Standard LSE Plan

Bear Valley Electric Service, Inc.

2022 INTEGRATED RESOURCE PLAN

November 1, 2022

Bear Valley
Electric Service, Inc.
A Subsidiary of American States Water Company

List of Figures and Tables

I. Executive Summary

The 2023-2035 Integrated Resource Plan (IRP) for Bear Valley Electric Service, Inc. (BVES)[1] is the primary document used in planning, evaluating, and acquiring energy resources to meet the forecasted energy requirements of BVES's retail customers, consistent with goals set by the state legislature and requirements enforced by the Energy Division of the California Public Utilities Commission (hereafter, CPUC or Commission). This IRP also serves as a contributing factor to the overall electric sector profile for state regulators to prepare a pathway for load-serving entities (LSEs) to achieve 100 percent of retail energy sales coming from eligible renewable and zero-carbon resources by 2045 in accordance with Senate Bill (SB) 100 (DeLeon, Chapter 312, Statutes of 2018).[2]

The objective of BVES's 2023-2035 IRP is to identify reliable, best-fit, least-cost, low-carbon energy resources to serve the needs of BVES's electric customers and to provide resource portfolio scenarios that consider evaluation of supply and demand-side resources to the Commission. The amount and types of resources in the IRP must also be consistent with Commission regulations and California State laws governing, among other issues, resource adequacy (RA), renewable energy (RE), and greenhouse gas (GHG) emissions limits, and reduction targets.

IRP Proceeding History

As a result of Senate Bill (SB) 350, the Commission was directed to develop an IRP process for its regulated electric utilities and service providers for long-term resource planning needs, assuring that the collective electric sector is on track to meet GHG reduction goals with secured reliable and least-cost resources. The IRP proceeding is designed on a two-year cycle, with LSE contribution to the Commission's Reference System Plan (RSP) provided in the form of conforming portfolios and planned procurement activities within their IRPs.

The first year of the CPUC IRP cycle consists of a self-initiated process undertaken by the Commission to develop a RSP of optimal planning resources integrated to meet the state's GHG reduction targets. The Commission considers LSE IRPs in the second year of the cycle and aggregates LSE portfolios into a single system-wide portfolio, the Preferred System Portfolio (PSP). The RSP and PSP jointly provide inputs for the California Independent System Operator (CAISO) Transmission Planning Process (TPP). On February 10, 2022, the Commission adopted an optimal planning portfolio for the 2021 PSP and evaluated the 2020 individual IRP filings through Decision (D.) 22-02-004 under Rulemaking (R.) 20-05-003. The adopted PSP meets a statewide 38 million metric ton (MMT) of carbon dioxide (CO_2) GHG target for the electric sector in 2030 with 35 MMT for 2032. Commission staff adjusted the timeframe beyond 2030 to

---

[1] Bear Valley Electric Service became incorporated as a subsidiary of American States Water Company as of July 1, 2020. Hereafter, the IRP references the LSE as Bear Valley Electric Service Incorporated (BVES) and BEAR through modeling designations.

[2]SB 1020 (The Clean Energy, Jobs, and Affordability Act of 2022) added Interim targets to the existing policy framework established by SB 100 by requiring renewable energy and zero-carbon resources to supply 90 percent of all electric retail sales by 2035 and 95 percent by 2040.

2035 in order to add resource required under D. 21-06-035[3] in response to the mid-term reliability assessment. The 2021 PSP decision also recommended to the CAISO that the 38 MMT PSP portfolio be utilized for both reliability and policy-driven base case for the 2022-2023 TPP. From this determination, the results urged both the Commission, CEC, and CAISO to establish a more aggressive GHG reduction case for the 2022 IRP cycle. [4]

Table 1: 2022 IRP Cycle GHG Assigned Benchmarks

Portfolio Scenario Common Title	BVES's Proportion of Total Emissions	2030 Load (GWh)	2035 Load (GWh)	2030 GHG Emissions Benchmark (MMT)	2035 Emissions Benchmark
25 MMT Benchmarks	0.000587773	138.8195496	142.4237088	0.014446927[A]	0.011684697[B]
30 MMT Benchmarks				0.019149114[C]	0.014623564[D]

[A] Meeting the 30 MMT electric sector GHG reduction targets
[B] Meeting the 25 MMT electric sector GHG reduction targets
[C] Meeting the 38 MMT electric sector GHG reduction targets
[D] Meeting the 30 MMT electric sector GHG reduction targets

Covering the years 2023-2035 in this IRP procedural process, the Commission established baseline assumptions and inputs that were utilized in framing the RSP. On June 15, 2022, Administrative Law Judge (ALJ) Ruling finalizing load forecasts and GHG benchmarks via R. 20-50-003. On June 28, 2022, the Commission issued the updated load forecasts and GHG benchmarks assigned to respondent LSEs through the IRP materials webpage. The Commission further updated and issued the narrative template for the IRP on June 15, 2022, the final CSP calculator on July 15, 2022, and the RDT on October 11, 2022. BVES did not elect or find the need to present an alternative portfolio for this IRP cycle. Additionally, BVES is not subject to additional procurement obligations required via D. 19-11-016[5] or D. 21-06-035, which supported additional capacity ordering outside of the RSP and PSP adoption processes for obligated LSEs to meet urgent procurement needs.

<u>BVES Service Area Characteristics</u>

BVES, a subsidiary of American States Water Company, is an investor-owned utility (IOU) regulated by the CPUC. BVES provides electric service in a mountainous resort community to approximately 24,500

---

[3] CPUC. Rulemaking 20-05-003, D.21-06-035 Decision Requiring Procurement to address Mid-Term Reliability (2023-2026)," https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

[4] LSEs are required to provide portfolios for the CPUC planning target (30 MMT of GHG emissions) as well as the target of 25 MMT, which are driven by SB 350 and modified by SB 100 state objectives in achieving 100 percent of electricity sales coming from eligible renewable and zero-carbon resources by 2045. The prior 2020 IRP cycle denoted acceptable GHG benchmark levels of 46 MMT for the reliability base case and 38 MMT for the policy-driven base case.

[5] CPUC. Rulemaking 16-02-007, D.19-11-016 "Decision Requiring Electric System Reliability Procurement for 2021-2023," http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF.

customers, of which approximately 22,500 are residential customers with a mix of roughly 40 percent full-time and 60 percent part-time residents.[6] Approximately 1,500 of the total number of customers are commercial, industrial, and public-authority customers, including two ski resorts. Additionally, approximately 500 accounts within the commercial and residential customer base are considered net energy metering (NEM) customers.

BVES's historical peak load is approximately 45 megawatts (MWs); winter monthly peaks occur when snowmaking machines at the ski resorts are operating and recreational visitors are present (generally between 5:00 pm and 11:00 pm on weekends). In the summer months, the load in BVES's service area ranges from an average minimum of about 10-12 MW (early summer mornings) to a maximum of approximately 24 MW (late evenings on holiday weekends). BVES purchases wholesale power to meet the majority of its energy requirements. To aid in meeting peak demand for electric energy, BVES installed and operates the Bear Valley Power Plant (BVPP), a natural gas-fired, 8.4 MW generation plant, with a tested heat rate of 12,000 British thermal units (Btu)/kilowatt-hour (kWh), in its service area. The BVPP became commercially operational on January 1, 2005. BVES's 45 MW peak load represents approximately 0.1 percent of the CAISO peak load.

BVES has two receipt points of power from Southern California Edison Company (SCE), which include the Goldhill transfer station and Radford Feeder. The majority of BVES's power is transmitted over SCE's 33 kilovolt (kV) subtransmission line from the Cottonwood substation to the Goldhill transfer station. The remainder of BVES's energy is transmitted over SCE's 33 kV distribution facilities from the Zanja substation near Redlands over the Radford Feeder to BVES's Village substation.[7]

BVES's distribution system is located and operates under the balancing authority (BA) of the CAISO. However, BVES does not own any transmission facilities and is not a Participating Transmission Owner (PTO) under the CAISO Tariff. BVES facilities are indirectly interconnected with the CAISO-controlled grid via wholesale distribution access facilities that are owned, controlled, and operated by SCE. These facilities are then directly interconnected with SCE transmission facilities that are part of the CAISO-controlled grid. Lastly, the BVPP does not operate under a Participating Generator Agreement (PGA) and thereby is not considered a CAISO-controlled unit under the CAISO Tariff. It should be noted that because BVES is a holder of Congestion Revenue Rights (CRRs), BVES falls under direct tariff regulation by the CAISO. BVES must indirectly adhere to the CAISO Tariff due to power scheduling and RA requirements. The requirements are imposed on BVES by its third-party schedule coordinator (SC), who must abide by the CAISO Tariff to schedule BVES's power and RA resources.[8]

IRP Process Overview & Study Findings

In this IRP, BVES includes two conforming and two preferred conforming portfolios as directed by the Commission for its proportional share of the two established benchmark targets. Consistent with BVES' inaugural Standard Plan format filing for the 2020 IRP, this 2022 IRP also follows the Standard Plan pursuant to R. 20-05-003. BVES also provides in this IRP its resource action plan through 2035, system-level planning discussions, a response addressing identification of disadvantaged communities and

[6] Based on number of active billed accounts as of October 2022.

[7] BVES refers to voltages on these SCE lines as 34.5 kV.

[8] Currently APX is under contract with BVES to act as its SC and provide schedule coordination services.

supply procurement impacts, and details surrounding the modeling design and GHG emissions benchmark results using established Commission assumptions and inputs.

Carbon accounting practices at BVES had previously assumed emissions intensity alignment with the power resource mix attributed to SCE's service territory. This is supported by the condition that supply from the CAISO-controlled grid is indirectly fed onto BVES's distribution system by way of SCE infrastructure and service area.[9] However, the methodology described in this IRP represents emissions factors that are assigned to LSEs with contracted system power supply and calculations supported by CPUC-driven models and assigned assumptions that address the CAISO system level proportional share to each LSE. As a result of this IRP, BVES found that additional procurement activities may be warranted in order to meet its forecasted GHG benchmark targets by 2035. These activities include securing power resources that are eligible renewable and making direct contracting agreements or market purchases for unit-specific generation. BVES plans to issue solicitations and requests for information that enable internal objectives to transition away from dependency on unspecified power generation contracts over time.

BVES is also in a hedged position in meeting the goals of the California Renewable Portfolio Standard (RPS) through its strategy in securing Renewable Energy Credits (RECs) contracts. In late 2011, D.11-12-052 defined and implemented portfolio content categories (PCCs). Most retail sellers subject to the RPS must procure certain quantities from each of the PCCs. The PCCs, in brief summary, consist of:

1. Generation facilities that have their first point of interconnection to the Western Electricity Coordinating Council transmission grid within the metered boundaries of a California BA area (PCC 1);[10]
2. Generation from a facility that is firmed and shaped with substitute electricity scheduled into a California BA within the same calendar year as the generation from the facility eligible for the RPS, and that the substitute electricity provides incremental electricity (PCC 2); and
3. Other products like unbundled RECs that do not apply to the first two categories (PCC 3).

Of importance, D.11-12-052 confirmed that BVES may satisfy its RPS obligations without regard to the PCC limitations to which most other retail sellers must adhere. Since BVES is exempt from following the product content categories distribution, it has complied with the majority of its RPS requirements with unbundled RECs (e.g., PCC 3) to the greatest extent allowed because it is the least expensive option of the RPS-eligible products. In meeting IRP requirements, BVES understands that PCC 2 and PCC 3 RECs are ineligible for the purposes of GHG emissions benchmark targets. As such, and in aligning with clean power adoption targets, BVES has adapted its previous 2020 IRP preferred portfolio to account for bundled, firm RE PPAs, for which it expects to meet future RPS compliance periods as well as meeting applicable standards for the IRP CSP model under varying GHG benchmark thresholds.

BVES faces constraints in substantially expanding its utility-owned renewable generation buildout due to factors such as limited large parcels being available in its remote service territory and the utility is not

---

9 SCE, "2021 Power Content Label", https://www.sce.com/sites/default/files/custom-files/Web%20files/2021%20Power%20Content%20Label.pdf.

10 Procurement claims from contract/ownership agreements executed before June 1, 2010, or January 13, 2011, for ESPs, are not subject to the PCC classifications established in D.11-12-052. For the purposes of RPS compliance, any eligible RPS RECs that are not subject to PCC 1, 2, or 3 will be placed in their own classification, referred to as PCC 0.

directly connected to the CAISO controlled grid. BVES will investigate the viability to procure unit-specific eligible resources that are wheeled in by the CAISO market as well as plans to secure contracts for firm renewable resources. BVES is in the process of revising its plans and resubmitting an Advice Letter for a solar photovoltaic (PV) plant coming online, (at this time planned for the fourth quarter (Q4) of 2024), which will help to support the ability to meet GHG reduction obligations, reduce reliance on wholesale power, and generate RECs for future compliance periods of the RPS. Additionally, BVES has recently worked with a third-party to develop a cost-benefit study to determine the feasibility in procuring a utility-scale battery energy storage solution (BESS) in its service territory. The current planned implementation target is also in late 2024 or early 2025 at the latest. For the purpose of the IRP modeling exercises, BVES has indicated a Q4 2024 operating date. These systems, however, are not currently planned to be hybridized.

Currently supplied primarily by shaped and firm unspecified system power contracts, BVES will continue to seek cost-appropriate renewable energy contracts and eligible renewable projects to assist in moving away from system power supply contracts over time to meet the 2035 benchmark and state energy sector GHG reduction targets.

Additional results from this IRP include the determination of net qualifying capacity (NQC) targets through 2035. BVES's latest contract for RA capacity expired in 2021. Efforts to procure additional RA capacity contracts to meet RA obligations are continuing through frequent, additional bid requests.

Preferred Portfolio & Action Plan

BVES is not seeking additional procurement actions from the Commission under its Preferred Conforming scenario through this IRP filing. BVES has historically accounted for its cost-effective, firm system power PPAs, owned BVPP, energy efficiency activities, demand response (DR) programs, and behind-the-meter (BTM) distributed energy resources (DER). BVES continues to plan for an owned solar facility supplying the BVES system, standalone BESS configuration, as well as migrating to a nearly 100 percent clean power delivery strategy through contracted firm renewable energy PPAs by 2035. Through these power supply planning characteristics, along with assigned load modifiers and the forecasted demand increase through 2035 by the most recent CEC Integrated Energy Policy Report (IEPR), BVES modeled future supply needs aligning with calculations and assumptions prescribed by the CPUC.

This analysis has resulted in an action plan that meets assigned GHG benchmarks and can be achieved over the planning horizon. Activities proposed to rapidly decrease BVES forecasted GHG emissions through energy supply management include: deploying the solar PV and battery storage projects over the next two-to-three years, obtaining cost-competitive firm RE contracts, and securing short-term system power contracts through 2035 to meet supply shortfalls aligning with state goals. Additionally, BVES will maintain awareness of local community impacts and maintain prudent utility responsibility to provide reliable, least-cost energy to all customers.

When using the CEC IEPR 2021 load modifiers and the assigned load forecast, BVES modeled its supply needs for future renewable contracts based on its ability to meet benchmarks for GHG emissions under the CPUC assumptions for carbon intensity of system power. BVES presents in this IRP Conforming Portfolio Scenarios for its proportional share among LSEs. At this time, BVES's greatest energy supply coming from firm energy seasonal and annual contracts is characterized as unspecified “brown” energy representing available, reliable, cost-effective delivery capabilities. BVES recognizes that the modeling scenarios incorporate carbon intensity measurements for system power mapped to that of dispatchable natural gas resources as it assumes no generating units in specific hours in addition to natural gas generation.

Table 2 presents BVES’s Conforming and Preferred Portfolio results for both GHG benchmarks for 2035. BVES generated two supply portfolios that conform to the IRP requirements. Both are considered for the preferred portfolio selection. While BVES illustrates both the 25 MMT and 30 MMT scenarios, the primary preferred portfolio aligns with the 30 MMT scenario. After completing the IRP analysis, BVES modeled portfolios where emissions targets reach just below the assigned threshold benchmarks.

Table 2: Conforming and Preferred Portfolio Results

Assumptions	Supply Side Resources	BVES 2030 Assigned Load Forecast (GWh)	BVES 2035 Assigned Load Forecast (GWh)	Assigned 2030 Emissions Benchmark (MMT)	Assigned 2035 Emissions Benchmark (MMT)	IRP GHG Emissions Results 2030 (MMT)	IRP GHG Emissions Results 2035 (MMT)
Conforming Portfolio Scenario (a)							
• Benchmarked against 25 MMT GHG threshold • CEC IEPR load modifiers • CEC IEPR demand side modifiers • Resource generation output using CPUC assumptions and capacity factors • Adjusted percent to 40 for C&I load through 2035	See **Error! Reference source not found.**	138.82	142.42	0.01446927	0.011684697	0.01154	0.01068
Conforming Portfolio Scenario (b)							
• Benchmarked against 30 MMT GHG threshold • CEC IEPR load modifiers • CEC IEPR demand side modifiers • Resource generation output using CPUC assumptions and capacity factors • Adjusted percent to 40 for C&I load through 2035	See Figure 2	138.82	142.42	0.019149114	0.014623564	0.01819	0.01402

Assumptions	Supply Side Resources	BVES 2030 Assigned Load Forecast (GWh)	BVES 2035 Assigned Load Forecast (GWh)	Assigned 2030 Emissions Benchmark (MMT)	Assigned 2035 Emissions Benchmark (MMT)	IRP GHG Emissions Results 2030 (MMT)	IRP GHG Emissions Results 2035 (MMT)
***Secondary* Preferred Conforming Portfolio Scenario**							
• Equal to Conforming Scenario (a) assumptions	See **Error! Reference source not found.**	138.82	142.42	0.014446927	0.011684697	0.01154	0.01068
***Primary* Preferred Conforming Portfolio Scenario**							
• Equal to Conforming Scenario (b) assumptions	See Figure 2	138.82	142.42	0.019149114	0.014623564	0.01819	0.01402

This IRP narrative discusses the objectives for the planning horizon, which aims to secure competitive bundled RE power purchase agreements (PPAs) that will replace phased out system power contracts, deploy both a battery storage device and solar generating facility within the BVES territory, and leverage BVES's existing load characteristics and peaker plant to account for any supply shortfalls in addition to spot market purchases. This IRP presents the study results of the conforming and preferred scenarios under both the 25 MMT and 30 MMT GHG reduction scenarios, the action plan in achieving the supply plan, and ongoing lessons over the last IRP cycles.

The study design in Section II will cover the methodology utilized to develop the analyses and modeling tools and approach. The study results, as discussed in Section III, address the conforming and any viewed alternative portfolios as well as indicate the final preferred conforming portfolios selected out of the completed analysis. This section will also address the final GHG emissions results and any local air pollutants with particular focus on disadvantaged communities. This section similarly describes the cost and rate analysis for the baseline case and both portfolio cases, system reliability analysis, and several power supply planning opportunities and challenges regarding areas such as high electrification planning, existing versus new build planning, hydro, long-duration storage, wind, and transmission planning, as well as addressing how BVES will work towards achieving clean firm power contracts.

The section covering the action plan presents the proposed procurement activities and potential barriers for success, as well as additional procurement obligations for required capacity planning. While BVES is not subject to either release of the procurement obligations, it addresses the subsections accordingly. The final subsections will respond to prompts addressing disadvantaged communities, any Commission direction requests, and a summary of BVES's lessons learned.

II. Study Design

The following describes the study design for the 2022 IRP.

