | *172,741* | *178,070* | *183,590* | *189,312* | *189,807* |
| Wind | *48,169* | *50,571* | *53,055* | *55,614* | *63,692* |
| Geothermal | *0* | *0* | *0* | *0* | *0* |
| **Non-Renewable Resources (MWh)** | | | | | |
| Existing | 0 | 0 | 0 | 0 | 0 |
| New Generic | 94,676 | 97,989 | 101,419 | 104,969 | 108,642 |
| TOTAL NON-RENEWABLE ENERGY | 94,676 | 97,989 | 101,419 | 104,969 | 108,642 |
| **TOTAL RESOURCES TO SERVE LOAD (MWh)** | **315,585** | **326,631** | **338,063** | **349,895** | **362,142** |
| Surplus/(Deficit) | 0 | 0 | 0 | 0 | 0 |

## 16.11 Anticipated Portfolio Mix (%)

| PROPOSED ENERGY PORTFOLIO CONTENTS SUMMARY (%) | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Percent of Gross Consumption Forecast (%)** | | | | | |
| Line Losses | 6.86% | 6.81% | 6.77% | 6.74% | 6.70% |
| AAEE | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| BTM Solar | 4.24% | 4.82% | 5.31% | 5.79% | 6.23% |
| **TOTAL** | 11.10% | 11.64% | 12.09% | 12.53% | 12.93% |
| **Percent of Net Energy for Load (%)** | | | | | |
| Solar | 22.82% | 24.77% | 35.12% | 41.77% | 43.34% |
| Wind | 16.18% | 16.82% | 9.05% | 4.98% | 5.99% |
| Geothermal | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **SUBTOTAL - RENEWABLE** | 39.00% | 41.58% | 44.17% | 46.75% | 49.33% |
| Non-Renewable | 61.00% | 58.42% | 55.83% | 53.25% | 50.67% |
| **TOTAL ENERGY FOR LOAD SUPPLY** | **100.00%** | **100.00%** | **100.00%** | **100.00%** | **100.00%** |

| PROPOSED ENERGY PORTFOLIO CONTENTS SUMMARY (%) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|
| **Percent of Gross Consumption Forecast (%)** | | | | | | |
| Line Losses | 6.66% | 6.63% | 6.60% | 6.57% | 6.54% | 6.51% |
| AAEE | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| BTM Solar | 6.65% | 7.05% | 7.43% | 7.78% | 8.11% | 8.41% |
| **TOTAL** | 13.31% | 13.68% | 14.02% | 14.35% | 14.65% | 14.92% |
| **Percent of Net Energy for Load (%)** | | | | | | |
| Solar | 44.81% | 46.30% | 47.80% | 49.30% | 50.82% | 52.36% |
| Wind | 7.10% | 8.20% | 9.29% | 10.36% | 11.43% | 12.48% |
| Geothermal | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **SUBTOTAL - RENEWABLE** | 51.92% | 54.50% | 57.08% | 59.67% | 62.25% | 64.83% |
| Non-Renewable | 48.08% | 45.50% | 42.92% | 40.33% | 37.75% | 35.17% |
| **TOTAL ENERGY FOR LOAD SUPPLY** | **100.00%** | **100.00%** | **100.00%** | **100.00%** | **100.00%** | **100.00%** |

| PROPOSED ENERGY PORTFOLIO CONTENTS SUMMARY (%) | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|
| **Percent of Gross Consumption Forecast (%)** | | | | | |
| Line Losses | 6.48% | 6.46% | 6.14% | 6.08% | 6.02% |
| AAEE | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| BTM Solar | 8.71% | 9.02% | 9.78% | 10.58% | 11.43% |
| **TOTAL** | 15.20% | 15.47% | 15.92% | 16.66% | 17.46% |
| **Percent of Net Energy for Load (%)** | | | | | |
| Solar | 53.90% | 55.45% | 55.20% | 54.97% | 54.74% |
| Wind | 13.52% | 14.55% | 14.80% | 15.03% | 15.26% |
| Geothermal | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **SUBTOTAL - RENEWABLE** | 67.42% | 70.00% | 70.00% | 70.00% | 70.00% |
| Non-Renewable | 32.58% | 30.00% | 30.00% | 30.00% | 30.00% |
| **TOTAL ENERGY FOR LOAD SUPPLY** | **100.00%** | **100.00%** | **100.00%** | **100.00%** | **100.00%** |

| PROPOSED ENERGY PORTFOLIO CONTENTS SUMMARY (%) | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| **Percent of Gross Consumption Forecast (%)** | | | | |
| Line Losses | 5.96% | 5.90% | 5.82% | 5.75% |
| AAEE | 0.00% | 0.00% | 0.00% | 0.00% |
| BTM Solar | 12.35% | 13.32% | 14.36% | 15.46% |
| **TOTAL** | 18.31% | 19.22% | 20.18% | 21.21% |
| **Percent of Net Energy for Load (%)** | | | | |
| Solar | 54.52% | 54.31% | 54.11% | 52.41% |
| Wind | 15.48% | 15.69% | 15.89% | 17.59% |
| Geothermal | 0.00% | 0.00% | 0.00% | 0.00% |
| **SUBTOTAL - RENEWABLE** | 70.00% | 70.00% | 70.00% | 70.00% |
| Non-Renewable | 30.00% | 30.00% | 30.00% | 30.00% |
| **TOTAL ENERGY FOR LOAD SUPPLY** | **100.00%** | **100.00%** | **100.00%** | **100.00%** |

# 17 LEGISLATIVE AND REGULATORY MANDATES

This IRP is prepared with the intention to comply with all applicable legislative, regulatory and reliability mandates. Legislative mandates, some of which are more specifically described below, are embodied in the California Public Utilities Code (PUC). MVU is regulated by its local governing board, the Moreno Valley City Council, and is not subject to regulatory oversight by the California Public Utilities Commission (CPUC). The CPUC regulates California's investor-owned utilities and other energy service providers and load serving entities that are not local publicly-owned utilities.

Some aspects of MVU's performance are monitored and guided by the California Energy Commission (CEC), which is tasked among other responsibilities with issuing guidance and ensuring legislative compliance by local publicly owned utilities such as MVU. The CPUC and CEC work together to coordinate electric utility long-term planning. In addition, these agencies coordinate with the California Independent System Operator and other balancing area authorities in the state to ensure bulk electric grid reliability, resource adequacy and appropriate transmission planning. The CAISO and other balancing area authorities implement reliability standards established by the North American Electric Reliability Corporation (NERC), and its regional authority, the Western Electricity Coordinating Council (WECC).

## 17.1 Renewable Portfolio Standard[11] (RPS)

Established in 2002 under Senate Bill 1078, California's Renewables Portfolio Standard (RPS) was accelerated in 2006 under Senate Bill 107 by requiring that 20 percent of electricity retail sales be served by renewable energy resources by 2010. Subsequent recommendations in California energy policy reports advocated a goal of 33 percent by 2020, and on November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08 requiring that "...[a]ll retail sellers of electricity shall serve 33 percent of their load with renewable energy by 2020."

