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Vernon Public Utilities
2018 Integrated Resource Plan

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EXECUTIVE SUMMARY

The prevailing mission at Vernon Public Utilities (VPU) is to provide its customers with reliable, safe and affordable energy in a manner consistent with California's progressive goals as the state transitions toward cleaner forms of energy. VPU has developed an Integrated Resource Plan (IRP) that is designed to provide a long-term strategy to meet the electric service needs of its customers and comply with state and federal energy policies. The IRP is a road map charting a resource acquisition strategy favoring the procurement of more renewable energy resources and fewer carbon-emitting resources. Resource investment decisions were evaluated using an integrated approach to ensure reliability, environmental stewardship, and to ensure that mandated renewable resource requirements are achieved at the lowest possible cost.

IRP Goals

VPU used an integrated approach to develop this IRP including the consideration of several goals such as supplying reliable and affordable energy to its customers, achieving 60% renewable portfolio standard (RPS) mandate by 2030 and reducing greenhouse gas emissions (GHG) by 40% from 1990 levels by 2030 as required by Senate Bill 32 (SB 32). The IRP provides a forward-looking view of resource options available to ensure base-load local generation is in place after 2028 for system reliability purposes. The IRP also identifies a strategic plan to increase energy efficiency savings, facilitate the adoption of distributed energy resources (DERs) and support transportation electrification activities. This IRP aligns with the Senate Bill 350 energy policy requirements and sets VPU on a path towards achieving 100% carbon-free energy by 2045, in accordance with Senate Bill 100 (SB 100).

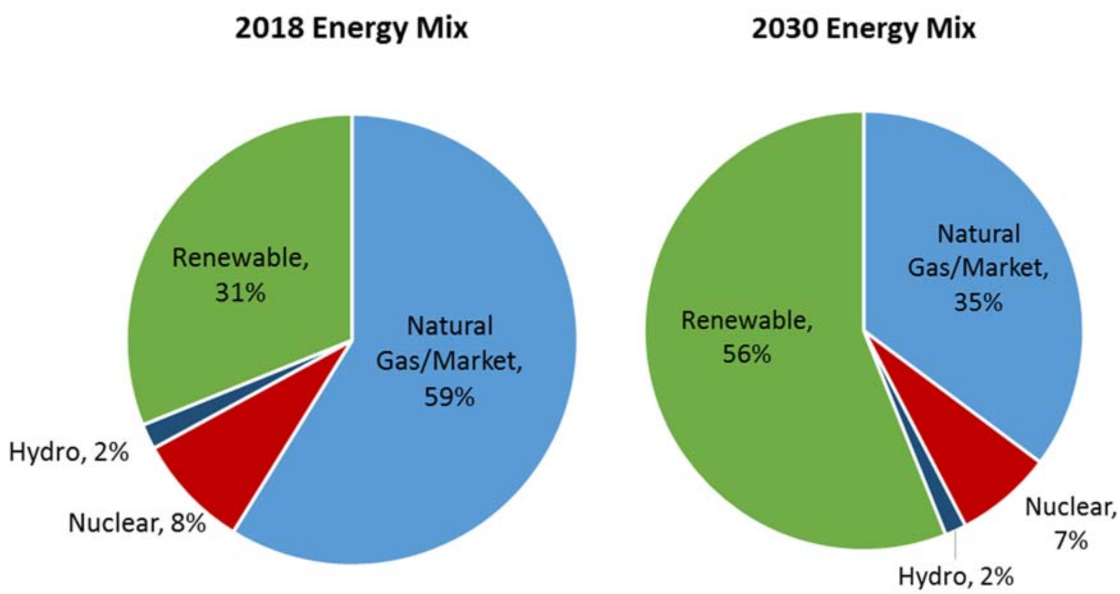
Stakeholder Process

VPU strives to increase customer engagement and foster transparency as we consider our long-term resource plans and procurement decisions. During the IRP process, VPU conducted customer outreach through a customer survey and by holding multiple stakeholder meetings to receive customer input. Survey results indicate that the primary concern of VPU customers is to maintain affordable rates and maintain system reliability. This feedback was included in the IRP analysis process and became a key metric in the selection of the optimal resource portfolio.

Preferred Portfolio

The Preferred Portfolio represents a diversified, least-cost resource plan that satisfies VPU's system reliability, compliance with RPS requirements, and reduction of GHG emissions. VPU's Preferred Portfolio is a utility-scale resource plan that increases reliance on renewable energy and decreases dependence on the usage of natural gas. In 2018, approximately 59% of VPU's electricity will be supplied by the Malburg Generating Station (MGS)[1] and 31% will be supplied by renewable resources. Under the Preferred Portfolio, VPU's renewable energy supply mix will increase to 56% (equivalent to 62% RPS) and reliance on natural gas will decrease to 35% by 2030. ES 1 below illustrates VPU's changing energy supply mix in 2018 and 2030.

ES 1: Changing Energy Supply Mix [2]



Through its existing renewable resource commitments, VPU has already procured enough renewables to comply with California's third RPS compliance period of 2017-2020.

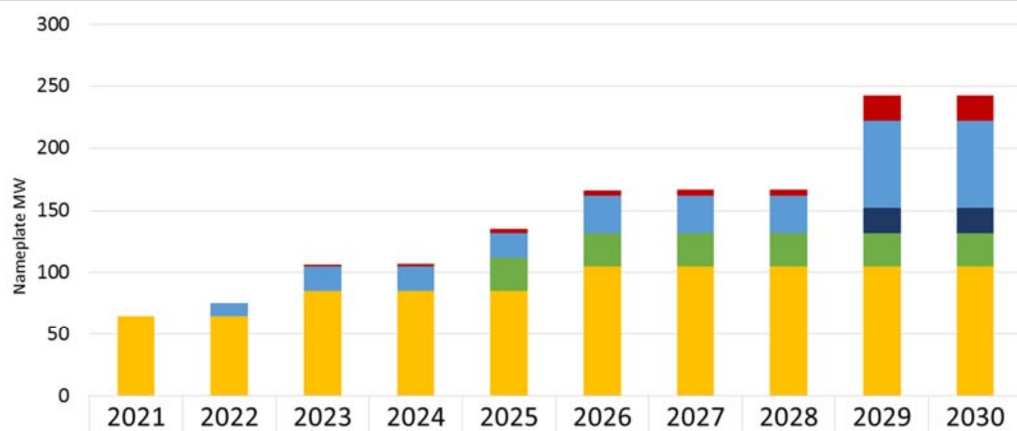
[1] Malburg Generation Station (MGS) is a 134 MW natural gas-fired plant. VPU has a contract for the output of this plant through a power purchase tolling agreement that expires at the end of 2028.
[2] Energy supply mix and RPS are calculated differently. Energy supply mix is based upon the percentage of generation, whereas RPS is based upon total eligible renewable resources divided by retail sales.

VPU will need to acquire additional renewable resources starting in 2021. The Preferred Portfolio recommends procuring 65 MW of solar in 2021, 20 MW in 2023 and an additional 20 MW in 2026 for a total cumulative solar investment of 105 MW by 2030. The Preferred Portfolio also includes the acquisition of 27 MW of wind in 2025 and 20 MW of geothermal in 2029 to provide resource diversity. Diversifying the renewable resource mix with resources other than solar benefits the system by providing energy during hours when solar resources are off-line.

The existing MGS Power Purchase Agreement (PPA) expires in 2028. VPU does not assume MGS will be in the resource portfolio post-2028, but requires a plan that includes base load generation located within its local service territory after 2028 for reliability purposes. Resource options to replace the MGS PPA include re-contracting/acquiring MGS, procuring another local existing natural gas plant, or acquiring energy storage technology.

The Preferred Portfolio recommends 1 MW of incremental energy storage in each of the years from 2023 to 2027 increasing to a cumulative total of 20 MW by 2029. These energy storage additions help to partially replace MGS and mitigate over-generation from solar. The Preferred Portfolio identifies 70 MW of capacity that could potentially be sourced from either MGS or another market-based natural gas resource in 2029. ES 2 below lists the cumulative nameplate capacity additions for the Preferred Portfolio.

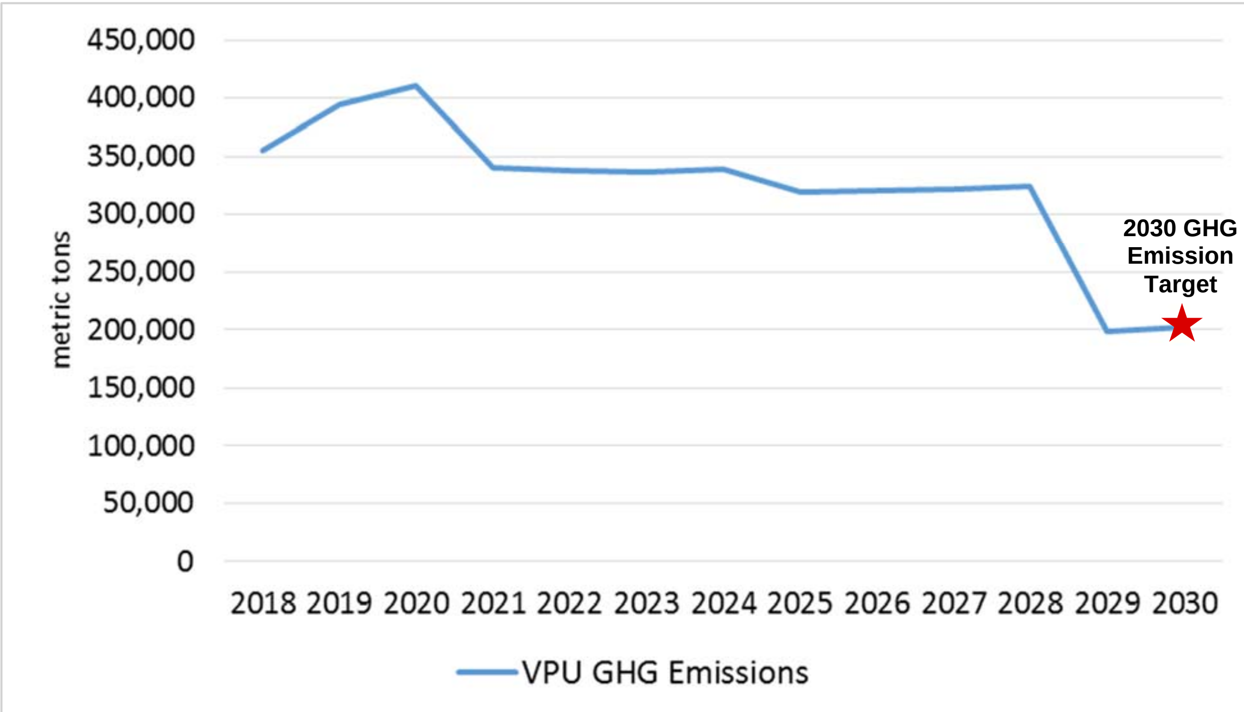
ES 2: Preferred Portfolio's Resource Expansion



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Storage			1	2	3	4	5	5	20	20
MGS/Market		10	20	20	20	30	30	30	70	70
Geothermal									20	20
Wind					27	27	27	27	27	27
Solar	65	65	85	85	85	105	105	105	105	105

The Preferred Portfolio embraces a "wait and see" strategy for procuring small amounts of energy storage in the near-term and delaying procurement of larger amounts of energy storage. Energy storage costs are expected to decrease over time and future advances in energy storage technology will likely materialize. VPU performed a sensitivity analysis on energy storage costs to evaluate the impact on the resource plan if energy storage costs were to substantially decline.

The Preferred Portfolio complies with RPS and GHG reduction mandates by 2030. The Preferred Portfolio includes the acquisition of renewable resources to serve 62%[3] of its retail demand with renewables while reducing its GHG emissions to 201,661 metric tons of CO2. These measures slightly exceed the SB 100 RPS and the SB 32 GHG emission reduction mandates. ES 3 demonstrates how VPU will comply with SB 32 by 2030.



ES 3: GHG Emission Reduction Compliance per SB 32

Nuclear and hydropower resources are ineligible for RPS credit, but qualify as carbon-free resources. VPU's power supply is approximately 44% carbon-free in 2018, increasing to 71% by 2030 and reaches 86% by the end of the planning period. The Preferred Portfolio puts VPU on the path towards the SB 100 sustainability goal of being 100% carbon-free by 2045.

[3] Renewable procurement is 62% in 2030 which is greater than the 60% RPS requirement in 2030. The additional procurement factors in potential that some solar generation could be curtailed.

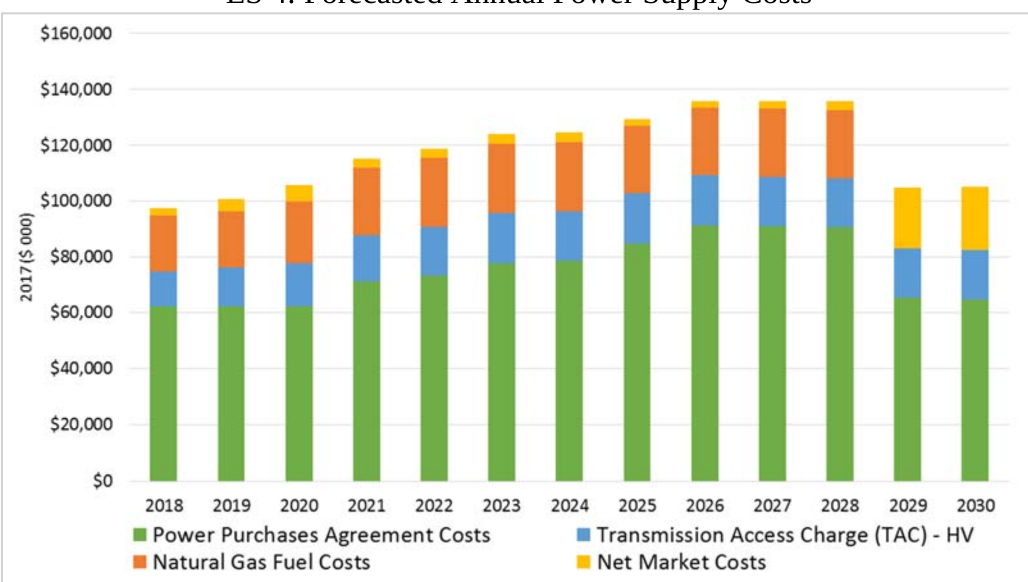
Disadvantaged Communities

VPU's overall transition to sustainable resources and its action plans to develop more defined Distributed Energy Resources (DERs) will benefit all business, customers and residents across varying socio-economic demographics. All of the sustainability measures pursued by VPU will have a positive environmental impact through the reduction in GHG emissions which will improve the quality of life in Vernon and our neighboring disadvantaged communities. Executing and implementing the action items set forth in this IRP will require collaboration, input, and hard diligent efforts by both VPU staff and VPU customers.

Rate Impact to Customers

The Preferred Portfolio identifies the lowest cost, bulk power supply portfolio. The cost of procuring the additional renewables selected in the Preferred Portfolio is forecasted to increase VPU's power supply costs at a rate of 0.86% annually between 2018 and 2028, based on 2017 real dollars. Power supply cost represents only one component of the VPU cost of service that determines the overall retail rate. In addition to the power supply cost, the retail rate includes bond payments, reserve requirements, electric system capital improvement cost, operating & maintenance cost, along with administrative and general expenses, etc. Further, the power supply cost forecast is based on the real rate of change and it does not account for inflation. A separate cost of service study will adjust the power supply cost forecast based on annual inflation rates. Therefore, power supply costs are not a forecast of customers' total electric rates and should be only used by customers to gauge, at a high level, the impact of renewable procurement costs on their electric bills. Power supply costs are expected to decrease in 2029 when the existing MGS PPA expires. ES 4 below shows the projected annual bulk power supply costs broken down by the contributing components.

ES 4: Forecasted Annual Power Supply Costs

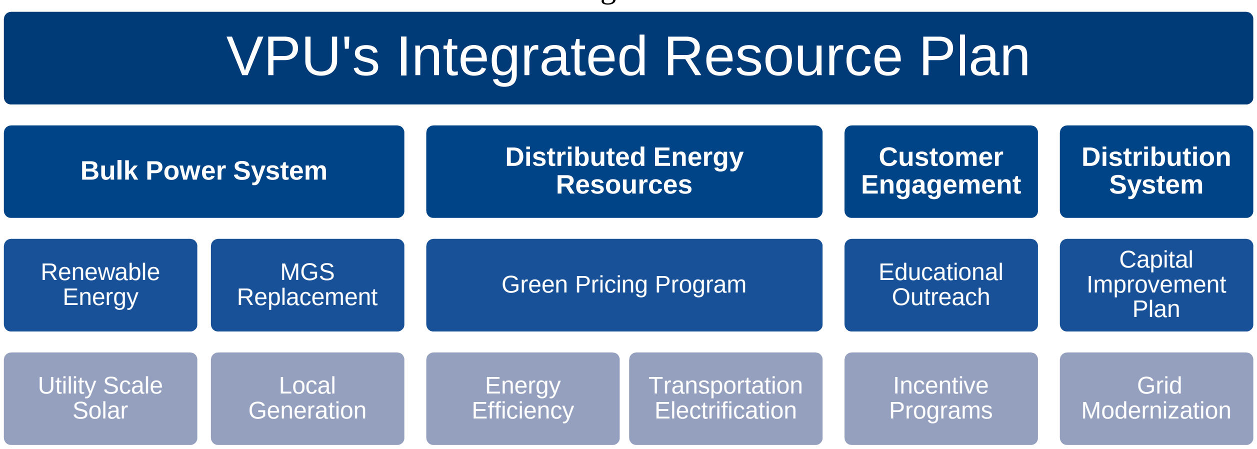


VPU is in the midst of conducting a Cost of Service (COS) study that will be used to forecast future retail rates. The power supply costs derived from this IRP will be used as one of the major components considered in the COS study to determine the retail rate impacts of the IRP.

Integrated Resource Plan

This IRP is a comprehensive plan that identifies not only the optimal resource procurement strategy at the bulk power system level but also includes a number of other action plans. The action plans were designed to encourage the growth of distributed energy resources, add resiliency to the VPU distribution system and foster customer engagement. ES 5 below shows the four main components VPU is focused on developing.

ES 5: VPU's Integrated Resource Plan



This integrated planning approach requires careful consideration of the costs and benefits of varying program outcomes when developing action plans. For example, higher than expected penetration levels of DERs could result in VPU procuring fewer utility-scale resources. Conversely, higher DER adoption may require additional investments in the distribution system to support those DERs. The action plans developed as a result of this integrated analysis are designed to be flexible and malleable to changes in the planning environment.

Recommended Action Plans

The sections below briefly describe the action plans recommended for implementation of the IRP. These action plans commit to a direction that will ensure that time, resources, and financial investments are maximized. The IRP will be reviewed on a regular basis and adjustments to the plan can be made to ensure the plan remains viable from a technical, regulatory and financial perspective.

Bulk Power System Action Plans

VPU completed a demand forecast and resource needs analysis to determine the timing, type, and size of future utility-scale resources. The resource needs analysis showed that VPU has sufficient capacity resources until 2028 when the current MGS contract expires. VPU will need to acquire additional renewable resources as soon as 2021. Resource procurement strategies will focus on near-term resource shortfalls for the 4th RPS Compliance Period (2021-2024) and the evaluation of future MGS resource options.

Utility-Scale Resource Procurement

Resource procurement is a multi-year comprehensive process. Among other things, resource procurement may require identifying procurement options, consideration of timing, quantifying risk and benefits, diversification, solicitation through RFPs, contract negotiations, and project construction. Resource procurement for delivery in year 2021 should start immediately. The Preferred Portfolio recommends acquiring 65 to 85 MW of utility-scale solar between 2021 and 2024. The timing of the procurement and the actual annual amounts may vary based upon received offers. The resource procurement action plans include:

1) Issue a renewable resource RFP to evaluate utility-scale solar and/or solar plus storage PPAs for delivery between 2021 and 2024;
2) Update solar cost and operating characteristics of submitted solar PPAs using a production cost model to re-evaluate impacts on the entire VPU resource portfolio; and
3) Request that California Independent System Operator (CAISO) provide a projection of future flexible capacity requirements corresponding to the addition of 65 to 85 MW of incremental utility-scale solar.

Malburg Generating Station Replacement

Malburg Generating Station is an important local resource that provides reliable power to the VPU system. System reliability may be compromised without MGS under a double contingency (N-2) situation, where two 66 KV transmission lines are out of service at the same time. Below is a list of action plans VPU intends to undertake related to MGS:

1) Evaluate reduced generation levels and options to reconfigure MGS to allow for more operational flexibility;
2) Evaluate alternative resource options to replace MGS when the existing PPA expires; and
3) Ensure MGS or an alternative local base load generation is in-place post 2028.

Distributed Energy Resources Action Plans

Response from the customer survey indicated a growing interest in distributed solar, electric vehicles along with electric vehicle charging infrastructure, and energy storage. VPU intends to provide outreach, education, and utility services to incentivize and facilitate the adoption of DERs. The sections below briefly describe the action plans related to DERs.

Distributed Solar

VPU is in the process of designing a Green Power Program . The Program will allow residents and businesses to meet their own sustainability goals by purchasing clean and affordable renewable energy through this innovative program. The Program enables customers to offset all or a portion of their electricity usage with either renewable energy or renewable energy certificates (RECs). In addition to the Green Power Program VPU is investigating programs that will:

1) Install solar systems at city-owned facilities and partner with customers to install solar systems at customer-owned facilities;
2) Evaluate a community solar product offering; and
3) Assist customers with installation of rooftop solar systems under existing net-metering tariffs.

Energy Efficiency

VPU has identified action plans to implement new energy efficiency measures throughout its city-owned facilities. In 2017, VPU realized approximately 3 GWh of energy efficiency savings. The VPU energy efficiency goal is to increase its energy efficiency savings to 6 GWh and contribute to the statewide goal of doubling energy efficiency. To increase energy efficiency savings VPU will:

1) Continue existing energy efficiency programs and educate customers on more efficient uses of electricity;
2) Perform energy efficiency upgrades at all city-owned facilities as needed; and
3) Purchase energy efficient transformers, capacitors and other increasingly efficient distribution system equipment when appropriate.

Transportation Electrification

VPU has limited light-duty electric vehicle infrastructure in place, but has identified initial steps it can take to accelerate transportation electrification within its service territory. VPU intends to develop a plan to increase the use of light-duty electric vehicles with the goal of adding approximately 1.7 MW of load to the system by 2030. The action plan to affect the acceleration and adoption of transportation electrification include:

1) Explore partnering with customers to install and maintain EV charging stations at customer-owned facilities;
2) Evaluate increasing the number of City-owned electric vehicles fleet; and
3) Coordinate with local air quality agencies on available programs and initiatives.

Demand Response and Energy Storage

VPU currently has a reliability-driven interruptible load program but has not implemented a demand response (DR) customer program that is based on market pricing. Below is a list of demand response and energy storage action plans VPU intends to evaluate and undertake in the coming years:

1) Implement a Voluntary Load Reduction Program offering discounted rates to customers that reduce their load;
2) Provide customer education on demand response programs available through the CAISO and encourage participation in these programs; and
3) Participate in strategic partnerships with customers to advance energy storage opportunities.

Customer Engagement Action Plans

VPU conducted customer and stakeholder outreach during the IRP process through the distribution of a survey soliciting input on topics such as the IRP, customer service and DERs. Survey responses were used to develop action plans for enhancing customer engagement and increasing customer satisfaction. They include:

1) Collect and prioritize customer feedback on the IRP;
2) Increase the frequency of customer outreach activities and educational events; and
3) Offer more utility products and services to customers.

Distribution System Action Plans

VPU has maintained a highly reliable electric system and was the recipient of Diamond Level Reliable Public Power Provider award from the American Public Power Association (APPA). VPU will continue to invest in the electric distribution system to maintain a high level of reliability and support the increased penetration of DERs. VPU is taking the following actions to modernize the distribution system:

1) Continue to replace and upgrade VPU distribution system aging infrastructure in order to maintain system reliability;
2) Implement new distribution system automation by installing intelligent line switches that can be operated remotely and
3) Upgrade line conductors, transformers, and complete voltage conversions at electric distribution substations.

Next Steps

This IRP will be presented to the Vernon City Council for approval prior to filing with the California Energy Commission (CEC). The VPU IRP will be incorporated into the CEC's statewide integrated energy policy report (IEPR). The approach, analysis, and completed standardized reporting requirements are in compliance with the IRP guidelines developed by the CEC. VPU developed a checklist of requirements to ensure this IRP meets all of the guidelines and analytical requirements that accompany this IRP as supporting documentation.

INTRODUCTION

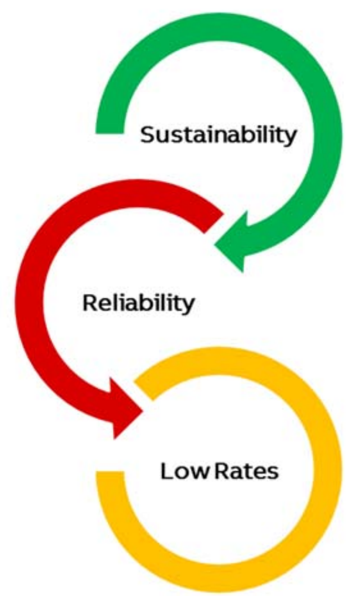
The IRP is a forward-looking plan initiated to ensure that necessary investments are made in a timely manner to maintain a reliable power system. The plan aims to incorporate the best mix of generation and transmission resources to meet current and future customer electric demand. This IRP will be used in conjunction with the VPU Capital Improvement Plan and other forward-looking management plans.

1 Role of the Integrated Resource Plan

The main role of the IRP is to serve as a roadmap for implementing the VPU long-term resource strategy. The IRP provides an analytical framework for assessing resource investment tradeoffs and stranded asset risk. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to the VPU selection of the preferred portfolio of generation, demand, and distributed resources.

Integrated Resource Plan Goals

The goal of VPU IRP is to present a long-term strategy to meet the City of Vernon's future electric needs. The IRP lays out the amount, timing, and type of resources that can achieve this goal at the lowest reasonable cost, while meeting sustainability and reliability requirements. The IRP was performed using a 20-year planning period from 2018 to 2037, however, results are reported for the 2018-2030 time period due to the nature of the regulatory uncertainty after 2030.



The IRP provides information associated with resource acquisitions to meet customers' future electricity demand, including capacity and energy supply resources, renewable energy, and demand side management. This IRP attempts to meet the following general resource planning goals:

- Provide customers with reliable and affordable energy;
- Maintain compliance with all laws and regulations applicable to VPU and our business activities;
- Optimize the operation of system resources that includes maintaining reliable base load generation within Vernon's city limits beyond 2028;
- Reduce greenhouse gas emissions to comply with Assembly Bill 32 (AB 32), the "California Global Warming Solutions Act of 2006", as expanded by Senate Bill 32 (SB 32), which mandates that Greenhouse Gas (GHG) emissions in California be reduced to 40% below the 1990 level by 2030;
- Comply with Senate Bill 350 (SB 350) including the RPS requirements and IRP filing requirements;

- Comply with Senate Bill 100's (SB 100) RPS goal of supplying 60% of retail energy sales from renewable resources by 2030;
- Contribute to the statewide goal of doubling energy efficiency savings by 2030;
- Incentivize and facilitate the adoption of transportation electrification; and
- Develop policies that foster economic, health, and electric rate benefits for low income customers and neighboring disadvantaged communities.

2 Overview

On March 21, 2017, the Vernon City Council adopted Ordinance No. 1240, consolidating all utilities-related services under the management of the stand-alone entity “Vernon Public Utilities” for better oversight and management of the day-to-day activities of such independent utilities.

Formerly known as Vernon Light and Power and Vernon Gas & Electric, the department is now called Vernon Public Utilities (“VPU”), providing electric services in addition to water, gas, and fiber services. As changes occur locally, nationally, and on a global scale, VPU is committed to building a resilient utility which will not only withstand challenges, but can also take advantage of the opportunities that may arise. While VPU remains dedicated to reliability, safety, and continuity of service, as a full service utility, we strive to move forward in a manner that is financially and environmentally responsible. As a publicly owned utility, VPU is community focused by design, and residents and business owners alike are partners in addressing local matters. Local control affords the Vernon business community some recognizable advantages: transparency in governance; competitive rates; the ability to tailor utility policies to customer needs, programs to serve the priorities of the local community; and a strong voice in the decision making process.

VPU strives to work earnestly as stewards of the community to supply valuable, responsive, and reliable services to businesses and residents cost effectively, sustainably, and with a customer oriented approach. Locally, leadership is provided by the City Council and City Administration in support of the efforts put forth by VPU staff. We are committed to partnering with the local community in shaping and constructing a sustainable energy future for the City of Vernon.

Nationally Recognized Reliable Electrical Service

The VPU electric division aspires to achieve safety and reliability metrics that rank them among the top 10% of public utilities per national benchmarking studies. In April of 2016, VPU was awarded the prestigious Diamond Level designation of Reliable Public Power Provider (RP3) from the American Public Power Association (APPA). VPU earned this honor by providing exceptionally reliable and safe electric service. The RP3 distinction recognizes public power utilities that demonstrate proficiency in four key disciplines: reliability, safety, workforce development, and system improvement. VPU is one of just eight public utilities among over 2,000 public power utilities in the U.S. to achieve Diamond level recognition over this 3-year period.

Engineering and Capital Improvements

VPU has developed a 7-year Capital Improvement Plan to sustain reliability, high quality service and competitive rates. The $64M Plan details a solid capital improvement program that aims to achieve an overarching strategic vision that addresses the 5 square miles and uniquely industrial characteristics that make up the City. The Plan defines strategies that involve an in-depth evaluation of the condition of the electric system; performs a detailed engineering analysis of distribution system capability and performance; and lists construction and upgrade projects to transform the system into an intelligent, increasingly automated and technologically advanced electric system.

Electric Power System

VPU serves about 2,000 mainly commercial and industrial customers with electric sales of approximately 1,128 GWh annually and peak loads of approximately 184 MW in the summer and 174 MW in the winter. Vernon summer and winter peak loads are similar primarily because of the large number of industrial customers that are located in the VPU service territory. Large and small commercial and industrial load comprises 99% of VPU's demand and energy sales. The electric system also benefits from a very stable customer base. Many industrial customers have an occupancy history of up to 80 years in Vernon with the 25 largest customers having an average tenancy of 31 years in the City. Further, the electric system boasts an annual average load factor of over 70%, due to the predominantly industrial customer mix. The electricity demand in the City is poised to grow in the upcoming years.

Distribution System Overview

The municipally owned electric system includes generation, transmission, and distribution facilities. Vernon participates in the CAISO wholesale energy markets under a Metered Subsystem Agreement (MSSA)[4]. VPU's electrical distribution and generation facilities are located entirely within the CAISO balancing area and are connected to the CAISO through the Southern California Edison (SCE) 220-66 kV Laguna Bell Substation.

The Vernon load is supplied and supported by five 66KV source lines that exit the SCE Laguna Bell 220/66 KV Substation. Under double contingency situation (N-2) situations where two 66

[4] In 2005, the City of Vernon and CAISO entered into a Metered Substation Agreement (MSSA) to allow the City to convert from a Utility Distribution System (UDC) to a Metered Substation (MSS). The MSSA includes the terms and conditions under which the City operates its generating units, submits bids and self-schedules into the CAISO Balancing Authority Area and CAISO markets, and set forth the manner in which the City and CAISO meet their obligations under the CAISO Tariff. The second amendment to the MSSA was enacted as a result of the CAISO's implementation of FERC Order 764 which changes intertie scheduling and settlement from an hourly to a new Fifteen Minute Market (FMM).

KV transmission lines are out of service, the VPU electric system reliability will most likely not be compromised with the existence of local generation.

Vernon system peak load is served in part by two generation facilities that are located within VPU service territory. MGS, a 134 MW natural gas-fired plant and two H. Gonzales units, a combined 10 MW natural gas plant. In addition to the local generation, VPU purchases energy to supply its 184 MW system demand from long-term agreements including the Palo Verde Nuclear Generating Station, Hoover Dam, solar generating facilities, landfill gas facilities, and from short-term power purchases.

Generation Resources

The subsequent sections provide a brief overview of the primary generation resources owned by or that are under VPU long-term contracts.

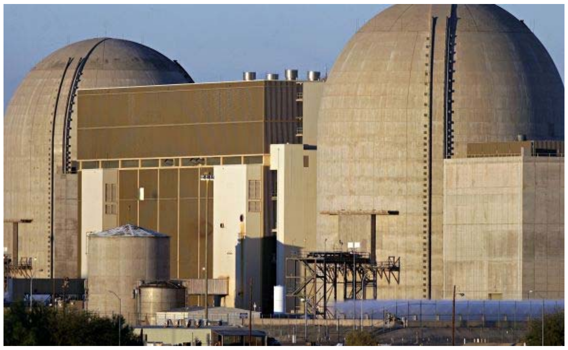
Malburg Generating Station (MGS)

The Malburg Generating Station (MGS) is a 134 MW combined-cycle plant located in the City of Vernon. The MGS includes two Siemens (formerly Alstom) GTXI00 natural gas-fired combustion turbine generators (CTGs) and a steam turbine generator (STG). MGS has duct burners and evaporative inlet air coolers and filters that enable the units to achieve higher levels of power output in selected modes of operation. MGS was built by the City of Vernon and later sold to a private entity, Bicent Power LLC (Bicent); however, pursuant to the power purchase tolling agreement (PPTA), the City acquired all of the capacity and energy of the MGS for a fifteen-year term ending in 2023. The term will likely be extended for an additional five years to 2028.

H. Gonzales Generating Station Units 1 & 2

Vernon owns and operates two natural gas-fired combustion turbine units (H. Gonzales Generating Station #1 and #2), which are also located within the City of Vernon. The H. Gonzales natural gas-fueled combustion turbines are Allison 571-KA combustion turbines, rated at 5.75 MW each. The combustion turbine units began commercial operation in 1988. Each of the units is restricted by air quality regulators to run on natural gas for no more than six hours per day.

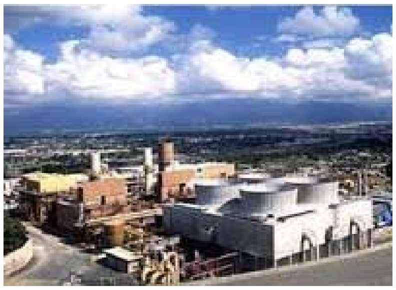
Palo Verde Nuclear Station



Palo Verde Nuclear Generating Station (PVNGS) is located approximately 55 miles west of Phoenix, Arizona. PVNGS consists of three nuclear electric generating units, Units 1, 2 and 3, with dependable capacity of 1,311 MW, 1,314 MW and 1,312 MW, respectively.

In 1981, Vernon, in conjunction with other municipalities in the area, entered into a contract with SCPPA to purchase power generated from PVNGS. Under the power sales contract with SCPPA, the City is obligated, on a" take or pay" basis, for its proportionate share of power generated, as well as the operating and maintenance expenses of the station. In addition, the contract requires VPU to its proportionate share of debt service on any bonds or debt, whether or not the project or any part of the project or its output is suspended, reduced or terminated.

Puente Hills Landfill Gas



The Puente Hills Landfill Gas-to-Energy facility is a 46 MW conventional Rankine Cycle Steam Power Plant that uses landfill gas (LFG) as fuel to generate electricity. LFG is fired in the plant’s boilers producing superheated steam. The superheated steam is used to drive the steam turbine/generator to generate electric power. The Puente Hills Landfill Gas to Energy facility was constructed by Los Angeles County Sanitation District and began full commercial operation in January 1987 and has remained on-line 95 percent of the time since then.

On behalf of its members, SCPPA entered into a PPA with the Sanitation Districts of Los Angeles for 43 MW of generating capacity from the Puente Hills Landfill Gas-to-Energy Project. VPU, through SCPPA, is entitled to 10 MW of renewable capacity from the Puente Hills Landfill Gas-to-Energy Project. The power purchase agreement expires on December 31, 2030.

Hoover Dam Hydroelectric Power Plant

The Hoover Power Plant (Hoover Plant) is located on the Arizona-Nevada border approximately 25 miles southeast of Las Vegas, Nevada and is part of the Hoover Dam facility, which was completed in 1935 and controls the flow of the Colorado River. The Hoover Plant consists of 17 generating units and two service generating units with a total installed capacity of 2,080 MW.

In 1987, Vernon entered into an agreement for the purchase of firm capacity and energy from the United States Department of Energy Western Area Power Administration (Western). SCPPA and other contractor allocations of Hoover power and energy has been extended for 50 years beyond the contract's expiration in 2017. Vernon's purchase represents 22 MW of an energy entitlement of 26,600 MWh/year.

Astoria II Solar Photovoltaic Facility

The City of Vernon, in conjunction with five other SCPPA member municipal utilities participated in a PPA with Recurrent Energy to purchase the output from the Astoria II Solar facility for 20 years from Recurrent Energy. The PPA entitle Vernon to 20 MW of capacity from January 2017 to December 2021, and 30 MW for the remaining contract period of January 2022 to December 2036. The project is sited on approximately 840 acres in California between Los Angeles and Kern Counties, and interconnects with the CAISO system at the SCE Whirlwind Substation.

Antelope DSR 1 Solar Project

The Antelope DSR 1 Solar Project is a 50 MW solar project that was developed by Sustainable Power Group (sPower) and came on-line in December 2016. The Antelope DSR project is located in the City of Lancaster, Los Angeles County. VPU, through SCPPA, has an agreement with Antelope DSR 1 LLC (a subsidiary of sPower) that entitles VPU to 50 percent of the capacity (25 MW nameplate) and output of the solar project through December 31, 2036.

In addition, the contracting cities (Riverside and Vernon) negotiated an energy storage option in the PPA which provides for potential design, build, and operation of an energy storage facility, when economically feasible, in conjunction with the solar project.

