Docket No. A.26-01-022

Exhibit No. ____________________

Date July 27, 2026 (Errata August 17, 2026)

Witness William A. Monsen

DIRECT TESTIMONY OF WILLIAM A. MONSEN
REGARDING RESULTS OF OPERATIONS
ON BEHALF OF SNOW SUMMIT LLC
IN BEAR VALLEY ELECTRIC SERVICES GENERAL RATE CASE
APPLICATION 26-01-022

[PUBLIC VERSION]

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I. Introduction and Summary of Testimony

Q. Please state your name, position and business address.

A. My name is William A. Monsen. I am a Principal Consultant at MRW & Associates, LLC (MRW). My business address is 1736 Franklin Street, Suite 700, Oakland California.

Q. Please describe you background, experience and expertise.

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, electric consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including Arizona, Colorado, California, Nevada, New England, and Wisconsin. Prior to joining MRW, I worked at Pacific Gas and Electric Company (PG&E). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley, and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison.

Q. Have you previously testified as an expert witness?

A. Yes. I have previously testified before the California Public Utilities Commission (Commission) on behalf of Snow Summit, Bear Mountain, The Utility Reform Network, the City of San Diego, the City of Long Beach, the Independent Energy Producers Association, the California Cogeneration Council, Duke Energy North America, the Alliance for Retail Energy Markets, the Center for Energy Efficiency and Renewable Technologies, the Local Governmental Commission Coalition, Clearwater Port, Commercial Energy, The Vote Solar Initiative, and the California Solar Energy Industries Association. I have also submitted testimony in proceedings before the Federal Energy Regulatory Commission as well as state utility commissions in Arizona, Colorado, Massachusetts, Oregon, and Nevada. Finally, I have submitted expert reports in Federal Court and in arbitration. Additional information about my qualifications is provided in Attachment 1.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Snow Summit LLC (Snow Summit).

Q. Please describe Snow Summit.

A. Snow Summit LLC operates two ski resorts in Big Bear Lake – the Snow Summit Resort and Bear Mountain Resort. Both ski resorts are customers of Bear Valley Electric Service (BVES). Snow Summit LLC is the single largest customer of BVES. In total, Snow Summit LLC has 15 separate accounts with BVES. Three of these accounts are large power accounts that take service under BVES's Tariff Schedule A-5 Primary (A5-

P). BVES has no other customers that currently take service under this rate schedule. These accounts take interruptible service, meaning that BVES has the option to curtail deliveries to these accounts under provisions spelled out in Schedule A-5. In addition, Snow Summit LLC has 12 accounts that take service under BVES's A-1, A-2, and A-3 commercial rate schedules.

Q. Has Snow Summit's service with BVES changed recently?

A. Yes. Snow Summit and BVES entered into an Added Facilities Agreement under which BVES would upgrade the delivery capability to the Snow Summit resort. This work involved replacing the existing Summit substation with a new substation that has greater delivery capacity. The work also involved installing a new substation BVES-owned at the top of the Snow Summit resort (the Ridge substation) and interconnecting the Ridge substation to the BVES system via BVES-owned distribution lines and equipment. Between the expanded Summit substation and the new Ridge substation, Snow Summit can now take up to 20 MW of service from BVES under Schedule A5-P.

Q. Why did Snow Summit enter into the Added Facilities Agreement to expand its interconnection with BVES?

A. Snow Summit has an existing diesel-fired generation system that provided much of the energy needed for snowmaking at Snow Summit. These facilities were aging and would require significant upgrades to their emissions control systems to be able to run as frequently as they had in the past. With the expanded interconnection with BVES, Snow Summit can retain the existing generation systems and operate within tighter emissions limits. I understand that there is a limit on the number of hours the generation system can operate per calendar year. This limitation requires Snow Summit to apportion run hours for the generators in January-March so that it has run hours available for snowmaking in November and December of the same calendar year.

Q. When did the new substations come online?

A. Snow Summit executed the Added Facilities Agreement in August of 2022.[1] After a very long design, procurement, and construction process, the substations and other new facilities came online on September 29, 2025 (i.e., in time for the 2025-2026 ski season).[2]

Q. Have the new substations installed by BVES pursuant to the Added Facilities Agreement allowed Snow Summit to not run its onsite generation for snowmaking?

A. No. Because BVES was unable to meet all of Snow Summit's electric needs for snowmaking during the 2025-2026 ski season, Snow Summit found it necessary to run its onsite generation on numerous occasions since the substations were energized in late September 2025.

Q. What are Snow Summit's interests in this proceeding?

A. As a major energy user and single largest customers on the BVES system, Snow Summit is concerned with the large increase in BVES's requested revenue requirements in this proceeding. Snow Summit is also concerned about how various incorrect assumptions in BVES's marginal cost study have resulted in an incorrect revenue allocation. Finally,

[1] BVES Advice Letter 452-E, September 20, 2022.
[2] BVES Advice Letter 540-E, February 23, 2026.

Snow Summit is concerned about how its payments to BVES exceed BVES's costs of serving Snow Summit. This testimony presents Snow Summit's concerns regarding BVES's proposed revenue requirements.[3]

Q. **How does BVES characterize the increase in deliveries to Snow Summit?**

A. BVES states that this is an expansion of the Snow Summit resort.[4]

Q. **Is this a correct characterization?**

A. No. Snow Summit did not expand its operations. As noted above, Snow Summit simply increased its ability to take power from BVES through the expanded Summit and new Ridge substations (while planning to reduce operation of its onsite generation for snowmaking.)

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony regarding BVES's Results of Operations is to discuss BVES's proposals in this General Rate Case (GRC) proceeding that affect BVES's overall revenue requirements.

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[3] BVES served Volumes 1-5 of its opening testimony (regarding Results of Operations and other matters) with its application (Application (A.) 26-01-022) on January 30, 2026. BVES served Volume 6 on March 13, 2026. Volume 6 addresses BVES's proposals regarding marginal costs, revenue allocation, and rate design. BVES revised its Results of Operations because it was unable to proceed with a solar generating project that BVES had planned to come online in 2027. BVES revised the calculation of its Results of Operations on July 15, 2026, but did not serve updated testimony consistent with its revised Results of Operation. BVES provided Snow Summit with updated models for its Results of Operation on July 15, 2026. BVES's change in its assumptions underlying its Results of Operations resulted in changes to BVES's marginal costs and revenue allocation. BVES provided Snow Summit with updated models and results for the changes to marginal costs and revenue allocation on July 16, 2026. In this testimony, Snow Summit presents results based on BVES's revised models. Pursuant to a ruling by Administrative Law Judge (ALJ) Van Dyken dated July 22, 2026, Snow Summit will submit testimony related to its concerns regarding BVES's proposed marginal costs, revenue allocation and rate design on August 12, 2026. Unless otherwise indicated, BVES's testimony is referred to as "BVES Testimony" with an associated volume number.

[4] BVES Testimony, Volume 1, p. 44.

Q. Please summarize your recommendations and conclusions regarding BVES's Results of Operations.

A. BVES is asking the Commission to authorize an overall 17.0 percent increase in average rates in 2027, followed by increases of between 4.5-8.5 percent in 2028-2030. Three customer classes will see increases of more than 20 percent in 2027: A5 TOU Secondary (30.6 percent), A5 TOU Primary (24.5 percent) and Permanent Residential (21.4 percent).[5] One factor that causes this increase is BVES's request for a significant increase in its return on equity (from 10.0 percent to 11.3 percent). BVES's requested increase is completely at odds with the return on equity of 9.75 percent that was recently adopted by the Commission in Decision (D.) 26-03-017 for a very similar utility (Liberty Utilities (CalPeco)). BVES's witness regarding return on equity does not include Liberty Utilities (CalPeco) as a comparable utility when developing BVES's recommended return on equity. Snow Summit recommends that the Commission should recognize that Liberty Utilities (CalPeco) is an excellent benchmark to BVES and that the Commission's recent decision regarding cost of capital for Liberty Utilities (CalPeco) is indicative of a reasonable return on equity for BVES.

BVES's load forecast the A5-P customer class is flawed and the Commission should order BVES to revise it. This flawed load forecast results in BVES forecasting higher supply costs than are reasonable. In addition, the flawed load forecast has implications

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[5] BVES identifies customer classes in different ways in its testimony. In this testimony, I refer to A5 TOU Primary as "A5-P" and A5 TOU Secondary as "A5-S."

for the determination of marginal costs. BVES's load forecast for A5-P customers has two major flaws:

- The forecast for non-snowmaking months (i.e., April – October) increases unreasonably in 2025 compared to loads in 2024. The installation of new substations at the Snow Summit resort was not completed until late September 2025, which is nearly the end of the non-snowmaking season. In addition, Snow Summit has not installed new equipment or changed operations during its non-snowmaking months. The Commission should order BVES to reduce its load forecast for the non-snowmaking months of 2026-2030 for the A5-P customer class.
- BVES's load forecasts appear unreasonable during snowmaking months (i.e., November-March). Historic usage for 2026 for the A5-P class is far below BVES's forecasted loads. BVES also uses inconsistent hourly load forecasts for the A5-P class in two different parts of its modeling, with loads exceeding BVES's generation and import capacity in the model BVES uses to determine marginal costs and revenue allocation (but possibly correctly modeling maximum load in BVES's supply cost model). BVES also admits that it does not attempt to forecast curtailments of load for A5-P customers, eventhough the A5-P class will incur greater levels of curtailments in the future as a result of the installation of new substations at Snow Summit. By failing to even attempt to forecast additional curtailments, BVES likely overstates loads for the A5-P class during some hours in which A5-P customers make snow. The Commission should order BVES to reduce its load forecast for the A5-P class in non-snowmaking months, reduce its load forecast by 12.5 percent during snowmaking months, and to reflect likely future curtailments in its hourly loads during

snowmaking months.

Q. How is your testimony organized?

A. After this introduction and summary section, Chapter II summarizes BVES's proposals in this proceeding regarding Results of Operations and revenue allocation. Next, Chapter III discusses BVES's improper cost of capital proposal. Chapter IV identifies and addresses BVES's incorrect assumptions regarding the load forecast for the A5-P customer class. Chapter V presents a short conclusion to this testimony regarding BVES's Results of Operations.

Q. Does your testimony provide quantitative changes to BVES's Results of Operations based on your recommendations?

A. No. This testimony does not provide revised estimates of BVES's revenue requirements resulting from Snow Summit's recommendations. Snow Summit had intended to provide calculations of BVES's revised Results of Operations, marginal costs, and revenue allocations pursuant to its recommendations in this proceeding. Snow Summit made numerous attempts through discovery and informal meetings with BVES to obtain copies of the complete, functional models used by BVES in the development of its testimony and recommendations. Obtaining those models likely would have allowed Snow Summit to do such analysis. However, despite Snow Summit's efforts, it became clear that Snow Summit had not received complete, fully linked copies of the models used by BVES to develop its testimony. As a result, this testimony will provide Snow Summit's recommendations for changes to factors affecting BVES's Results of Operations but will not provide estimates of quantitative impacts of its recommendations.[6]

II. Summary of BVES's Proposal

Q. What is the purpose of this chapter of your testimony?

A. This chapter briefly summarizes BVES's proposals regarding revenue requirements and cost allocation for different customer classes.

Q. At a high level, please describe the purpose of BVES's application in this proceeding.

A. BVES's application has three main purposes. First, BVES proposes to establish its revenue requirement for the Test Year 2027 and the three other years (i.e., the "attrition years") in this GRC cycle (i.e., the "revenue requirements" process).[7] This revenue requirement is a portion of BVES's Results of Operations. Second, BVES proposes to allocate that overall revenue requirement to different customer classes (i.e., the "revenue allocation" process.) This step is also referred to as cost allocation, reflecting the Commission's principle that costs should be allocated to the customers that cause them to be incurred.) Third, BVES proposes to design rates to recover the revenue requirement that is allocated to each customer class (i.e., the "rate design" process). As part of the revenue allocation and rate design steps, BVES relies on its marginal cost study.

[6] Snow Summit anticipates that it will use a similar approach in its testimony regarding marginal costs and revenue allocation.
[7] BVES has a 4-year GRC cycle.

Q. How do the first two categories (i.e., revenue requirements and revenue allocation) relate to customer rates?

A. Total revenue requirements divided by total sales are equal to system average rates (i.e., revenue per kWh sold). Similarly, class revenue requirements divided by sales to the class results in average rates for the customer class.

Q. Are class-average rates comparable to rates developed in the rate design phase of the proceeding?

A. In theory, both should recover a comparable amount of revenue from the customer class as a whole. However, if a customer class has many different customers, then the revenue per kWh recovered from any particular customer is almost certainly not equal to the average revenue per kWh recovered from the class overall. The only exception to this is when a customer class has a single customer, which is the case in this proceeding: Snow Summit is the only customer in the A5-P customer class since the accounts in the A5-P class are the ski resorts owned and operated by Snow Summit. Thus, the average rate per kWh for the A5-P customer class is directly comparable to the average revenue per kWh for Snow Summit's accounts on A5-P.

Q. What are BVES's proposed revenue requirements and revenue allocation in this proceeding?

A. The following presents BVES's proposed revenue requirements and revenue allocation by customer class and year.

Table 1: BVES's Proposed Revenue Allocation in Application Without Solar

	Current 2026	2027	2028	2029	2030
Residential Permanent Service	$14,530,082	$16,683,831 ~~$17,389,685~~	$17,202,043 ~~$17,219,862~~	$17,572,389 ~~$17,590,741~~	$18,606,588 ~~$18,625,552~~
Residential Non-Permanent Service	25,141,698	30,598,713 ~~29,460,046~~	33,100,712 ~~33,146,181~~	35,657,329 ~~35,706,455~~	39,386,988 ~~39,440,210~~
General Service - Small (A1)	8,466,164	10,150,955 ~~9,996,563~~	10,851,611 ~~10,862,244~~	11,535,354 ~~11,546,660~~	12,621,818 ~~12,633,874~~
General Service - Medium (A2)	2,606,700	2,936,929 ~~2,835,475~~	2,937,058 ~~2,936,549~~	2,921,281 ~~2,920,713~~	2,978,275 ~~2,977,635~~
General Service - Large (A3)	3,644,683	4,329,442 ~~4,170,275~~	4,353,646 ~~4,354,018~~	4,459,051 ~~4,459,355~~	4,816,464 ~~4,816,689~~
General Service - Time-of-Use (A4-TOU)	2,280,931	2,845,254 ~~2,932,510~~	3,230,671 ~~3,226,838~~	3,262,681 ~~3,258,663~~	3,209,807 ~~3,205,813~~
Time-of-Use Service (A5 TOU Secondary)	629,322	784,681 ~~821,842~~	820,068 ~~817,613~~	850,371 ~~847,746~~	914,986 ~~912,161~~
Time-of-Use Service (A5 TOU Primary)	5,749,203	6,428,229 ~~7,159,362~~	6,689,140 ~~6,619,302~~	6,885,985 ~~6,811,619~~	7,422,090 ~~7,342,421~~
Street Lighting	64,529	84,537 ~~76,814~~	89,204 ~~91,548~~	93,984 ~~96,474~~	100,746 ~~103,407~~
Total Revenues excl. OOR	$63,113,312	$74,842,571	$79,274,154	$83,238,425	$90,057,761
Year-over-Year Increase %		18.6%	5.9%	5.0%	8.2%
Other Operating Revenues (OOR)	1,884,921	1,885,007	1,885,093	1,885,178	1,885,264
Total Revenues w/ OOR	64,998,233	76,727,578	81,159,247	85,123,603	91,943,026

Source: Derived from Marginal Cost and Rate (MCR) model, tab "Target Revenues."

As can be seen from Table 1 above, BVES is proposing overall revenue requirements of $76.728 million in Test Year 2027. This is an increase of $11.729 million (i.e., 18.0%) compared to the revenue that BVES forecasts that it would collect in 2026 under rates that were in effect at the start of 2026.[8]

[8] BVES's changes to its Results of Operations due to removal of the solar project reduced BVES's 2026 Revenue Requirement w/ OOR (Other Operating Revenues) from $67.612 million to $64.998 million. BVES explained to Snow Summit that this reduction in 2026 Revenue Requirement w/ OOR was because BVES would no longer implement a rate increase in 2026 associated with the cancelled solar project. BVES stated that it would have implemented that rate increase in late 2026. As a result of this surprising result, the year-over-year increase from 2026 to 2027 is larger without the solar project ($11.729 million instead of $10.759 million) and the percentage increase in Revenue Requirement w/o OOR without the solar project is also larger (18.6 percent instead of 16.4 percent.)

The following table presents the change in class-average rates and the compound average growth rate (CAGR) over the entire GRC cycle by customer class and year:

Table 2: Percentage Increase in Class Average Rates Proposed by BVES by Year and Customer Class Without Solar

	2027	2028	2029	2030	CAGR over GRC Cycle
Residential Permanent Service	14.8%~~21.4%~~	3.1%~~0.4%~~	2.2%~~3.8%~~	5.9%~~7.6%~~	6.4%~~8.0%~~
Residential Non-Permanent Service	21.7%~~13.7%~~	8.2%~~9.3%~~	7.7%~~4.6%~~	10.5%~~7.4%~~	11.9%~~8.7%~~
General Service - Small (A1)	19.9%~~14.6%~~	6.9%~~6.6%~~	6.3%~~4.4%~~	9.4%~~7.4%~~	10.5%~~8.2%~~
General Service - Medium (A2)	12.7%~~14.1%~~	0.0%~~8.8%~~	-0.5%~~4.6%~~	2.0%~~7.4%~~	3.4%~~8.7%~~
General Service - Large (A3)	18.8%~~10.5%~~	0.6%~~9.1%~~	2.4%~~4.6%~~	8.0%~~7.4%~~	7.2%~~7.9%~~
General Service - Time-of-Use (A4-TOU)	24.7%~~15.5%~~	13.5%~~1.4%~~	1.0%~~3.9%~~	-1.6%~~7.6%~~	8.9%~~7.0%~~
Time-of-Use Service (A5 TOU Secondary)	24.7%~~30.6%~~	4.5%~~-0.5%~~	3.7%~~3.7%~~	7.6%~~7.6%~~	9.8%~~9.7%~~
Time-of-Use Service (A5 TOU Primary)	11.8%~~24.5%~~	4.1%~~-7.5%~~	2.9%~~2.9%~~	7.8%~~7.8%~~	6.6%~~6.3%~~
Street Lighting	31.0%~~19.0%~~	5.5%~~19.2%~~	5.4%~~5.4%~~	7.2%~~7.2%~~	11.8%~~12.5%~~
Total	18.6%~~17.0%~~	5.9%~~5.1%~~	5.0%~~4.5%~~	8.2%~~7.8%~~	9.3%~~8.5%~~

Source: Derived from MCR model, tab "Target Revenues." Note that these changes are w/o OOR.

As can be seen from Table 2 above, BVES is proposing ~~more than~~ a 14.8~~21~~% increase in class-average rates in 2027 for the Permanent Residential class. BVES is also proposing a compound average annual increases of between ~~6.3~~3.4% and ~~12.5~~11.9% for each year of the 4-year GRC cycle for all customer classes.

The following table presents the revenue allocation fractions by customer class and year:

Table 3: Revenue Allocation Fractions Proposed by BVES Without Solar

	2026 At Present Rates	2027	2028	2029	2030
Residential Permanent Service	23.0%~~23.0%~~	22.3%~~23.2%~~	21.7%~~21.7%~~	21.1%~~21.1%~~	20.7%~~20.7%~~
Residential Non-Permanent Service	39.8%~~39.8%~~	40.9%~~39.4%~~	41.8%~~41.8%~~	42.8%~~42.9%~~	43.7%~~43.8%~~
General Service - Small (A1)	13.4%~~13.4%~~	13.6%~~13.4%~~	13.7%~~13.7%~~	13.9%~~13.9%~~	14.0%~~14.0%~~
General Service - Medium (A2)	4.1%~~4.1%~~	3.9%~~3.8%~~	3.7%~~3.7%~~	3.5%~~3.5%~~	3.3%~~3.3%~~
General Service - Large (A3)	5.8%~~5.8%~~	5.8%~~5.6%~~	5.5%~~5.5%~~	5.4%~~5.4%~~	5.3%~~5.3%~~
General Service - Time-of-Use (A4-TOU)	3.6%~~3.6%~~	3.8%~~3.9%~~	4.1%~~4.1%~~	3.9%~~3.9%~~	3.6%~~3.6%~~
Time-of-Use Service (A5 TOU Secondary)	1.0%~~1.0%~~	1.0%~~1.1%~~	1.0%~~1.0%~~	1.0%~~1.0%~~	1.0%~~1.0%~~
Time-of-Use Service (A5 TOU Primary)	9.1%~~9.1%~~	8.6%~~9.6%~~	8.4%~~8.3%~~	8.3%~~8.2%~~	8.2%~~8.2%~~
Street Lighting	0.1%~~0.1%~~	0.1%~~0.1%~~	0.1%~~0.1%~~	0.1%~~0.1%~~	0.1%~~0.1%~~
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Derived from MCR model, tab "Target Revenues." These fractions are w/o OOR.

Revenue allocation fractions present the fraction of BVES's total revenue requirements (excluding OOR) assigned to each customer class by year. As can be seen from Table 3 above, the revenue fractions for each customer class change from 2027 to 2030, with some fractions increasing (e.g., Residential Non-Permanent Service) and others decreasing (e.g., Residential Permanent Service, A5-P).

Q. Does Snow Summit have concerns with BVES's Results of Operations proposals?

A. Yes. I address these concerns in the following chapters of this testimony.

Q. Does this testimony address Snow Summit's concerns with BVES's revenue allocation proposals that result from Snow Summit's recommended changes in BVES's load forecast?

A. No. Pursuant to the revised procedural schedule, Snow Summit will address marginal costs and revenue allocation issues in its testimony on August 12, 2026.

III. The Commission Should Reduce BVES's Proposed Increases Return on Equity

Q. What is the purpose of this chapter of your testimony?

A. This chapter addresses Snow Summit's concerns with BVES's proposed increase in its assumed cost of capital. Snow Summit proposes a reduction in BVES's proposed return on equity.

A. BVES's Proposed Increase in Return of Equity

Q. What is BVES's currently authorized capital structure?

A. In the last GRC, the Commission adopted the following capital structure for BVES:

Table 4: BVES Current Cost of Capital and Capital Structure

	Rate	Fraction	Cost
Equity	10.00%	57%	5.70%
Debt	5.51%	43%	2.37%
Weighted-Average Cost of Capital			8.07%

Source: Derived from D.25-01-007, pp. 8-9.

Q. What is BVES's proposed capital structure for this GRC cycle?

A. BVES is proposing a very large increase in its weighted-average cost of capital (WACOC) in this proceeding:

Table 5: BVES Proposed Cost of Capital and Capital Structure

	Rate	Fraction	Cost
Equity	11.30%	60%	6.78%

Debt	5.92%	40%	2.37%
Weighted-Average Cost of Capital			9.15%

Source: Derived from BVES Testimony, Volume 4, p. 1.

This increase in BVES's WACOC is driven primarily by proposed increases in its return on equity (from 10.0% to 11.3%) and its equity fraction (from 57% to 60%).