Senate Bill X1-2 (*Simitian, Chapter 1, Statutes of 2011) – Renewables Portfolio Standard* was signed by Governor Edmund G. Brown, Jr., in April 2011 setting the RPS target at 33% by 2020. This new RPS applied to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. All of these entities had to adopt the new RPS goals of 20 percent of retails sales from renewables by the end of 2013, 25 percent by the end of 2016, and the 33 percent requirement being met by the end of 2020.

Most recently, Governor Edmund G. Brown, Jr. signed into legislation Senate Bill 350 in October 2015, which requires retail sellers and publicly owned utilities to procure 50 percent of their electricity from eligible renewable energy resources by 2030. **See also**: Governor's Executive Order S-3-05 – *2050 GHG Reduction Goal*.

The CEC has developed a number of guidance documents and programs to implement the RPS. Among them are:

- RPS Eligibility Guidebook

[11] Source: California Energy Commission website

- RPS Enforcement Procedures for Publicly Owned Utilities
- RPS Certification and Verification
- RPS Online System
- Integrated Energy Policy Report
- SB 350 Guidance
- POU IRP Submission and Review Guidance

The following are also relevant CEC dockets:

- 16-RPS-01 - Renewables Portfolio Standard Guidelines
- 16-RPS-03 - Renewables Portfolio Standard POU Enforcement Procedures
- 17-IEPR-07 - Integrated Resource Planning
- 16-OIR-01 - General Rulemaking Proceeding for Developing Regulations, Guidelines and Policies for Implementing SB 350 and AB 802

The CPUC has a number of related proceedings which, although not applicable to local publicly-owned utilities, are instructive as to the approach many of California's other load-serving entities are taking and include research and guidance that may be helpful to local publicly-owned utilities. Since the CEC and CPUC tend to coordinate closely, it is worthwhile for utilities such as VPU to monitor many of these developments at the CPUC. Among the relevant CPUC proceedings are:

- R1502020 **-** Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program
- R1105005 **-** Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program
- R1602007 - Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.

## 17.2 ENERGY EFFICIENCY[12]

Local publicly owned utilities are required to identify on a four-year cycle all feasible and cost-effective energy efficiency savings and establish 10-year annual goals.[13] In addition, they are required to provide to their customers and the CEC the results of evaluation studies that measure and verify claimed demand reduction and energy savings.

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) directs the CEC to establish energy efficiency targets that achieve a statewide, cumulative doubling of energy efficiency savings in

[12] SOURCE: California Energy Commission website
[13] Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) required 10-year efficiency targets to be set every three years. Assembly Bill 2227 (Bradford, Chapter 606, Statutes of 2012) changed the frequency of target setting to every four years.

electricity and natural gas final end uses by 2030, to the extent doing so is cost effective, feasible, and does not adversely impact public health and safety.

The proposed SB 350 doubling targets for electricity and natural gas consist of projected energy efficiency savings from programs and measures funded by utility ratepayers and from nonutility programs. Utility programs include programs funded by the state's investor-owned utilities, community choice aggregators (CCA), and regional energy networks (REN) under the CPUC's jurisdiction, as well as the state's local publicly owned utilities that are governed by local boards.

The CEC adopted energy efficiency targets at a business meeting held on November 8, 2017, as part of a final Commission Report, Senate Bill 350: Doubling Energy Efficiency Savings by 2030.

The report also proposes sub-targets for individual utilities and non-utility energy efficiency programs towards achieving the doubling of energy efficiency savings in electric and natural gas end uses by 2030, as required by SB 350. The targets show that California is currently close to achieving the doubling goal in 2030 with existing and expected programs, but a gap exists between current projections and the line representing the doubling of energy efficiency. Additional analysis will be undertaken to identify potential future programs and strategies that will help to fill the gap and achieve the doubling goal envisioned by SB 350.

Utility electricity programs account for about 44 percent of total projected savings, while nonutility programs contribute the remaining savings. The investor-owned utility programs account for about 30 percent of total projected savings, while local publicly owned utilities account for about 13 percent. About 36 percent of total projected savings is contributed by codes and standards, while financing programs make up 15 percent, and behavioral and market transformation comprise 2 percent. Nonutility agricultural and industrial sector savings make up about 1 percent of total projected savings.

Signed into law on October 8, 2015, Assembly Bill 802 (*Williams, Chapter 590, Statutes of 2015) (AB 802*) furthers California's support for enhancing energy efficiency statewide by authorizing the CEC to create a building energy-use benchmarking and disclosure program. In addition, AB 802 expands the CEC's energy data collection authority to improve the development and evaluation of policy and programs, and the state's energy infrastructure planning efforts. AB 802 also requires the CPUC to authorize electrical and gas corporations to provide financial incentives to their customers that increases the energy efficiency of existing buildings based on all estimated energy savings and energy usage reductions. **See also**: Assembly Bill 758 (*Skinner, Chapter, 470, Statutes of 2009) – Existing Building Energy Efficiency* AND Governor's Executive Order B-18-12 – *Energy Efficiency of State-Owned Buildings*.

The following are related CEC proceedings:

- 17-IEPR-06 - Doubling Energy Efficiency Savings
- 15-OIR-05 – Building Energy Use Disclosure and Public Benchmarking Program Mandated under Assembly Bill 802.

The following is an open CPUC proceeding relevant to energy efficiency:

- R1311005 **-** Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues

## 17.3 GHG Emissions Reduction

Approved by Governor Brown on September 08, 2016 and filed with the Secretary of State on September 08, 2016, the California Global Warming Solutions Act of 2006: Emissions Limit, Senate Bill 32 (SB 32) (Pavley) requires the California Air Resources Board (CARB) to ensure that statewide greenhouse gas emissions are reduced to 40% below the 1990 level by 2030. 42 million metric tons (MMT) by 2030[14] represents a 50 percent reduction in electric sector GHG emissions from 2015 levels and a 61 percent reduction from 1990 levels. **See also**: Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) – California Global Warming Solutions Act of 2006.

Previously, Executive Order B-30-15 established the new *interim* statewide greenhouse gas emission reduction target to reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030. It was intended to ensure that California meets its target of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. Reducing greenhouse gas emissions by 40 percent below 1990 levels in 2030 and by 80 percent below 1990 levels by 2050 aligns with scientifically established levels needed in the U.S. to limit global warming below 2$^{o}$C. The latest science shows that the path taken to achieve necessary science-based targets in 2050 is just as important as achieving the 2050 target itself and that we need a series of coordinated programs to capture cost-effective emission reductions opportunities wherever possible, not only in 2050, but at every point along the way. Setting clear targets beyond 2020 also provides market certainty to foster investment and growth in a wide array of industries throughout the State.

CARB Scoping Plan – According to CARB, in 2015, the state of California was responsible for the emission of 440.4 million metric tons of carbon dioxide equivalent greenhouse gases (MMT $CO_2e$ of GHG). In-state electricity generation constituted approximately 11% of that total, with electricity generation imports producing another 8%. CARB has established a 2030 GHG target of 260 MMT $CO_2e$. Of that target, the electric power sector has been allocated a goal of 30-53 MMT $CO_2e$. The high end of the range is the represented by CARB's Scoping Plan Scenario, and the low end by enhancements and additional electricity sector measures such as deployment of additional renewable power, greater behind-the-meter solar PV, and additional energy efficiency. CARB, the CPUC and the CEC are coordinating on this range of emission targets for the electric power sector in order to establish SB 350 IRP GHG reduction targets for utilities.