<u>Load Assignments for Each LSE</u>

For the 2023-2035 IRP, BVES performed a study designed on key factors that impact supply and demand side needs through the forecast period. As directed by the Commission, the 2021 CEC IEPR forecast for BVES was used as a baseline in the conforming portfolio scenario development. Load modifiers such as increased penetration of BTM distributed energy resources (DERs), energy efficiency (EE), electric vehicle (EV) adoption, and expected load growth are described in detail using CEC IEPR demand modifier inputs for modeling results. These values are also determined using forecasts from the RESOLVE and SERVM modeling results and subsequent instruction from the Commission. BVES did not modify any optional input entries or deviate from the assigned assumptions apart from the C&I demand modifier percentages as explained below. As discussed, BVES does not own any transmission assets, does not have any sourced energy projects that are CAISO-controlled, and receives supplied electricity fed in at the distribution level from SCE.

Table 3: BVES Assigned Load Forecast 2023 – 2035 (GWh)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
132	132	133	134	136	137	138	139	140	140	141	142	142

Table 3 reports the assigned sales forecast for BVES through 2035 resulting from the 2021 IEPR Forecast and approved in R.20-05-003 on June 15, 2022. BVES relies solely on this sales forecast for this IRP effort, as directed by the Commission. BVES represents the second smallest LSE of all those reported in the CSP calculator, and has a sales forecast nearly four-times smaller than the next larger small multi-jurisdictional utility (SMJU).

In addition to the sales forecast shown above, BVES relied on load modifier assumptions as presented in the CSP calculator to remain consistent with the 2021 IEPR forecast. BVES did not supply unique load modifier shapes in the CSP calculator for either the 25 MMT or 30 MMT scenario. However, BVES did include a customized assumption regarding the annual percent of commercial and industrial (C&I) load. While the default assumption included in the CSP model is 49-50 percent, BVES's system is anticipated to be 40 percent C&I by 2024 and onwards. This is supported by recorded percentage of sales attributed to the C&I customer accounts and plans for oncoming load growth in that customer category.

Table 4 reports the calculated demand inputs for BVES assigned sales forecast as calculated by the CSP calculator.

Table 4: BVES CSP Calculator Demand Inputs: 25 MMT and 30 MMT Scenarios

Active Demand Inputs	Units	2024	2026	2030	2035
Baseline net energy for load	**GWh**	**152**	**155**	**162**	**167**
Non-commercial/industrial portion of baseline (included in baseline total)	GWh	91	93	97	101
Commercial/industrial portion of baseline (included in baseline total)	GWh	61	62	65	67
Electric Vehicle Load	GWh	5	8	12	18
Building Electrification	GWh	1	1	2	4
Energy Efficiency	GWh	-2	-4	-6	-9
Behind-The-Meter Photovoltaics (BTM PV)	GWh	-13	-15	-20	-26
Behind-The-Meter Storage Losses (BTM Storage)	GWh	0	0	0	0
Calculated demand at utility-scale generator bus-bar	**GWh**	**143**	**145**	**150**	**154**

Required and Optional Portfolios

The CPUC developed the assumptions utilized in this IRP as a result of calibrated models executed through the RESOLVE and SERVM models. Additional inputs for load modifiers are derived from the CEC 2021 IEPR. In order to address the electric sector's proportion of GHG emissions abatement by 2035, the CPUC assigned LSEs proportional GHG emissions (in carbon dioxide CO_2 MMT) benchmarks. BVES developed its Conforming Portfolios/Preferred Portfolios using these assumptions for consistency and did not opt to select optional demand side entries. To produce a compliant IRP, BVES provides this IRP narrative and associated Resource Data Templates (RDTs) and CSP calculator models as part of its complete filing. BVES does not have any candidate resources subject to the baseline information utilized in the development of the CPUC RSP and responds to this prompt as "not applicable." Both the storage and solar facilities are considered incremental for RSP planning purposes. BVES also assumes all future RE firm PPA generating units are online and are regional to the CAISO system.

Additionally, BVES did not produce an optional Alternative Portfolio study for this IRP cycle and does not have any resources subject to the Cost Allocation Mechanism or Power Charge Indifference Adjustment relating to departing load. BVES references internal energy supply costs in forecasting capital cost and financing information that better reflect the position and unique conditions in long-term energy resource planning. While an incremental analysis on RA capacity is not warranted for this 2021-2022 IRP cycle, BVES presents a discussion on current efforts to address this concern in the short and long-term. BVES leveraged financial information both from the RESOLVE results as well as the characterization presented in its 2023 Test Year General Rate Case (GRC) for consistency. All other cost and rate analysis values are designed form publicly available inputs. This is discussed in detail in Subsection e of Section III.

The figures below illustrate the two supply-side portfolios generated under this analysis through 2035.

Figure 1: Resource Planning under 25 MMT Portfolio

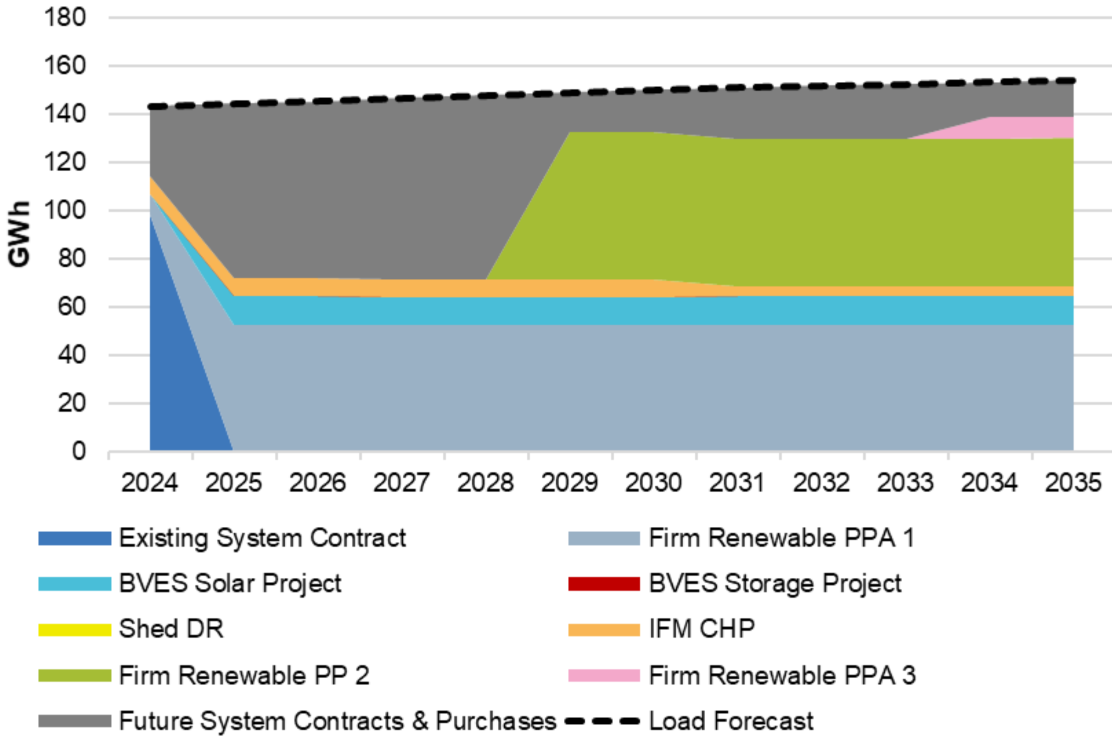
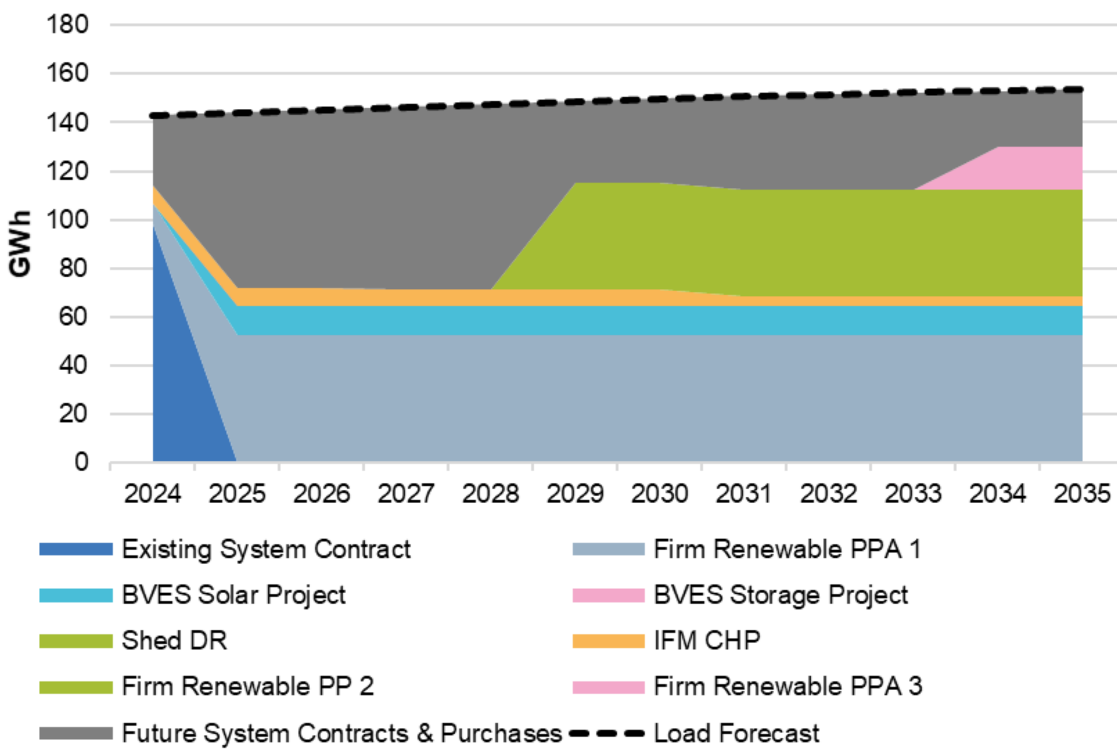


Figure 2: Resource Planning Under 30 MMT Portfolio



<u>GHG Emissions Benchmark</u>

BVES utilized benchmarks of GHG MMT CO_2 for 2030 and 2035 for both the 25 MMT and 30 MMT scenarios. BVES aligned its IRP approach to these established benchmarks as shortfall supply will be met by day-ahead energy purchases and short-term power contracts throughout BVES's energy management planning transition to achieving supply carbon reduction goals.[11]

Table 5 compares forecast sales and GHG emissions benchmarks between BVES and the other SMJU as well as the large investor-owned utilities (IOUs). The table shows that BVES, the smallest utility in the aggregated service territory area, proportion of emissions is 0.1 percent while Pacific Gas and Electric Company, the largest utility, is 33.8 percent of total emissions (338 percent greater than BVES). Further, BVES proportion of emissions represents 10 percent of the emissions associated with the two additional SMJUs, exemplifying the small size of BVES as an electric provider. In terms of load, BVES represents only 8.7 percent of combined SMJU load in 2035 and 0.07 percent of total load for the combined small and large IOUs in 2035.

Table 5: BVES Sales Forecast and GHG Emissions Benchmark Compared to Other LSEs

Aggregated Service Territory Area	Proportion of Emissions	2030 Load (GWh)	2035 Load (GWh)	2035 GHG Emissions Benchmark (25 MMT Scenario)	2035 GHG Emissions Benchmark (30 MMT Scenario)
BVES	0.1%	139	142	0.01	0.01
Other Small Multi-Jurisdictional Utilities (Liberty Utilities & PacifiCorp)	1.0%	1,466	1,496	0.27	0.22
Pacific Gas & Electric Area	33.8%	77,800	81,536	8.43	6.74
Southern California Edison Area	33.2%	86,946	88,816	8.07	6.42
San Diego Gas & Electric Area	8.8%	17,556	17,975	2.27	1.83

a. Objectives

BVES developed this IRP analytical work with the following objectives:

1. Inform the Commission of its studied 2023-2035 IRP through use of the CSP calculator and RDT models to contribute to the CPUC's RSP, PSP, and overall Reference System Plan;
2. Understand whether BVES is on target to meet its 2035 GHG benchmark under the Reference System Plan with its assigned load forecast and demand modifiers issued by the Commission;
3. Plan for firmed renewable power contracts and model where reduction of system power reliance can commence over time;
4. Present avenues to meet current and future policy goals given its unique service area, wholesale market energy supply, and overall customer profile, noting BVES does not have disadvantaged communities in its service territory;
5. Provide discussion results that address system-wide concerns and anticipated constraints; and

[11] The IRP Standard Plan narrative prompt states, " When calculating emissions in the CSP calculator, LSEs should achieve GHG emissions results that are slightly below their GHG benchmarks to leave room in the system for BTM CHP emissions that will be added during the portfolio aggregation process."

6. Utilizing the model results, provide an actionable plan for least-cost, reliable resource planning while identifying potential constraints.

In addition, BVES submits in its 2023-2035 IRP descriptions of: i) BVES future procurement investigations to achieve the GHG targets; and ii) BVES Preferred Conforming Portfolios that are comparable with the RSP. Supporting documents to this IRP include the two Conforming Portfolio Scenarios for the RDT model and CSP calculator (for both 25MMT and 30MMT scenarios).

b. Methodology

The following discusses the 2022 IRP methodology.

i. Modeling Tool(s)

Under direction of the Commission, BVES conducted a resource and GHG emissions planning analysis through the RDT and CSP calculator Excel models issued on July 15, 2022 and October 11, 2022, respectively. BVES assumed inputs and results from the RESOLVE model to understand capacity expansion needs and price forecasting as well as the resource planning assumptions within the RDT. BVES developed, with a consultant, an internal Excel power resource planning workbook to analyze the impacts of different portfolio scenarios on the supply-demand balance and portfolio emissions. The workbook was built to reflect the key inputs, assumptions, and logic assumed by both the RDT and CSP models to ensure consistency when analyzing different portfolio options. An additional Excel workbook was developed to project incremental costs (market purchases, renewable contracts, and investment costs) to determine the functionalized revenue requirement under the presented portfolio options.

ii. Modeling Approach

The presented Conforming Scenarios were developed under policy-driven modeling objectives as a base case approach for reliability while ultimately ensuring the emissions benchmarks assigned to BVES were met. BVES approached its analysis with the goal of evaluating a diverse range of supply portfolios that considered BVES's planned generation projects, additional firm and non-firm renewable generation PPA, and, simultaneously, a decrease in unspecified system power purchases as owned assets and PPAs begin delivering renewable energy and REC products.

The 2023-2035 energy resource planning strategy aims to secure achievable, cost appropriate PPAs (preferably with a REC product) while mitigating rate impacts with increasing renewables within the supply mix contingent with reduced system power contracting. BVES-owned projects (i.e., BVES Solar Project and the BESS) are discussed in the narrative and modeled in both the RDTs and CSP calculators along with the planned BVES contract for 7x24 block renewable power. All existing contracts are captured, including the current existing contract for system power that will expire November 1, 2024. Future system RA obligation contracts are modeled out through 2035 with the assumption that resource capacity is currently available and online (i.e., not incremental to the RSP nor anticipating new resources in the CAISO interconnection queue).

In building a given portfolio scenario, BVES varied the number of planned PPAs as well as the following characteristics of the PPAs: technology type, nameplate capacity, and contract start date. BVES considered new solar PPAs, new wind PPAs, and additional contracts mimicking the 7x24 block renewable product that BVES is planning to contract for in 2024. Mechanically, these supply options were modeled using the hourly renewable profiles provided in the CSP model for Solar Baseline

California and Wind Baseline California[12]. BVES developed a custom generation profile to reflect the aggregate attributes of the 7x24 renewable block products assumed within a given portfolio scenario.

The range of supply portfolios analyzed can be summarized as a "Wind Heavy" range of portfolios (majority of future contracts were associated with wind PPAs), "Solar Heavy" (majority of future contracts were associated with solar PPAs), "Equal Technology" (both wind and solar PPAs made up the portfolio), and "Firm Renewable" (future contracts were assumed to mimic the 7x24 renewable block product). By developing scenarios with different combinations of these renewable contracts BVES was able to estimate the amount of additional system power that would be required to serve load and the associated portfolio emissions[13].

BVES chose this range of scenarios to investigate as they represent the most achievable types of PPA contracts, for which BVES can hope to contract. Understanding existing procurement risks, transmission constraints, and current resources in the CAISO queue, BVES arrived at selecting a balancing portfolio of competitive RE resource types that can be assumed as online, having already received commercial operation dates, and will be available at the time of future PPA contracting.

By investigating a range of wind heavy and solar heavy supply portfolios BVES was able to analyze the impact of technology-specific renewable power on resulting supply-demand balance, portfolio emissions, and ultimately portfolio cost. As may be expected, where a greater amount of contracted solar power was assumed BVES saw an increased need for system purchases in the early-morning and late evening hours. Commensurate with those purchases, BVES saw an excess of contracted generation in the middle of the day that would need to either be sold or curtailed. These outcomes drive resulting portfolio emissions owing to the need for greater system purchases compared to a portfolio scenario that had a greater amount of contract wind generation of block 7x24 power. BVES included the analysis of portfolios centered on additional 7x24 block renewable power owing to its current early-stage success contracting for this type of product that would begin delivering in 2024.

BVES not only considered reliability and adherence to the emissions benchmark when scoring potential supply portfolios, but also analyzed the supply cost build-up for each portfolio. When investigating the range of scenarios, portfolio costs were estimated in a twostep process first to account for the contract expense associated with future renewable contracts and second to account for system purchases or sales. BVES modeled PPA costs using the levelized cost estimates (LCOE) from the RESOLVE model for wind and solar resources. Future 7x24 block product contracts were assumed to follow same escalation of other firm renewable sources like geothermal power but were indexed to BVES's current estimate for the upcoming contract in 2024. Where contract or owned generation fell short of demand on an hourly basis, day-ahead purchases or sales were valued using power market forwards as of September 2022 for CAISO SP-15. Hourly purchases or sales were determined using an hourly supply-demand balance calculation that mimicked the logic provided in the CSP calculator and accounted for curtailment of system sales should the maximum export limit be reached. To compare costs across portfolio scenarios

[12] In modeling all portfolio scenarios, BVES modeled generation for the upcoming BVES Solar Project using the Solar Baseline California renewable profile from the CSP model and the BVES Storage Project using the Battery Storage resource profile also from the CSP model.

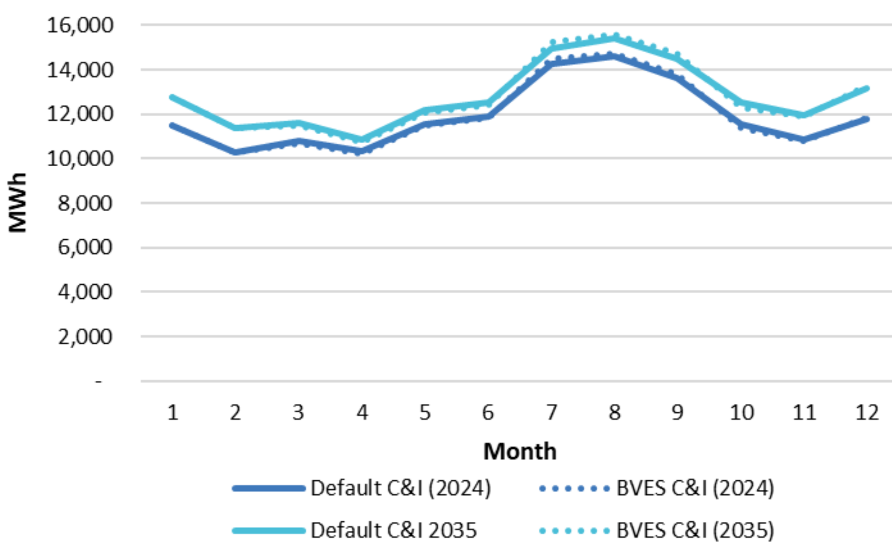
[13] Actual scenarios for net system power procurement will depend on the availability of solar and wind PPAs being offered at the time of awarding contracts.