Q. Why does BVES claim that it needs its proposed increase in its WACOC?

A. BVES states that:

> Given the current elevated wildfire risks, electric utilities are challenged in raising the financing necessary to implement all of its wildfire mitigation initiatives, as well as conduct core business services. As the risk is reduced due to the implementation of wildfire mitigation initiatives, it will remain challenging to convince the finance markets that the risks are indeed reduced, especially in light of the recent fires that have occurred in Southern California in early 2025. It will take time for the financial market to accept the effectiveness of mitigation efforts and will likely be based on a positive track record to be firmly established (e.g., no utility caused wildfires).[9]

In addition, BVES's witness regarding return on equity (ROE) describes numerous "business risks" that BVES faces that justify an upward adjustment of his original estimate of ROE.[10]

Q. How does BVES's proposed ROE compare with other utilities?

A. The Commission recently adopted a capital structure for Liberty Utilities' (Liberty Utilities (CalPeco)) Test Year 2025 GRC.[11] In that decision, the Commission adopted the following capital structure:

[9] BVES Testimony, Volume 4, pp. 1-2.
[10] BVES Testimony, Volume 4, pp. 50-59.
[11] D.26-03-017.

Table 6: Cost of Capital and Capital Structure for Liberty Utilities (CalPeco)

	Rate	Fraction	Cost
Equity	9.75%	52.5%	5.12%
Debt	5.87%	47.5%	2.79%
Weighted-Average Cost of Capital			7.91%

Source: D.26-03-017, p. 2.

As can be seen from the above table, the WACOG adopted by the Commission in the GRC for Liberty Utilities (CalPeco) is less than that currently in effect at BVES and 1.24 percentage points lower than that proposed by BVES. This table also shows that the Commission adopted an ROE for Liberty Utilities (CalPeco) that is 0.25% lower than BVES's current ROE (i.e., 9.75% vs. 10.0%) and is 1.55% lower than BVES's proposed ROE (i.e., 9.75% vs. 11.3%).

Q. In the development of BVES's recommended return on equity, did BVES include Liberty Utilities (CalPeco) in its group of comparables?

A. No. BVES's witness used a "Utility Proxy Group" that did not include Liberty Utilities (CalPeco), which is a wholly owned subsidiary of Liberty Utilities Co., which is an indirect, wholly owned subsidiary of Algonquin Power & Utilities Corp.[12]

Q. Do BVES and Liberty Utilities (CalPeco) have similar characteristics?

A. Yes. The following table provides some information about the two utilities:

[12] https://algonquinpower.com/about-us/our-history.html

Table 7: Comparison of BVES and Liberty Utilities (CalPeco) Utilities

	BVES	**Liberty Utilities (CalPeco)**
Location	Mountainous area near Big Bear Lake	Mountainous area near Lake Tahoe
Ownership	American States Water Company	Algonquin Power & Utilities Corp.
Number of Customers	~23~~4~~,000	~51~~0~~,5~~0~~00
Maximum Coincident Demand	~48~~55~~ MW	160~~41~~ MW
Owned Power Supply	8.4 MW Bear Valley Power Plant	77~~2.5~~ MW (solar and oil-fired)
Annual Sales (MWh) (2023)	~138,000~~58,000~~ MWh	~587~~44~~,000 MWh~~ (2023)~~
Current ROE	10.0%	9.75%
Serves Ski Resorts with Snowmaking	Yes: Snow Summit and Big Bear Mountain Resort	Yes: Heavenly, Palisades Tahoe, Northstar~~,~~ ~~Homewood~~
Permanent and Non-Permanent Residential Customer Class	Yes	Yes

As can be seen from the above table, BVES is somewhat smaller than Liberty Utilities (CalPeco) and has less generating capacity. Aside from those differences, the similarities are striking: both are wholly owned subsidiaries of much larger companies, serve mountainous service territories, have ski resorts as customers, and have a non-permanent residential customer class. Thus, while not precisely similar, both are very similar small jurisdictional electric utilities in California.

Q. Does BVES have regulatory structures that help mitigate some of its business risks?

A. Yes. BVES has a number of balancing accounts and memorandum accounts that limit BVES's business risks. These are presented in BVES's Preliminary Statement.[13] These include balancing accounts to allow BVES to recover its base revenue requirements (i.e.,

[13] https://www.bvesinc.com/assets/documents/preliminary-statements/preliminart-statement4-2026.pdf

the Base Revenue Requirement Balancing Account) and its supply costs (i.e., the Supply Adjustment Mechanism). These balancing account mechanisms mitigate BVES's risks of failure to recover authorized revenue requirements due to volatility in sales and power supply costs.

Q. Does Liberty Utilities (CalPeco) have similar balancing accounts?

A. Like BVES, Liberty Utilities (CalPeco) has a Base Revenue Requirement Balancing Account.[14] It also has an Energy Cost Adjustment Clause, which is similar to BVES's Supply Adjustment Mechanism.[15]

Q. Does BVES's witness regarding return on equity address BVES's balancing accounts when considering business risk for BVES?

A. Based on my review of BVES's testimony, I found no analysis of how different balancing accounts affect business risk and the impact of that business risk on the appropriate level of return on equity

Q. What do you recommend?

A. While Snow Summit is not presenting a detailed assessment of ROE such as is likely to be presented by Cal Advocates, Snow Summit recommends that the Commission should recognize that Liberty Utilities (CalPeco) is an excellent benchmark to BVES and that the

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[14] https://california.libertyutilities.com/uploads/LU-CA Electric Preliminary Statements 1-1-17/PreliminaryStatement_8.pdf

[15] https://california.libertyutilities.com/uploads/CalPeco Tariffs/ECAC Prelim Statement 6.pdf See Liberty Utilities (CalPeco)'s Preliminary Statement for a complete listing of its various balancing and memorandum accounts. https://california.libertyutilities.com/walker/commercial/rates-and-tariffs/electrical.html

Commission's recent decision regarding cost of capital for Liberty Utilities (CalPeco) is indicative of a reasonable ROE for BVES.

IV. BVES Should Correct Its Load and Peak Demand Forecasts For The A5-P Customer Class

Q. What is the purpose of this chapter?

A. This chapter addresses BVES's load and hourly demand forecasts for the A5-P customer class.

Q. How do the hourly demand forecasts affect BVES's Results of Operation?

A. One component of BVES's Results of Operation is its supply cost forecast. The loads for the A5-P class have a significant impact on supply costs. Over-forecasting the demands by the A5-P class will result in unreasonably high supply costs.

Q. What errors have you identified in BVES's load forecast and its hourly loads for the A5-P class?

A. I have identified the following errors that have impacts on BVES's revenue requirements:

1. BVES's sales forecast for the A5-P customer class is implausible. There are two major flaws with this forecast:
    a. BVES's forecast of loads in the months in which the A5-P class does not make snow shows an inexplicable increase in 2025. The increase in 2025 persists in the forecast of loads in 2026-2030 and in BVES's marginal cost study, improperly inflating the A5-P cost responsibility for energy supply.

b. BVES's forecast has hourly demands for the A5-P class that, if realized, could not be served by BVES because of a lack of local supply and transfer capability between BVES and its suppliers outside of the BVES service territory. This overstatement of hourly loads (which occur as a result of snowmaking activities) result in an overstatement of the top 100 hours of demand and the coincident maximum demands for BVES. BVES even demonstrates this inconsistency in its own modeling of its supply costs, where loads to meet supply are capped at 47.4 MW.

c. BVES's forecast of hourly loads during snowmaking do not reflect likely increases in curtailment of A5-P customers.

I address each of these errors below.

A. BVES Forecasts of Loads for A5-P Customer Class During Non-Snowmaking Months Are Unreasonably High

Q. What are BVES's forecasts of loads for the A5-P customer class in this proceeding?

A. As noted above, the A5-P customer class has significant loads related to snowmaking activities. However, the class also has loads in the non-snowmaking months but those are much lower. The following presents the monthly maximum demands and monthly energy forecasts from BVES in its MCR model:

Table 8: Maximum Demands and Total Loads for A5-P for Snowmaking and Non-Snowmaking Periods

	Maximum Demand (MW)			Total Load (MWh)		
	Snowmaking	Other Months	Annual Maximum	Snowmaking	Other Months	Total
2024	19.75	3.00	19.75	11,598	2,892	14,490
2025	34.11	3.20	34.11	16,517	2,817	19,334
2026	34.11	3.72	34.11	19,934	3,336	23,271
2027	34.11	3.72	34.11	19,687	3,298	22,985
2028	34.11	3.72	34.11	19,167	3,322	22,489
2029	34.11	3.72	34.11	19,237	3,331	22,568
2030	34.11	3.72	34.11	19,318	3,357	22,676

Source: Derived from MCR Model, tab “Hourly kWh”

From the above, it is seen that total loads in 2026 are significantly higher than in 2025 (or 2024). This increase corresponds with the first full year after BVES completed work on the two substations at Snow Summit.

Q. Is the increase in loads between 2025 and 2026 only during snowmaking months?

A. No. The forecasted loads during non-snowmaking months increases by more than 500 MWh between 2025 and 2026.

Q. Are you aware of any reason for the significant increase in loads during the non-snowmaking months of 2026 relative to 2024 or 2025?

A. Based on my discussions with Snow Summit management, they are not expecting any significant change in equipment or usage during the non-snowmaking months of April-October in 2026 compared to the same months in 2025 or 2024.

Q. Does BVES provide any explanation of this increase in its testimony?

A. No.

Q. What do you recommend?

A. BVES should adjust its monthly load forecasts for the A5-P class in the non-snowmaking months to correct the incorrect assumptions regarding increased loads in those months in 2026.

Q. How should BVES adjust its load forecasts for non-snowmaking months?

A. It would be reasonable to use the average monthly loads for the A5-P class for 2024 and 2025 as the monthly average loads for 2026-2030. The following table presents Snow Summit's recommended adjustments to loads during non-snowmaking months:

Table 9: Recommended Reduction in Monthly Loads for A5-P Customers (MWh)

Month	2026	2027	2028	2029	2030
4	(200)	(203)	(196)	(195)	(195)
5	(47)	(43)	(43)	(45)	(49)
6	(81)	(81)	(86)	(78)	(79)
7	(68)	(43)	(46)	(46)	(72)
8	(65)	(70)	(79)	(73)	(64)
9	(87)	(86)	(70)	(72)	(75)
10	67	81	52	33	30

Q. How would this change in load forecasts during the non-snowmaking hours affect BVES's proposals in this proceeding?

A. Snow Summit expects that reducing the loads for the A5-P class during non-snowmaking months will reduce BVES's supply costs during those months.

Q. What is the actual impact of this recommendation?

A. Given the detailed modeling by BVES to determine its revenue requirements, Snow Summit is not going to present an update to BVES's revenue requirements as a result of its recommended change in loads during non-snowmaking months. Instead, Snow Summit recommends that the Commission should adopt Snow Summit's load forecast adjustments.

Q. Will Snow Summit's recommendation result in a change in BVES's marginal costs?

A. Snow Summit will discuss the impact of its recommended change in loads on marginal costs and revenue allocation in its testimony that is to be served on August 12, 2026.

B. BVES Hourly Load Forecasts for The A5-P Customer Class For Certain Hours Are Unreasonable and Need To Be Reduced

Q. Why are BVES's hourly loads in certain hours too high for A5-P customers?

A. There are several reasons. First, BVES's hourly load forecasts are inconsistent between its supply model and its marginal cost model, with its hourly loads being higher in its marginal cost model. Second, BVES's load forecasts for 2026 are significantly higher than actual loads during the snowmaking months. Third, BVES's forecast of hourly loads during snowmaking months does not reflect likely increases in curtailments for the A5-P customer class because of the new substations serving Snow Summit and the limitations of BVES's generation and distribution systems. Each of these issues are discussed below.

1. BVES's Load Forecasts Are Inconsistent Within Its Own Testimony

Q. What load forecasts does BVES present in this proceeding?

A. BVES forecasts hourly loads for each customer class for 2026-2030. These are presented in two contexts: development of supply costs and development of marginal costs for revenue allocation.

Q. How did BVES develop these hourly load forecasts?

A. BVES claims to have used unitized[16] hourly load shapes from 2024 (adjusted to account for different numbers of weekdays and weekends in 2026-2030) to derive unitized load shapes for 2026-2030. BVES then applied monthly forecasts of total loads for 2026-2030 to the unitized load shapes for 2026-2030 to arrive at hourly loads for 2026-2030.[17]

Q. How are these hourly loads used by BVES?

A. The hourly loads are used as the basis for allocation of marginal energy costs, marginal generation capacity costs, and marginal distribution costs. They are also used to determine energy supply costs.

Q. Why are these hourly load forecasts important?

A. It is very important to have reasonable forecasts of hourly loads in order to have a reasonable forecast of costs and a reasonable cost allocation.

Q. What are BVES's load forecasts from this proceeding?

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[16] A unitized load shape is one where the hourly unitized loads in a month sum to 1.0 In other words, the unitized load for a particular hour is the percentage of the total monthly load that occurs in that hour. For example, if an hourly load in an hour is 1,000 kWh/hr and the total load in the same month is 20,000 kWh, then the unitized load shape for that hour is 1,000 / 20,000 or 0.05 (or 5%) of the monthly load.

[17] BVES Response to Snow Summit Data Request 2, Question 6.

A. The following table presents the two coincident peak demand forecasts that BVES uses in this proceeding:

Table 10: Comparison of Load Forecasts

Max Demand (MW)	Supply Model	MCR Model	Difference
2027	47.40	54.65	7.25
2028	47.40	54.89	7.49
2029	47.40	55.23	7.83
2030	47.40	56.23	8.83
Total Loads (MWh)	**Supply Model**	**MCR Model**	**Difference**
2027	170,385~~7~~	170,540	155~~3~~
2028	171,502	171,636	133
2029	171,995	172,148	153
2030	172,794	172,996	202

Source: Supply Model: Derived from Tab "Load Forecast Input"
MCR Model: Derived from Tab "Hourly kWh"

As can be seen from the above tables, BVES's supply model uses load forecasts that are lower than the forecasts used in BVES's MCR model. It is unclear how BVES derived the maximum hourly loads for its supply model, but I have to assume that lower maximum demand values in the supply model are somehow related to BVES's limited import capacity from SCE and its limited amount of generation capacity in its service area.

Q. How do BVES's loads vary between customer classes in the two parts of its testimony?

A. BVES's supply model does not present hourly loads by customer classes. However, since BVES has only one set of customers that take service under interruptible tariffs, I have to assume that the only difference in loads would occur for the A5-P customer class (i.e., BVES's supply model assumes that any loads above 47.4 MW would result from the curtailment of loads for the A5-P customer class.)

Q. What are the implications of BVES using two different load forecasts in its showing?

A. BVES uses higher loads for A5-P customers in some number of hours per year when it estimates marginal costs than it does when it estimates supply costs. Thus, BVES's marginal cost estimates are flawed.

Q. What do you recommend?

A. BVES should harmonize its forecast of hourly loads between its supply and MCR models. This harmonization should be consistent with system constraints on BVES's system (e.g., limits on import capability, limits on generation capacity in its service territory, operational limits BVES enforces in order to ensure that it can deliver reliable service to its customers, etc.).

Q. How would this harmonization affect BVES's proposals in this proceeding?

A. Snow Summit expects that this harmonization would result in a reduction in the loads for the A5-P class during hours of very high system load. This would likely reduce BVES's annual coincident peak demands and the Top 100 hours of peak demands, both of which are used in the development of marginal costs.

2. BVES's Overall Load Forecasts Overstate Loads Year-To-Date In 2026

Q. Do you have any comments about the overall level of load forecasts for the A5-P class?

A. Yes. It appears that BVES's monthly forecast of energy loads in 2026 for the A5-P class is significantly higher than actual loads. The following table compares monthly energy year-to-date 2026 for the A5-P customer class:

Table 11: Comparison of Forecast and Actual Loads for A5-P Class for 2026 (MWh)

Year	Month	Recorded Loads	BVES Forecast	Actual - Forecast (MWh)	Percent Error
2026	1	3,208	5,207	-2,000	-38.4%
2026	2	3,146	3,354	-208	-6.2%
2026	3	998	1,228	-230	-18.7%
2026	4	325	870	-545	-62.6%
2026	5	326	393	-67	-17.1%

Sources: Historic Data from BVES Response to Snow Summit Data Request 4, Question 10
Forecast Data from BVES MCR Model, tab "Hourly kWh"

As can be seen from the above table, BVES's forecasts of monthly loads year-to-date 2026 for customers in the A5-P class are significantly higher than actual loads for the same period, with forecast errors ranging from -6.2% to -62.6%. This indicates that BVES's forecast of loads in the snowmaking period may be far too high.

Q. Isn't it possible that 2026 is atypical and that the actual usage in those years is less than loads during a "typical" year?

A. That is possible, but it is difficult to test that hypothesis since it is unclear how exactly BVES's load forecasts for 2025-2030 were developed. When asked by Snow Summit about the error in the forecasts, BVES simply stated that "2025-2031 A5 Primary forecasts are based on 2022-2024 average monthly sales and expected expanded load for

Snow Summit."[18] Based on this, it is possible that BVES has significantly overestimated the expanded load for Snow Summit.

Q. What else can you say about BVES's forecasting approach?

A. Because BVES used 2024 hourly loads to determine loadshapes and used 2022-2024 average monthly sales to determine monthly loads, it appears that BVES did not attempt to weather-normalize or adjust the historic data to create "typical" year loads. Because of that, it is not possible to determine whether 2025 and YTD 2026 loads are atypical or whether BVES's load forecasts are in error.

Q. What do you recommend?

A. The Commission should order BVES to reduce its monthly load forecasts for the A5-P class for the snowmaking season by 12.5 percent. This conservative recommendation is about 50 percent of the total error in load forecast for January-March 2026. After reducing its load forecasts for the snowmaking months for 2026-2030, BVES should then revise its hourly loads and its supply cost forecast.[19]

3. BVES's Load Shape For The A5-P Class Could Overstate Loads During High Snowmaking Hours Because BVES Fails To Account For Greater Expected Levels of Curtailment

Q. Does BVES assume any curtailments in the development of its hourly load forecasts for the A5-P class?

[18] BVES Response to Snow Summit Data Request 7, Question 4.
[19] In addition, BVES should adjust its marginal cost forecasts consistent with these adjusted hourly loads.

A. BVES states that the only curtailments that it assumes were curtailments that occurred in the 2024 loads that it used to develop the unitized load shapes that it used to forecast hourly loads in 2026-2030.[20]

Q. What were the curtailments of the A5-P class in 2024?

A. Snow Summit asked BVES on several occasions to provide data about the curtailments of the A5-P class in 2024 (and other years.) BVES responded that it had no data about those curtailments.[21] Instead, BVES stated that the only information that it has about curtailments of Snow Summit's loads was provided in response to Snow Summit Data Request 2, Request 10.[22] Thus, BVES either cannot or will not say whether the frequency or severity of curtailments in 2024 were typical or atypical for the A5-P class.

Q. What data did BVES provide related to its prior curtailments of deliveries to Snow Summit?

A. BVES provided a single word document describing system conditions and BVES's actions in 2025 and 2026.[23]

Q. Would you expect that the number of hours of curtailment of A5-P customers in 2024 is indicative of the number of hours of curtailment after the new substations at Snow Summit were energized in late 2025?

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[20] BVES Response to Snow Summit Data Request 4, Question 4.
[21] BVES Response to Snow Summit Data Request 7, Question 6.
[22] BVES Response to Snow Summit Data Request 7, Question 5.
[23] CONFIDENTIAL BVES Response to Snow Summit Data Request 2, Question 10a, attachment.

A. It seems highly unlikely. Between 2025 and 2026, BVES forecasts that the loads on the BVES system will increase by 4.5% during the snowmaking months:

Table 12: Annual Loads for BVES from 2024-2030 (MWh)

	Loads (MWh)			Annual Increase (%)		
	Snowmaking Months	**Other Months**	**Total**	**Snowmaking Months**	**Other Months**	**Total**
2024	75,316	70,259	145,575			
2025	83,289	79,463	162,752	10.6%	13.1%	11.8%
2026	87,072	81,427	168,499	4.5%	2.5%	3.5%
2027	87,664	82,876	170,540	0.7%	1.8%	1.2%
2028	88,168	83,468	171,636	0.6%	0.7%	0.6%
2029	88,539	83,610	172,148	0.4%	0.2%	0.3%
2030	88,986	84,010	172,996	0.5%	0.5%	0.5%

Source: Derived from BVES MCR model, tab "Hourly kWh"

BVES also indicates that its interconnection capacity with SCE has not changed. In addition, BVES caps it total load forecast at 47.4 MW for 2027-2030 in its supply model. Also, BVES admits that limits on BVES's generating and delivery system are the cause of curtailments of load for A5-P customers.[24] Thus, increase in loads between 2024 and 2026 due to the new Snow Summit substations will place greater strain on the BVES generating and delivery system, which likely would result in greater numbers of and severity of curtailments in 2026 and beyond compared to 2024.

Q. Can you estimate the number of incremental curtailment hours implied by BVES's load forecasts from this proceeding?

A. Yes. Comparing the number of hours that BVES's forecast of hourly loads from its MCR model exceed the hourly loads in the same hour in BVES's supply model gives an estimate:

[24] BVES Response to Snow Summit Data Request 7, Question 3c.

Table 13: Estimate of Additional Hours of Curtailment for A5-P Customers

2027	2028	2029	2030
81~~2~~	72~~3~~	78~~9~~	85~~6~~

Source: Derived from BVES Supply Model, tab "Load Forecast Input" and BVES MCR Model, Tab "Hourly kWh"

It should be noted that the above table presents the additional hours of curtailment implicit in BVES's hourly load forecast, above what is embedded in the hourly unitized loads from 2024.

Q. Does BVES expect that 2024 is a typical year for customer hourly loads for A5-P customers?

A. BVES cannot say since it admits that "[n]o historic hourly analysis has been performed on historic A5-P customers. The 2024 hourly A5-P shapes are only used to spread the 2025-2030 monthly sales forecast into hourly values."[25] In other words, BVES used 2024 simply because it was the most recent rate class hourly loads available.[26] Since BVES admits that it cannot predict the frequency of curtailments,[27] it is hard to say whether it is a reasonable proxy for hourly load shapes for A5-P customers.

Q. What would happen if BVES forecasts hourly loads that are too high for A5-P customers?

[25] BVES Response to Snow Summit Data Request 7, Question 3a.
[26] BVES Response to Snow Summit Data Request 7, Question 3b.
[27] BVES Response to Snow Summit Data Request 7, Question 3c.

A. Because peak demands and energy usage are key factors in the development of supply costs, having loads that are too high would likely result in the supply costs that are higher than is reasonable.

Q. Is it possible that increasing the number of hours of curtailment assumed by BVES for A5-P customers would not increase supply costs?

A. BVES's supply cost model already limits maximum demands to 47.4 MW. Thus, the supply model may already implicitly account for increased curtailments of the A5-P class.

Q. What do you recommend?

A. BVES should adjust its hourly load forecast to account for the greater level of curtailment of load in the A5-P customer class.