The following are proceedings at the CEC and CPUC that are also relevant to GHG emissions reductions:

- CEC 17-IEPR-09 – Climate Adaptation and Resiliency
- CPUC R1103012 **-** Order Instituting Rulemaking to Address Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions.

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[14] This planning target is comparable to 46 MMT utilizing the GHG accounting methodology from CARB to develop its Scoping Plan Update, due mainly to differences in accounting for emissions from on-site combined heat and power.

For a more complete list of California's climate change related legislation, visit: the Climate Change Website .

## 17.4 INTEGRATED ENERGY POLICY REPORT (IEPR)

Senate Bill 1389 (SB 1389, Bowen and Sher, Chapter 568, Statutes of 2002) requires the CEC to:

"[C]onduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. The Energy Commission shall use these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety." (Pub. Res. Code § 25301(a)).

The California Energy Commission adopts an *Integrated Energy Policy Report* (IEPR, pronounced eye'-per) every two years and an update every other year. The IEPR includes issues of energy policy importance. In 2017, these included the following dockets:

- 17-IEPR-01 - General/Scope
- 17-IEPR-02 - Electricity Resource / Supply Plans
- 17-IEPR-03 - Electricity and Natural Gas Demand Forecast
- 17-IEPR-04 - Natural Gas Outlook
- 17-IEPR-05 - Transportation Energy Demand Forecast
- 17-IEPR-06 - Doubling Energy Efficiency Savings
- 17-IEPR-07 - Integrated Resource Planning
- 17-IEPR-08 - Barriers Study Implementation
- 17-IEPR-09 - Climate Adaptation and Resiliency
- 17-IEPR-10 - Renewable Gas
- 17-IEPR-11 - Southern California Energy Reliability
- 17-IEPR-12 - Distributed Energy Resources
- 17-IEPR-13 - Strategic Transmission Investment Plan
- 17-IEPR-14 - Existing Power Plant Reliability Issues

MVU provides information in support of the IEPR pursuant to CEC's 16-OIR-03 - Data Collection Rulemaking.

# 18 ACRONYMS/GLOSSARY

Terms in the following are frequently used in the electric power industry and may or may not be used in this IRP.

# LINKS TO OTHER GLOSSARIES:

Don't see the term you're looking for in the list below? Try one of these alternatives:

- EIA Glossary
- FERC Acronyms
- FERC Glossary
- CAISO Tariff Definitions
- NERC Glossary of Terms
- California Energy Commission Acronyms
- California Energy Commission Glossary
- Energy Central Glossary

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*AAEE – Additional Achievable Energy Efficiency:* Energy Efficiency savings that is incremental to committed savings in the baseline forecast.

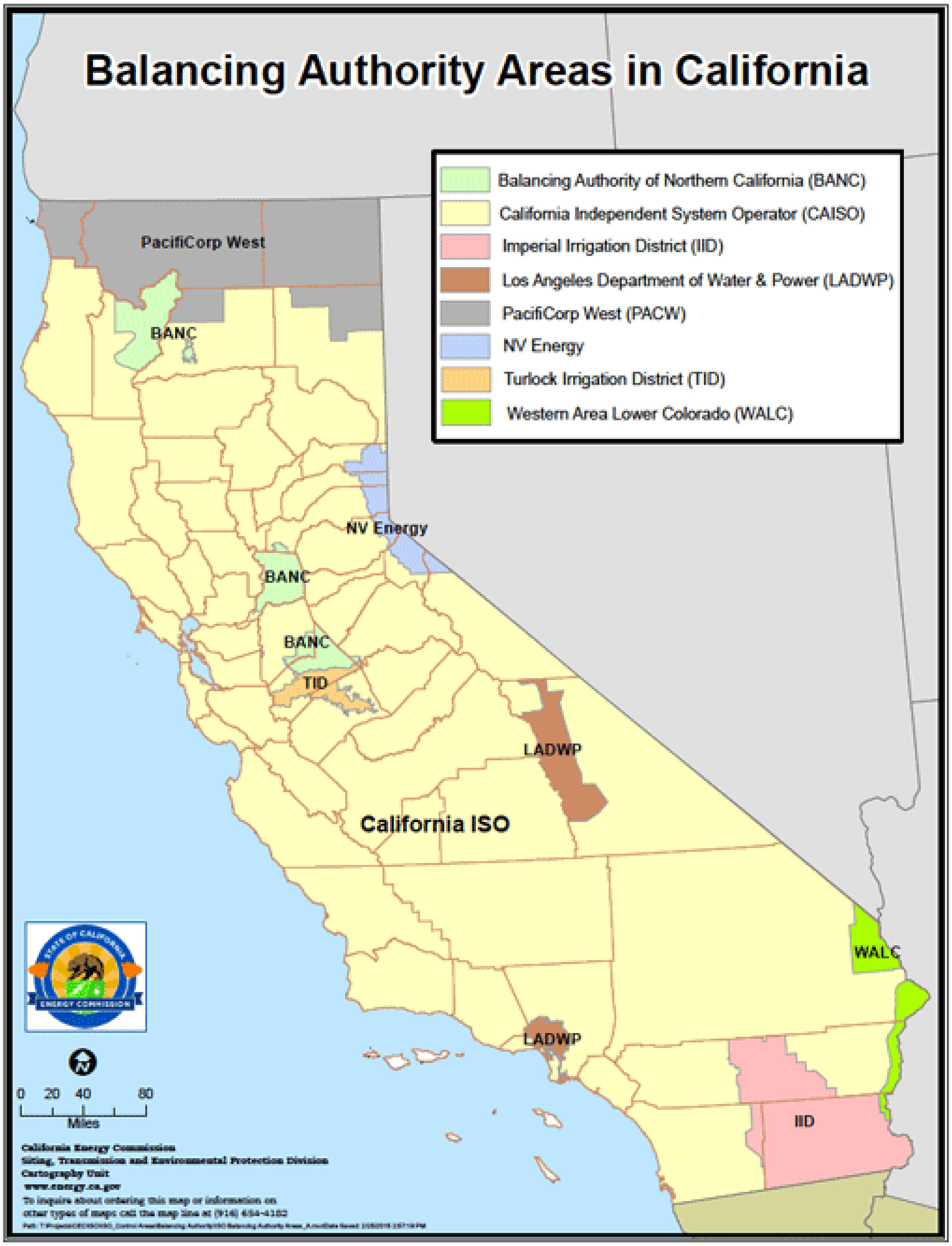
*ACE – Area Control Error*: The instantaneous difference between a BA – *Balancing Authority*'s net actual and scheduled interchange, taking into account the effects of frequency bias, correction for meter error, and automatic time error correction.

*AGC – Automatic Generator Control*: Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus frequency bias. AGC may also accommodate automatic inadvertent payback and time error correction.

*Ancillary Services*: Ancillary services support the reliable operation of the transmission system as it moves high voltage electricity (generally >100 kV) from power plants to retail customers. Current ancillary services in the CAISO market include: regulation (up and down), spinning reserve, non-spinning reserve, voltage support, and black start.