BVES looked both at total portfolio cost as well as average energy price (total portfolio cost divided by owned and contract generation).

As a part of this portfolio analysis BVES analyzed the CEC IEPR provided load forecast against internal, utility derived load forecasts that include updated information on future large customer loads and DG adoption. Importantly, in early fall 2022 BVES came to an agreement with its largest non-residential customer to serve an additional 7.1 gigawatt-hours (GWh) annually beginning in late 2024[14]. BVES had not confirmed this expansion project when the 2021 IEPR forecast proceeding was ongoing and thus this adjustment is not reflected in the IEPR forecast for BVES. With this service expansion confirmed, additional drivers of load uncertainty primarily stem from EV adoption and distributed generation uptake. BVES will continue to monitor the adoption of BTM distributed energy resources (DERs) and consult CPUC RSP and CEC IEPR study results to forecast accordingly.

Within the available customizations in the CSP calculator, BVES did ensure to include a customized assumption for the split between residential and non-residential load. Using the most recently available load data provided in Application (A.) 22-08-010, BVES estimated that non-residential sales account for only 40 percent of total retail sales, a 9 percent difference compared to the 49 percent assumption included in the CSP calculator. Figure 3 compares the monthly load between BVES's customized non-residential load assumption and the CSP calculator default assumption. Decreasing the percent of non-residential sales has the impact of shifting load out of the shoulder months (March, April, October) and into the summer months as well as shifting the daily load profile to slightly more evening peaking. This adjustment ultimately makes it harder for BVES to reach or be below its assigned emissions benchmarks owing to the need for additional system purchases in the early evening hours when solar generation is reduced or unavailable, however, BVES included this adjustment to best reflect its load makeup.

Figure 3: Comparison of Monthly Load with Default C&I Assumption and BVES Customized C&I Assumption



[14] BVES discussed the possibility of this load expansion in its 2020 IRP and additional details on this expansion can be found In A.22-08-010.

The one demand response (DR) program currently offered by BVES targets its four largest customers through a time-of-use (TOU) interruptible tariff, first approved in its 2009 GRC.[15] This tariff provides a lower rate in exchange for the customer's agreement to interrupt or reduce load when called upon by BVES to do so, even to a zero load. This DR program currently provides approximately 8.98 MW of interruptible load during winter months and 0.19 MW of interruptible load during the summer months. The 12 MW of coincident winter demand reduction can be called upon during BVES's highest peak demands. These measures can shift load usage by a few hours and even minutes to achieve the resource balance needed during peak hours. BVES expects the additional oncoming load in late 2024 to double this interruptible load to approximately 18 MW in the winter and 0.4 MW in the summer. Additional load balancing can be achieved by way of the planned BESS and solar PV facility to meet peak load requirements, which also provides additional customer benefits. Solar production in the daytime with energy storage solution can provide some capacity constraint relief to the service area, as well.

With respect to RA capacity obligations, the calculation of this obligation begins with BVES providing its previous year's historical annual load shape, year-ahead annual forecast, and BVPP output to the CEC who, in turn, issues to BVES its coincident peak demand level. BVES provided its updated NQC annual requirement issued by the CAISO within the RDT models. Because BVES is a winter-peaking utility and has its summer peaks on holiday weekends, BVES's contribution to the CAISO system monthly coincident peak loads is insignificant because of the BVES system load timing diversity with CAISO. For planning purposes, BVES assumes that its RA procurement obligations are as defined by the CAISO Tariff default provisions, which parallel the CPUC's program for jurisdictional LSEs; therefore, BVES plans for RA requirements equal to the CEC determined monthly coincident forecasted load, including reserves.

III. Study Results

The following describes the modeling results of BVES's planned resource mix and GHG emissions benchmarks.

a. Conforming and Alternative Portfolios

The information below presents the modeled outputs in developing a Conforming Portfolio under the two GHG benchmark scenarios. BVES applied CEC IEPR assumptions that mapped to calculating factors and weights that projects the ability to meet benchmarks by 2035. Planned owned projects will be located in BVES' service territory and, therefore, will not be directly tied to the CAISO electric grid. There are no direct comparisons to the planned buildout within the RSP that can be made from these IRP generating facility initiatives. Under the 25 MMT conforming portfolio scenario, BVES presents a case for rapid, higher capacity, procurement of renewable power supplies. This supply mix portfolio enables the utility to immediately plan for a greater portion of demand to be served by carbon-free resources.

BVES presents a change in the firm RE PPA contracting plans under the 30 MMT portfolio scenario. A reduction of delivery across all three planned RE PPA contracts covering all years represents the consideration of the updated CPUC's reliability-driven case under the 30 MMT portfolio scenario, which will allow LSEs additional time to transform their supply mix to achieve 100 percent of electricity sales

[15] Rate Schedule A-5 TOU.

from clean resources by 2045. For the purposes of modeling planned capacity and resource mix needs, BVES plans to deploy its solar PV facility at 5 MW as well as storage facility in 2024 providing local benefits at 5 MWs / 20 MWhs four-hour discharge. Estimates for contract life are based on life-of-facility assessments.[16] Exact contracting details for these projects are still being considered or negotiated. RDTs are based on BVES's current estimated timeline deployment and are subject to delays due to the current pandemic crisis and other constraints or barriers in executing the contract approvals.

The two projects similarly represented under both portfolio scenarios planned for implementation are identified as:

- BVES-owned approximately 5 MW solar PV facility directly connected to the BVES system; and
- BVES-owned 5 MW four-hour battery facility.

Planned renewable energy procurement will also take shape under firm competitive RE solicitations for contracts that target existing and online CAISO resources that are cost-appropriate consisting of a mix of 24x7 flat delivery. Current plans address three batches of RE firm PPA contracts. BVES plans to reach 100 percent clean energy by 2045 in alignment with state goals, however, anticipates spot market purchases for peak periods upwards of 5 percent through 2035 to mitigate risk exposure in the market. Discussion captured in the IRP narrative for identified initiatives are viewed and agreed to by BVES management and are subject to BVES Board and CPUC approval. The portfolios presented favorably position BVES in achieving its GHG emissions targets under both the 25 MMT and 30 MMT portfolio scenarios. Due to uncertainties with current implementation activities, BVES is not requesting any direct action by the Commission at this time through this 2023 -2035 IRP filing.

Table 6: RPS Resource Custom Profile - 3 Firm RE PPAs

GHG Portfolio Scenario	Annual GWhs in 2024	Annual GWhs in 2026	Annual GWhs in 2030	Annual GWhs in 2035
25 MMT	9	53	114	123
30 MMT	9	53	96	114

The following table and figures present the RDT contract information as well as the forecasted energy supply mix in 2035 as a result of this IRP modeling.

[16] National Renewable Energy Laboratory. "Life Prediction Model for Grid-Connected Li-Ion Battery Energy Storage System," May 26, 2017. https://www.nrel.gov/docs/fy17osti/67102.pdf.

Table 7: Conforming Portfolio with Contract and Supply Details in 2035

Conforming Portfolio of Resources and Contracts						
					25 MMT Portfolio Scenario	30 MMT Portfolio Scenario
Resource Type (RDT)[17]	Project / Resource Name	Existing Contract or Owned Asset	Existing Resource for Planned Future Contract	BVES New Resource Investment	Modeled Annual Total in 2035 (GWhs)	Modeled Annual Total in 2035 (GWhs)
_New_generic_solar_1 axis	Bear Valley Solar Plant, solar, 5 MW	Planned utility asset	New resource that is indirectly tied to the CAISO-controlled electric grid and thus is characterized as a load modifier directly supplying the distribution system and adding BVES customer benefits	BVES will own and operate the asset	13.24	
_new_generic_battery_st orage	BVES Battery Storage Project, Li-Ion or Flow storage, 5 MW / 20 MWh	Planned utility asset	New resource that is indirectly tied to the CAISO-controlled electric grid and thus is characterized as a load modifier directly charging from and dispatching to the BVES distribution system and adding BVES customer benefits	BVES will own and operate the asset	(1.55)	
existing _generic_un known	Competitive RE Firm PPA	Not an existing contract, i.e., to be procured	Assumes the resource is already available within the CAISO-controlled electric grid	Energy delivery only (preference given to contracts with a REC product)	52.6	52.6
existing _generic_un known	Competitive RE Firm PPA	Not an existing contract, i.e., to be procured	Assumes the resource is already available within the CAISO-controlled electric grid	Energy delivery only (preference given to contracts with a REC product)	61	43.8
existing _generic_un known	Competitive RE Firm PPA	Not an existing contract, i.e., to be procured	Assumes the resource is already available within the CAISO-controlled electric grid	Energy delivery only (preference given to contracts with a REC product)	9	17.5
Existing _generic _peaker	BVPP	Existing owned asset	Existing resource not under CAISO control	BVES owns and operates this asset	0.27	
_Unspecified _non_ import	Annual Shaped System Energy Contract	Existing contract	Existing unspecified annual shaped system power	Energy delivery only	N/A; Contract expires on October 31, 2024	
_Unspecified _non_ import	Shaped base delivery contract of unspecified, unknown mix at a reduction of existing annual contract capacity reservations	To be procured	Assumes the resource will already be available within the CAISO-controlled electric grid	Energy delivery only	N/A; Contract expires on October 31, 2027	

[17] Resource list in this table includes existing contracts but does not profile expired contracts.

Conforming Portfolio of Resources and Contracts						
					25 MMT Portfolio Scenario	30 MMT Portfolio Scenario
Resource Type (RDT)[17]	**Project / Resource Name**	**Existing Contract or Owned Asset**	**Existing Resource for Planned Future Contract**	**BVES New Resource Investment**	**Modeled Annual Total in 2035 (GWhs)**	**Modeled Annual Total in 2035 (GWhs)**
_Unspecified _non_ import	Shaped base delivery contract of unspecified, unknown mix at a reduction of existing annual contract capacity reservations	To be procured	Assumes the resource will already be available within the CAISO-controlled electric grid	Energy delivery only	49	
_Unspecified _non_ import	Seasonal firm energy delivery contract of unspecified, unknown mix at a reduction of existing annual contract capacity reservations	To be procured	Assumes the resource will already be available within the CAISO-controlled electric grid	Energy delivery only	23	
Sellers _choice	2023 RA Capacity Contract for remaining system RA obligations	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2024 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2025 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2026 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2027 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2028 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2029 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2030 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers _choice	2031 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	

Conforming Portfolio of Resources and Contracts						
					25 MMT Portfolio Scenario	30 MMT Portfolio Scenario
Resource Type (RDT)[17]	Project / Resource Name	Existing Contract or Owned Asset	Existing Resource for Planned Future Contract	BVES New Resource Investment	Modeled Annual Total in 2035 (GWhs)	Modeled Annual Total in 2035 (GWhs)
Sellers_choice	2032 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers_choice	2033 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers_choice	2034 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Sellers_choice	2035 System RA Capacity Contract	To be procured	Assumes resource will already be available for future capacity contracting with no locational preference	Generic System RA capacity contract	No energy delivered	
Existing_generic_dr	Local demand response program to curtail commercial load	Existing	Bear Valley Electric Service, Inc., local demand response program to curtail commercial load, Tariff agreement structure	Energy delivery only	26	

Figure 4: Forecast Supply Mix in 2035 - 25 MMT Scenario

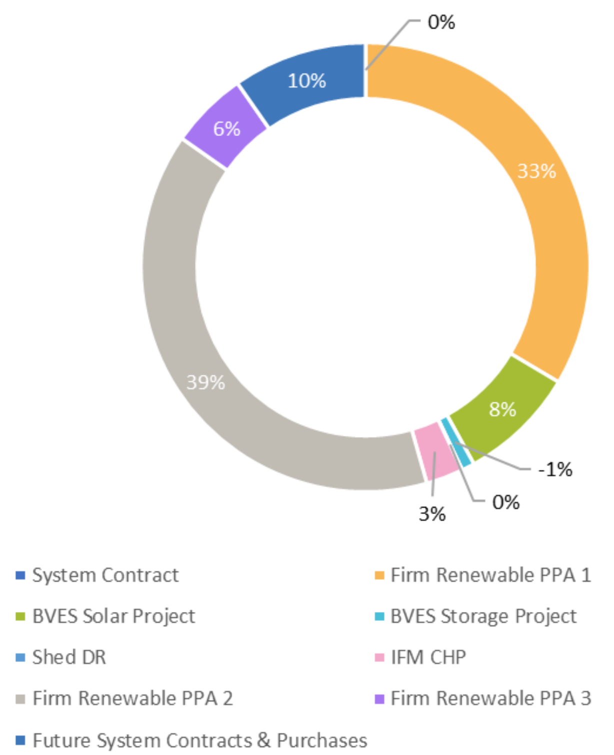


Figure 5: Forecast Supply Mix in 2035 - 30 MMT Scenario

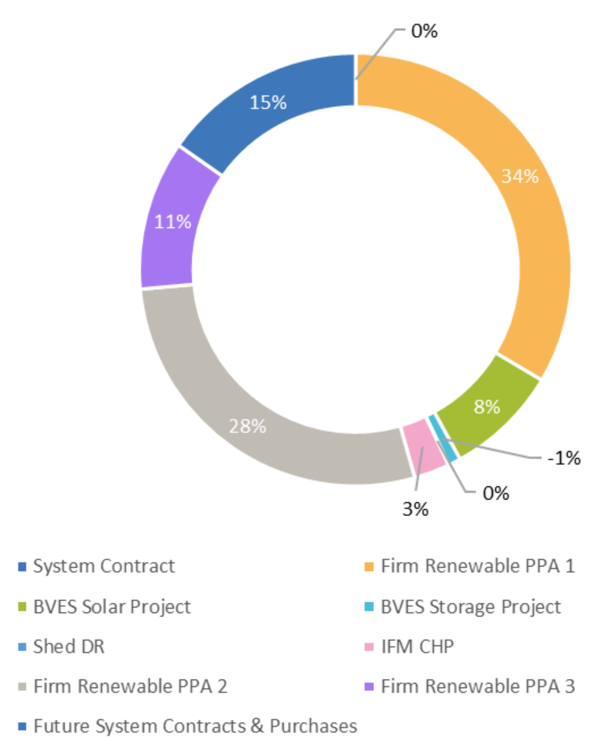


Table 8: BVES Portfolio Scenarios 2023-2035

Portfolio Scenario for 2023 - 2035	Assumptions	BVES 2030 Load Forecast (GWh)	BVES 2035 Load Forecast (GWh)	Assigned 2030 Emissions Benchmark (MMT)	Assigned 2035 Emissions Benchmark (MMT)	IRP GHG Emissions Results 2030 (CO_2 MMT)	IRP GHG Emissions Results 2035 (CO_2 MMT)
Conforming Scenario (a)	• Benchmarked against 25 MMT GHG threshold • CEC IEPR load modifiers • CEC IEPR demand side modifiers • Resource generation output using CPUC capacity factors • Modified 40 percent commercial and industrial (C&I) load through 2035	138.82	142.42	0.01447	0.01168	0.01154	0.01068
Conforming Scenario (b)	• Benchmarked against 30 MMT GHG threshold • CEC IEPR load modifiers • CEC IEPR demand side modifiers • Resource generation output using CPUC capacity factors • Modified 40 percent commercial and industrial (C&I) load through 2035	138.82	142.42	0.01915	0.01462	0.01819	0.01402

BVES calculated the results of both the 25 MMT and 30 MMT scenario models using the assigned load forecast and load modifiers derived from the 2021 CEC IEPR. Selected options include the modifications made to the C&I growth profile under the demand inputs and RPS-eligible custom hourly profile for the three planned RE firm PPA contracts for the submitted Conforming Portfolios. The CSP calculator's modeled carbon emissions intensity measurements align CAISO system power (as represented by BVES unspecified firm energy contracts and day ahead market purchases) to the carbon intensity of natural gas dispatch. Additionally, BVES understands that the Commission ruled to restrict incorporation of PCC 2 and PCC 3 REC contracts into the CSP calculator for GHG emissions benchmark comparisons as stipulated in the model's instructions and guidance documents. BVES does not own any CAISO controlled generating facilities or contracts. As a result of the modeling exercise, BVES's power resource forecast positions the utility along an appropriate pathway to achieve its GHG emissions benchmark thresholds for both Conforming Portfolio Scenarios.

In June 2012, BVES issued an RFP for RECs that sought pre-2011 volumes in addition to its then-current and future compliance period needs. After identifying a successful bidder, BVES began negotiations for a long-term contract for unbundled RECs. In February 2013, the filed Advice Letter 277-E proposed a ten-year RPS agreement for the purchase of RECs from Iberdrola Renewables, LLC (now called Avangrid Renewables, LLC, or Avangrid). CPUC Resolution E-4604, issued in July 2013, approved the ten-year contract. The volumes in the ten-year REC contract were originally forecasted to fulfill all of BVES's RPS obligations through 2022. The updated retail sales forecast now projects full RPS compliance through 2021-2022 with the use of PCC 3s. Understanding the movement away from contracting with long-term PCC 3 contracts, BVES will update its RPS program annual submission in 2023 to account for the targeted PPA bundled products as well as generation output from its future solar PV plant. BVES is still on target to meet its Compliance Period 4 goals of 44 percent in 2024 with the use of these additional bundled PCC 1 RECs planned with the firm PPAs.

Such that the solar PV facility moves forward in finalizing authorization to operate in 2024, BVES will be able to meet REC obligations starting late 2024 and early 2025 with option RECs to meet the difference if the awarded competitive firm RE PPA does not materialize in time for REC retirements. BVES has not secured agreements to fulfill compliance obligations for the 2024-2030 timeframe, however, this IRP strategy will influence future RPS planning to connect requirements and enable BVES to achieve both GHG reduction targets and meet RPS compliance period goals. BVES demonstrates assurance in meeting California RPS goals in each future compliance period through its former strategy in securing unbundled PCC 3 REC contracts and will shift to secure bundled generation and REC product contracts starting in 2024.

The energy balance results from the CSP calculator present a downward trend in reliance on system power by 2035 as shown in both figures below. With the inclusion of the battery facility, increased shed demand response, and the installation of the solar facility (only projected in 2035 per modeling limits), BVES can meet additional gaps by procuring firm renewable PPA contracts and shortfall market purchases in addition to reducing the need for long-term unspecified generation mix power contracts.