C. Recommendation: Adjust BVES's Load Forecast

Q. What are your conclusions regarding BVES's load forecast for the A5-P class and supply costs?

A. There are several conclusions:

- It is clear that BVES has forecasted higher loads for the A5-P class during the non-snowmaking months of April-October than are reasonable. Reducing those loads will reduce BVES's forecasted supply costs.
- Actual load data for 2026 for the A5-P class indicate that BVES may have over-forecasted loads during snowmaking months in 2026-2030. Reducing those loads to

more reasonable levels will also reduce BVES's forecasted supply costs.

- BVES may have over-forecasted hourly loads during periods in which A5-P customers make snow. The impact of this error on supply costs is not clear.

Q. Based on the above, what are your recommendations regarding BVES's load forecast?

A. The Commission should adopt monthly loads for A5-P customers during snowmaking and non-snowmaking months consistent with the above recommendations. In addition, the Commission should order BVES to revise its hourly load forecasts for high load hours to account for greater levels of curtailment. Finally, the Commission should adopt forecasts of supply costs consistent with those revised loads. Snow Summit expects that those lower loads would result in lower supply costs.

V. Recommendations and Conclusion

Q. What is your overall recommendation?

A. The Commission should adopt Snow Summit's recommendations regarding ways to mitigate the increases in revenue requirements proposed by BVES. One way to do this is to adopt a lower return on equity than proposed by BVES.

The Commission should also reduce ratepayer costs by reducing BVES's sales forecast for the A5-P class, which is clearly too high in the non-snowmaking months of April-October. In addition, the Commission should require BVES to harmonize its hourly demand forecasts for the A5-P class to ensure that BVES is using consistent hourly demand forecasts for developing revenue requirements and marginal costs. Finally, the Commission should order BVES to update its hourly load forecast to more accurately reflect greater levels of curtailments for the A5-P class.

Q. Does this conclude your opening testimony?

A. Yes, at this time.

ATTACHMENT 1

RESUME FOR WILLIAM A. MONSEN

RESUME FOR WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal Consultant
MRW & Associates, LLC
(1989 - Present)
Specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)
Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
(1980 - 1981)
Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.
B.S., Engineering Physics, University of California, Berkeley, 1977.

Prepared Testimony and Expert Reports

1. California Public Utilities Commission (CPUC) Applications 90-08-066, 90-08-067, 90-09-001
   Prepared Testimony with Aldyn W. Hoekstra regarding the California-Oregon Transmission Project for Toward Utility Rate Normalization (TURN). November 29, 1990.

2. CPUC Application 90-10-003
   Prepared Testimony with Mark A. Bachels regarding the Value of Qualifying Facilities and the Determination of Avoided Costs for the San Diego Gas & Electric Company for the Kelco Division of Merck & Company, Inc. December 21, 1990.

3. California Energy Commission Docket No. 93-ER-94
   Rebuttal Testimony regarding the Preparation of the 1994 Electricity Report for the Independent Energy Producers Association. December 10, 1993.

4. CPUC Rulemaking 94-04-031 and Investigation 94-04-032
   Prepared Testimony Regarding Transition Costs for The Independent Energy Producers. December 5, 1994.

5. Massachusetts Department of Telecommunications and Energy DTE 97-120
   Direct Testimony regarding Nuclear Cost Recovery for The Commonwealth of Massachusetts Division of Energy Resources. October 23, 1998.

6. CPUC Application 97-12-039
   Prepared Direct Testimony Evaluating an Auction Proposal by SDG&E on Behalf of The California Cogeneration Council. June 15, 1999.

7. CPUC Application 99-09-053
   Prepared Direct Testimony of William A. Monsen on Behalf of The Independent Energy Producers Association. March 2, 2000.

8. CPUC Application 99-09-053
   Prepared Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association. March 16, 2000.

9. CPUC Rulemaking 99-10-025
   Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. July 3, 2000.

10. CPUC Application 99-03-014
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. September 29, 2000.

11. CPUC Rulemaking 99-11-022
Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 7, 2001.

12. CPUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 30, 2001.

13. CPUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California Water Company's Application to Increase Rates for Electric Service in the Bear Valley Electric Customer Service Area. December 20, 2001.

14. CPUC Application 00-10-045; 01-01-044
Direct Testimony on Behalf of the City of San Diego. May 29, 2002.

15. CPUC Rulemaking 01-10-024
Prepared Direct Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. May 31, 2002.

16. CPUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. June 5, 2002.

17. Arizona Corporation Commission Docket Numbers E-00000A-02-0051, E-01345A-01-0822, E-0000A-01-0630, E-01933A-98-0471, E01933A-02-0069
Rebuttal Testimony on Behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.: Track A Issues. June 11, 2002.

18. CPUC Application 00-11-038
Testimony on Behalf of the Alliance for Retail Energy Markets in the Bond Charge Phase of the Rate Stabilization Proceeding. July 17, 2002.

19. CPUC Rulemaking 01-10-024
Prepared Testimony in the Renewable Portfolio Standard Phase on Behalf of Center for Energy Efficiency and Renewable Technologies. April 1, 2003.

20. CPUC Rulemaking 01-10-024
Direct Testimony of William A. Monsen Regarding Long-Term Resource Planning

Issues on Behalf of the City of San Diego. June 23, 2003.

21. CPUC Application 03-03-029
Testimony of William A. Monsen Regarding Auxiliary Load Power Metering Policy and Standby Rates on Behalf of Duke Energy North America. October 3, 2003.

22. CPUC Rulemaking 03-10-003
Opening Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of the Local Government Commission Coalition. April 15, 2004.

23. CPUC Rulemaking 03-10-003
Reply Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of Local Government Commission. May 7, 2004.

24. CPUC Rulemaking 04-04-003
Direct Testimony of William A. Monsen Regarding the 2004 Long-Term Resource Plan of San Diego Gas & Electric Company on Behalf of the City of San Diego. August 6, 2004.

25. Sonoma County Assessment Appeals Board
Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157.September 10, 2004.

26. Sonoma County Assessment Appeals Board
Presentation of Results from Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

27. Sonoma County Assessment Appeals Board
Presentation of Rebuttal Testimony and Results of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157.October 18, 2004.

28. CPUC Rulemaking 04-03-017
Testimony of William A. Monsen Regarding the Itron Report on Behalf of the City of San Diego. April 13, 2005.

29. CPUC Rulemaking 04-03-017
Rebuttal Testimony of William A. Monsen Regarding the Cost-Effectiveness of Distributed Energy Resources on Behalf of the City of San Diego. April 28, 2005.

30. CPUC Application 05-02-019
Testimony of William A. Monsen SDG&E's 2005 Rate Design Window Application on Behalf of the City of San Diego. June 24, 2005.

31. CPUC Rulemaking 04-01-025, Phase II
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 18, 2005.

32. CPUC Application 04-12-004, Phase I
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 29, 2005.

33. CPUC Application 04-12-004, Phase I
Rebuttal Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. August 26, 2005.

34. CPUC Rulemakings 04-04-003 and 04-04-025
Prepared Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. August 31, 2005.

35. CPUC Application 05-01-016 et al.
Prepared Testimony of William A. Monsen Regarding SDG&E's Critical Peak Pricing Proposal on Behalf of the City of San Diego. October 5, 2005.

36. CPUC Rulemakings 04-04-003 and 04-04-025
Prepared Rebuttal Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. October 28, 2005.

37. Public Utilities Commission of the State of Colorado Docket No. 05A-543E
Answer Testimony of William A. Monsen on Behalf of AES Corporation and the Colorado Independent Energy Association. April 18, 2006.

38. CPUC Application 04-12-004
Prepared Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 14, 2006.

39. CPUC Application 04-12-004
Prepared Rebuttal Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 31, 2006.

40. Public Utilities Commission of Nevada Dockets 06-06051 and 06-07010
Testimony of William A. Monsen on Behalf of the Nevada Resort Association Regarding Integrated Resource Planning. September 13, 2006.

41. CPUC Application 07-01-047
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design. August 10, 2007.

42. Public Utilities Commission of the State of Colorado Docket No. 07A-447E
Answer Testimony of William A. Monsen on Behalf of the Colorado Independent Energy Association. April 28, 2008.

43. CPUC Application 08-02-001
Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil Department Concerning the Application of San Diego Gas & Electric Company and Southern California Gas Company for Authority to Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. June 18, 2008.

44. CPUC Application 08-02-001
Rebuttal Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil Department Concerning the Application of San Diego Gas & Electric Company and Southern California Gas Company for Authority to Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. July 10, 2008.

45. CPUC Application 08-06-001 et al.
Prepared Testimony of William A. Monsen On Behalf of the California Demand Response Coalition Concerning Demand Response Cost-Effectiveness and Baseline Issues. November 24, 2008.

46. CPUC Application 08-02-001
Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas & Electric Company and Southern California Gas Company Biennial Cost Allocation Proceeding. December 23, 2008.

47. CPUC Application 08-06-034
Testimony of William A. Monsen On Behalf of Snow Summit, Inc. Concerning Cost Allocation and Rate Design. January 9, 2009.

48. CPUC Application 08-02-001
Rebuttal Testimony of William A. Monsen on Behalf of the City of Long Beach Gas & Oil Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas & Electric Company and Southern California Gas Company Biennial Cost Allocation Proceeding. January 27, 2009.

49. CPUC Application 08-11-014
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Cost Allocation and Electric Rate Design. April 17, 2009.

50. Public Utilities Commission of the State of Colorado Docket No. 09-AL-299E
Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. – Notice of Confidentiality: A Portion of Document Has Been Filed Under Seal. October 2, 2009.

51. Public Utilities Commission of the State of Colorado Docket No. 09-AL-299E
Supplemental Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. October 8, 2009.

52. Public Utilities Commission of the State of Colorado Docket No. 09AL-299E
Surrebuttal Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. December 18, 2009.

53. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," September 15, 2010.

54. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Supplemental Findings and Conclusions Regarding Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," November 2, 2010.

55. CPUC Application 10-05-006
Testimony of William Monsen on Behalf of the Independent Energy Producers Association in Track III of the Long-Term Procurement Planning Proceeding Concerning Bid Evaluation. August 4, 2011.

56. Public Utilities Commission of the State of Colorado Docket No. 11A-869E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. June 4, 2012.

57. CPUC Application 11-10-002
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocations, and Electric Rate Design. June 12, 2012.

58. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. July 16, 2012.

59. CPUC Rulemaking 12-03-014
Reply Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track One of the Long-Term Procurement Proceeding. July 23, 2012.

60. CPUC Application 12-03-026
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. July 23, 2012.

61. CPUC Application 12-02-013
Testimony of William A. Monsen on Behalf of Snow Summit, Inc. Concerning Revenue Requirement, Marginal Costs, and Revenue Allocation. July 27, 2012.

62. CPUC Application 12-03-026
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. August 3, 2012.

63. CPUC Application 12-02-013
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit, Inc. in Response to the Division of Ratepayer Advocates' Opening Testimony. August 27, 2012.

64. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. September 14, 2012.

65. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. October 5, 2012.

66. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Direct Testimony of William A. Monsen. November 16, 2012.

67. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Exhibit 300 Witness Reply Testimony of William A. Monsen. January 14, 2013.

68. CPUC Rulemaking 12-03-014
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. September 30, 2013.

69. CPUC Rulemaking 12-03-014
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. October 14, 2013.

70. CPUC Application 13-07-021
Response Testimony of William A. Monsen on Behalf of Interwest Energy Alliance Regarding the Proposed Merger of NV Energy, Inc. with Midamerican Energy Holdings Company. October 24, 2013.

71. CPUC Application 13-12-012
Testimony of William A. Monsen on Behalf of Commercial Energy Concerning SDG&E’s 2015 Gas Transmission and Storage Rate Application. August 11, 2014.

72. Public Utilities Commission of Nevada Docket No. 14-05003
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. August 25, 2014.

73. CPUC Application 13-12-012/I.14-06-016
Rebuttal Testimony of William A. Monsen on Behalf of Commercial Energy Concerning SDG&E's 2015 Gas Transmission & Storage Application. September 15, 2014.

74. CPUC Rulemaking 12-06-013
Testimony of William A. Monsen on Behalf of Vote Solar Concerning Residential Electric Rate Design Reform. September 15, 2014.

75. CPUC Rulemaking 13-12-010
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Phase1A of the 2014 Long-Term Procurement Planning Proceeding. September 24, 2014.

76. CPUC Application 14-01-027
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. November 14, 2014.

77. CPUC Application 14-01-027
Rebuttal Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. December 12, 2014.

78. CPUC Rulemaking 13-12-010
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Supplemental Testimony in Phase1A of the 2014 Long-Term Procurement Planning Proceeding. December 18, 2014.

79. CPUC Application 14-06-014
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Standby Rates in Phase 2 of SCE's 2015 Test Year General Rate Case. March 13, 2015.

80. CPUC Application 14-04-014
Opening Testimony of William A. Monsen on Behalf of ChargePoint, Inc. Regarding SDG&E's Vehicle Grid Integration Pilot Program. March 16, 2015.

81. Public Utilities Commission of the State of Hawaii Docket No. 2015-0022
Direct Testimony on Behalf of AES Hawaii, Inc. July 20, 2015.

82. Federal Energy Regulatory Commission Docket Nos. EL02-60-007 and EL02-62-006 (Consolidated)
Prepared Answering Testimony of William A. Monsen on Behalf of Iberdrola Renewables Regarding Rate Impacts of the Iberdrola Contract. July 21, 2015.

83. Public Utilities Commission of Nevada Docket Nos. 15-07041 and 15-07042
Prepared Direct Testimony of William A. Monsen on Behalf of the Alliance for Solar Choice (TASC). October 27, 2015.

84. Arizona Corporation Commission Docket No. E-00000J-14-0023
Rebuttal Testimony of William A. Monsen on Behalf of the Alliance for Solar Choice (TASC). April 7, 2016.

85. Arizona Corporation Commission Docket No. E-01461A-15-0363
The Energy Freedom Coalition of America's (EFCA) Direct Testimony of William A. Monsen. June 1, 2016.

86. Public Utilities Commission of the State of Colorado Proceeding No. 16AL-0048-E
Answer Testimony of William A. Monsen on Behalf of Vail Summit Resorts, Inc. June 6, 2016.

87. CPUC Application 15-04-012
Direct Testimony of William A. Monsen on Behalf of the City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design. July 5, 2016.

88. Arizona Corporation Commission Docket No. E-01461A-15-0363
The Energy Freedom Coalition of America's (EFCA) Direct Testimony of William A. Monsen and Patrick J. Quinn. July 29, 2016.

89. Arizona Corporation Commission Docket No. E-01461A-15-0363
The Energy Freedom Coalition of America's (EFCA) Rebuttal Testimony of William A. Monsen. August 15, 2016.

90. CPUC Application 15-04-012
Rebuttal Testimony of William A. Monsen on Behalf of the City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design. October 14, 2016.

91. Public Utilities Commission of Nevada Docket No. 16-07001 and 16-08027
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. November 10, 2016.

92. CPUC Application 15-04-012
Joint Supplemental Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, R. Thomas Beach on Behalf of The Solar Energy Industries Association, Maurice Brubaker on Behalf of The Federal Executive Agencies, And William A. Monsen on Behalf of the City of San Diego. November 14, 2016.

93. CPUC Application 15-04-012
Joint Supplemental Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Nathan Chau on Behalf of The Office of Ratepayer Advocates, William Monsen on Behalf of the City of San Diego and Alison M. Lechowicz on Behalf of the California City-County Street Light Association. November 16, 2016.

94. Public Utilities Commission of Nevada Docket No. 16-07001 and 16-08027
Supplemental Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. November 17, 2016.

95. Public Utilities Commission of the State of Colorado Proceeding No. 16A-0396E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association. December 9, 2016.

96. JAMS Arbitration Case No: 1220049998
Declaration of William A. Monsen on Behalf of Watson Cogeneration Company and Camino Energy, LLC. January 11, 2017.

97. CPUC Application A.16-06-013
Direct Testimony of William A. Monsen and Anna Casas on Behalf of South San Joaquin Irrigation District. March 15, 2017.

98. CPUC Application A.16-09-003
Direct Testimony of William A. Monsen on Behalf of the California Solar Energy Industries Association in Southern California Edison's Rate Design Window Application. April 28, 2017.

99. American Arbitration Association Case No. 01-16-0002-2121
Claimant Buena Vista Biomass Power, LLC's Expert Witness Disclosure. August 18, 2017.

100. American Arbitration Association Case No. 01-16-0005-1073
Expert Report of William A. Monsen on Behalf of Saguaro Power Company. September 15, 2017.

101. CPUC Application A.17-05-004
Direct Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case Application. September 29, 2017.

102. CPUC Application A.17-05-004
Rebuttal to Testimony by the Office of Ratepayer Advocates by William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case Application. October 27, 2017.

103. Superior Court of California, County of San Diego Case No. 37-2015-00014540-CU-MC-CTL
Declaration in Support of Defendant's Motion for Summary Judgement, or in the Alternative, Motion for Summary Adjudication. February 3, 2018.

104. CPUC Application 17-06-030
Testimony of William A. Monsen on Behalf of the Coalition for Affordable Street Lights Concerning Street Light Rates and LED Conversions. March 23, 2018.

105. CPUC Application 17-09-006
Direct Testimony of William A. Monsen on Behalf of The Western Manufactured Housing Communities Association in Pacific Gas & Electric's 2018 Gas Cost Allocation and Rate Design Proceeding. June 20, 2018.

106. JAMS Arbitration No. 1100088728
Expert Report by William A. Monsen for Aera Energy, LLC. July 24, 2018.

107. JAMS Arbitration No. 1100088728
Conclusions and Summary of Opinions of William A. Monsen for Aera Energy, LLC. July 24, 2018.

108. CPUC Application 18-03-003
Prepared Joint Testimony of Brandon Charles on Behalf of the California Farm

Bureau Federation, William A. Monsen on Behalf of the City of San Diego and Cynthia Fang on Behalf of San Diego Gas and Electric Company. August 20, 2018.

109. CPUC Application 18-03-003
Prepared Supplemental Testimony of Brandon Charles on Behalf of the California Farm Bureau Federation, William A. Monsen on Behalf of the City of San Diego and Cynthia Fang on Behalf of San Diego Gas and Electric Company. September 27, 2018.

110. CPUC Application 19-03-002
Direct Testimony of William A. Monsen on Behalf of the City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design. April 6, 2020.

111. CPUC Application 19-11-019
Direct Testimony of William A. Monsen and Carlo Bencomo-Jasso on Behalf of the California Farm Bureau Federation Concerning Revenue Allocation and Agricultural Rate Design. November 20, 2020.

112. Rachel Kropp et al vs Southern California Edison Company Case No. BC698926
Declaration of William A. Monsen on Behalf of Brent & Foil, LLP. December 24, 2020.

113. CPUC Application 19-11-019
Reply Testimony of William A. Monsen and Carlo Bencomo-Jasso on Behalf of the California Farm Bureau Federation Concerning Revenue Allocation and Agricultural Rate Design. February 26, 2021.

114. CPUC Application 20-10-012
Direct Testimony of William A. Monsen on Behalf of the California Farm Bureau Federation Concerning Revenue Allocation and Agricultural Rate Design. July 26, 2021.

115. Public Utilities Commission of the State of Colorado Docket No. 21A-0141E
Hearing Exhibit No. 1000 Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. October 11, 2021.

116. Kern County Assessment Appeals Board
Testimony of William A. Monsen on Behalf of Clearway Energy Regarding Differences Between Standard Offer Contracts and Modern PPAs. October 19, 2021.

117. Public Utilities Commission of the State of Colorado Docket No. 21A-0141E
Hearing Exhibit No. 1001 Cross-Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. November 12, 2021.

118. Public Utilities Commission of the State of Colorado Docket No. 21A-0141E Hearing Exhibit No. 1002 Testimony and Attachments in Opposition to the Non-Unanimous Partial Settlement Agreement of William A. Monsen on Behalf of the Colorado Independent Energy Association. December 6, 2021.

119. CPUC Application 21-06-021
Prepared Testimony of William A. Monsen Addressing Generation Supply Costs on Behalf of The Utility Reform Network (TURN). June 13, 2022

120. CPUC Application 22-05-016
Prepared Testimony of William A. Monsen Addressing Generation Supply Costs on Behalf of The Utility Reform Network. March 27, 2023.

121. CPUC Application 22-08-010
Direct Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case. May 26, 2023.

122. CPUC Application 22-08-010
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case. June 16, 2023.

123. CPUC Rulemaking 23-01-007
Prepared Testimony of William A. Monsen Addressing Costs of the Diablo Canyon Power Plant on Behalf of The Utility Reform Network. June 30, 2023.

124. CPUC Application 23-01-008
Direct Testimony of William A. Monsen on Behalf of The City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design in Application 23-01-008. January 8, 2024.

125. CPUC Application 23-01-008
Rebuttal Testimony of William A. Monsen on Behalf of The City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design in Application 23-01-008. February 7, 2024.

126. CPUC Application 23-05-010
Prepared Direct Testimony of William A. Monsen Addressing Generation Supply Costs on Behalf of the Utility Reform Network. February 29, 2024.

127. CPUC Application 24-03-018
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's 2025 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform Network. July 29, 2024.

128. CPUC Application 23-12-014

Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's Proposal to Uprate Capacity at Helms Creek Pumped Storage Project on Behalf of the Utility Reform Network. November 22, 2024.

129. Public Utilities Commission of the State of Colorado Docket No. 24A-0442E Hearing Exhibit No. 700, Rev 2 Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. May 30, 2025.

130. Public Utilities Commission of the State of Colorado Docket No. 24A-0442E Hearing Exhibit No. 701 Cross-Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. May 23, 2025.

131. CPUC Application 25-03-015
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's 2026 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform Network. July 24, 2025.

132. CPUC Application 25-03-015
Supplemental Testimony of William A. Monsen Addressing Escalators For Fixed Management Fees in Pacific Gas & Electric's 2026 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform Network. October 20, 2025.

133. CPUC Application 25-05-009
Prepared Testimony of William A. Monsen Addressing Generation Supply Costs on Behalf of The Utility Reform Network. February 13, 2026.

134. CPUC Application 24-09-014
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's Proposals Regarding Marginal Costs on Behalf of The Utility Reform Network. March 9, 2026.

135. CPUC Application 26-03-031
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's 2027 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform Network. July 17, 2026.

ATTACHMENT 2

DATA REQUEST RESPONSES REFERENCED IN TESTIMONY

REDACTED

BVES Response to Snow Summit Data Request 2, Question 6

Application 26-01-022
Second Set of Data Requests of Snow Summit to
Bear Valley Electric Service
May 5, 2026

Reference: BVES's responses to Snow Summit's First Set of Data Requests

Request No. 2:

1. Please explain the bases for BVES's forecast that energy costs by time-of-use period will be 50-60% higher than the forecasts made in A.22-08-010.

RESPONSE:

BVES observes the $/MWh from A.22-08-010 to A.26-01-022 increased 58% on average across all TOU periods. The increase in $/MWh is due to four primary reasons:

1. Higher PPA Costs: Recently procured PPA $/MWh prices are significantly higher than those in the previous application. Renewable energy required for increasing RPS compliance obligations is substantially more expensive than brown power. Additionally, brown power between the two applications is more expensive. The newly procured green PPA $/MWh is 72% higher than the previous brown PPA, and the newly procured brown PPA $/MWh is 38% higher than the previous brown PPA.