*BA – Balancing Authority*: The balancing authority is the responsible entity that maintains the balance of load and generation within a balancing authority area, the exchange of power between the balancing authority area and others, and supports interconnection frequency in real time. The California Independent System Operator (CAISO) is an example of a balancing authority, and it operates a balancing authority area. Moreno Valley's electric utility is in the CAISO balancing authority area.

*BAA – Balancing Authority Area*: A balancing authority area is the collection of generation, transmission, and electrical loads within the metered boundaries of the balancing authority.




*Biomass*: A renewable energy source made of organic, non-fossil material of biological origin. Sources may include wood, agricultural waste and other living-cell material that can be burned to produce heat energy. They also include algae, sewage and other organic substances that may be used to make energy through chemical processes.

*Biomethane or Biogas*: A medium Btu gas containing methane and carbon dioxide, resulting from the action of microorganisms on organic materials, such as may occur at a landfill or dairy waste digester. (see also Landfill Gas).

*CAISO – California Independent System Operator*: CAISO is the California Independent System Operator, an impartial, non-profit corporation that reliably plans and operates the electrical transmission grid for most of the state of California and that operates a day-ahead and real-time wholesale power market. The CAISO is also known as a balancing authority. Most electrical utilities in California, including Moreno Valley, are CAISO members. Non-members include the Los Angeles Department of Water & Power, Sacramento Municipal Utilities Department, Imperial Irrigation District, and cities of Burbank and Glendale. For more information, see the CAISO website at: www.caiso.com.

*Capacity Factor (CF):* A percentage that reflects the ratio of energy produced or consumed over a given period of time to the peak capacity multiplied by the maximum number of periods in that same period of time. For example, if the amount of energy produced or consumed in a calendar year is 262,800 MWh, and the peak production or demand is 100 MW, the capacity factor is 30%, calculated as 262,800 MWh divided by (100 MW x 8760 hours/year)

*CARB – California Air Resources Board*: ARB's mission is to promote and protect public health, welfare and ecological resources through the effective and efficient reduction of air pollutants, while recognizing and considering the effects on the state's economy. An 11-member board appointed by the governor governs the ARB. Six of the members are experts in fields such as medicine, chemistry, physics, meteorology, engineering, business and law. Five others are elected officials who represent regional air pollution control agencies--one each from the Los Angeles region, the San Francisco Bay area, San Diego, the San Joaquin Valley and another to represent other, more rural areas of the state. The ARB also oversees the activities of 35 local and regional air pollution control districts. These districts regulate industrial pollution sources. They also issue permits, develop local plans to attain healthy air quality and ensure that the industries in their area adhere to air quality mandates.[15]

*CCA – Community Choice Aggregator::* A “community choice aggregator” (CCA) means any of the following entities, if that entity is not within the jurisdiction of a local publicly owned electric utility that provided electrical service as of January 1, 2003:

(a) Any city, county, or city and county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers’ program.

(b) Any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency established under Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code.

*CCCT – Combined Cycle Combustion Turbine*: A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power. This is how a combined-cycle plant works to produce electricity and captures waste heat from the gas turbine to increase efficiency and electrical output:

[15] Source: California Air Resources Board

1. Gas turbine burns fuel.
    a. The gas turbine compresses air and mixes it with fuel that is heated to a very high temperature. The hot air-fuel mixture moves through the gas turbine blades, making them spin.
    b. The fast-spinning turbine drives a generator that converts a portion of the spinning energy into electricity.
2. Heat recovery system captures exhaust.
    a. A Heat Recovery Steam Generator (HRSG) captures exhaust heat from the gas turbine that would otherwise escape through the exhaust stack.
    b. The HRSG creates steam from the gas turbine exhaust heat and delivers it to the steam turbine. 3. Steam turbine delivers additional electricity.
    c. The steam turbine sends its energy to the generator drive shaft, where it is converted into additional electricity.[16]

*CEC – California Energy Commission*: The California Energy Commission ("CEC"), formally the Energy Resources Conservation and Development Commission, is California's primary energy policy and planning agency. Established by the Legislature in 1974 and located in Sacramento, seven core responsibilities guide the Energy Commission as it sets California energy policy[17]:

- Forecasting future energy needs;
- Promoting energy efficiency and conservation by setting the state's appliance and building energy efficiency standards;
- Supporting energy research that advances energy science and technology through research, development and demonstration projects;
- Developing renewable energy resources;
- Advancing alternative and renewable transportation fuels and technologies;
- Certifying thermal power plants 50 megawatts and larger;
- Planning for and directing state response to energy emergencies.

The Governor appoints the commissioners to staggered five-year terms and selects a chair and vice chair from among the members every two years. The appointments require Senate approval. By law, one commission member must be selected from the public at large. The remaining commissioners represent the fields of engineering / physical science, economics, environmental protection, and law.

*Coincident Peak*: The energy demand during periods of peak system (e.g., CAISO) demand. A utility or customer may have a peak demand of X, but if the entire system of which it is a part peaks at a different time, the coincident peak demand may be something less than X.

*Cogeneration*: Production of electricity from steam, heat, or other forms of energy produced as a byproduct of another process.

*Community Solar (aka Solar Gardens)*: Some customers are interested in the benefits of rooftop solar energy systems but are unable to install them for a variety of reasons, such as the structure or

[16] Source: General Electric - GE Power Combined Cycle Power Plants – How it works
[17] Source: California Energy Commission - About the California Energy Commission

angle of their roof, shading, or because they do not own the property. "Community Shared Solar" projects or "Solar Gardens" offer an alternative for these customers. A shared solar program typically involves a single, larger solar energy system designed to benefit multiple electric consumers by allowing consumers to choose to invest in (or "subscribe" to) the program and receive a portion of the electricity generated by the system with typically lower initial investment costs, economies of scale, and the ability to transfer if they relocate. The output of the customer's participation in these projects can offset a portion or most of their regular power bill.

*Contingency*: The unexpected failure or outage of an electric system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

*CPUC – California Public Utilities Commission*: The California Public Utilities Commission (CPUC) is a regulatory agency that regulates privately owned public utilities (e.g., Southern California Edison, San Diego Gas & Electric, and Pacific Gas & Electric) in the state of California, including electric power, telecommunications, natural gas, water, railroad, rail transit and passenger transportation companies. The CPUC does not regulate Moreno Valley, but some of the policies set by the CPUC are coordinated with the CAISO and CEC, and may consequently impact Moreno Valley's electric utility.

*CY – Calendar Year*: The period of 365 days (or 366 days in leap years) starting from the first of January.

*Demand* – 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed as capacity in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.

*DG – Distributed Generation*: A generator that is located close to the particular load that it is intended to serve. General, but non-exclusive, characteristics of these generators include: an operating strategy that supports the served load; and interconnection to a distribution or sub-transmission system (138 kV or less).

*Disadvantaged Communities*: Disadvantaged Communities are defined as those scoring above the 75th percentile using the CalEnviroScreen Tool created by the California Environmental Protection Agency (CalEPA).