Table 9: Energy Balance Results - 25 MMT Conforming Portfolio

Supply Summary	Unit	2024	2026	2030	2035
Large Hydro	GWh	-	-	-	-
Imported Hydro	GWh	-	-	-	-
Asset Controlling Supplier	GWh	-	-	-	-
Nuclear	GWh	-	-	-	-
Biogas	GWh	-	-	-	-
Biomass	GWh	-	-	-	-
Geothermal	GWh	-	-	-	-
Small Hydro	GWh	-	-	-	-
Wind CAISO	GWh	-	-	-	-
Wind Out Of State	GWh	-	-	-	-
Wind Offshore	GWh	-	-	-	-
Solar Utility Scale	GWh	-	13	13	13
Solar Distributed	GWh	-	-	-	-
Hybrid or Paired Solar and Battery	GWh	-	-	-	-
Shed DR	GWh	0.0	0.0	0.0	0.0
Pumped Storage	GWh	-	-	-	-
Battery Storage	GWh	-	(1)	(2)	(1)
Storage Resource Custom Profile	GWh	-	-	-	-
RPS Resource Custom Profile	GWh	9	53	114	123
GHG-free non-RPS Resource Custom Profile	GWh	-	-	-	-
Coal	GWh	-	-	-	-
IFM CHP	GWh	7	7	7	4

Supply Demand Balance Summary	Unit	2024	2026	2030	2035
LSE Supply, before curtailment and exports	GWh	*16*	*72*	*133*	*139*
Net Purchases, before curtailment and exports	GWh	*127*	*73*	*17*	*15*
Curtailment	GWh	-	-	(1)	(2)
Exports	GWh	-	(0)	(2)	(3)
Zero Emissions Power From System	GWh	5	2	1	1
Net System Power (incurs emissions)	**GWh**	**122**	**72**	**19**	**20**

Table 10: Energy Balance Results - 30 MMT Conforming Portfolio

Supply Summary	Unit	2024	2026	2030	2035
Large Hydro	GWh	-	-	-	-
Imported Hydro	GWh	-	-	-	-
Asset Controlling Supplier	GWh	-	-	-	-
Nuclear	GWh	-	-	-	-
Biogas	GWh	-	-	-	-
Biomass	GWh	-	-	-	-
Geothermal	GWh	-	-	-	-
Small Hydro	GWh	-	-	-	-
Wind CAISO	GWh	-	-	-	-
Wind Out Of State	GWh	-	-	-	-
Wind Offshore	GWh	-	-	-	-
Solar Utility Scale	GWh	-	13	13	13
Solar Distributed	GWh	-	-	-	-
Hybrid or Paired Solar and Battery	GWh	-	-	-	-
Shed DR	GWh	0.0	0.0	0.0	0.0
Pumped Storage	GWh	-	-	-	-
Battery Storage	GWh	-	(1)	(1)	(1)
Storage Resource Custom Profile	GWh	-	-	-	-
RPS Resource Custom Profile	GWh	9	53	96	114
GHG-free non-RPS Resource Custom Profile	GWh	-	-	-	-
Coal	GWh	-	-	-	-
IFM CHP	GWh	7	7	7	4

Supply Demand Balance Summary	Unit	2024	2026	2030	2035
LSE Supply, before curtailment and exports	GWh	*16*	*72*	*116*	*130*
Net Purchases, before curtailment and exports	GWh	*127*	*73*	*34*	*24*
Curtailment	GWh	-	-	(1)	(2)
Exports	GWh	-	(0)	(1)	(3)
Zero Emissions Power From System	GWh	5	1	1	0
Net System Power (incurs emissions)	**GWh**	**121**	**72**	**35**	**28**

BVES presents its Conforming Portfolio results in benchmarking future supply GHG emissions to the proportional share attributed to electricity delivery to its service area for both the 25 MMT and 30 MMT benchmark threshold scenarios. BVES did not develop an Alternative Portfolio or apply any optional deviations from the Conforming Portfolio. Additionally, the models utilize all 2021 IEPR, RESOLVE, and CPUC-assigned assumptions and calibrations for resource attributes such as carbon intensity measurements, capacity and generating factors, and seasonal impacts to intermittent resources.

Table 11 and Table 12 present the CO_2 MMT/year results under the 25 MMT and 30 MMT Conforming Portfolios.

Table *11*: BVES 25 MMT Conforming Scenario Carbon Dioxide Emissions Forecast

CO_2	Unit	2024	2026	2030	2035	Notes
Coal	MMt/yr	-	-	-	-	*Included in GHG emissions total*
CHP	MMt/yr	0.0032	0.0032	0.0031	0.0019	
Biogas	MMt/yr	-	-	-	-	
Biomass	MMt/yr	-	-	-	-	

CO_2	*Unit*	2024	2026	2030	2035	*Notes*
System Power	*MMt/yr*	0.0519	0.0303	0.0085	0.0088	*Includes emissions from in-CAISO dispatchable gas and unspecified imports*
Asset Controlling Supplier	*MMt/yr*	-	-	-	-	
Total	***MMt/yr***	**0.0551**	**0.0335**	**0.0115**	**0.0107**	*Includes both in-CAISO and import emissions*
Average emissions intensity	*tCO2/MWh*	0.4160	0.2491	0.0831	0.0750	*Emissions per MWh of sales*
Oversupply Emissions Credits	*MMt/yr*	-	-	0.0003	0.0004	*When hourly supply exceeds hourly load and system power is on the margin, LSE recieves credit at the system power emissions rate. Impact included in Total.*

Table *12*: BVES 30 MMT Conforming Scenario Carbon Dioxide Emissions Forecast

CO_2	*Unit*	2024	2026	2030	2035	*Notes*
Coal	*MMt/yr*	-	-	-	-	*Included in GHG emissions total*
CHP	*MMt/yr*	0.0033	0.0033	0.0032	0.0019	
Biogas	*MMt/yr*	-	-	-	-	
Biomass	*MMt/yr*	-	-	-	-	
System Power	*MMt/yr*	0.0516	0.0301	0.0150	0.0121	*Includes emissions from in-CAISO dispatchable gas and unspecified imports*
Asset Controlling Supplier	*MMt/yr*	-	-	-	-	
Total	***MMt/yr***	**0.0548**	**0.0334**	**0.0182**	**0.0140**	*Includes both in-CAISO and import emissions*
Average emissions intensity	*tCO2/MWh*	0.4140	0.2483	0.1310	0.0984	*Emissions per MWh of sales*
Oversupply Emissions Credits	*MMt/yr*	-	-	0.0000	0.0003	*When hourly supply exceeds hourly load and system power is on the margin, LSE receives credit at the system power emissions rate. Impact included in Total.*

b. Preferred Conforming Portfolios

In this 2023-2035 planning horizon IRP, BVES selected both Conforming Portfolios discussed above as the Preferred Conforming Portfolios for the 25 MMT and 30 MMT benchmark threshold scenarios. Please see Table 7 above for the listing.

The CPUC has demonstrated through its modeling methodology that LSEs are to move away from reliance on unspecified system power and replace with renewable LSE-owned or contracted power resources. BVES applied a thoughtful approach in capturing the distinct objectives presented under both

Conforming Portfolio scenarios. In both cases, the utility illustrates the ability to move toward achieving state objectives in GHG emissions reduction and established, by way of this IRP, a framework and roadmap for meeting 2035 targets.

BVES initially prefers the portfolio scenario under the 30 MMT reliability case as the utility faces unique constraints in deploying clean energy facilities within its service area. Compounded by the fact that BVES's system ties into SCE's distribution system, BVES understands that cost impact may be high for its customers when replacing system power contracts with renewable firm PPAs at the rate presented in the 25 MMT portfolio scenario. For this, cost estimates align with the GRC methodology with an inflation adder to account for planned revenue requirement (RR) by 2035. BVES modeled its cost analysis using its current GRC application for the 2023 Test Year. BVES will make every effort to seek cost-competitive renewable energy PPAs that maintain a parallel cost impact estimate with the RR forecast displayed in this IRP as possible. Modeling inputs assume that the applicable units to be solicited for available capacity are: (1) currently online; (2) able to provide delivery at the identified hours of demand for offloading system power supply; and (3) are located within the CAISO-controlled grid. Out-of-state contracts or a need for a new resource build are not directly modeled but are considered a risk factor in the roadmap to transition to 100 percent electric retail sales coming from clean energy resources. This IRP describes the Preferred Conforming Portfolios consistent with the relevant statutory and administrative requirements (Public Utilities Code (PUC) Section 454.52(a)(1)).

To meet the statutory requirements, this IRP demonstrates that the portfolios meet the GHG reduction targets established by the California Air Resources Board in coordination with the CEC and highlights BVES's supply-side planning indicating that BVES is poised to procure at least 60 percent RE resources by December 31, 2030. Additionally, BVES understands it must fulfill its obligation to its customers to present just and reasonable rates and minimize rate impacts. This discussion is presented later within this section. BVES also accounts for system and local reliability both in the near-term and long-term, wherever possible, and selected a supply model that does not weaken the resilience of the transmission grid while maintaining its remote location to the CAISO. BVES plans to build two utility-scale projects that will enhance its distribution system reliability and demand-side energy management while minimizing localizing air pollutants and other GHGs. Under this rationale, BVES meets the requirements set forth in PUB Section 454.52(a)(1).

As presented above, BVES's 25 MMT benchmark is slightly lower than the threshold assignment primarily due to the limitations of the CSP modeling ability, which requires whole number inputs for planned capacity. The arranged PPAs will also be structured in rounded MW units rather than proportion of energy supply, which will also account for any spot market purchase that BVES may have to leverage. The 7x24 block design will have a minimal impact on transmission capability largely due to the size of the contracts and BVES size. Lastly, BVES does not model any resources within its preferred conforming portfolios that include new natural gas units.

c. GHG Emissions Results

The result of BVES GHG emissions benchmark for two Conforming Portfolios are shown in the tables below. Based on the results from CSP calculator, the CO_2 GHG emission results are 0.01154 MMT for 2030 and 0.01068 MMT in 2035 based on the 25 MMT portfolio scenario. The benchmarks assigned to BVES for 2030 and 2035 are 0.0145 MMT and 0.0117 MMT, respectively. In the 30 MMT CO_2 GHG reduction scenario, BVES achieved GHG emissions results of 0.01819 MMT in 2030 and 0.01402 MMT in

2035. The benchmarks assigned to BVES under this scenario for these years are 0.1915 MMT and 0.0146 MMT, respectively.

BVES included a custom hourly load shape in the CSP calculator for both scenarios assuming 100 percent guaranteed delivery despite the capacity factors of solar and wind mixed resources. Contingent on the analysis of the current contract(s) in negotiation, BVES finds it achievable to shape profiles with firm RE PPAs for its particular size based on current market availability.

Table 13: BVES 25 MMT GHG Results Based on Clean System Power Calculator

Emissions Total	*Unit*	*2024*	*2026*	*2030*	*2035*	*Notes*
CO2	MMt/yr	0.0551	0.0335	**0.0115**	**0.0107**	Includes both in-CAISO and import emissions
PM2.5	tonnes/yr	2.0372	1.2912	0.4919	0.4246	Only In-CAISO emissions
SO2	tonnes/yr	0.1932	0.1233	0.0483	0.0411	Only In-CAISO emissions
NOx	tonnes/yr	2.9629	2.1061	1.1965	0.8338	Only In-CAISO emissions

Table 14: BVES 30 MMT GHG Results Based on Clean System Power Calculator

Emissions Total	*Unit*	*2024*	*2026*	*2030*	*2035*	*Notes*
CO2	MMt/yr	0.0548	0.0334	**0.0182**	**0.0140**	Includes both in-CAISO and import emissions
PM2.5	tonnes/yr	2.0219	1.3872	0.7947	0.6542	Only In-CAISO emissions
SO2	tonnes/yr	0.1920	0.1324	0.0766	0.0626	Only In-CAISO emissions
NOx	tonnes/yr	2.9683	2.2055	1.5594	1.0911	Only In-CAISO emissions

The CSP calculator models for both 25 MMT GHG and 30 MMT GHG opt not to present seasonality mixtures or time-of-day dispatch units. BVES did include a shaped hourly profile for RPS-eligible PPAs for its plan RE firm contracts beginning in 2024. This determination is based on 100 percent of delivery of the blended resource of predominately solar and wind. This due diligence in available units has been part of BVES's investigation into contracting for this first PPA in the next year. The contract is still under negotiations.

The results of GHG emissions in both portfolios are favorable in meeting the Commission's benchmark limits, BVES anticipates meeting this benchmark (for both 25MMT and 30MMT portfolios) that the 2030 and 2035 emissions target years will remain at or below the target values as strategic planning efforts enable more deployment of DER resources and procurement of renewable firm PPA contracts when existing system power contracts are poised to expire. BVES understands that the CSP modeling inputs present a conservative, GHG policy-driven calibration of carbon emissions related to system power.

As system power mix varies during different periods of the day, seasons, and peak scenarios, internal GHG forecasts for BVES consider the unspecified system power contracts aligning with more appropriate dispatch schedules based on the contract details. For example, when renewable intermittent resources are typically generating, the CAISO system supply dashboard can display from 25 - 50 percent of system power, including CAISO mix resources and imports, is from renewable resources including wind and solar.[18] Additionally, CAISO and imported power carbon emissions per MWh of production is anticipated to continue declining from 2020 to 2030 due to tax incentives policy, reduced cost of solar panels, and California RPS goals. This will lead to even more penetration of renewable resources including solar and wind generation at the CAISO system level and the continued growth in customer-based DG adoption. Other states in the Western Electricity Coordinating Council regions will share in this trend. These changes lead to a reduction in the annual carbon emissions for imported power serving BVES's service area.

In aligning with the Commission's approach, and to comply with the requirements from the IRP process to depict these conservative emissions intensity calculations, BVES conducted an evaluation of a new procurement strategy to rapidly contract with existing CAISO generators for eligible renewable power and move away from the previous approach. Aside from the BVES-owned generation assets being considered, any increase in GHG-related costs will be passed onto BVES via its wholesale energy purchases as demonstrated by the results of the CSP calculator models for both 25 MMT and 30 MMT benchmark thresholds. BVES understands the critical need to reduce its reliance on system power by procuring renewable PPAs and investing in eligible renewable generators. The costs of GHG and state emissions reduction requirements will be compared via the competitive bidding process that BVES undergoes when acquiring resources and entering into future agreements with energy providers. BVES anticipates this situation will continue in future RFP processes.

BVES's resource supply portfolio in the RDT supports the movement toward meeting goals for reduced GHG emissions. In future planning cycles, BVES intends to use a larger share of solar and wind supply within the CAISO balancing area in the resource portfolio over the next ten years by pursing cost favorable, RE firm PPAs and battery technologies. BVES will be using more transmitted supply to hedge contracts, which will have less carbon emissions per MWh due to more solar penetration in the CAISO market, though it is not modeled in the emissions calculations provided for this IRP study. Further, BVES expects to have a significant amount of load displaced by EE and customer solar generation.

With a ten-year contract for RECs expiring, BVES anticipates satisfying its obligations under California's RPS program through bundled firm RE PPAs along with generation from its solar facility. The current PCC3 REC contract, approved by the Commission in July 2013, provides the flexibility needed to manage the current RPS requirements that ramp up to 60 percent by 2030.[19] BVES understands that the nature of the RPS program and IRP misalign with the restrictions of PCC2 and PCC3 RECs within the GHG reduction model. BVES has worked to change its prior power supply strategy to account for these restrictions and now aims to procure bundled PCC1 REC products with generation. The rest of the RPS requirement will materialize upon deployment of the BVES solar facility, which is expected to generate approximately 13.24 GWhs annually and a new REC contract either by way of planned renewable energy PPAs or as a separate solicitation if unavailable at the time of bid awarding. This project is expected to have a 25-year life, and the MWh of generation is expected to qualify as local renewable energy meeting the RPS. BVES will evaluate the additional RECs required after the solar project is approved and will base the decision for modification to the plan contracting capacity for renewable PPAs in a subsequent IRP.

---

[18] http://www.caiso.com/TodaysOutlook/Pages/supply.aspx

[19] SB 100 was signed by Governor Brown in 2018 and, among other changes, accelerates eligible-renewable electricity sales targets to achieve 60 percent by 2030 and 100 percent by 2045.

d. Local Air Pollutant Minimization and Disadvantaged Communities

i. Local Air Pollutants

BVES presents the results of local air pollutants that may directly impact those in and surrounding its service area. Because BVES plans for PPAs, firm and shaped energy contracts, and wholesale market purchases, system power emissions reflect the majority of GHG accountability for the utility. BVES addresses within the Action Plan of this IRP its strategy in securing affordable, reliable energy contracts contingent with future investigations into locally sited and utility owned DERs.

Under the Preferred Conforming Scenario using 25 MMT GHG benchmark thresholds, the figure below presents the particulate matter (PM2.5), sulfur dioxide (SO_2), and nitrogen oxide (NOx) results from the CSP calculator.

Figure 6: BVES Conforming Portfolio GHG Local Emissions Results: 25 MMT Benchmark

CO_2	Unit	2024	2026	2030	2035	Notes
Coal	MMt/yr	-	-	-	-	Included in GHG emissions total
CHP	MMt/yr	0.0032	0.0032	0.0031	0.0019	
Biogas	MMt/yr	-	-	-	-	
Biomass	MMt/yr	-	-	-	-	
System Power	MMt/yr	0.0519	0.0303	0.0085	0.0088	Includes emissions from in-CAISO dispatchable gas and unspecified imports
Asset Controlling Supplier	MMt/yr	-	-	-	-	
Total	**MMt/yr**	**0.0551**	**0.0335**	**0.0115**	**0.0107**	Includes both in-CAISO and import emissions
Average emissions intensity	tCO2/MWh	0.4160	0.2491	0.0831	0.0750	Emissions per MWh of sales
Oversupply Emissions Credits	MMt/yr	-	-	0.0003	0.0004	When hourly supply exceeds hourly load and system power is on the margin, LSE recieves credit at the system power emissions rate. Impact included in Total.

PM2.5	Unit	2024	2026	2030	2035	Notes
Coal	tonnes/yr	-	-	-	-	Information only, not included in total
CHP	tonnes/yr	0.1801	0.1775	0.1730	0.1038	
Biogas	tonnes/yr	-	-	-	-	
Biomass	tonnes/yr	-	-	-	-	
System Power	tonnes/yr	1.8571	1.1138	0.3189	0.3208	In-CAISO emissions only - unspecified import emissions excluded
Total	**tonnes/yr**	**2.0372**	**1.2912**	**0.4919**	**0.4246**	Only In-CAISO emissions
Average emissions intensity	kg/MWh	0.0154	0.0096	0.0035	0.0030	Emissions per MWh of sales

SO_2	Unit	2024	2026	2030	2035	Notes
Coal	tonnes/yr	-	-	-	-	Information only, not included in total
CHP	tonnes/yr	0.0192	0.0189	0.0184	0.0110	
Biogas	tonnes/yr	-	-	-	-	
Biomass	tonnes/yr	-	-	-	-	
System Power	tonnes/yr	0.1740	0.1044	0.0299	0.0300	In-CAISO emissions only - unspecified import emissions excluded
Total	**tonnes/yr**	**0.1932**	**0.1233**	**0.0483**	**0.0411**	Only In-CAISO emissions
Average emissions intensity	kg/MWh	0.0015	0.0009	0.0003	0.0003	Emissions per MWh of sales

NOx	Unit	2024	2026	2030	2035	Notes
Coal	tonnes/yr	-	-	-	-	Information only, not included in total
CHP	tonnes/yr	0.8389	0.8205	0.7870	0.4099	
Biogas	tonnes/yr	-	-	-	-	
Biomass	tonnes/yr	-	-	-	-	
System Power	tonnes/yr	2.1240	1.2856	0.4096	0.4238	In-CAISO emissions only - unspecified import emissions excluded
Total	**tonnes/yr**	**2.9629**	**2.1061**	**1.1965**	**0.8338**	Only In-CAISO emissions
Average emissions intensity	kg/MWh	0.0224	0.0157	0.0086	0.0059	Emissions per MWh of sales

Under the Preferred Conforming Scenario using 30 MMT GHG benchmark thresholds, the figure below presents the PM2.5, SO_2, and NOx results from the CSP calculator.