2. Higher Day Ahead Energy Prices: BVES uses S&P Global energy price forecast for long term planning. The forecast continues its increase in energy prices, increasing the cost of DA purchases. On-Peak and Off-peak prices are 66% and 88% higher than the previous application, respectively.

3. A shift from PCC3 to PCC1 Renewable Energy Credits (RECs): BVES is transitioning away from lower cost PCC3 RECs in compliance with RPS and IRP requirements to meet California's GHG reduction goals. Between the two applications, the average cost per REC is approximately 87% higher.

4. Higher Natural Gas Costs: An increase in natural gas costs to operate the Bear Valley Power Plant. Any rate increase imposed by SWGas ultimately gets passed to BVES to operate the plant. Natural gas costs $/MWh are 37% higher between the two applications.

Overall, increased market energy prices, utility rate increases, and compliance with California renewable energy and GHG reduction requirements have all contributed to an increase in the average $/MWh energy cost between the two application periods. The increased $/MWh spans across all TOU periods.

2. What are the marginal energy costs shown in Figure 5 of Volume 6 of the testimony when they are adjusted to reflect the costs of purchasing RECs and CAISO charges?

RESPONSE:

The RECs and CAISO charges are estimated to be 37.46% of energy supply costs during the 2027-2030 period. For illustrative purposes, the marginal energy costs by TOU period have been scaled up by 37.46% to include RECs and CAISO charges and presented in the table below.

Marginal Energy Costs ($ per MWh)		Projected 2027-30 [1]
Winter - On-Peak	$	78.69
Winter - Mid-Peak	$	85.74
Winter - Off-Peak	$	94.11
Summer - On-Peak	$	63.24
Summer - Mid-Peak	$	76.87
Summer - Off-Peak	$	85.12
[1] Adjusted to add RECs and CAISO charges		

3. Please identify the increased distribution investments and the cost of each such investment that support the increases in marginal T&D coincident and non-coincident demand costs.

RESPONSE:

- **System:** Filter for FERC Accounts 350 – 359.1, as well as 360-367, in column J of tab, Forecasted Addition by Pro WS4, of the "SEC7-8-9-UPIS Reserve RB.xlsx" workbook of the RO Model shared for this current GRC.

- **A-5 TOU Primary:** Filter for FERC Account 362 on tab, Forecasted Addition by Pro WS4, of the "SEC7-8-9-UPIS Reserve RB.xlsx" workbook of the RO Model shared for this current GRC.

4. Please provide the top 100 hours used in A.22-08-010 and the top 100 hours used in this application, the total coincident demand for each hour in both applications, and the coincident demands of each customer class for each hour in both applications. Please provide this information in Excel.

RESPONSE:

For Top 100 hours data, please refer to tabs, A. 22-08-010 Top 100 Hours Load and A. 26-01-022 Top 100 Hours Load, of the "Snow Summit Set 2 Attachment 1.xlsx" workbook.

For coincident demand data, please refer to tabs, A. 22-08-010 CP Demands and A. 26-01-022 CP Demands of the "Snow Summit Set 2 Attachment 1.xlsx" workbook.

5. Please provide all forecasted hourly demands disaggregated by customer class for 2027-2030. Please provide this information in Excel.

RESPONSE:

Please refer to tab, Hourly kWh of the "Snow Summit Set 2 Attachment **2**.xlsx" workbook.

6. Regarding BVES's forecast of hourly demands for customers in the A-5 Primary class, did BVES account for interruptions and curtailments pursuant to Special Conditions 9 through 13 of Schedule No. A-5 TOU Primary in the development of the hourly demands for this class and in the development of the top 100 hours used in this application? If not, please explain why not. If so, please explain how those interruptions and curtailments are forecast for the years 2027-2030 and provide all workpapers supporting BVES's estimates.

RESPONSE:

BVES estimated rate-class-specific forecasted hourly demands for this GRC by applying 2024 monthly hourly rate-class-specific load study demands (converted to hourly proportions) to the BVES GRC monthly 2027-2030 rate-class-specific sales forecast (with class specific losses included). For the A-5 Primary rate class, any interruptions or curtailments that occurred in 2024 would be accounted for in the 2024 load study demands. BVES made no other adjustments to the A-5 hourly 2027-2030 hourly demand forecasts.

7. Was the 2013 estimate of the cost to connect a typical A-5 customer based on the recorded costs incurred to connect an actual A-5 customer? Other than applying an escalation factor, has BVES taken any action to verify that the 2013 estimated costs accurately reflect the costs of connecting an A-5 customer in 2027? If so, please identify all such actions and provide the results of those actions.

RESPONSE:

The 2013 estimate of the cost to connect a typical A-5 customer was developed using the Company's engineering and construction cost assumptions at that time. It was not based on the recorded costs of connecting an actual A-5 customer, as only two companies, making up a total of three customers, currently take service under the A-5 rate. None of those customers required a new service connection that could serve as a cost benchmark.

Since 2013, BVES has taken steps to evaluate whether the original estimate, adjusted annually using standard escalation factors, continues to reflect the expected cost of connecting a new A-5 customer in 2027. While the Company has not had a new A-5 customer interconnect during this period, BVES recently completed the interconnection of a large A-4 customer whose service requirements and construction scope are broadly comparable to those of a typical A-5 customer. The total recorded cost of that project was approximately $100,000 higher than the escalated 2013 A-5 estimate.

This recent project provides the most relevant and reliable real-world data point available. Based on this comparison, BVES concludes that:

1. The escalated 2013 A-5 estimate remains reasonable, as it is directionally consistent with the cost of connecting a similarly sized customer.

2. If anything, the estimate is slightly conservative, given that the actual A-4 interconnection cost exceeded the escalated A-5 estimate by roughly $100,000.

3. No evidence suggests that the 2013 estimate understates future A-5 interconnection costs, and the available data supports its continued use for developing A-5 marginal customer costs.

BVES Response to Snow Summit Data Request 4, Question 10 and attachment

Application 26-01-022
Fourth Set of Data Requests of Snow Summit to
Bear Valley Electric Service
May 22, 2026

1. It appears that several sets of input data to BVES's MCS Rate Design model were not provided to Snow Summit. For example:

   - Tab "Plant," cells P115:U116 and all other cells in blue font in columns P:U
   - Tab "O&M," all cells in blue font in columns P:U
   - Tab "Hourly kWh," all data in cells F78914:N131497
   - Tab "Customers," cells C42:C268
   - Tab "Target Revenues," cells B11:B12

   There may be other missing input data to the MCS model in addition to the items listed above.

   Please provide copies of all models that provided input data to BVES's MCS Rate Design model. If any of the input data are outputs from models previously provided to Snow Summit, please provide precise file names and cell references for those data. Please provide these models in Excel with all formulae intact and all links live.

   Response: Please see the enclosed Marginal Cost of Service (MCOS) and Rate Design (RD) model with all formulas intact and links live. Please also see all workpapers that contain input data for the MCOS and RD Model.

2. Refer to BVES's MCS Rate Design model, tab "Target Revenues."
   a. Refer to cells A11:B12. Please explain why Added Facility Charge Revenues ($1,801,512) is allocated to all Distribution Demand Revenues in BVES's EPMC calculation.
   Response:
   The purpose of cells A11:B12 is to determine the Company's total demand-related distribution cost of service. The Added Facility Charge Revenues are included as these reflect costs associated with the Company's Snow Summit Substation.

   b. Refer to row 37. Please explain how the line "Revenue Requirements (Reconciled) (EPMC)" is used by BVES in the development of its revenue allocation proposal.

   Response:
   The line "Revenue Requirements (Reconciled) (EPMC)" represents total class revenue requirements, including revenue requirements to be recovered through other operating revenues and A-5 Primary Added Facility Charge Revenues. The

line is informational and not directly utilized in the development of Company's revenue allocation proposal.

The revenue requirements associated with base rates and supply rates based on 100% EPMC method are presented in Row 40 and Row 45 respectively. The Company proposes to set each class's revenue targets at 10.0 percent, based on EPMC method, and 90.0 percent, based on the System Average Percentage (SAP) method.

c. Please explain where in BVES's modeling (including BVES's RO models) the values for "Added Facility Charge Revenues" ($1,801,512) and "Other Revenues" ($83,495) are used. Please provide the workpapers supporting the derivation of these values. Please provide citations to BVES's testimony and workpapers, including citations to BVES's Excel models, supporting your response.

Response:
The Other Operating Revenues and Added Facility Charge Revenues are based on the Company's projections for 2027-2030 period. Please refer to the Company workpaper 'SEC 3.0_Revenue_Filing.xlsx', Tab: 'OOR by Category WS9'.

These revenues are included as Other Operating Revenues (OOR) in the Company's RO Model. Similarly, these revenues are considered non-base rate revenues in rate design model and excluded when establishing proposed base rates for each class.

Refer to Chapter 4 Part B: Revenues, Section IV (Miscellaneous Revenue and Other Operating Revenue (OOR) of Volume 1 Results of Operations Testimony for additional details.

3. Please provide BVES's models for the development of the hourly loads for all customer classes shown in tab "Hourly kWh." Please provide both the model (in Excel) and all models used by BVES to develop the inputs to the models used by BVES to develop the hourly loads shown in tab "Hourly kWh." Please also provide a description of the operation of the models, the sources of input assumptions, and the logic behind the models.

Response:
1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads

2) .csv starting "2024_class_hourly" - results from 1) to be used for the 2025-2031 hourly class forecast

3) spreadsheet starting "2025_31 Class Loads Monthly" - takes GRC monthly class sales forecast and applies loss factors or the 2025-2031 hourly class forecast

4) .csv starting "Mo_Forecast_with_Losses" - results from 3) to be used for the 2025-2031 hourly class forecast

5) .txt starting "_2025_31 Hourly Forecast SAS" - SAS code that uses 2) and 4) inputs to develop 2025-31 hourly class forecast.

4. Refer to tab "Hourly kWh" in BVES's MCS Rate Design model.
   a. Does the data shown for A5P for 2016-2024 reflect curtailments or interruptions of deliveries to BVES in 2016-2024? If so, please explain how the hourly loads for 2016-2024 are derived during hours in which A5P customers' loads were curtailed or interrupted.
   b. Please provide BVES's best estimates of the hourly load curtailment or interruption for each hour from 2016-2024 in which load was curtailed or interrupted. Please provide the workpapers supporting these estimates in Excel with all formulae intact and all links live.

   Response
   4a. Any interrupted/curtailed loads in 2024 are incorporated in the class hourly load data employed to develop A5 Primary hourly loads. Any interrupted/curtailed activity during 2022-2024 is also incorporated in the historic monthly billing data used to create the GRC monthly A5 Primary sales forecast. Nothing else was for interrupted/curtailed service.

   4b. BVES does not have this historical information because BVES doesn't track this information.

5. Refer to BVES's response to Snow Summit's Second Set of Data Requests, Request 6. Please provide BVES's best estimate of the hourly load curtailment or interruption for each hour from 2027-2030 in which load is assumed to be curtailed or interrupted. Please provide the workpapers supporting these estimates in Excel with all formulae intact and all links live.

   Response
   BVES does not forecast hourly load curtailments or interruptions in its 2027-2030 load forecast. BVES does not have this information.

6. Refer to BVES's response to Snow Summit's Second Set of Data Requests, Request 2. Please provide the basis for BVES's estimate of 37.46% for RECs and CAISO charges. Please provide all workpapers supporting the assumptions underlying and development of that estimate.

   Response
   The 37.46% is derived based on the Company's 2027-2030 projected RECs expenditures and CAISO charges divided by the projected 2027-2030 cost of supply.

Please refer to 'BVES GRC Supply Forecast Model MAIN FILE CONFIDENTIAL' Tabs: 'MGE-Other_Charges' and 'Supply Expense'.

7. Refer to BVES's response to Snow Summit's Second Set of Data Requests, Request 3. For all investments that support the development of marginal T&D coincident and non-coincident demand costs, please provide the following information:
   a. The name of the project
   b. The date the project was proposed
   c. A full description of the purpose of the project as presented to BVES management in advance of approval to pursue the project
   d. Any economic analysis, cost-benefit analysis, sensitivity analysis, or alternative analysis performed to support the proposed project
   e. Whether BVES believes that the project was needed to support load growth on the BVES and why BVES holds that belief
   f. The meaning of the value in the "Recurring Project Flag" in "SEC7-8-9-UPIS Reserve RB.xlsx," tab "Forecasted Additions by Pro"

Response:

For responses to 7a, 7b & 7c, please see the table provided.

Project ID	Project Name	Project Proposed Year	Project Description
B-001	Substation and Grid Infrastructure Improvements	Annual Blanket	Refer to BVES TY 2027 GRC Testimony.
B-002	Generating Facility Infrastructure Improvements	Annual Blanket	Refer to BVES TY 2027 GRC Testimony.
B-003	Overhead Distribution and Transmission Infrastructure Improvements	Annual Blanket	Refer to BVES TY 2027 GRC Testimony.
B-004	Underground Distribution and Transmission Infrastructure Improvements	Annual Blanket	Refer to BVES TY 2027 GRC Testimony.
B-007	EV Infrastucture Improvements	2025	Refer to BVES TY 2027 GRC Testimony.
B-008	New Business Funded by GSWC and Others	Annual Blanket	Refer to BVES TY 2027 GRC Testimony.
C-001	Covered Conductor Replacement Project	2020	Refer to BVES TY 2027 GRC Testimony.
C-002	Evacuation Route Hardening Project - 600 poles per year	2023	Refer to BVES TY 2027 GRC Testimony.
C-003	Switch and Field Device Automation	2023	Refer to BVES TY 2027 GRC Testimony.
C-004	Fuse TripSaver Automation	2023	Refer to BVES TY 2027 GRC Testimony.
C-005	Tree Attachment Removal Project (removes 100 per year)	2023	Refer to BVES TY 2027 GRC Testimony.
C-006	Partial Safety and Technical Upgrades to Village Substation	2022	Refer to BVES TY 2027 GRC Testimony.
C-007	Safety and Technical Upgrades to Fawnskin Substation	2022	Refer to BVES TY 2027 GRC Testimony.

Project ID	Project Name	Project Proposed Year	Project Description
C-008	Mobile Emergency Generation	2025	Refer to BVES TY 2027 GRC Testimony.
C-011	Autonomous Monitoring of Power Line Infrastructure	2025	Refer to BVES TY 2027 GRC Testimony
C-012	Weather Station Upgrades	2025	Refer to BVES TY 2027 GRC Testimony.
C-015	Getaway Feeder Replacement Project	2025	Refer to BVES TY 2027 GRC Testimony.
C-016	Underground Facilities Upgrade Project	2025	Refer to BVES TY 2027 GRC Testimony.
C-017	Underground Fault Indicator Project	2025	Refer to BVES TY 2027 GRC Testimony.
C-018	Padmount Distribution Transformer Upgrade Project	2025	Refer to BVES TY 2027 GRC Testimony.
C-019	Install Underground Submersible Distribution Switches	2025	Refer to BVES TY 2027 GRC Testimony.
C-020	System and Substation Capacity EV Optimization Project	2025	Refer to BVES TY 2027 GRC Testimony.
C-021	Meadow Substation SF6 gas Circuit Breakers Replacement Project	2025	Refer to BVES TY 2027 GRC Testimony.
C-023	Snow Summit Project	2015	Upgrade aging substation and provide new substation that supplies Snow Summit Resort.
C-024	Radford Line Project	2019	Replace aging infrastructure.
C-025	Partial Safety and Technical Upgrades to Maltby Substation Project	2022	Replace aging substation.
C-028	Pole Loading	2018	Replace aging infrastructure.
C-029	Substation Automation	2022	Automate BVES substations into BVES' SCADA system.
C-030	Capacitor Bank Upgrade	2023	Replace aging capacitor banks and automate into BVES' SCADA system.
C-031	Fault Indicators Program	2023	Install fault indicators and automate into BVES SCADA system.
C-032	TE Commercial Pilot	2019	EV commercial pilot program. Replace bare wires with covered conductors.
C-034	Online Diagnostic System	2023	Install advanced sensors on 34KV and 4KV system for WMP.

Project ID	Project Name	Project Proposed Year	Project Description
C-037	BVPP Phase 4 Upgrade	2024	Upgrade generators for t enhanced efficiency and reliability.
C-038	Lake Sub Partial Safe & Tech Upgrad	2025	Replace aging substation and automate into BVES SCADA system.
C-039	Pineknot	2019	Replace aging substation.
C-040	Whispering Pine Mobile Home park		Mobile Home Park Conversation Program
C-041	Fiber Nework Phase 1	2019	Install fiber system for BVES' SCADA system.
C-042	Fiber Nework Phase 2	2019	Install fiber system for BVES' SCADA system.

7d. BVES did not complete or perform economic analysis, cost-benefit analysis, sensitivity analysis, or alternative analysis for proposed projects in the table provided. However, these projects are crucial for the reliability of BVES' system.

7e. All proposed projects in above table for questions 7 responses support BVES' system and hence, load growth on the system.

7f. The value of "1" in the "Recurring Projects Flag" column indicates that the project is recurring. Capital expenditure for that program is closed into utility plant in service at end of the year, and begins depreciating. The value of "0" means that the project is not recurring. A specific year in column E indicates the in-service date of the project.

8. Please provide a listing and description of every curtailment or BVES-ordered interruption of load for the period from 2020 to the present. Please provide any notes, logs, or other documentation associated with BVES's decision to curtail or interrupt deliveries to customers. If not indicated in the notes, logs, or other documentation, please indicate the customer classes that have had their loads curtailed or interrupted due to BVES's actions for each curtailment or interruption.

   Response: BVES doesn't have any additional information than what was already provided in Snow Summit's Second Set of Data Requests, Request 10 response attachment.

9. Has BVES ever considered using any method for determining the Marginal Customer Access Costs other than the New Customer Only method? If so, please indicate when BVES made such considerations, whether BVES ever used a method other the New Customer Only, and when BVES used the method other than New Customer Only. If BVES ever used a method other than New Customer Only for determination of Marginal Customer Access Costs, please provide a copy of all documents demonstrating such instances.

Response
The Company did not consider using an alternative to the New Customer Only method for this proceeding. Please also refer to the Company's response to PubAdv-BVES-022-STA.

10. Please provide the recorded A-5 Primary usage for January 1, 2026 to present. Please provide this information in the format used in BVES's response to Snow Summit's Second Set of Data Requests, Request 8.
Response: See file, "A5 Primary kwh 2026."

11. Refer to BVES's response to Snow Summit's Second Set of Data Requests, Request 10. For each curtailment described in these responses, please provide the following information:
    a. The date of the curtailment or interruption
    b. The duration of the curtailment or interruption
    c. BVES's estimate of the hourly loads that BVES had expected prior to the curtailment or interruption
    d. BVES's estimate of the hourly loads that BVES actually served during the curtailment or interruption

Response: BVES doesn't have any additional information than what was already provided in Snow Summit's Second Set of Data Requests, Request 10 response attachment.

12. Refer to BVES's response to Snow Summit's Second Set of Data Requests, Request 10d. BVES indicates that "BVPP Generation Unit 5 was out for maintenance from 5/27/25 – 8/15/25." Please respond to the following questions:
    a. Does BVES contend that no portion of the BVPP was out on partial or full forced or maintenance outage for any period other than 5/27/25 – 8/15/25 from January 1, 2025 to present? If not, please provide a complete listing of the date and duration of each partial or full forced or maintenance outages at the BVPP from January 1, 2025 to present, the reason for each outage, and the amount of capacity that was unavailable during each outage.

Response
Please see attached supporting documentation "BVPP Minor Repair_Maintenance" where BVPP performed minor repairs and maintenances due to unexpected situations and minor upgrades. All BVPP Generation Units were back up and running within 8-10 hours. "

13. Refer to BVES's response to Snow Summit Second Set of Data Requests, Request 12. Please respond to the following questions about that response.
    a. BVES's response to subpart (b) indicates that only certain substations are "A5 Customer." Please explain the meaning of that designation.
    b. Please indicate the number of customers that take service from each substation. For clarity, please define the "number of customers" taking service from each substation as (1) the number of customers taking service directly from each

BVES Response to Snow Summit Data Request 7, Question 4.

Application 26-01-022
Seventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 1, 2026

1. Please provide the hourly loads for the A5-P accounts for Snow Summit and Big Bear Mountain for the period from January 1, 2024 to the present. Please disaggregate the hourly loads for each meter at which Snow Summit or Big Bear Mountain takes delivery on the A5-P tariff. Please indicate the point of interconnection for each meter. Please provide this information in the format used in BVES's response to Snow Summit's Second Set of Data Requests, Request 8. Please provide this response in Excel.

   RESPONSE: Attached is a file named "2024 A5 Primary Customer Hourly.csv" with 2024 hourly A5 customer specific demands. The point of interconnection for Bear Mountain ("Customer") is located at the customer switchgear building where BVES metering is located. The point of interconnection for Snow Summit ("Customer") is located at the customer switchgear building, but BVES metering is located at the BVES Snow Summit Substation.

2. Refer to BVES's response to Snow Summit Data Request Set 4, Request 3. In its response, BVES states that "1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads". Please respond to the following questions:
   a. Please explain how BVES calibrated its "initial rate class hourly loads" to "system 2025 hourly loads." Should this reference be to "system 2024 hourly loads?"

      RESPONSE: It should be 2024 system hourly loads (a correction is made to the answer to June 3rd Response 1b).

   b. What was the basis of the "initial rate class hourly loads?"

      RESPONSE: BVES load research sample rate class weighted average hourly loads and 2024 BVES calendar monthly sales by class with losses.

   c. On what date did BVES perform this calibration?

      RESPONSE: May 7, 2025

   d. Does this response imply that the curtailments of Snow Summit deliveries in the fourth quarter of 2025 are reflected in the hourly loads in BVES's "Hourly kWh" used in its MCS model?

      RESPONSE: 2025 hourly kWh in the MCS model based on 2025 monthly sales forecast with losses.

3. Refer to BVES's response to Snow Summit Data Request Set 4, Request 4. Please respond to the following requests:
   a. Does BVES believe that 2024 is a typical year for customer hourly loads for A5-P customers? If so, please explain the reasons for BVES's belief.

      RESPONSE: No historic hourly analysis has been performed on historic A5-P customers. The 2024 hourly A5-P shapes are only used to spread the 2025-2030 monthly A5-P sales forecast into hourly values.

   b. Please explain why it is appropriate for use 2024 as the basis for hourly loads for 2025-203 for A5-P customers.

      RESPONSE: 2024 is the most recent rate class hourly loads available to spread 2025-2030 monthly rate class sales forecasts into hourly values.

   c. Does BVES believe that the frequency of curtailments and interruptions of customer loads for A5-P customers in 2024 are likely to be the same as the frequency of curtailments and interruptions as for 2025-2030? If so, please explain the reasons for BVES's belief.

      RESPONSE: BVES cannot predict whether the frequency of A5-P customer curtailments or interruptions during 2025–2030 will be similar to 2024. Curtailments are driven by real-time system conditions, including weather, holiday timing, and local peak demand. Because these factors are inherently variable, BVES does not plan curtailments in advance and cannot determine whether 2024 or any future year represents typical operating conditions.

   d. Does BVES believe that the relative magnitude of curtailments and interruptions for customer loads for A5-P customers for 2024 are likely to be the same as the relative magnitude of curtailments and interruptions for 2025-2030. For purposes of this question, "relative magnitude" means percentage of otherwise requested loads after curtailments and interruptions. For example, if A5-P customers desired 10 MW in an hour in 2024 and BVES only delivered 7 MW, then the relative magnitude of curtailment in that hour would be 30% ((10 MW – 7 MW)/10 MW).