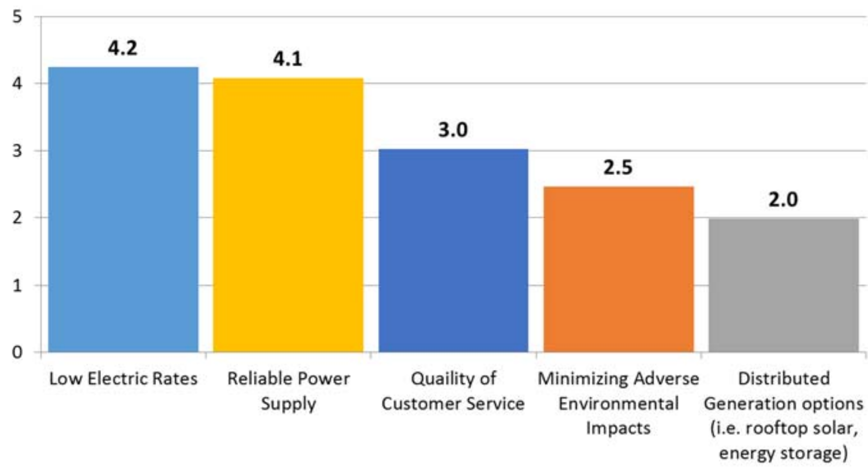
3 Stakeholder Process

VPU conducted significant customer and stakeholder outreach during this IRP process via email, phone calls, personal visits to customer sites, and a series of presentations hosted by the utility at City Hall. VPU distributed a comprehensive survey of customer energy-related plans and IRP topics. VPU hosted a series of four public stakeholder events to provide stakeholders and the general public an opportunity to provide comments on the IRP. At each stakeholder event VPU provided progress reports on the IRP and solicited feedback to incorporate into the IRP. The final stakeholder presentation of the IRP results was held on September 27, 2018.

Customer Survey

The utilization of customer surveys was intended to better understand customers' thoughts and preferences regarding VPU plans to provide reliable power, comply with the California's RPS and GHG mandates, the quality of VPU's customer service and customer's energy related priorities. The customer survey was available for customers to complete between January 15, 2018 through April 9, 2018. One survey question asked respondents to rank five energy and customer service related issues. At the top of the list of important issues to stakeholders was low electric rates while maintaining a reliable power supply. Figure 1 summarizes the results of the most important issues to customers, where 5 = The Most Important and 1 = The Least Important.

Figure 1: Issues Important to Customers

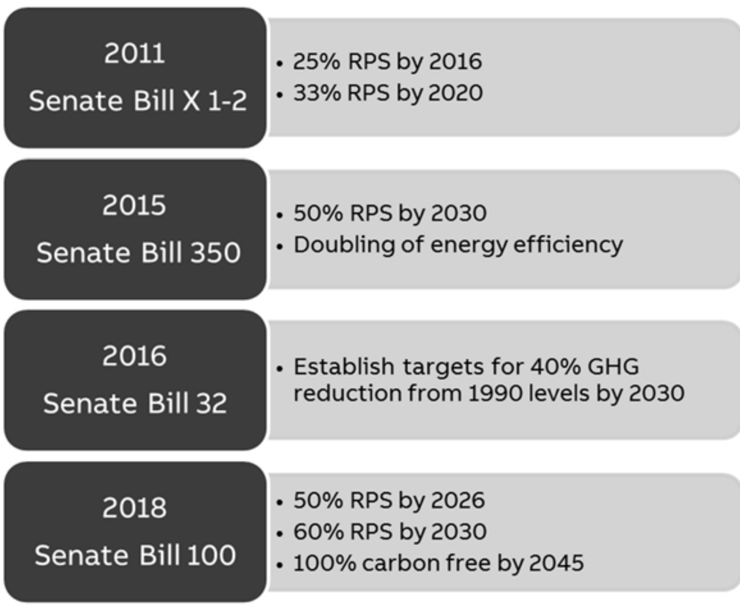


A more comprehensive summary of customer responses from the IRP stakeholder survey can be found in Appendix C.

PLANNING ENVIRONMENT

The environment in which utilities must plan their future resources continues to evolve adding risk and uncertainty to long-term resource acquisition plans. Significant issues and concerns facing VPU during this IRP planning cycle include: applicable environmental legislation and regulations, global and state-wide economic conditions, natural gas and power markets supply and pricing, and the utility's own local planning priorities. The following sections discuss the major external factors that influence the VPU long-term resource planning activities.

4 Sustainability Requirements



California is a leader in the sustainability movement and has swiftly passed legislation addressing the impacts of climate change. Under the current regulatory environment VPU is required to meet aggressive RPS and GHG reduction targets mandated by the state of California. VPU is setting a plan in motion to transform the utility resource portfolio mix. Sustainable resources will supply electricity from renewable and zero carbon sources by 2045 as mandated by California's most historic climate law to date - Senate Bill 100 (SB 100). There have been a number of state and federal laws that have impacted the approach VPU takes in acquiring resources. Some of the most impactful legislative changes deal with renewable energy and greenhouse gas emissions. At the state level, this includes SB X1-2, SB 350, AB 32, SB 32 and SB 100.

Starting in 2011 with the passage of Senate Bill X1-2, California's RPS was set at 33% by 2020. Four years later, in 2015, Senate Bill 350 (SB 350) was passed increasing the RPS to 50% by 2030 and requiring the cumulative doubling of energy efficiency savings in electricity and natural gas final end uses by 2030. In 2016, SB 32 set goals for California load-serving entities[5] (LSEs) to achieve 40% reduction of GHG from 1990 levels from the electric power sector including incentivizing and incorporating the impacts of transportation electrification.

[5] Load-serving entities is an entity that serves end users and has been granted authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end users.

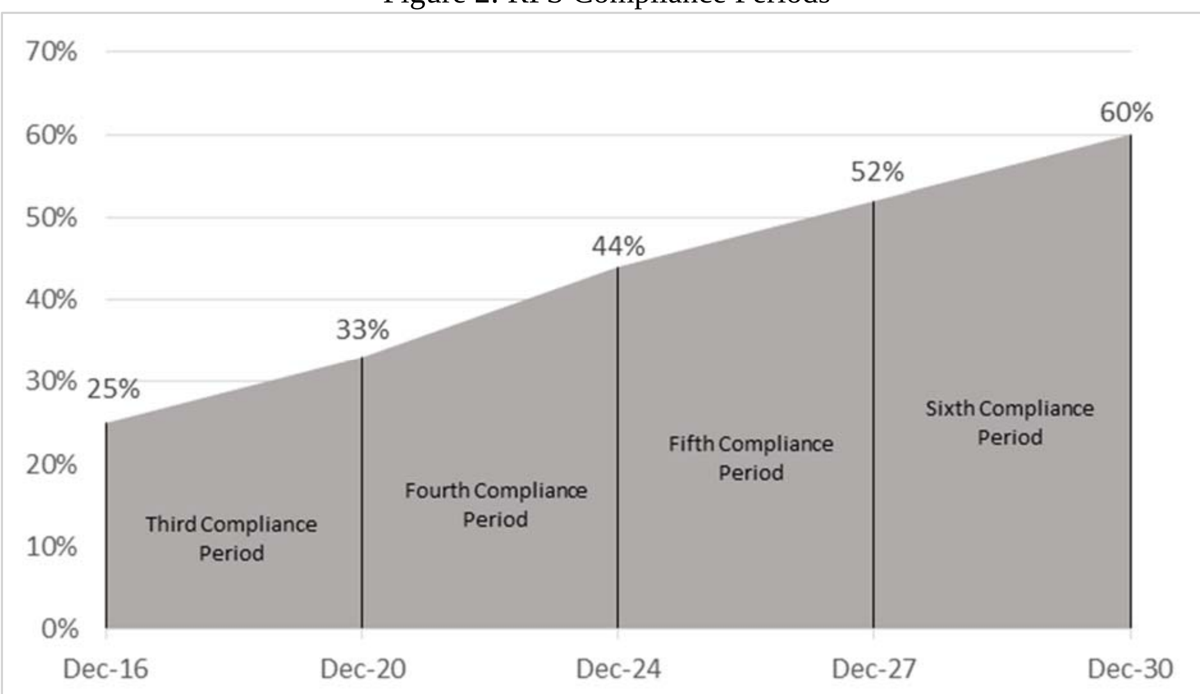
Most recently, in September 2018, the legislation for Senate Bill 100 (SB 100) was signed by Governor Edmund G. Brown and passed into law. SB 100 is a mandate that requires LSEs to achieve 50% RPS by 2026, 60% RPS by 2030, and sets a longer-term goal for LSEs to provide 100% clean carbon-free electricity by 2045.

Proposed future legislation includes possible mandates for energy storage and carve-outs for specific resources such as geothermal in the Imperial Valley. Given the speed of regulatory change in California, it is important for VPU to continuously monitor the regulatory landscape and determine if adjustments to the procurement roadmap are necessary to accommodate future regulatory mandates that affect procurement plans. A brief description of relevant laws, market changes and regulations is included in Appendix B.

Renewable Portfolio Standards

This IRP plans for the procurement of sufficient eligible renewable energy resources to serve at least 50 % of annual retail load by the end of 2026 and 60 % by the end of 2030, reflective of SB 100. There are four compliance periods during the period between 2017 and 2030. Figure 2 shows the compliance period years and the RPS target for each period.

Figure 2: RPS Compliance Periods



Source: California Energy Commission, (http://www.energy.ca.gov/portfolio/)

Procurement targets for each compliance period are based on annual retail sales, and the procurement plan demonstrates reasonable progress toward "soft targets" in each individual year. Compliance with the RPS for each compliance period can be accomplished through the procurement of renewables from different sources. However, beginning in 2021, at least 65% of renewable energy must be supplied by resources owned by utilities or through long-term (10+ year) contracts. The CEC verifies RPS procurement for retail sellers and POUs. The CEC determines whether a POU is in compliance with its RPS procurement requirements. In addition, the VPU mix of renewables must meet portfolio content category requirements. The Portfolio Content Category (PCC) helps to define renewable energy products that have different origins and thus may have different impacts to the overall electric grid. Table 1 lists the different PCC categories in which renewable energy products are grouped for RPS compliance purposes.

Table 1: RPS Portfolio Balance Requirements

Portfolio Content Category (PCC)	Renewable Energy Product Description	Requirement
0	Any contract or ownership agreement originally executed prior to June 1, 2010, shall "count in full" toward the RPS procurement requirements.[6]	N/A
1	Eligible renewable energy resource electricity products that: ▪ Have a first point of interconnection with a California balancing authority; ▪ Are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source; or, ▪ 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%

Source: California Energy Commission (http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-SD.pdf)

[6] Any contract or ownership agreement originally executed prior to June 1, 2010, shall "count in full" toward the RPS procurement requirements 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.

Accordance with each compliance period is calculated by averaging the soft targets (i.e. 33% RPS by the end of 2020) to be achieved in the compliance period years. VPU can meet targets in the third RPS compliance period (2017-2020) by maintaining an average RPS of 30% for the entire period. Table 2 below lists the committed renewable energy products, including RECs, VPU has secured to meet the RPS for the third compliance period.

Table 2: VPU RPS Third Compliance Period Procurement

Calendar Year	2017	2018	2019	2020
Retail Sales (MWhs)	1,061,829	1,083,066	1,193,636	1,204,467
RPS Requirement (MWhs)	286,694	314,089	370,027	397,474
Resource (MWhs)				
Biomethane	92,841	93,684	94,522	92,289
Wind	74,162	64,000	64,000	64,000
Solar	138,485	198,194	190,221	189,603
TOTAL	**305,488**	**355,878**	**348,743**	**345,892**
Annual RPS %	29%	33%	29%	29%
VPU Average RPS	**30%**			
Compliance period Requirement	**30%**			

VPU is required to procure eligible renewable energy resources equivalent to at least 50% of its retail sales by 2026 and 60% by 2030 under SB 100. There are four remaining compliance periods[7] between 2017 and 2030. The forecasted procurement targets for each compliance period may be adjusted to reflect specific RPS provisions, such as voluntary green pricing programs, historical carryover from pre-2011 procurement, excess procurement from previous compliance periods and renewable energy credits.

[7] Compliance periods 5 and 6 include only three years, December 31, 2024 to December 31, 2027 and December 31, 2027 to December 31, 2030, respectively. The other compliance periods include four years.

Greenhouse Gas Reduction Targets

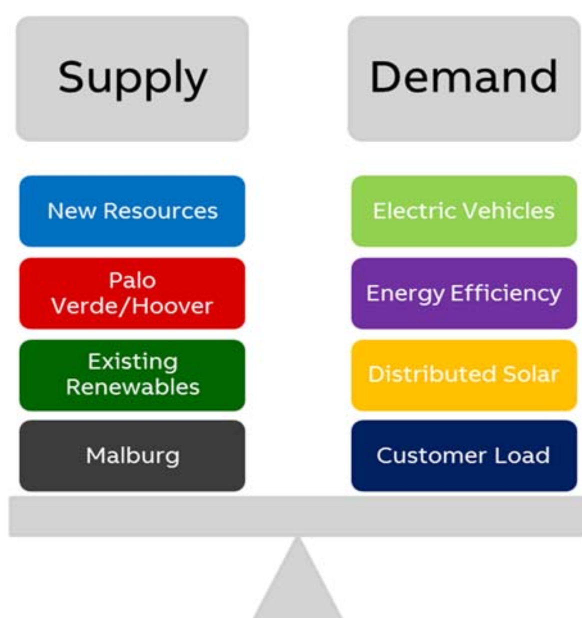
SB 350 requires the CEC to review the IRPs of the 16 largest POUs to ensure that their respective IRPs meet the GHG targets. The review methodology proposed by the CEC, based on the California Air Resources Board's (CARB) practice for allocating GHG emissions allowances to distribution utilities for the period 2021 – 2030, uses estimates of GHG emissions in 2030 to determine each utility's assigned share of electricity sector GHG emissions. This method attempts to balance the efforts needed by each publicly-owned utility (POU) to reach their respective targets (and thus the overarching electricity sector target) across all POUs by requiring utilities endowed with zero-carbon resources, such as large hydroelectricity and nuclear generation, to achieve lower emissions intensities than utilities that do not have GHG-free-resources in their portfolios.

VPU's target share of the 2030 GHG emission target was derived using the CEC's 2015 IEPR demand forecast to enable California to achieve the economy wide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.

The VPU 2030 GHG emission target is 208,683 metric tons CO_2-e. VPU's GHG emission must be below 208,683 metric tons CO_2-e by 2030 to comply with SB 32. Over the IRP planning period, VPU's addition of renewable resources are expected to keep Vernon well below its emission target. When the CEC updates its IEPR, it is likely that revised GHG goals will be identified once every California LSE has filed resource procurement plans.

5 Reliability Planning

Electric utilities 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 customers. VPU adopted a 15 percent reserve margin to match the System Resource Adequacy (RA) requirement adopted by the CPUC in its RA policy framework.

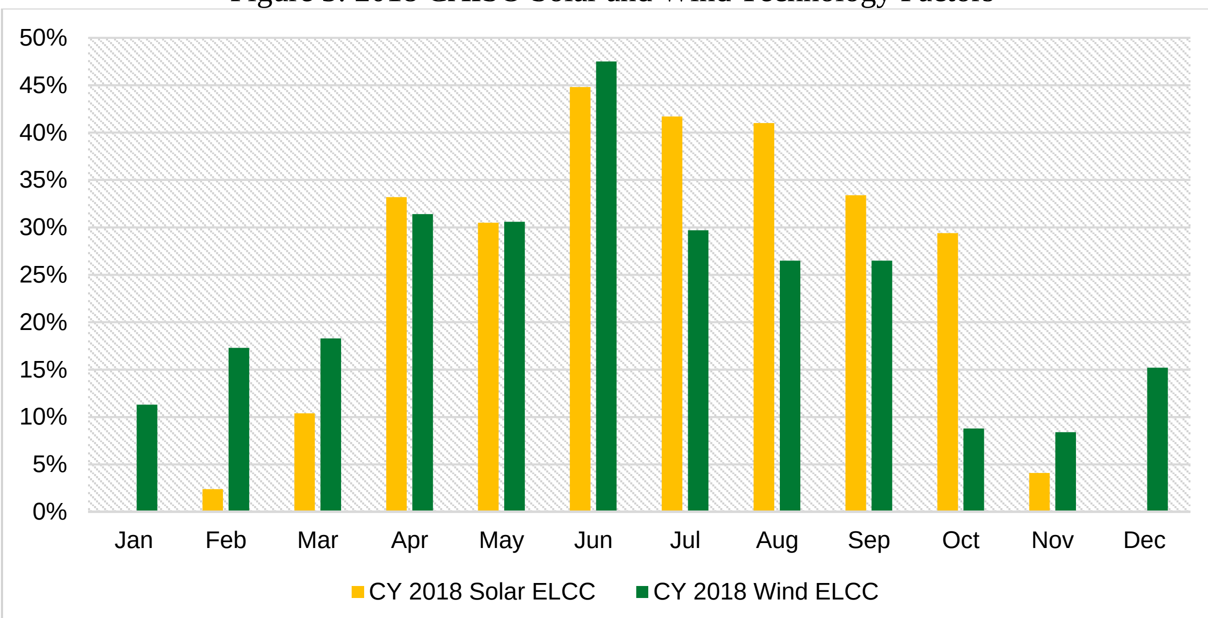


The contribution of each type of resource to this requirement depends on the performance characteristics and availability to produce power during the most constrained periods of the year. This contribution is referred to as Net Qualifying Capacity. For most thermal generation, the Net Qualifying Capacity is relatively close to 100% of the rated capacity.

Renewable resources with full deliverability capacity status (FCDS) are assumed to contribute to system RA 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.

The contribution of variable renewable resources to system RA is based on the resources "Effective Load Carrying Capability" (ELCC)[8]. Solar resources were assumed to have a 41% ELCC for dependable capacity purposes in 2018 and to decline by 1 percent each year. Wind resources were assumed to have a 27 percent ELCC in 2018 and the ELCC remains constant throughout the study period. The ELCC is based upon the 2019 CAISO Technology Factors report published as part of the Net Qualifying Capacity (NQC) list. Figure 3 below shows the CAISO's monthly dependable capacity rating for wind and solar resources.

Figure 3: 2018 CAISO Solar and Wind Technology Factors



Source: CAISO

The contribution of energy storage, a user-limited resource, 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).

[8] ELCC is defined as the incremental load that may be met when a resource is added to a system while preserving the same level of reliability. The contribution of wind and solar PV resources to RA depends not only on the coincidence of the resource operating during peak loads, but also on the characteristics of the other variable resources on the system as well.

Resource Adequacy (RA)

VPU is required to provide the CAISO with annual and monthly RA plans to demonstrate compliance with the reliability requirements of CAISO Tariff Section 40. Failure to demonstrate sufficient RA resources in the annual or monthly resource plans may trigger the CAISO's capacity procurement mechanism pursuant to CAISO Tariff Section 43, and VPU may be responsible for its share of the associated costs.

VPU must demonstrate the existence of three different types of RA capacity available on their system: (1) System RA, (2) Local RA, and (3) Flexible RA. There may be some overlap between the three types of RA capacity. 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.

System Resource Adequacy

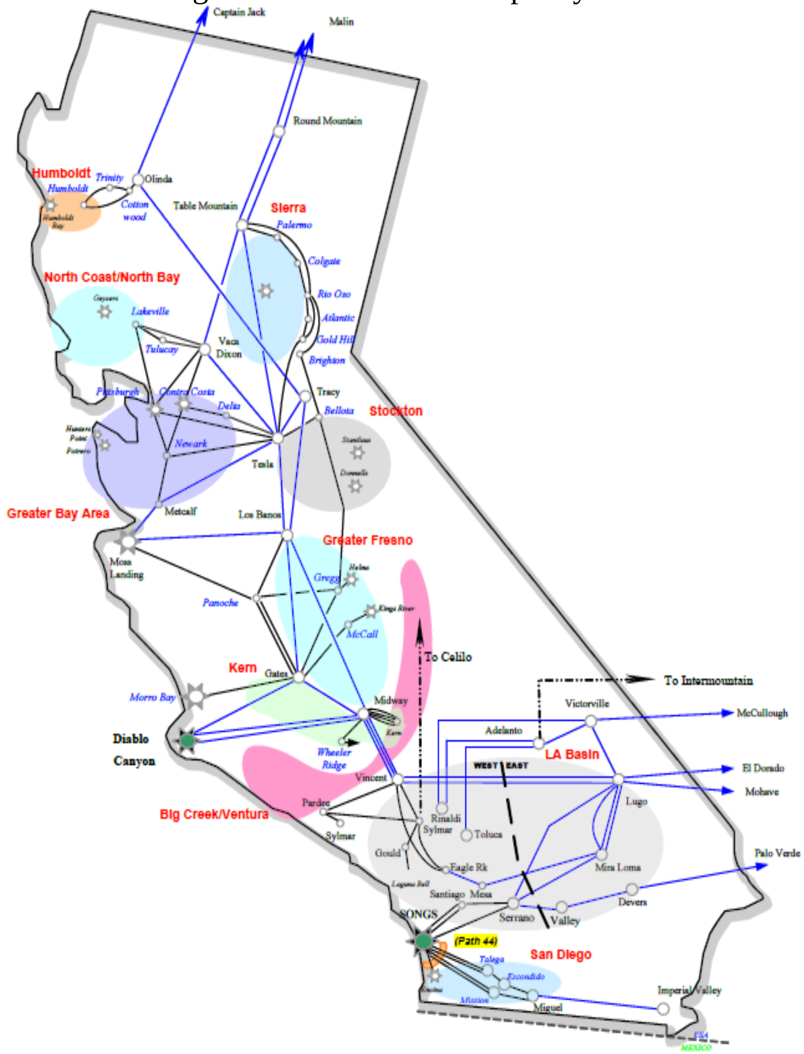
In its annual and monthly RA plans, VPU must demonstrate ownership, control or contractual rights to system RA resources with sufficient CAISO verified net qualifying capacity to meet VPU monthly coincident peak demand, plus a 15 percent planning reserve margin. The VPU seasonal load profile is unique because VPU has a very high load factor of above 70 percent in both summer and winter months.

A resource needs analysis was completed to determine the capacity needed in each year of the planning horizon to maintain the target reliability level. From 2018 to 2028, VPU meets RA requirements primarily through its existing and contracted power resources and its transmission capacity that is capable of importing 100% of its actual peak load.

Local Resource Adequacy – Los Angeles Basin

Local capacity 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. Vernon is located in the Los Angeles (LA Basin) local capacity area and has approximately a 75 MW local RA obligation. CAISO identifies ten transmission constrained local pockets as shown in Figure 4.

Figure 4: CAISO Local Capacity Areas

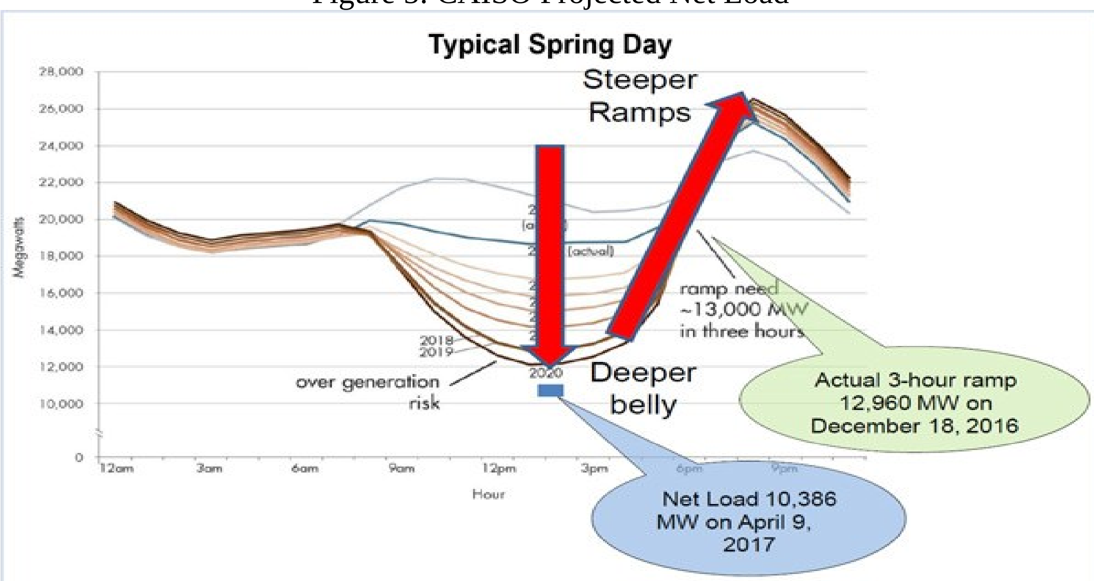


MGS and H. Gonzales are important generating resources because they are native generation, meaning that they are located in the LA Basin local reliability zone and they contribute to the VPU local RA requirements. Without native generation, the VPU system reliability would most likely be compromised under a double contingency (N-2) situation where two 66 KV transmission lines are out of service due to an unplanned outage, maintenance, or other contingency.

Flexible Resource Adequacy

The CAISO has identified a need for sufficient capacity that is operationally flexible enough to respond to dispatch instructions necessary to address the variability of changing load profiles and of intermittent energy resources such as wind and solar. Each year, the CAISO conducts a flexible capacity system-wide assessment to specifically identify the largest forecasted three-hour net load ramps plus 3.5% of expected peak load in order to determine the required procurement target for each LSE. In order to manage the effects of variable energy resources, the CAISO must have a resource mix to call upon that can react and adjust quickly to meet net demand while mitigating the risk of over-generation. To do so, the CAISO must ramp generation resources down in the morning/noon hours when solar generation begins production and then conversely ramp resources back up in the evening when solar generation drops off as the sun sets, as illustrated in Figure 5 below.

Figure 5: CAISO Projected Net Load



Source: CAISO

There are three categories of flexible RA 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 RA resources are illustrated in

Table 3.

Table 3: Flexible RA Categories

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

Source: CAISO

Table 4 shows VPU's monthly flexible capacity requirements for 2018. To comply with the CAISO's procurement target for flexible capacity, VPU utilizes MGS, which has 78 MW of eligible flexible capacity. This resource is not only local to VPU's load, but has the ability to meet and/or exceed VPU's flexible capacity needs.

Table 4: 2018 VPU Flexible Capacity Requirements

Month	Base %	CAT 1 – Base (MW)	CAT 2 – Peak (MW)	CAT 3 – Super peak (MW)	Total Needs (MW)
Jan	39%	17.28	25.2	2.24	44.72
Feb	39%	17.8	25.96	2.3	46.07
Mar	39%	13.93	20.32	1.8	36.05
Apr	39%	14.38	20.98	1.86	37.22
May	55%	22.03	16.15	2.01	40.19
Jun	55%	16.17	11.85	1.47	29.49
Jul	55%	21.4	15.69	1.95	39.04
Aug	55%	18.24	13.38	1.66	33.28
Sep	55%	20.86	15.3	1.9	38.06
Oct	39%	14.26	20.8	1.84	36.9
Nov	39%	15.02	21.91	1.94	38.87
Dec	39%	15.9	23.2	2.06	41.16

Source: CAISO

As more solar resources enter the CAISO market the flexible capacity requirements[9] will need to increase to support ramping requirements. Using the 2019 Flexible Resource Adequacy Assessment as a guide, VPU assumed that the addition of each 100 MW of solar would correspond to a 60 MW increase in flexible capacity and the addition of 100 MW of wind would only require 3 MWs of additional flexible capacity. The flexibility requirements and associated costs were factored into the analysis of the optimal resource portfolio. Table 5 below lists VPU 2018 RA requirements and the respective contribution of each committed resource toward meeting all components of the RA program.

Table 5: VPU 2018 Resource Adequacy

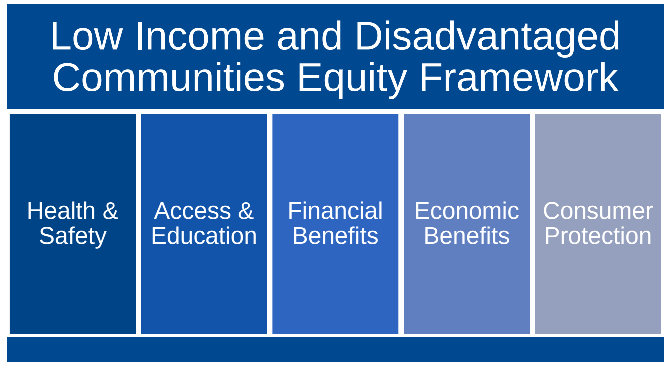
Resource Adequacy 2018	System	Local	Flexible
Boulder Canyon (Hoover)	17		
H Gonzales 1 & 2	10	10	10
Malburg Combined Cycle	134	134	78
Palo Verde	11		
Puente Hills Landfill	9		
Antelope DSR Solar PV	10		
Astoria Solar PV	8		
2018 Resource Adequacy	**199**	**144**	**88**
2018 RA Requirement	**177**	**75**	**45**
Long/(Short)	**22**	**69**	**43**

6 Impact on Customer Rates

Under current laws, publicly-owned electric utilities, such as VPU, can set guidelines and limits on what customers pay for electricity. If procurement of renewables or sustainability targets prove to be costly and have excessive adverse impacts on electric rates, the governing body of the City of Vernon has some discretion to make a determination that the new sustainability goals should not be complied with “at all costs”. A determination to not comply with state-mandated sustainability goals would require that a large majority of VPU’s customers voice their objection to the sustainability mandates on the basis of adverse rate impact. The main purpose of the VPU IRP is to develop a plan that complies with state RPS and GHG mandates, while ensuring that impacts to future rates are as low as possible.

[9] http://www.caiso.com/Documents/Presentation2019FinalFlexibilityCapacityNeedsAssessment-May312018.pdf

7 Benefits for Disadvantaged Communities



The CalEnviroScreen Tool identifies the City of Vernon as an area with high pollution and low population. Vernon is not classified as a disadvantaged community but is surrounded by disadvantaged communities. The disadvantaged community equity framework is a set of guiding principles that utilities can use when designing and implementing energy-related community programs. The guiding principles ensure that programs are not cost- prohibitive for low income and disadvantaged community members. VPU's IRP will provide benefits to all business and residents across all socio-economic demographics both within Vernon and in neighboring low income communities. The implementation of IRP related action plans need to take into account socio-economic equality and ensure clean, sustainable energy is available and accessible to all community members.

DEMAND FORECAST

The energy and peak demand forecasts are important in the development of the IRP because retail energy sales growth drives future system resource decisions and costs. When planning to meet the electricity needs of VPU's customers, a forecast of peak demand is used to determine the timing and type of new capacity resources needed to meet customer demand and ensure system reliability. In other words, VPU must not only meet the energy needs of its customers, but also have enough capacity to meet the peak demand including planning reserves. The energy forecast identifies the amount of energy needed to serve customers every hour of the day and is used to estimate system costs and future fuel supply requirements. Both demand and energy can be reduced by demand-side management measures, including energy efficiency.

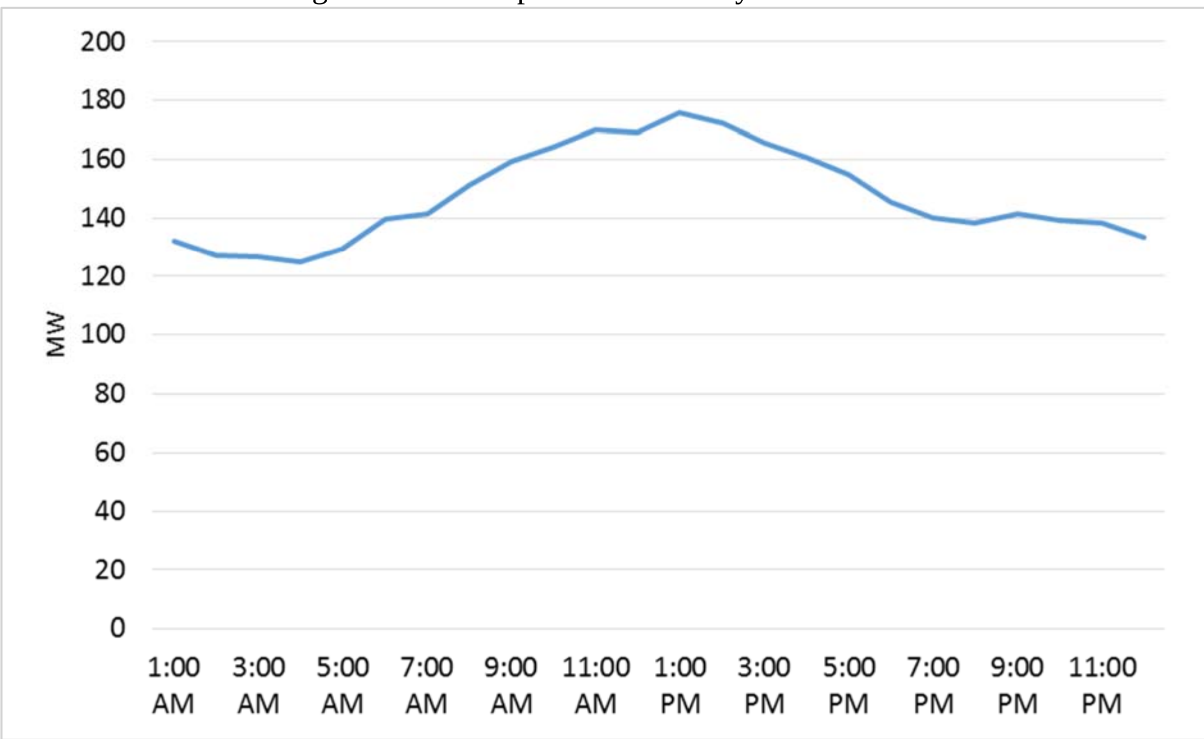
Since the year 2000, VPU's peak demand and energy load has remained relatively flat with fluctuations tied to changes in the economy, customer migration, customer additions, and distributed energy resources such as energy efficiency measures and customer-sited solar PV. Table 6 shows VPU actual peak demand and energy sales since 2000.

Table 6: Historical VPU Electric Demand

Year	Peak Demand (MW)	Energy (GWh)	Load Factor
2000	196	1,206	70%
2001	199	1,159	66%
2002	220	1,181	61%
2003	194	1,202	71%
2004	196	1,215	70%
2005	216	1,186	63%
2006	197	1,219	71%
2007	206	1,289	71%
2008	204	1,258	70%
2009	197	1,179	68%
2010	195	1,180	69%
2011	193	1,194	71%
2012	193	1,189	70%
2013	194	1,189	70%
2014	191	1,184	71%
2015	197	1,164	68%
2016	194	1,154	67%
2017	184	1,129	70%

The VPU daily and seasonal load profile is relatively flat, primarily due to a predominantly commercial and industrial customer base. This customer mix contributes to VPU's relatively high load factor of approximately 70 percent. The average VPU daily load profile does not have a spike in electricity demand between the super peak hours of 5 pm and 9 pm and typically peaks earlier in the day, between 12 pm and 2 pm, suitably correlating with ample solar generation. This load pattern makes the "duck curve" less pronounced for the VPU system. The daily load profile shown in Figure 6 below is similar to the generation profile of solar.

Figure 6: VPU Representative Daily Load Profile



8 Demand Forecast Methodology and Assumptions

An econometric forecasting methodology was used to forecast peak demand and energy demand forecast. Econometric forecasting models show relationships between energy and demand sales and economic variables as well as other variables such as weather to forecast future electricity usage. The process first estimates the historical relationship between energy and demand sales and relevant variables, which may include a number of variables such as weather, economic conditions, demographic trends, seasonal patterns, or retail electricity prices. The resulting estimates of the relationship between each variable and the associated outcome (e.g., demand or energy usage) are then applied to the forecasts of the variables to develop demand and energy sales forecasts. The statistical models are reviewed to ensure that the estimated relationships are reasonable.

VPU demand and energy forecasts are system-level forecasts inclusive of residential, commercial and industrial sectors. VPU opted to use system level peak demand and energy forecasts rather than customer class level forecasts because the customer base in Vernon is primarily commercial and industrial customers.

The adjusted peak demand from each month for the time period between 2000 to 2017 was used to model the monthly peak demand forecast. The adjusted monthly energy usage from 2000 to 2017 was used to model the energy forecast. Both models were estimated using Ordinary Least Squares ("OLS") linear regression model. The resulting estimates were used in combination with normal weather, forecasted economic data and two dummy variables[10] to forecast peak demands and energy consumption for 2018 through 2038. Multiple combinations of the variables described above were tested in the development of the system-level energy and demand forecasts. The models were refined to ensure that the estimates were logically reasonable (e.g., energy usage increased with Real Industrial Production) and statistically significant (or approaching statistical significance). The variables included in the final peak demand and energy regression model were heating degree days, cooling degree days, Real Industrial Production and Manufacturing Employment and lag dependent variables.

The model for the peak demand forecast is as follows:

$$Peak_i = \beta_0 + \beta_1 HDD_i + \beta_2 CDD_i + \beta_3 RIP_i + \beta_4 EMPLOY_i + \beta_5 Peak_{i-1} + \mathcal{E}_i$$

Where:

$Peak_i$	= Peak demand forecast at the month of i;
CDD_i	= cooling degree days at the month of i, 60-degree threshold;
HDD_i	= heating degree days at the month of i, 60-degree threshold;
RIP_i	= real industrial production at the month of i;
$EMPLOY_i$	= manufacturing employment at the month of i;
$Peak_{i-1}$	= Peak demand forecast at one month before i (lag variable); and
i	= time interval, monthly for this study.

The model for the energy forecast is as follows:

$$Energy_i = \beta_0 + \beta_1 HDD_i + \beta_2 CDD_i + \beta_3 RIP_i + \beta_4 EMPLOY_i + \beta_5 Energy_{i-1} + \mathcal{E}_i$$

Where:

$Energy_i$	= Energy forecast at the month of i;
CDD_i	= cooling degree days at the month of i, 60-degree threshold;
HDD_i	= heating degree days at the month of i, 60-degree threshold;
RIP_i	= real industrial production at the month of i;
$EMPLOY_i$	= manufacturing employment at the month of i;
$Energy_{i-1}$	= Energy forecast at one month before i (lag variable); and
i	= time interval, monthly for this study.

[10] Seasonal and Lag dummy variables were also included in the final regression model. The Seasonal Dummy variable was added to account for seasonality of Vernon's actual load data and each month's historical data was designated as either winter or summer.

Results from the econometric models were first used to develop the base peak demand and energy forecasts. These forecasts were then adjusted taking into consideration customer load additions, expected Electric Vehicle (EV) energy demand, estimated customer-side solar PV installations, and the effects of demand side management and energy efficiency.