Figure 7: BVES Conforming Portfolio GHG Local Emissions Results: 30 MMT Benchmark

CO_2	Unit	2024	2026	2030	2035	Notes
Coal	MMt/yr	-	-	-	-	Included in GHG emissions total
CHP	MMt/yr	0.0033	0.0033	0.0032	0.0019	
Biogas	MMt/yr	-	-	-	-	
Biomass	MMt/yr	-	-	-	-	
System Power	MMt/yr	0.0516	0.0301	0.0150	0.0121	Includes emissions from in-CAISO
Asset Controlling Supplier	MMt/yr	-	-	-	-	
Total	**MMt/yr**	**0.0548**	**0.0334**	**0.0182**	**0.0140**	Includes both in-CAISO and import
Average emissions intensity	tCO2/MWh	0.4140	0.2483	0.1310	0.0984	Emissions per MWh of sales
Oversupply Emissions Credits	MMt/yr	-	-	0.0000	0.0003	When hourly supply exceeds hourly load

PM2.5	Unit	2024	2026	2030	2035	Notes
Coal	tonnes/yr	-	-	-	-	Information only, not included in total
CHP	tonnes/yr	0.1803	0.1789	0.1768	0.1060	
Biogas	tonnes/yr	-	-	-	-	
Biomass	tonnes/yr	-	-	-	-	
System Power	tonnes/yr	1.8417	1.2083	0.6179	0.5482	In-CAISO emissions only - unspecified
Total	**tonnes/yr**	**2.0219**	**1.3872**	**0.7947**	**0.6542**	Only In-CAISO emissions
Average emissions intensity	kg/MWh	0.0153	0.0103	0.0057	0.0046	Emissions per MWh of sales

SO_2	Unit	2024	2026	2030	2035	Notes
Coal	tonnes/yr	-	-	-	-	Information only, not included in total
CHP	tonnes/yr	0.0192	0.0190	0.0188	0.0113	
Biogas	tonnes/yr	-	-	-	-	
Biomass	tonnes/yr	-	-	-	-	
System Power	tonnes/yr	0.1728	0.1134	0.0578	0.0513	In-CAISO emissions only - unspecified
Total	**tonnes/yr**	**0.1920**	**0.1324**	**0.0766**	**0.0626**	Only In-CAISO emissions
Average emissions intensity	kg/MWh	0.0014	0.0010	0.0006	0.0004	Emissions per MWh of sales

NOx	Unit	2024	2026	2030	2035	Notes
Coal	tonnes/yr	-	-	-	-	Information only, not included in total
CHP	tonnes/yr	0.8411	0.8309	0.8125	0.4220	
Biogas	tonnes/yr	-	-	-	-	
Biomass	tonnes/yr	-	-	-	-	
System Power	tonnes/yr	2.1272	1.3746	0.7469	0.6691	In-CAISO emissions only - unspecified
Total	**tonnes/yr**	**2.9683**	**2.2055**	**1.5594**	**1.0911**	Only In-CAISO emissions
Average emissions intensity	kg/MWh	0.0224	0.0164	0.0112	0.0077	Emissions per MWh of sales

ii. Focus on Disadvantaged Communities

BVES utilized the most recent CalEnviroScreen tool (CalEnviroScreen 4.0) to determine whether any disadvantaged communities fall within the utility service territory. Disadvantaged communities are defined by CalEPA's CalEnviroScreen tool as any community scoring in the top 25 percent statewide, any community in one of the 22 census tracts within the top five percent of communities with the highest pollution burden that do not have an overall score, any lands under control of federally recognized Tribes, or any of the 307 census identified in the 2017 Disadvantaged Communities designation by CalEPA[20]. Table 15 reports the status CalEnviroScreen4.0 scores for those census tracts within BVES's

[20] See http://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30 and https://calepa.ca.gov/wp-content/uploads/sites/62/2017/04/SB-535-Designation-Final.pdf.

service territory which consists of Big Bear Lake, Big Bear City, and Fawnskin.[21] BVES determined that no communities within the service territory meet the designation of disadvantaged community under the CalEPA's designation. BVES will continue to track applicable disadvantaged community metric reports to ensure proper representation of its customer base that may be impacted by the local emissions profile while ensuring safe and reliable delivery of electricity.

Table 15: Census Tracts and Demographics within BVES's Service Territory

Census Tract Number	Total Population	County	CES 4.0 Percentile	CES 4.0 Percentile Range	SB 535 Disadvantaged Community
6071011102	1,760	San Bernardino	34	30-40	No
6071011203	1,404	San Bernardino	53	50-60	No
6071011204	1,685	San Bernardino	23	20-30	No
6071011300	1,398	San Bernardino	51	50-60	No
6071011401	4,507	San Bernardino	54	50-60	No
6071011403	3,451	San Bernardino	17	10-20	No
6071011404	4,585	San Bernardino	19	10-20	No
6071011500	2,125	San Bernardino	24	20-30	No

BVES understands that emissions associated with its system contracts and market purchases do not abide by geographic boundaries but instead are felt across the broader region. As a part of this planning effort BVES ensured that the Preferred Conforming Portfolios met the emissions benchmarks and as such limit BVES's future emission significantly, especially compared to a portfolio scenario completely reliant on system power. By planning for a low emissions future, BVES aims to limit the impact of emissions associated with its generation on disadvantaged communities across the state.

e. Cost and Rate Analysis

<u>Cost and Rate Analysis Background and Methodology</u>

BVES's power supply costs come from two categories: purchase power costs and owned asset costs (including the BVPP). Because BVES has historically relied predominantly on system power contracts and PCC3 contracts, purchase power costs have accounted for more than 93 percent of BVES's total supply cost. Other costs beyond purchase power and owned assets include transmission on SCE-owned and operated facilities (including the 33 kV lines from Cottonwood Substation to Goldhill transfer station and Zanja Substation to BVES's Village Substation), transmission over the CAISO grid, ancillary services charges, reserve requirements, schedule-dispatch charges and CAISO grid-management charges, including CRRs.

When modeling portfolio costs and associated rate payer impacts, BVES relied on the inputs and modeling approach used in GRC application A.22-08-010 to ensure consistency between proceedings. Notably the costs shown in **Table *16*: Revenue Requirements and Bundled System Average Rates for Baseline Scenario (2021 $)**Table 16 for the "Baseline Scenario" directly reflects those costs

[21] Fawnskin is located in census track 6071011300

presented in A.22-08-010 though adjusted to reflect the IEPR load forecast.[22] Key inputs that were held constant from A.22-08-010 in this modeling exercise included: system contract prices and REC price assumptions, forward power prices for day-ahead purchases, and the requested change to return on equity and associated weighted cost of capital.

Purchase power costs were modeled following the methodology BVES utilized in A.22-08-010 whereby costs related to capacity and energy purchases are built up from volumes purchased and the associated purchase price. Fixed costs related to BVES's market purchases and use of SCE's transmission system are also included and discussed later in this section. Where the makeup of purchase power contracts deviated from the Baseline Scenario presented in Table 16 (e.g., both Preferred Conforming Portfolios include 7x24 block renewable contracts), day-ahead and system contract purchases were reduced to accommodate the additional contract generation in-line with results shown in the RDT and CSP calculators. Future contract costs for planned 7x24 block renewable contracts were estimated by indexing LCOE estimates for similar sources of firm renewable power (e.g., geothermal generation) to BVES's most recent estimate for the upcoming 7x24 block renewable contract set to deliver in 2024.

Because both the Baseline Scenario and the Preferred Conforming Portfolios all depend in some part on contracts for system power as well as day-ahead purchases for monthly short positions, a key driver in these costs estimates are the forecast of CAISO market prices. Since the inception of the CAISO market, BVES has been able to meet its monthly short positions with Day-Ahead purchases and Inter-SC Trades. The price BVES pays for short positions is the Locational Marginal Price (LMP) at the default SCE load aggregation point and is calculated and published by approximately 1:00 PM the day before power flows. To align this cost exercise with results presented in A.22-08-010, BVES used power market forward curves from November 2021 published by IHS Markit.

Recently, wholesale power markets have seen significant price volatility stemming from a myriad of factors including the COVID-19 pandemic, an overall slowdown in US natural gas production, and persistent issues and required maintenance for natural gas storage and delivery in Southern California. At the same time hydro production, a key source for low-cost baseload generation, has plunged below 50 percent of normal production in Northern California boosting the demand for natural gas. Looking forward commodity prices are expected to decline from their current high-point as storage and delivery maintenance is completed and as natural gas demand on the whole declines in response to policy initiatives and clean energy goals. Intermittency of renewables production will continue to challenge the CAISO markets as gas fired generation assets with fast ramp-up capabilities are required to follow renewable production declines. Careful planning will pay off significantly in mitigating the supply cost exposure due to market price volatility during these uncertain times.

BVES will continue to manage energy requirement prices with firm power agreements after the existing and proposed contracts expire through this IRP forecast horizon. Electricity and capacity prices are anticipated to increase, potentially creating price spikes in the energy and RA capacity market. The result would be significant increases in energy and non-energy price components, which would affect

22 In determining costs for the "Baseline Scenario" BVES utilized the supply portfolio assumptions from A.22-08-010 with those variable costs (system contracts, energy purchases, and similar) adjusted downwards to reflect lower load forecast utilized in this IRP compared to the load forecast utilized in A.22-08-010. Fixed costs like CAISO charges were assumed fixed and not adjusted downwards.

supply costs for BVES. BVES will pursue energy and capacity products to mitigate this potentially significant price increase from 2023 to 2035.

Transmission costs represent the next largest cost component within BVES purchase power costs. BVES pays SCE for transmission service on SCE's 33 kV lines that deliver power up the mountain to BVES, and for SCE wholesale distribution access tariff (WDAT) service (for service from SCE's Victor Substation near Victorville to SCE's Cottonwood Substation in Lucerne Valley and from SCE's Vista Substation to SCE's Zanja Substation near Redlands). BVES also pays the CAISO for transmission of energy imported into and through California. Together these transmission charges are approximately $3,700,000 annually.[23]

Currently, BVES is charged on a monthly basis for four different uses of SCE's non-CAISO grid. The four different categories of monthly charges for transmission and wholesale distribution services from SCE total approximately $890,000 annually. The CAISO charges BVES, through its Scheduling Coordinator (SC) Automated Power Exchange (APX), for ancillary services, grid management charges, imbalance energy, and CAISO uplifts.[24] Ancillary services are the services necessary to follow the moment-to-moment changes in load, such as regulation, load following, voltage support and operating reserve capacity. Grid management charges are the cost of operating the California transmission grid and include costs associated with running the CAISO markets. Imbalance energy charges apply to deviations between scheduled and metered energy and typically represent a very small portion of BVES's energy requirements. BVES will continue to strive to minimize imbalance costs through accurate day ahead power forecasts.

Congestion Costs are one of the two components of the cost to deliver energy from one point to another within the CAISO (transmission losses being the other). The cost of congestion is the difference in the Marginal Congestion Cost (MCC) component of the LMP between the price nodes specified for energy delivery and takeout.[25] For BVES supply contracts, the source from the CAISO settlements perspective is the aggregated generation hub price for SP15 (TH_SP15_Gen-APND) area.[26] The sink, or takeout, point is the SCE Default Load Aggregation Price (DLAP_SCE). This price is the load weighted aggregation of all load nodes within the SCE TAC area. The Congestion Cost is calculated using the Day Ahead Market Prices as follows:

Congestion Costs = Source Marginal Congestion Cost – Sink Marginal Congestion Costs

Congestion costs can be mitigated through the use of CRRs. BVES's power contracts are for delivery to the SP15 area, so BVES must bear the cost for any congestion between SP15 and the DLAP. As the

23 Including Schedule Coordinator fees.

24 CAISO uplift charges are collected from all customers to ensure market participants, including suppliers, are made whole. They reflect costs incurred to run the market for which there is no direct assignment to specific LSEs. They are collected from all customers to ensure the CAISO market is ultimately revenue neutral.

25 The CAISO's market design creates marginal nodal or locational prices in its Day Ahead market process. The Locational Marginal Price or LMP is the algebraic sum of the 1) Marginal Energy Cost (MCE), 2) MCC, and 3) Marginal Loss Cost (MLC).

26 The CAISO derives the aggregated generation hub price by calculating a weighted average for all generators within the SP15 area. Weights are pre-determined by the CAISO on an annual basis based on previous year output. Generator hub prices are calculated for NP15, ZP26 and SP15 areas. Generation scheduled to the aggregate generation hub is paid/charged the weighted hub price as calculated in the Day Ahead market.

economic conditions within California improve and system load increases, the cost of congestion may increase corresponding to heavier system loading.

While purchase power costs are anticipated to represent the majority of supply costs for BVES through the forecast period under Preferred Conforming Portfolios, owned asset costs will grow as new facilities come online. As discussed previously in this IRP, BVES plans to build a 5 MW solar facility and a 5 MW storage facility with both facilities planned to come online by Q4 of 2024 or early 2025. BVES is still in the pre-planning phase for these projects and as such anticipates asset costs and resulting impact on rate payers may change as additional details of the projects are finalized. For the cost estimate presented here BVES modeled costs associated with the key revenue requirement line items of Net Income, Operations and Maintenance Expense, Administrative and General Expense, Property and Local Taxes, and State and Federal Income Tax, which result in a final all-in annual expense. BVES leveraged estimates of variable operations and maintenance expense by technology type from the RESOLVE model.

To maintain consistency with BVES's recent GRC proceeding, the IRP cost and rate analysis and calculations leveraged the same return on equity and associated weighted cost of capital as submitted in the 2023 Test Year GRC. BVES also included an adjustment to account for an assumed 26 percent ITC tax credit for the solar facility and a 20 percent ITC tax credit for the storage facility[27]. Because these future owned assets were not included as a part of BVES's GRC these costs are not included in Table 16.

Table 16: Revenue Requirements and Bundled System Average Rates for Baseline Scenario (2021 $)

Line No.	Cost Category	2023	2024	2025	2026	2027	2028
1	*Distribution*	$ 7,329,038	$ 7,449,956	$ 7,572,869	$ 7,697,810	$ 7,824,813	$ 7,953,910
2	*Transmission*	$ 210,826	$ 216,962	$ 223,277	$ 229,775	$ 236,463	$ 243,345
3	*Generation (Less Purchase Power)*	$ 728,224	$ 750,827	$ 774,131	$ 798,159	$ 822,932	$ 848,475
4	*Demand Side Programs*	$ -	$ -	$ -	$ -	$ -	$ -
5	*Other (Purchase Power Expense)*	$10,688,810	$10,181,350	$ 9,521,969	$ 9,837,405	$10,258,877	$10,284,901
6 (sum lines 1-5)	*Preferred Conforming Portfolio Revenue Requirement*	$18,956,898	$18,599,095	$18,092,246	$18,563,150	$19,143,085	$19,330,631
7	*System Sales (GWh)*	143.0	143.0	144.1	145.1	146.5	147.6
8	*Bundled Sales (GWh)*	143.0	143.0	144.1	145.1	146.5	147.6
9	*System Average Delivery Rate (¢/kWh)*	5.27	5.36	5.41	5.46	5.50	5.55
10	*Bundled Generation Rate (¢/kWh)*	0.51	0.52	0.54	0.55	0.56	0.57

[27] BVES is aware that the recently passed Inflation Reduction Act modifies these tax incentives as well as provides additional areas of financial incentive for renewable facilities. BVES will update these assumptions as well as the estimated installed asset price in future proceedings as appropriate while the projects continue to develop in the pre-construction phase.

Line No.	Cost Category	2023	2024	2025	2026	2027	2028
11	Bundled System Average Rate (¢/kWh)	13.26	13.00	12.55	12.79	13.07	13.09

Table 16 Continued

Line No.	Cost Category	2029	2030	2031	2032	2033	2034	2035
1	Distribution	$ 8,085,138	$ 8,218,531	$ 8,354,124	$ 8,491,955	$ 8,632,059	$ 8,774,475	$ 8,919,241
2	Transmission	$ 250,428	$ 257,716	$ 265,217	$ 272,936	$ 280,880	$ 289,055	$ 297,468
3	Generation (Less Purchase Power)	$ 874,810	$ 901,963	$ 929,958	$ 958,823	$ 988,583	$ 1,019,267	$ 1,050,903
4	Demand Side Programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Other (Purchase Power Expense)	$ 10,469,468	$ 11,314,199	$ 11,711,811	$ 11,968,934	$ 12,296,427	$ 12,695,906	$ 13,150,024
6 (sum lines 1-5)	Preferred Conforming Portfolio Revenue Requirement	$ 19,679,844	$ 20,692,409	$ 21,261,110	$ 21,692,647	$ 22,197,949	$ 22,778,703	$ 23,417,636
7	System Sales (GWh)	148.8	149.9	150.9	151.6	152.4	153.0	153.8
8	Bundled Sales (GWh)	148.8	149.9	150.9	151.6	152.4	153.0	153.8
9	System Average Delivery Rate (¢/kWh)	5.60	5.65	5.71	5.78	5.85	5.92	5.99
10	Bundled Generation Rate (¢/kWh)	0.59	0.60	0.62	0.63	0.65	0.67	0.68
11	Bundled System Average Rate (¢/kWh)	13.22	13.80	14.09	14.31	14.57	14.88	15.22

Table 17: Revenue Requirements and Bundled System Average Rates for 25 MMT Preferred Conforming Portfolio (2021 $)

Line No.	Cost Category	2023	2024	2025	2026	2027	2028
1	Distribution	$ 7,329,038	$ 7,449,956	$ 7,572,869	$ 7,697,810	$ 7,824,813	$ 7,953,910
2	Transmission	$ 210,826	$ 216,962	$ 223,277	$ 229,775	$ 236,463	$ 243,345
3	Generation (Less Purchase Power)	$ 728,224	$ 750,827	$ 3,754,858	$ 3,771,600	$ 3,644,317	$ 3,523,074
4	Demand Side Programs	$ -	$ -	$ -	$ -	$ -	$ -
5	Other (Purchase Power Expense)	$10,661,906	$10,372,884	$10,892,193	$11,025,737	$11,207,596	$11,185,101
6 (sum lines 1-5)	Preferred Conforming Portfolio Revenue Requirement	$18,929,994	$18,790,629	$22,443,197	$22,724,923	$22,913,188	$22,905,430
7	System Sales (GWh)	143.0	143.0	144.1	145.1	146.5	147.6
8	Bundled Sales (GWh)	143.0	143.0	144.1	145.1	146.5	147.6
9	System Average Delivery Rate (¢/kWh)	5.27	5.36	5.41	5.46	5.50	5.55
10	Bundled Generation Rate (¢/kWh)	0.51	0.52	2.61	2.60	2.49	2.39

Line No.	Cost Category	2023	2024	2025	2026	2027	2028
11	Bundled System Average Rate (¢/kWh)	13.24	13.14	15.57	15.66	15.64	15.51

Table 17 Continued

Line No.	Cost Category	2029	2030	2031	2032	2033	2034	2035
1	Distribution	$ 8,085,138	$ 8,218,531	$ 8,354,124	$ 8,491,955	$ 8,632,059	$ 8,774,475	$ 8,919,241
2	Transmission	$ 250,428	$ 257,716	$ 265,217	$ 272,936	$ 280,880	$ 289,055	$ 297,468
3	Generation (Less Purchase Power)	$ 3,407,732	$ 3,298,159	$ 3,197,276	$ 3,101,912	$ 3,011,949	$ 2,931,130	$ 2,851,549
4	Demand Side Programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Other (Purchase Power Expense)	$ 13,725,787	$ 13,785,135	$ 13,781,429	$ 13,768,569	$ 13,797,956	$ 14,237,910	$ 14,254,094
6 (sum lines 1-5)	Preferred Conforming Portfolio Revenue Requirement	$ 25,469,085	$ 25,559,541	$ 25,598,046	$ 25,635,372	$ 25,722,844	$ 26,232,570	$ 26,322,352
7	System Sales (GWh)	148.8	149.9	150.9	151.6	152.4	153.0	153.8
8	Bundled Sales (GWh)	148.8	149.9	150.9	151.6	152.4	153.0	153.8
9	System Average Delivery Rate (¢/kWh)	5.60	5.65	5.71	5.78	5.85	5.92	5.99
10	Bundled Generation Rate (¢/kWh)	2.29	2.20	2.12	2.05	1.98	1.92	1.85
11	Bundled System Average Rate (¢/kWh)	17.11	17.05	16.96	16.91	16.88	17.14	17.11