      RESPONSE: See 3.c above.

4. Refer to BVES's response to Snow Summit Data Request Set 4, Request 10. Please explain why the GRC forecasted usage for each month exceeds the actual usage for those months. Please provide workpapers supporting your response. Please also provide copies of all material upon which your response is based.

   RESPONSE: 2025-2031 A5 Primary forecasts are based on 2022-2024 average monthly sales and expected expanded load for Snow Summit.

5. Please provide a listing of each and every curtailment or interruption of deliveries to Snow Summit and Bear Mountain ordered by BVES from September 1, 2019 to the

BVES Response to Snow Summit Data Request 4, Question 4.

Application 26-01-022
Fourth Set of Data Requests of Snow Summit to
Bear Valley Electric Service
May 22, 2026

1. It appears that several sets of input data to BVES's MCS Rate Design model were not provided to Snow Summit. For example:

   - Tab "Plant," cells P115:U116 and all other cells in blue font in columns P:U
   - Tab "O&M," all cells in blue font in columns P:U
   - Tab "Hourly kWh," all data in cells F78914:N131497
   - Tab "Customers," cells C42:C268
   - Tab "Target Revenues," cells B11:B12

   There may be other missing input data to the MCS model in addition to the items listed above.

   Please provide copies of all models that provided input data to BVES's MCS Rate Design model. If any of the input data are outputs from models previously provided to Snow Summit, please provide precise file names and cell references for those data. Please provide these models in Excel with all formulae intact and all links live.

   Response: Please see the enclosed Marginal Cost of Service (MCOS) and Rate Design (RD) model with all formulas intact and links live. Please also see all workpapers that contain input data for the MCOS and RD Model.

2. Refer to BVES's MCS Rate Design model, tab "Target Revenues."
   a. Refer to cells A11:B12. Please explain why Added Facility Charge Revenues ($1,801,512) is allocated to all Distribution Demand Revenues in BVES's EPMC calculation.
      Response:
      The purpose of cells A11:B12 is to determine the Company's total demand-related distribution cost of service. The Added Facility Charge Revenues are included as these reflect costs associated with the Company's Snow Summit Substation.

   b. Refer to row 37. Please explain how the line "Revenue Requirements (Reconciled) (EPMC)" is used by BVES in the development of its revenue allocation proposal.

      Response:
      The line "Revenue Requirements (Reconciled) (EPMC)" represents total class revenue requirements, including revenue requirements to be recovered through other operating revenues and A-5 Primary Added Facility Charge Revenues. The

line is informational and not directly utilized in the development of Company's revenue allocation proposal.

The revenue requirements associated with base rates and supply rates based on 100% EPMC method are presented in Row 40 and Row 45 respectively. The Company proposes to set each class's revenue targets at 10.0 percent, based on EPMC method, and 90.0 percent, based on the System Average Percentage (SAP) method.

c. Please explain where in BVES's modeling (including BVES's RO models) the values for "Added Facility Charge Revenues" ($1,801,512) and "Other Revenues" ($83,495) are used. Please provide the workpapers supporting the derivation of these values. Please provide citations to BVES's testimony and workpapers, including citations to BVES's Excel models, supporting your response.

Response:
The Other Operating Revenues and Added Facility Charge Revenues are based on the Company's projections for 2027-2030 period. Please refer to the Company workpaper 'SEC 3.0_Revenue_Filing.xlsx', Tab: 'OOR by Category WS9'.

These revenues are included as Other Operating Revenues (OOR) in the Company's RO Model. Similarly, these revenues are considered non-base rate revenues in rate design model and excluded when establishing proposed base rates for each class.

Refer to Chapter 4 Part B: Revenues, Section IV (Miscellaneous Revenue and Other Operating Revenue (OOR) of Volume 1 Results of Operations Testimony for additional details.

3. Please provide BVES's models for the development of the hourly loads for all customer classes shown in tab "Hourly kWh." Please provide both the model (in Excel) and all models used by BVES to develop the inputs to the models used by BVES to develop the hourly loads shown in tab "Hourly kWh." Please also provide a description of the operation of the models, the sources of input assumptions, and the logic behind the models.

Response:
1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads

2) .csv starting "2024_class_hourly" - results from 1) to be used for the 2025-2031 hourly class forecast

3) spreadsheet starting "2025_31 Class Loads Monthly" - takes GRC monthly class sales forecast and applies loss factors or the 2025-2031 hourly class forecast

4) .csv starting "Mo_Forecast_with_Losses" - results from 3) to be used for the 2025-2031 hourly class forecast

5) .txt starting "_2025_31 Hourly Forecast SAS" - SAS code that uses 2) and 4) inputs to develop 2025-31 hourly class forecast.

4. Refer to tab "Hourly kWh" in BVES's MCS Rate Design model.
   a. Does the data shown for A5P for 2016-2024 reflect curtailments or interruptions of deliveries to BVES in 2016-2024? If so, please explain how the hourly loads for 2016-2024 are derived during hours in which A5P customers' loads were curtailed or interrupted.
   b. Please provide BVES's best estimates of the hourly load curtailment or interruption for each hour from 2016-2024 in which load was curtailed or interrupted. Please provide the workpapers supporting these estimates in Excel with all formulae intact and all links live.

   Response
   4a. Any interrupted/curtailed loads in 2024 are incorporated in the class hourly load data employed to develop A5 Primary hourly loads. Any interrupted/curtailed activity during 2022-2024 is also incorporated in the historic monthly billing data used to create the GRC monthly A5 Primary sales forecast. Nothing else was for interrupted/curtailed service.

   4b. BVES does not have this historical information because BVES doesn't track this information.

5. Refer to BVES's response to Snow Summit's Second Set of Data Requests, Request 6. Please provide BVES's best estimate of the hourly load curtailment or interruption for each hour from 2027-2030 in which load is assumed to be curtailed or interrupted. Please provide the workpapers supporting these estimates in Excel with all formulae intact and all links live.

   Response
   BVES does not forecast hourly load curtailments or interruptions in its 2027-2030 load forecast. BVES does not have this information.

6. Refer to BVES's response to Snow Summit's Second Set of Data Requests, Request 2. Please provide the basis for BVES's estimate of 37.46% for RECs and CAISO charges. Please provide all workpapers supporting the assumptions underlying and development of that estimate.

   Response
   The 37.46% is derived based on the Company's 2027-2030 projected RECs expenditures and CAISO charges divided by the projected 2027-2030 cost of supply.

BVES Response to Snow Summit Data Request 7, Question 6.

Application 26-01-022
Seventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 1, 2026

1. Please provide the hourly loads for the A5-P accounts for Snow Summit and Big Bear Mountain for the period from January 1, 2024 to the present. Please disaggregate the hourly loads for each meter at which Snow Summit or Big Bear Mountain takes delivery on the A5-P tariff. Please indicate the point of interconnection for each meter. Please provide this information in the format used in BVES's response to Snow Summit's Second Set of Data Requests, Request 8. Please provide this response in Excel.

   RESPONSE: Attached is a file named "2024 A5 Primary Customer Hourly.csv" with 2024 hourly A5 customer specific demands. The point of interconnection for Bear Mountain ("Customer") is located at the customer switchgear building where BVES metering is located. The point of interconnection for Snow Summit ("Customer") is located at the customer switchgear building, but BVES metering is located at the BVES Snow Summit Substation.

2. Refer to BVES's response to Snow Summit Data Request Set 4, Request 3. In its response, BVES states that "1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads". Please respond to the following questions:
   a. Please explain how BVES calibrated its "initial rate class hourly loads" to "system 2025 hourly loads." Should this reference be to "system 2024 hourly loads?"

      RESPONSE: It should be 2024 system hourly loads (a correction is made to the answer to June 3rd Response 1b).

   b. What was the basis of the "initial rate class hourly loads?"

      RESPONSE: BVES load research sample rate class weighted average hourly loads and 2024 BVES calendar monthly sales by class with losses.

   c. On what date did BVES perform this calibration?

      RESPONSE: May 7, 2025

   d. Does this response imply that the curtailments of Snow Summit deliveries in the fourth quarter of 2025 are reflected in the hourly loads in BVES's "Hourly kWh" used in its MCS model?

      RESPONSE: 2025 hourly kWh in the MCS model based on 2025 monthly sales forecast with losses.

3. Refer to BVES's response to Snow Summit Data Request Set 4, Request 4. Please respond to the following requests:
    a. Does BVES believe that 2024 is a typical year for customer hourly loads for A5-P customers? If so, please explain the reasons for BVES's belief.

       RESPONSE: No historic hourly analysis has been performed on historic A5-P customers. The 2024 hourly A5-P shapes are only used to spread the 2025-2030 monthly A5-P sales forecast into hourly values.

    b. Please explain why it is appropriate for use 2024 as the basis for hourly loads for 2025-203 for A5-P customers.

       RESPONSE: 2024 is the most recent rate class hourly loads available to spread 2025-2030 monthly rate class sales forecasts into hourly values.

    c. Does BVES believe that the frequency of curtailments and interruptions of customer loads for A5-P customers in 2024 are likely to be the same as the frequency of curtailments and interruptions as for 2025-2030? If so, please explain the reasons for BVES's belief.

       RESPONSE: BVES cannot predict whether the frequency of A5-P customer curtailments or interruptions during 2025–2030 will be similar to 2024. Curtailments are driven by real-time system conditions, including weather, holiday timing, and local peak demand. Because these factors are inherently variable, BVES does not plan curtailments in advance and cannot determine whether 2024 or any future year represents typical operating conditions.

    d. Does BVES believe that the relative magnitude of curtailments and interruptions for customer loads for A5-P customers for 2024 are likely to be the same as the relative magnitude of curtailments and interruptions for 2025-2030. For purposes of this question, "relative magnitude" means percentage of otherwise requested loads after curtailments and interruptions. For example, if A5-P customers desired 10 MW in an hour in 2024 and BVES only delivered 7 MW, then the relative magnitude of curtailment in that hour would be 30% ((10 MW – 7 MW)/10 MW).

       RESPONSE: See 3.c above.

4. Refer to BVES's response to Snow Summit Data Request Set 4, Request 10. Please explain why the GRC forecasted usage for each month exceeds the actual usage for those months. Please provide workpapers supporting your response. Please also provide copies of all material upon which your response is based.

   RESPONSE: 2025-2031 A5 Primary forecasts are based on 2022-2024 average monthly sales and expected expanded load for Snow Summit.

5. Please provide a listing of each and every curtailment or interruption of deliveries to Snow Summit and Bear Mountain ordered by BVES from September 1, 2019 to the

present. Please disaggregate your response by customer. If available, please disaggregate your response by point of delivery to Snow Summit and Bear Mountain. If available, please indicate the duration of each curtailment or interruption. If BVES does not have data available for the entire period from September 1, 2019 to the present, please provide all data that are available for that period. Please provide your response in Excel.

RESPONSE: BVES doesn't have any additional information other than what was already provided in its response to Snow Summit's Second Set of Data Requests, Request 10.

6. Refer to BVES's response to Snow Summit Data Request Set 5, Request 5. Does BVES contend that it has no data related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024? If your response is anything other than an unqualified "yes", please provide all information in BVES's possession related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024.
RESPONSE: Yes

7. Refer to BVES's development of marginal distribution costs and marginal substation costs in its MCS model. Please provide the following information regarding BVES's development of those marginal costs:
   a. The theoretical basis upon which BVES relies for using this approach.

      RESPONSE: BVES relies on a variation of the NERA Regression method to estimate the marginal distribution and marginal substation cost in its MCS model.

   b. All citations to documents explaining the theoretical basis for BVES using this approach for determination of marginal distribution and marginal distribution substation costs.

      RESPONSE: The NERA Regression method has been utilized in the industry for determination of marginal distribution costs, including by other California Investor-Owned Utilities. For example, Southern California Edison and San Diego Gas & Electric utilized the NERA Regression method in A. 20-10-012 and A. 23-01-008 respectively. In addition, BVES utilized the method in its past two rate case applications.

   c. Is BVES aware of the so-called "NERA method" for determining marginal distribution costs? If so, please explain BVES's understanding of the NERA method for determining marginal distribution costs. Does BVES contend that it is using the "NERA method" in this proceeding? If so, where is BVES using it and how.

      RESPONSE: Yes. Please refer to responses to parts 7(a) and 7(b). BVES has utilized a variation of the NERA Regression method for determining marginal distribution capacity costs.

BVES Response to Snow Summit Data Request 7, Question 5.

Application 26-01-022
Seventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 1, 2026

1. Please provide the hourly loads for the A5-P accounts for Snow Summit and Big Bear Mountain for the period from January 1, 2024 to the present. Please disaggregate the hourly loads for each meter at which Snow Summit or Big Bear Mountain takes delivery on the A5-P tariff. Please indicate the point of interconnection for each meter. Please provide this information in the format used in BVES's response to Snow Summit's Second Set of Data Requests, Request 8. Please provide this response in Excel.

   RESPONSE: Attached is a file named "2024 A5 Primary Customer Hourly.csv" with 2024 hourly A5 customer specific demands. The point of interconnection for Bear Mountain ("Customer") is located at the customer switchgear building where BVES metering is located. The point of interconnection for Snow Summit ("Customer") is located at the customer switchgear building, but BVES metering is located at the BVES Snow Summit Substation.

2. Refer to BVES's response to Snow Summit Data Request Set 4, Request 3. In its response, BVES states that "1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads". Please respond to the following questions:
   a. Please explain how BVES calibrated its "initial rate class hourly loads" to "system 2025 hourly loads." Should this reference be to "system 2024 hourly loads?"

      RESPONSE: It should be 2024 system hourly loads (a correction is made to the answer to June 3rd Response 1b).

   b. What was the basis of the "initial rate class hourly loads?"

      RESPONSE: BVES load research sample rate class weighted average hourly loads and 2024 BVES calendar monthly sales by class with losses.

   c. On what date did BVES perform this calibration?

      RESPONSE: May 7, 2025

   d. Does this response imply that the curtailments of Snow Summit deliveries in the fourth quarter of 2025 are reflected in the hourly loads in BVES's "Hourly kWh" used in its MCS model?

      RESPONSE: 2025 hourly kWh in the MCS model based on 2025 monthly sales forecast with losses.

3. Refer to BVES's response to Snow Summit Data Request Set 4, Request 4. Please respond to the following requests:
    a. Does BVES believe that 2024 is a typical year for customer hourly loads for A5-P customers? If so, please explain the reasons for BVES's belief.

        RESPONSE: No historic hourly analysis has been performed on historic A5-P customers. The 2024 hourly A5-P shapes are only used to spread the 2025-2030 monthly A5-P sales forecast into hourly values.

    b. Please explain why it is appropriate for use 2024 as the basis for hourly loads for 2025-203 for A5-P customers.

        RESPONSE: 2024 is the most recent rate class hourly loads available to spread 2025-2030 monthly rate class sales forecasts into hourly values.

    c. Does BVES believe that the frequency of curtailments and interruptions of customer loads for A5-P customers in 2024 are likely to be the same as the frequency of curtailments and interruptions as for 2025-2030? If so, please explain the reasons for BVES's belief.

        RESPONSE: BVES cannot predict whether the frequency of A5-P customer curtailments or interruptions during 2025–2030 will be similar to 2024. Curtailments are driven by real-time system conditions, including weather, holiday timing, and local peak demand. Because these factors are inherently variable, BVES does not plan curtailments in advance and cannot determine whether 2024 or any future year represents typical operating conditions.

    d. Does BVES believe that the relative magnitude of curtailments and interruptions for customer loads for A5-P customers for 2024 are likely to be the same as the relative magnitude of curtailments and interruptions for 2025-2030. For purposes of this question, "relative magnitude" means percentage of otherwise requested loads after curtailments and interruptions. For example, if A5-P customers desired 10 MW in an hour in 2024 and BVES only delivered 7 MW, then the relative magnitude of curtailment in that hour would be 30% ((10 MW – 7 MW)/10 MW).

        RESPONSE: See 3.c above.

4. Refer to BVES's response to Snow Summit Data Request Set 4, Request 10. Please explain why the GRC forecasted usage for each month exceeds the actual usage for those months. Please provide workpapers supporting your response. Please also provide copies of all material upon which your response is based.

    RESPONSE: 2025-2031 A5 Primary forecasts are based on 2022-2024 average monthly sales and expected expanded load for Snow Summit.

5. Please provide a listing of each and every curtailment or interruption of deliveries to Snow Summit and Bear Mountain ordered by BVES from September 1, 2019 to the

present. Please disaggregate your response by customer. If available, please disaggregate your response by point of delivery to Snow Summit and Bear Mountain. If available, please indicate the duration of each curtailment or interruption. If BVES does not have data available for the entire period from September 1, 2019 to the present, please provide all data that are available for that period. Please provide your response in Excel.

RESPONSE: BVES doesn't have any additional information other than what was already provided in its response to Snow Summit's Second Set of Data Requests, Request 10.

6. Refer to BVES's response to Snow Summit Data Request Set 5, Request 5. Does BVES contend that it has no data related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024? If your response is anything other than an unqualified "yes", please provide all information in BVES's possession related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024.
   RESPONSE: Yes

7. Refer to BVES's development of marginal distribution costs and marginal substation costs in its MCS model. Please provide the following information regarding BVES's development of those marginal costs:
   a. The theoretical basis upon which BVES relies for using this approach.

      RESPONSE: BVES relies on a variation of the NERA Regression method to estimate the marginal distribution and marginal substation cost in its MCS model.

   b. All citations to documents explaining the theoretical basis for BVES using this approach for determination of marginal distribution and marginal distribution substation costs.

      RESPONSE: The NERA Regression method has been utilized in the industry for determination of marginal distribution costs, including by other California Investor-Owned Utilities. For example, Southern California Edison and San Diego Gas & Electric utilized the NERA Regression method in A. 20-10-012 and A. 23-01-008 respectively. In addition, BVES utilized the method in its past two rate case applications.

   c. Is BVES aware of the so-called "NERA method" for determining marginal distribution costs? If so, please explain BVES's understanding of the NERA method for determining marginal distribution costs. Does BVES contend that it is using the "NERA method" in this proceeding? If so, where is BVES using it and how.

      RESPONSE: Yes. Please refer to responses to parts 7(a) and 7(b). BVES has utilized a variation of the NERA Regression method for determining marginal distribution capacity costs.

BVES Response to Snow Summit Data Request 2, Question 10a and CONFIDENTIAL attachment.

Application 26-01-022
Second Set of Data Requests of Snow Summit to
Bear Valley Electric Service
May 5, 2026

Reference: BVES's responses to Snow Summit's First Set of Data Requests

Request No. 2:

1. Please explain the bases for BVES's forecast that energy costs by time-of-use period will be 50-60% higher than the forecasts made in A.22-08-010.

RESPONSE:

BVES observes the $/MWh from A.22-08-010 to A.26-01-022 increased 58% on average across all TOU periods. The increase in $/MWh is due to four primary reasons:

1. Higher PPA Costs: Recently procured PPA $/MWh prices are significantly higher than those in the previous application. Renewable energy required for increasing RPS compliance obligations is substantially more expensive than brown power. Additionally, brown power between the two applications is more expensive. The newly procured green PPA $/MWh is 72% higher than the previous brown PPA, and the newly procured brown PPA $/MWh is 38% higher than the previous brown PPA.

2. Higher Day Ahead Energy Prices: BVES uses S&P Global energy price forecast for long term planning. The forecast continues its increase in energy prices, increasing the cost of DA purchases. On-Peak and Off-peak prices are 66% and 88% higher than the previous application, respectively.

3. A shift from PCC3 to PCC1 Renewable Energy Credits (RECs): BVES is transitioning away from lower cost PCC3 RECs in compliance with RPS and IRP requirements to meet California's GHG reduction goals. Between the two applications, the average cost per REC is approximately 87% higher.

4. Higher Natural Gas Costs: An increase in natural gas costs to operate the Bear Valley Power Plant. Any rate increase imposed by SWGas ultimately gets passed to BVES to operate the plant. Natural gas costs $/MWh are 37% higher between the two applications.

Overall, increased market energy prices, utility rate increases, and compliance with California renewable energy and GHG reduction requirements have all contributed to an increase in the average $/MWh energy cost between the two application periods. The increased $/MWh spans across all TOU periods.

2. What are the marginal energy costs shown in Figure 5 of Volume 6 of the testimony when they are adjusted to reflect the costs of purchasing RECs and CAISO charges?

RESPONSE:

The RECs and CAISO charges are estimated to be 37.46% of energy supply costs during the 2027-2030 period. For illustrative purposes, the marginal energy costs by TOU period have been scaled up by 37.46% to include RECs and CAISO charges and presented in the table below.

Marginal Energy Costs ($ per MWh)		Projected 2027-30 [1]
Winter - On-Peak	$	78.69
Winter - Mid-Peak	$	85.74
Winter - Off-Peak	$	94.11
Summer - On-Peak	$	63.24
Summer - Mid-Peak	$	76.87
Summer - Off-Peak	$	85.12

[1] Adjusted to add RECs and CAISO charges

3. Please identify the increased distribution investments and the cost of each such investment that support the increases in marginal T&D coincident and non-coincident demand costs.

RESPONSE:

- **System:** Filter for FERC Accounts 350 – 359.1, as well as 360-367, in column J of tab, Forecasted Addition by Pro WS4, of the "SEC7-8-9-UPIS Reserve RB.xlsx" workbook of the RO Model shared for this current GRC.

- **A-5 TOU Primary:** Filter for FERC Account 362 on tab, Forecasted Addition by Pro WS4, of the "SEC7-8-9-UPIS Reserve RB.xlsx" workbook of the RO Model shared for this current GRC.

4. Please provide the top 100 hours used in A.22-08-010 and the top 100 hours used in this application, the total coincident demand for each hour in both applications, and the coincident demands of each customer class for each hour in both applications. Please provide this information in Excel.

RESPONSE:

For Top 100 hours data, please refer to tabs, A. 22-08-010 Top 100 Hours Load and A. 26-01-022 Top 100 Hours Load, of the "Snow Summit Set 2 Attachment 1.xlsx" workbook.

For coincident demand data, please refer to tabs, A. 22-08-010 CP Demands and A. 26-01-022 CP Demands of the "Snow Summit Set 2 Attachment 1.xlsx" workbook.

5. Please provide all forecasted hourly demands disaggregated by customer class for 2027-2030. Please provide this information in Excel.

RESPONSE:

Please refer to tab, Hourly kWh of the "Snow Summit Set 2 Attachment **2**.xlsx" workbook.

6. Regarding BVES's forecast of hourly demands for customers in the A-5 Primary class, did BVES account for interruptions and curtailments pursuant to Special Conditions 9 through 13 of Schedule No. A-5 TOU Primary in the development of the hourly demands for this class and in the development of the top 100 hours used in this application? If not, please explain why not. If so, please explain how those interruptions and curtailments are forecast for the years 2027-2030 and provide all workpapers supporting BVES's estimates.