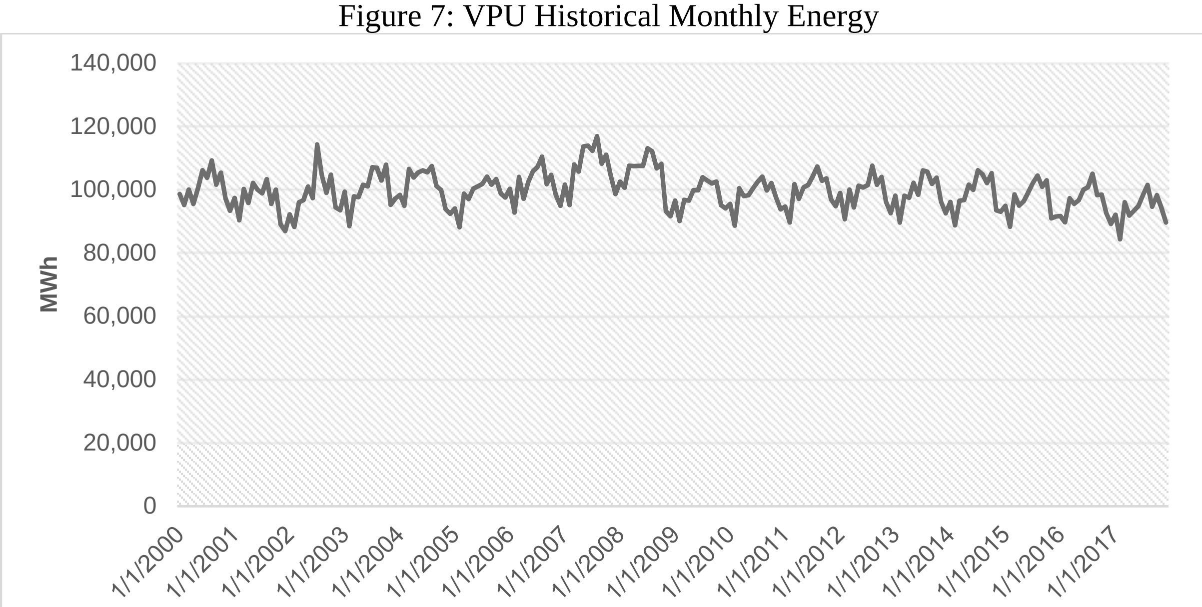
Key Assumptions and Drivers

The following are the key assumptions and drivers supporting VPU's long-term load forecast and methodology:

Historical Load Data

VPU used historical system-level hourly load data that has been maintained since 2000 for the regression analysis. The data set was reviewed to ensure accuracy and any data anomalies were corrected. Historical load data shows that, on average, VPU's electricity usage from 2000 through 2012 increased slightly but the effects of VPU's Energy Efficiency Programs, the installation of solar PV systems in the VPU service territory and the loss of a number of large-demand customers have resulted in decreasing electricity usage since 2013. VPU does not expect the load to decline over the IRP planning period. VPU's energy efficiency programs are not expected to achieve as much energy and peak demand savings as were realized from 2011 through 2016. VPU considers the large customer load losses that occurred between 2008 and 2013 to be isolated, unusual events rather than an on-going trend. Therefore, since VPU's historical load data between 2013 and 2017 shows an overall negative growth rate, VPU opted to adjust the historical data used in the regression analysis to exclude the effects of certain large customer losses and past energy efficiency programs. Figure 7 shows VPU's actual monthly energy usage from January 1, 2000 through December 31, 2017.

Figure 7: VPU Historical Monthly Energy



Weather Data

Historical weather data, heating degree days ("HDD") and cooling degree days ("CDD"), for the Los Angeles airport weather station was extracted from ABB's Velocity Suite database. The weather variables in the energy and demand forecasts are set to reflect "normal" conditions, which is interpreted as the average weather conditions over 20 years.

Economic Data

Economic historical and forecast data for Los Angeles County were obtained from the California County-Level Economic Forecast dataset that is published by the Office of State Planning of the California Department of Transportation

Economics Branch. This dataset included historic data from 2000 to 2017 and forecasted data for the years 2017 through 2050. Though this dataset includes several economic variables, VPU determined that the relevant variables to test in the regression analysis for the load forecasts were Manufacturing Employment, Real Industrial Production and Total Taxable Sales. In addition, historical and forecasted electric prices were obtained from ABB's Velocity Suite database.

Large Customer Growth Assumptions

VPU periodically reviews the growth plans of the largest existing customers and potential new customers in its service territory. These expected load increases can be uncertain and depend to a great extent on economic conditions. Table 7 shows anticipated large customer load additions for the period 2018 through 2020.

Table 7: Large Customer Load Additions 2018 – 2020

Customer	2018		2019		2020	
	MW	MWh	MW	MWh	MW	MWh
Customer A		3	3	18,396	3	18,396
Customer B	3	4,637	10	61,320		
Customer C			2	12,264	2	12,264
Customer D					1	6,132
ANNUAL TOTAL	**3**	**18,396**	**15**	**91,980**	**6**	**36,792**

This information was compiled based on information gathered by VPU staff and adjusted to reflect the level of certainty expressed by the customer that the growth will actually occur. These annual changes in large customer loads are reflected in the peak demand and energy load forecasts.

Distributed Energy Resources Forecast

Distributed Solar

On January 1, 2008, in accordance with California Senate Bill 1 (SB 1), VPU adopted, implemented and financed a solar initiative program for the purpose of investing in and encouraging the increased installation of, residential and commercial solar energy systems. Customers that elect to participate in VPU's Program are served pursuant to the terms and conditions of the City's Net Metering Service Schedule No. NM.

VPU currently has about 3.5 MW of existing distributed solar on the system and the target is to increase the total distributed solar on the VPU electric system to 15 MW. VPU expects modest growth in the Distributed Generation (DG) Solar program over the IRP study period. The customer survey results indicated that customers are interested in VPU expanding its current program to include community solar, customer-sited solar installation and customer-sited solar system maintenance services.

Table 8 shows the expected new cumulative Distributed Generation (DG) solar additions from 2018 through 2030. This solar DG forecast was applied to VPU peak demand and energy forecasts.

Table 8: VPU New Distributed Solar Forecast

Year	DG Solar Installed Capacity (MW)	DG Solar Energy (MWh)
2018	0.3	1,760
2019	0.7	3,949
2020	1.1	6,138
2021	1.4	8,327
2022	1.8	10,516
2023	2.1	12,705
2024	2.4	14,893
2025	2.7	17,082
2026	2.9	19,271
2027	3.1	21,460
2028	3.3	23,649
2029	3.5	25,838
2030	3.4	25,580

Energy Efficiency and Demand Response

VPU has provided an Energy Efficiency Program for its customers since 2011 that includes incentives to encourage the exploration and implementation of energy efficiency technologies. The current VPU program provides cash incentives to customers that implement the latest lighting technology and install energy efficient equipment. In accordance with SB 350, VPU intends to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of energy efficiency savings from retail customers by January 1, 2030. VPU does not anticipate major changes in the energy efficiency program in order to achieve this doubling of energy efficiency savings. VPU intends to focus on encouraging businesses in Vernon to carefully evaluate their operations identify any potential energy savings that could be realized through replacement of inefficient compressors or use of heat conversion and refrigeration controls technology to save energy rather than simply addressing lighting retrofits. This increase in energy efficiency savings is reflected in the VPU peak demand and energy forecasts. VPU will also seek energy efficiency savings through water and gas systems upgrades, distribution system equipment and conductor upgrades, and building envelope energy savings.

Customer Incentive Programs

Lighting technology developments have produced more efficient and economic LED lighting that uses less energy and lasts longer. The VPU lighting program provides rebates on a $/kWh basis for reduced lighting energy usage. The program includes a maximum incentive for lighting improvements installed by qualified customers.

The non-lighting incentive portion of the VPU program can include, but is not limited to: variable speed drives, air compressors, motors, refrigeration, chiller replacement, air conditioner replacement, and building envelope. The Incentive Program also includes energy management systems and other load and energy controlling devices.

Table 9 below shows the savings achieved by VPU's energy efficiency programs in fiscal year (FY) FY2014 through FY2017.

Table 9: FY2014 through FY2017 Energy Efficiency Program Savings

Program	FY14-15 Savings		FY15-16 Savings		FY16-17 Savings	
Savings	**MW**	**MWh**	**MW**	**MWh**	**MW**	**MWh**
Lighting Retrofit Incentives	0.422	2,764	0.26	1,432	0.53	2,432
Non-Lighting Incentives	0.023	0.19	0.21	1,175	0	177
Total	**0.45**	**2,765**	**0.47**	**2,607**	**0.53**	**2,609**

Customer-Directed Programs

VPU provides funds for customized projects demonstrating energy and cost savings and/or commercial market potential in the area of energy efficiency. Customers must fund at least 25 percent of total project cost. Projects are only eligible if they do not qualify for any of the other programs.

Energy Audit Program

The Energy Audit provides on-site audits for commercial and industrial customers and includes a comprehensive audit that analyzes a customer's energy usage and costs, identifies potential energy conservation measures, and recommends a course of actions.

Time of Use Rate Programs

All customers with electrical demand that exceeds 100 kW are eligible for time-of-use rates. By shifting energy usage to times of the day when energy usage in the community is lower, customers are eligible for lower rates, saving the customer money and lowering VPU peak demand that can potentially defer the addition of generation facilities. Most large Vernon customers take advantage of the TOU rate schedule, however, some of the smaller customers do not.

Additional Achievable Energy Efficiency (AAEE)

SB 350 establishes annual targets for statewide energy efficiency savings and demand reduction that will produce a cumulative doubling of statewide energy efficiency savings for final end use retail customers by Jan 1, 2030. In FY 2017 VPU realized about 0.53 MW and 2.6 GWh of energy efficiency savings primarily from the lighting rebate program. Going forward VPU assumes that an incremental 0.5 MW or 3 GWh of energy efficiency savings can be achieved.

Transportation Electrification

Governor Edmund G. Brown Jr.'s Executive Order B-16-2012 implemented statewide efforts to electrify the transportation sector, calling on the CEC and other state agencies to achieve 1.5 million zero emission vehicles (ZEVs) by 2025. Nearly 14,000 public chargers, including 1,500 direct current fast chargers (DCFC) are installed today serving almost half a million plug-in electric vehicles (PEV). On January 28, 2018 Governor Brown issued Executive Order B-48-18 that aggressively increased the goal to 5 million ZEVs by 2030. Plug-in Hybrid Electric Vehicles (PHEVs) discharge emissions, but are partially electric. Plug-in Electric Vehicle (PEV) defines any vehicle that partially uses electricity, such as ZEVs and PHEVs. Table 10 shows the California and VPU forecast for electric vehicle additions from 2018 through 2030 using CEC Electric Vehicle Calculator Tool for the Light-Duty vehicle sector.

Table 10: Forecasted Number of Plug-In Electric Vehicles

Year	California PEVs	VPU PEVs
2018	461,293	277
2019	609,091	365
2020	778,724	467
2021	967,872	581
2022	1,173,822	704
2023	1,394,050	836
2024	1,625,912	976
2025	1,866,987	1,120
2026	2,114,946	1,269
2027	2,367,753	1,421
2028	2,623,702	1,574
2029	2,881,494	1,729
2030	3,140,242	1,884

Source: CEC Light-Duty Plug-In Electric Vehicle (PEV) Energy and Emission Calculator

VPU used the CEC Light-Duty Plug-In EV Energy and Emission calculator to estimate PEV penetrations and corresponding increases in GHG emissions directly caused by additional EV load. The electric vehicle additions forecast shown above translates into a small amount of additional load.

Table 11 below shows the high level estimated impact that these additional electric vehicles in the City of Vernon may have on VPU's load and GHG emissions.

Table 11: VPU Light-Duty Electric Vehicle Load Impacts

Year	EV Coincident Peak (MW)	EV Energy Load (GWh)	GHG Emissions from PEV (metric tons)
2018	0.3	1.4	450
2019	0.4	1.9	609
2020	0.5	2.4	783
2021	0.6	3.0	797
2022	0.7	3.6	935
2023	0.8	4.2	1,055
2024	0.9	4.9	1,225
2025	1.1	5.5	1,292
2026	1.2	6.2	1,397
2027	1.3	6.9	1,557
2028	1.4	7.5	1,718
2029	1.6	8.2	1,230
2030	1.7	8.9	1,349

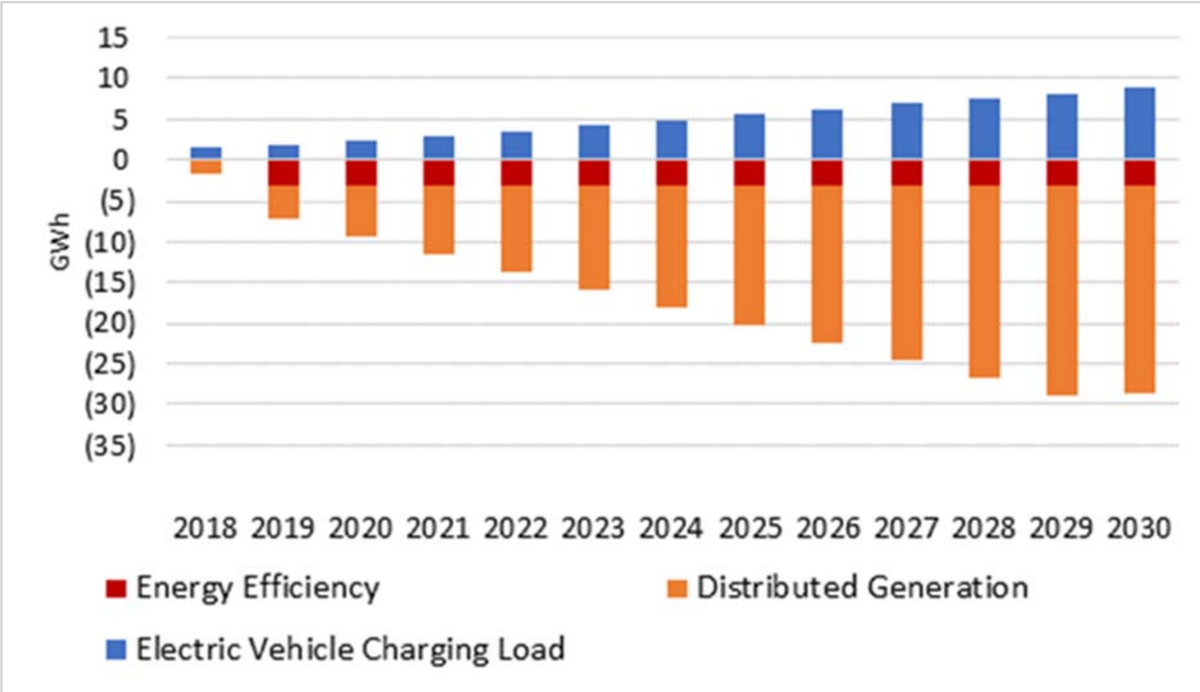
Source: CEC Electric Vehicle Calculator Tool

The CEC assumes that if electric vehicle loads are served by customer-sited generation the net impact of GHG should be zero. GHG impacts from electric vehicle adoption in the VPU service territory could be significant because of the limited distributed solar available to service EV load. High electric vehicle adoption levels will be difficult to achieve due to city demographics and a customer base that is mostly commercial and industrial. Costs of heavy-duty fleet electrification must come down substantially before it becomes a viable option for VPU business owners.

VPU currently has negligible amounts of existing EV infrastructure and does not have enough information to provide supplemental information on future transportation electrification investments and programs. Action plans from this IRP will help determine the next steps VPU may take to increase transportation electrification in both the light-duty and heavy-duty vehicle sectors.

VPU will coordinate with the South Coast Air Quality Management (SCAQMD) as needed on initiatives to reduce air pollution in the greater Los Angeles region. Figure 8 shows the forecasted impact various DERs are expected to have on VPU's energy demand.

Figure 8: Forecasted Energy Demand from Distributed Energy Resources



9 Demand Forecast Results

The demand forecasts indicate that overall load growth in the VPU service territory will be slow, specifically, less than one percent year-over-year through the Planning Period. In part, the effects of the utility's energy efficiency programs and expected solar DG installations will reduce future retail system peak demand (MW) and retail energy sales (MWh). VPU anticipates that a number of customers will add load between 2018 and 2020 based on discussions with existing large-demand customers and these load additions were incorporated into the load forecast.

Peak and Energy Demand Forecast

The final system-level monthly peak demand and energy forecasts were then computed by:

1) Applying the monthly peak demand and energy growth rates determined from the regression analysis to VPU's 2017 adjusted actual data;
2) Subtracting the adjustments from the forecast made for historical energy efficiency programs and large customer load losses that were added to the historical data prior to running the regression analysis;
3) Adding future load from large customers that have indicated that they anticipate expanding their current load; and

4) Accounting for the effects of future energy efficiency programs, additional solar PV and electric car charging to the load forecast produced from the econometric methods.

In addition, high and low load forecasts were developed to allow the City to assess risk associated with uncertainty related to load growth.

When future energy efficiency programs, additional distributed solar and electric vehicle charging are added to the load forecast, the average peak demand growth rate is 0.88% and the energy growth rate is .96% over the 2018 to 2037 planning period.

Table 12 includes VPU's annual peak demand and energy forecast adjusted for future energy efficiency, distributed generation and electric vehicle load for 2018 through 2037.

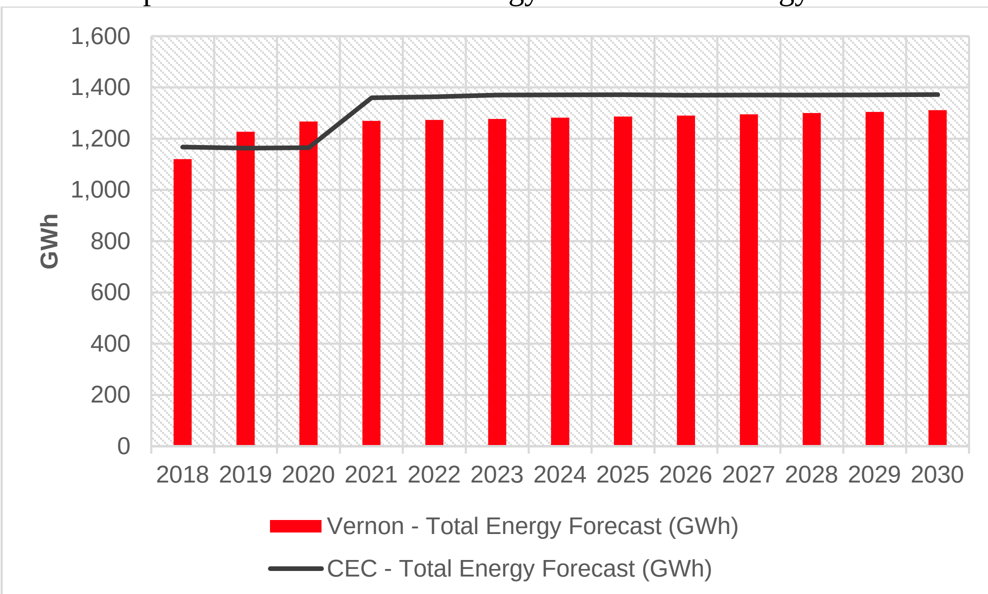
Table 12: Adjusted Peak and Energy Load Forecast

Year	Peak Demand (MW)	Peak Demand (MW) including DERs	Energy Demand (GWh)	Energy Demand (GWh) including DERs
2018	181	181	1,123	1,122
2019	200	199	1,231	1,226
2020	206	205	1,273	1,265
2021	207	205	1,276	1,268
2022	207	205	1,281	1,271
2023	208	206	1,287	1,275
2024	208	206	1,291	1,278
2025	209	207	1,296	1,281
2026	209	207	1,300	1,284
2027	210	208	1,305	1,288
2028	211	208	1,311	1,292
2029	211	209	1,318	1,297
2030	212	210	1,324	1,304
2031	213	211	1,331	1,311
2032	214	212	1,338	1,319
2033	215	213	1,345	1,327
2034	216	214	1,352	1,334
2035	217	216	1,359	1,343
2036	218	217	1,367	1,351
2037	219	218	1,375	1,360
CAGR 2018-2037	**0.89%**	**0.88%**	**1.01%**	**0.96%**

VPU Comparison to CEC Demand Forecast

VPU compared its econometric load forecast to the forecasts completed by the CEC for its 2017 Integrated Energy Policy Report released in February 2018 (Docket # 17-IEPR-03). VPU compared the expected demand forecast to the CEC IEPR Energy Demand Forecast 2018 – 2030, Mid Demand Baseline Case, Mid Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Photovoltaic (AAPV). The VPU energy demand forecast is similar to the IEPR forecast over the long-term with comparable growth rates over the twelve year forecast period and less than five percent difference in the 2030 energy demand. For planning purposes VPU considers the difference between the two forecasts acceptable. Figure 9 shows the VPU forecast in comparison with CEC Energy Demand Forecast.

Figure 9: Comparison with California Energy Commission Energy Demand Forecast



Demand Growth Scenarios

The base load forecast is assumed to represent the expected midpoint of possible future outcomes, meaning that actual peak demand and energy requirements in future years may deviate from the midpoint projections. VPU developed upper and lower confidence bands around the base peak demand and energy forecasts. VPU calculated a 70% prediction interval which means that future peak demand and energy consumption will occur within these bands with a 70% probability. The 70% band limit was added to the base peak demand and energy forecast to develop the high peak demand and energy forecasts and the band limit was subtracted from the base peak demand and energy forecast for the low load forecasts.

Table 13 includes the values for the Base, High and Low peak demand and energy forecasts including the effects of future energy efficiency, PV solar distributed generation additions and electric vehicle load. Energy load growth is estimated to vary from a compound average growth rate (CAGR) of 0.68% in the low demand scenario to 1.18% in the high demand scenario as shown below in Table 13.

Table 13: High and Low Peak and Energy Demand Forecast Scenarios

Year	Peak (MW)			Energy (GWh)		
	Base	Low	High	Base	Low	High
2018	181	181	181	1,122	1,122	1,122
2019	199	192	205	1,226	1,170	1,282
2020	205	199	211	1,266	1,210	1,322
2021	205	199	212	1,268	1,212	1,324
2022	205	199	212	1,271	1,215	1,327
2023	206	199	212	1,275	1,218	1,331
2024	206	200	213	1,278	1,222	1,335
2025	207	200	213	1,281	1,224	1,338
2026	207	200	214	1,284	1,226	1,341
2027	208	201	214	1,288	1,230	1,345
2028	208	201	215	1,292	1,234	1,350
2029	209	202	216	1,297	1,238	1,356
2030	210	203	217	1,304	1,245	1,364
2031	211	204	218	1,311	1,251	1,372
2032	212	205	219	1,319	1,258	1,380
2033	213	206	220	1,327	1,265	1,389
2034	214	207	222	1,334	1,271	1,398
2035	216	208	223	1,343	1,278	1,406
2036	217	209	224	1,351	1,286	1,416
2037	218	210	226	1,360	1,293	1,426
CAGR 2018-2037	**0.94%**	**0.76%**	**1.11%**	**0.96%**	**0.71%**	**1.21%**

The variance in the low and high energy demand growth projections ranges from negative 0.26% to 0.24%. The variance in the energy demand under low and high growth would have some impact on the resource procurement requirements, in particular the RPS. RPS is calculated based upon a percentage of renewable generation divided by retail sales. Retail sales would change slightly under the different growth scenarios. However, given the small difference in forecasted energy and peak demand between the base forecast and the high and low growth scenarios the optimal resource mix would not likely be impacted. VPU did not construct resources portfolios using the low and high demand forecast scenarios given the negligible impact on the optimal resource portfolio selection. VPU also did not construct scenario evaluating higher or lower penetration levels of DERs because of the uncertainty of how much DER is economically achievable given the unique demographics of the VPU customer base.

RESOURCE PORTFOLIO EVALUATION

10 Approach and Methodology

VPU's analysis included evaluating various generating resource portfolios using an hourly chronological production cost model to determine the least cost portfolio. VPU used a production cost modeling software from ABB (Portfolio Optimization). Production cost modeling simulates the hourly operation of the resources available to a utility and is used to forecast system cost and risk exposure. A production cost model includes an hourly dispatch model, with a load forecast and fixed resources to serve that load. The model simulates a load every hour, then economically serves that load with the available resources, including interaction with the market, and captures the associated cost. The representation of the VPU power system is a simple two zone topology in which VPU can buy and sell power on an economic basis in the CAISO South of Path 15 (SP15) market zone, which is a reflection of how VPU optimizes energy operations today.

Inputs for electricity prices, natural gas prices, technology costs, and generation characteristics were fed into Portfolio Optimization. The software modeled the unit operating constraints and market conditions to provide a generation schedule for energy and ancillary services, fuel nominations, support the evaluation and pricing of potential short-term transactions, and facilitate the analysis and simulation of deterministic scenarios.

The resources defined in the model consist of existing VPU generating resources, and generic types of future generating resources with locations or projects that are not yet identified. The resource mix of renewable generating resources and thermal generating resources must satisfy: (1) RA requirements for reliability, (2) specific increasing targets of renewable resources as a percentage of retail energy sales, and (3) other goals and objectives such as the 2030 GHG reduction target.

Candidate portfolio scenarios were developed based on current technology and market intelligence regarding resource availability. These resource portfolio options were then screened to filter out the non-viable scenarios given VPU's planning goals, and the remaining scenarios were analyzed using extensive quantitative production cost modeling analysis. VPU used the net present value (NPV) of system costs to summarize the cost of all resource portfolios. The total cost for each resource portfolio includes fixed and variable costs, as well as the net market revenue or expense associated with net sales or purchases in the portfolio. The model outputs were scored and stress tests performed before a final portfolio was recommended. VPU ranked the resource portfolios and the preferred resource portfolio represents the optimal resource mix that will meet RPS compliance requirements, GHG emission reduction target, maintain high reliability, and will ensure VPU maintains affordable electric service for its customers.

Modeling Inputs and Assumptions

Planning Horizon

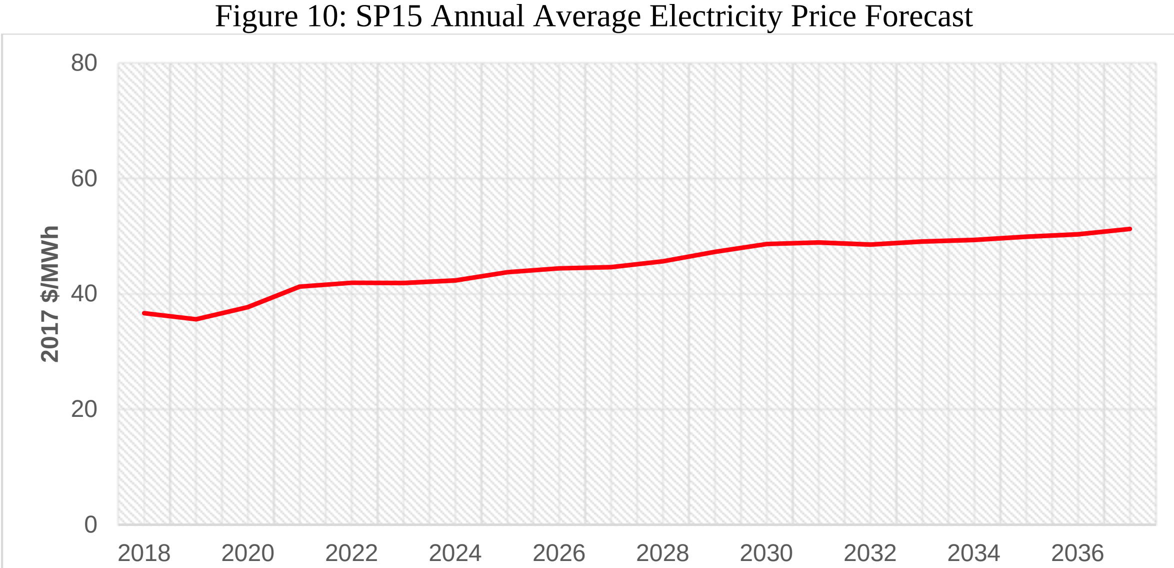
The IRP Submission Guidelines require that each POU select a planning period that begins no later than January 1 of the year that the POU governing board adopts the IRP and ends no earlier than December 31, 2030. However, POUs are encouraged to extend their planning horizon to include a post-2030 period. This timeframe ensures that the POU achieves specific goals and targets by 2030 including meeting the GHG and the 60% RPS targets. VPU has selected the time period from 2018 through 2037 as the planning horizon for this IRP. The study period from 2030 to 2037 provides some planning guidance on VPU progress towards meeting the 2045 100% carbon-free goal.

Energy Market Assumptions

VPU used forecasts from the ABB Fall 2017 WECC 25 Year Reference Case outlook for natural gas, electricity and CO2 emissions prices. The long-term hourly electricity price forecasts for the California – Southern California Edison (CA-SCE) market area were used to model economy purchases. These long-term energy market price forecasts served as the basis for analysis of the VPU resource portfolio. The price outlook was derived based on a combination of legislative and regulatory requirements and ABB's long-term economic assumptions, to develop a fundamentals-driven framework for long-term market price forecasts.

The SoCal Citygate natural gas price forecast was used for the fuel cost assumption for the MGS unit. The Western Climate Initiative (WCI) emissions cost forecast, also included in the Fall 2017 Reference Case, was used to represent the cost of CO_2 emissions. The charts below summarize the forecasts for electricity prices, natural gas, and GHG emission allowance prices used in the IRP. All numbers are expressed in 2017 real prices unless specified otherwise

Figure 10: SP15 Annual Average Electricity Price Forecast

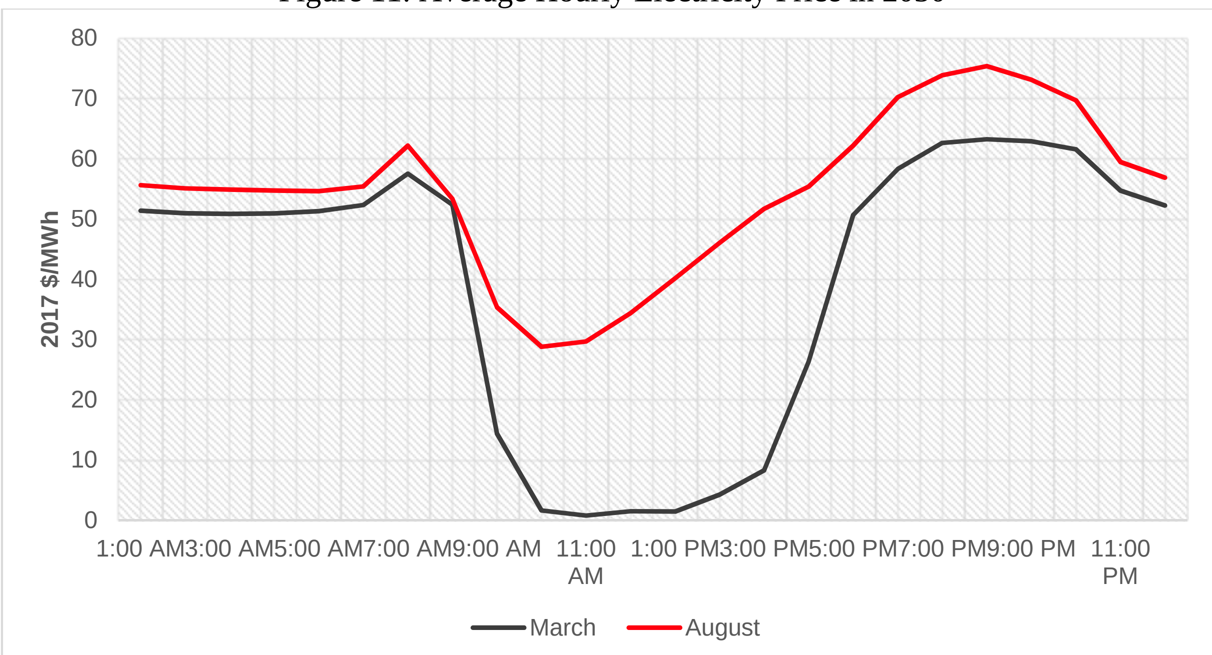


Source: ABB

Average annual electricity prices shown in Figure 10 above are expected to gradually rise due to increasing natural gas prices and GHG emission allowance prices. Natural gas resources are still expected to set the market price for electricity in over 90% of the hours. However, as more solar resources enter the market there will be times when solar will displace natural gas generation and set the hourly price of power. The market has seen zero and negative electricity prices during hours when solar generation exceeds energy demand.

Figure 11 shows the impact increasing solar penetration has on hourly electricity prices on a typical spring and summer day in California.

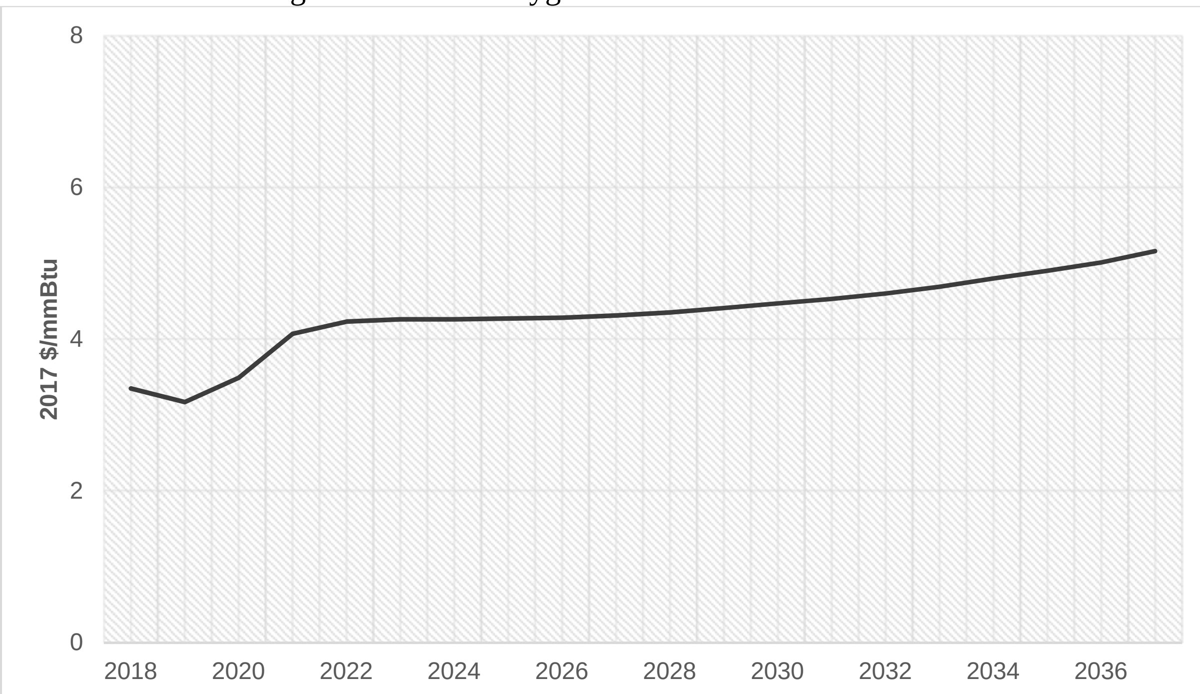
Figure 11: Average Hourly Electricity Price in 2030



Source: ABB

Figure 12 depicts the natural gas price forecast for the southern California region. ABB's outlook for natural gas reflects lower demand for natural gas in California and across the US due to low electricity demand growth combined with increasing renewable energy penetration.

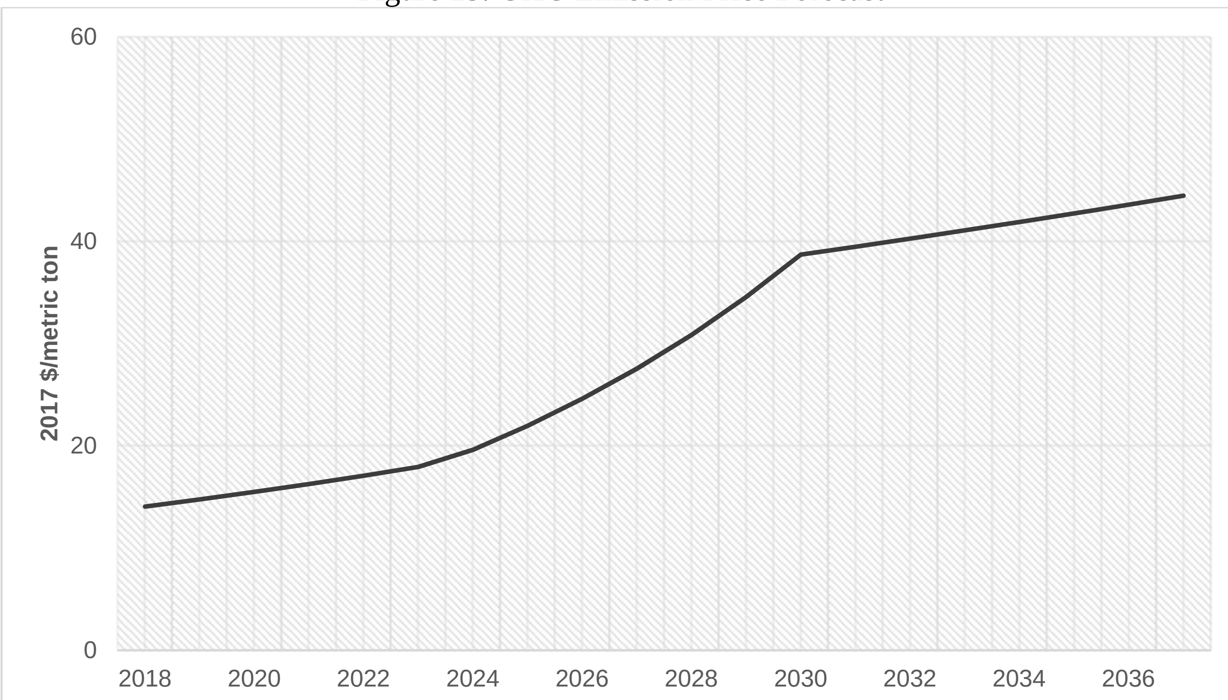
Figure 12: SoCal Citygate Natural Gas Price Forecast



Source: ABB

Figure 13 depicts the forecasted GHG emission allowance price. The GHG emission allowance price in California is normally included as uplift cost reflected in electricity prices.

Figure 13: GHG Emission Price Forecast



Source: ABB

Existing Resources

The VPU generation supply is either owned or purchased under tolling or joint PPAs. VPU is a participant in several generation projects in conjunction with SCPPA through joint PPAs. This practice reduces construction, financing, and operating costs and allows VPU to achieve economies of scale and obtain favorable financing rates. VPU's generation supply consists of a mix of natural gas-fired, nuclear, hydroelectric, landfill gas and solar PV resources. Table 14 below lists the location, fuel type, contract start and expiration dates and capacity under contract for VPU's generation supply.