Table 18: Revenue Requirements and Bundled System Average Rates for 30 MMT Preferred Conforming Portfolio (2021 $)

Line No.	Cost Category	2023	2024	2025	2026	2027	2028
1	Distribution	$ 7,329,038	$ 7,449,956	$ 7,572,869	$ 7,697,810	$ 7,824,813	$ 7,953,910
2	Transmission	$ 210,826	$ 216,962	$ 223,277	$ 229,775	$ 236,463	$ 243,345
3	Generation (Less Purchase Power)	$ 728,224	$ 750,827	$ 3,754,858	$ 3,771,600	$ 3,644,317	$ 3,523,074
4	Demand Side Programs	$ -	$ -	$ -	$ -	$ -	$ -
5	Other (Purchase Power Expense)	$ 10,661,906	$ 10,372,884	$ 10,892,193	$ 11,025,737	$ 11,207,596	$ 11,185,101
6 (sum lines 1-5)	Preferred Conforming Portfolio Revenue Requirement	$ 18,929,994	$ 18,790,629	$ 22,443,197	$ 22,724,923	$ 22,913,188	$ 22,905,430
7	System Sales (GWh)	143.0	143.0	144.1	145.1	146.5	147.6
8	Bundled Sales (GWh)	143.0	143.0	144.1	145.1	146.5	147.6
9	System Average Delivery Rate (¢/kWh)	5.27	5.36	5.41	5.46	5.50	5.55
10	Bundled Generation Rate (¢/kWh)	0.51	0.52	2.61	2.60	2.49	2.39

Line No.	Cost Category	2023	2024	2025	2026	2027	2028
11	Bundled System Average Rate (¢/kWh)	13.24	13.14	15.57	15.66	15.64	15.51

Table 18 Continued

Line No.	Cost Category	2029	2030	2031	2032	2033	2034	2035
1	Distribution	$ 8,085,138	$ 8,218,531	$ 8,354,124	$ 8,491,955	$ 8,632,059	$ 8,774,475	$ 8,919,241
2	Transmission	$ 250,428	$ 257,716	$ 265,217	$ 272,936	$ 280,880	$ 289,055	$ 297,468
3	Generation (Less Purchase Power)	$ 3,407,732	$ 3,298,159	$ 3,197,276	$ 3,101,912	$ 3,011,949	$ 2,931,130	$ 2,851,549
4	Demand Side Programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Other (Purchase Power Expense)	$ 12,981,527	$ 13,152,515	$ 13,207,618	$ 13,237,689	$ 13,313,541	$ 13,946,849	$ 13,985,887
6 (sum lines 1-5)	Preferred Conforming Portfolio Revenue Requirement	$ 24,724,824	$ 24,926,921	$ 25,024,235	$ 25,104,492	$ 25,238,429	$ 25,941,509	$ 26,054,146
7	System Sales (GWh)	148.8	149.9	150.9	151.6	152.4	153.0	153.8
8	Bundled Sales (GWh)	148.8	149.9	150.9	151.6	152.4	153.0	153.8
9	System Average Delivery Rate (¢/kWh)	5.60	5.65	5.71	5.78	5.85	5.92	5.99
10	Bundled Generation Rate (¢/kWh)	2.29	2.20	2.12	2.05	1.98	1.92	1.85
11	Bundled System Average Rate (¢/kWh)	16.61	16.63	16.58	16.56	16.56	16.95	16.94

Cost and Rate Impact

Table 16 through Table 18 report the results of BVES's cost and rate impact analysis for the Baseline Scenario (reflecting those inputs and assumptions from A.22-08-010) and the two Preferred Conforming Portfolios. In terms of the Bundled System Average Rate (total costs divided by total load), the 25 MMT scenario is shown to be 12.4 percent higher by 2035 compared to the Baseline Scenario and the 30 MMT scenario is shown to 11.3 percent higher than the Baseline Scenario by 2035. The largest cost disparities between these profiles occur in 2029 and decline throughout the remainder of the IRP forecast horizon. The drivers for this increased cost stem from both categories of supply costs – purchase power and owned assets. Purchase power costs increased under the Preferred Conforming Portfolios owing to the inclusion of higher priced 7x24 block renewable power contracts rather than system power contracts or market purchases. This impact is seen most in 2029 when the second 7x24 block renewable contract is assumed to begin delivering in both conforming portfolios.

While these contracts are higher priced than alternative options like system power contracts, they present several key strengths that outweigh their estimated price including but not limited to the bundled nature of the product (these products offer 1:1 RECs), the firm nature of the product (ensuring BVES does not have to over-size renewable contracts to make up for the shaped nature of wind or solar only PPAs), the simplicity in contracting for and administering fewer contracts instead of numerous alternative renewable contracts and increased local reliability. BVES's portfolio modeling indicated that relying on wind or solar only PPAs would necessitate four or more renewable contracts over the IRP forecast horizon (the larger number necessitated by the shaped nature of the generation from these technologies), while the same emissions benchmarks could be achieved from only two additional 7x24 block renewable contracts.[28] As discussed elsewhere in this IRP filing, BVES has struggled to contract for renewable generation historically owing to low bid receivables and lack of cost-competitive offers and thus minimizing the number of required contracts is essential in ensuring supply portfolio achievability. Since the last IRP cycle, BVES has continuously issued RFPs for available RE contracts with preference given to bundled products including RECs. Only recently, BVES has identified a potential pathway to securing firm RE PPAs, for which an initial purchase agreement for roughly one-third of supply needs will be met by 2024, subject to negotiations and contracting requirements.

Owned asset costs as reflected on Line 3 of Tables 16 Through 18 also increase under the Preferred Conforming Portfolios compared to the Baseline Scenario as they include the costs associated with BVES's solar project and the separate storage project. While these assets are higher priced than what commensurate system contracts or market purchases would require, the benefits these projects provide in terms of reliability for BVES's system and independence from the grid cannot be overstated.

Ultimately, BVES is keenly aware of the current financial pressures on rate payers in this time of high inflation and significant power market volatility. BVES considered portfolio costs in each step of this IRP planning process from the initial investigation of a broad range of supply portfolios through to the final comparison between the Baseline Scenario and Preferred Conforming Portfolios. While the portfolios presented here represent an increased cost compared to the Baseline Scenario, it is important to remember the Baseline Scenario does not meet the emissions benchmarks and thus does not provide a fulsome view of BVES's future supply costs under these emissions requirements. To meet the further encouraged GHG reduction policy initiatives and clean energy targets set by the state of California, significant changes will have to be made to BVES's supply portfolio and that evolution in generation will ultimately be felt by the utility and the rate payer.

f. System Reliability Analysis

The following tables depict the RDT modeling results for utility-controlled energy supply. Due to the lack of CAISO-controlled resources mapped to RSP-identified generators and the BVPP considered to reduce capacity needs for BVES's local load center, RA system capacity needs must be met through available contracts as no physical resources currently owned by or contracted with the utility provide this qualified capacity. To address CAISO system reliability needs, BVES's load can be reduced by continued CAISO BTM deployments and other load modifying efforts. BVES assumes enough RA to be available in future years to compensate for any supply shortfalls. BVES continues to seek RA capacity reservations for flexible and generic system needs. BVES will update the Commission through RDT biannual filings as contracts are secured over the 2023-2035 horizon.

[28] BVES included the planned generation from the 7x24 block renewable contract it is currently negotiating to begin delivering in Q4 2024 in all portfolios analyzed.

Table 19: 25 MMT Load and Resource Table by Contract Status

Load and Resource Table by Contract Status	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LSE reliability need (MW)	**47**	**49**	**50**	**49**	**48**	**49**	**51**	**49**	**48**	**46**	**45**	**43**
ELCC by contract status (effective MW)												
Online	-	-	-	-	-	-	-	-	-	-	-	-
Development	-	-	-	-	-	-	-	-	-	-	-	-
Review	-	-	-	-	-	-	-	-	-	-	-	-
PlannedExisting	-	-	-	-	-	-	-	-	-	-	-	-
PlannedNew	-	1	1	1	0	0	0	0	0	0	0	0
BTM PV	0	0	0	0	1	1	0	1	1	1	1	1
LSE total supply (effective MW)	**0**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net capacity position (+ve = excess, -ve = shortfall) (effective MW)	**(47)**	**(48)**	**(49)**	**(48)**	**(47)**	**(48)**	**(50)**	**(48)**	**(47)**	**(45)**	**(44)**	**(42)**

Figure 8: 25 MMT LSE Capacity by Contract Status

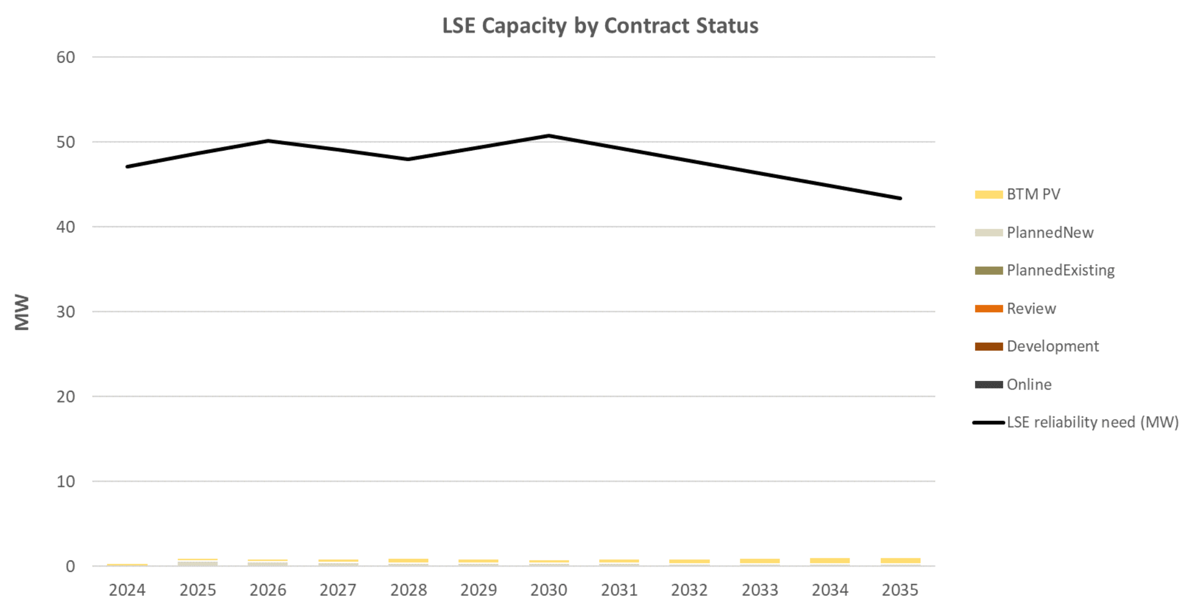
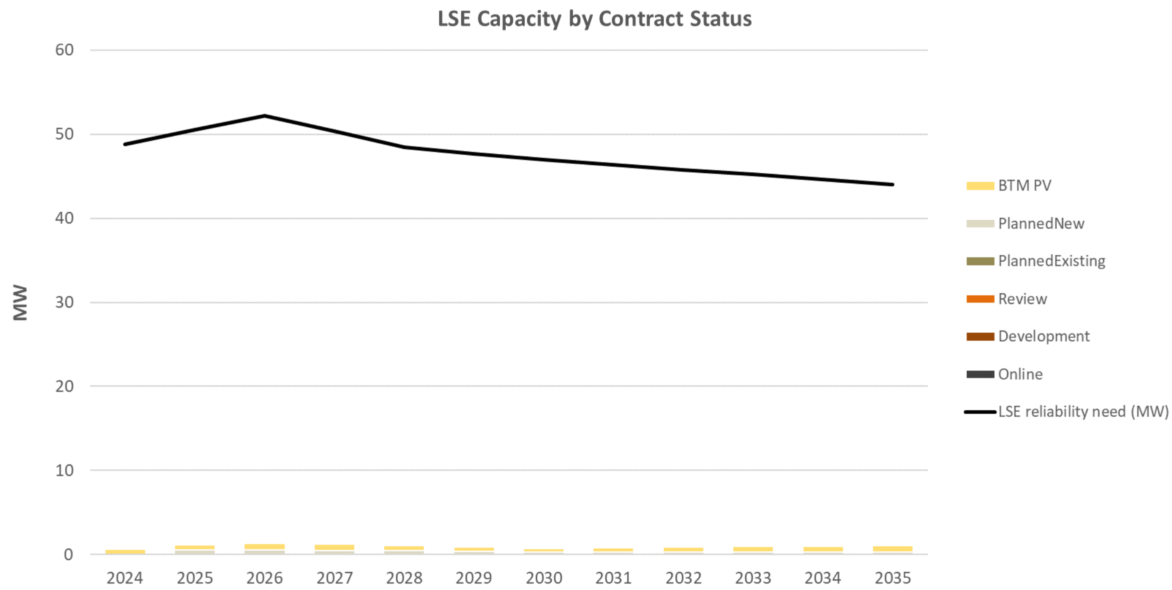


Table 20: 30 MMT Load and Resource Table by Contract Status

Load and Resource Table by Contract Status	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LSE reliability need (MW)	**49**	**51**	**52**	**50**	**48**	**48**	**47**	**46**	**46**	**45**	**45**	**44**
ELCC by contract status (effective MW)												
Online	-	-	-	-	-	-	-	-	-	-	-	-
Development	-	-	-	-	-	-	-	-	-	-	-	-
Review	-	-	-	-	-	-	-	-	-	-	-	-
PlannedExisting	-	-	-	-	-	-	-	-	-	-	-	-
PlannedNew	-	1	1	1	0	0	0	0	0	0	0	0
BTM PV	1	1	1	1	1	1	0	1	1	1	1	1
LSE total supply (effective MW)	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net capacity position (+ve = excess, -ve = shortfall) (effective MW)	**(48)**	**(49)**	**(51)**	**(49)**	**(47)**	**(47)**	**(46)**	**(46)**	**(45)**	**(44)**	**(44)**	**(43)**

Figure 9: 30 MMT LSE Capacity by Contract Status



The potential significant increase in load due to forecasted expansion at Snow Summit and implementation of BVES-owned solar PV and storage projects will modify the hourly load profile and shift energy use towards a more fully utilized capacity. Facilitating this change in the load shape and capacity utilization will be the battery used for stored energy forecasted to come online in later years. Daytime load is increased as the battery charges over a four-hour period, and the evening load is reduced as the battery discharges. This will allow BVES to serve load above the capacity limit set by the SCE transmission contract serving BVES and the BVPP capacity combined. Planned solicitations to procure renewable firm contracts will also support load shape flattening as reliance on system power agreements is reduced over the ten-year planning cycle.

The annual and seasonal contracts combined will hedge approximately 90 percent of the load requirement through 2024 with anticipated wholesale market purchases to meet the shortfall in 2023 that is a result of delayed implementation of the solar generating facility. The BVPP provides a partial hedge for the remaining 10 percent as gas prices still drive the BVPP generation marginal power cost. The BVPP has an 8.4 MW capacity and can therefore provide hedge equal to the gas price plus transportation cost at the approximate 12,000 BTU/kWh heat rate of the BVPP. Although this provides some protection, the BVPP supply price is subject to potential gas price spikes.

In 2004, the CPUC adopted an RA policy framework (PUC Section 380) to ensure the reliability of electric service in California. In an effort to meet its RA requirements, BVES will continue to issue solicitations to contract RA resources including a 15 percent reserve margin and will use its BVPP as a BTM DG resource. BVES will also continue to comply with the CAISO Tariff applicable to LSEs and their RA obligations through its SC.

BVES complies with Federal Energy Regulatory Commission requirements and the CAISO Tariff by following these key provisions:

- BVES closely mirrors the State's monthly coincident peak demand calculation and provides the data to the CEC.[29]
- BVES treats the BVPP as a distributed generation resource because the BVPP is not under a PGA and is behind the CAISO metering point.

Other options for reducing the RA obligations and the associated cost will include development of the BVES-owned solar project and to facilitate further renewable DG growth in the residential and commercial sectors, as well as the development of the 5 MW / 20 MWh (four-hour) battery solution. These sources of solar production will decrease BVES's overall load and therefore reduce the RA requirement for BVES. BVES is assessing the benefits of stored power as a means to manage its load profile and reduce peak load and therefore contribute to the reduction of its RA requirement. Results of the preliminary analysis indicate that the battery solution would provide a reduction in the RA requirement, a daily arbitrage, an increase in capacity served, and other load shaping and frequency benefits.

The planned solar project will also offer a long-term strategy on pricing, RA, RECS, a daytime capacity increase, and a means of reducing emissions for BVES. The Federal Investment Tax Credit available for the solar and battery solution makes this proposal even more cost effective for customers provided that this incentive is available in the implementation stage.

Due to its small size and as a distribution-only utility, BVES has virtually no impact on the CAISO system. BVES's peak load of approximately 45 MW when compared to the CAISO peak load of over 45,000 MWs represents less than one percent of the total CAISO peak load. Compared to the CPUC 2021 RSP, BVES presents the following table.

Table 21: BVES Resource Mix in 2035 Compared to RSP

RSP Resource Mix (Cumulative MWs) Compared to 2019-2020 RSP Assessment								25 MMT Scenario Preferred	30 MMT Scenario Preferred	**Comments**
Resource Type	**2020**	**2021**	**2022**	**2023**	**2024**	**2026**	**2030**	Owned & Contracted Resources (rounded whole MWs) in 2035		
Nuclear	2,935	2,935	2,935	2,935	1,785	635	635	0	0	
CHP	2,296	2,296	2,296	2,296	2,296	2,296	2,296	0	0	
Natural Gas	27,562	25,113	25,113	25,113	25,113	25,113	25,084	8	8	*BVPP*
Coal	480	480	480	480	480	-	-	0	0	
Hydro (Large)	7,070	7,070	7,070	7,070	7,070	7,070	7,070	0	0	
Hydro (Scheduled Imports)	2,852	2,852	2,852	2,852	2,852	2,852	2,852	0	0	
Biomass	903	903	903	903	903	903	901	0	0	
Geothermal	1,851	1,851	1,851	1,851	1,851	1,851	1,851	0	0	

[29] The CEC reviews this data and provides to BVES a procurement obligation value consistent with the treatment provided to other CPUC-jurisdictional LSEs.

Hydro (Small)	974	974	974	974	974	974	974	0	0	
Wind	7,357	7,490	9,406	9,406	10,193	10,193	10,293	0	0	
Out-of-State Wind on New Transmission	-	-	-	-	-	-	606	0	0	
Solar	16,310	18,766	20,887	22,887	22,887	22,887	25,905	13	13	*BVES Solar Facility*
Customer Solar	9,827	11,137	12,284	13,303	14,288	16,156	20,066	26	26	*IEPR/CSP assumptions*
Battery Storage	1,846	4,614	4,717	4,887	6,073	9,065	12,138	5	5	*BVES BESS Facility*
Pumped (long-duration) Storage	1,599	1,599	1,599	1,599	1,599	2,573	2,573	0	0	
Shed Demand Response	2,195	2,418	2,418	2,418	2,418	2,418	2,418	10	10	*Interruptible customers*
Gas Capacity Not Retained	-	-	-	-	-	-	-30	0	0	

Source Data: 2019 - 2020 RSP R.16-02-007, Table 6

g. High Electrification Planning

To investigate the impact of a "High Electrification" scenario on BVES's Preferred Conforming Portfolios, BVES modelled a high load scenario within its supply model. The high load scenario assumed additional load from electrification beginning in 2026 and growing an additional 10 percent of total load by 2035, a load increase of 14.2 GWh in 2035 (prior to application of demand modifiers). Under this scenario, BVES would need to increase the size of planned 7x24 block renewable contracts to serve a portion of this additional load while maintaining compliance with the emissions benchmarks and may require additional batteries or expanded capacity in the Big Bear Valley. Table 22 shows the result of this analysis.