RESPONSE:

BVES estimated rate-class-specific forecasted hourly demands for this GRC by applying 2024 monthly hourly rate-class-specific load study demands (converted to hourly proportions) to the BVES GRC monthly 2027-2030 rate-class-specific sales forecast (with class specific losses included). For the A-5 Primary rate class, any interruptions or curtailments that occurred in 2024 would be accounted for in the 2024 load study demands. BVES made no other adjustments to the A-5 hourly 2027-2030 hourly demand forecasts.

7. Was the 2013 estimate of the cost to connect a typical A-5 customer based on the recorded costs incurred to connect an actual A-5 customer? Other than applying an escalation factor, has BVES taken any action to verify that the 2013 estimated costs accurately reflect the costs of connecting an A-5 customer in 2027? If so, please identify all such actions and provide the results of those actions.

RESPONSE:

The 2013 estimate of the cost to connect a typical A-5 customer was developed using the Company's engineering and construction cost assumptions at that time. It was not based on the recorded costs of connecting an actual A-5 customer, as only two companies, making up a total of three customers, currently take service under the A-5 rate. None of those customers required a new service connection that could serve as a cost benchmark.

Since 2013, BVES has taken steps to evaluate whether the original estimate, adjusted annually using standard escalation factors, continues to reflect the expected cost of connecting a new A-5 customer in 2027. While the Company has not had a new A-5 customer interconnect during this period, BVES recently completed the interconnection of a large A-4 customer whose service requirements and construction scope are broadly comparable to those of a typical A-5 customer. The total recorded cost of that project was approximately $100,000 higher than the escalated 2013 A-5 estimate.

This recent project provides the most relevant and reliable real-world data point available. Based on this comparison, BVES concludes that:

1. The escalated 2013 A-5 estimate remains reasonable, as it is directionally consistent with the cost of connecting a similarly sized customer.

2. If anything, the estimate is slightly conservative, given that the actual A-4 interconnection cost exceeded the escalated A-5 estimate by roughly $100,000.

3. No evidence suggests that the 2013 estimate understates future A-5 interconnection costs, and the available data supports its continued use for developing A-5 marginal customer costs.

Accordingly, BVES has reviewed the available information and determined that the escalated 2013 estimate continues to provide a reasonable and supportable basis for estimating the cost of connecting an A-5 customer in 2027.

8. Please provide the recorded A-5 Primary usage for 2025.

RESPONSE: See Excel file, "CONFIDENTIAL 2025-26 BVE Monthly Revenue detail 0510."

9. Please identify the specific distribution substations that serve the A5-Primary customer class. Please provide a figure showing which distribution substations serve the A5-Primary customer class.

RESPONSE: The A-5 Primary rate class is served through the Company's integrated transmission and distribution system. Please refer to the Company's response to Question 12, which identifies the distribution substations associated with facilities currently serving the A-5 Primary customers.

10. From January 2025 to the present:
    a. Please identify each hour when BVES interrupted or curtailed customer load.

       Response: Please see the attached document titled "CONFIDENTIAL BVES Load Restrictions Log 2025–2026," which identifies each hour during which BVES interrupted or curtailed customer load during non-PSPS events.

    b. For each event of interruption or curtailment of customer load identified in your response to Request 10.a, please identify whether the interruption or curtailment was required due to a lack of generation capacity, lack of transfer capability between SCE and BVES, issues on the transmission system, issues on the distribution system, or some other reason.

Response: The cause of each interruption or curtailment is identified in the "CONFIDENTIAL BVES Load Restrictions Log 2025–2026" document referenced in Response 10.a. The log specifies, for each event, whether the curtailment resulted from generation capacity limitations, transfer constraints between SCE and BVES, transmission system issues, distribution system issues, or other operational factors.

c. For each event of interruption or curtailment of customer load identified in your response to Request 10.a, please state the specific reason that BVES needed to interrupt or curtail customer load and identify the number of customers in each customer class affected by the curtailment or interruption.

   Response: BVES does not track interruptions due to outages or limits on SCE lines. BVES reports all outages due to unexpected events/issues on BVES system per CPUC requirements.

d. For the period from January 1, 2025, to the present, please identify all hours when one or more units of the Bear Valley Power Plant were on outage or were otherwise unavailable to provide service. For each such hour, please identify the units that were on outage or otherwise unavailable and the reason each unit was on outage or otherwise unavailable.

   Response: BVPP Generation Unit 5 was out for maintenance service from 5/27/25 – 8/15/25.

e. Please identify the hourly loading (on a MW and percentage basis) on BVES's interties with SCE at the Goldhill Transfer Station and the Harnish Metering Station, respectively, for the period from January 2025 to the present. Please provide this information in Excel.

   Response: Please see spreadsheets in Shay.zip, Radford.zip, and Baldwin.zip, as well as aggregate data for January – August of 2025 in Stations_MV90.xlsx.

11. With regard to the Snow Summit substations:

   a. Are the Snow Summit substations included in BVES's plant in service?

      Response: Yes

   b. When were the Snow Summit substations first booked to plant in service?

      Response: November 2025

   c. What is the original amount booked to plant in service for the Snow Summit substations?

      Response: $12,249,598.15

   d. What is the current depreciated book value booked to plant in service for the Snow Summit substations?

      Response: $11,616,135.99

e. Is BVES authorized to earn a rate of return on the undepreciated rate base associated with the Snow Summit substations?

Response: As described in Rule 2(H)(2)(c)(3) (https://www.bvesinc.com/assets/bvesinc/rules/rule-2.pdf), the Monthly Ownership Charge (MOC) payment includes a rate of return on the undepreciated rate base associated with the Snow Summit substations. In this case, BVES does earn a rate of return on the undepreciated rate base, which BVES recovers from Snow Summit.

f. Is the $1,810,512 shown for Added Facility Charges in Table 4J on p. 53 of Volume 1 of BVES's testimony the payment Snow Summit makes under its Added Facilities Agreement with BVES?
Response: The current MOC payment from Snow Summit is $1,835,676. The $1,801,512 on Table 4J was based upon an estimate at the time of filing.

g. Were the costs of the Snow Summit substations included in the development of marginal substation costs? If so, did the marginal cost analysis also consider the Monthly Ownership Charge that BVES receives from Snow Summit to cover the cost of the Snow Summit substations?

Response: Yes. The development of marginal substation costs includes costs of the Snow Summit substation.

The Monthly Ownership Charge does not reduce or offset the A-5 marginal costs. Rather, it is separately recognized as revenue from A-5 customers, in addition to base rate revenues. Please refer to "BVES MCS Rate Design_vFinal (CONFIDENTIAL).xlsx," Tab: "Target Revenues," Row 23.

12. Please provide the following information about BVES's transmission and distribution substations:

   a. A figure showing which transmission and distribution facilities serve customers in the A5-Primary customer class.
   b. For each substation, please provide the following:
      1. The name of the substation.
      2. The date that the substation entered service.
      3. The summer and winter ratings of the substations (in MVA).
      4. The voltage of the substation (in kV).
      5. If the facility provides service to customers in the A5-Primary customer class.

RESPONSE:

a. **Response:** The A-5 Primary rate class is served through the Company's integrated transmission and distribution system. Please refer to the table below for transmission and distribution facilities associated with serving A-5 Primary customers.

b. **Response:**

Substation	Circuit	Approx Service Date	Rating (MVA)	Voltage (kV)	A5 Customer?

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BVES Load Restrictions Log 2025_2026

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

This document is considered to be confidential document, protected under Cal. Gov. Code 7927.705, Cal. Evid. Code §1060, Civ. Code §3426.1(d), Penal Code §499c(a)(9), and Pub. Util. Code §583.

[redacted]

[redacted]

BVES Response to Snow Summit Data Request 7, Question 3c.

Application 26-01-022
Seventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 1, 2026

1. Please provide the hourly loads for the A5-P accounts for Snow Summit and Big Bear Mountain for the period from January 1, 2024 to the present. Please disaggregate the hourly loads for each meter at which Snow Summit or Big Bear Mountain takes delivery on the A5-P tariff. Please indicate the point of interconnection for each meter. Please provide this information in the format used in BVES's response to Snow Summit's Second Set of Data Requests, Request 8. Please provide this response in Excel.

   RESPONSE: Attached is a file named "2024 A5 Primary Customer Hourly.csv" with 2024 hourly A5 customer specific demands. The point of interconnection for Bear Mountain ("Customer") is located at the customer switchgear building where BVES metering is located. The point of interconnection for Snow Summit ("Customer") is located at the customer switchgear building, but BVES metering is located at the BVES Snow Summit Substation.

2. Refer to BVES's response to Snow Summit Data Request Set 4, Request 3. In its response, BVES states that "1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads". Please respond to the following questions:
   a. Please explain how BVES calibrated its "initial rate class hourly loads" to "system 2025 hourly loads." Should this reference be to "system 2024 hourly loads?"

      RESPONSE: It should be 2024 system hourly loads (a correction is made to the answer to June 3rd Response 1b).

   b. What was the basis of the "initial rate class hourly loads?"

      RESPONSE: BVES load research sample rate class weighted average hourly loads and 2024 BVES calendar monthly sales by class with losses.

   c. On what date did BVES perform this calibration?

      RESPONSE: May 7, 2025

   d. Does this response imply that the curtailments of Snow Summit deliveries in the fourth quarter of 2025 are reflected in the hourly loads in BVES's "Hourly kWh" used in its MCS model?

      RESPONSE: 2025 hourly kWh in the MCS model based on 2025 monthly sales forecast with losses.

3. Refer to BVES's response to Snow Summit Data Request Set 4, Request 4. Please respond to the following requests:
    a. Does BVES believe that 2024 is a typical year for customer hourly loads for A5-P customers? If so, please explain the reasons for BVES's belief.

       RESPONSE: No historic hourly analysis has been performed on historic A5-P customers. The 2024 hourly A5-P shapes are only used to spread the 2025-2030 monthly A5-P sales forecast into hourly values.

    b. Please explain why it is appropriate for use 2024 as the basis for hourly loads for 2025-203 for A5-P customers.

       RESPONSE: 2024 is the most recent rate class hourly loads available to spread 2025-2030 monthly rate class sales forecasts into hourly values.

    c. Does BVES believe that the frequency of curtailments and interruptions of customer loads for A5-P customers in 2024 are likely to be the same as the frequency of curtailments and interruptions as for 2025-2030? If so, please explain the reasons for BVES's belief.

       RESPONSE: BVES cannot predict whether the frequency of A5-P customer curtailments or interruptions during 2025–2030 will be similar to 2024. Curtailments are driven by real-time system conditions, including weather, holiday timing, and local peak demand. Because these factors are inherently variable, BVES does not plan curtailments in advance and cannot determine whether 2024 or any future year represents typical operating conditions.

    d. Does BVES believe that the relative magnitude of curtailments and interruptions for customer loads for A5-P customers for 2024 are likely to be the same as the relative magnitude of curtailments and interruptions for 2025-2030. For purposes of this question, "relative magnitude" means percentage of otherwise requested loads after curtailments and interruptions. For example, if A5-P customers desired 10 MW in an hour in 2024 and BVES only delivered 7 MW, then the relative magnitude of curtailment in that hour would be 30% ((10 MW – 7 MW)/10 MW).

       RESPONSE: See 3.c above.

4. Refer to BVES's response to Snow Summit Data Request Set 4, Request 10. Please explain why the GRC forecasted usage for each month exceeds the actual usage for those months. Please provide workpapers supporting your response. Please also provide copies of all material upon which your response is based.

   RESPONSE: 2025-2031 A5 Primary forecasts are based on 2022-2024 average monthly sales and expected expanded load for Snow Summit.

5. Please provide a listing of each and every curtailment or interruption of deliveries to Snow Summit and Bear Mountain ordered by BVES from September 1, 2019 to the

present. Please disaggregate your response by customer. If available, please disaggregate your response by point of delivery to Snow Summit and Bear Mountain. If available, please indicate the duration of each curtailment or interruption. If BVES does not have data available for the entire period from September 1, 2019 to the present, please provide all data that are available for that period. Please provide your response in Excel.

RESPONSE: BVES doesn't have any additional information other than what was already provided in its response to Snow Summit's Second Set of Data Requests, Request 10.

6. Refer to BVES's response to Snow Summit Data Request Set 5, Request 5. Does BVES contend that it has no data related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024? If your response is anything other than an unqualified "yes", please provide all information in BVES's possession related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024.
RESPONSE: Yes

7. Refer to BVES's development of marginal distribution costs and marginal substation costs in its MCS model. Please provide the following information regarding BVES's development of those marginal costs:
   a. The theoretical basis upon which BVES relies for using this approach.

      RESPONSE: BVES relies on a variation of the NERA Regression method to estimate the marginal distribution and marginal substation cost in its MCS model.

   b. All citations to documents explaining the theoretical basis for BVES using this approach for determination of marginal distribution and marginal distribution substation costs.

      RESPONSE: The NERA Regression method has been utilized in the industry for determination of marginal distribution costs, including by other California Investor-Owned Utilities. For example, Southern California Edison and San Diego Gas & Electric utilized the NERA Regression method in A. 20-10-012 and A. 23-01-008 respectively. In addition, BVES utilized the method in its past two rate case applications.

   c. Is BVES aware of the so-called "NERA method" for determining marginal distribution costs? If so, please explain BVES's understanding of the NERA method for determining marginal distribution costs. Does BVES contend that it is using the "NERA method" in this proceeding? If so, where is BVES using it and how.

      RESPONSE: Yes. Please refer to responses to parts 7(a) and 7(b). BVES has utilized a variation of the NERA Regression method for determining marginal distribution capacity costs.

BVES' understanding of the NERA method is as follows. The NERA method is a regression-based approach for estimating marginal distribution demand costs by measuring the relationship between cumulative incremental distribution investments and cumulative system load growth. The regression analysis treats load growth as the independent variable and distribution investments as the dependent variable. The analysis produces an estimated marginal cost of distribution capacity, expressed in dollars per kW.

8. Refer to the SAS code provided in response to Snow Summit's Data Request Set 4, Request 3. Please respond to the following request:
    a. Please provide copies of all input files to and output files from that SAS program as it was used in the development of BVES's hourly load forecasts used in this proceeding. Please provide your response in Excel. Please provide your response in the format used by the SAS program. Please ensure that the names of the files and the file formats of the files are the same as the files used in the SAS code.

        RESPONSE:
        Input files for monthly sales and 2024 hourly load research sales are included as part of response to this data request: 2024_class_hourly.csv, mo_forecast_with_losses.csv
        Output file: fohr25_3127.csv attached.

9. Please provide the following information about the operation of the BVES generating, transmission, and distribution system for each hour in 2024 and 2027 (in Excel):
    a. The hourly maximum transfer capability between SCE and BVES. Please indicate the transfer capability for each point of interconnection between SCE and BVES.

        RESPONSE: BVES has SCE contractual limits of 34 MW at Goldhill and 5 MW at Radford/Bear Valley and import capacity is available 24/7/365. 2024 load data is attached in file, "2024 Load" and 2027 is the supply forecast previously provided.

    b. The maximum hourly generating capacity of the Bear Valley Power Plant.

        RESPONSE: 8.4 MW, available 24/7/365 except during maintenance windows.

    c. The hourly maximum hourly generating capacity from any other BVES owned power plants within the BVES service territory.

        RESPONSE: BVES does not own any other power plants.

    d. The maximum hourly generating capacity for all non-utility generating units (e.g., NEM, distributed energy resources) on the BVES system. Please indicate the total capacity of NEM generators on the BVES. Please provide the names and generating capacity of each distributed energy resource on the BVES system.

BVES Response to Snow Summit Data Request 7, Question 3a.

Application 26-01-022
Seventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 1, 2026

1. Please provide the hourly loads for the A5-P accounts for Snow Summit and Big Bear Mountain for the period from January 1, 2024 to the present. Please disaggregate the hourly loads for each meter at which Snow Summit or Big Bear Mountain takes delivery on the A5-P tariff. Please indicate the point of interconnection for each meter. Please provide this information in the format used in BVES's response to Snow Summit's Second Set of Data Requests, Request 8. Please provide this response in Excel.

   RESPONSE: Attached is a file named "2024 A5 Primary Customer Hourly.csv" with 2024 hourly A5 customer specific demands. The point of interconnection for Bear Mountain ("Customer") is located at the customer switchgear building where BVES metering is located. The point of interconnection for Snow Summit ("Customer") is located at the customer switchgear building, but BVES metering is located at the BVES Snow Summit Substation.

2. Refer to BVES's response to Snow Summit Data Request Set 4, Request 3. In its response, BVES states that "1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads". Please respond to the following questions:
   a. Please explain how BVES calibrated its "initial rate class hourly loads" to "system 2025 hourly loads." Should this reference be to "system 2024 hourly loads?"

      RESPONSE: It should be 2024 system hourly loads (a correction is made to the answer to June 3rd Response 1b).

   b. What was the basis of the "initial rate class hourly loads?"

      RESPONSE: BVES load research sample rate class weighted average hourly loads and 2024 BVES calendar monthly sales by class with losses.

   c. On what date did BVES perform this calibration?

      RESPONSE: May 7, 2025

   d. Does this response imply that the curtailments of Snow Summit deliveries in the fourth quarter of 2025 are reflected in the hourly loads in BVES's "Hourly kWh" used in its MCS model?

      RESPONSE: 2025 hourly kWh in the MCS model based on 2025 monthly sales forecast with losses.

3. Refer to BVES's response to Snow Summit Data Request Set 4, Request 4. Please respond to the following requests:
   a. Does BVES believe that 2024 is a typical year for customer hourly loads for A5-P customers? If so, please explain the reasons for BVES's belief.

      RESPONSE: No historic hourly analysis has been performed on historic A5-P customers. The 2024 hourly A5-P shapes are only used to spread the 2025-2030 monthly A5-P sales forecast into hourly values.

   b. Please explain why it is appropriate for use 2024 as the basis for hourly loads for 2025-203 for A5-P customers.

      RESPONSE: 2024 is the most recent rate class hourly loads available to spread 2025-2030 monthly rate class sales forecasts into hourly values.

   c. Does BVES believe that the frequency of curtailments and interruptions of customer loads for A5-P customers in 2024 are likely to be the same as the frequency of curtailments and interruptions as for 2025-2030? If so, please explain the reasons for BVES's belief.

      RESPONSE: BVES cannot predict whether the frequency of A5-P customer curtailments or interruptions during 2025–2030 will be similar to 2024. Curtailments are driven by real-time system conditions, including weather, holiday timing, and local peak demand. Because these factors are inherently variable, BVES does not plan curtailments in advance and cannot determine whether 2024 or any future year represents typical operating conditions.

   d. Does BVES believe that the relative magnitude of curtailments and interruptions for customer loads for A5-P customers for 2024 are likely to be the same as the relative magnitude of curtailments and interruptions for 2025-2030. For purposes of this question, "relative magnitude" means percentage of otherwise requested loads after curtailments and interruptions. For example, if A5-P customers desired 10 MW in an hour in 2024 and BVES only delivered 7 MW, then the relative magnitude of curtailment in that hour would be 30% ((10 MW – 7 MW)/10 MW).

      RESPONSE: See 3.c above.

4. Refer to BVES's response to Snow Summit Data Request Set 4, Request 10. Please explain why the GRC forecasted usage for each month exceeds the actual usage for those months. Please provide workpapers supporting your response. Please also provide copies of all material upon which your response is based.

   RESPONSE: 2025-2031 A5 Primary forecasts are based on 2022-2024 average monthly sales and expected expanded load for Snow Summit.

5. Please provide a listing of each and every curtailment or interruption of deliveries to Snow Summit and Bear Mountain ordered by BVES from September 1, 2019 to the

present. Please disaggregate your response by customer. If available, please disaggregate your response by point of delivery to Snow Summit and Bear Mountain. If available, please indicate the duration of each curtailment or interruption. If BVES does not have data available for the entire period from September 1, 2019 to the present, please provide all data that are available for that period. Please provide your response in Excel.

RESPONSE: BVES doesn't have any additional information other than what was already provided in its response to Snow Summit's Second Set of Data Requests, Request 10.

6. Refer to BVES's response to Snow Summit Data Request Set 5, Request 5. Does BVES contend that it has no data related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024? If your response is anything other than an unqualified "yes", please provide all information in BVES's possession related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024.
RESPONSE: Yes

7. Refer to BVES's development of marginal distribution costs and marginal substation costs in its MCS model. Please provide the following information regarding BVES's development of those marginal costs:
    a. The theoretical basis upon which BVES relies for using this approach.

       RESPONSE: BVES relies on a variation of the NERA Regression method to estimate the marginal distribution and marginal substation cost in its MCS model.

    b. All citations to documents explaining the theoretical basis for BVES using this approach for determination of marginal distribution and marginal distribution substation costs.

       RESPONSE: The NERA Regression method has been utilized in the industry for determination of marginal distribution costs, including by other California Investor-Owned Utilities. For example, Southern California Edison and San Diego Gas & Electric utilized the NERA Regression method in A. 20-10-012 and A. 23-01-008 respectively. In addition, BVES utilized the method in its past two rate case applications.

    c. Is BVES aware of the so-called "NERA method" for determining marginal distribution costs? If so, please explain BVES's understanding of the NERA method for determining marginal distribution costs. Does BVES contend that it is using the "NERA method" in this proceeding? If so, where is BVES using it and how.

       RESPONSE: Yes. Please refer to responses to parts 7(a) and 7(b). BVES has utilized a variation of the NERA Regression method for determining marginal distribution capacity costs.

BVES' understanding of the NERA method is as follows. The NERA method is a regression-based approach for estimating marginal distribution demand costs by measuring the relationship between cumulative incremental distribution investments and cumulative system load growth. The regression analysis treats load growth as the independent variable and distribution investments as the dependent variable. The analysis produces an estimated marginal cost of distribution capacity, expressed in dollars per kW.

8. Refer to the SAS code provided in response to Snow Summit's Data Request Set 4, Request 3. Please respond to the following request:
    a. Please provide copies of all input files to and output files from that SAS program as it was used in the development of BVES's hourly load forecasts used in this proceeding. Please provide your response in Excel. Please provide your response in the format used by the SAS program. Please ensure that the names of the files and the file formats of the files are the same as the files used in the SAS code.

    RESPONSE:
    Input files for monthly sales and 2024 hourly load research sales are included as part of response to this data request: 2024_class_hourly.csv,
    mo_forecast_with_losses.csv
    Output file: fohr25_3127.csv attached.

9. Please provide the following information about the operation of the BVES generating, transmission, and distribution system for each hour in 2024 and 2027 (in Excel):
    a. The hourly maximum transfer capability between SCE and BVES. Please indicate the transfer capability for each point of interconnection between SCE and BVES.

    RESPONSE: BVES has SCE contractual limits of 34 MW at Goldhill and 5 MW at Radford/Bear Valley and import capacity is available 24/7/365. 2024 load data is attached in file, "2024 Load" and 2027 is the supply forecast previously provided.

    b. The maximum hourly generating capacity of the Bear Valley Power Plant.

    RESPONSE: 8.4 MW, available 24/7/365 except during maintenance windows.

    c. The hourly maximum hourly generating capacity from any other BVES owned power plants within the BVES service territory.