Table 14: Existing Resources under Contract/Ownership

Generating Unit(s)	City or Locality	Fuel Type	Contract Start Date	Contract Expiration Date	Capacity Under Contract (MW)
Malburg	Vernon, California	Natural Gas	10/15/2005	4/9/2028	134 MW
H. Gonzales	Vernon, California	Natural Gas	1988		11.5 MW
Palo Verde Nuclear 1,2,3	Wintersburg, Arizona	Nuclear	4/1/1986	12/31/2030	11.59 MW
Hoover - 17 turbines	Clark County, Nevada	Hydro	8/1/1987	12/31/2067	22 MW
Astoria II	Kern County, California	Solar	1/1/2017	12/31/2036	20 MW [2017-2021]; 30 MW [2022-2036]
Big Sky Solar 1 (Antelope)	Lancaster, California	Solar	1/1/2017	12/31/2036	25 MW
Puente Hills	City of Industry, California	Landfill Gas	1/1/2017	12/31/2030	10 MW

Starting in 2021, 65% of VPU's contracts must be accounted for in long-term contracts that last ten or more years. VPU is in compliance with long-term contracting requirement and will procure future renewable resources under long-term PPAs to stay in compliance with this requirement. For purposes of modeling past 2030, VPU assumed that all PPAs would be renewed past the expiration dates with exception to the MGS PPA.

Future Resource Options

The following sections provide details about the resource options that were included in the IRP evaluation to meet future VPU resource procurement requirements.

Conventional Resources

Given the current regulatory environment, VPU did not evaluate any new natural gas-fired resources in the analysis because it is unlikely VPU would invest in a new natural gas resource. However, it is possible for VPU to re-procure the MGS unit after the PPA expires in 2028. VPU did consider capacity resources that may be able to provide flexible capacity and RA through a RA market purchase. Existing natural gas-fired resources or a new MGS contract would be the likely source of RA capacity rather than procuring a new natural gas resource.

Renewable Resource Options

VPU is expected to have adequate resources between 2017 and 2020 to serve forecasted load and meet the procurement requirement for the third RPS compliance period. Regarding the evaluation of new renewable resource costs and characteristics, VPU adopted resource cost assumptions from the 2017 CPUC Integrated Resource Plan (CPUC IRP). Assumptions on the cost and performance of potential candidate renewable resources are based on CPUC IRP inputs. Figure 14 below shows the renewable resource zones in California where new resources are likely to be sourced from.

Figure 14: Renewable Resource Zones

Source: CPUC IRP – Sept 2017

In-State Renewable Resources

Solar resources from the SoCal Desert were used as proxy for likely future solar costs and wind resources from the Tehachapi region as proxy for future wind resource costs. In addition to utility-scale wind and solar, Vernon also evaluated geothermal from the Greater Imperial region as a potential future resource. Table 15 below lists the capital cost and LCOE of candidate in-state renewable energy resources.

Table 15: In-State Candidate Renewable Resources

Type	Resource	Capacity Factor	Capital Cost (2016 $/kW)				Implied Levelized Cost of Energy (2016 $/MWh)			
			2018	2022	2026	2030	2018	2022	2026	2030
Biomass	InState	86%	$6,231	$6,231	$6,231	$6,231	$161	$161	$161	$161
Geothermal	Greater Imperial	88%	$5,349	$5,349	$5,349	$5,349	$92	$92	$92	$92
	Northern California	80%	$5,011	$5,011	$5,011	$5,011	$89	$89	$89	$89
Solar	Central Valley North Los Banos	30%	$1,908	$1,841	$1,788	$1,699	$53	$52	$69	$67
(solar capital costs shown in $/kW-ac)	Distributed	23%	$3,269	$3,040	$2,886	$2,725	$104	$99	$126	$120
	Greater Carrizo	32%	$1,908	$1,841	$1,788	$1,699	$49	$48	$64	$62
	Greater Imperial	34%	$1,908	$1,841	$1,788	$1,699	$47	$46	$61	$58
	Mountain Pass El Dorado	34%	$1,908	$1,841	$1,788	$1,699	$46	$45	$59	$57
	Northern California	30%	$1,908	$1,841	$1,788	$1,699	$53	$52	$69	$66
	Riverside East Palm Springs	34%	$1,908	$1,841	$1,788	$1,699	$46	$45	$60	$58
	Solano	29%	$1,908	$1,841	$1,788	$1,699	$54	$53	$70	$67
	Southern California Desert	35%	$1,908	$1,841	$1,788	$1,699	$46	$45	$60	$57
	Tehachapi	35%	$1,908	$1,841	$1,788	$1,699	$45	$44	$58	$56
	Westlands	30%	$1,908	$1,841	$1,788	$1,699	$52	$51	$67	$65
Wind	Central Valley North Los Banos	31%	$2,019	$2,004	$1,989	$1,974	$57	$70	$78	$77
	Distributed	28%	$2,499	$2,480	$2,462	$2,443	$88	$100	$108	$107
	Greater Carrizo	31%	$2,063	$2,048	$2,033	$2,018	$60	$73	$80	$80
	Greater Imperial	31%	$2,032	$2,017	$2,002	$1,987	$52	$65	$73	$73
	Kramer Inyokern	32%	$2,028	$2,012	$1,997	$1,983	$61	$73	$81	$81
	Northern California	29%	$2,000	$1,985	$1,970	$1,955	$66	$78	$85	$85
	Riverside East Palm Springs	33%	$2,018	$2,003	$1,988	$1,974	$59	$71	$79	$79
	Solano	30%	$2,022	$2,007	$1,992	$1,977	$61	$73	$81	$81
	Southern California Desert	27%	$2,010	$1,995	$1,980	$1,965	$66	$79	$87	$86
	Tehachapi	33%	$2,119	$2,103	$2,087	$2,072	$55	$67	$75	$75

Source: CPUC IRP – Sept 2017

Table 16 below lists the capital cost and LCOE of candidate out-of-state renewable energy resources.

Table 16: Out-of-State (OOS) Candidate Renewable Resources

Type	Resource	Capacity Factor	Capital Cost (2016 $/kW)				Implied Levelized Cost of Energy (2016 $/MWh)			
			2018	2022	2026	2030	2018	2022	2026	2030
Geothermal	Pacific Northwest	84%	$4,952	$4,952	$4,952	$4,952	$82	$82	$82	$82
	Southern Nevada	80%	$6,259	$6,259	$6,259	$6,259	$104	$104	$104	$104
Solar *(solar capital costs shown in $/kW-ac)*	Arizona	34%	$1,750	$1,689	$1,640	$1,558	$39	$38	$53	$51
	New Mexico	33%	$1,754	$1,692	$1,644	$1,562	$39	$38	$54	$52
	Southern Nevada	32%	$1,850	$1,784	$1,733	$1,647	$47	$45	$62	$59
	Utah	30%	$1,793	$1,730	$1,680	$1,597	$46	$45	$62	$60
Wind	Arizona	29%	$1,824	$1,810	$1,797	$1,784	$58	$71	$79	$78
	Idaho	32%	$1,916	$1,901	$1,887	$1,873	$56	$68	$76	$76
	New Mexico (Existing Tx)	36%	$1,843	$1,830	$1,816	$1,803	$44	$56	$65	$64
	New Mexico	44%	$1,846	$1,832	$1,819	$1,805	$31	$44	$53	$53
	Pacific Northwest (Existing Tx)	30%	$2,188	$2,171	$2,155	$2,139	$69	$81	$89	$88
	Pacific Northwest	32%	$2,101	$2,085	$2,069	$2,054	$63	$75	$83	$82
	Southern Nevada	28%	$2,164	$2,148	$2,132	$2,116	$80	$91	$98	$98
	Utah	31%	$1,902	$1,888	$1,874	$1,860	$60	$72	$80	$80
	Wyoming	44%	$1,757	$1,744	$1,731	$1,718	$28	$41	$50	$50

Source: CPUC IRP – Sept 2017

Table 17 below lists the generic renewable technology performance assumptions and applicable investment tax (ITC) or production tax credits (PTC) used for the resource evaluation.

Table 17: Renewable Resources Parameters

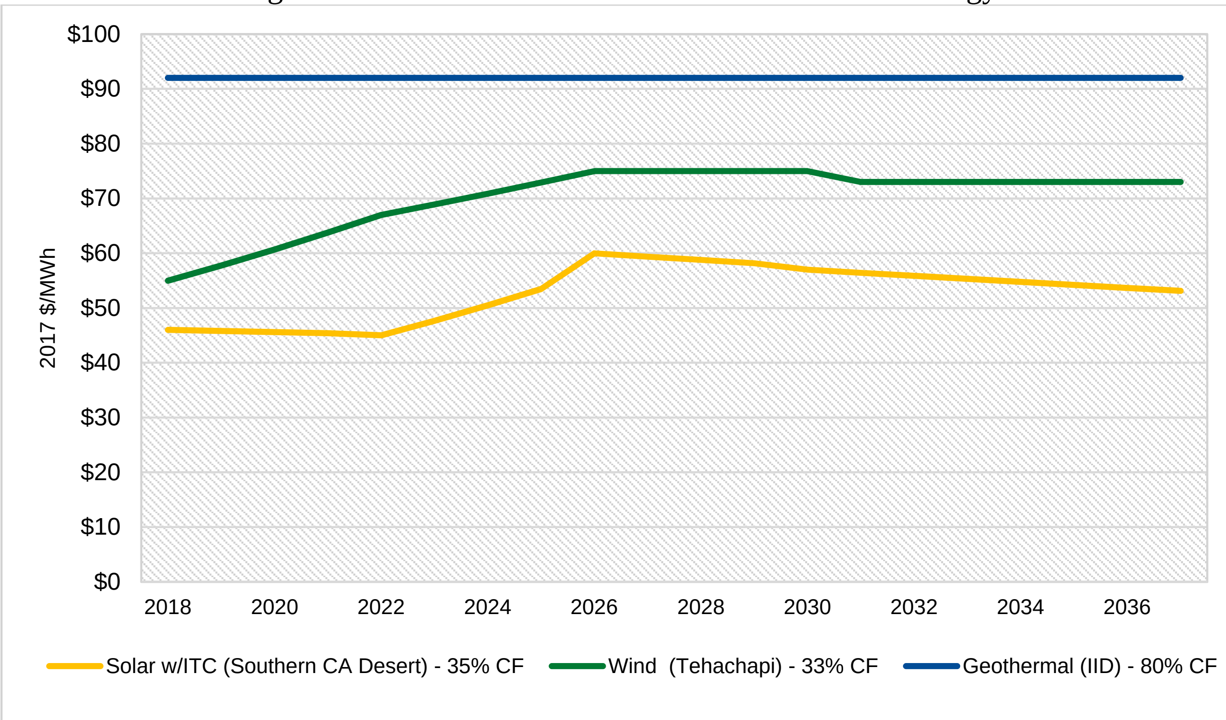
Renewable Resources	Solar	Wind	Geothermal	Biomass
Location	**SoCal Desert**	**Tehachapi**	**Greater Imperial**	**California**
Capacity Factor	35%	33%	80%	86%
Capacity Credit[11]	40%	27%	100%	100%
2018 LCOE $/MWh	$46	$55	$92	$161
2030 LCOE $/MWh	$57	$75	$92	$161

Source: CPUC IRP – Sept 2017

The cost for solar increases in the near-term corresponding to the gradual phasing down of the solar investment tax credit to 10%, but decreases over the long-term due to anticipated declines in solar panel pricing. Figure 15 shows levelized cost of energy for solar, wind, and geothermal resources.

[11] Capacity credit for wind and solar are based on the 2018 CAISO Net Qualifying Capacity Technology Factors.

Figure 15: Renewable Resources Levelized Cost of Energy



Source: CPUC IRP – Sept 2017

Energy Storage Systems

The CEC is responsible for reviewing the procurement targets and policies that were developed and adopted by POUs to ensure that targets and policies include the procurement of cost-effective and viable energy storage systems. AB 2514 required VPU to determine appropriate targets for cost-effective energy storage before October 1, 2014. In accordance with State law, the City must evaluate storage options and determine whether or not to establish a goal for energy storage every three years. Therefore, no later than October 1, 2017, VPU's governing body was required to adopt a target for the amount of appropriate energy storage the POU will procure by December 31, 2020.

In a staff report completed in 2017, VPU staff recommended to the Vernon City Council that a resolution to target procurement of energy storage systems was not cost-effective nor appropriate at the time. VPU committed to continually evaluate the cost-effectiveness of energy storage for utility operations in the future. CEC POU Integrated Resource Plan Submission and Review Guidelines require POU's to re-evaluate the role and cost-effectiveness energy storage may have in POU resource plans.

Lithium ion battery energy storage systems (BESS) were included as a possible future resource to provide flexible capacity, reduce solar over-generation, and replace the capacity provided by MGS when the PPA expires in 2028. The assumed fixed Operations and Maintenance (O&M) costs expressed as a percentage of capital costs are include in Table 18. The capital costs for BESS are typically broken down into two main components:

- Power Component (MW) – Represents the cost of the non-storage parts of the battery including interconnection, EPC, installation, and balance of plant (BOP). A 20-year book life was assumed.
- Energy Component (MWh) – Represents the cost of the lithium-ion energy storage component of the plant. Assumptions for this component include a 10-year book life before full degradation, battery cells are replaced after 10 years and the cost of replacement is included in the energy component.

The BESS capital costs for a Mid, Low, and High cost option, including interconnection and installation costs, are shown in Table 18.

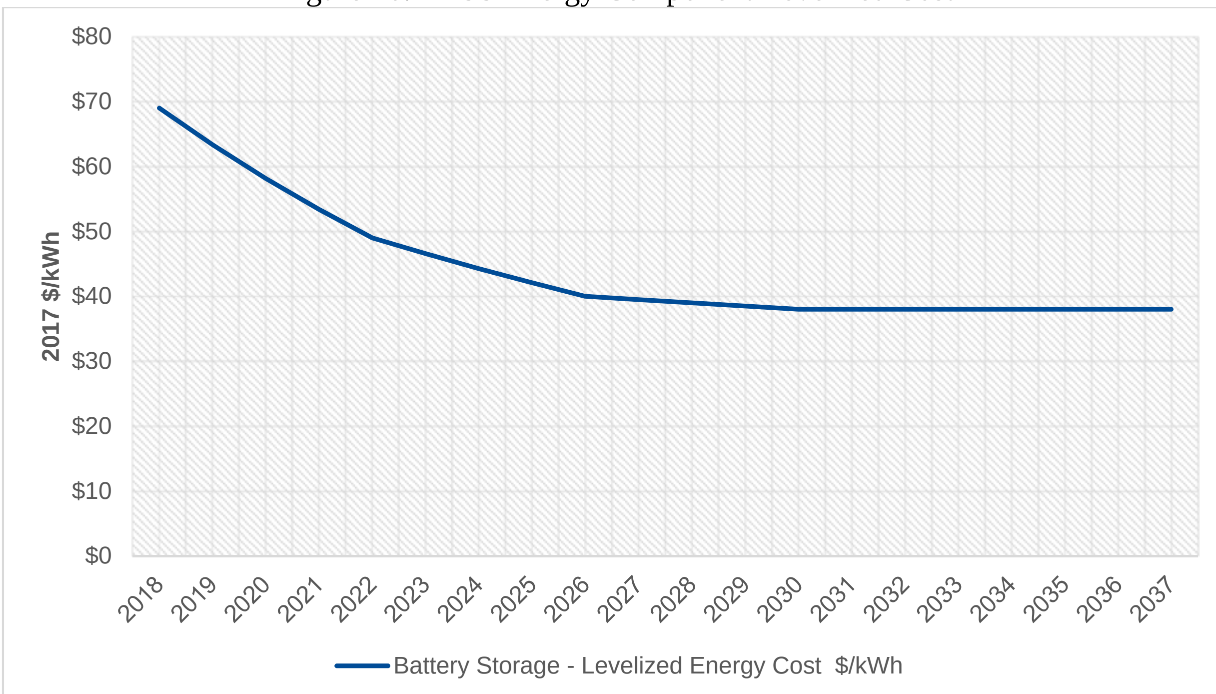
Table 18 Battery Energy Storage System Costs

Li-Ion Battery Energy Storage System (BESS) Costs				
Capital Cost – Power ($/kW)	**Year**	**Low**	**Mid**	**High**
	2018	$208	$248	$285
	2022	$172	$197	$218
	2026	$154	$172	$186
	2030	$150	$166	$179
Capital Cost – Energy Storage Component ($/kWh)	**Year**	**Low**	**Mid**	**High**
	2018	$491	$689	$878
	2022	$406	$548	$672
	2026	$363	$479	$574
	2030	$352	$462	$550
Fixed O&M (%)	1%			

Source: CPUC IRP – Sept 2017

Figure 16 shows the energy component levelized cost of a Li-Ion BESS assuming a 20-year life including battery cell replacement after 10 years. Between now and 2030 BESS costs are expected to decrease by almost 50%.

Figure 16: BESS Energy Component Levelized Cost

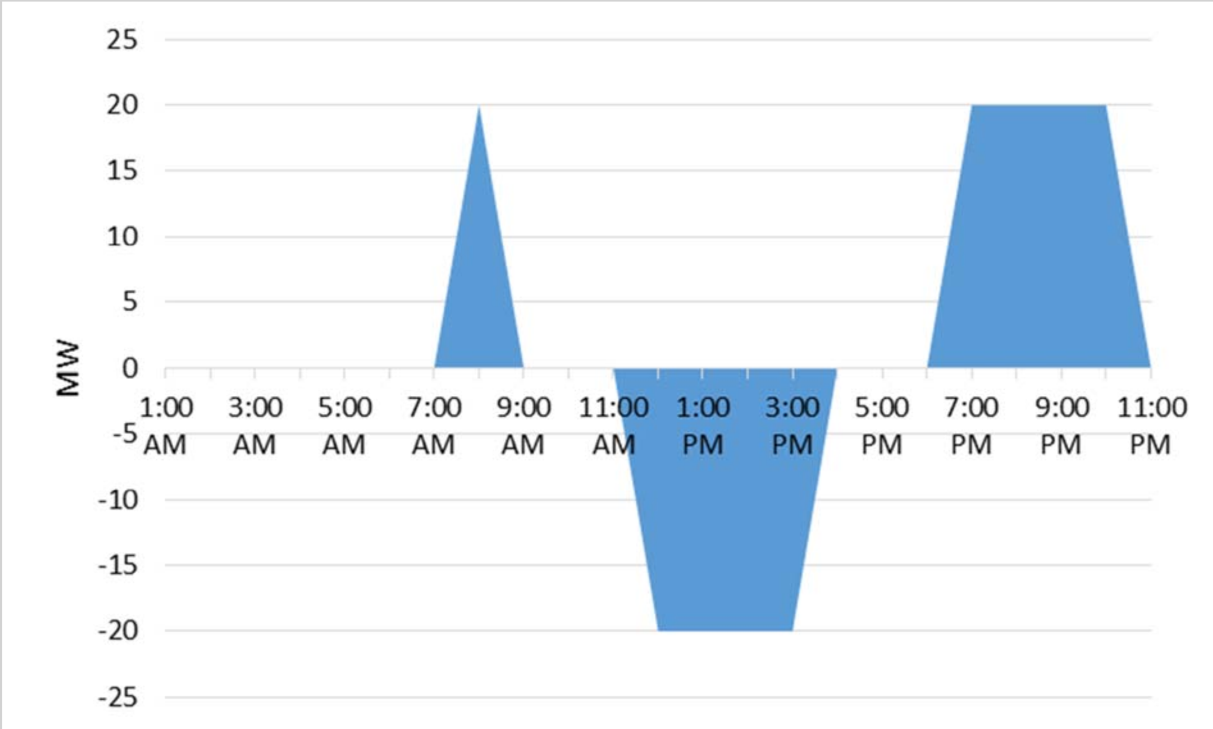


Source: CPUC IRP – Sept 2017

The projected future cost of BESS is uncertain, therefore, VPU used a conservative estimate of future BESS cost declines. Efforts to electrify the transportation sector will have a significant bearing on how fast BESS technology costs decline over the long term. The demand for Li-ION is much greater in the transportation sector compared to the electric sector. Higher adoption rates of electric vehicles would likely lead to lower cost for stationary storage technology. The cost assumptions for energy storage technology will be reviewed in future IRP updates.

Figure 17 below shows the charge and discharge profile used to model a generic Li-Ion BESS

Figure 17: BESS Expected Charge/Discharge Profile



Utility-scale energy storage in the form of a BESS can provide many system benefits including energy arbitrage, RA, reduction of solar over-generation, as well as providing ancillary services. VPU performed a sensitivity analysis on the cost of energy storage, which is discussed in the risk analysis section.

Demand Response

VPU has limited capabilities for demand response based upon the industrial nature of the customer base. Commercial and industrial processes are not readily interrupted and demand response exposes VPU's commercial and industrial customers to economic losses from lost production. Feedback from VPU's customers did not indicate a strong interest in demand response programs. VPU currently has an interruptible load program in place but no demand response programs based upon market price signals. Demand response resources were not included as candidate resource options in the portfolio development. However, customer-sited energy storage can be considered a form of demand response.

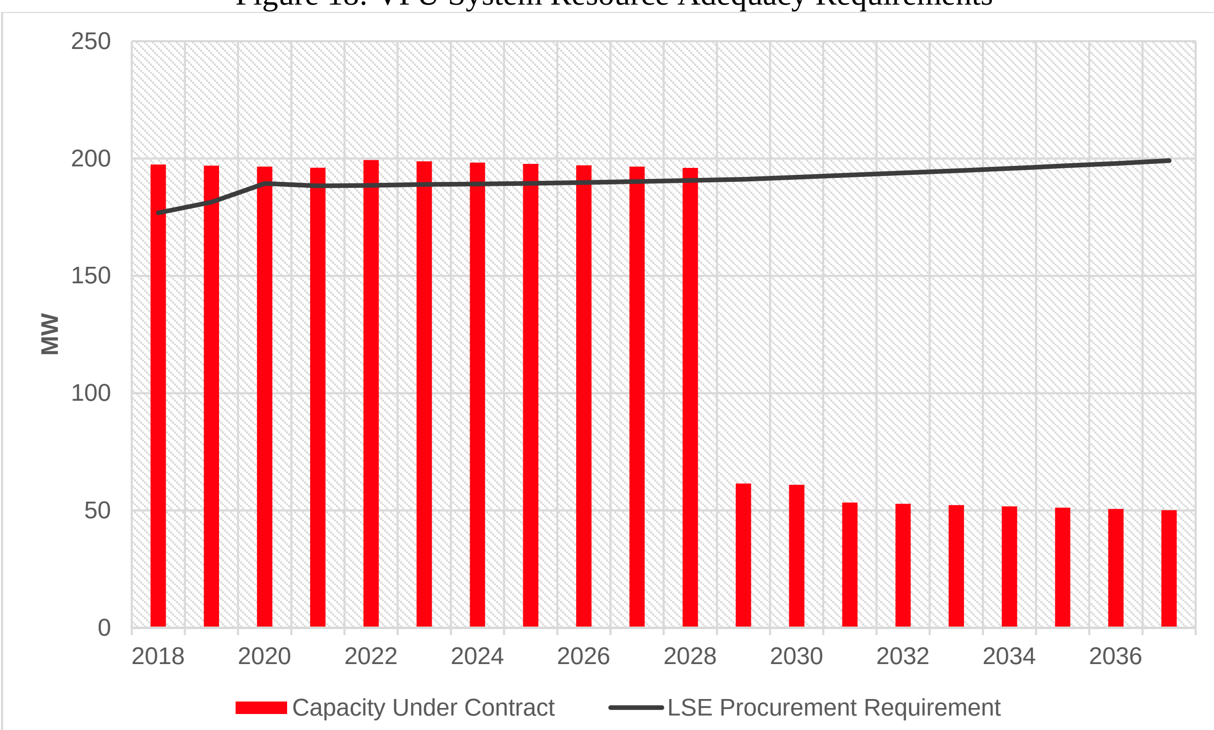
11 Portfolio Analysis

VPU considered various combinations of resource plans designed to meet RA, flexible capacity, renewable portfolio standards and GHG emission reduction goals. VPU developed resource plans for a 20-year horizon from 2018-2037, but primarily focused on the best performing portfolios over the 2018-2030 time-frame. VPU evaluated the net present value (NPV) of bulk power system costs from 2018-2030 in the analysis because existing RPS and GHG goals must be met by 2030. Resource acquisitions identified post-2030 represent current regulatory requirements. However, due to regulatory uncertainty, post-2030 resource acquisitions are likely to be revised in future IRPs. The portfolios developed in this IRP include resources that VPU will need to acquire post 2030, based on current assumptions, to meet California's 100% carbon-free goal by 2045.

Resource Needs Analysis

VPU developed a resource needs analysis by comparing its annual peak demand with the annual peak capability of existing resources. The resource needs analysis highlights the year in which forecast load exceeds resources and indicates a need for additional generation. The load and resource gap analysis takes into account the planning reserve requirement. As depicted on Figure 18 the utility does not have a capacity deficit until 2029 when the existing MGS PPA expires.

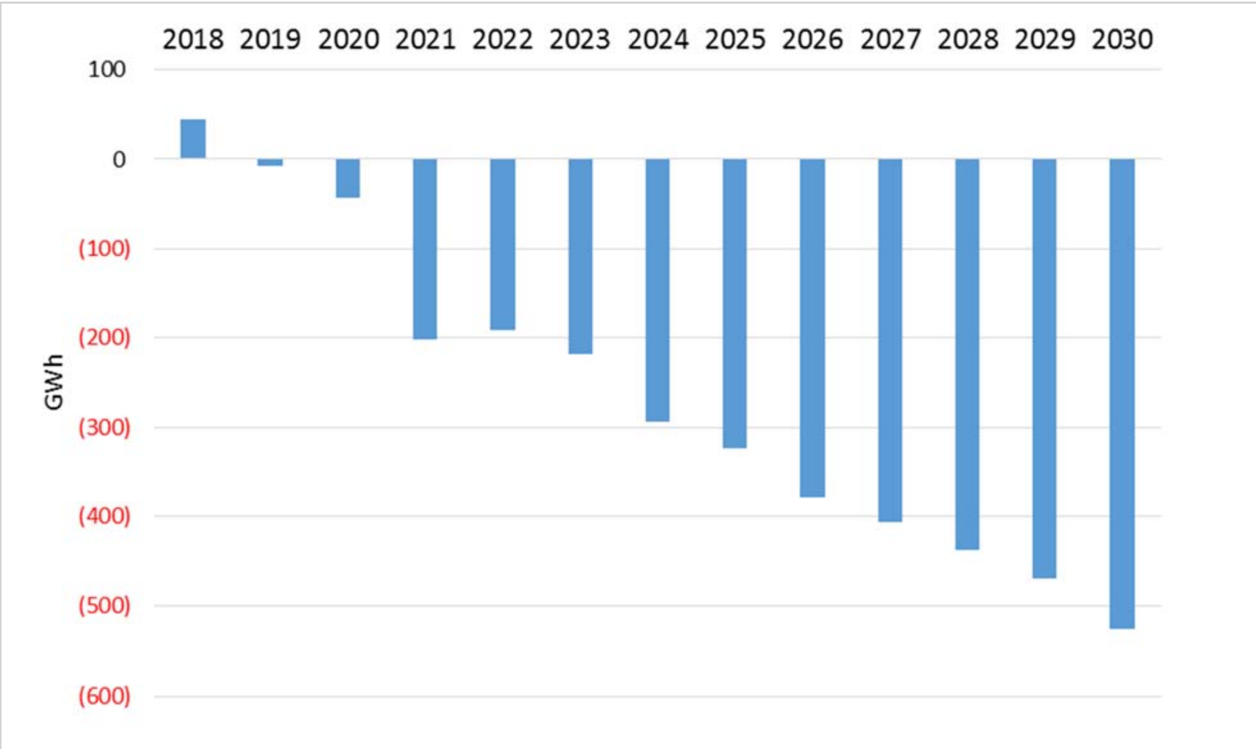
Figure 18: VPU System Resource Adequacy Requirements



Renewable Net Short

VPU will need to procure additional renewable resources to meet future RPS compliance requirements. VPU's existing committed renewable resources will satisfy RPS Compliance Period 3 requirements, but not subsequent RPS Compliance Periods. Figure 19 provides information on the VPU annual renewable supply position relative to the RPS procurement requirements. Negative values indicate a renewable shortfall.

Figure 19: VPU Renewable Net Long/Short



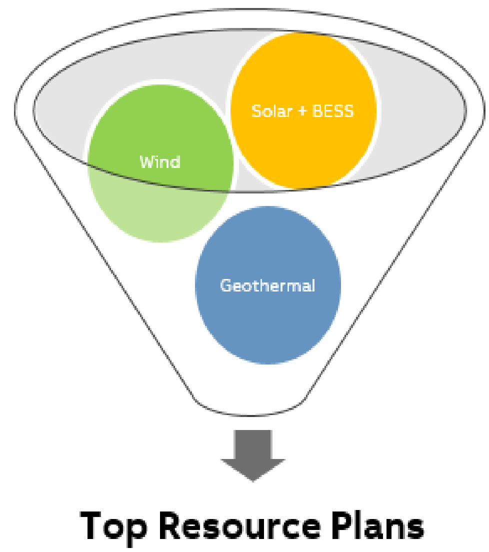
Greenhouse Gas Emissions Reduction Target

In 2016, Senate Bill 32 (SB 32) expanded the statewide GHG emissions reduction goal to 40% below 1990 levels by 2030. Industry experts and regulatory bodies including the CPUC, CEC, CAISO, and CARB worked in collaboration to develop a California economy-wide GHG emissions target. The targets for California GHG emissions by 2030 were originally set at 62 MMT, 52 MMT, 42 MMT and 30 MMT in which the 52 MMT case corresponds to a 50% RPS by 2030 and the 42 MMT corresponds to an RPS between 55-60% by 2030. The 30 MMT case was determined to be too aggressive and not a feasible target for California LSEs to meet.

Ultimately, the governing bodies in California set the economy-wide GHG target at 42 MMT for LSEs to use in the first cycle of SB 350 IRP filings. This target corresponded to a 40% reduction in GHG from 1990 levels. It is likely that after review of filed IRPs by all California LSEs that the individual LSEs targets could be adjusted and/or the total California economy-wide target will be adjusted.

TOP PERFORMING RESOURCE PORTFOLIOS

VPU developed screening portfolios to eliminate resources that were not cost-effective and narrowed down the candidate resources to utility-scale solar, wind, geothermal and BESS. VPU also evaluated DERs, such as distributed solar, energy efficiency, demand response, and electric vehicles (EVs). VPU concluded that the resource potential of these technologies is not significant enough, based upon responses to customer surveys, to develop resource plans heavily favoring DERs. The screening level analysis of candidate resources yielded insights into the resources that performed the best and matched VPU resource needs.



12 Portfolios Evaluated

VPU simulated various scenarios and identified four top performing portfolios that provide varying benefits to the VPU system. The top four portfolios, Portfolio 1 through Portfolio 4 included a mix of solar, wind, geothermal and BESS. The key differences between the portfolios are listed below:

- Portfolio 1 – includes solar, wind, geothermal and battery storage
- Portfolio 2 – does not include any battery storage
- Portfolio 3 – does not include any wind resources
- Portfolio 4 – includes 50 MW of BESS in 2030.

Existing resources listed in Table 15 are common to all portfolios. Utility-scale solar was consistently the lowest cost incremental resource in the 2021 to 2024 time period. VPU tested scenarios in which either wind, solar + storage, or small hydro was procured rather than solar in 2021. In each case, solar turned out to be the lowest cost resource. The addition of 65 MW of new utility-scale solar in 2021 and 20 MW of geothermal in 2029 was common in all the top four portfolios.

The addition of 85 MW of incremental new utility solar increases the total solar on the VPU system to 140 MW in 2025. When all 140 MW of solar resources generate at peak output and MGS is operating at its minimum generation level of 70 MW, solar curtailment may be necessary. Although wind resources are more expensive and provide lower RA value as compared to solar, wind profiles are better aligned with the VPU load profile. To take advantage of this benefit, Portfolio 1 includes 27 MW of new wind in 2025. Portfolio 3 tested the impact of excluding wind as a resource option.

Geothermal is not a viable resource in 2025 because it is a baseload resource that will compete with MGS. Therefore, a 20 MW geothermal unit was added in the four top performing portfolios in 2029, because it provides capacity replacement for MGS, replaces the baseload Puente Hills contract, does not increase flexible capacity requirements, and displaces market purchases of natural gas-fired generation during super-peak hours.

VPU completed a sensitivity analysis to understand the potential impact of BESS on the system, and this analysis is described in the Risk Analysis section. Portfolio 2 evaluated the impact of excluding BESS all together and Portfolio 4 tested increased levels of energy storage in 2030 by including 50 MW of BESS rather than 20 MW, the amount that was included in Portfolio 1 and Portfolio 3. VPU analyzed each portfolio to determine the risk and benefits of the resource mix in each portfolio to determine the optimal scenario. Table 19 below shows the four resource combinations subjected to further analysis to determine the optimal resource portfolio.

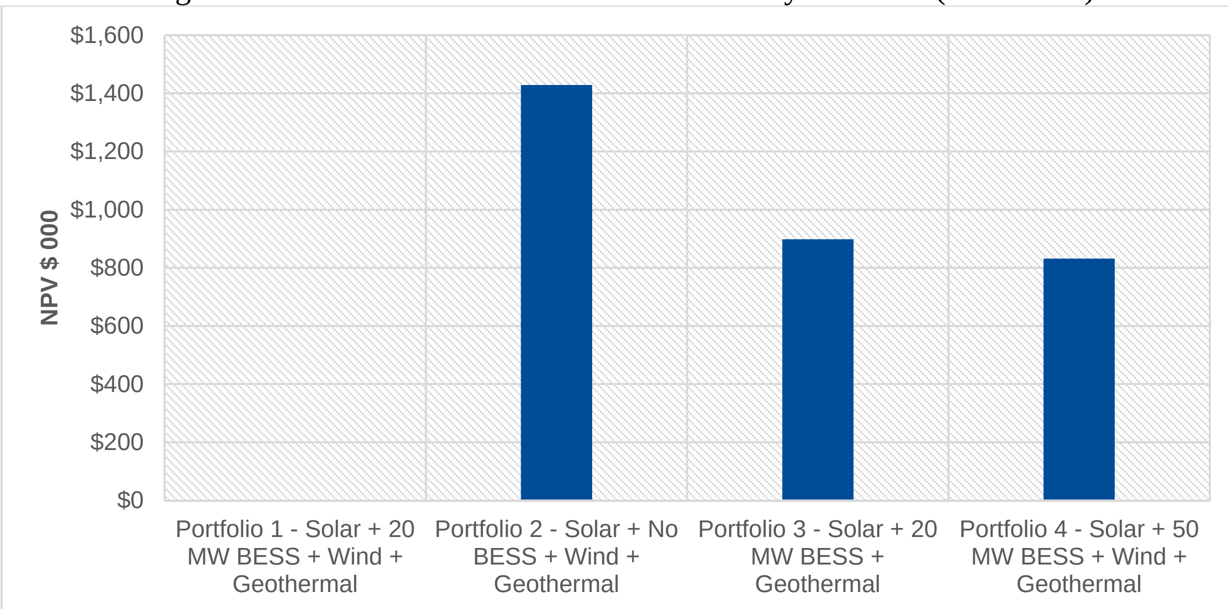
Table 19: Resource Portfolio Capacity Comparison in 2030

Resource Portfolio (MW)	Solar	Wind	Geothermal	MGS/Market	Energy Storage
Portfolio 1 - Solar + 20 MW BESS + Wind + Geothermal	105	27	20	70	20
Portfolio 2 - Solar + No BESS + Wind + Geothermal	105	27	20	110	0
Portfolio 3 - Solar + 20 MW BESS + Geothermal	130	0	20	70	20
Portfolio 4 - Solar + 50 MW BESS + Wind + Geothermal	105	27	20	40	50

Each portfolio modelled targeted the equivalent amount of renewable energy, GHG reduction, and reliability.

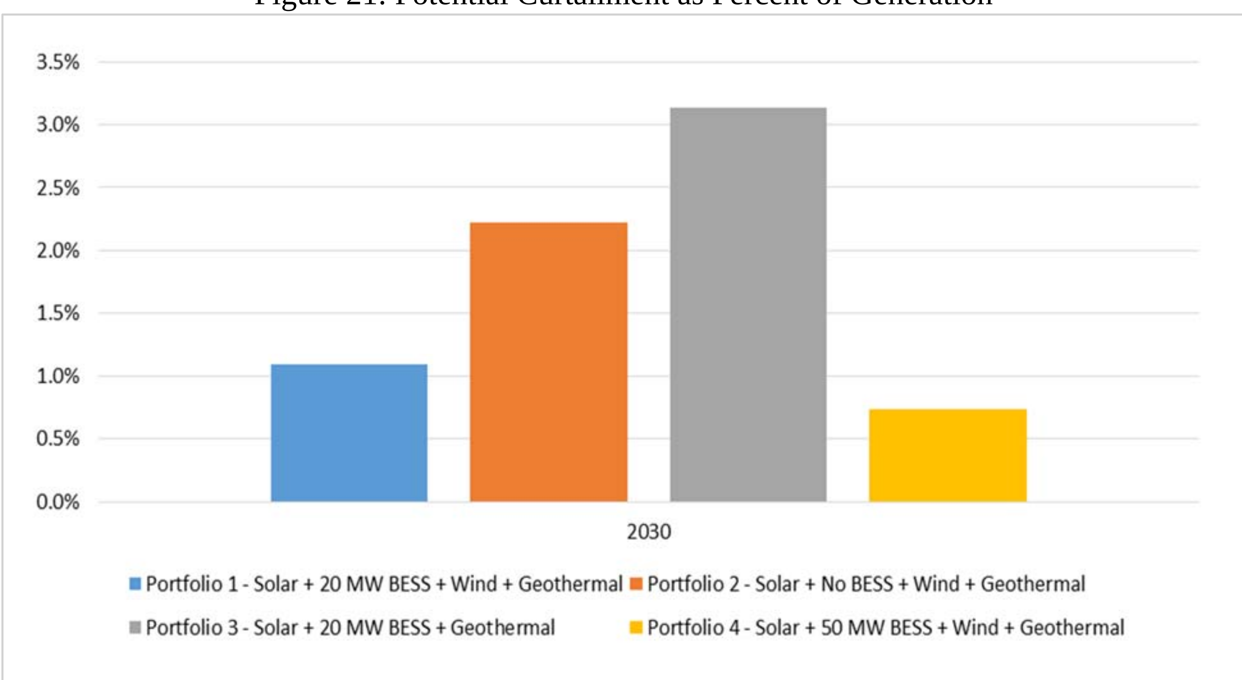
The top 4 portfolios were identified as the best performing portfolios primarily based upon portfolio cost. The overall cost of each portfolio was measured by the net present value (NPV) of the portfolio from 2018 through 2030. Portfolio 1 was the least-cost portfolio. Although the four Portfolios include different levels of solar, wind, and energy storage resources, the difference in the NPV of power system costs is relatively small. The main reason for the small difference in the NPV between the portfolios is that the majority of the resource additions occur later in the study horizon. Figure 20 shows the delta between the net present values of Portfolios 2 through 4 compared to Portfolio 1, the lowest cost portfolio.