Under the 25 MMT emissions benchmark and the High Electrification scenario BVES would need to procure an additional 2 MW of 7x24 block renewable generation. Under the 30 MMT emissions benchmark and the High Electrification scenario, BVES would need to procure an additional 1 MW of 7x24 block renewable power in 2029 and an additional 2 MW of 7x24 block renewable power in 2034 compared to the Preferred Conforming Portfolios. The 30 MMT Preferred Conforming Portfolio requires a greater increase in non-emitting generation when applied to the "High Electrification" scenario because the included firm renewable contracts are sized smaller than those under the 25 MMT Preferred Conforming Portfolio.

Table 22: Additional Contract Procurements Under High Electrification Scenario[30]

Resource Type	MWs	Annual GWh	2035 GHG target	Transmission Zone	Substation/ Bus	Alternative location
7x24 Block Renewable Power	2	17,520	25 MMT	n/a	n/a	n/a
7x24 Block Renewable Power	3	26,280	30 MMT	n/a	n/a	n/a

[30] BVES does not presently have guidance on the transmission zone or substation/bus that would be associated with these additional contract capacities as they would be largely dependent on the counterparty's broader portfolio within CAISO.

h. Existing Resource Planning

In developing the preferred conforming portfolios, BVES considered both existing and new resources to fulfill its supply needs. Specifically, BVES plans to bring online two new generation facilities – the 5 MW BVES Solar Project and the 5 MW BVES Storage Project. Outside of these two new resources, BVES's Preferred Conforming Portfolios rely on the contracts that deliver 7x24 block renewable power from existing resources. BVES is in the unique position currently of being actively engaged with a counterparty to contract for this type of firm renewable product that would begin delivery in Q4 2024. The counterparty for this contract operates a significant renewable generation portfolio that can promise delivery for the relatively small amount of contract power (53 GWh annually) BVES requires. While BVES engages in the competitive procurement process, in the time since the 2020 IRP BVES has been unable to contract for cost competitive renewable PPAs to replace existing system power contracts. Owing to these challenges as well as BVES's recent early-stage success with its counterparty for firm renewable power, BVES believes it is reasonable to plan to contract for the same firm renewable product in 2029 and 2034 (as both Preferred Conforming Portfolios require). BVES's small size is an unusual benefit when seeking 7x24 block renewable as some counterparties are able to leverage large, diverse renewable portfolios that are oversized compared to the generation BVES ultimately requires.

BVES determined the size of these future 7x24 block renewable contracts based on the supply-demand balancing analysis and the resulting emissions of the portfolio as a part of determining the Preferred Conforming Portfolios. Notably under both the 25 MMT and 30 MMT scenarios future contracts for firm renewable power are at most 1 MW larger in terms of contract capacity compared to the contract BVES is under negotiations for with its current counterparty. BVES thus believes the size of these contracts are achievable and also fall well within the size of the generation portfolio managed by the current counterparty as well as similar counterparties that offer these types of products.

Challenges to procuring generation from existing facilities will not be unique to BVES as the broader pool of LSEs are likely interested in the broad benefits provided by firm renewable power. While BVES's small size is a benefit in terms of contract achievability, it also limits BVES's risk appetite owing to its small customer base as well as limits the amount of financial collateral BVES is able to put up to support these long-term power contracts. BVES chose the final Preferred Conforming Portfolios as they broke up the required contracts into two tranches so as to limit the amount of financial collateral BVES would have to support at any one time. Additionally, BVES acknowledges the risk of depending on a single counterparty for both the upcoming contract in 2024 as well as the planned future contracts in 2029 and 2034. Accordingly, the financial size and strength of the single counterparty will be an important consideration for BVES in selecting the counterpart to these contracts.

i. Hydro Generation Risk Management

While BVES is not directly exposed to hydro generation risk, delivery from large hydro facilities carried through the CAISO power grid can lead to a market risk exposure that may impact the CPUC's RSP as well as BVES's power supply forecasts in shortfall day-ahead demand scheduling. During drought years, the availability of hydroelectric generation production can be severely limited. It is well known that the Big Creek/Ventura area is a local capacity requirement area that relies on Big Creek generation to meet North American Electricity Reliability Corporation planning standards. The recent trend shows that hydroelectricity generation declined between 2001 and 2015, largely due to drought conditions. The precipitation and hydro reservoir subsequently increased from 2015 to 2017, prior to declining again in

2018 through 2021. Additionally, more supply of run-of-river hydroelectric power generally reduces the need for baseload generation and imports. Hydro conditions also impact the amount of hydroelectric power and ancillary services available during peak hours from units with reservoir storage.

Year-to-year variation in hydroelectric power supply in California can have a significant impact on supply mix and the performance of the wholesale energy market. Hydro-electric generation in 2015 was the lowest since 1998 and followed many years of decreasing output.[31] During a drought year in 2015 the Big Creek area of the SCE system experienced a reduction of generation production 80 percent below average production. Natural gas-fired capacity and renewables were used to help offset lower levels of generation from hydropower facilities. Total hydro-electric production increased in both 2016 and 2017 before exhibiting a 39 percent decrease in 2018. While California hydro conditions for 2019 were above normal, hydro conditions in 2020 were down and hydro production in 2021 amounted to a 26 percent decrease compared to 2020.[32] The current forecast shows the potential changes in hydro conditions and availability within the state for future resource planning periods. Results indicate a likelihood of reduction of released hydroelectric generation and an increase in in-state supply from new solar generation.

j. Long-Duration Storage Planning

Both the remote nature as well as the small customer base associated with BVES make long duration storage financially infeasible for BVES at this time owing to increased TAC charges among other factors. BVES does however, plan to own and operate a 5 MW, 4-hour duration storage facility within its service territory that will come online in 2025 at the latest. As a part of future IRP proceedings BVES will continue to investigate the cost effectiveness and practicality of long-duration storage.

k. Clean Firm Power Planning

As discussed above, BVES is currently in the process of contracting for a 7x24 block renewable product that would deliver approximately 30 percent of BVES annual supply beginning in late 2024. This product will be delivered on a 7x24 basis for a block of 6 MW of renewable power indicating a 100 percent capacity factor. The counterparty indicates this type of product is achievable through a mix of multiple renewable resources that together can provide a firm product, made easier by the small contract capacity BVES requires. BVES understands from discussions with its potential counterparty that the resources that will provide this firm renewable product in 2024 are all located within the CAISO balancing authority. BVES sees significant benefits for contracting for this type of generation product both in the near future as well as for the planned procurements included in the Preferred Conforming Portfolios in 2029 and 2034.

These types of firm renewable contract generation are especially advantageous to BVES, which is limited in its ability to sell existing excess system power contract generation that would be inherent in procuring the amount of generation required from shaped, renewable resources. Additionally, contracting for this

---

31 CAISO. "Annual Report on Market Issues and Performance." 2016. http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

32 CAISO. "Annual Report on Market Issues and Performance." 2021. http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf

type of firm renewable power can be readily aligned with BVES historic approach of procuring firm system power but does not require the additional step of having to purchase unbundled RECs via PCC3 contracts to retire towards the RPS program. Ultimately, procuring firm renewable contracts for BVES is its best path forward to ensure compliance with the emissions benchmarks.

l. Out-of-State Wind Planning

BVES understands that out-of-state (OOS) wind development is being proposed to supplement existing generation capacity due to land and resource constraints on further wind development within the state of California. However, BVES believes it would incur significant losses should it pursue out-of-state wind generation, likely making this initiative cost-prohibitive for investment. BVES does not currently see potential in pursuing contracts with OOS wind resources and does not project a need to procure power generated by any new OOS wind developments before the end of this IRP forecast horizon.

m. Offshore Wind Planning

Given the size of BVES's load (< 0.1 percent of total large and small IOU load in CA) and commensurately small customer base (<25,000 total customers), at this time BVES does not view offshore wind as a necessary option to achieve its clean energy goals and emissions benchmarks at this time. BVES will continue to monitor related offshore wind proceedings and investigate the need for such generation and affordability should such generation be required in future IRP proceedings.

n. Transmission Planning

Due to BVES's two supply interconnection points, transmission capacity expansion is not applicable nor a suitable, least-cost option to present in this IRP. BVES understands that as more renewable generation is added within the CAISO area, it is expected that transmission use will increase and ultimately add to the overall cost of congestion. To mitigate this direct risk, BVES will continue to participate in the CAISO CRR process to secure the appropriate financial hedge to mitigate potentially increasing congestion costs or secure PPAs that deliver energy to the DLAP_SCE on behalf of BVES.

Additionally, BVES evaluations do not require busbar mapping exercises for capacity planning with regard to its presented resource portfolio as it has no current projects under CAISO-control and no current projects in the interconnection queue.

IV. Action Plan

BVES's action plan to meet the targets proposed in this IRP is as follows:

1. Strive to meet forecasted GHG emissions benchmark from BVES energy supply:
    a. Transition to obtaining "unit-specific renewable energy block contracts" (firm renewable energy contracts for both base and seasonal loads);
2. Reduce reliance on system power over this IRP planning period:
    a. BVES has acquired an annual hourly variable shaped contract from December 1, 2019 to October 31, 2024;

    b. BVES has acquired the contract for seasonal hourly shaped delivery from November 1, 2019 – December 31, 2022;
    c. Any daily imbalances are either purchased or sold through the CAISO market; and
    d. BVES plans to meet GHG emissions benchmark by focusing on procuring competitive PPAs for renewable power supply. This includes filling the gap in its portfolio due to the delay of the solar project and, over time, changing term lengths for future system power seasonal and baseload contracts and procure unit specific renewable resources as available.
3. Develop a pathway to deploy approximately 5 MW total capacity solar PV project:
    a. BVES has secured a new site location and conducted preliminary studies to assure viability of the projects;
    b. BVES has begun the process of negotiating a purchase and sales agreement and plans to submit an application to the Commission in 2023; and
    c. The RECs and energy generated from this project will hedge BVES for future RPS and IRP compliance terms.
    d. BVES will continue to update the Commission as concrete implementation steps materialize.
4. Local, flex, and system RA capacity obligations:
    a. BVES continues to seek new RA contracts, facing significantly higher costs for capacity since California reserve margins may drop below 15 percent unless additional resources are brought online, stimulating higher capacity prices and therefore, higher RA prices, in the power market;
    b. Securing cost competitive or any RA contracts has been a challenging issue among most LSEs in California, including BVES;
    c. BVES's BVPP is not an eligible RA program resource for local capacity requirements; and;
    d. BVES will continue to frequently solicit RFPs for RA capacity contracts in a commercially reasonable manner in an effort to procure additional RA capacity.
5. BESS facility:
    a. BVES conducted a battery study with an outside consultant and is currently working with a vendor to install a battery solution; and
    b. Plans to implement the initial approval steps for an approximate 5 MW BESS device after working with the outside consultant.
6. Secure firm future renewable energy only contracts
    a. Focus on firm RE supply starting in 2024; and
    b. Two additional blended firm RE PPAs over the course of the planning horizon
7. Expand capacity to provide supplemental service to BVES's largest customer:
    a. BVES's largest customer, the Snow Summit ski resort, plans to retire its diesel fueled power generation; and
    b. The Commission recently approved an Added Facilities Agreement between BVES and Snow Summit to construct and operate facilities to increase the capacity to provide supplemental service to the Snow Summit ski resort.
8. Demand side management:
    a. BVES uses electric vehicle pilot program, time of use rate program, and energy efficiency in an effort to optimize load patterns to achieve higher load factor.

b. Transportation Electrification Pilot Program:
    i. BVES began the process of implementing this program and will track adoption and success rates; and
    ii. At the time of this filing at least 15 residential customers (and one commercial customer) are in the process of acquiring EV charging stations at their residence.
c. Lighting EE Program:
    i. BVES has successfully implemented two EE programs and is considering new programs for BVES customers. BVES has one active EE program as part of its Energy Savings Assistance (ESA) program.[33]
d. Investigation into TOU rate structure:
    i. Pilot study program for a TOU incentive rate for EV and EV charger customers.

a. Proposed Procurement Activities and Potential Barriers

The LSE should provide responses for each of the following resource categories:

i. Resources to meet D.19-11-016 procurement requirements

Not applicable. BVES was not assigned an additional procurement obligation in D. 19-11-016.

ii. Resources to meet D.21-06-035 procurement requirements, including:

Not applicable. BVES was not assigned an additional procurement obligation in response the mid-term reliability analysis in D.21-06-035. This response addresses the following subcategories below relating to this Commission Decision.

a. 1,000 MW of firm zero-emitting resource requirements

Not applicable. BVES was not assigned an additional procurement obligation in response the mid-term reliability analysis in D.21-06-035.

b. 1,000 MW of long-duration storage resource requirements

Not applicable. BVES was not assigned an additional procurement obligation in response the mid-term reliability analysis in D.21-06-035.

c. 2,500 MW of zero-emissions generation, generation paired with storage, or demand response resource requirements

Not applicable. BVES was not assigned an additional procurement obligation in response the mid-term reliability analysis in D.21-06-035.

---

[33] The ESA program, funded through the Public Purpose Program Adjustment Mechanism, is available only for qualifying low-income residential customers. The ESA Program provides funding for energy efficient refrigerators, hard-wired compact fluorescent fixtures, compact fluorescent bulbs, LEDs, smart strip surge protectors, low-flow showerheads and weatherization measures. BVES also provides educational materials to all customers promoting the use of energy efficient appliances, weatherization materials, thermostatic controls, and lifestyle changes.

d. All other procurement requirements

Not applicable. BVES was not assigned an additional procurement obligation in response the mid-term reliability analysis in D.21-06-035.

e. Offshore wind

Not applicable. BVES was not assigned an additional procurement obligation in response the mid-term reliability analysis in D.21-06-035.

Out-of-state wind

Not applicable. BVES was not assigned an additional procurement obligation in response the mid-term reliability analysis in D.21-06-035.

i. Other renewable energy not described above

Not applicable. BVES plans to attain 7x24 block RE PPAs, which are based on the counterparty's supply portfolio of existing generation or planned generation ahead of the contract operational date.

ii. Other energy storage not described above

Not applicable. BVES plans to attain 7x24 block RE PPAs, which are based on the counterparty's supply portfolio of existing generation or planned generation ahead of the contract operational date.

iii. Other demand response not described above

Not applicable. BVES already has a DR program in place with its largest C&I customer enabling the ability to curtail load if ever called upon. No other potential barriers are considered in this analysis.

iv. Other energy efficiency not described above

Not applicable. BVES maintains its energy efficiency program and does not find any potential barrier or proposed activity to report.

v. Other distributed generation not described above

Not applicable. BVES has no other additional DER potential barriers to address for this analysis.

vi. Transportation electrification, including any investments above and beyond what is included in Integrated Energy Policy Report (IEPR)

Not applicable. BVES did not find additional insight into transportation electrification beyond what is discussed in the IEPR.

vii. Building electrification, including any investments above and beyond what is included in Integrated Energy Policy

Not applicable. BVES did not find additional insight into building electrification beyond what is discussed in the IEPR.

BVES does not have direct activities that necessitate approval from the Commission through this IRP filing. In order to implement the Preferred Conforming Portfolios and reduce forecasted GHG emissions attributed to BVES supply, BVES will investigate all available resource procurement options. BVES will consider other local supply options and storage solutions as a hedge for supply cost, an instrument for increasing capacity, and a means of reducing carbon emissions during the timeframe of this IRP. For the current IRP outlook, the PPAs for system power will continue to supply power through 2024 and any shortfalls will be addressed with wholesale power purchases until an anticipated RE 24x7 block PPA is successfully contracted. BVES will continue its efforts to develop a pathway forward to deploy a utility-scale and owned solar PV facility as well as the BESS.

Table 23: BVES Power Procurement Summary

RDT Resource Procurement Plan Summary				
Resource Type	**Procurement Plan**	**Correspondence to Proposed Activities**	**Potential Barriers**	**Resource Viability**
_New_generic_solar_1axis	Utility-owned solar generating plant directly supplying the BVES distribution system	Addresses #3 in the action plan	Contracting and construction timelines; potential delays due to uncontrolled factors and pricing	BVES does not require financing or interconnection process for this project.
_new_generic_battery_storage	Utility-owned, standalone storage facility Li-Ion or flow technology	Addresses #5 in the action plan	Contracting and construction timelines; siting constraints; potential delays due to uncontrolled factors	BVES does not require financing or interconnection process for this project.
_existing_generic_unknown	Currently negotiation with a counterparty for a ten-year contract to supply nearly one third of supply needs with bundled REC and capacity products	Addresses #2 and #6 in the action plan	In-state PPAs may not be available or cost competitive; counterparty risk concerns; competition for firm RE PPAs; cost prohibited investments; may have to procure out-of-state	BVES does not require financing for this PPA
_existing_generic_unknown	Seeking to replicate the initial firm RE PPA contract to provide up to two-thirds of RE firm 7x24 contracts to replace termed system power PPAs	Addresses #2 and #6 in the action plan	In-state PPAs may not be available or cost competitive; counterparty risk concerns; competition for firm RE PPAs; cost prohibited investments; may have to procure out-of-state	BVES does not require financing for this PPA
_existing_generic_unknown	Seeking to replicate the initial and second firm RE PPA contracts to supply nearly all BVES's load with RE firm 7x24 contracts, replacing the system power PPAs once they expire	Addresses #2 and #6 in the action plan	In-state PPAs may not be available or cost competitive; counterparty risk concerns; competition for firm RE PPAs; cost prohibited investments; may have to procure out-of-state	BVES does not require financing for this PPA

RDT Resource Procurement Plan Summary				
Resource Type	Procurement Plan	Correspondence to Proposed Activities	Potential Barriers	Resource Viability
_Unspecified_non_import	In effort to reduce system power reliance, seeking 75-85 percent initially of current base annual contract amounts after current contract expires	Addresses #2 in the action plan	Prioritizing renewable PPA procurement, BVES may have to rely on system power contracts and day ahead purchases in the interim but forecasts to require the conservative presentations of unspecific system power within its power mix by 2035	BVES does not require financing for this PPA
_Unspecified_non_import	BVES plans to support its peak periods with seasonal firm contracts for an additional term that aligns with renewable power contracting plans	Addresses #2 in the action plan	Prioritizing renewable PPA procurement, BVES may have to rely on system power contracts in the interim but forecasts to require the conservative presentations of unspecific system power within its power mix by 2035	BVES does not require financing for this PPA

BVES aims to minimize criteria air pollutants through the proposed initiatives in this IRP to provide air quality benefits to part-time and permanent residents within its service area through the planned utility-owned renewable generation projects. As discussed in this IRP, BVES does not have disadvantaged communities that would warrant additional outreach or input relative to these proposed activities. BVES will continue its efforts to implement steps for the solar facility and BES solution projects, secure renewable firm PPAs, issue RFPs for available local, flex, and system RA capacity, and exhaust its ten-year PCC 3 REC contract strategy and replace it with bundled energy and REC product contracts to hedge for its long-term supply needs as well as to meet the state objectives of GHG emissions reduction from retail electricity sales as available. Net baseline supply will otherwise be supported by short-term PPAs for system power or unit-specific renewable power purchases as the utility phases in new renewable energy contracts to its power content mix.