*DR – Demand Response*: Demand response programs are incentive-based programs that encourage electric power customers to temporarily reduce their demand for power at certain times in exchange for a reduction in their electricity bills. Some demand response programs allow electric power system operators to directly reduce load, while in others, customers retain control. Customer-controlled reductions in demand may involve actions such as curtailing load, operating onsite generation, or shifting electricity use to another time period. Demand response programs are one type of demand-side management, which also covers broad, less immediate programs such as the promotion of energy-efficient equipment in residential and commercial sectors.

*DSM – Demand Side Management*: The term for all activities or programs undertaken by a utility or its customers to influence the amount or timing of electricity they use, or any utility action that reduces or curtails end-use equipment or processes. DSM is often used in order to reduce customer load during peak demand and/or in times of supply constraint. DSM includes programs that are focused, deep, and immediate such as the brief curtailment of energy-intensive processes used by a utility's most demanding industrial customers, and programs that are broad, shallow, and less immediate such as the promotion of energy-efficient equipment in residential and commercial sectors.

*EE – Energy Efficiency*: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption, often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

*EIA – Energy Information Administration*: An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and does analytical and modeling analyses of energy issues. The Agency must satisfy the requests of Congress, other elements within the Department of Energy, Federal Energy Regulatory Commission, the Executive Branch, its own independent needs, and assist the general public, or other interest groups, without taking a policy position.[18]

*EIM – Energy Imbalance Market*: The automated CAISO system balances electricity supply and demand every five minutes by choosing the least-cost resource to meet the needs of the grid. External to the CAISO, however, utilities still manually balance supply and demand. A broader and more precise system helps with the transformation to a more diverse energy mix. Renewable resources introduce new operating dynamics best met by modernized grid dispatching. The EIM technology increases visibility of interconnected systems and uses automated tools to more accurately balance resources, which is why it is referred to as an "energy imbalance market" or EIM. Participants in the Western EIM are listed in *Table 18-1* below. Participation is open to other regional utilities as well.

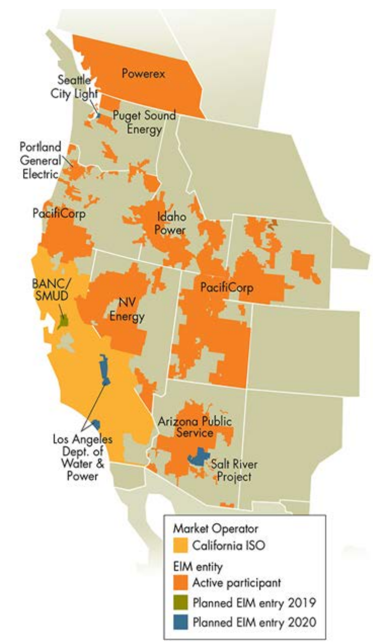



*Figure 18-1 - Western Energy Imbalance Market*

*Table 18-1 – Western EIM Participants*

| PARTICIPANTS | |
|---|---|
| **ACTIVE** | PENDING |
| CAISO | |
| PacifiCorp **(2014)** | |
| NV Energy **(2015)** | Seattle City Light (2019) |
| Puget Sound Energy **(2016)** | Los Angeles Dept. of Water & Power (2019) |
| Arizona Public Service **(2016)** | Balancing Authority of Northern California/SMUD (2019) |
| Portland General Electric **(2017)** | Salt River Project (2020) |
| Idaho Power Company **(2018)** | |
| Powerex **(2018)** | |

[18] Source: EIA - EIA Glossary

*ELCC – Effective Load Carrying Capacity*: ELCC is a percentage that expresses how well a resource is able to meet reliability conditions and reduce expected reliability problems or outage events (considering availability and use limitations). It is calculated via probabilistic reliability modeling and yields a single percentage value for a given facility or grouping of facilities. ELCC can be thought of as a derating factor that is applied to a facility's maximum output (Pmax) in order to determine its QC. Because this derating factor is calculated considering both system reliability needs and facility performance, it will reflect not just the output capabilities of a facility but also the usefulness of this output in meeting overall electricity system reliability needs.

*Energy Storage*: Energy Storage is the capture of energy produced at one time for use at a later time. Some examples include pumped storage, batteries (e.g., lithium ion, flow, et. al.), compressed air energy storage, and flywheels.

*EPA – U.S. Environmental Protection Agency*: The United States Environmental Protection Agency (EPA or sometimes USEPA) is an agency of the U.S. federal government which was created for the purpose of protecting human health and the environment by writing and enforcing regulations based on laws passed by Congress.

*FERC – Federal Energy Regulatory Commission*: The Federal Energy Regulatory Commission[19] (FERC) is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects. The Energy Policy Act of 2005 gave FERC additional responsibilities as outlined and updated in its Strategic Plan.

*FiT – Feed-In Tariff*: A feed-in tariff, or "FiT," is a standard offer contract designed to accelerate investment in renewable energy technologies by offering long-term contracts to renewable energy producers at prices that are typically based on the cost of generation of each technology in order to facilitate project financing.

*FRAC – Flexible Resource Adequacy Capacity*: CAISO has identified a need for sufficient capacity that is operationally flexible enough to address the uncertainty and variability of changing load profiles and of intermittent energy resources such as wind and solar. Flexible resource adequacy capacity, also known as "FRAC," is a subset of resource adequacy capacity, with specific operating characteristics, as defined in Section 40.10 of the CAISO Tariff, to address these needs. There are three categories of flexible resource adequacy capacity resources: Base Ramping, Peak Ramping, and Super Peak Ramping.

*FY – Fiscal Year*: The period of 365 days (or 366 days in leap years) starting from the first of July, used by Moreno Valley for accounting and financial statement purposes.

*GHG – Greenhouse Gas*: A greenhouse gas is any gaseous compound in the atmosphere that is capable of absorbing infrared radiation, thereby trapping and holding heat in the atmosphere. Gases such as water vapor, methane, carbon dioxide, ozone, nitrous oxide, and fluorine-containing compounds are called "greenhouse" gases because they trap heat and warm the

[19] Source: Federal Energy Regulatory Commission (FERC) - What FERC Does

planet's surface[20]. Some of these gases are generated naturally, and some through human activities. Policies and regulations that call for reducing GHG emissions are most commonly targeting carbon dioxide ($CO^2$).

*GT – Gas Turbine*: A plant in which the prime mover is a gas turbine (typically natural gas-fired). A gas turbine consists typically of an axial-flow air compressor and one or more combustion chambers where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand drive the generator and are then used to run the compressor.

*IOU – Investor Owned Utility*. A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return. The three major California IOUs are Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Pacific Gas & Electric (PG&E). They are regulated by the California Public Utilities Commission (CPUC).

*IPP – Independent Power Producer*. Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, co-generators, small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.

*IRP – Integrated Resource Plan*: An Integrated Resource Plan (IRP) is a long-range (typically 20-year) utility plan for meeting forecasted peak capacity and energy demand, plus some established reserve margin, within a defined geographic area or service territory, through a combination of supply-side and demand-side resources. Supply-side resources may include (i) conventional generation, such as nuclear, coal-fired, natural gas-fired, and large hydroelectric and/or (ii) renewable generation, such as wind, solar, geothermal and bioenergy. Demand-side resources can include conservation or energy efficiency and demand response. The IRP is a comprehensive decision support tool and road map for meeting the objectives of providing reliable, affordable, and environmentally responsible electric service to all customers while addressing the substantial risks and uncertainties inherent in the electric utility business. The IRP is generally updated every couple of years to keep it fresh in response to changing conditions.