Figure 20: Delta of Net Present Value of Power System Cost (2018-2030)



Utility-scale solar clearly was identified as the lowest cost resource, but high penetrations of solar can lead to solar curtailment and the need for additional flexible ramping capacity requirements. Figure 21 shows the potential curtailment of the top four portfolios as a percentage of the total generation in 2030. VPU reviewed the level of curtailment the modeling estimated for each portfolio and identified that Portfolio 3 has the highest curtailment risk.

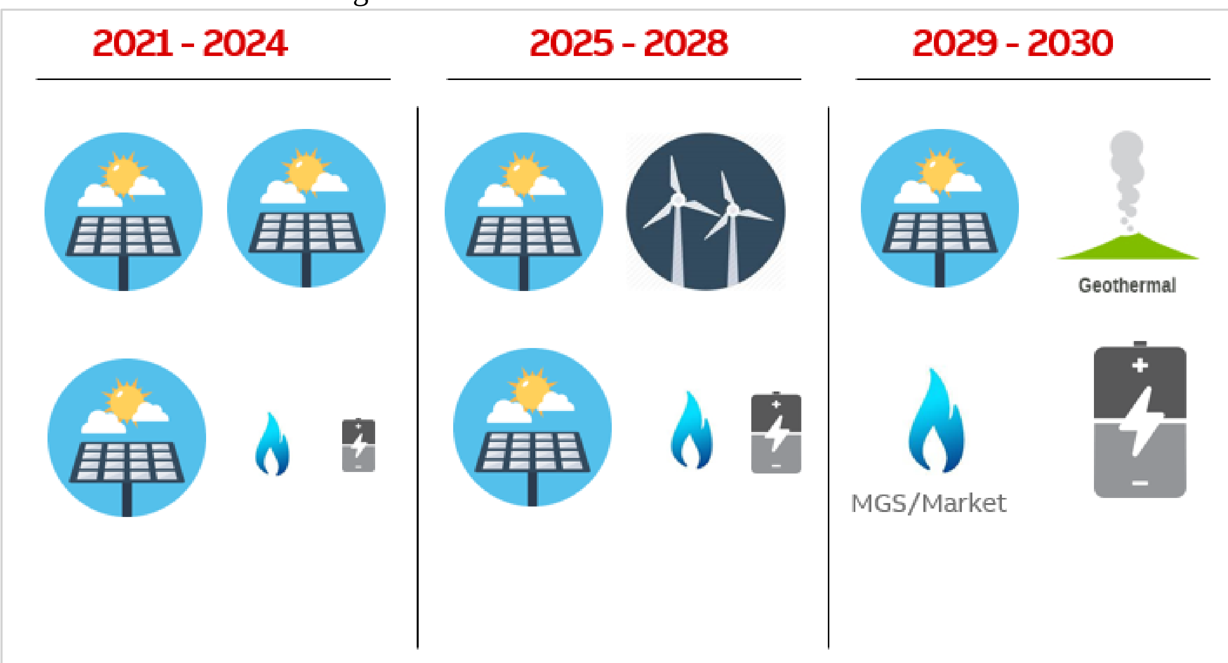
Figure 21: Potential Curtailment as Percent of Generation



13 Recommended Preferred Portfolio

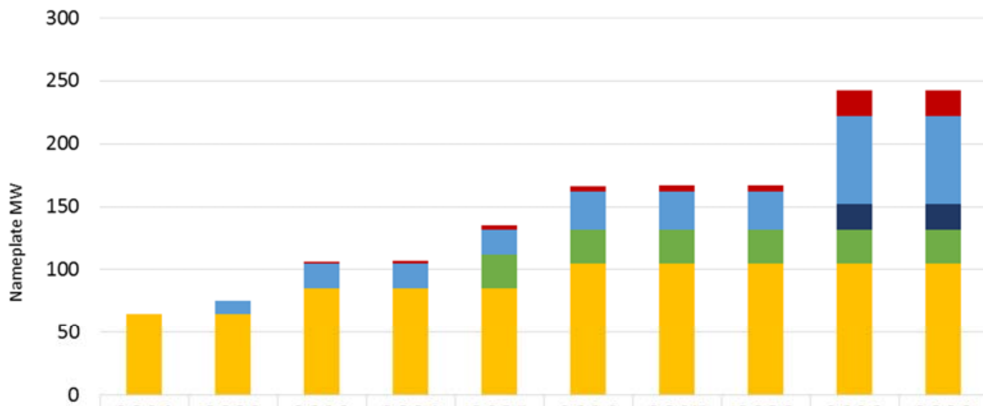
Portfolio 1, the portfolio that VPU considers to be the Preferred Portfolio, represents a balanced and diversified portfolio. This portfolio primarily includes solar resources along with lesser amounts of wind, geothermal, BESS, and market RA. Portfolio 1 is recommended as the Preferred Portfolio because it is the lowest cost portfolio compared to the other three portfolios and achieves the same level of sustainability and reliability metrics. Figure 22 depicts the incremental new resources in the Preferred Portfolio

Figure 22: New Resources Preferred Portfolio



The Preferred Portfolio represents the optimal resource acquisition plan that meets VPU's objectives of system reliability, compliance with the RPS, reduction of GHG emissions and low cost. Figure 23 below shows the cumulative new resource additions from 2021 to 2030.

Figure 23 Preferred Portfolio Cumulative Resource Expansion



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Storage			1	2	3	4	5	5	20	20
Natural Gas/Market		10	20	20	20	30	30	30	70	70
Geothermal									20	20
Wind					27	27	27	27	27	27
Solar	65	65	85	85	85	105	105	105	105	105

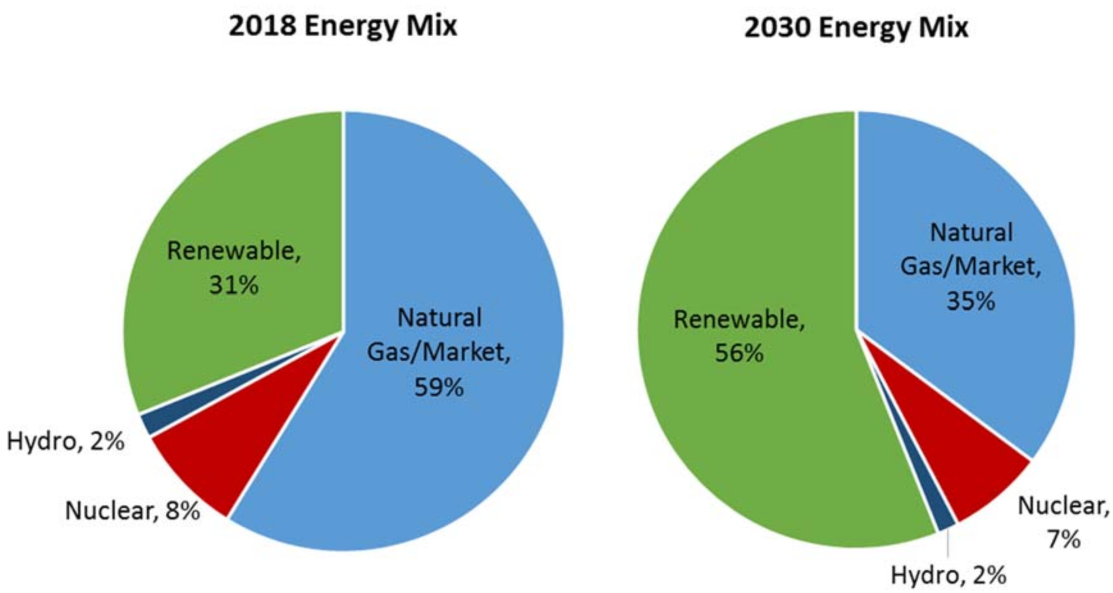
VPU will need to acquire additional renewable resources starting in 2021. The Preferred Portfolio recommends procuring 65 MW of solar in 2021, 20 MW in 2023 and an additional 20 MW in 2026 for a total cumulative solar investment of 105 MW by 2030. The Preferred Portfolio also includes the acquisition of 27 MW of wind in 2025 and 20 MW of geothermal in 2029 to provide resource diversity. Diversifying the renewable resource mix with resources other than solar benefits the system by providing energy during hours when solar resources are off-line.

The existing MGS PPA expires in 2028. VPU does not assume MGS will be in the resource portfolio post 2028, but requires a plan that includes base load generation located within its local service territory after 2028 for reliability purposes. Resource options to replace the MGS PPA include re-contracting or acquiring MGS, procuring another local existing natural gas plant, or acquiring energy storage technology.

The Preferred Portfolio recommends 1 MW of incremental energy storage in each of the years from 2023 to 2027, increasing to a cumulative total of 20 MW by 2029. These energy storage additions help to partially replace MGS and mitigate over-generation from solar. The Preferred Portfolio identifies 70 MW of capacity that is sourced from either MGS or another market-based natural gas resource in 2029.

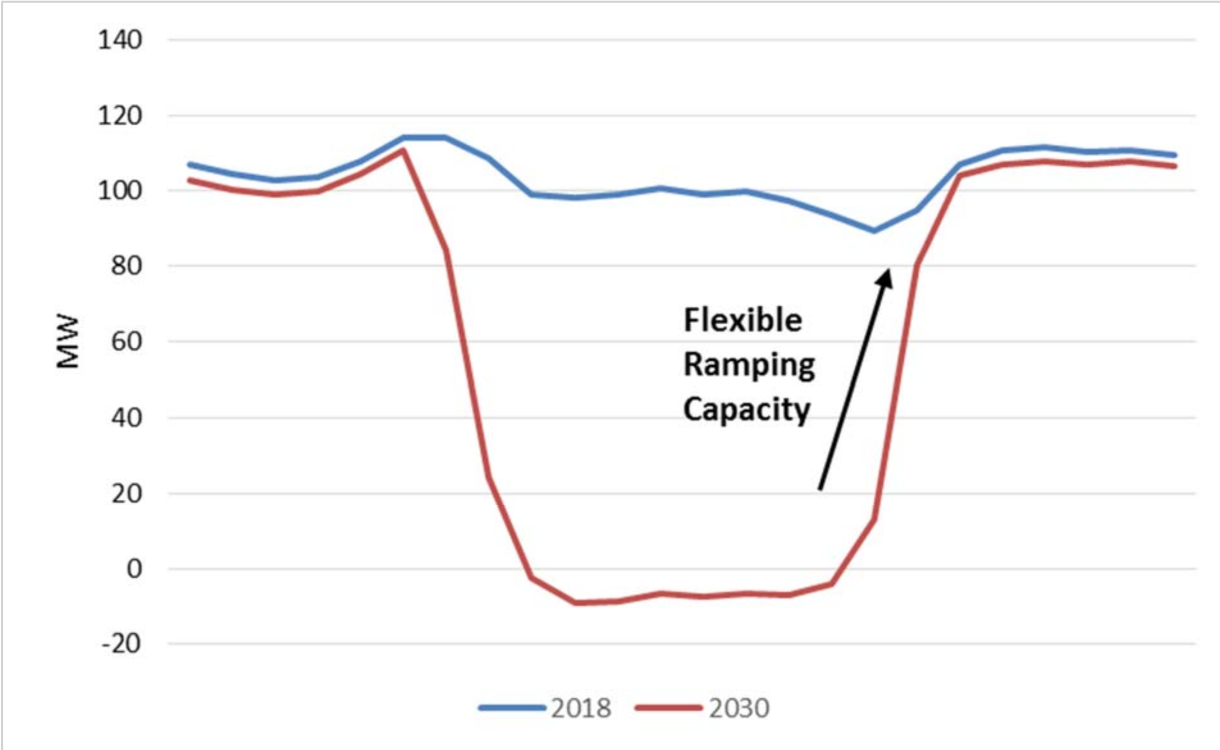
The Preferred Portfolio resource expansion plan sets VPU on a path towards attainment of the long-term 100% carbon-free goal. Renewable energy procurement will lead to higher levels of renewable resources by 2030, increasing from 31% in 2018 to 56% by 2030. As renewable energy increases, VPU will be less reliant on natural gas-fired generation. Reliance on natural gas declines from 59% of the energy supply in 2018 to 35% in 2030. Figure 24 shows the anticipated change in the supply mix between 2018 and 2030.

Figure 24: Changing Energy Supply Mix in 2018 and 2030



To achieve long-term sustainability goals, VPU will need to procure solar resources which can cause over-supply issues at very high penetration levels. The VPU customer demand shape reveals a very suitable alignment to solar output and customer demand peaking roughly at the same time. Solar and wind resources are intermittent and considered to be non-dispatchable resources. In practice, VPU's dispatchable resources such as MGS will be used to serve the remaining load after renewable energy has been subtracted from the electric demand. In the electric power industry this is referred to as the Net Load, or the remaining load after accounting for renewable energy. Figure 25 shows VPU's net load profiles for a typical spring day in 2018 and in 2030.

Figure 25: Changing Net Load in 2018 and 2030



In 2018, VPU has about 45 MW[12] of solar on the system. By 2030, based upon the Preferred Portfolio, VPU will need to add an incremental 105 MW of solar bringing the total installed solar to 160 MW. The end result of adding so much solar on the system is that the belly of the "duck curve" gets bigger and creates a system need for additional flexible capacity that can ramp up quickly to meet a steep increase in the net load. Energy storage resources can help address some of the ramping constraints and over-generation concerns, but natural gas resources such as MGS will likely be needed to support the integration of so much solar into the power grid.

[12] VPU share of capacity from Astoria solar increases from 20 MW to 30 MW in 2022

As the energy mix changes over time the operating mode of MGS is expected to change as well. Figure 26 illustrates a typical hourly dispatch of resources to meet VPU load on a summer day in 2018. MGS is considered to be a baseload and intermediate type resource that normally runs as base load at approximately 70 MW. MGS does have the ability to ramp up to its full 134 MW maximum capacity if it is economic to do so. In 2018, MGS is expected to be the primary resource in the VPU resource mix.

Figure 26: Typical Summer Day Generation Dispatch in 2018 (The peak appears to be low)

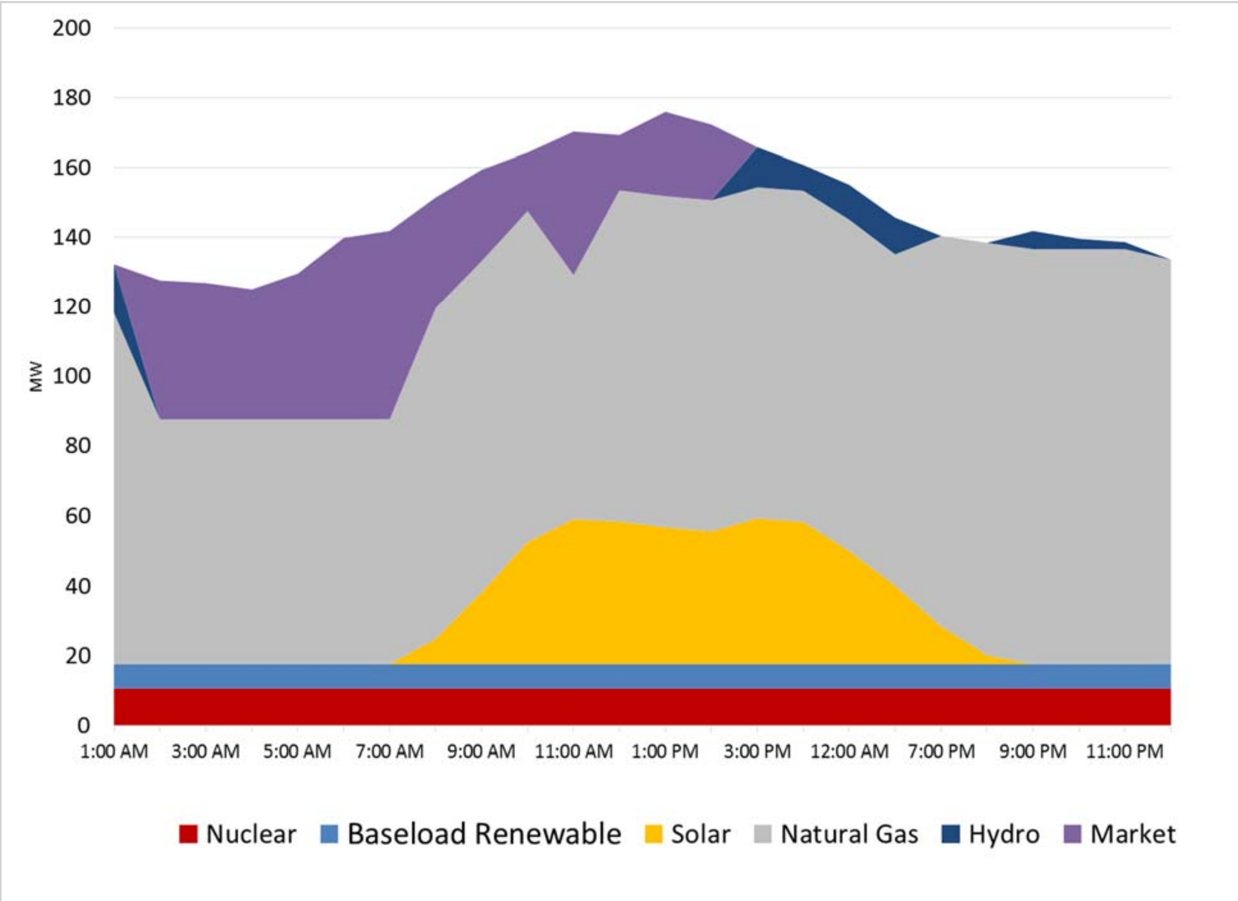
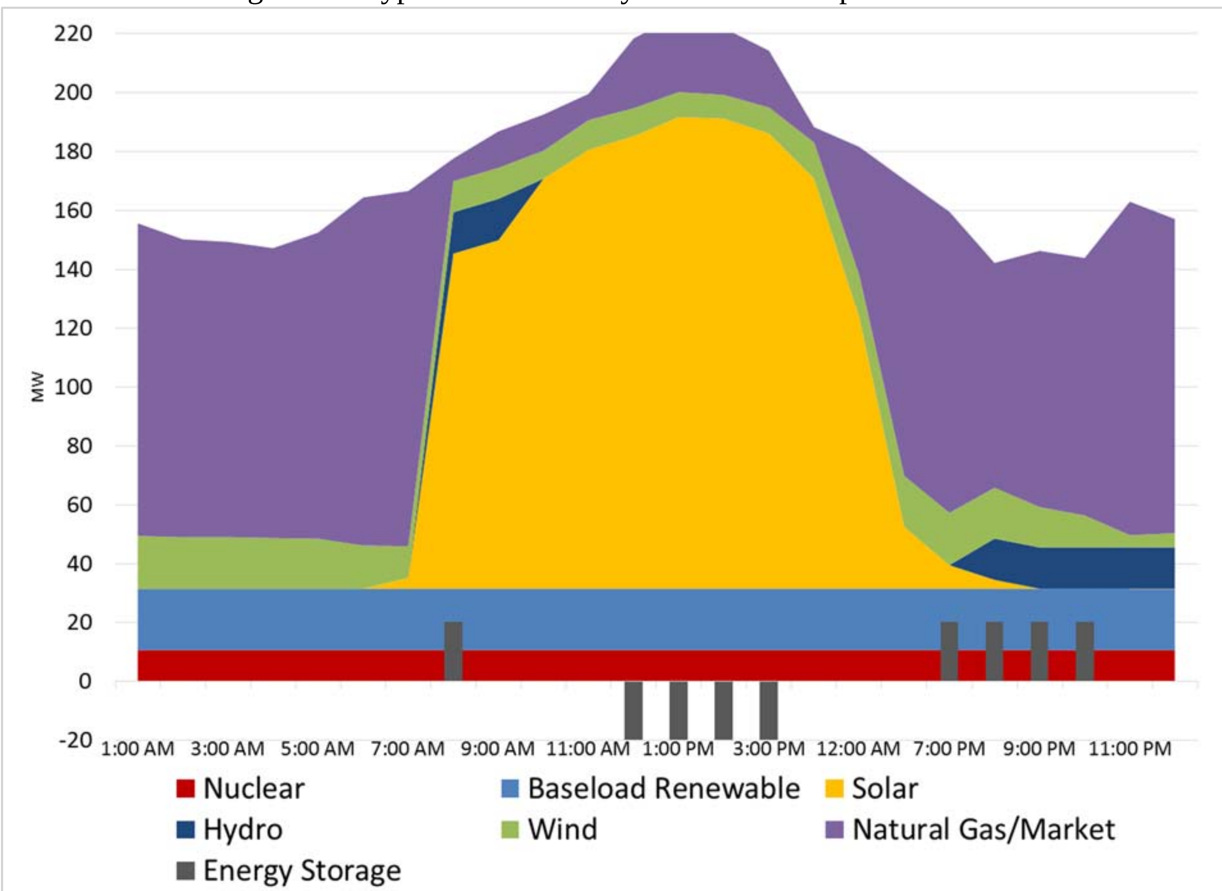


Figure 27 shows the expected typical hourly dispatch of resources to meet VPU load on a summer day in 2030. By 2030, solar generation will represent a much larger part of the resource mix and VPU will need to either operate MGS or purchase energy from a natural gas-fired unit that can operate primarily when solar is not available.

Figure 27: Typical Summer Day Generation Dispatch in 2030



VPU developed a load and resource balance to compare its annual peak demand with the annual peak capability of existing resources and the resources identified in the Preferred Portfolio. The load and resource balance for the 2019 through 2030, which includes the base load forecast, reserve requirements, existing resources, purchases, interruptible contracts and future resources proposed in the Preferred Portfolio, is shown in Table 20 below.

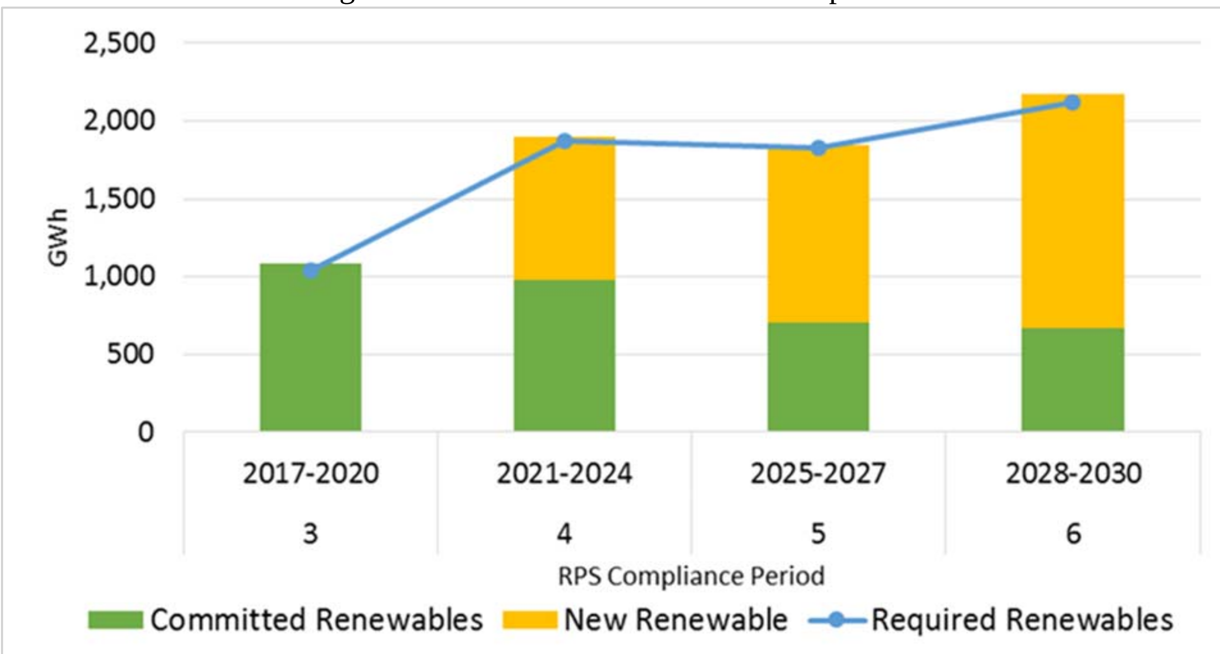
Table 20: Preferred Portfolio – Load and Resource Balance (2018-2030)

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1-in-2 Peak	181	200	206	207	207	208	208	209	209	210	211	211	212
Energy Efficiency	0	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Coincidence Adj.	-15.4	-15.5	-15.3	-16.3	-16.4	-16.5	-16.7	-16.9	-17.0	-17.2	-17.4	-17.6	-17.7
Interruptible Load	-13	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25
Distributed Solar	-0.3	-0.7	-1.1	-1.4	-1.8	-2.1	-2.4	-2.7	-2.9	-3.1	-3.3	-3.5	-3.4
Electric Vehicle	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.2	1.3	1.4	1.6	1.7
Net Peak*	**153.2**	**158.2**	**164.7**	**163.9**	**164.2**	**164.4**	**164.7**	**164.8**	**165.0**	**165.4**	**165.9**	**166.4**	**167.3**
Dependable Capacity (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Hoover	17	17	17	17	17	17	17	17	17	17	17	17	17
H Gonzales 1 & 2	10	10	10	10	10	10	10	10	10	10	10	10	10
Malburg	134	134	134	134	134	134	134	134	134	134	134		
MGS/Market					10	20	20	20	30	30	30	70	70
Palo Verde	11	11	11	11	11	11	11	11	11	11	11	11	11
Puente Hills Landfill	9	8	7	7	6	6	6	5	5	5	4	4	4
Antelope DSR Solar	10	10	10	10	9	9	9	9	8	8	8	8	7
Astoria Solar PV	8	8	8	8	11	11	11	10	10	10	9	9	9
New Geothermal												20	20
New Wind								7	7	7	7	7	7
New Solar				25	24	31	30	29	35	34	33	32	30
New Energy Storage						1	2	3	4	5	5	20	20
Total Dependable	**199**	**198**	**197**	**221**	**233**	**249**	**249**	**255**	**271**	**270**	**268**	**207**	**206**
Resource Adequacy (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
RA Requirement	176	182	189	188	189	189	189	190	190	190	191	191	192
Excess System RA	**23**	**16**	**8**	**32**	**44**	**60**	**59**	**66**	**81**	**80**	**78**	**16**	**13**

Renewable Portfolio Standard Compliance

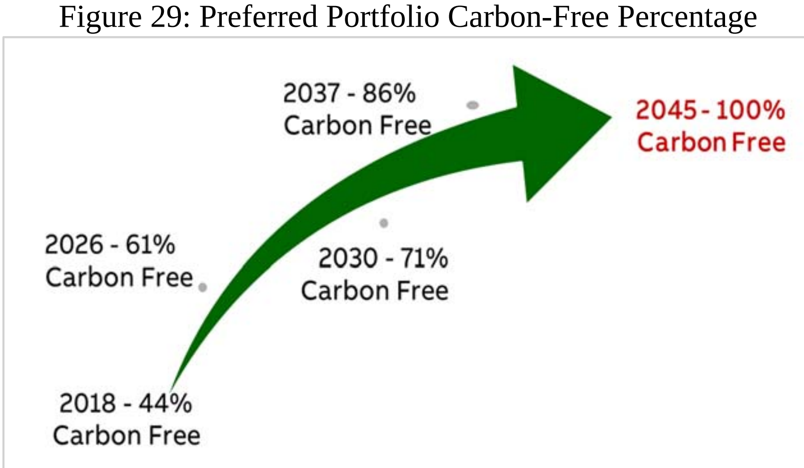
The Preferred Portfolio allows VPU to achieve its future RPS compliance requirements under SB 100. The Preferred Portfolio includes renewable resource additions post-2030 to ensure that VPU stays in compliance with the RPS. The Preferred Portfolio takes into account the portfolio content category requirements to ensure that VPU complies with all aspects of the RPS procurement rules. Figure 28 below shows VPU's RPS by compliance period through 2030.

Figure 28: Preferred Portfolio RPS Compliance



VPU is estimated to be 44% carbon-free in 2018, increasing to 71% by 2030, and 86% carbon-free by 2037. The Preferred Portfolio provides a viable trajectory to achieve 100% carbon-free status by 2045. Figure 29 displays the percent of generation that comes from carbon-free sources in the Preferred Portfolio.

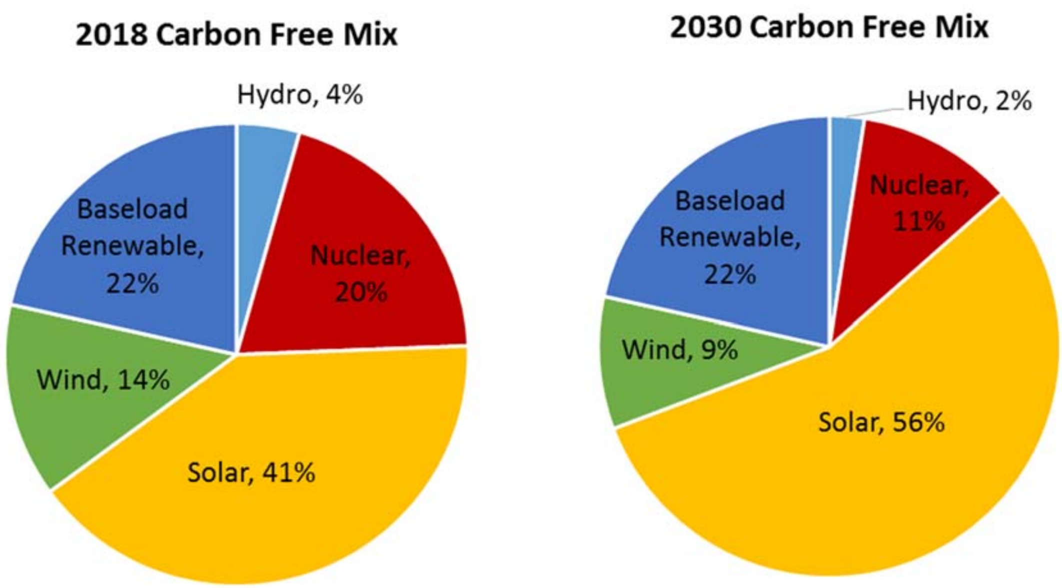
Figure 29: Preferred Portfolio Carbon-Free Percentage



The difference between the RPS and the clean energy standard is that the clean energy percentage calculation includes non-RPS eligible carbon-free sources such as Hoover (hydro) and Palo Verde (nuclear).

Figure 30 below shows the change in the composition of carbon-free resources from 2018 to 2030. Solar resources represent 41% of the carbon-free energy in 2018 and increase to 56% in 2030.

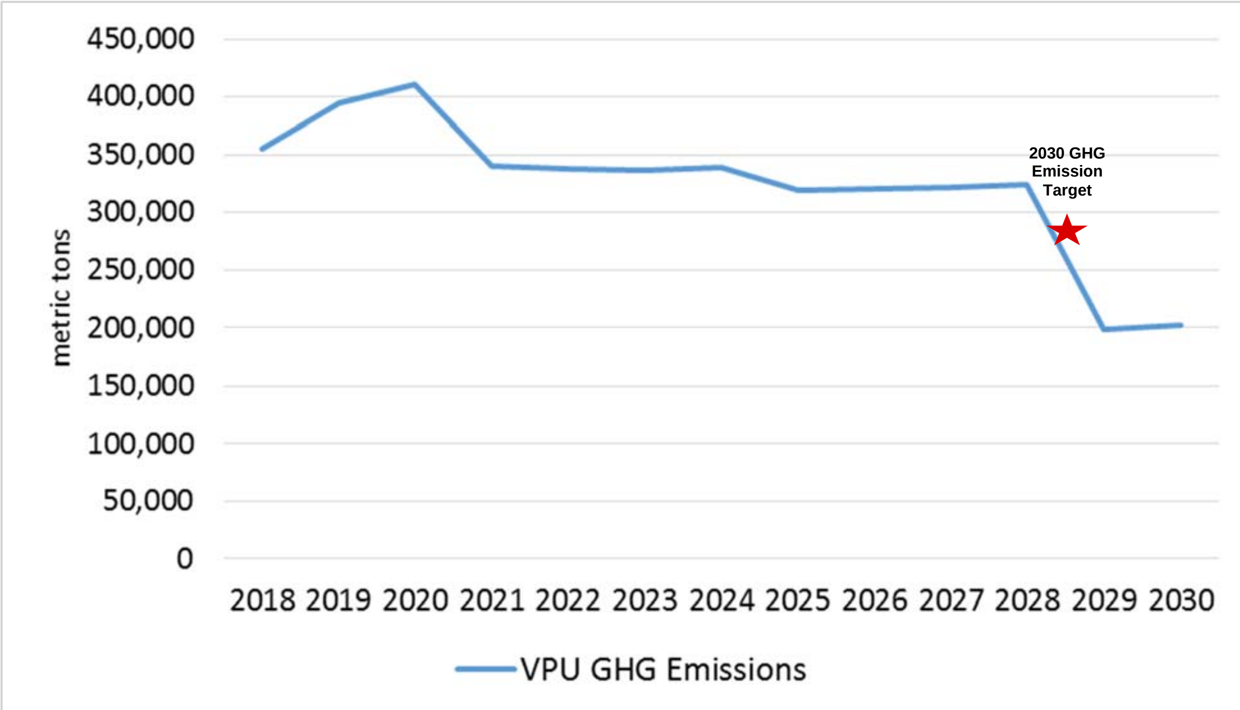
Figure 30: Carbon-Free Energy Supply Mix in 2018 and 2030



Greenhouse Gas Emission Reduction Compliance

There is a clear relationship between RPS and GHG emissions. As renewable energy procurements ramp up over time, VPU will realize GHG emission reductions because natural gas-fired resources will be displaced by zero GHG-emitting resources. The Preferred Portfolio enables VPU to achieve the GHG emission reduction targets by 2030 through the procurement of renewables and reduction in generation from MGS. The Preferred Portfolio includes a geothermal baseload resource in 2029 along with solar and energy storage as partial replacements for MGS resulting in a significant reduction of VPU GHG emissions. Figure 31 shows the progress VPU is estimated to make, using the Preferred Portfolio's procurement plan, to achieve the 2030 GHG emission target.

Figure 31 Estimated GHG Emissions from Preferred Portfolio



Currently, neither the CEC nor CARB provide any guidance for interim GHG emission targets before 2030. The GHG emission reduction goal is only for the year 2030. Based upon current legislation, VPU can continue to operate MGS normally, dispatching it economically until the PPA expires in 2028, without concerns about reducing operation due to GHG emissions. As renewable procurement increases over time, VPU will generate less emissions and be on a glide path to meet the 2030 GHG emission target as long as VPU continues to procure renewable energy and replace at least a portion of the energy currently supplied by MGS in 2029 with a carbon-free energy source.

Reliability Compliance

The Preferred Portfolio ensures that the system, local, and flexible capacity components of the RA requirement are satisfied.

Figure 32 illustrates the dependable capacity of each resource including renewable resources and how much each resource contributes to system RA. Figure 32 shows that VPU's total resources are greater than the required LSE capacity procurement requirement.