Table 24: BVES Procurement Implementation Summary

RDT Procurement Plan Execution					
Resource Type	RDT Resource Line #	Contract Anticipated Start[34]	Solicitation Type	Solicitation Plan	Notes
_New_generic_solar_1axis	6	12/1/2024	System design elements and construction needs	Reengage contract negotiations for phased deployment; BVES withdrew prior applications and is working with an external party for the design phase	Bear Valley Solar Plant, solar, 5 MW

[34] Contract start dates are estimated based on this IRP cycle, the IEPR demand forecast, and the state of decision-making under the BVES' senior leadership approval process.

RDT Procurement Plan Execution					
Resource Type	RDT Resource Line #	Contract Anticipated Start[34]	Solicitation Type	Solicitation Plan	Notes
new_generic_battery_storage	7	12/1/2024	RFPs for system design elements and construction needs; siting needs	Issue solicitations as siting is secured	Bear Valley Electric Service Battery Storage Project, Li-Ion or Flow storage, 5 MW with four-hour discharge
generic_unknown	23	11/1/2024	RFPs for available competitive RE 7x24 block PPAs; BVES is currently in negotiations with a counterparty	Negotiations with counterparty	No locational preference, full contract supply, assumes unit-specific solar and wind is currently available for power purchase agreement; bundled with RECs and capacity
generic_unknown	24	1/1/2029	RFPs for available competitive RE 7x24 block PPAs	Begin developing RFPs immediately after the operational date of the first RE PPA	No locational preference, full contract supply, assumes unit-specific solar and wind is currently available for power purchase agreement; bundled with RECs and capacity
generic_unknown	25	1/1/2034	RFPs for available competitive RE 7x24 block PPAs	Begin developing RFPs after the operational date of the second RE PPA	No locational preference, full contract supply, assumes unit-specific solar and wind is currently available for power purchase agreement; bundled with RECs and capacity
_unspecified_non_import	21	11/1/2024	Solicitations will be issued for system power as a net resource as renewable PPAs are acquired	Harden netted system energy needs as firm RE 7x24 PPA contracts come online	BVES plans to execute a shorter-term contract for annual firm delivery and seasonal energy to support high load months as all firm RE PPAs come online
	22	1/1/2023			
sellers_choice	8	1/1/2023	BVES will issue Request for offers (RFOs) in continued effort to hedge its RA capacity reservation requirements	BVES must purchase its capacity amounts to meet RA obligations through contracts	Anticipating the need to secure future system RA capacity contracts through 2035
	9	1/1/2024			
	10	1/1/2025			
	11	1/1/2026			
	12	1/1/2027			
	13	1/1/2028			
	14	1/1/2029			
	15	1/1/2030			
	16	1/1/2031			
	17	1/1/2032			
	18	1/1/2033			

RDT Procurement Plan Execution					
Resource Type	RDT Resource Line #	Contract Anticipated Start[34]	Solicitation Type	Solicitation Plan	Notes
	19	1/1/2034			
	20	1/1/2035			

As a prudent utility, BVES assumes a low-risk posture. BVES seeks greater certainty in total power supply costs through long-term contracts rather than risk substantial upward price movements in the volatile spot market. For many years, BVES has been able to fix a large percentage of its total power supply costs through long-term PPAs. This has allowed BVES to reduce its exposure to market price uncertainty, but BVES still faces other sources of risk. BVES takes into account the Value at Risk (VAR) when determining how much of its future energy supplies to purchase through long-term PPAs. The VAR is a measure of how much total costs change when underlying variables, such as natural gas prices, change. Steps taken or under consideration to mitigate VAR include the following:

- use of assets such as gas fired generation, which indexes power prices to natural gas prices;
- use of solar project(s) to fix prices to the cost of capital of the solar facility;
- use of physical call options with fixed strike prices to cap power prices; and
- battery applications to condition the system load and facilitate asset and contract coverage are under review at this time.

Two major goals in risk management strategy of BVES resources are as follows. 1) Meet the capacity of the firm customers first and interruptible customers second, and 2) secure favorable prices through a competitive bid process for future energy requirement expenditures via fixed price contracts for both interruptible and non-interruptible customers, addition of utility owned solar capacity, and the conditioning of system load to fit assets and contracts through batteries. Additional risks BVES faces include forecast accuracy, market-price fluctuations, regulatory uncertainty, unplanned supply constraints, counterparty decision making, customer behavior, or any combination thereof. The growing portion of energy consumption from customer-owned distributed generation via the NEM program and its successor tariff is also a significant concern. BVES continues to closely monitor customer DG growth and will reassess resource requirements in future IRPs.

Forecast risk is the risk associated with over- or under-forecasting BVES's retail requirements and having either too much or too little energy under long-term PPAs, requiring that BVES either buy at higher than expected costs in the spot market or sell surplus energy from existing contracts at a loss.[35] BVES mitigates this risk by improving on forecasting models, using multiple models (regression, statistically adjusted end-use, conditional demand analysis models for individual customers) for long-term and mid-term forecasting periods, and neural network models for next day forecasting.

Market-price risk is the risk associated with entering into long-term PPAs with wholesale prices subsequently falling, such that BVES could have purchased the energy less expensively in the short-term or spot market. Conversely, if BVES chooses not to enter into a long-term PPA at current prices and then prices rise, BVES's price of power could rise dramatically as compared to not locking in prices at current rates. To mitigate market-price risk, BVES's planning assumptions utilize the forecasting of IHS-

[35] BVES is refining its Load Research Project to improve forecasts; specifically, future plans are to include addition of more refined customer data via, among other methods, a pole top collection system.

Cambridge Energy Research Associates (CERA) experts in global and regional economic trends, all facets of energy markets, policy assessments, and industry practices. IHS-CERA fully integrates all of the forecast products into one harmonious determination of available power fuels markets, and economy. The firm is well connected with energy, policy, manufacturing, and service sector leaders. Scenario analysis is also incorporated in the IHS-CERA support of BVES's IRP planning process. BVES incorporates this external analysis into the internal analysis used to plan for its future resource needs.

Counterparty risk is the risk that a counterparty defaults on its obligations and BVES incurs additional costs to replace energy contracted from the counterparty. To attempt to mitigate this risk, BVES utilizes collateral requirements and parent company guarantees to the extent possible. BVES also attempts to deal primarily with companies that have good credit ratings.

BVES cannot avoid all risk. Risk that cannot be avoided is managed to the extent feasible. Although BVES cannot control the actions of the market or other entities, BVES seeks to design its resource acquisition strategy to minimize the potential financial impacts of forecast and market risk. For example, BVES has fixed the price of roughly 90 percent of its energy requirements until new renewable contracts come online through the acquisition of competitively priced long-term PPAs, which minimizes the impact of sudden price spikes in the spot market. BVES's planned new generation assets of solar and battery storage should secure supply and offer price hedges tied to another source. This is in addition to the planned competitive RE 7x24 block PPAs. Diversity of resources is a key element in the development of the capacity mix available to BVES.

BVES will seek to meet its RA obligation based on its contribution to monthly CAISO coincident peak load and will offset its peak with the use of the BVPP as a DER BTM resource and future batteries. Local RA and flexible capacity requirements will remain an area of focus for BVES. BVES will continue to seek use of RA contracts, solar production, and energy storage to meet all of the flexible, local, and system RA requirements in the future. BVES continues to promote the benefits of reduced consumption, in line with state goals and regulatory policies.

Regulatory risk is the risk of changes in regulations or new regulations that increase BVES's cost of doing business. For example, if BVES takes actions to meet current regulations and regulations are subsequently changed, BVES may incur increased and unforeseen costs to (1) undo earlier actions, and (2) meet the new regulations. To mitigate regulatory risk, BVES utilizes a number of resources to assess current and future policy affecting California energy markets. BVES utilizes various legal and market consultants as well as internal subject matter experts to fully assess options that BVES should take in planning for the future. BVES will continue to monitor, assess, and reduce, where possible, its regulatory risk at both the federal and state levels. Different or new energy and environmental goals, at both the federal and state levels, could add new complexity and costs to BVES's operations. Any proposed changes, both at the federal and state level, will be taken into consideration by BVES in its integrated resource planning process.

b. Disadvantaged Communities

While no disadvantaged communities sit within BVES's service territory, BVES understand that air pollutants do not abide by geographic boundaries and thus could impact disadvantaged communities outside of BVES's service territory. BVES aims to reduce the impact of emissions on disadvantaged communities primarily through its long-term goal of reducing dependence on system power. BVES strives to do this under the Preferred Conforming Portfolios through procurement of 7x24 block renewable power which is zero emitting. BVES can provide accessible materials in predominate languages spoken in the state including Spanish, Mandarin, and Tagalog. No other tribal communities are present requiring additional language capabilities. General outreach has been limited over the last IRP cycle due to the COVID pandemic. BVES will also strive to communicate targeted outreach on its new procurement plan in order to mitigate rate shock and express the benefits of shifting to a clean power supply portfolio. This will be further described in a future IRP filing.

c. Commission Direction of Actions

Not applicable.

This prompt is not applicable to BVES at this time as procurement decisions are made through alternative Commission procedures. BVES does not seek any new actions from the Commission at this time related to its procurement forecasts for its two Preferred Conforming Portfolio scenarios.

V. Lessons Learned

BVES appreciates the opportunity to present Conforming and Preferred Portfolio scenarios to the Commission to help meet overall objectives of an optimized resource planning portfolio under the Standard Plan template since the 2020 IRP cycle. The Commission's approach for this IRP's analysis established uniform assumptions that enable standardized comparisons across all LSEs and transfer easily into the Reference System Plan. This provides an achievable avenue for the Commission and state agencies/entities to develop an achievable pathway to successfully reduce electric sector GHG emissions and meet state mandates. BVES understands this pathway and has adapted its internal processes to remain compliant with and not conflict with biannual IRP compliance filings and long-term plan updates.

BVES has historically relied on unspecified power contracts as a least-cost option for reliable supply as unspecified system power contracts are generally more cost-favorable for long-term resource planning. BVES, however, presents in this IRP a new roadmap for meeting GHG emissions benchmarks and reducing reliance on CAISO system power along with deployment of the storage and solar facilities. BVES's current primary energy supply resource is categorized as unspecific system power and thus is tied to carbon intensity of natural gas dispatch on the CAISO-controlled grid in modeling emissions through 2035, which BVES does not believe is a true reflection of the California power mix. While internal methodology takes into account the resource mix profile of SCE's service territory for local emissions supply mix forecasts, BVES understands the applied dispatch conditions and calculated emissions allocated to LSEs that aim to account for generating units called upon by the CAISO to meet BVES load center demand and therefore necessitates an evaluation of the CAISO system mix profile for more accurate carbon emission accounting. BVES presents a common planning concern regarding potential rate impact to its customers for the discussed activities to seek clean energy power delivery agreements.

BVES requests that the Commission consider modifying the CSP modeling capabilities to allow for overwriting the proportional GHG emissions assigned to LSE dependent on system power contracts with the California system supply mix incorporating clean energy delivery in order to, at minimum, compare prior carbon accounting methodologies with the conditional weights presented in the CPUC's CSP model assumptions in this IRP cycle. BVES also requests further discussion surrounding the incorporation of PCC 2 and PCC 3 REC products in the CSP modeling methodology and the alignment against the RPS program compliance periods and unbundled REC retirements

Glossary of Terms

Alternative Portfolio: *LSEs are permitted to submit "Alternative Portfolios" developed from scenarios using different assumptions from those used in the Preferred System Plan with updates. Any deviations from the "Conforming Portfolio" must be explained and justified.*

Approve (Plan)*: the CPUC's obligation to approve an LSE's integrated resource plan derives from Public Utilities Code Section 454.52(b)(2) and the procurement planning process described in Public Utilities Code Section 454.5, in addition to the CPUC obligation to ensure safe and reliable service at just and reasonable rates under Public Utilities Code Section 451.*

Balancing Authority Area (CAISO): *the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.*

Baseline resources: *Those resources assumed to be fixed as a capacity expansion model input, as opposed to Candidate resources, which are selected by the model and are incremental to the Baseline. Baseline resources are existing (already online) or owned or contracted to come online within the planning horizon. Existing resources with announced retirements are excluded from the Baseline for the applicable years. Being "contracted" refers to a resource holding signed contract/s with an LSE/s for much of its energy and capacity, as applicable, for a significant portion of its useful life. The contracts refer to those approved by the CPUC and/or the LSE's governing board, as applicable. These criteria indicate the resource is relatively certain to come online. Baseline resources that are not online at the time of modeling may have a failure rate applied to their nameplate capacity to allow for the risk of them failing to come online.*

Candidate resource: *those resources, such as renewables, energy storage, natural gas generation, and demand response, available for selection in IRP capacity expansion modeling, incremental to the Baseline resources.*

Capacity Expansion Model: *a capacity expansion model is a computer model that simulates generation and transmission investment to meet forecast electric load over many years, usually with the objective of minimizing the total cost of owning and operating the electrical system. Capacity expansion models can also be configured to only allow solutions that meet specific requirements, such as providing a minimum amount of capacity to ensure the reliability of the system or maintaining greenhouse gas emissions below an established level.*

Certify (a Community Choice Aggregator Plan)*: Public Utilities Code 454.52(b)(3) requires the CPUC to certify the integrated resource plans of CCAs. "Certify" requires a formal act of the Commission to determine that the CCA's Plan complies with the requirements of the statute and the process established via Public Utilities Code 454.51(a). In addition, the Commission must review the CCA Plans to determine any potential impacts on public utility bundled customers under Public Utilities Code Sections 451 and 454, among others.*

Clean System Power (CSP) methodology*: the methodology used to estimate GHG and criteria pollutant emissions associated with an LSE's Portfolio based on how the LSE will expect to rely on system power on an hourly basis.*

Community Choice Aggregator*: a governmental entity formed by a city or county to procure electricity for its residents, businesses, and municipal facilities.*

Conforming Portfolio*: the LSE portfolio that conforms to IRP Planning Standards, the 2030 LSE-specific GHG Emissions Benchmark, use of the LSE's assigned load forecast, use of inputs and assumptions matching those used in developing the Reference System Portfolio, as well as other IRP requirements including the filing of a complete Narrative Template, a Resource Data Template and Clean System Power Calculator*.

Effective Load Carrying Capacity*: a percentage that expresses how well a resource is able avoid loss-of-load events (considering availability and use limitations). The percentage is relative to a reference resource, for example a resource that is always available with no use limitations. It is calculated via probabilistic reliability modeling, and yields a single percentage value for a given resource or grouping of resources.*

Effective Megawatts (MW): *perfect capacity equivalent MW, such as the MW calculated by applying an ELCC % multiplier to nameplate MW.*

Electric Service Provider*: an entity that offers electric service to a retail or end-use customer, but which does not fall within the definition of an electrical corporation under Public Utilities Code Section 218.*

Filing Entity*: an entity required by statute to file an integrated resource plan with CPUC.*

Future*: a set of assumptions about future conditions, such as load or gas prices.*

GHG Benchmark (or LSE-specific 2030 GHG Benchmark)*: the mass-based GHG emission planning targets calculated by staff for each LSE based on the methodology established by the California Air Resources Board and required for use in LSE Portfolio development in IRP.*

GHG Planning Price: *the systemwide marginal GHG abatement cost associated with achieving a specific electric sector 2030 GHG planning target.*

Integrated Resources Planning Standards (Planning Standards)*: the set of CPUC IRP rules, guidelines, formulas and metrics that LSEs must include in their LSE Plans.*

Integrated Resource Planning (IRP) process*: integrated resource planning process; the repeating cycle through which integrated resource plans are prepared, submitted, and reviewed by the CPUC*

Long term*: more than 5 years unless otherwise specified.*

Load Serving Entity*: an electrical corporation, electric service provider, community choice aggregator, or electric cooperative.*

Load Serving Entity (LSE) Plan*: an LSE's integrated resource plan; the full set of documents and information submitted by an LSE to the CPUC as part of the IRP process.*

Load Serving Entity (LSE) Portfolio*: a set of supply- and/or demand-side resources with certain attributes that together serve the LSE's assigned load over the IRP planning horizon.*

Loss of Load Expectation (LOLE): *a metric that quantifies the expected frequency of loss-of-load events per year. Loss-of-load is any instance where available generating capacity is insufficient to serve electric demand. If one or more instances of loss-of-load occurring within the same day regardless of duration* *are counted as one loss-of-load event, then the LOLE metric can be compared to a reference point such as the industry probabilistic reliability standard of "one expected day in 10 years," i.e. an LOLE of 0.1.*

Maximum Import Capability: a California ISO metric that represents a quantity in MWs of imports determined by the CAISO to be simultaneously deliverable to the aggregate of load in the ISO's Balancing Authority (BAA) Area and thus eligible for use in the Resource Adequacy process. The California ISO assess a MIC MW value for each intertie into the ISO's BAA and allocated yearly to the LSEs. A LSE's RA import showings are limited to its share of the MIC at each intertie.

Net Qualifying Capacity (NQC): *Qualifying Capacity reduced, as applicable, based on: (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the California ISO pursuant to the provisions of this California ISO Tariff and the applicable Business Practice Manual.*

Non-modeled costs*: embedded fixed costs in today's energy system (e.g., existing distribution revenue requirement, existing transmission revenue requirement, and energy efficiency program cost).*

Nonstandard LSE Plan*: type of integrated resource plan that an LSE may be eligible to file if it serves load outside the CAISO balancing authority area.*

Optimization*: an exercise undertaken in the CPUC's Integrated Resource Planning (IRP) process using a capacity expansion model to identify a least-cost portfolio of electricity resources for meeting specific policy constraints, such as GHG reduction or RPS targets, while maintaining reliability given a set of assumptions about the future. Optimization in IRP considers resources assumed to be online over the planning horizon (baseline resources), some of which the model may choose not to retain, and additional resources (candidate resources) that the model is able to select to meet future grid needs.*

Planned resource: *any resource included in an LSE portfolio, whether already online or not, that is yet to be procured. Relating this to capacity expansion modeling terms, planned resources can be baseline resources (needing contract renewal, or currently owned/contracted by another LSE), candidate resources, or possibly resources that were not considered by the modeling, e.g., due to the passage of time between the modeling taking place and LSEs developing their plans. Planned resources can be specific (e.g., with a CAISO ID) or generic, with only the type, size and some geographic information identified.*

Qualifying capacity*: the maximum amount of Resource Adequacy Benefits a generating facility could provide before an assessment of its net qualifying capacity.*

Preferred Conforming Portfolio*: the conforming portfolio preferred by an LSE as the most suitable to its own needs; submitted to CPUC for review as one element of the LSE's overall IRP plan.*

Preferred System Plan: *the Commission's integrated resource plan composed of both the aggregation of LSE portfolios (i.e., Preferred System Portfolio) and the set of actions necessary to implement that portfolio (i.e., Preferred System Action Plan).*

Preferred System Portfolio: *the combined portfolios of individual LSEs within the CAISO, aggregated, reviewed and possibly modified by Commission staff as a proposal to the Commission, and adopted by the Commission as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Preferred System Plan.*

Short term*: 1 to 3 years (unless otherwise specified).*

Staff: *CPUC Energy Division staff (unless otherwise specified).*

Standard LSE Plan: *type of integrated resource plan that an LSE is required to file if it serves load within the CAISO balancing authority area (unless the LSE demonstrates exemption from the IRP process).*

Transmission Planning Process (TPP): *annual process conducted by the California Independent System Operator (CAISO) to identify potential transmission system limitations and areas that need reinforcements over a 10-year horizon.*