*kW or kWh – Kilowatt or Kilowatt-Hour*. A kilowatt is one thousand watts of electric capacity. A kilowatt-hour is a measure of electricity defined as a unit of work or energy, measured as 1 kilowatt (1,000 watts) of power expended for 1 hour. One kWh is equivalent to 3,412 Btu.

*LCR – Local Capacity Requirement*. Certain geographical areas have transmission constraints that may limit the amount of generation that can be reliably imported into the area to serve electrical load. These areas are defined by the CAISO as "local capacity areas." A minimum amount of internal generation within the constrained transmission boundaries of these local capacity areas must be available to ensure that electrical load will be served reliably. This generation is known as local resource adequacy capacity.

*LFG – Landfill Gas*: Gas that is generated by decomposition of organic material at landfill disposal sites. The average composition of landfill gas is approximately 50 percent methane and 50 percent carbon dioxide and water vapor by volume. The methane percentage, however, can vary from 40 to 60 percent, depending on several factors including waste composition (e.g. carbohydrate and

[20] Source: NASA Jet Propulsion Laboratory - Global Climate Change

cellulose content). The methane in landfill gas may be vented, flared, combusted to generate electricity or useful thermal energy on-site, or injected into a pipeline for combustion off-site.

*Load Factor*: Load factor is the ratio of the average load divided by the peak load in a specified time period. High load factor indicates a steady load with low-variability.

*Local Solar*: Local solar refers to solar power that is located within the Moreno Valley electric utility distribution service territory and that does not require the use of the high voltage (100 kV and above) bulk transmission grid to import the power into the community. Local solar may be located on individual customer or business rooftops, in parking lots, or may be larger scale ground mounted installations, as long as it is directly connected to the Moreno Valley distribution grid.

*LOLE/LOLP – Loss of Load Expectation/Loss of Load Probability*: The Loss of Load Expectation (LOLE) is an adequacy index that identifies the likelihood that generation will be insufficient to meet demand during a part of the year. NERC defines this index as:

The expected number of days in the year when the daily peak demand exceeds the available generating capacity.

It is obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year. The index is referred to as Hourly Loss-of-Load-Expectation if hourly demands are used in the calculations instead of daily peak demands. LOLE is also sometimes referred to as Loss-of-Load-Probability (LOLP).

*LNG – Liquified Natural Gas*: Reducing the temperature of natural gas to minus 259 degrees at atmospheric pressure will convert the gas into a liquid. Its volume as a liquid is about 1/600 compared to its volume as a gas.

*LRA – Local Regulatory Authority*: The state or local governmental authority, or the board of directors of an electric cooperative, responsible for the regulation or oversight of a utility. For Moreno Valley's electric utility, the local regulatory authority is the Moreno Valley City Council.

*LSE – Load Serving Entity*: An organization that secures energy and transmission service to serve the electrical demand and energy requirements of its end-use customers. Moreno Valley's electric utility is a load serving entity.

*MMBtu – Million British Thermal Units*: A British Thermal Unit (BTU) is a measure of the heating value of a fuel (the term MMBtu or "Dekatherm" is commonly used as a measure of natural gas consumption in generation). A Btu is the amount of heat energy required to raise the temperature of one pound of water one degree Fahrenheit.

*MW – Megawatt*: MW stands for megawatt, or one million watts (one thousand kilowatts). A MW is a measure of power or capacity (the potential to do work).

*MWh – Megawatt-Hour*: MWh is megawatt hour, or one million watts per hour. A MWh is a measure of energy (the amount of work done over an hour). One MWh is one MW of power flowing for one hour. A MWh is equivalent to one thousand 100-watt light bulbs burning for 10 hours.

*NERC – North American Electric Reliability Corporation*: The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people.[21]

*Net Energy Demand:* Equals total end use load plus losses minus self-generation (behind the meter).

*Net Load*: In the context of reliability and resource planning, net load is the difference between forecasted electrical load and expected electricity production from variable generation resources such as wind and solar. Net load projections help power resource planners anticipate periods of potential over-generation and times when flexible resources may be required to ramp quickly up or down in response to changes in system load and variable generation. The CAISO chart below in *Figure 18-2* illustrates the "duck curve," the potential changes in net load as levels of variable generation increase. As the penetration of solar generation increases, the "belly" of the duck gets lower, increasing the risk of potential overgeneration and curtailment. In addition, the "neck" of the duck gets longer, as more non-solar generation is required to meet loads as the sun sets. Learn more at: What the duck curve tells us about managing a green grid.

[21] Source: North American Electric Reliability Corporation - About NERC

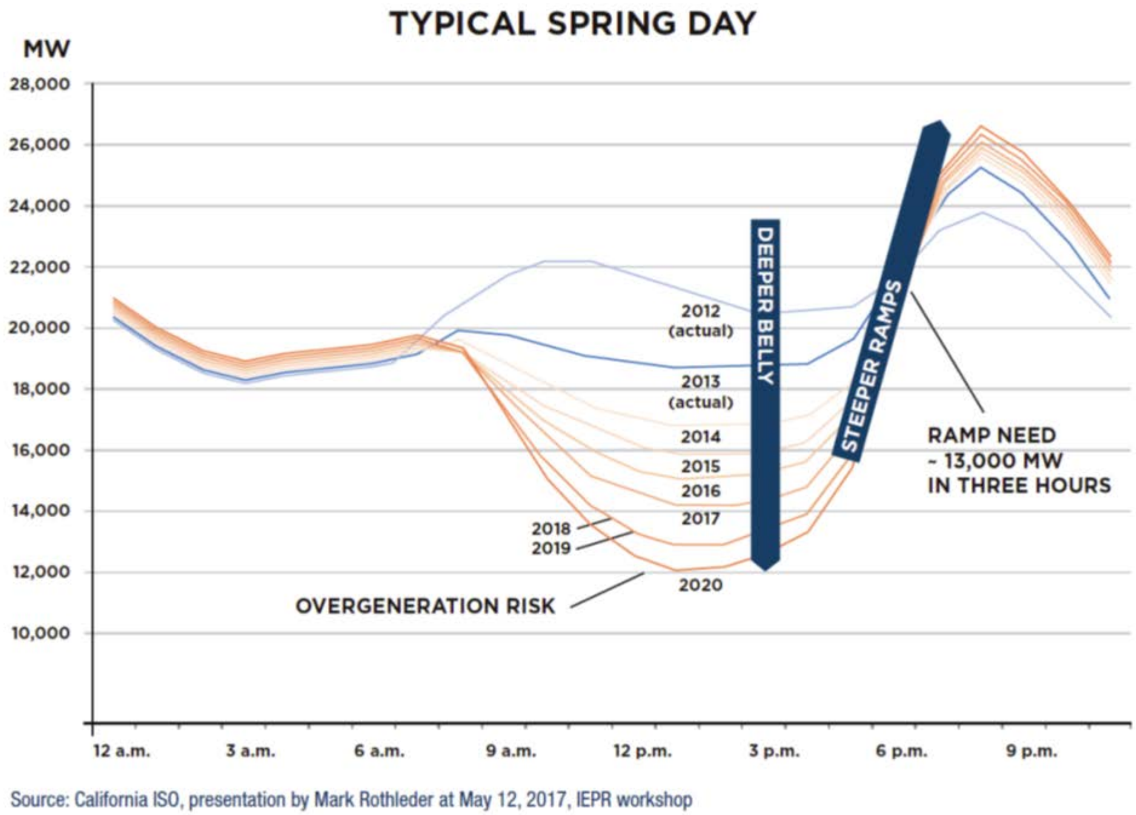



*Figure 18-2 - CAISO Duck Chart*

*Non-Spinning Reserve*: Non-spinning reserve is either (a) generating reserve not connected to the system but capable of serving demand within a specified time (generally within 10 minutes), or (b) interruptible load that can be removed from the system within a specified time (generally within 10 minutes). See also: Operating Reserve.