Figure 32: System Resource Adequacy Compliance

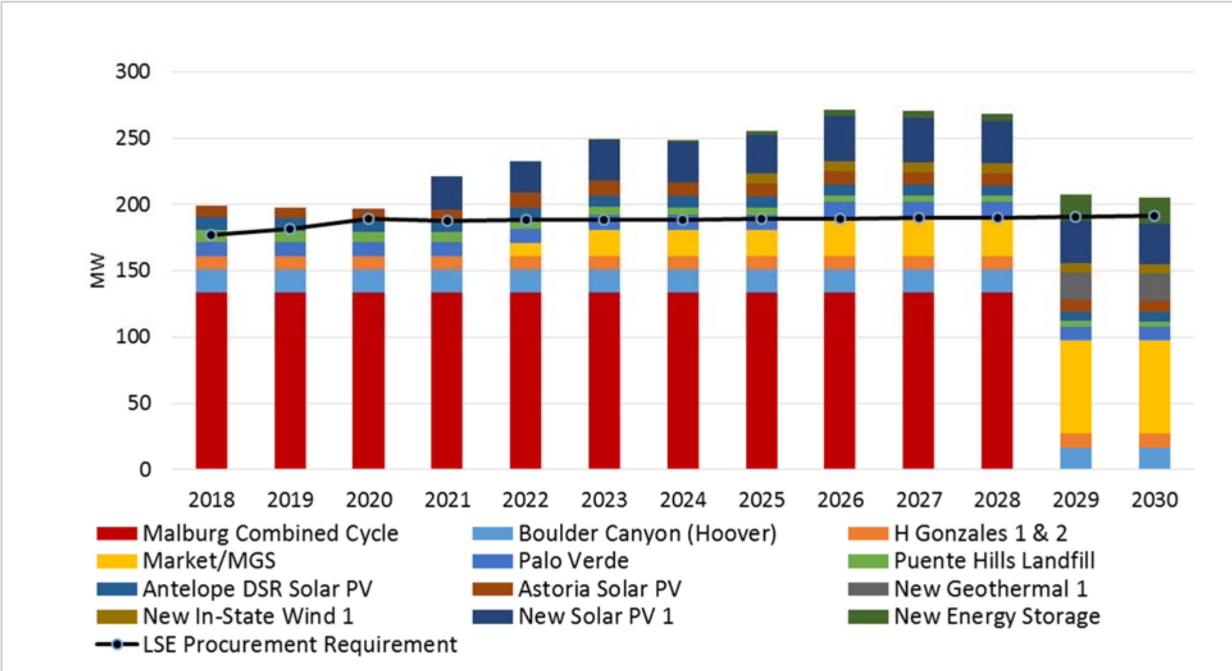
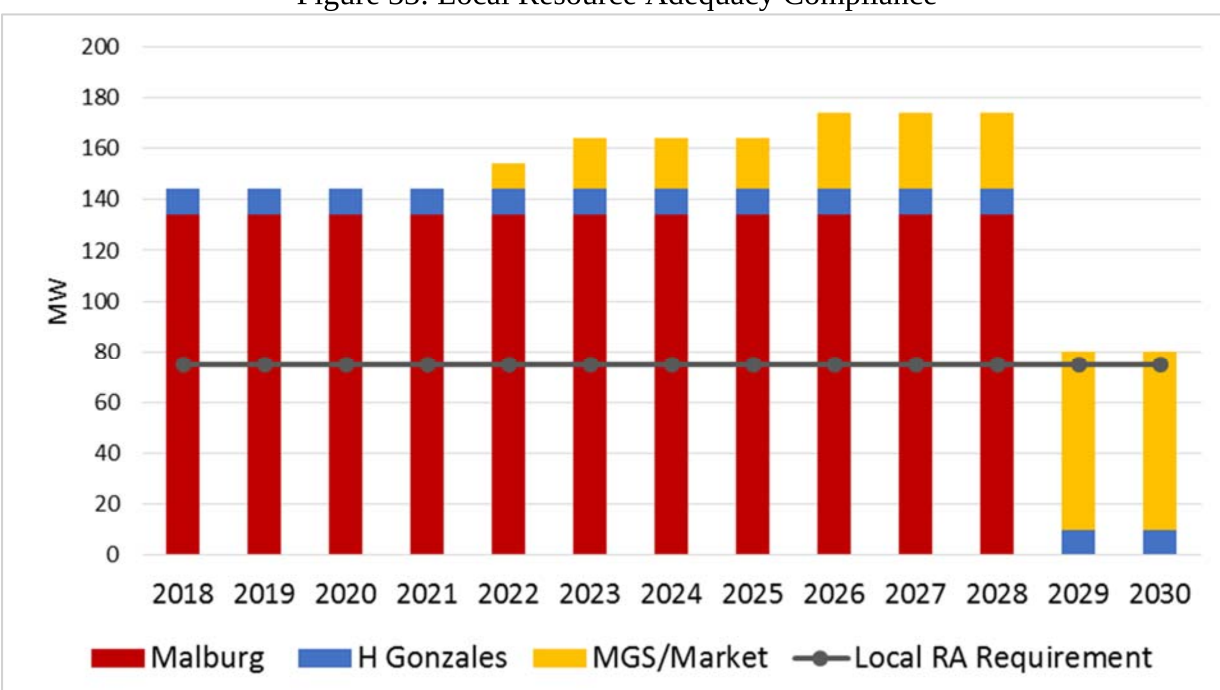


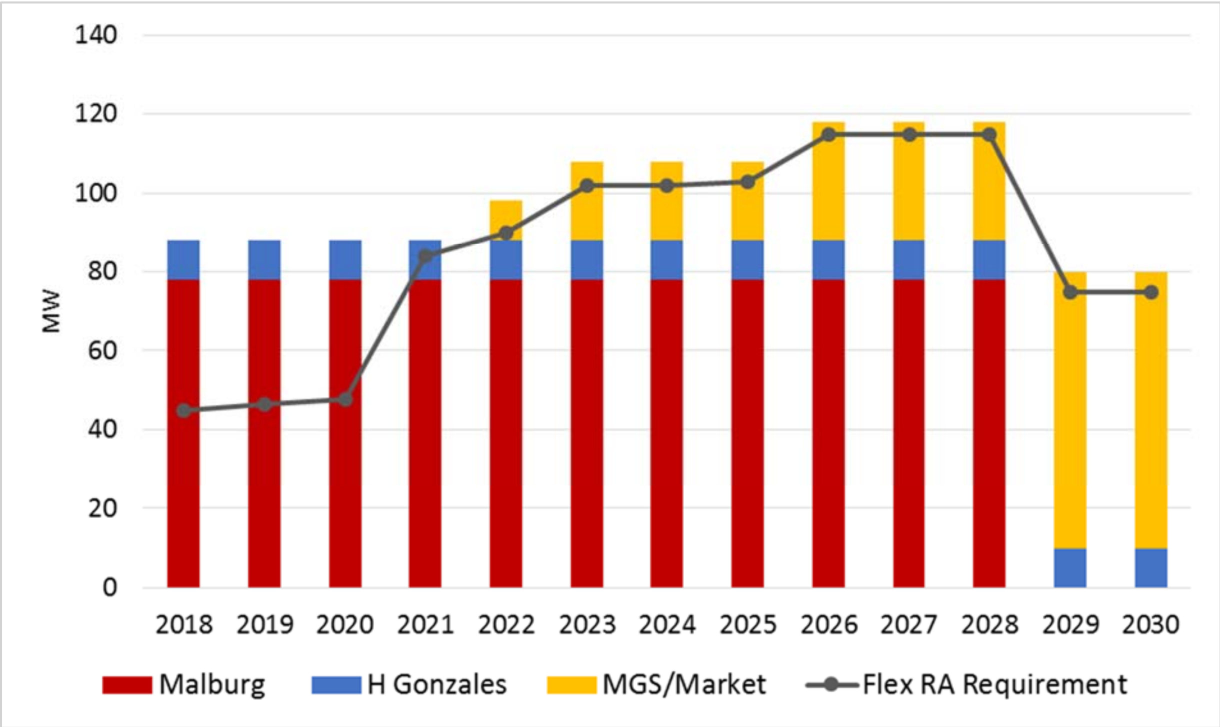
Figure 33 illustrates the local capacity requirement of the Preferred Portfolio. VPU will have excess local RA until the MGS PPA expires in 2028. It is possible that VPU will be able to re-contract or procure MGS under more favorable commercial terms.

Figure 33: Local Resource Adequacy Compliance



For purposes of this IRP, the Preferred Portfolio selects a generic existing natural gas-fired resource as a placeholder for either the re-procurement of MGS or another natural gas-fired unit located in the LA Basin. Flexible capacity requirements are estimated to increase in relationship to higher levels of solar procurement. VPU assumed a 60% flexible capacity requirement for each incremental MW of solar procured. Using this assumption, 100 MW of nameplate solar would require 60 MW of additional flexible capacity. When VPU has 160 MW of nameplate solar capacity on its system in 2028, the estimated flexible capacity requirement increases from 45 MW in 2018 to 115 MW. Figure 34 below illustrates the flexible capacity requirements and how VPU intends to meet those requirements in the Preferred Portfolio.

Figure 34: Flexible Resource Adequacy Capacity Compliance



In 2029, flexible capacity requirements decrease due to the procurement of 20 MW of energy storage. However, flexible capacity rules are unclear with respect to the treatment of energy storage. VPU will need additional guidance from the CAISO on the corresponding Flex RA requirements for the Preferred Portfolio. VPU assumed that energy storage can absorb 20 MW of solar when the sun is shining and discharge during the evening ramp. The flexible capacity requirements will be reduced by 200% of the power rating (MW) of energy storage. Therefore, VPU assumed 20 MW of energy storage can reduce flexible capacity requirements by 40 MW.

Retail Rate Impacts

VPU customer feedback identified the primary customer concern as maintaining low cost electrical service. The Preferred Portfolio identifies the lowest bulk power supply cost portfolio going forward while meeting reliability and sustainability requirements. The cost of procuring renewables through power purchase agreements (PPAs) will increase power supply costs between 2018 and 2028, but power supply costs are expected to decrease in 2029 primarily due to the expiration of the existing MGS PPA. Figure 35 below displays the annual bulk power supply costs broken down by the different bulk power supply components.

Figure 35: Estimated Power Supply Cost from Preferred Portfolio

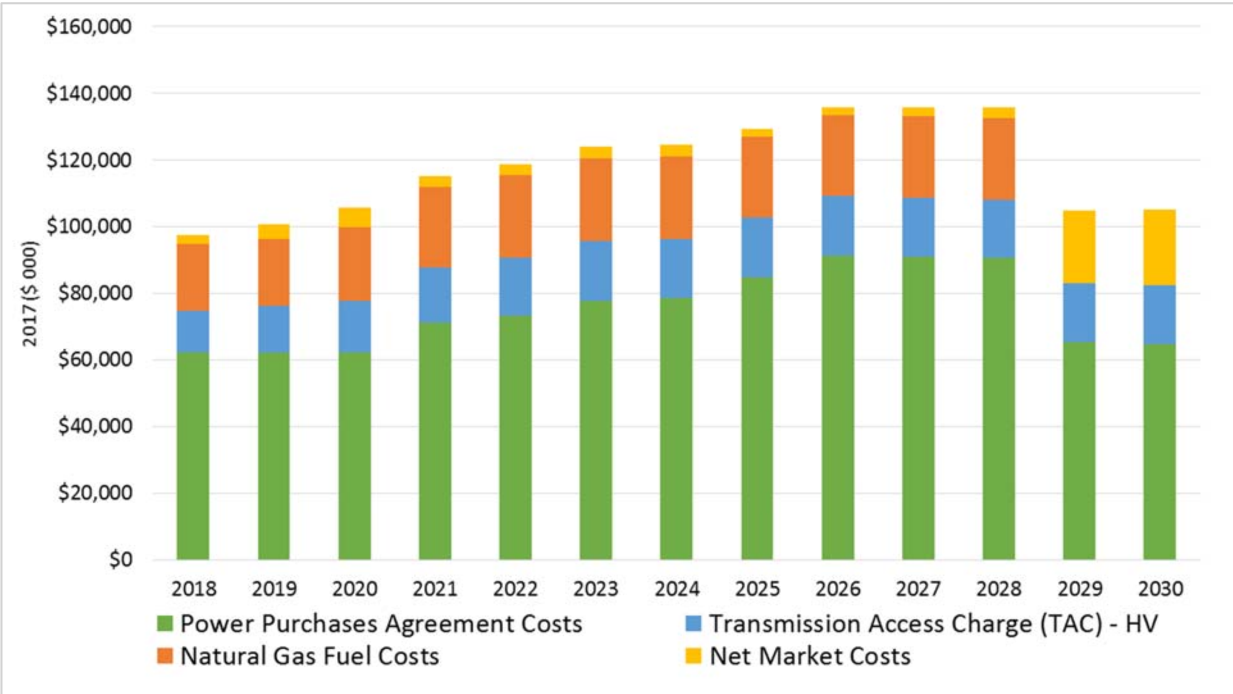


Figure 35 shows, on an annualized basis, average power supply costs from 2018-2028 are estimated to increase at a real rate of 0.86% per year.

Power supply cost represents only one component of the Utility cost of service that determines the overall retail rate. In addition to the power supply cost, the retail rate includes bond payments, reserve requirements, electric system capital improvement cost, operating & maintenance cost, administrative & general expenses, etc. Further, the power supply cost forecast is based on the real rate of change. It does not account for inflation. A cost of service study will adjust the power supply cost forecast based on annual inflation rates. Therefore, power supply costs are not a forecast of customers' total electric rates and should be only used by customers to gauge, at a high level, the impact of renewable procurement costs on their electric bills.

VPU is working on a Cost of Service (COS) study that will be used to forecast future retail rates. The power supply costs derived from this IRP will be used as one of the components in the COS study to determine retail rate impacts of the IRP.

14 Risk Analysis

A comprehensive review of the IRP allowed VPU to identify potential risks that may alter the IRP. The following sections provide a qualitative discussion of some of the risks that should be taken into consideration.

Regulatory Risk

The energy industry landscape is changing rapidly. Over a very short period of time, the RPS went from 20% to 33% then to 50% and most recently, with the passage of SB 100 into law VPU will need to comply with a 100% carbon-free energy mandate. The passage of SB 32 also requires load-serving entities to achieve a 40% reduction in GHG emissions from 1990's level by 2030, with further uncertainty if a proposed 80% GHG reduction by 2050 will be codified in the future. Proposed California legislation, Assembly Bill 1405 (AB 1405) and Assembly Bill 893 (AB 893), could also alter the portfolio planning requirements.

Assembly Bill 1405 (AB 1405) would define a four-hour peak-load time period that requires a percentage of that period be served with clean energy. Each utility would have to meet increasing clean peak targets every three years beginning in 2020, reaching 40% in 2029. AB 1405 would likely push utilities towards procuring more energy storage and would establish a "clean peak' standard.

AB 893 legislation, proposed by Assembly member Eduardo Garcia, would require California LSEs to purchase geothermal energy in support of climate change and diversification of the state's resource mix. The current version of AB 893 would require California utilities to buy 3,000 MW of new geothermal power by 2030. If this legislation is passed into law, development of vast geothermal resources in the Salton Sea area of the Imperial Valley may become a priority.

Resource Technology Risk

The resource technology that appears to be the best solution today may not be the most viable option ten years from now. Before solar PV gained market share as the dominant solar technology, solar thermal appeared to be the best technology. As much as the cost of solar technology has decreased in the past several years, the recent development of bi-facial (two-sided) solar panels could result in even further costs declines. Similarly, lithium ion (Li-ION) based battery technology appears to be the dominant energy storage resource, but a competing technology such as flow batteries may experience a manufacturing breakthrough and overtake Li-ION in the future.

To mitigate the technology risk VPU intends to avoid, if possible, being the early adopter of new technologies until they become commercially proven and costs stabilize. As such, the Preferred Portfolio recommends a gradual phasing in of energy storage from 1 MW in 2023 to 5 MW in 2028 to aid in renewable integration. A larger acquisition of 15 MW by 2029 is recommended as partial replacement for MGS. The Preferred Portfolio includes a total cumulative battery storage acquisition of 20 MW. Energy storage could be in the form of behind-the-meter or in front of the meter. Should another energy storage technology experience breakthrough in costs by 2029, VPU will still have the flexibility to evaluate other energy storage resources in addition to Li-ION.

It is difficult to forecast with great certainty the potential resources that will be available many years in the future. As a small utility, VPU would not take the lead on some of the larger power projects that have been proposed in the West. Large projects such as the Compressed Air Energy Storage (CAES) in Utah, 3,000 MW of wind in Wyoming, and a proposal by the Los Angeles Department of Water and Power (LADWP) to add large pumps to the Hoover hydro project are speculative today, but could be potential resource options by 2030. If some of the larger projects are eventually built, VPU may have the option to be an off-taker on those projects. These speculative projects were not evaluated as new resource options during this IRP cycle.

Natural Gas Price Risk

In the current planning environment, the price of natural gas is not a main driver of resource procurement decisions. Natural gas prices have a direct relationship to electricity prices and impact VPU fuel costs for operating natural gas-fired plants. Volatility in long-term natural gas prices have little bearing on the optimal resource plan because procuring renewable energy is the primary need. Transitioning to a cleaner energy supply will help VPU hedge against higher natural gas and GHG emission prices. Limitations on GHG emissions eliminates resource strategies that increase reliance on natural gas-fired generation. Even under a low natural gas price environment VPU would still pursue the same renewable procurement strategy.

Distributed Energy Resource Program Effectiveness

A major shift towards DERs over a long-term horizon could significantly reduce utility-scale resource procurement by VPU. The IRP recommends action plans to increase the level of DERs on the VPU system from very small penetration levels today.

The current levelized costs of solar indicates that utility-scale solar resources are lower cost than distributed solar, but costs are starting to converge. As renewable procurements increase over time, future utility-scale renewable resources will likely be located further away from urban areas such as the Mohave Desert or the Tehachapi region. Utility-scale renewable resources located in remote locations may require additional transmission to deliver power to California cities. Factoring in the cost of transmission upgrades for utility-scale renewable resources, it is possible that DG resource may become more cost-competitive.

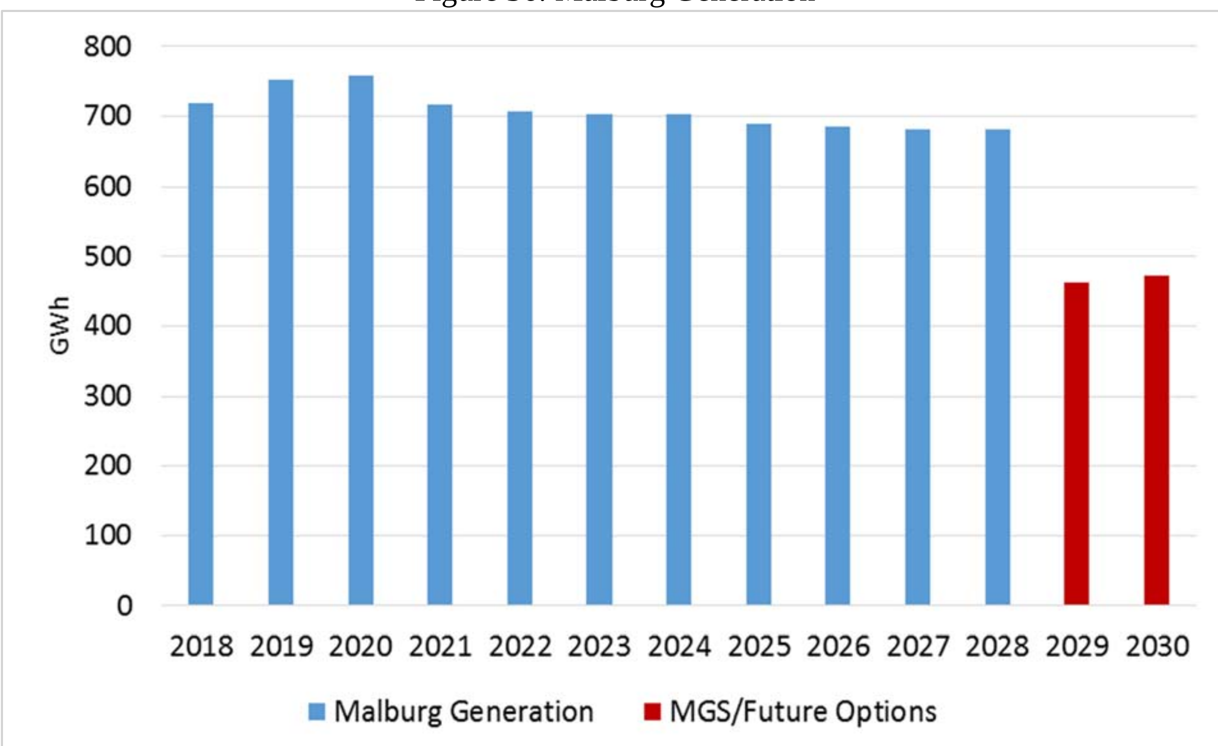
The base case forecast for EVs assumes a 1.7 MW load increase attributed to EVs in 2030, however, should transportation electrification increase significantly the impacts on VPU load could be significant.

Local Generation Risk

MGS is an important resource in the VPU power supply mix because it provides system reliability under a (N-2) system contingency. When the MGS PPA expires in 2028, VPU will need to develop a plan to replace the capacity and energy that was supplied by MGS with another local resource. As shown in Figure 36, MGS supplies VPU with a substantial portion of the energy necessary to serve load and meet RA requirements.

Figure 36 below shows the forecasted generation from MGS. From 2029 and beyond, either MGS or a replacement for MGS will need to generate at lower operating levels to support VPU GHG emission reduction goals.

Figure 36: Malburg Generation



VPU is currently evaluating options on how MGS can be reconfigured to provide more operational flexibility. The potential reconfiguration of the MGS plant as a resource option post-2028 was not evaluated as part of this IRP, however VPU assumed that the RA pricing would be a proxy for a reconfigured MGS plant.

Battery Storage Sensitivity

The projected future cost of energy storage is a major uncertainty that can have a large impact on future resource decisions. Reaching the 100% carbon-free goal by 2045 may require replacement of existing natural gas-fired resources with energy storage technology. VPU will be faced with such a resource decision when the existing MGS PPA expires in 2028. Energy storage sited locally could be a direct replacement for MGS if energy storage cost decrease at a rate faster than expected. The base case levelized cost of energy (LCOE) for the energy component (storage) of a battery is $38/kWh in 2030 and is expected to drop by 58% to $16/kWh in 2030 in the low sensitivity case. To test the risk associated with acquiring battery storage, VPU completed a sensitivity analysis that varied the cost of battery storage. The assumptions used in the energy storage cost sensitivity analysis are listed below:

<u>Battery Energy Storage Assumptions</u>

- 100 MW
- 85% Efficiency
- 100% Depth of Discharge(DOD)/100% State of Charge (SOC)
- Operate daily for 4 hours a day for 350 days/year
- 2030 Levelized Cost of Power =$28/kW
- 2030 Levelized Cost of Energy =$38/kWh
- Low Sensitivity - 2030 Levelized Cost of Power =$17/kW
- Low Sensitivity – 2030 Levelized Cost of Energy =$16/kWh
- 140,000 MWh annual generation
- Charging cost is equal to LCOE of solar

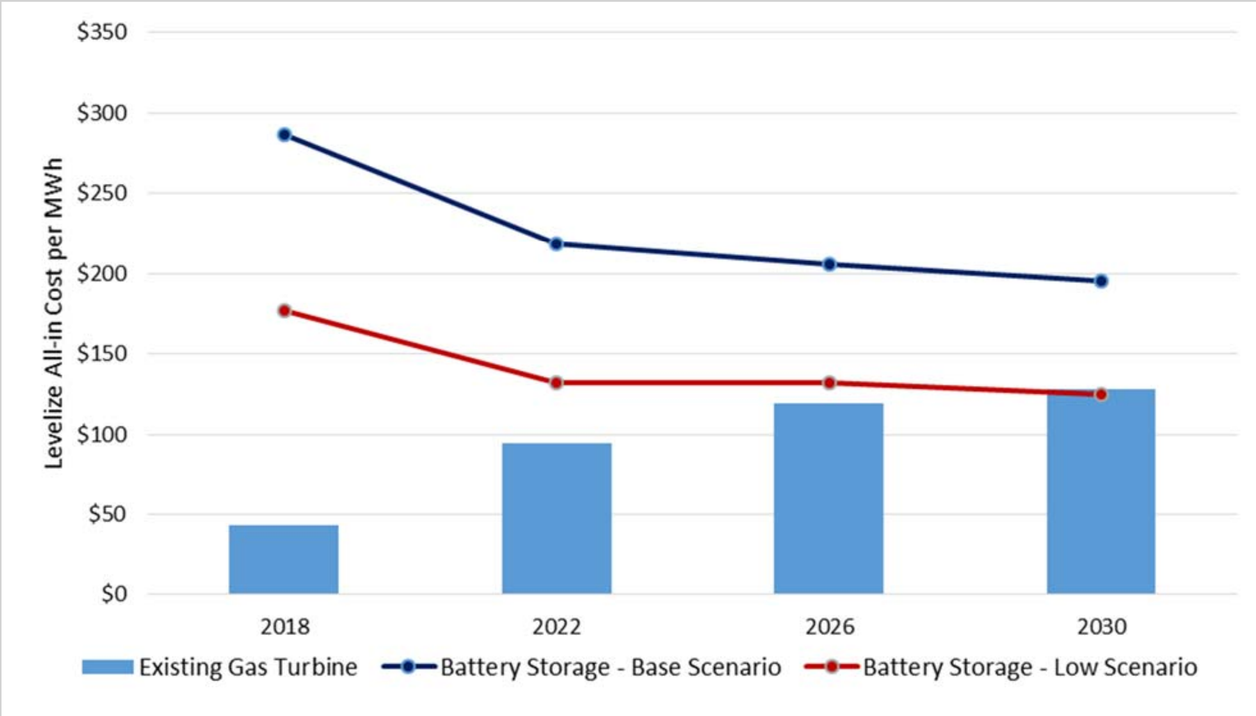
<u>Natural Gas Turbine Assumptions</u>

- 100 MW
- 2030 Levelized capital cost Existing Natural Gas Plant = $88/kW-yr
- 2030 Levelized capital cost New Natural Gas Plant = $197/kW-yr
- Heat Rate 10,000 Btu/kWh
- Variable O&M $3.65/MWh
- Operate daily for 4 hours a day for 350 days/year
- 2030 Natural Gas Prices = $4.28/MMBtu
- 2030 GHG Price = $39/metric ton
- 140,000 MWh annual generation

Under a low energy storage cost sensitivity, the all-in-cost of energy storage appears to be cost-competitive with natural gas-fired generation in future years. The all-in-cost is defined as the levelized capacity, storage, fuel, variable operating costs divided by the total annual generation.

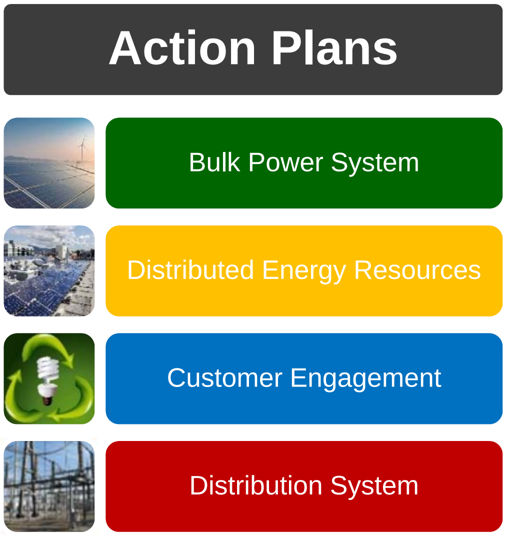
Figure 37 below shows the economic comparison between energy storage and an existing natural gas resource.

Figure 37: Low Energy Storage Cost Comparison with Natural Gas



The cost of operating natural gas-fired generation increases over time due to increasing capacity, fuel, and emission costs. The cost of energy storage is expected to decline over time due to decreasing capital costs. The cost of energy storage intersects with the cost of natural gas-fired generation in 2030 under the low energy storage cost sensitivity case. This high level sensitivity analysis was performed by VPU to stress test how energy storage costs could impact resource decisions. Faster declines in battery energy storage technology costs between now and 2028 could make replacing MGS with energy storage a viable resource option.

RECOMMENDED ACTION PLANS



The Preferred Portfolio is the main component of VPU's IRP. The Preferred Portfolio represents the resource procurement strategy at the bulk power system level to meet forecasted customer electric demand. The IRP is an optimal set of utility action plans that identifies the best investments, strategies, and planning approaches with regard to bulk power system resource procurement, distributed energy resources (DERs), customer engagement, and the distribution system. Implementing the roadmap outlined in the IRP requires defining action plans to implement the vision of the IRP. Some action plans will take more time to implement and will require many years to complete, however, there are action plans that will yield immediate results. It is important to commit to a direction to ensure that time, resources, and financial investments are maximized. Subsequent IRPs will refine the direction as additional information becomes available. The IRP allows for flexibility to incorporate necessary adjustments over time. The implementation of the IRP must be viable from a technical, regulatory and financial perspective to best balance reliability, environmental stewardship, and cost to ratepayer priorities.

The IRP identifies an optimal procurement strategy for large-scale energy resources at the wholesale transmission level, but VPU utilized an integrated approach which includes important investments in DERs to support long-term sustainability goals. Development of DER programs must take into consideration participation and benefits to low income and neighboring disadvantaged community members and not disproportionately benefit certain socio-economic demographics.

The following sections briefly describe the action plans recommended for implementation of the IRP.

15 Bulk Power System Action Plans

The Preferred Portfolio is the main component of the resource procurement strategy at the bulk power system level. Solar resources are targeted in the 4^{th} RPS Compliance Period from 2021-2024 based upon the Preferred Portfolio. Resource procurement recommendations past the 2021 - 2024 time period are less urgent and are more likely to change with the passage of time.

Utility-Scale Resource Procurement

Resource procurement is a multi-year comprehensive process. Among other things it may require identifying procurement options, timing, quantifying risk and benefits, diversification, solicitation through RFPs, contract negotiations, and project construction. Resource procurement for delivery in year 2021 should start immediately. The Preferred Portfolio recommends that VPU acquire as much as 65 MW of solar resources by 2021 increasing to a total of 85 MW by 2024. The timing and annual amounts may vary based upon offers received. VPU can solicit offers of solar PPAs either through a Request for Proposal (RFP) process conducted solely by VPU or in collaboration with existing SCPPA RFP process. The action plans for acquisition of utility-scale solar include:

1) Issue a renewable resource RFP to evaluate utility-scale solar and/or solar plus storage PPAs for delivery between 2021 and 2024;
2) Update solar cost and operating characteristics of submitted solar PPAs using a production cost model to re-evaluate impacts on the entire VPU resource portfolio; and
3) Request that CAISO provide a projection of future flexible capacity requirements corresponding to the addition of 65 to 85 MW of incremental utility-scale solar.

Malburg Generating Station

MGS is the single largest source of GHG on the VPU system, but because it is located in Vernon's service territory, it is a very important resource in the VPU power supply portfolio. MGS is a local resource that provides system reliability, provides ancillary services, integrates renewable energy and has the capability to generate dependable electricity when needed unlike intermittent solar and wind resources. When the existing MGS PPA expires in 2028, VPU cannot simply assume that MGS will be replaced by renewable energy resources without jeopardizing reliability. The MGS is the primary source of reliable generation in Vernon and under certain contingency situations, VPU system reliability could be compromised without native generation.

Below is a list of action plans VPU intends to undertake in the coming years related to MGS:

1) Evaluate reduced generation levels and options to reconfigure MGS to allow for more operational flexibility;
2) Evaluate alternative resource options to replace MGS when the existing PPA expires; and
3) Ensure MGS or an alternative local base load generation is in-place post 2028.

16 Distributed Energy Resources Action Plans

Customers that responded to the customer survey indicated an interest in distributed solar, electric vehicle infrastructure, and energy storage. VPU intends to provide outreach, education, and utility services to incentivize and facilitate investment and customer adoption of DERs to better adapt to a more decentralized power system. The sections below briefly describe the action plans related to DERs.

Distributed Solar

VPU is in the process of designing a Green Power Program. The Program will allow Vernon residents and businesses to meet their own sustainability goals by purchasing clean and affordable renewable energy through this program. The Program enables customers to offset all or a portion of their electricity usage with either renewable energy or renewable energy credits. In addition to the Green Power Program VPU is investigating programs that will:

1) Install solar systems at city-owned facilities and partner with customers to install at their facilities;
2) Evaluate a community solar product offering; and
3) Assist customers with installation of rooftop solar systems under existing net-metering tariffs.

Energy Efficiency

VPU has identified action plans to implement new energy efficiency measures throughout its city-owned facilities. In 2017, VPU realized approximately 3 GWh of energy efficiency savings. VPU has a goal to double its energy efficiency from 2017 and contribute toward the statewide goal of doubling energy efficiency. VPU also has a goal is to achieve 6 GWh, double the 2017 amount, by implementing the following energy efficiency action plans in cooperation with other City departments:

1) Continue existing energy efficiency programs and educate customers on more efficient uses of electricity;
2) Perform energy efficiency upgrades at all city-owned facilities as needed; and
3) Purchase energy efficient transformers, capacitors and other distribution equipment when appropriate.

Transportation Electrification

VPU is working to incentivize transportation electrification through investments in electric vehicle charging infrastructure. The presence and convenience of EV charging stations will motivate public purchases of electric vehicles, having a direct impact on local air quality conditions. The City of Vernon lacks open space (parks, libraries etc.) requiring greater participation from Vernon businesses for siting and installation of EV charging stations.

Load impacts from EVs are minimal today, by 2030 VPU intends to develop a plan to increase EVs to add 1.7 MW of load representing less than 0.5% of energy demand through cooperation with other City departments to:

1) Explore partnering with customers and car dealerships to install and maintain EV charging stations at customer facilities;
2) Evaluate increasing the number of City-owned electric vehicles; and
3) Coordinate with local air quality agencies on available programs and initiatives.

Demand Response and Energy Storage

Demand response is one of the ways customers can conserve energy by curtailing electricity usage when it is most needed by the electric grid. Demand response programs have proven to be an effective means for utilities to manage system peaks by controlling customer loads. By participating in demand response programs, customers can help VPU achieve California GHG emissions reduction goals and delay infrastructure investments by the utility. Further, customers can be financially compensated for reducing usage when the price of energy is at its highest.

VPU has a reliability driven interruptible load program, but no DR customer programs based upon market pricing. Below is a list of demand response program and energy storage action plans VPU intends to evaluate and undertake in the coming years:

1) Implement a Voluntary Load Reduction Program offering discounted rates to customers that reduce their load;
2) Provide customer education on demand response programs available through the CAISO and encourage participation in these programs; and
3) Participate in strategic partnerships with customers to advance energy storage opportunities.

17 Customer Engagement Action Plans

As part of the IRP process VPU conducted customer and stakeholder outreach through a survey that solicited input on topics such as the IRP, customer service and DERs. Feedback received from the customer survey indicated that low rates and reliable power were primary concerns for the majority of customers. Customer feedback from the survey and from the stakeholder meetings also indicated a growing interest in distributed solar, electric vehicle infrastructure, and energy storage. Action plans for customer engagement will include.

1) Collect and prioritize customer feedback on the IRP;
2) Increase the frequency of customer outreach and educational events; and
3) Offer more utility products and services to customers.

18 Distribution System Action Plans

VPU has maintained a highly reliable electric system and was awarded Diamond Level Reliable Public Power Provider by the American Public Power Association (APPA). VPU has developed a distribution system capital improvement program aimed at replacing aging infrastructure and making permanent repairs to distribution equipment and facilities. Through the program, VPU successfully reduced the frequency and duration of distribution outages, maintained system reliability, improved safety, system efficiency, and operating flexibility. As the power system becomes more decentralized, the VPU distribution system will need to evolve, modernize and incorporate emerging technology to support higher penetration levels of DERs.

Below is a list of distribution system action plans VPU intends to undertake in the coming years:

1) Continue to replace and upgrade Vernon distribution aging infrastructure in order to maintain system reliability;
2) Implement new distribution system automation by installing intelligent line switches that can be operated remotely and
3) Upgrade line conductors, transformers, and complete voltage conversions at electric substations.

19 Next Steps

This IRP outlines the VPU plan to satisfy the VPU system reliability, meet California RPS and GHG reduction mandate, reduce natural gas generation from local power plants, increase customer-sited solar generation, partner with customers to deploy electric vehicle charging stations to promote the electrification of the transportation industry, and offer various energy efficiency improvement programs. VPU's integrated approach in transitioning to a sustainable power supply includes procuring renewable resources at the wholesale level in addition to developing programs to increase DER adoption across the entire system.

VPU presented results from the IRP to stakeholders on September 27, 2018, posted the presentation on the City's website and solicited report comments from stakeholders. VPU plans to present the IRP to the City Council on November 20, 2018.

Table 21 is a schedule of targeted dates for completion of the IRP process.

Table 21: IRP Schedule of Events

Item	Event	Date
1	Integrated Resource Plan Introduction	02/14/2018
2	Integrated Resource Plan Update	03/29/2018
3	Integrated Resource Plan Preliminary Results	05/02/2018
4	Integrated Resource Plan Summary and Action Plan	09/27/2018
5	Plan Posted on City Website	10/23/2018
6	Integrated Resource Plan Customer Feedback	11/07/2018
7	Integrated Resource Plan City Council Approval	11/20/2018

The IRP must be filed with the CEC by January 1, 2019. The approach, analysis, and completed standardized reporting requirements are in compliance with the IRP guidelines developed by the CEC.

20 Conclusion

VPU has a strong foundation of reliable, affordable, and sustainable electric service. The IRP identified a long-term strategy that includes a specific set of optimal resources based on known and reasonable planning assumptions. The results of the IRP will be used to chart a resource acquisition strategy favoring more renewable energy and fewer carbon-emitting resources. VPU is well-positioned to meet its energy needs and regulatory obligations for the next three years. VPU’s current long supply position affords the utility the luxury to revisit long-term plans and strategies set forth in the IRP when new information regarding pending regulatory proceedings and legislation becomes available or when market conditions change. The results of the IRP will also be used to support a broader resource planning study across California with GHG target-setting being performed by the CPUC, CEC, and CARB.

Feedback from customers indicate a desire for VPU to provide more incentives, educational services, utility product offerings and services to support more DERs. VPU used this information to identify actionable steps in which VPU can provide economic, health and environmental benefits to customers. The IRP represents a diversified, least-cost resource plan that satisfies VPU system reliability, compliance with RPS requirements, and reduction of GHG emissions.

APPENDIX A: CEC STANDARDIZED TABLES FOR RECOMMENDED PREFERRED PORTFOLIO

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

Scenario Name: Preferred Portfolio

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

Units = MW

			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	PEAK LOAD CALCULATIONS															
1	Forecast Total Peak-Hour 1-in-2 Demand			182	199	206	206	207	208	208	209	209	209.8	210.5	211.3	212.1
2	[Customer-side solar: nameplate capacity]			0	0.7	1.1	1.4	1.8	2.1	2.4	2.7	2.9	3.1	3.3	3.5	3.4
2a	[Customer-side solar: peak hour output]			0	0.3	0.4	0.5	0.7	0.8	0.8	0.9	1.0	1.0	1.0	1.1	1.0
3	[Peak load reduction due to thermal energy storage]			0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	[Light Duty PEV consumption in peak hour]			0	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.2	1.3	1.4	1.6	1.7
5	Additional Achievable Energy Efficiency Savings on Peak			1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
6	Demand Response / Interruptible Programs on Peak			13	25	25	25	25	25	25	25	25	25	25	25	25
7	**Peak Demand (accounting for demand response and AAEE) (1-5-6)**			169	174	180	181	181	182	183	183	184	184	185	186	187
8	Planning Reserve Margin			25	26	27	27	27	27	27	27	28	28	28	28	28
9	Firm Sales Obligations			0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total Peak Procurement Requirement (7+8+9)**		0	194	200	207	208	209	209	210	211	211	212	213	214	215
	EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES															
	Utility-Owned Generation and Storage (not RPS-eligible):	For fuel type, choose from list or enter value														
	[list resource by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11a	H Gonzales 1 & 2			10	10	10	10	10	10	10	10	10	10	10	10	10
	Long-Term Contracts (not RPS-eligible):															
	[list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11h	Boulder Canyon (Hoover)			17	17	17	17	17	17	17	17	17	17	17	17	17
11i	Malburg Combined Cycle			134	134	134	134	134	134	134	134	134	134	134		
11j	Palo Verde Nuclear			11	11	11	11	11	11	11	11	11	11	11	11	11
11	**Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a...11n)**		0	172	172	172	172	172	172	172	172	172	172	172	38	38
	Utility-Owned RPS-eligible Resources:															
	[list resource by plant or unit]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12n																
	Long-Term Contracts (RPS-eligible):															
	[list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12o	Puente Hills Landfill			8.7	7.8	7.4	7.0	6.4	6.1	5.7	5.3	5.0	4.8	4.4	4.2	4.0
12p	Antelope DSR Solar PV			10.3	10.0	9.8	9.5	9.3	9.0	8.8	8.5	8.3	8.0	7.8	7.5	7.3
12q	Astoria Solar PV			8.2	8.0	7.8	7.6	11.1	10.8	10.5	10.2	9.9	9.6	9.3	9.0	8.7
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a...12t)**		0	27	26	25	24	27	26	25	24	23	22	21	21	20
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		0	199	198	197	196	199	198	197	196	195	194	193	59	58
	GENERIC ADDITIONS															
	NON-RPS ELIGIBLE RESOURCES:															
	[list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
14a	Market Resource Adequacy Purchases Flex							10	20	20	20	30	30	30	70	70
14b	New Energy Storage								1	2	3	4	5	5	20	20
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		0	0	0	0	0	10	21	22	23	34	35	35	90	90
	RPS-ELIGIBLE RESOURCES:															
	[list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
15a	New Solar PV 1	Solar PV					25	24	23	23	22	21	20.8	20.15	19.5	18.9
15b	New Solar PV 2	Solar PV							7.2	7.0	6.8	6.6	6.4	6.2	6.0	5.8
15c	New In-State Wind	Wind									2	2	2	2	2	1.9
15d	New Solar PV 3	Solar PV										7	6.4	6.2	6	5.8
15e	New Geothermal 1	Geothermal													20	20
15	**Total peak dependable capacity of generic RPS-eligible resources**				0	0	25	24	31	30	31	37	35	34	53	52
16	**Total peak dependable capacity of generic supply resources (14+15)**				0	0	25	34	52	52	54	71	70	69	143	142
	CAPACITY BALANCE SUMMARY															
17	**Total peak procurement requirement (from line 10)**		0	194	200	207	208	209	209	210	211	211	212	213	214	215
18	**Total peak dependable capacity of existing and planned supply resources (from line 13)**		0	199	198	197	196	199	198	197	196	195	194	193	59	58
19	**Current capacity surplus (shortfall) (18-17)**		0	5	(2)	(10)	(12)	(10)	(12)	(13)	(15)	(16)	(18)	(19)	(155)	(157)
20	**Total peak dependable capacity of generic supply resources (from line 16)**				0	0	25	34	52	52	54	71	70	69	143	142
21	**Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)**		0	5	(2)	(10)	13	24	40	39	39	54	53	50	(12)	(14)

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

Scenario Name:

Units = MWh

Yellow fill relates to an application for confidentiality.