    RESPONSE: BVES does not own any other power plants.

    d. The maximum hourly generating capacity for all non-utility generating units (e.g., NEM, distributed energy resources) on the BVES system. Please indicate the total capacity of NEM generators on the BVES. Please provide the names and generating capacity of each distributed energy resource on the BVES system.

BVES Response to Snow Summit Data Request 7, Question 3b.

Application 26-01-022
Seventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 1, 2026

1. Please provide the hourly loads for the A5-P accounts for Snow Summit and Big Bear Mountain for the period from January 1, 2024 to the present. Please disaggregate the hourly loads for each meter at which Snow Summit or Big Bear Mountain takes delivery on the A5-P tariff. Please indicate the point of interconnection for each meter. Please provide this information in the format used in BVES's response to Snow Summit's Second Set of Data Requests, Request 8. Please provide this response in Excel.

   RESPONSE: Attached is a file named "2024 A5 Primary Customer Hourly.csv" with 2024 hourly A5 customer specific demands. The point of interconnection for Bear Mountain ("Customer") is located at the customer switchgear building where BVES metering is located. The point of interconnection for Snow Summit ("Customer") is located at the customer switchgear building, but BVES metering is located at the BVES Snow Summit Substation.

2. Refer to BVES's response to Snow Summit Data Request Set 4, Request 3. In its response, BVES states that "1) spreadsheet starting "2024 Big Bear Class" - calibrates initial rate class hourly loads to system 2025 hourly loads". Please respond to the following questions:
   a. Please explain how BVES calibrated its "initial rate class hourly loads" to "system 2025 hourly loads." Should this reference be to "system 2024 hourly loads?"

      RESPONSE: It should be 2024 system hourly loads (a correction is made to the answer to June 3rd Response 1b).

   b. What was the basis of the "initial rate class hourly loads?"

      RESPONSE: BVES load research sample rate class weighted average hourly loads and 2024 BVES calendar monthly sales by class with losses.

   c. On what date did BVES perform this calibration?

      RESPONSE: May 7, 2025

   d. Does this response imply that the curtailments of Snow Summit deliveries in the fourth quarter of 2025 are reflected in the hourly loads in BVES's "Hourly kWh" used in its MCS model?

      RESPONSE: 2025 hourly kWh in the MCS model based on 2025 monthly sales forecast with losses.

3. Refer to BVES's response to Snow Summit Data Request Set 4, Request 4. Please respond to the following requests:
    a. Does BVES believe that 2024 is a typical year for customer hourly loads for A5-P customers? If so, please explain the reasons for BVES's belief.

       RESPONSE: No historic hourly analysis has been performed on historic A5-P customers. The 2024 hourly A5-P shapes are only used to spread the 2025-2030 monthly A5-P sales forecast into hourly values.

    b. Please explain why it is appropriate for use 2024 as the basis for hourly loads for 2025-203 for A5-P customers.

       RESPONSE: 2024 is the most recent rate class hourly loads available to spread 2025-2030 monthly rate class sales forecasts into hourly values.

    c. Does BVES believe that the frequency of curtailments and interruptions of customer loads for A5-P customers in 2024 are likely to be the same as the frequency of curtailments and interruptions as for 2025-2030? If so, please explain the reasons for BVES's belief.

       RESPONSE: BVES cannot predict whether the frequency of A5-P customer curtailments or interruptions during 2025–2030 will be similar to 2024. Curtailments are driven by real-time system conditions, including weather, holiday timing, and local peak demand. Because these factors are inherently variable, BVES does not plan curtailments in advance and cannot determine whether 2024 or any future year represents typical operating conditions.

    d. Does BVES believe that the relative magnitude of curtailments and interruptions for customer loads for A5-P customers for 2024 are likely to be the same as the relative magnitude of curtailments and interruptions for 2025-2030. For purposes of this question, "relative magnitude" means percentage of otherwise requested loads after curtailments and interruptions. For example, if A5-P customers desired 10 MW in an hour in 2024 and BVES only delivered 7 MW, then the relative magnitude of curtailment in that hour would be 30% ((10 MW – 7 MW)/10 MW).

       RESPONSE: See 3.c above.

4. Refer to BVES's response to Snow Summit Data Request Set 4, Request 10. Please explain why the GRC forecasted usage for each month exceeds the actual usage for those months. Please provide workpapers supporting your response. Please also provide copies of all material upon which your response is based.

   RESPONSE: 2025-2031 A5 Primary forecasts are based on 2022-2024 average monthly sales and expected expanded load for Snow Summit.

5. Please provide a listing of each and every curtailment or interruption of deliveries to Snow Summit and Bear Mountain ordered by BVES from September 1, 2019 to the

present. Please disaggregate your response by customer. If available, please disaggregate your response by point of delivery to Snow Summit and Bear Mountain. If available, please indicate the duration of each curtailment or interruption. If BVES does not have data available for the entire period from September 1, 2019 to the present, please provide all data that are available for that period. Please provide your response in Excel.

RESPONSE: BVES doesn't have any additional information other than what was already provided in its response to Snow Summit's Second Set of Data Requests, Request 10.

6. Refer to BVES's response to Snow Summit Data Request Set 5, Request 5. Does BVES contend that it has no data related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024? If your response is anything other than an unqualified "yes", please provide all information in BVES's possession related to the curtailment or interruption of customers in the Schedule A5-P customer class for the period from 2020 through 2024.
RESPONSE: Yes

7. Refer to BVES's development of marginal distribution costs and marginal substation costs in its MCS model. Please provide the following information regarding BVES's development of those marginal costs:
   a. The theoretical basis upon which BVES relies for using this approach.

      RESPONSE: BVES relies on a variation of the NERA Regression method to estimate the marginal distribution and marginal substation cost in its MCS model.

   b. All citations to documents explaining the theoretical basis for BVES using this approach for determination of marginal distribution and marginal distribution substation costs.

      RESPONSE: The NERA Regression method has been utilized in the industry for determination of marginal distribution costs, including by other California Investor-Owned Utilities. For example, Southern California Edison and San Diego Gas & Electric utilized the NERA Regression method in A. 20-10-012 and A. 23-01-008 respectively. In addition, BVES utilized the method in its past two rate case applications.

   c. Is BVES aware of the so-called "NERA method" for determining marginal distribution costs? If so, please explain BVES's understanding of the NERA method for determining marginal distribution costs. Does BVES contend that it is using the "NERA method" in this proceeding? If so, where is BVES using it and how.

      RESPONSE: Yes. Please refer to responses to parts 7(a) and 7(b). BVES has utilized a variation of the NERA Regression method for determining marginal distribution capacity costs.

BVES' understanding of the NERA method is as follows. The NERA method is a regression-based approach for estimating marginal distribution demand costs by measuring the relationship between cumulative incremental distribution investments and cumulative system load growth. The regression analysis treats load growth as the independent variable and distribution investments as the dependent variable. The analysis produces an estimated marginal cost of distribution capacity, expressed in dollars per kW.

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    a. Please provide copies of all input files to and output files from that SAS program as it was used in the development of BVES's hourly load forecasts used in this proceeding. Please provide your response in Excel. Please provide your response in the format used by the SAS program. Please ensure that the names of the files and the file formats of the files are the same as the files used in the SAS code.

    RESPONSE:
    Input files for monthly sales and 2024 hourly load research sales are included as part of response to this data request: 2024_class_hourly.csv, mo_forecast_with_losses.csv
    Output file: fohr25_3127.csv attached.

9. Please provide the following information about the operation of the BVES generating, transmission, and distribution system for each hour in 2024 and 2027 (in Excel):
    a. The hourly maximum transfer capability between SCE and BVES. Please indicate the transfer capability for each point of interconnection between SCE and BVES.

    RESPONSE: BVES has SCE contractual limits of 34 MW at Goldhill and 5 MW at Radford/Bear Valley and import capacity is available 24/7/365. 2024 load data is attached in file, "2024 Load" and 2027 is the supply forecast previously provided.

    b. The maximum hourly generating capacity of the Bear Valley Power Plant.

    RESPONSE: 8.4 MW, available 24/7/365 except during maintenance windows.

    c. The hourly maximum hourly generating capacity from any other BVES owned power plants within the BVES service territory.

    RESPONSE: BVES does not own any other power plants.

    d. The maximum hourly generating capacity for all non-utility generating units (e.g., NEM, distributed energy resources) on the BVES system. Please indicate the total capacity of NEM generators on the BVES. Please provide the names and generating capacity of each distributed energy resource on the BVES system.

ATTACHMENT 3

EXCERPTS FROM DOCUMENTS REFERENCED IN TESTIMONY

Excerpt from BVES Advice Letter 452-E

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Bear Valley Electric Service, Inc.
ELC (Corp ID 913)
Status of Advice Letter 452E
As of October 18, 2022

Subject: Snow Summit Added Facilities Agreement

Division Assigned: Energy

Date Filed: 09-20-2022

Date to Calendar: 09-23-2022

Authorizing Documents: D1908027

Disposition:	**Accepted**
Effective Date:	**09-20-2022**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

Nguyen Quan
(909) 394-3600 X664
RegulatoryAffairs@bvesinc.com

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Bear Valley Electric Service, Inc (913-E)

Utility type:
- ☐ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Nguyen Quan
Phone #: (909) 394-3600 x664
E-mail: RegulatoryAffairs@bvesinc.com
E-mail Disposition Notice to: RegulatoryAffairs@bvesinc.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 452-E

Tier Designation: 1

Subject of AL: Snow Summit Added Facilities Agreement

Keywords (choose from CPUC listing): Compliance

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ✓ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.19-08-027

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? Yes ✓ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? Yes ✓ No

Requested effective date: 9/20/22

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: see Advice Letter

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Nguyen Quan
Title: Regulatory Affairs Manager
Utility Name: Bear Valley Electric Service, Inc
Address: 630 E. Foothill Blvd
City: San Dimas State: California
Telephone (xxx) xxx-xxxx: (909) 394-3600 x 664
Facsimile (xxx) xxx-xxxx: None
Email: RegulatoryAffairs@bvesinc.com; nquan@gswater.com

Name: Ronald Moore
Title: Regulatory Affairs Dept.
Utility Name: Bear Valley Electric Service, Inc
Address: 630 E. Foothill Blvd
City: San Dimas State: California
Telephone (xxx) xxx-xxxx: (909) 394-3600 x 682
Facsimile (xxx) xxx-xxxx: None
Email: RegulatoryAffairs@bvesinc.com; rkmoore@gswater.com

Clear Form

Bear Valley Electric Service, Inc.
P.O. Box 9028
San Dimas, CA 91773-9028
A Subsidiary of American States Water Company

September 20, 2022

Advice Letter No. 452-E **(913 E)**

California Public Utilities Commission

Bear Valley Electric Service, Inc. ("BVES") hereby transmits for filing the following:

SUBJECT: *Snow Summit Added Facilities Agreement*

PURPOSE

In compliance with Ordering Paragraph #10 of California Public Utilities Commission ("Commission") Decision No. ("D.") 19-08-027, dated August 15, 2019, BVES hereby submits this Tier 1 Advice Letter, with an effective date of September 20, 2022.

Ordering Paragraph #10 in D. 19-08-027 states,

> *Golden State Water Company, on behalf of Bear Valley Electric Service Division, is authorized to file a Tier 1 advice letter if and when an agreement is reached with Snow Summit, Inc. regarding supplemental service consistent with the utility's proposal contained in Special Request #1 in accordance with Section 8.1 of the Settlement Agreement. If an agreement is materially different than the provisions of Special Request #1, the utility is authorized to file a Tier 3 Advice Letter with an explanation of the material changes.*

Additionally, Section 8.1 of the Settlement Agreement adopted by D.19-08-027 (the "Settlement Agreement") states in relevant part:

> *The Settling Parties agree that BVES may offer supplemental service to Snow Summit as provided in Special Request #1, attached as Exhibit C hereto, and BVES may implement the revised Rule 2H and the two Additional Facilities Agreements (included as part of Special Request #1) by filing a Tier 1 Advice Letter. Bear Valley shall file a Tier 1 Advice Letter if and when an agreement consistent with the provisions of Special Request #1 is reached between BVES and Snow Summit regarding supplemental service to Snow Summit.*[1] *(emphasis added) If an agreement between BVES and Snow Summit regarding supplemental service is materially different than the provisions of Special Request #1, such an agreement shall be filed*

[1] See D.19-08-027, (Amended) Appendix A, Settlement Agreement, Section 8.1, Special Request #1, Snow Summit Supplemental Service.

with the Commission via a Tier 3 advice letter with an explanation of the material changes.

On August 29, 2022, BVES and Snow Summit, LLC ("Snow Summit") executed an Added Facilities Agreement (the "Added Facilities Agreement"). The Added Facilities Agreement, as executed, is not materially different from the provisions of the Added Facilities Agreement included as part of Special Request #1 of Section 8.1 of the Settlement Agreement. Accordingly, a Tier 1 advice letter filing seeking approval of the Added Facilities Agreement is authorized and appropriate. The executed Added Facilities Agreement is included as Attachment A to this advice letter.

BACKGROUND

Golden State Water Company ("GSWC"), on behalf of its BVES Division, submitted its General Rate Case Application No. ("A.") 17-05-004 [2], which included Special Request #1, which sought approval to provide supplemental service to its largest customer, Snow Summit. Special Request #1 also sought approval of a revised Rule 2H and two proposed versions of an Added Facilities Agreement.

A settlement agreement was reached ("Settlement Agreement") and the Commission approved it in D.19-08-027. Section 8.1 of the Settlement Agreement includes authorization to provide supplemental service to the Snow Summit Ski Resort, and implementation of the revised Rule 2H and the two Additional Facilities Agreements.

On March 15, 2021, BVES filed Advice Letter No. 415-E, seeking approval of the revised Rule 2H and the two proposed Added Facilities Agreements. Advice Letter No. 415-E was approved, effective March 15, 2021.

The revised Rule 2H provides that if BVES determines there are unacceptable credit risks regarding the collection of continuing monthly ownership charges, the applicant will be required to provide credit enhancement measures acceptable to BVES in its sole opinion. BVES determined that there were unacceptable credit risks regarding the proposed supplemental service to Snow Summit. A Credit Enhancement Agreement, executed by BVES and Snow Summit on August 31, 2022, provides credit enhancement measures acceptable to BVES in its sole opinion, and is attached hereto for informational purposes only. The executed Credit Enhancement Agreement is included as Attachment B to this advice letter.

COMPLIANCE

This advice letter is in full compliance with D.19-08-027.

TIER DESIGNATION

This advice letter is submitted with a Tier 1 designation.

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[2] Effective July 1, 2020, BVES was no longer a Division of GSWC and became a separate wholly-owned subsidiary of American States Water Company.

EFFECTIVE DATE

BVES respectfully requests this advice letter become effective on September 20, 2022.

NOTICE AND PROTESTS

A protest is a document objecting to the granting in whole or in part of the authority sought in this advice letter. A response is a document that does not object to the authority sought, but nevertheless presents information that the party tendering the response believes would be useful to the CPUC in acting on the request.

A protest must be mailed within 20 days of the date the CPUC accepts the advice letter for filing. The Calendar is available on the CPUC's website at www.cpuc.ca.gov.

A protest must state the facts constituting the grounds for the protest, the effect that approval of the advice letter might have on the protestant, and the reasons the protestant believes the advice letter, or a part of it, is not justified. If the protest requests an evidentiary hearing, the protest must state the facts the protestant would present at an evidentiary hearing to support its request for whole or partial denial of the advice letter.

The utility must respond to a protest within five days.

All protests and responses should be sent to:
California Public Utilities Commission, Energy Division
ATTN: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

Copies of any such protests should be sent to this utility at:

Bear Valley Electric Service, Inc.
ATTN: Nguyen Quan
630 East Foothill Blvd.
San Dimas, CA 91773
Fax: 909-394-7427
E-mail: RegulatoryAffairs@bvesinc.com

If you have not received a reply to your protest within 10 business days, contact Nguyen Quan at (909) 394-3600 ext. 664.

Correspondence:

Any correspondence regarding this compliance filing should be sent by regular mail or e-mail to the attention of:

Nguyen Quan
Manager, Regulatory Affairs
Bear Valley Electric Service, Inc.
630 East Foothill Blvd.
San Dimas, California 91773
Email: RegulatoryAffairs@bvesinc.com

The protest shall set forth the grounds upon which it is based and shall be submitted expeditiously. There is no restriction on who may file a protest.

Sincerely,

/s/Ronald Moore
Ronald Moore
Regulatory Affairs Department
Bear Valley Electric Service. Inc.

c:
Laura Martin , Energy Division
R. Mark Pocta, California Public Advocates Office
BVES General Order 96-B Service List

ATTACHMENT A

ADDED FACILITIES AGREEMENT - BVES FINANCED

BEAR VALLEY ELECTRIC SERVICE, INC.

ADDED FACILITIES AGREEMENT

BVES FINANCED

Snow Summit, LLC ("Applicant") and Bear Valley Electric Service, Inc. ("BVES"), referred to collectively as "Parties", and individually as "Party", agree, as an accommodation to the Applicant, that BVES shall install the electric facilities described in Exhibit A, and hereinafter referred to as "Added Facilities", the cost of which shall be borne by the Applicant and which will be located at the service address as shown in Exhibit A. Added Facilities are defined in BVES Tariff Rule 2.H as those which are in addition to, or in substitution for, the standard facilities BVES would normally install to provide electric service. The Parties agree as follows:

1. Applicant shall pay a monthly ownership charge based on the estimated total installed cost for BVES-Financed Added Facilities as set forth in Exhibit A, pursuant to BVES's Tariff Rule 2.H, as filed with the California Public Utilities Commission ("Commission") and as changed from time to time by the Commission. The monthly ownership charge for BVES-Financed Added Facilities includes replacement coverage for the term of this Agreement. Accordingly, the total installed cost of such Added Facilities used as the basis for determining the ownership charge Applicant pays BVES shall not be adjusted during 20-year term of this Agreement whenever Added Facilities are replaced as set forth in Paragraph 12(a).

   With regard to the ownership charge, applicant shall pay to BVES, at BVES' sole option, either (BVES to select one):

   (a) A monthly ownership charge (as described in Rule 2H) based upon the percentage amount of 1.4864%, as set forth in Rule 2.H(2)(c)(1), times the total installed cost of such Added Facilities as set forth in Exhibit A, for the 20- year term of this Agreement, with such credit enhancement measures, if any, deemed necessary in BVES' sole opinion; or

   (b) A one-time, up-front ownership charge payment representing the present worth of the monthly ownership charge for the Added Facilities, as described in subparagraph (a) immediately above, for the 20-year term of this Agreement.

   At the end of the 20-year term, this Agreement terminates in accordance with the provisions of Paragraph 16. If Applicant wants to continue being served from the Added Facilities, Applicant must sign a new Added Facilities Agreement, the terms and conditions of which shall reflect the current cost of service, subject to approval of the Commission.

2. Applicant shall pay to BVES in advance of construction by BVES, any one-time costs (including the Income Tax Component of Contribution (ITCC) when applicable) to rearrange existing facilities and/or to provide facilities normally installed by the Applicant as set forth in Exhibit A.

3. The costs and charges paid by Applicant pursuant to Paragraphs 1 and 2 will normally be based upon estimated costs. When the recorded book costs have been determined by BVES, the charges may be based upon such recorded costs and adjusted retroactively to the date when service was first rendered by means of such Added Facilities. For existing facilities which are allocated for Applicant's use as Added Facilities, the resulting Paragraph 1 charges paid by the Applicant will be based upon the Added Facilities investment amount calculated on a RCNLD basis. Additional charges resulting from such adjustments will, unless other terms are mutually agreed upon, be payable within thirty (30) days from the date of presentation of a bill therefor. Any credits resulting from such adjustments will, unless other terms are mutually agreed upon, be refunded to Applicant.

4. When BVES elects to provide Added Facilities hereunder on a recorded book cost basis, BVES has the right to revise its estimated costs and bill Applicant using such revised estimated costs during the period preceding determination of the recorded book costs. BVES shall indicate such revisions on Exhibit A or a superseding Exhibit A and provide a copy to Applicant. BVES shall commence billing the charge paid by Applicant pursuant to Paragraph 1 above using such revised estimate not earlier than thirty (30) days from the date the revised estimate is provided to Applicant.

5. The monthly ownership charge to be paid by Applicant pursuant to Paragraph 1 as determined in Exhibit A shall automatically increase or decrease without formal amendment to this Agreement if the Commission subsequently authorizes a higher or lower percentage rate in the calculation of the costs of ownership for Added Facilities as stated in Rule 2.H, effective with the date of such authorization.

6. Where it is necessary to install Added Facilities on Applicant's property, Applicant hereby grants to BVES (a) the right to make such installation on Applicant's property including installation of a line extension along the shortest practical route thereon and (b) the right of ingress to and egress from Applicant's property as determined by BVES in its sole discretion for any purpose connected with the operation and maintenance of the Added Facilities. Applicant shall provide rights of way or easements of sufficient space which provide legal clearance from all structures now or hereafter erected on Applicant's property for any facilities of BVES.

7. Where formal rights-of-way or easements are required in, on, under, or over Applicant's property or the property of others for the installation of the Added Facilities, BVES shall not be obligated to install the Added Facilities unless and until any necessary rights-of-way or easements, satisfactory to BVES, are granted without cost to BVES. Upon termination of this Agreement in accordance with Paragraph 16, BVES will quitclaim all easements and rights-of-way in, on, under, and over Applicant's property which are, as determined by BVES in its sole discretion, no longer required by BVES due to the removal of its Added Facilities.

8. BVES shall not be responsible for any delay in completion of the installation of the Added Facilities resulting from shortage of labor or materials, strike, labor disturbances, war, riot, weather conditions, governmental rule, regulation or order, including orders or judgments of any court or commission, delay in obtaining necessary rights-of-way and easements, act of God, or any other cause or condition beyond control of BVES. BVES shall have the right in the event it is unable to obtain materials or labor for all of its construction requirements, to allocate materials and labor to construction projects which it deems, in its sole discretion, most important to serve the needs of its customers, and any delay in construction hereunder resulting from such allocation shall be deemed to be a cause beyond BVES's control.

9. Added Facilities provided hereunder shall at all times remain the property of BVES.

10. This Agreement supplements the appropriate application and contract(s) for electric service presently in effect between the Parties.

11. If it becomes necessary for BVES to alter or rearrange the Added Facilities including, but not limited to, the conversion of overhead facilities to underground, Applicant shall be notified of such necessity and shall be given the option to either terminate this Agreement in accordance with Paragraphs 13 and 16, or to pay to BVES additional charges consisting of:

    (a) The cost to remove any portion of the Added Facilities which is no longer necessary because of alteration or rearrangement, such charge to be determined in the same manner as described in Paragraph 16; plus

    (b) An additional payment (one-time cost), if any, for any work required as defined in Paragraph 2; plus

    (c) A revised Paragraph 1 ownership charge based on the total net additional installed cost of all new and remaining Added Facilities. Such revised ownership charge shall be determined in the same manner as described in Paragraphs 1 and 3.

12.12.

(a) Whenever Added Facilities are replaced due to damage or equipment failure, the work will be completed at BVES' expense.

(b) Whenever Added Facilities are replaced due to Applicant's increased load, such replacement will be at Applicant's expense and the Applicant shall pay BVES a revised Paragraph 1 charge based on the revised Added Facilities investment amount resulting from such replacement.