*NQC – Net Qualifying Capacity*: NQC is Net Qualifying Capacity, the maximum capacity of a resource that is eligible for the Resource Adequacy requirement counting process based on a generating facility's historical capacity availability during peak electrical demand periods. For certain renewable resources without an availability history, the CAISO may base NQC on the Effective Load Carrying Capability for a resource of the same type and location until an availability history is established.

*OATT – Open Access Transmission Tariff*: Electronic transmission tariff (service and rate schedule) accepted by the U.S. Federal Energy Regulatory Commission (FERC) requiring the transmission service provider to furnish to all shippers with non-discriminating service comparable to that provided by transmission owners to themselves.

*Operating Reserves*: That generating capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. Because large sections of the United States power grid are interconnected, it is important that balancing area operators like the CAISO maintain operating reserves to recover from contingency events[22], rather than drawing on power from neighboring systems, overloading transmission circuits and causing cascading outages throughout the grid. Operating reserve margin is the amount of generation (including imports) and dispatchable load, above current electrical demand during real-time operations. Operating reserve excludes generation that is not scheduled to operate, shut down for planned maintenance, or generation that is unable to be delivered due to transmission problems. Balancing areas, such as the CAISO, are required by national and regional reliability standards to carry a minimum amount of operating reserve equal to 3% of load plus 3% of generation. There are two types of operating reserve: spinning and non-spinning. At least 50% of the minimum operating reserve requirement must be in the form of spinning reserve.

*Peak Demand*: 1. The highest hourly integrated net energy for load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.

*Planning Reserve Margin*: Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in the planning horizon. A planning reserve margin is a long-term measurement intended to assure sufficient electricity supplies can meet real-time operating reserve requirements and avoid the possibility that a loss of load would occur more frequently that one-day-in-ten-years. A one-day-in-ten-years loss of load probability equates to roughly a 15-17% planning reserve target. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of resource adequacy. Generally, the projected demand is based on a 50/50 forecast. Based on experience, for bulk power systems that are not energy-constrained, reserve margin is the difference between available capacity and peak demand, normalized by peak demand shown as a percentage to maintain reliable operation while meeting unforeseen increases in demand (e.g. extreme weather) and unexpected outages of existing capacity. Further, from a planning perspective, planning reserve margin trends identify whether capacity additions are keeping up with demand growth. Since this is a capacity based metric, it does not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources or renewable capacity with variable generation such as wind or solar. The North American Electric Reliability Corporation (NERC) sets a reference planning reserve margin that is equivalent to the target reserve margin of the applicable regional or sub-regional reliability council (in Moreno Valley's case, WECC). WECC's own specific planning reserve margin is based on load, generation, and transmission characteristics as well as regulatory requirements. If a planning reserve margin is not provided by the regional reliability council, NERC has assigned a 15 percent planning reserve margin for predominately thermal systems and 10 percent for predominately hydro systems.[23] Moreno Valley's target planning reserve margin is 15%.

*Pmax:* The maximum normal capability of the Generating Unit. Pmax should not be confused as an emergency rating of the Generating Unit.

[22] A contingency in this context is defined as the unexpected failure or outage of a bulk electric system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
[23] Source: North American Electric Reliability Council (NERC) - Planning Reserve Margin

*PPA – Power Purchase Agreement*: A power purchase agreement is a contract between a generator or seller of electricity and related products and a purchaser or buyer of those products.

*POU – Publicly Owned Utility*: A class of ownership found in the electric power industry. This group includes those utilities operated by municipalities and State and Federal power agencies.

*PSE – Purchasing-Selling Entity*: The entity that purchases or sells, and takes title to, energy, capacity, and interconnected operations services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.

*Pseudo-Tie*: A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the automatic generation control (AGC)/area control error (ACE) equation, but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

*PTO – Participating Transmission Owner*: An investor owned utility, a publicly owned utility, or a federal power marketing authority that has turned over its transmission facilities and/or entitlements to the CAISO's operational control.

*PV – Palo Verde (Nuclear Plant)*: The Palo Verde Nuclear Generation Station consists of 3 units totaling 3,379 MW of capacity, located approximately 40 miles west of Phoenix, Arizona. Construction began in 1976. Units 1 and 2 were completed in 1986 and Unit 3 was completed in 1988. The plant is operated by Arizona Public Service (APS), and is jointly owned by APS (29.1%), Salt River Project (SRP – 17.5%), El Paso Electric Company (15.8%), Southern California Edison (SCE – 15.8%), Public Service of New Mexico (PNM – 10.2%), Southern California Public Power Authority (SCPPA – 5.9%), and the Los Angeles Department of Water and Power (LADWP – 5.7%). The SCPPA participants include Azusa, Banning, Burbank, Colton, Glendale, Imperial Irrigation District, LADWP, Pasadena, Riverside and Vernon.

*PV – Photovoltaic*: Energy radiated by the sun is converted into electricity by means of photovoltaic solar cells or concentrating (focusing) collectors. A photovoltaic cell is an electronic device consisting of layers of semiconductor materials fabricated to form a junction (adjacent layers of materials with different electronic characteristics) and electrical contacts and being capable of converting incident light directly into electricity (direct current). A photovoltaic module is an integrated assembly of interconnected photovoltaic cells designed to deliver a selected level of working voltage and current at its output terminals, packaged for protection against environmental degradation, and suited for incorporation in photovoltaic power systems.

*QC – Qualifying Capacity*: The maximum Resource Adequacy capacity that a Resource Adequacy resource may be eligible to provide. The criteria and methodology for calculating the Qualifying Capacity of resources may be established by the CPUC or other applicable Local Regulatory Authority and provided to the CAISO. A resource's eligibility to provide Resource Adequacy capacity may be reduced below its Qualifying Capacity through the CAISO's assessment of Net Qualifying Capacity.

*RA – Resource Adequacy*: Resource adequacy (RA) capacity is sufficient generation or demand-side management resources available to the CAISO when and where needed to serve the demands of electrical load in "real time" (i.e., instantaneously). The RA program requires that Load Serving Entities (LSE) like Moreno Valley meet a planning reserve margin for their obligations. The program provides deliverability criteria that each LSE must meet, as well as system, local and flexible capacity requirements. Rules are provided for "counting" resources towards meeting resource adequacy obligations. The resources that are counted for RA purposes must make themselves available to the CAISO for the capacity for which they were counted.