Historical Data

	NET ENERGY FOR LOAD CALCULATIONS	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Retail sales to end-use customers	1,061,829	1,078,083	1,182,118	1,222,141	1,225,720	1,230,251	1,235,554	1,240,328	1,244,526	1,248,683	1,253,778	1,259,659	1,265,721	1,272,031
2	Other loads														
3	Net energy for load	1,104,302	1,122,659	1,226,039	1,265,994	1,268,035	1,271,107	1,275,011	1,278,384	1,281,168	1,283,913	1,287,636	1,292,171	1,296,889	1,304,423
4	Retail sales to end-use customers (accounting for AAEE impacts)	1,061,829	1,083,066	1,193,636	1,204,467	1,217,314	1,220,262	1,224,011	1,227,248	1,229,921	1,232,556	1,236,130	1,240,484	1,245,013	1,252,246
5	Net energy for load (accounting for AAEE impacts)	1,104,302	1,122,659	1,226,039	1,265,994	1,268,035	1,271,107	1,275,011	1,278,384	1,281,168	1,283,913	1,287,636	1,292,171	1,296,889	1,304,423
6	Firm Sales Obligations														
7	Total net energy for load (accounting for AAEE impacts) (5+6)	1,104,302	1,122,659	1,226,039	1,265,994	1,268,035	1,271,107	1,275,011	1,278,384	1,281,168	1,283,913	1,287,636	1,292,171	1,296,889	1,304,423
8	[Customer-side solar generation]			3,949	6,138	8,327	10,516	12,705	14,893	17,082	19,271	21,460	23,649	25,838	25,580
9	[Light Duty PEV electricity consumption/procurement requirement]			1,894	2,417	2,986	3,593	4,227	4,879	5,543	6,211	6,878	7,541	8,196	8,860
10	[Other transportation electricity consumption/procurement requirement]			-	-	-	-	-	-	-	-	-	-	-	-
11	[Other electrification/fuel substitution; consumption/procurement requirement]			-	-	-	-	-	-	-	-	-	-	-	-

EXISTING AND PLANNED GENERATION RESOURCES

	Utility-Owned Generation Resources (not RPS-eligible): [list resource by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12a	H Gonzales 1 & 2			0	#	#	#	#	#	#	#	#	0	0	0	0
	Long-Term Contracts (not RPS-eligible): [list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12h	Boulder Canyon (Hoover)			21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
12i	Malburg Combined Cycle			719,478	753,388	759,080	716,285	707,779	703,736	702,774	688,940	685,575	681,193	680,788		
12j	Palo Verde Nuclear			94,200	94,200	94,464	94,200	94,200	94,200	94,464	94,200	94,200	94,200	94,464	94,200	94,200
12	Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a...12n)		0	834,678	868,588	874,544	831,485	822,979	818,936	818,238	804,140	800,775	796,393	796,252	115,200	115,200
	Utility-Owned RPS-eligible Generation Resources: [list resource by plant or unit]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
13a																
	Long-Term Contracts (RPS-eligible): [list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
13o	Puente Hills Landfill		92,841	61,320	61,320	61,488	61,320	56,046	53,023	50,465	46,512	43,488	42,093	39,070	36,512	34,651
13p	Antelope DSR Solar PV		70,645	70,645	70,291	69,940	69,590	69,242	68,896	68,552	68,209	67,868	67,528	67,191	66,855	66,520
13q	Astoria Solar PV		53,684	53,684	53,416	53,148	52,883	91,000	90,545	90,092	89,642	89,193	88,747	88,304	87,862	87,423
13	Total energy from RPS-eligible resources (sum of 13a...13t, and 13z)		217,170	185,649	185,027	184,576	183,793	216,289	212,464	209,109	204,362	200,550	198,369	194,564	191,229	188,595
13z	Undelivered RPS energy															
14	Total energy from existing and planned supply resources (12+13)		217,170	1,020,327	1,053,615	1,059,120	1,015,277	1,039,268	1,031,400	1,027,346	1,008,502	1,001,325	994,761	990,816	306,429	303,795

GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
15a	New Energy Storage	0							0	0	0	0	0	0	0	0
15	Total energy from generic supply resources (not RPS-eligible)				0	0	0	0	0	0	0	0	0	0	0	0
	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
16a	New Solar PV 1	Solar PV		0	#	#	199,000	199,000	261,000	261,000	261,000	322,000	322,000	322,000	322,000	322,000
16b	New In-State Wind	Solar PV		0	#	#	0	0	0	0	79,000	79,000	79,000	79,000	79,000	79,000
16c	New Geothermal 1	Wind		0	#	#	0	0	0	0	0	0	0	0	148,920	148,920
16	Total energy from generic RPS-eligible resources				0	0	199,000	199,000	261,000	261,000	340,000	401,000	401,000	401,000	549,920	549,920
17	Total energy from generic supply resources (15+16)				0	0	199,000	199,000	261,000	261,000	340,000	401,000	401,000	401,000	549,920	549,920
17z	Total energy from RPS-eligible short-term contracts															

ENERGY FROM SHORT-TERM PURCHASES

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
18	Short term and spot market purchases:		124,000	181,618	214,218	129,131	132,074	132,904	138,725	103,959	110,046	119,172	124,508	462,356	471,170
18a	Short term and spot market sales (only report sales of energy from resources already included in the EBT):		21,395	8,922	7,071	75,101	98,964	150,021	148,415	171,021	228,186	227,025	223,881	21,544	20,189

ENERGY BALANCE SUMMARY

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
19	Total energy from supply resources (14+17+17z)		1,020,327	1,053,615	1,059,120	1,214,277	1,238,268	1,292,400	1,288,346	1,348,502	1,402,325	1,395,761	1,391,816	856,349	853,715
19a	Undelivered RPS energy (from 13z)		0	0	0	0	0	0	0	0	0	0	0	0	0
20	Net Short term and spot market purchases (18 - 18a)		102,605	172,696	207,146	54,030	33,111	(17,117)	(9,691)	(67,063)	(118,140)	(107,854)	(99,373)	440,812	450,980
21	Total delivered energy (19-19a+20)		1,122,931	1,226,311	1,266,266	1,268,307	1,271,379	1,275,283	1,278,656	1,281,440	1,284,185	1,287,908	1,292,443	1,297,161	1,304,695
22	Total net energy for load (from 7)		1,122,659	1,226,039	1,265,994	1,268,035	1,271,107	1,275,011	1,278,384	1,281,168	1,283,913	1,287,636	1,292,171	1,296,889	1,304,423
23	Surplus/Shortfall (21-22)		272	272	272	272	272	272	272	272	272	272	272	272	272

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

Scenario Name:

Yellow fill relates to an application for confidentiality.

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

1,000,000

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY RESOURCES

	Utility-Owned Generation (not RPS-eligible): [list resource by name]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1a	H Gonzales 1 & 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	Long-Term Contracts (not RPS-eligible): [list contracts by name]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1h	Boulder Canyon (Hoover)	0		0	0	0	0	0	0	0	0	0	0	0	0	0
1i	Malburg Combined Cycle	0.426		0.307	0.319	0.321	0.303	0.300	0.299	0.299	0.294	0.293	0.292	0.292	0	0
1j	Palo Verde Nuclear	0		0	0	0	0	0	0	0	0	0	0	0	0	0
1	Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a...1n)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

	Utility-Owned RPS-eligible Generation Resources: [list resource by plant or unit]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2a																

	Long-Term Contracts (RPS-eligible): [list contracts by name]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2o	Puente Hills Landfill	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2p	Antelope DSR Solar PV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
sq	Astoria Solar PV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total GHG emissions from RPS-eligible resources (sum of 2a...2t)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Total GHG emissions from existing and planned supply resources (1+2)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

EMISSIONS FROM GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
4a	New Energy Storage								0	0	0	0	0	0	0	0
4	Total GHG emissions from generic supply resources (not RPS-eligible)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
5a	New Solar PV 1						0	0	0	0	0	0	0	0	0	0
5b	New In-State Wind										0	0	0	0	0	0
5c	New Geothermal 1														0	0
5	Total GHG emissions from generic RPS-eligible resources		0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total GHG emissions from generic supply resources (4+5)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
7	Net spot market/short-term purchases:	0.428	0	0.044	0.074	0.089	0.023	0.014	-0.007	-0.004	-0.029	-0.051	-0.046	-0.043	0.189	0.193

TOTAL GHG EMISSIONS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8	Total GHG emissions to meet net energy for load (3+6+7)	0	0.3505	0.3930	0.4097	0.3262	0.3144	0.2915	0.2947	0.2652	0.2425	0.2456	0.2495	0.1887	0.1930

EMISSIONS ADJUSTMENTS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8a	Undelivered RPS energy (MWh from EBT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8b	Firm Sales Obligations (MWh from EBT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8c	Total energy for emissions adjustment (8a+8b)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8d	Emissions intensity (portfolio gas/short-term and spot market purchases)														
8e	Emissions adjustment (8Cx8D)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PORTFOLIO GHG EMISSIONS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8f	Adjusted Portfolio emissions (8-8e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
[illegible]	GHG emissions reduction due to [illegible] displacement - LD PEV		0.00083	0.00108	0.00136	0.00166	0.00199	0.00233	0.00268	0.00304	0.00341	0.00377	0.00413	0.00448	0.00484
10	GHG emissions increase due to LD PEV electricity loads		0.000450	0.000609	0.000783	0.000797	0.000935	0.001055	0.001225	0.001292	0.001397	0.001557	0.001718	0.001230	0.001349
11	GHG emissions reduction due to fuel displacement - other transportation electrification		0	0	0	0	0	0	0	0	0	0	0	0	0
12	GHG emissions increase due to increased electricity loads - other transportation electrification		0	0	0	0	0	0	0	0	0	0	0	0	0

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

Scenario Name:

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	Beginning balances Start of 2017	Compliance Period 3					Compliance Period 4					Compliance Period 5				Compliance Period 6		
			2017	2018	2019	2020		2021	2022	2023	2024		2025	2026	2027		2028	2029	2030
1	Annual Retail sales to end-use customers (accounting for AAEE impacts) (From EBT)		1,061,829	1,083,066	1,193,636	1,204,467		1,217,314	1,220,262	1,224,011	1,227,248		1,229,921	1,232,556	1,236,130		1,240,484	1,245,013	1,252,246
2	Green pricing program Exclusion, (may include other exclusions like self generation exclusion)																		
3	Soft target (%)		27.00%	29.00%	31.00%	33.00%		34.75%	36.50%	38.25%	40.00%		41.67%	43.33%	45.00%		46.67%	48.33%	50.00%
4	Required procurement for compliance period		1,368,284					1,827,496					1,602,833				1,806,772		
	Category 0, 1 and 2 Resources (bundled with RECs)																		
5	Excess balance at beginning/end of compliance period						0					0				0			
6	RPS-eligible energy procured (copied from EBT)		215,870	217,170	185,649	185,027		382,793	415,289	473,464	470,109		544,362	601,550	599,369		595,564	741,149	738,515
6A	Amount of energy applied to procurement obligation		215,870	217,170	185,649	185,027		382,793	415,289	473,464	470,109		544,362	601,550	599,369		595,564	741,149	738,515
7	Net purchases of Category 0, 1 and 2 RECs		89,618	170,515	170,515	170,515		35,000	34,825	34,651	34,478		34,305	34,134	33,963		33,793	33,624	33,000
7A	Excess balance and REC purchases applied to procurement obligation		89,618	170,515	170,515	170,515		35,000	34,825	34,651	34,478		34,305	34,134	33,963		33,793	33,624	33,000
8	Net change in balance/carryover (RECs and RPS-eligible energy) (6+7-6A-7A)		0	0	0	0		0	0	0	0		0	0	0		0	0	0
	Category 3 Resources (unbundled RECs)																		
9	Excess balance at beginning/end of compliance period						120,000					120,000				120,000			
10	Net purchases of Category 3 RECs			40,000	40,000	40,000													
11	Excess balance and REC purchases applied to procurement obligation																		
12	Net change in REC balance			40,000	40,000	40,000		0	0	0	0		0	0	0		0	0	0
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		1,404,877					1,880,608					1,847,682				2,175,645		
14	Over/under procurement for compliance period (13 - 4)		36,593					53,112					244,849				368,873		

APPENDIX B: EXISTING ELECTRICAL AND WATER SYSTEM

Vernon Service Territory

The area served by the Vernon electric utility includes approximately 5.2 square miles, located approximately four miles southeast of downtown Los Angeles. Appendix 1 below shows the location of the City of Vernon relative to other Los Angeles area electric utilities and its service territory boundary.

Appendix 1: City of Vernon Electric Utility Service Territory

Bulk Transmission System

The California restructuring statute, AB 1890, established the California Independent System Operator (CAISO) as the balancing authority[13] for investor owned utilities (IOUs) in the state. Municipal utilities which had transmission agreements with IOUs were also included in the jurisdiction of the newly established balancing authority, although POUs, unlike IOUs, were not required to transfer operational control of transmission assets. POUs which had previously

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13. Balancing Authority – Entity responsible for ensuring generation and load is balanced to maintain frequency and voltage stability for electricity users

operated in separate balancing authorities, such as the Los Angeles Department of Water and Power and Imperial Irrigation District, continued operation of these balancing authorities.

VPU was among the municipal utilities whose load came under the jurisdiction of the CAISO. VPU's load and its generation resources are located within the CAISO balancing authority area and access to the CAISO transmission grid is required for delivery of market energy purchases to support the Vernon electric system's load. Vernon customers pay Transmission Access Charges (TAC) and CAISO Grid Management Charge (GMC) under the Transmission Control Agreement (TCA) with the CAISO. When CAISO approves new transmission system upgrades and expansion requirements within the CAISO control area, the capital costs are rolled into the general transmission rates of the Participating Transmission Owners (PTO) and recovered through the CAISO grid TAC.

Transmission Service Agreements

Vernon is a transmission dependent utility. Historically, Vernon has relied on transmission contracts with LADWP and SCE to transmit its out-of-state power supply resources to Vernon's electric system load. VPU transmission contract entitlements include:

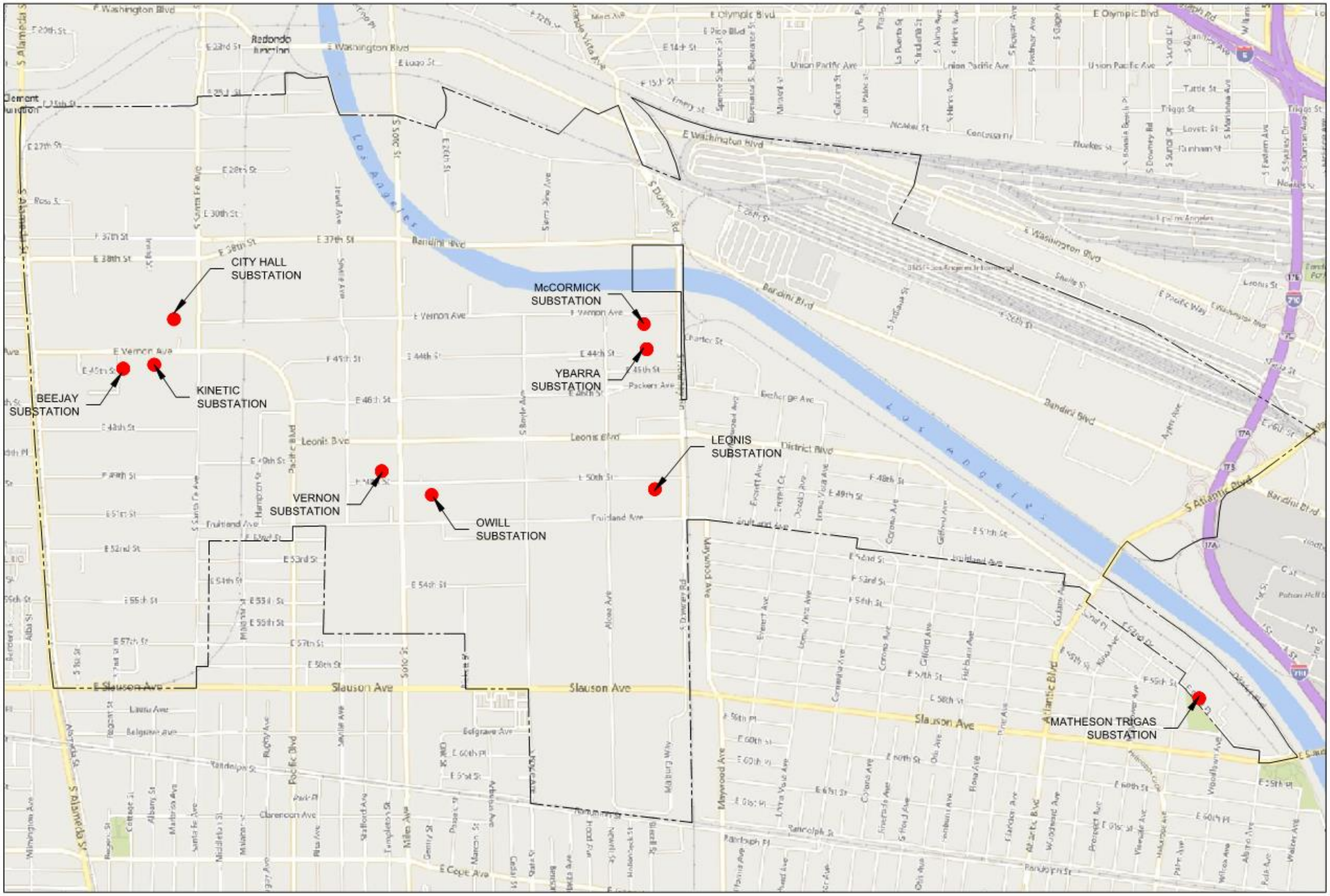
- 81 MW from Victorville-Lugo Midpoint 500 kV line that interconnects the LADWP Victorville substation to the SCE Lugo substation;
- 11 MW from Lugo Midpoint-Laguna Bell 500 kV line that interconnects the SCE Lugo substation to the Vernon Laguna Bell substation; and
- 26 MW from Mead-Laguna Bell 230 kV line that interconnects the SCE Mead substation to the Vernon Laguna Bell substation.

The City has rights to transmit through Lugo Midpoint-Laguna Bell line its share of generation from PVNGS, and also transmit through Mead-Laguna Bell line its entitlement to Hoover generation. The City has additional rights to use these transmission lines to import power from wholesale market purchases. As a PTO in the CAISO markets, Vernon turned over to the CAISO all of its power scheduling rights under its transmission contracts for CAISO's use. Vernon expects to continue to be a PTO in the CAISO market for the foreseeable future.

Distribution System

VPU is connected to the bulk transmission grid operated by the CAISO through five 66-kV lines. VPU's service territory includes 145 miles of transmission and distribution lines and includes three voltage levels, 7kV, 16 kV and 66 kV. Approximately 80 percent of the distribution system conductors and lines are overhead. The VPU electric system has eight substations, five of which are regular distribution substations and three are dedicated customer substations.

Appendix 2: City of Vernon Substation Map



The VPU electric system is unique due to the nature of its load (commercial and industrial load comprises 99 percent of VPU's demand and energy sales) and small geographical service area. Large industrial and commercial loads create abnormal challenges for electric system operation and protection. The small geographical service area and dense loading results in shorter than average distribution circuits with multiple circuits on the same pole (Birla, 2015).

In June 2015, VPU completed a DG Impact Study to determine the impact of allowing such as solar photovoltaic (PV) facilities, diesel and natural gas fueled facilities and wind generators, to interconnect their distribution system. The study included an assessment of the impacts of DG on the following areas: physical and operational impacts on the distribution system, the environment, public safety, and the fiscal impacts on rate payers. In addition, the current mandatory requirement of a Conditional Use Permit (CUP) for all DGs regardless of the size and type of DG was reviewed and analyzed.

Based on the assessment and analysis of each area of study, the report includes a recommended optimal level of DGs without causing significant impacts. Finally, the study also includes a review of current electric rates to evaluate potential financial impacts associated with allowing increased levels of DGs on the distribution system and recommended restructuring of electric rates for long-term financial security and stability.

The results of the DG Impact Study indicate that:

- The existing distribution system can generally support DG up to a full peak load 190 MW, but no DG can be connected to any of Leonis Substation 7 kV distribution circuits until the feeder circuit breaker is replaced with higher interrupting current rating.
- As required by net metering law and AB 327, allowing DG up to 5% of peak loads (non-coincident peak load of each class of customers); 9,924 kW based on the 2014 peak load.
- Solar PV projects up to 1.0 MW can be exempted from the conditional use permit (CUP) requirements without significant environmental impacts. The CUP requirement should be maintained for the other types of DG evaluated in the study and solar PV projects above 1.0 MW.
- Existing regulations will provide adequate safety protection related to hazardous materials that may be associated with solar PV, fuel cells and fossil-fuel DG projects. Electric safety hazards are manageable by adopting prudent operating and maintenance procedures, interconnections agreement requirements, and guidelines and requirements of compliance of DG with industry standards such as IEEE Std.1547 and UA 1741.

The following recommendations were identified based on the results of the study:

- Permit solar PV DG up to 1.0 MW without CUP process and continue CUP process for all other types of DG both renewable and non-renewable. Modify and update CUP language regarding diesel engines strictly used as a back-up and stand by generators, to clarify that those are exempt from the CUP.
- All 7 kV circuit breakers at the Leonis substation should be replaced with higher interrupting current rating as soon as practical and before any DG is connected to 7 kV circuits.

- Continue to upgrade Vernon electric distribution infrastructure in order to maintain system reliability
- Upgrade line conductors, transformers, and other aging infrastructure
- Convert electric substations from 7 kV to 16 KV

VPU has maintained a highly reliable electric system and was awarded Diamond Level Reliable Public Power Provider by the American Public Power Association (APPA). VPU has developed a distribution system capital improvement program aimed to replace aging infrastructure and make permanent repairs to distribution infrastructure. Through the program, VPU successfully reduced the number of distribution outages, maintained system reliability, improved safety, system efficiency, and operating flexibility. As the power systems becomes more decentralized the VPU distribution system will need to evolve and modernize to support higher penetration levels of DERs. As adoption of DERs increase over time additional upgrades to the distribution system will be needed to support resources that may reside at the grid's edge.

Below is a list of distribution system action plans VPU intends to undertake in the coming years:

1) Continue to replace and upgrade Vernon distribution aging infrastructure in order to maintain system reliability;
2) Implement new distribution system automation by installing intelligent line switches that can be operated remotely and
3) Upgrade line conductors, transformers, and complete voltage conversion at electrical substations.

Distribution System Capital Improvement Program (CIP)

Vernon has conducted an assessment of its Distribution System to ascertain the condition of the existing system. The study has identified a number of distribution improvements that are needed to maintain system reliability, improve safety, system efficiency, and operating flexibility. VPU developed a seven-year Capital Improvement Plan to achieve these objectives. The CIP details a solid program aiming to achieve an overarching strategic vision that addresses the five square miles and uniquely industrial characteristics that make-up the City. The Plan defines strategies that involve an in-depth evaluation of the condition of the electric system; performs a detailed engineering analysis of distribution system capability and performance; and lists construction and upgrade projects to transform the system into an intelligent electric system.

While VPU is not subject to CPUC jurisdiction, it follows CPUC General Orders (GO) as a best practice. The inspections are performed in adherence with GO 165 and GO 174. As a result of the inspections, VPU has replaced over 650 deteriorating wood power poles that were identified under the CPUC general order standards; has completed the replacement of 30 oil filled substation circuit breakers; has replaced aging underground substation getaway cables; has replaced numerous electromechanical relays with solid state relays; has performed voltage conversion on limited segments of its distribution system; has installed a fully functional geographic Information system (GIS) and has performed many additional upgrades and replacements of capital infrastructure. VPU is currently in the process of replacing aging substation transformers. Construction of a new distribution substation has been prioritized in the seven year Capital Improvement Plan to address the needs of an aging infrastructure and is currently in the planning stage.

Other than measures identified above, VPU has included in its CIP plans the replacement over 2000 HPS street lights with LEDs resulting in 200KW net system load reduction and 0.8 GWH of energy; replacement of less efficient distribution and power transformers; installation of distribution line capacitor banks resulting 1.8MW net system load reduction and the expansion of automated line switches and real time customer meter reading.

System Reliability

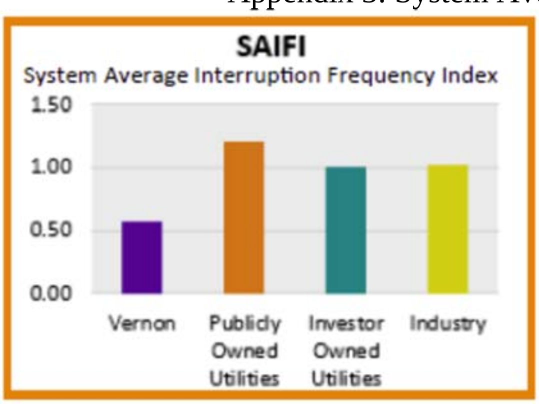
VPU prides itself on supplying customers with a highly reliable electrical system. VPU was awarded Diamond Level Reliable Public Power Provider by the American Public Power Association. Appendix 3 includes VPU's reliability indices charts for 2017.

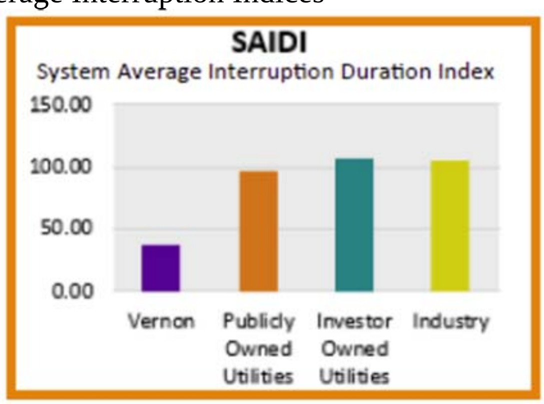
1) System Average Interruption Frequency Index (SAIFI)

2) System Average Interruption Duration Index (SAIDI)

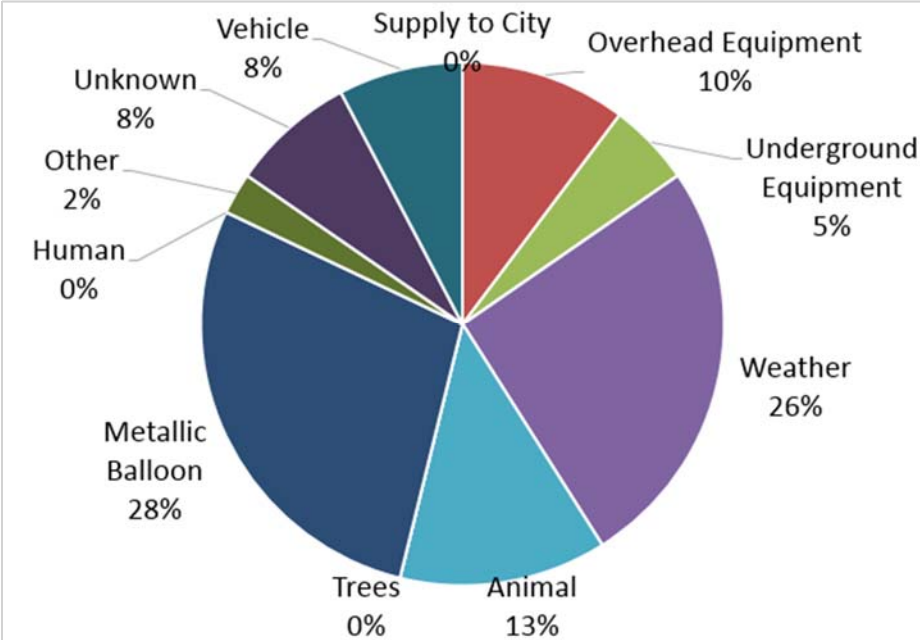
SAIDI is a measure of the average outage duration for the average customer over a defined period of time such as one year. SAIFI is an indicator of average number of interruptions that a customer experiences over a given period of time and is measured in units of interruptions per customer. VPU's SAIFI and SAIDI indices are well below the average SAIDI and SAIFI indices for POUs and IOUs. Appendix 4 shows the typical outage causes in VPU by type. In order to provide customers with reliable electrical service VPU is continually monitoring the status of its transmission and distribution system. VPU does not have any transmission or distribution system reliability concerns. The transmission system reliability will be a concern when MGS is fully decommissioned in 2028 without a local generation replacement.

Appendix 3: System Average Interruption Indices





Appendix 4: Typical VPU Outage Cause by Type



APPENDIX C: REGULATORY ENVIRONMENT SUMMARY

Senate Bill 1 – Subsidies for Customer Solar (2005)

In 2006, SB 1 was enacted with the intention of expanding rooftop solar PV systems as a means to reduce energy use and therefore GHG. The legislation requires the governing body of a local publicly owned electric utility to adopt, implement and finance a solar initiative program for the purpose of investing in and encouraging the increased installation of residential and commercial solar energy systems.

Senate Bill 1368 – Fossil Fuel Emissions Limits (2006)

SB 1368 requires all long-term (greater than five year) baseload power purchase agreements to conform to new greenhouse emission limits. It sets emission limits on resources that California electric utilities can import from outside California. Pursuant to SB 1368, California electric utilities will not be able to enter into energy contracts for terms longer than five years from high-GHG power resources, such as coal. In particular, SB 1368 specifies that for resources expected to run at greater than a 60% capacity factor, the average CO_2 output needs to be less than 1,100 lbs/MWh. Finally, it requires new renewable generation to be certified by the CEC prior to contract execution.

Assembly Bill 2021 -- Energy Efficiency (EE) & Demand Side Management (DSM)

In September 2006, Governor Schwarzenegger signed AB 2021 into law requiring municipal utilities to adhere to the California Energy Action Plan resource loading order. All municipal utilities, including City of Vernon must acquire all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible prior to investing in new fossil fuel power plants or purchasing fossil fuel generation. In addition, municipals are required to develop an estimate of all potentially feasible, cost-effective electric efficiency savings and to establish 10-year targets for annual energy efficiency savings and demand reduction.

AB 2021 requires the Energy Commission to develop a statewide estimate of all potentially achievable cost-effective electricity and natural gas efficiency savings and establish statewide annual targets for energy efficiency savings and demand reduction programs. POU's specifically are required to identify achievable, cost-effective efficiency potential every three years and establish annual targets based on that potential for a 10-year period. The costs for these efforts are funded through a 2.85% energy sales charge that is applied to all retail customers in the POU's service territory. All POU's are required to report annually on their sources of funding, cost-effectiveness, and verified energy efficiency and demand reduction results from independent evaluations.

Assembly Bill 32 - California Global Warming Solutions Act of 2006

AB 32 of the Global Warming Solutions Act and Governor Schwarzenegger's Executive Order S-14-08 was ratified by the state of California; it is now known as the "California Global Warming Solutions Act of 2006." This legislation requires that aggregated Greenhouse Gas (GHG) emissions from the state of California be reduced to the levels measured in 1990 by the year 2020. CARB was tasked with producing regulations necessary to enact the provisions of AB 32. CARB has finalized two sets of regulations pursuant to AB 32: Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, and a Cost of Implementation Fee Regulation.

The regulations implementing AB 32 include the creation of a cap and trade market for carbon emissions. Under the proposed rules, the CARB creates a new tradable commodity known as a "California Compliance Instrument" (CCI). There are two types of CCIs: Allowances and Offsets. Allowances are essentially permits created and issued by the CARB. The holder of the Allowance is allowed to legally emit one metric ton (MT) of GHG measured in carbon dioxide equivalent (CO2e). Offsets are created if an approved project results in a GHG reduction or GHG removal. These must be real, additional, quantifiable, permanent, verifiable, and enforceable reductions or removals. Ultimately, an independent third-party verifier must periodically inspect the project and issue an opinion of the project's compliance with individual project protocols that are created or adopted by the CARB. Allowances and offsets are treated equally for compliance purposes in that one allowance and one offset each allow for the legal emission of one MT of GHG, measured in CO2e.

Senate Bill 32 - California Global Warming Solutions Act of 2006

In 2016, SB 32 expanded the statewide GHG emissions reduction goal to 40% below 1990 levels by the year 2030. To meet the AB 32 and SB 32 goals, VPU will begin reducing its reliance on gas-fired generation that produces GHG emissions, and transitioning to more renewable resources. In addition to GHG emission reductions from VPU's power supply, further GHG reductions will come from complementary efforts including increased energy efficiency measures, local solar, and transportation electrification. The California Air Resources Board, in conjunction with CEC, is in the process of developing utility specific GHG reduction targets for California utilities as prescribed through the passage of SB 350.

Assembly Bill 2514 -- Energy Storage (2010)

California law AB 2514 was signed into law as Section 2836 of the California Public Utilities Code in September 2010. Section 2836 specifies the requirements for the procurement of cost-effective and viable energy storage systems by electric utilities in the State of California. Under this law, the California Public Utilities Commission was required to adopt energy storage procurement targets for the state's Investor-owned Utilities by October 2013.

The California Public Utilities Commission (CPUC) was also given the responsibility for oversight of investor-owned utilities' (IOUs) energy storage program development. The most recent activity in this oversight proceeding was the CPUC's adoption of procurement targets for IOUs totaling 1,325 MW by December 31, 2020. The CPUC ruling specifies that procuring the respective energy storage targets for the IOUs on the basis of competitive solicitations is the most cost-effective means of allowing the burgeoning energy storage market to develop and that requiring solicitation targets based on transmission-, distribution- and customer-side installations would incentivize procurement of diverse sets of technologies and ownership models.

In addition, the CEC was given the responsibility to review the procurement targets and policies that are developed and adopted by POUs to ensure that the targets and policies include and reflect the procurement of cost-effective and viable energy storage systems. The CEC must report to the Legislature regarding the progress made by each local POU serving end-use customers in meeting the requirements of AB 2514. The CEC staff and Commission have been clear that they value the importance of using energy storage to help in meeting the State's environmental goals and plan to act early to ensure energy storage procurement plans are implemented statewide.

The law clearly identifies specific deadlines for POUs' compliance within the statute. In summary:

- POUs have the responsibility to evaluate the cost-effectiveness and viability of energy storage systems in their respective electric systems. Additionally, POUs may also consider various policies to encourage the cost-effective deployment of energy storage systems. The initial evaluation was to occur before October 1, 2014.
- With this responsibility, POUs also have the authority and discretion to deem any, all or no energy system(s) that are evaluated as being "cost-effective and viable". With the variability between POUs' electric system requirements, the cost-effectiveness and viability of energy storage technology options will be different for each POU.
- At the conclusion of these evaluations, and no later than October 1, 2014, the Governing body of each POU was required to adopt a target, if appropriate, for the amount (e.g. kW or MW) of energy storage the POU will procure by December 31, 2016. In addition, at the same time, the governing body was required to adopt an additional target for the amount (e.g. kW or MW) of appropriate energy storage the POU will procure by December 31, 2020. Policies to encourage the cost-effective deployment of energy storage systems may also be considered by the Governing body. Each Governing body must reevaluate its procurement targets and any policies at least once every three years.

Senate Bill X 1-2 - Renewables Portfolio Standard (2011)

Senate Bill X 1-2 (SB X 1-2) was signed by Governor Edmund G. Brown, Jr., in April 2011. The "California Renewable Energy Resources Act," the official name for Senate Bill X 1-2, fundamentally modified the state's renewable portfolio standard program and sets forth new RPS requirements applicable to POUs.

City of Vernon, as a POU, is covered under the legislation. The law defines what resources can be used for compliance, establishes requirements as a specified percentage of retail sales, establishes the minimum increases in those specified percentages over time, and imposes requirements specific to the location and delivery point for renewable resources. The specific targets are:

- Calendar years 2011-2013 – average of 20% of retail load for the 3-year period.

- Calendar years 2014-2016 – no less than 25% of retail load by December 31, 2016.
- Calendar years 2017-2020 – no less than 33% of retail load by no later than calendar year 2020.
- Calendar year 2021 and beyond – no less than 33% of retail load each year.

This bill makes the requirements of the RPS program applicable to local publicly owned electric utilities; except that the utility's governing board is responsible for implementing those requirements. However, certain enforcement authority with respect to local publicly owned electric utilities was given to the Energy Commission and State Air Resources Board.