*Reliable Operation*: Operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

*RESOLVE Model*: The Renewable Energy Solutions Model (RESOLVE) was developed by Energy and Environmental Economics Inc. (E3) in 2014 and has been adapted and licensed for the California Public Utilities Commission (CPUC) to use in its IRP proceeding under the administration of CPUC's Energy Division. RESOLVE is a resource investment model that identifies optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. RESOLVE was designed in 2014 to assess the investment needs of systems seeking to integrate large quantities of variable renewable resources. RESOLVE adds capacity expansion logic to a simplified production simulation model to estimate an optimal investment plan, accounting for both the capital costs of new resources and the variable costs of reliably operating the grid. The core of the RESOLVE model is written in the Python scripting language. The RESOLVE Model is free software under the terms of the GNU Affero General Public License as published by the Free Software Foundation (Version 3 of the License, or (at the user's option) any later version.

*RFP – Request for Proposals*: A request for proposal (RFP) is a solicitation made, often through a bidding process, by an agency or company interested in procurement of a commodity, service or valuable asset, to potential suppliers to submit business proposals.

*RPS – Renewable Portfolio Standard*: A renewable portfolio standard ("RPS") is a regulation that requires the increased production of energy from renewable sources, such as wind, solar, geothermal, and biomethane. The current California RPS is at least 33 percent by the end of 2020, and at least 50 percent by the end of 2030. Today, the 50% RPS is a minimum level of renewable energy procurement, although publicly owned utilities such as Moreno Valley are allowed certain exceptions, such as establishing a cost limitation, under the law.

*SB (Senate Bill) 350*: The California Clean Energy and Pollution Reduction Act of 2015 (De León), Approved by Governor Brown October 07, 2015. Established a new set of objectives in clean energy, clean air, and pollution reduction for 2030 and beyond, including: (1) To increase from 33 percent to 50 percent, the procurement of our electricity from renewable sources, and (2) To double the energy efficiency savings in electricity and natural gas final end uses of retail customers through energy efficiency and conservation.

*SB (Senate Bill) 100*: California Renewables Portfolio Standard Program: emissions of greenhouse gases, as amended (De León), January 11, 2017. If passed, the goal of the program is to achieve a target of 50% renewable resources by December 31, 2026, and 60% by December 31, 2030. The bill would modify California's existing RPS to require that retail sellers and local publicly owned electric utilities procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kilowatt-hours of those products sold to their retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. The bill would state that it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to serve California end-use customers and all state agencies no later than December 31, 2045. Achievement of this policy for California must not increase carbon emissions elsewhere in the western grid and must not allow resource shuffling.

*SCPPA – Southern California Public Power Authority*: SCPPA is a joint powers agency consisting of eleven municipal utilities and one irrigation district. SCPPA members deliver electricity to approximately 2 million customers over an area of 7,000 square miles, with a total population of 4.8 million. The Members include the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, Vernon, and the Imperial Irrigation District. SCPPA was formed in 1980 to finance the acquisition of generation and transmission resources for its members. Currently, SCPPA has several generation and transmission projects, bringing power from Arizona, New Mexico, Utah, and Nevada. For more info, see SCPPA.

*Spinning Reserve*: Spinning reserve includes generation that is synchronized to the grid, and fully available to serve load within the 15-minute disturbance recovery period following a contingency event, or load that is fully removable from the system within the 15-minute disturbance recovery period following a contingency event. See also Operating Reserve.

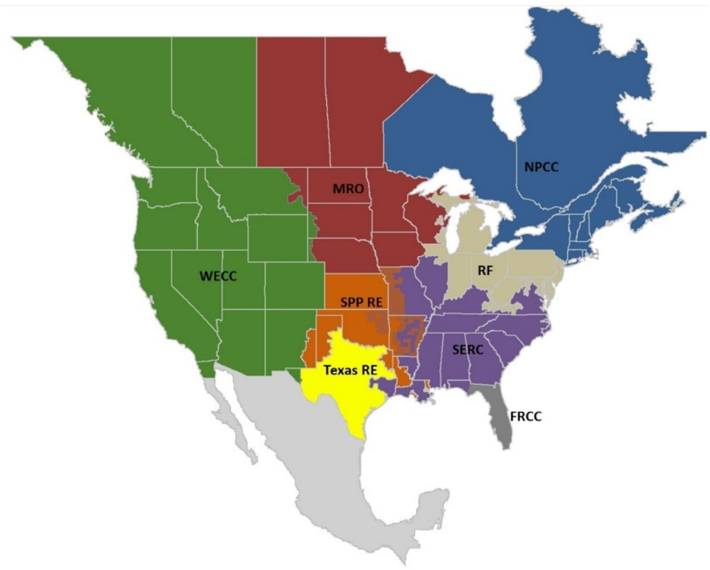
*SONGS – San Onofre Nuclear Generating Station*: The San Onofre Nuclear Generating Station (SONGS) is an inoperative nuclear power plant located in the northwestern corner of San Diego County, south of San Clemente, CA. The plant is decommissioning after being closed in 2013 following the failure of recently replaced steam generators. The nuclear facility was operated by Southern California Edison (SCE). Edison International, parent of SCE, holds 78.2% ownership in the plant; San Diego Gas & Electric (SDG&E), 20%; and the City of Riverside Utilities Department, 1.8%. When fully functional, the plant had employed over 2,200 people. The plant's first unit, Unit 1, operated at up to 436 MW (net) from 1968 to 1992. Unit 2, at 1,070 MW (net) was started in 1983 and Unit 3, at 1,080 MW (net) started in 1984. Southern California Edison announced on June 7, 2013 that it would "permanently retire" Unit 2 and Unit 3.

*Stochastic Modeling*: A method of portfolio modeling in which one or more variables within the model are random. Stochastic modeling is for the purpose of estimating the probability of outcomes within a forecast to predict what conditions might be like under different situations. The random variables are usually constrained by historical data. The Monte Carlo Simulation is an example of a stochastic model. When used in portfolio evaluation, multiple simulations of the performance of the portfolio are done based on the probability distributions of the individual outcomes. A statistical analysis of the results can then help determine the probability that the portfolio will provide the desired performance.

*Total Energy to Serve Load:* Equals retail sales plus transmission and distribution system losses.

*Transmission*: An interconnected group of lines and associated equipment for the movement or transfer of bulk energy products from where they are produced or generated to other electric systems, or to distribution lines that carry the energy products to consumers.

*WECC – Western Electricity Coordinating Council*: The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. In addition, WECC provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws. WECC is geographically the largest and most diverse of the eight regional entities that have delegation agreements with the North American Electric Reliability Corporation (NERC). The Western Interconnection, WECC's service territory, extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between, as indicated in blue in the Western Interconnection map, and green in the NERC map below.[24]


REGIONAL ENTITIES: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool, RE (SPP), Texas Reliability Entity (TRE), Western Electricity Coordinating Council (WECC).

*Wheeling*: The transmission of electricity by an entity that does not own or directly use the power it is transmitting.

[24] Source: Western Electricity Coordinating Council - About WECC