SB 350 - The Clean Energy and Pollution Reduction Act of 2015

On October 7, 2015, Governor Edmund G. Brown signed the nation's most far-reaching climate change legislation by California Senate President pro Tempore Kevin de León, SB 350. The legislature calls for a new set of objectives to improve air quality and public health, reduce greenhouse gas emissions and climate change, and expand clean energy policies. The objectives of the bill consist of the following:

- Requires all electricity providers in the state to get at least 50% of their supply of electricity from renewable energy resources like wind and solar by no later than 2030.
- Directs state agencies to double the energy savings in electricity and natural gas final end uses of retail customers through energy efficiency and conservation.
- Takes an important step forward toward creating an Integrated Western System to consolidate control over electric grid operations (right now more than 38 separate entities run smaller parts of the grid), paving the way for easier integration and continued growth of renewable energy resources.

The governing board of a local POU shall adopt an integrated energy resource plan and a process for updating the plan at least once every five years to ensure the utility achieves all of the following:

- Ensures procurement of at least 50% eligible renewable energy resources by 2030
- A diversified procurement portfolio consisting of both short-term and long-term electricity, electricity-related, and demand response products.
- Meets the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the Public Utility Commission and the Energy Commission, for the electricity sector and each local publicly owned electric utility that reflect the electricity sector's role in achieving economy wide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.

Senate Bill 100 – 100 Percent Clean Energy Act of 2018

On September 10, 2018, Governor Edmund G. Brown signed into law a bill that puts California on the path to 100 percent carbon-free energy by 2045. This new legislation increases the 2030 goal from 50% renewables to 60%, sets an interim goal of 50% renewables by 2026 and establishes a 100 percent carbon-free energy goal by 2045. The bill mandates the PUC, State Energy Resources Conservation and Development Commission, and CARB work to develop plans to achieve the goal of 100 percent of total retail sales of electricity in California be supplied by eligible renewable energy resources and zero-carbon resources by December 31, 2045.

Assembly Bill 1405 (2017 - Proposed)

Assembly Bill 1405 (AB 1405) would define a four-hour peak-load time period around the hour of each day that exhibits the highest peak demand, and direct state regulators to determine the percentage of clean kilowatt hours each electric utility delivers. A 40% for clean energy at the peak was proposed by the California Senate. This bill currently has not been passed by neither chamber of the California Legislature.

Assembly Bill 893 (2018 - Proposed)

Legislation proposed by Assembly member Eduardo Garcia would require California LSEs to purchase geothermal energy in support of climate change and diversification of the state's resource mix. The current version of AB 893 would require California utilities to buy 3,000 MW of new geothermal power by 2030. If this legislation is passed into law development of vast geothermal resources in the Salton Sea area of the Imperial Valley may occur in the future.

CAISO Market Initiatives

There is a multitude of ongoing mandates that impact CAISO market operations, CAISO has instituted market initiatives to address them. These market initiatives are in various stages of development and implementation and have the involvement of large number of stakeholder groups. The primary/overarching themes/issues in these market initiatives are as follow:

- Create efficient market paradigms to solve grid reliability issues
- Appropriate cost allocation equitably and fairly
- Maintain regulatory jurisdiction in the decision making process

The most important CAISO market initiatives now under way are described in more detail below.

Energy Imbalance Market (EIM) Initiative

This market initiative started as an attempt within the Western Electricity Coordinating Council (WECC) to improve regional diversity in the operation and utilization of power resources to integrate an increasing amount of intermittent resources throughout the West. In 2012, the CPUC requested that the CAISO develop a market paradigm that could improve on the market efficiency while taking into account the regional diversity in load and resources. In 2013, the CAISO and PacifiCorp signed a Memorandum of Understanding (MOU) to develop such a market paradigm for the West by leveraging the current CAISO centralized market structure in managing the real time imbalance requirements throughout the West. The thrust/concept is by managing diverse resource portfolio across a larger grid footprint, economic efficiency can be captured while enhancing reliability.

The California ISO's western Energy Imbalance Market (EIM) is now a real-time bulk power trading market; its advanced market systems automatically find the lowest-cost energy to serve real-time customer demand across a wide geographic area. Its participants include Idaho Power Company, Powerex, Portland General Electric, Puget Sound, Arizona Public Service, Nevada Energy, PacifiCorp, and CAISO. Utilities maintain control over their assets and remain responsible for balancing requirements while sharing in the cost benefits the market produces for participants.

Since launching in 2014, the western EIM has enhanced grid reliability and generated cost savings in the millions for its participants. Besides its economic advantages, the EIM improves the integration of renewable energy, which leads to a cleaner, greener grid.

CAISO Flexible Resource Adequacy and Enhanced Must Offer Obligation

Given the increasing amount of intermittent resources that are anticipated to come online in the foreseeable future, CAISO is anticipating significant changes in operational needs within its system. Historically, utilities and the CAISO have dealt with supply uncertainty within the generation fleet by imposing a reserve margin or RA margin; normally 15% additional capacity above the monthly peak demand of each load serving entity. This RA margin is designed to take into account forced generation outage events and weather driven load swings. However, this traditional approach will no longer be sufficient in the presence of large amounts of intermittent resources, given their high variability and aggregated impact on daily operations.

Recently, the CAISO illustrated the changing operational needs within its system by plotting the expected normal system hourly load minus the amount of intermittent generation. When significant solar PV generation will continue to come online, the expected system-wide ramping requirement in the evening hours will significantly increase. This increase results from the combined effect of increasing evening loads with the rapid falloff of solar power generation when the sun goes down, presenting significant challenges to balance load and resources during a short timeframe (3-hour timeframe). The CAISO asserts that it needs a significant amount of flexible capacity that can be ramped up and down fairly quickly to assist in managing this supply and demand balance. Also, such flexible capacity must be made available to the CAISO to meet these ramping needs as opposed to utilities using their own resources to meet their individual load requirements.

FERC Order 755

Recent FERC Orders have started to level the playing field for energy storage technologies. Existing market rules were not designed with energy storage resources in mind which can be located behind or in front of the meter. In 2011, FERC Order 755 (Pay for Performance) was passed that ordered ISO/RTOs to develop market rules to compensate fast responding resources for performance in frequency regulation. Under the older frequency compensation, fast responding resources such as energy storage were compensated the same as slower responding resource such as natural gas even though energy storage resource could respond faster and more accurately to automated generation control (AGC) signals.

FERC Order 841

In early 2018 FERC passed Order 841 which directs ISO/RTOs to come up with market rules for energy storage to participate in the wholesale energy, capacity and ancillary services markets that recognize the physical and operational characteristics of the resource. Energy storage resources would be able to participate and respond to wholesale market pricing signals regardless if it was on the transmission system, distribution system, or behind the meter. The passage of this rule will help to eliminate a major barrier of energy storage by providing for more opportunities to provide grid benefit with fair compensation for those services.

APPENDIX D: CUSTOMER AND STAKEHOLDER SURVEY

As a customer-owned electric utility, VPU is very focused on the relationship it has with its customers, which are predominantly industrial and large commercial accounts. To ensure that VPU's customer's had an opportunity to understand and provide input in VPU's IRP, VPU conducted significant customer and stakeholder outreach during the IRP process. The outreach was conducted over a five-month period and included email correspondence, phone calls, personal visits to customer sites, information posted on VPU's website and a series of customer meetings where VPU staff provided information and updates about the IRP process.

In addition, VPU distributed a comprehensive survey to customers that included customer service, energy and IRP related questions. The purpose of the stakeholder outreach and survey was to present to customers the major issues facing VPU as they develop their IRP and allow customers to weigh in on how those issues should be addressed. VPU gathered stakeholder feedback on several categories of topics, such as customer's future plans, VPU's IRP and customer service. The survey drilled down into each of these categories to determine customer's concerns about several specific power related issues such as future electrical usage including the addition of electric vehicle charging infrastructure, interest in participating in demand response and energy efficiency programs and California's Renewable Portfolio Standard including the role of distributed generation in compliance the state's RPS. VPU also provided an opportunity for stakeholders to comment on the quality of VPU's customer service, including their overall satisfaction with VPU's level of service. Survey responses provided by stakeholders were used to better understand and appreciate the diverse viewpoints among the different stakeholder groups. Comments received during these stakeholder meetings and responses to survey questions were considered in the development of the IRP.

Stakeholder Meetings

VPU hosted three public stakeholder events to provide stakeholders and the general public an opportunity to provide comments on the IRP. The first meeting was held on March 29, 2018. During this meeting VPU staff provided attendees with an overview of the purpose of the IRP process and the regulations that VPU must consider as it develops its plan. Stakeholders were informed about the composition of VPU's existing resource portfolio and a preliminary view of how the resource mix will likely change in the future to provide reliable power, comply with GHG reduction and RPS mandates. The presentation also included a discussion about various factors that impact electricity rates and how VPU monitors market conditions when evaluating long-term resource decisions. A timeline for completing the IRP was presented detailing the various tasks and decisions necessary to complete the IRP. VPU staff encouraged stakeholders in attendance to complete the customer survey reminding them that their feedback is an important component of the IRP process.

The second stakeholder meeting was held on May 2, 2018. The primary focus of this meeting was to share Customer Survey results and preliminary IRP results with stakeholders. VPU staff discussed the results of the Customer Survey highlighting the programs that VPU intends to investigate for future implementation or expansion. Preliminary results for three scenarios that focused on a specific resource type focus were also reviewed and discussed at this meeting. These plans included a Solar Resource Plan, a Wind Resource Plan and a Diverse Resource Plan. At the time of the meeting, the optimal mix of resources (lowest cost plan) included a combination of solar and storage. VPU staff closed the meeting by reviewing their list of steps necessary to complete the IRP and to expand future energy efficiency, demand response and distributed generation programs. At each stakeholder event VPU provided progress reports on the IRP and solicited feedback to incorporate into the IRP to ensure that VPU developed an effective long-term resource plan.

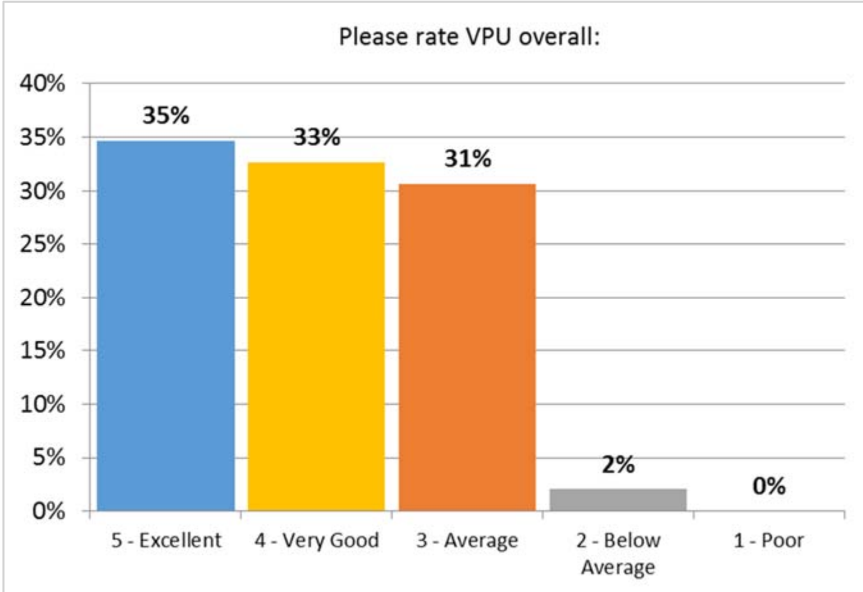
The third and final stakeholder meeting was held on September 27, 2018. The IRP process was reviewed including steps that VPU completed in the development of the IRP. VPU's IRP objectives were reviewed. The objectives include ensuring affordable rates and compliance with regulatory requirements and mandates. The Preferred Portfolio was presented which included a discussion about how the Preferred Portfolio meets California's environmental regulations. The Action Plans that VPU has developed to implement the IRP were also shared with stakeholders. The meeting ended with a review of the timeline for completion of the IRP, City Council approval and filing requirements with the CEC.

Customer Survey Summary

VPU developed a customer survey with the intent to better understand customer's thoughts and preferences regarding VPU's plans to comply with California's RPS and GHG mandates, the quality of VPU's customer service and customer's energy related priorities. VPU's service territory is predominantly made up of commercial and industrial customers. The customer mix consists of approximately 33% industrial, 62% commercial, 5% other, and less than 1% residential. The customer survey was available for customers to complete from January 15, 2018 through April 9, 2018 and during that time VPU made a significant effort to encourage stakeholders to complete the survey through email notifications, telephone call reminders and visits to customer sites. VPU received 83 total responses to the survey, however, only 62 customers provided a response to all survey questions. Industrial customers provided the majority of the survey responses.

As shown in Appendix 5, survey results showed that the majority of survey respondents are satisfied with the electric service that VPU is providing with 68% of the respondents giving VPU an overall rating of excellent or very good.

Appendix 5: Customer Survey – VPU Overall Rating



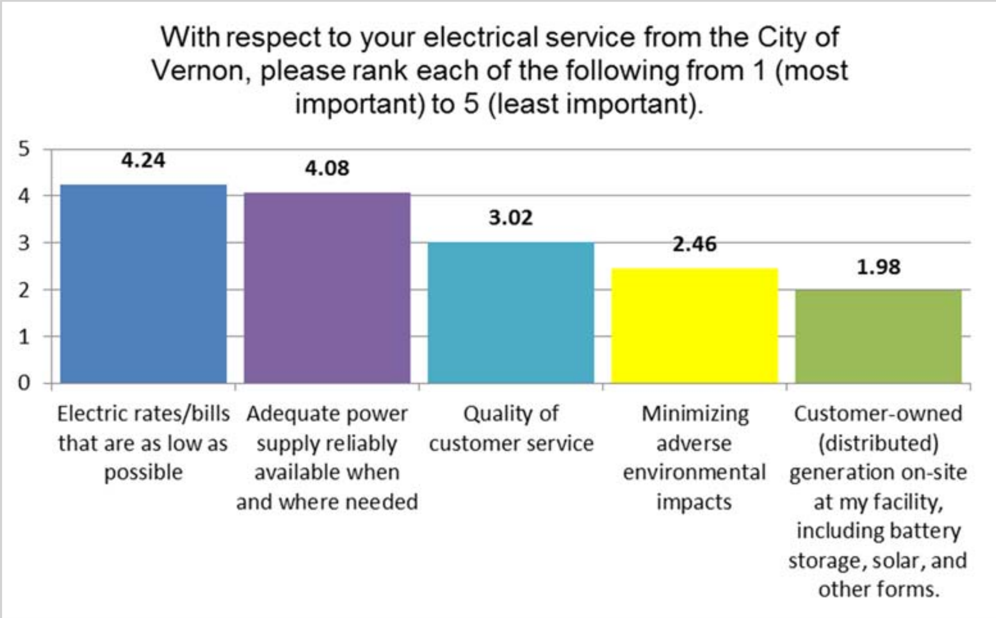
Survey results also showed high satisfaction with the reliability of service that VPU provides and VPU's customer service and responsiveness to customer inquiries. In addition, customers indicated that the lowest possible electric bills and having a local public utility that responds to customer input was their highest priority. This concern about the cost-effectiveness of electricity was also reflected in responses customers provided with respect to distributed generation, energy storage and the installation of electric vehicle infrastructure. Additional details about the survey questions and responses are provided in the following sections.

Customer Satisfaction and Priorities

Customer service is a top priority for VPU. Therefore, a section of the survey was devoted to determining how customer perceive VPU's customer service and the services and products that VPU provides. The survey asked customer to rank VPU on several varying customer service metrics such as if customers are satisfied with the methods that VPU uses to communicate with customers, the reliability of their electric service, and the choice of products that VPU offers.

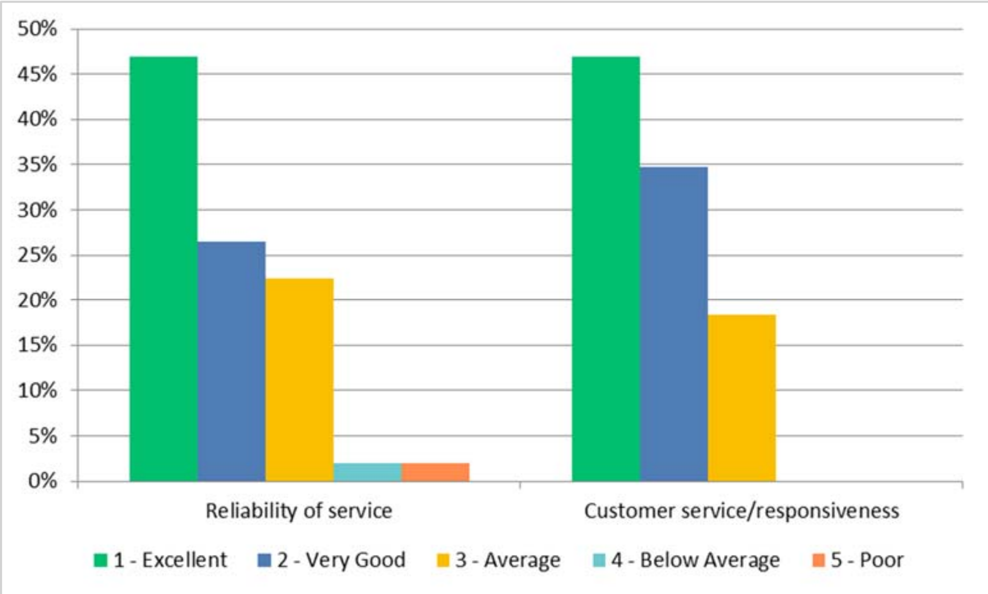
To better understand the concerns of their customers, VPU asked customers to rank the importance of certain aspects of their electric service. As Appendix 6 shows, customers are almost equally concerned about their electric rates and that they have an adequate and reliable power supply. In a community where the majority of the customers are industrial or commercial businesses the cost and reliability of their electric service is very important.

Appendix 6: Customer Service – Electric Service Rankings



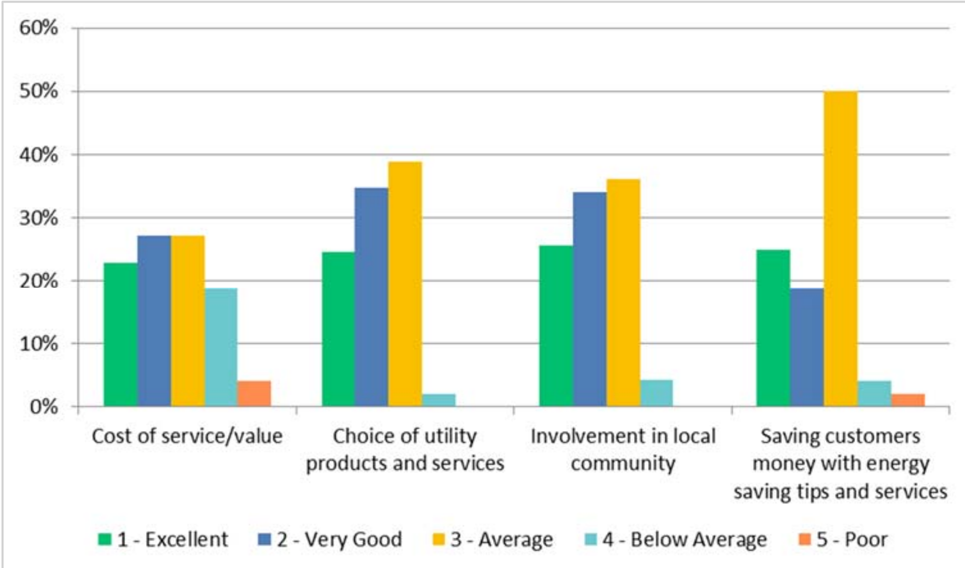
The survey also asked customer to rate VPU on a variety of electric service metrics. As shown in Appendix 7, 74% of the customer respondents rated VPU excellent or very good for its reliability of service and 82% rated VPU excellent or very good for their customer service and responsiveness to customer inquiries.

Appendix 7: Customer Survey – VPU Electric Service Ratings



In addition, feedback provided by the majority of the survey respondents indicates that VPU's cost of service, product and services offerings, involvement in the community and energy saving tips and services are very good or average. Appendix 8 shows survey results for VPU product and services offerings.

Appendix 8: Customer Survey – VPU Product and Service Ratings



The future needs of customers are a key consideration in the development of an IRP. Therefore, VPU included a series of survey questions to better understand, and be able to plan for, the future electricity needs and energy related plans of their customers. Appendix 9 shows that the majority of the customers that responded to the customer survey indicated that they would be altering their electrical usage in the future (60% responded yes and 40% responded no). The majority of respondents indicated that they plan to implement new energy efficiency measures such as lighting retrofit, building insulation or process improvements. However, when asked if they planned to add distributed generation, EV charging stations or energy storage the majority indicated that they did not have any plans for these additions in the future.

VPU was also interested in understanding customer's interest in partnering with VPU on certain programs related to energy storage, EV charging station installations and demand response programs. The survey results showed that the majority of respondents were either not interested or needed more information before deciding to participate in a program. However, the majority of respondents did show interest in Vernon providing solar installation services. VPU will use the results from these survey questions to develop future distributed generation, EV charging, demand response and energy efficiency programs.

Appendix 9: Customer Survey – Program Interest

Survey Question	No	Yes	Not Sure/ Need more information
Energy Efficiency			
Does your facility plan to implement new energy efficiency measures such as lighting retrofit, building insulation, motor upgrade, or process improvement?	79%	21%	
Are you familiar with VPU's energy efficiency programs?	31%	33%	37%
Distributed Generation			
Has your company installed or is it planning to install a solar photovoltaic system?	81%	19%	
Would you be interested in partnering with the City of Vernon or with other businesses in the City to install one or more solar photovoltaic systems?	20%	25%	55%
Does your facility plan to install other forms of on-site power generation, such as combined heat and power or other systems?	85%	15%	
Would you be interested in the City of Vernon providing solar installation services?	29%	71%	
Demand Response			
Would you be interested in participating in demand response programs where your on-site generation, energy storage, or load is paid to respond to instructions to provide power or reduce load?	65%	35%	
Energy Storage			
Has your facility installed, or is it planning to install, an energy storage system such as batteries or compressed air systems to back up and/or shape your electricity usage, or to manage your peak electricity consumption?	76%	24%	
Would you be interested in partnering with the City of Vernon or with other businesses in the City to install one or more energy storage systems?	21%	19%	60%

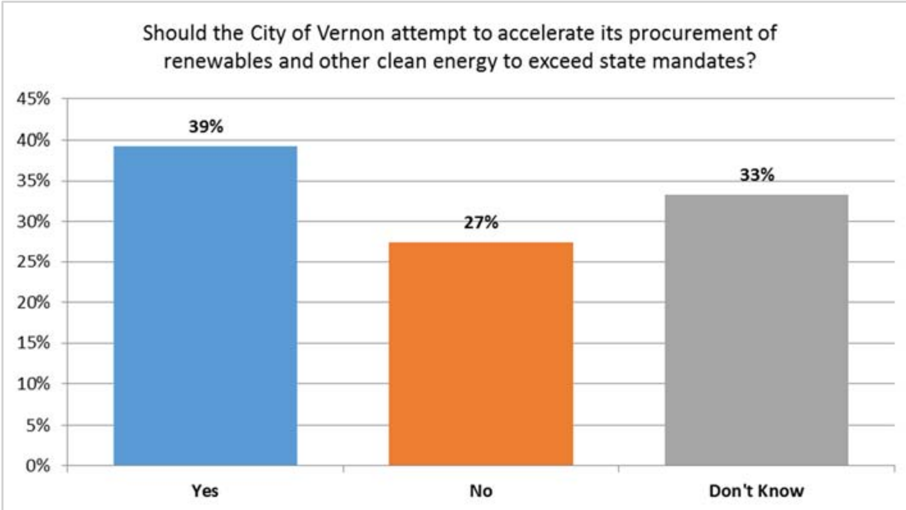
Survey Question	No	Yes	Not Sure/ Need more information
Electric Vehicle Charging			
Does your company have any plans to install electric vehicle charging stations?	72%	28%	
Would you like the City of Vernon to install fee-based public EV charging stations for electric vehicles on your property?	69%	31%	
Would you prefer that VPU install and maintain your EV charging stations?	56%	44%	

Integrated Resource Plan Approach

This section of the survey was intended to gauge customer's understanding and support of VPU's approach in developing its IRP and the actions necessary to meet the energy related state mandates such as the RPS and GHG reduction regulations.

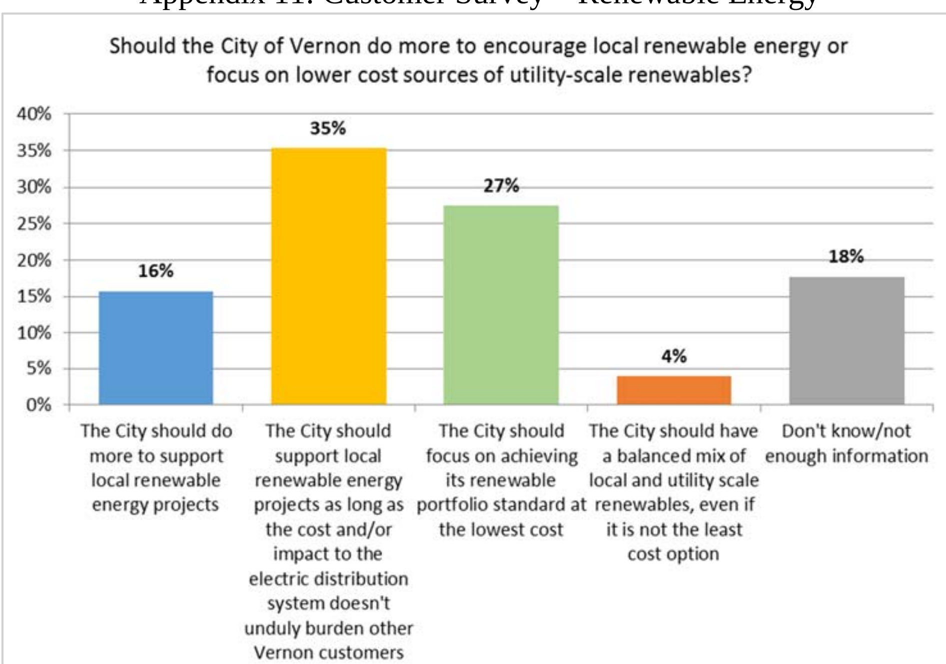
VPU's power supply includes a significant amount of renewable energy and VPU is currently meeting the current state RPS requirement. In 2017, approximately 29% of VPU's energy load was served by eligible utility-scale renewable resources. That percentage is on track to meet or exceed the 60% by 2030 requirement recently approved in CA Senate Bill 100. Therefore, VPU asked customers if they support or oppose accelerated procurement of renewables and other clean energy resources. As shown in Appendix 10, slightly more than one third of the respondents indicated that they think that VPU should accelerate its procurement of renewables as long as the cost and/or rate impact to the electric distribution system doesn't unduly burden other Vernon customers. However, one third of the respondents answered that they were not sure and commented that it depended on the cost and rate impact.

Appendix 10: Customer Survey – IRP Approach

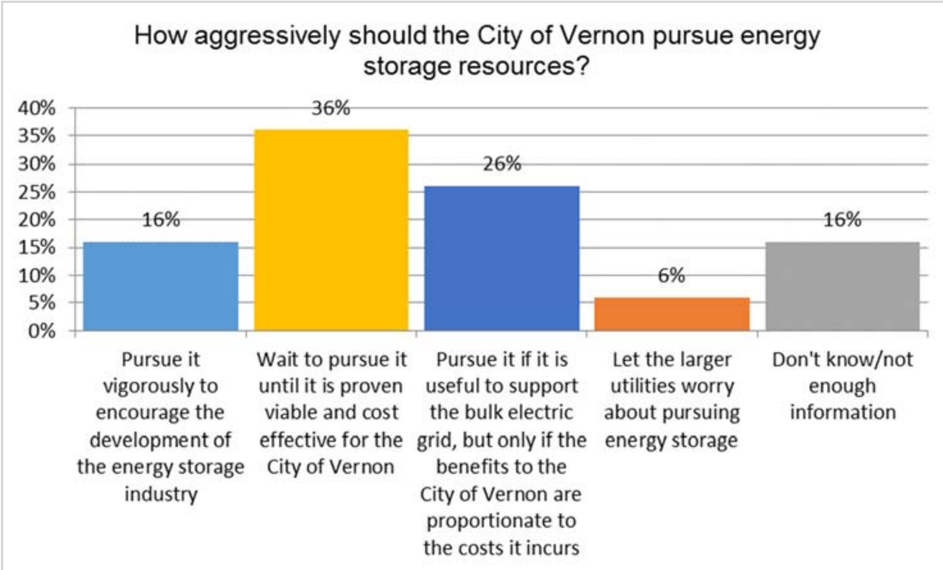


When asked about the selection of future resources most respondents indicated that the cost of the portfolio is a key consideration in future resource selection as shown in Appendix 11 and Appendix 12. As noted previously and indicated in some of the survey responses, the cost effectiveness of VPU's future resource selections and the rate impact of those selections are important to VPU's customers.

Appendix 11: Customer Survey – Renewable Energy

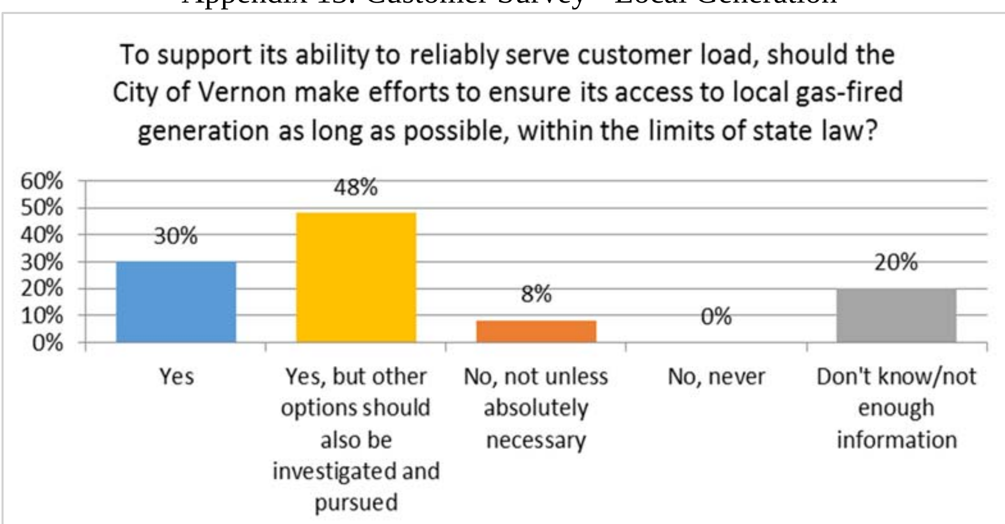


Appendix 12: Customer Survey – Future Resource Cost



VPU must develop an IRP that not only complies with state energy mandates but also provides for reliable electricity for customers into the future. Low cost renewables such as wind and solar supply energy intermittently requiring resources that rely on fossil fuels to supply energy when renewable resources are not available or operating at reduced output. VPU asked customers if VPU should make efforts to ensure its access to local generation as long as possible, within the limits of state law, to support its ability to reliably serve customers. Appendix 13: Customer Survey - Appendix 13 shows that survey respondents are in favor of local gas-fired generation to help ensure reliable electric service.

Appendix 13: Customer Survey - Local Generation



APPENDIX E: ACRONYMS AND DEFINITIONS

ACRONYM	Definitions
AAEE	Additional Achievable Energy Efficiency is the incremental amount of cost effective energy efficiency savings that can be achieved.
AAPV	Additional Achievable Photovoltaic
AB	Assembly Bill is legislation that originates from the California State Assembly.
AGC	Automated Generation Control
APPA	American Public Power Association
BA	Balancing Authority
BESS	Battery Energy Storage System is a type of energy storage that uses batteries as the main source of storage.
BTM	Behind the Meter refers to load or generation impacts that are captured in customer meter reads.
CAGR	Compound Average Growth Rate
CARB	California Air Resources Board is the regulatory body that regulates air quality and implements programs related to climate change.
Carbon-Free %	Total non-carbon emitting resources divided by the total retail sales. Similar to RPS calculation, but includes non-RPS eligible resources such as nuclear and large hydro.
CC	Combined Cycle is a type of natural-fired generation technology that uses gas turbines paired with a steam recovery cycle.
CCA	Community Choice Aggregation are communities formerly served by the IOUs that have formed a separate power supply procurement organization.
CDD	Cooling Degree Days
CEC	California Energy Commission is the state's primary energy policy and planning organization
CAISO	California Independent System Operator operates and manages the transmission system.
CIP	Capital Improvement Plan is the plan on future investments for Vernon Public Utilities.
CF	Capacity Factor is the percentage a time a generator produces electricity compared to its maximum generation output.
CO2-e	CO2-e is the measure of the carbon dioxide equivalent.
COS	Cost of Service is the study performed by utilities to forecast the cost to provide services to retail customers.
CPUC	California Public Utilities Commission regulates IOUs and natural gas utilities operating in California.
CTG	Combustion Turbine Generator
CUP	Conditional User Permit
DER	Distributed Energy Resources is any resource located on the distribution system or behind the meter that can provide or absorb energy.
DR	Demand Response are resources that are able to provide electricity from load or price signals.
DG	Distributed Generation is the same as Distributed Energy Resources.
DSM	Demand Side Management are programs on the demand-side that allow for the reduction of demand.

ACRONYM	Definitions
EE	Energy Efficiency are energy savings realized from the implementation of energy saving technologies.
EIM	Energy Imbalance Market is the enhanced real time market in the WECC to re-optimize resources every 5 minutes.
ELCC	Effective Load Carry Capability is the percentage of the maximum capacity a resource is expected to contribute towards meeting the peak load.
EO	Executive Order is regulation issued by the executive branch of the government that is applied like law.
ES	Energy Storage is resource technology that can generate and store electricity.
EV	Electric vehicle is a vehicle that uses energy stored in its rechargeable batteries, which are recharged by electricity.
FERC	Federal Energy Regulatory Commission is the government agency in charge of overseeing interstate transmission, electricity markets, and fuel markets.
GT	Gas Turbine is a peaking resource technology that uses natural gas to produce electricity.
GWh	Gigawatt-hour (Measure of Generation or Energy Demand)
HDD	Heating Degree Days
HV	High Voltage
IEPR	Integrated Energy Policy Report is the main planning document developed by the California Energy Commission evaluating energy policy, planning, and regulations.
IOU	Investor-Owned Utility are utilities owned by investor shareholders, such as PG&E, SCE, and SDG&E
IRP	Integrated Resource Plan is a forward=-looking planning document identifying future resource acquisitions.
ISO	Independent System Operator
ITC	Investment Tax Credits
GHG	Greenhouse Gas is any gas that contributes to the greenhouse effect such as carbon dioxide and chlorofluorocarbons.
GMC	Grid Management Charge are administrative type costs the CAISO charges for operating and managing the transmission system.
kV	Kilovolt
kW	Kilowatt
LADWP	Los Angeles Department of Power and Water
LCOE	Levelized Cost of Energy
LMP	Locational Marginal Pricing is the price of electricity at a price node that includes the system energy cost, congestion, and loss component.
LF	Load Factor is the percentage the average load compares to the peak load.
LFG	Landfill Gas
Li-ION	Lithium Ion
LSE	Load Serving Entity is any regulated energy provider that is responsible for serving electric demand.
MMT	Million Metric Tons
MW	Megawatt (Measure of Capacity or Peak Demand)
MWh	Megawatt-hour (Measure of Generation or Energy Demand)
MGS	Malburg Generating Station
MOU	Memorandum of Understanding
MSSA	Meter Subsystem Agreement

ACRONYM	Definitions
MSS	Meter substation is a geographically contiguous single zone that has been acting as an electric utility before the formation of the CAISO.
MT	Metric tons
N-2	N-2 is the simultaneous loss of two major elements in the bulk power system such as a generator or a transmission line.
Net Load	Net load is the remaining load after non-dispatchable resources such as renewable energy have been accounted for.
NPV	Net Present Value is the value in the present of a sum of money.
NQC	Net Qualifying Capacity is the capacity that is available to meet the peak demand per CAISO.
PCC	Portfolio Content Category is comprised of three defined renewable energy products eligible for meeting California's RPS.
PEV	Plug-in Electric Vehicle is vehicle that can operate using a battery that is recharged by plugging it into an external source of electric power.
PHEV	Plug-In Hybrid Electric Vehicle is a vehicle that can operate using a battery that is recharged by plugging it into an external source of electric power or by an on-board gas engine.
PPA	Power Purchase Agreement is financially binding agreement to purchase a product such as electricity under certain commercial terms.
PPTA	Power Purchase Tolling Agreement
OLS	Ordinary Least Squares
OOS	Out of State
O&M	Operations and Maintenance
POU	Publicly-Owned Utility
PTC	Production Tax Credits
PTO	Participating Transmission Owners
PV	Photovoltaic is a type of solar technology using photovoltaic panels to produce electricity.
PVNGS	Palo Verde Nuclear Generating Station
RA	Resource Adequacy is the reliability program administered by the CPUC to ensure supply resources are sufficient to maintain system reliability.
REC	Renewable Energy Credit is the green attribute associated with a unit of electricity produced by a renewable resource.
RFP	Request for Proposal
RP3	Reliable Public Power Provider is a designation provided by the American Public Power Agency for outstanding service and reliability for a three year period.
RPS	Renewable Portfolio Standards is the state mandate for renewable procurement which is calculated by total eligible RPS generation divided by total retail electric sales.
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index is measure of how long an outage lasts.
SAIFI	System Average Interruption Frequency Index is a measure how many times outages occurs.
SB	Senate Bill is legislation proposed by the California State Senate.
SCAQMD	South Coast Air Quality Management District is the air pollution agency covering Orange County and the urban portions of Los Angeles, Riverside, and San Bernardino County.

ACRONYM	Definitions
SCE	Southern California Edison
SCPPA	Southern California Public Power Authority is joint powers agency consisting of twelve members in southern California.
SP15	South of Path 15 Electric Pricing Zone
Substation	Electric system equipment that converts voltages from high to low or low to high.
STG	Steam Turbine Generator
TAC	Transmission Access Charge is the cost recovery mechanism issued by the CAISO to recover transmission system investments.
TCA	Transmission Control Agreement
TOU	Time of use is time periods where electricity use is more expensive compared to other parts of the day.
WCI	Western Climate Initiative
WECC	Western Electric Coordination Council is the reliability organization responsible for reliability planning across the western states.
VPU	Vernon Public Utilities
ZEV	Zero Emission Electric Vehicle