13. This Agreement shall remain in effect for 20 years or until terminated by either party on at least thirty (30) days' advance written notice. Applicant shall pay all costs incurred to the date of termination pursuant to Paragraph 16 including charges for any engineering, surveying, right-of-way and easement acquisition expenses and other associated expenses incurred by BVES for that portion of the Added Facilities not installed.

14. BVES has the right to charge Applicant under the terms and conditions of this Agreement commencing with the date BVES, in its sole opinion, is ready to serve or commencing with the ready to serve date requested by Applicant, whichever is later.

15. Construction of the Added Facilities shall not commence prior to receipt by BVES of appropriate rights of way and/or easements and Applicant's payment of all monies due as described in Paragraphs 1 and 2.

16. Upon discontinuance of the use of any Added Facilities due to termination of service, termination of this Agreement, or otherwise:

(a) Applicant shall pay to BVES on demand (in addition to all other monies to which BVES may be legally entitled by virtue of such termination) a facility termination charge defined as the installed cost (including any ITCC), plus the removal cost, less the salvage value for the Added Facilities to be removed. Commencing in the sixteenth (16) year after the date service is first rendered by means of Added Facilities, 20 percent of the termination charge shall be subtracted from that charge each year until the total charge is zero.

(b) BVES shall be entitled to remove and shall have a reasonable time in which to remove any portion of the Added Facilities located on the Applicant's property.

(c) BVES may, at its option, alter, rearrange, convey, or retain in place any portion of the Added Facilities off Applicant's property. Where all or any portion of the Added Facilities located off Applicant's property are retained in place and used by BVES to provide permanent service to other customers, the facility termination charge described in Paragraph 16(a) shall be reduced by the installed cost of the retained facilities.

17. Applicant may assign this Agreement only with BVES' written consent. Such consent will not unreasonably be withheld. Furthermore, such assignment shall be deemed to include, unless otherwise specified therein, all of Applicant's rights to any refunds which might become due upon discontinuance of the use of any Added Facilities.

18. This Agreement shall, at all times, be subject to changes or modifications as the Commission may, from time to time, direct in the exercise of its jurisdiction.

19. In witness whereof, the Parties hereto have caused this Agreement to be signed by their duly authorized representatives/agents. This Agreement is effective as of the last date set forth below.

BEAR VALLEY ELECTRIC SERVICE, INC.	APPLICANT
BY:	BY: Wade R
NAME:	NAME: Wade Reeser
TITLE:	TITLE: BBMR President/COO
DATE SIGNED:	DATE SIGNED: 8/29/22

BEAR VALLEY ELECTRIC SERVICE, INC.

ADDED FACILITIES AGREEMENT
BVES FINANCED

EXHIBIT "A"

APPLICANT Snow Summit, LLC____

SERVICE ADDRESS 880 Summit Blvd Big Bear Lake, CA 92315______________________

APPLICANT REQUESTED READY TO SERVE DATE TBD__________________

All estimated Costs Shown in this Exhibit "A" (BVES to Select One):

X are not binding estimates (final billing based on recorded costs), or

_____ are binding estimates valid for Added Facilities completed on or before ___________, ________

DESCRIPTION OF ADDED FACILITIES:

1. Installation of a 10 MVA 34.5 kV to 4.160 kV skid-mounted substation in the vicinity of the Snow Summit Main Generating Facility at the base of the Snow Summit resort. This substation will be referred to as Summit Base Substation. This portion includes constructing the interconnect between the Summit Base Substation and the Snow Summit internal facility switchgear located at the Main Generating Facility to support snowmaking and resort operations as well as the interconnect between the Summit Base Substation and the BVES Summit Residential Circuit.

2. Installation of a 10 MVA 34.5 kV to 4.160 kV skid-mounted substation in the vicinity of the Snow Summit Soko Generating Facility at the top of the Snow Summit Mountain. This substation will be referred to as Summit Top Substation. This portion includes constructing the interconnect between the Summit Top Substation and the Snow Summit internal facility switchgear located at the Soko Generating Facility to support snowmaking and resort operations.

3. Installing the following 34.5kV underground cables:

   - Base to the Summit Top Substation. Underground design will include spare and communication conduit.

   - Across the Snow Summit Resort parking lot to feed both the Summit Base Substation and 34.5 kV underground circuit feeding the Summit Top Substation.

Original Estimated Demand 20 MVA
W.O. No(s) TBD________________

DESCRIPTION OF ONE-TIME COSTS (Paragraph 2):

W.O. No(s) TBD____

EXHIBIT "A"

ADDED FACILITIES AGREEMENT BVES FINANCED

BVES's Actual Ready to Serve Date TBD

APPLICANT INITIALS AND DATE (Original Estimate Only)	ORIGINAL ESTIMATE DATE May 5, 2022	AMENDMENT DATE
A) ADDED FACILITIES INVESTMENT (Paragraph 1)	$6,500,000	
B) ADDED FACILITIES INVESTMENT (RCNLD*)(Paragraph 3)	$0.00	
C) ADDED FACILITIES MONTHLY CHARGE BASE (A + B) (Paragraphs 1, 3 & 4)	$6,500,000	
D) MONTHLY ADDED FACILITIES CHARGE (C X_) (Paragraphs 1 & 5)	$96,616	
E) ONE-TIME PAYMENT OPTION OWNERSHIP COSTS ONLY [Paragraph 1(b)]	N/A	N/A
F) ONE-TIME COSTS INCLUDING ITCC (Paragraph 2)	N/A	N/A

	AMENDMENT	FINAL RECORDED COSTS
	DATE ____________	DATE ____________
A) ADDED FACILITIES INVESTMENT (Paragraph 1)	____________	
B) ADDED FACILITIES INVESTMENT (RCNLD*)(Paragraph 3)	____________	
C) ADDED FACILITIES MONTHLY CHARGE BASE (A + B) (Paragraphs 1, 3 & 4)		
D) MONTHLY ADDED FACILITIES CHARGE (C X_) (Paragraphs 1 & 5)		
E) ONE-TIME PAYMENT OPTION OWNERSHIP COSTS ONLY [Paragraph 1(b)]		N/A
F) ONE-TIME COSTS INCLUDING ITCC (Paragraph 2)		N/A

*Cost of existing facilities reallocated as added facilities on a Reconstruction Cost New, Less Depreciation (RCNLD) basis.

ATTACHMENT B

CREDIT ENHANCEMENT AGREEMENT

CREDIT ENHANCEMENT AGREEMENT

This Credit Enhancement Agreement, dated as of this 31st day of August, 2022, is by and between Bear Valley Electric Service, Inc. ("BVES") and Snow Summit, LLC ("Customer"). BVES and Customer may sometimes be referred to herein individually as a "Party", or together as the "Parties".

WHEREAS, contemporaneously herewith, BVES and Customer have entered into that certain Added Facilities Agreement (the "Added Facilities Agreement") pursuant to which BVES will finance and construct the Added Facilities Agreement therein for the benefit of Customer; and

WHEREAS, Section 1(a) of the Added Facilities Agreement contemplates that Customer will provide such credit enhancement for its obligations under the Added Facilities Agreement as deemed necessary by BVES.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, and intending to be legally bound, BVES and Customer agree to the following:

1. Following receipt by BVES of all governmental approvals required to construct the Added Facilities (as defined in the Added Facilities Agreement), BVES shall give written notice to Customer stating that credit enhancement is to be provided by Customer in accordance with the Added Facilities Agreement. Within five (5) business days following receipt of such notice, Customer, shall provide, and shall cause to be maintained in effect at all times while the Added Facilities Agreement is in effect, credit enhancement in the form of an irrevocable standby letter of credit substantially in the form of Exhibit A hereto, or otherwise acceptable to BVES in its sole discretion ("Letter of Credit"), issued by a bank which is a U.S. bank or a U.S. branch of a foreign bank in each case having a credit rating of at least A– from Standard & Poor's Ratings Services and A3 from Moody's Investor Services, Inc. (the "Required Ratings"), in either case securing the full and faithful performance and payment of all of Customer's obligations under the Added Facilities Agreement for the entire term of the Added Facility Agreement. The Letter of Credit shall be in the initial amount of $6.5 Million US Dollars ($6,500,000). BVES and Customer agree that the amount of the Letter of Credit is intended to cover the construction costs and any other applicable costs of the Added Facilities as described in Exhibit A of the Added Facilities Agreement (the "Added Facilities Investment") for which BVES is liable. The value of the Added Facilities Investment can and should be adjusted to reflect the actual installed cost for the Added Facilities as well as any other applicable costs for which BVES is liable as described in Exhibit A of the Added Facilities Agreement recorded by BVES in accordance with the Added Facilities Agreement. If there is a change required to the amount of the current Letter of Credit, BVES shall provide written notice of the amount of the new Letter of Credit for the one-year period commencing on the anniversary of the original Letter of Credit no later than ninety (90) days prior to such anniversary, and the Letter of Credit shall be reissued or amended to reflect such amount. Given that BVES will amortize the value of the Added Facilities Investment over a 20-year period, the amount of the Letter of Credit shall be reduced to reflect such amortization as recorded by BVES in accordance with generally accepted accounting principles on an annual basis on the anniversary date of the Added Facilities Agreement. Amortization of the Added Facilities will only begin once the Added Facilities are fully commissioned and in service; therefore, no adjustments for amortization will occur until then. In addition to the

annual adjustment to the Letter of Credit due to amortization, adjustments may also be made to cover any other applicable costs of the Added Facilities as described in Exhibit A of the Added Facilities Agreement (the "Added Facilities Investment") for which BVES is liable or other costs incurred due to California Public Utilities Commission direction.

2. If at any time while the Added Facilities Agreement is in effect, BVES determines that, as of such time, any bank that issued a Letter of Credit in favor of BVES no longer has the Required Ratings, then BVES may submit a written notice of such determination to Customer (which notice shall provide BVES's basis for such determination), and within five (5) business days after Customer's receipt of such notice from BVES, Customer shall deliver to BVES, and shall thereafter maintain, a replacement Letter of Credit from a bank with the Required Ratings in the amount required by Section 1.

3. Any Letter of Credit that is provided to BVES pursuant to the foregoing shall permit partial draws and shall have an expiry date no earlier than twelve (12) calendar months after issuance thereof. Customer shall furnish extensions or replacements of such Letter of Credit sixty (60) days prior to the expiration thereof, from time to time until the expiration of the Added Facilities Agreement. All extensions, amendments and replacements of any Letter of Credit shall be delivered to BVES in the form of such outstanding Letter of Credit, or in a form otherwise satisfactory to BVES in its sole discretion; provided, however, that any automatic renewal or extension of a Letter of Credit in accordance with the terms thereof shall be deemed to satisfy Customer's obligation to furnish extensions or replacements of such Letter of Credit, subject to modification of the amount of such Letter of Credit as permitted by Section 1. BVES shall have the right to draw against any outstanding Letter of Credit upon: (a) failure to make payment when due under the Added Facilities Agreement; or (b) the failure of Customer to deliver any applicable extension, amendment or replacement of an outstanding Letter of Credit as provided herein; or (c) Customer's rejection of the Added Facilities Agreement in a bankruptcy or other insolvency proceeding. In the event of a draw due to the failure or refusal of Customer to deliver any applicable extension, amendment or replacement of an outstanding Letter of Credit, which draw may be in part or in whole, the proceeds of the draw shall be retained by BVES until the earlier of (i) BVES receives a replacement Letter of Credit (in which event, such monies shall be returned immediately to Customer) or (ii) BVES does in fact incur any costs, expenses or damages as a result of a breach by Customer of any of its obligations under the Added Facilities Agreements (in which event, such monies shall be applied against the same and the balance shall be retained by BVES until the earlier of (i) or (ii) above). If drawn in part or in whole, Customer shall immediately thereafter provide a replacement Letter of Credit in an amount equal to the amount drawn by BVES. Any draw made by BVES under an outstanding Letter of Credit shall not relieve Customer of any liabilities, deficiencies, costs, expenses or damages beyond what is drawn under such Letter of Credit. Customer's Letter of Credit (representing any undrawn portion thereof), to the extent it still remains, or any cash deposit held by BVES shall be returned to Customer on or before the sixtieth (60th) day after the later to occur of (i) the date on which the Added Facilities Agreement terminated or expired and (ii) the date on which all of Customer's performance and payment obligations under the Added Facilities Agreement (including, without limitation, any damages arising from breach of such Agreement) have been fulfilled. The parties agree that nothing in this Section 3 shall be deemed to create undertakings and obligations on the part of Customer under the Added Facilities Agreement beyond what is stated therein.

4. Any proceeds from draws under a Letter of Credit may be applied by BVES, in its sole discretion, against any losses, costs, expenses or damages as a result of a breach by Customer of any of its obligations (including a breach arising out of the termination or rejection of the Added Facilities Agreement under the U.S. Bankruptcy Code or other applicable insolvency legal requirements) under the Added Facilities Agreement in respect of which BVES is legally entitled to receive payment.

5. Except to the extent of any amounts paid to BVES, the use, application or retention of any draw upon a Letter of Credit, or any portion thereof, by BVES shall not (subject to any applicable limitations or exclusions on damages to which BVES has agreed in writing) prevent BVES from exercising any other right or remedy provided under the Added Facilities Agreement, or which BVES may have at law or in equity, by statute or regulation, and shall not operate as a limitation on any recovery to which BVES may otherwise be entitled. For the avoidance of doubt, BVES shall not be permitted any additional or duplicative recovery or remedies for any damages, payments, or other amounts for which BVES has received payments or other compensation pursuant to the terms of this Credit Enhancement Agreement or the Added Facilities Agreement.

6. Notice. Except as herein otherwise provided, any notice, request, demand, statement, or bill provided for in this Credit Enhancement Agreement, or any notice which either Party desires to give to the other, must be in writing and will be considered duly delivered only if delivered by hand, by nationally recognized overnight courier service, or by certified mail (postage prepaid, return receipt requested) to the other Party's address set forth below:

Customer:________________
Address for Legal Notices:
880 Summit Blvd.
P.O. Box 77
Attn: President & COO
Big Bear Lake, California 92315
Email: wreeser@bbmr.com

With a copy to:
Alterra Mountain Company
3501 Wazee Street, Suite 400
Denver, Colorado 80216
Attn: Chief Legal & Social Responsibility Officer
Email: legal@alterramtnco.com

BVES:

Bear Valley Electric Service, Inc.
630 East Foothill Boulevard
San Dimas, CA 91773
Attention: President
Facsimile: (909) 866-5056
Email: Paul.Marconi@bvesinc.com

Golden State Water Company
630 East Foothill Boulevard
San Dimas, CA 91773
Attention: Chief Financial Officer

Email: egtang@gswater.com

or at such other address as either Party designates by written notice. Delivery shall be deemed to occur at the time of actual receipt; or, if receipt is refused or rejected, upon attempted delivery, provided, however, that if receipt occurs after normal business hours or on a weekend or national holiday, then delivery shall be deemed to occur on the next business day.

7. Modifications. Except as provided otherwise in this Credit Enhancement Agreement, no modification of the terms and provisions of this Credit Enhancement Agreement shall be effective unless contained in writing and executed by both BVES and Customer.

8. CHOICE OF LAW. THIS CREDIT ENHANCEMENT AGREEMENT SHALL BE INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIORNIA, EXCLUDING ANY CONFLICT OF LAW RULES THAT MAY REQUIRE THE APPLICATION OF THE LAWS OF ANOTHER JURISDICTION. ANY SUIT BROUGHT WITH RESPECT TO OR RELATING TO THIS AGREEMENT SHALL BE BROUGHT IN THE COURTS OF LOS ANGELES COUNTY, CALIFORNIA OR IN THE UNITED STATES DISTRICT COURT, THE SOUTHERN DISTRICT OF CALIFORNIA. EACH PARTY HEREBY IRREVOCABLY WAIVES ANY AND ALL RIGHTS TO TRIAL BY JURY WITH RESPECT TO ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS CREDIT ENHANCEMENT AGREEMENT.

9. Rules and Regulations. This Credit Enhancement Agreement and the obligations of the Parties hereunder are subject to all applicable laws, rules, orders and regulations of governmental authorities having jurisdiction and, in the event of conflict, such laws, rules, orders and regulations of governmental authorities having jurisdiction shall control.

10. Counterparts. This Credit Enhancement Agreement may be executed by facsimile and in multiple counterparts or by other electronic means (including by PDF), each of which when so executed shall be deemed an original, but all of which shall constitute one and the same Agreement.

[Signature page follows]

IN WITNESS WHEREOF, the Parties hereto have caused this Credit Enhancement Agreement to be duly executed by their duly authorized officers as of the day and year first above written.

Bear Valley Electric Service, Inc.	**Snow Summit, LLC**
By: ______________________	By: Walt K
Title: ______________________	Title: President/COO
Date: ______________________	Date: 8/31/22

Excerpt from BVES Advice Letter 540-E

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Bear Valley Electric Service, Inc (913-E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Jenny Chen
Phone #: (909) 394-3600 x664
E-mail: RegulatoryAffairs@bvesinc.com
E-mail Disposition Notice to: RegulatoryAffairs@bvesinc.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 540-E

Tier Designation: 2

Subject of AL: Request to recover costs for the 2025 Switch and Field Device Automation Project and Maltby Substation Project, and Notification of Completion of the Snow Summit Added Facilities Project

Keywords (choose from CPUC listing): Compliance, Tariffs

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Decision No. 25-01-007

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date:

No. of tariff sheets: 18

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: See Attachment D - Tariff Sheet Summary

Service affected and changes proposed[1]: see Advice Letter

Pending advice letters that revise the same tariff sheets:

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Jenny Chen
Title: Regulatory Affairs Manager
Utility Name: Bear Valley Electric Service, Inc
Address: 630 E. Foothill Blvd
City: San Dimas State: California
Telephone (xxx) xxx-xxxx: (909) 394-3600
Facsimile (xxx) xxx-xxxx: (909) 394-7427
Email: RegulatoryAffairs@bvesinc.com; Jenny.Chen@gswater.com

Name: Alicia Menchaca
Title: Rate Analyst
Utility Name: Bear Valley Electric Service, Inc
Address: 630 E. Foothill Blvd
City: San Dimas State: California
Telephone (xxx) xxx-xxxx: (909) 394-3600 x497
Facsimile (xxx) xxx-xxxx:
Email: RegulatoryAffairs@bvesinc.com; alicia.menchaca@bvesinc.co

Clear Form

Bear Valley Electric Service, Inc.
P.O. Box 9028
San Dimas, CA 91773-9028
A Subsidiary of American States Water Company

February 23, 2026

Advice Letter No. 540-E **(U 913 E)**

California Public Utilities Commission

Bear Valley Electric Service, Inc. ("BVES") hereby transmits for filing the following:

SUBJECT: *Request to recover costs for the 2025 Switch and Field Device Automation Project and Maltby Substation Project, and Notification of Completion of the Snow Summit Added Facilities Project*

PURPOSE

Pursuant to the Settlement Agreement between BVES, the California Public Utilities Commission's ("Commission") Public Advocates Office and Snow Summit ("the Settling Parties"), which was adopted in Decision No. ("D.") 25-01-007, dated January 16, 2025, BVES hereby requests for the Commission's approval to add the cost of the Snow Summit Expansion Project to BVES's adopted rate base and to add the Operation and Maintenance expenses for the new substations to BVES's revenue requirement. BVES will offset the revenue requirement by monthly payments from Snow Summit, in accordance with BVES's Rule 2.H., adopted in D.25-01-007. BVES will record these payments to Other Operating Revenues ("OOR")[1]. BVES is not requesting to adjust customer rates via this advice (AL) letter for the Snow Summit Expansion Project.

Additionally, the Settlement Agreement, adopted in D.25-01-007, converted the Switch and Field projects spanning over the 4-year rate cycle, and the Maltby Substation project into Advice Letter Projects, which are subject to approval of cost recovery through the Base Rate Revenue Requirement Balancing Account ("BRRBA") by a Tier 2 Advice Letter filing[2]. BVES seeks cost recovery of the following authorized Advice Letter Projects through changes to base rates:

- Switch and Field Device Automation Project costs completed for 2025
- Partial Safety and Technical Upgrades to Maltby Substation Project

The recovery costs include Allowance for Funds Used During Construction ("AFUDC"), which has been added to the project costs.

[1] BVES 2023 GRC Decision 25-01-007, pp. 15
[2] BVES 2023 GRC Decision 25-01-007, pp. 10

BACKGROUND

On August 30, 2022, BVES filed Application No. ("A.") 22-08-010, which among other things, sought approval of four capital projects. The four capital projects were the Radford Line Project, the Switch and Field Device Automation Projects spanning over the 4 year rate cycle, the Partial Safety and the Technical Upgrades to Maltby Substation Project, and the Advanced Metering Infrastructure (AMI) Project. On January 16, 2025, the Commission issued D.25-01-007, which approved the four capital projects and their cost recovery to be requested by Tier 2 Advice Letter filings, once each capital project was completed and used and useful.

As part of the Settlement Agreement, approved in D.25-01-007, BVES was authorized to construct and implement these projects and seek cost recovery, which included applicable AFUDC, through rates. The Switch and Field Device Automation Project completed for 2025 and the Maltby Substation Project, the subject of this advice letter filing, are now completed and used and useful.

SNOW SUMMIT SUBSTATION EXPANSION PROJECT

The Snow Summit Substation Expansion Project was approved in D.19-08- 027 (BVES's 2018 GRC Decision) for BVES to offer supplemental service to Snow Summit under an Added Facilities Agreement. The Snow Summit Substation Expansion Project would install two new 10-megawatt (MW) substations, with one placed at the bottom of Snow Summit and the other placed at the top of Snow Summit, which were dedicated to serving only the load at Snow Summit. The two substations solely service Snow Summit. The costs associated with the project would be recovered from Snow Summit through an Added Facilities Agreement.[3]

In BVES's prior General Rate Case decision (D.25-01-007), the Settling Parties agreed to remove the capital costs for the Snow Summit Substation Expansion Project from BVES's rate base, and the estimated Operation and Maintenance costs for the new substations from BVES's forecasted expenses[4]. Instead, the Commission ordered BVES to file a Tier 2 advice letter requesting the Commission's approval to add the cost of the project, plus AFUDC, to rate base and to add the Operation and Maintenance expenses for the new substations to BVES's revenue requirement. BVES will offset the revenue requirement by monthly payments from Snow Summit, and therefore, is not requesting any changes to customers' base rates for this project.[5]

Under the Added Facilities Agreement, Snow Summit will pay a Monthly Ownership Charge of 1.2488%[6] for the costs of the project, including capital expenditures and Operations and Maintenance costs, resulting in an annual payment from Snow Summit of approximately $1.84 million. On September 29, 2025, the Snow Summit Substation

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[3] BVES 2023 GRC Decision 25-01-007, pp. 13
[4] BVES 2023 GRC Decision 25-01-007, pp. 15
[5] BVES 2023 GRC Decision 25-01-007, pp. 15
[6] BVES 2023 GRC Decision 25-01-007, Appendix A

Expansion Project became operational. Therefore, BVES is filing this Tier 2 advice letter to notify the Commission of completion of the project, and request to add the following project costs, including AFUDC, to the adopted rate base. In accordance with the Added Facilities Agreement, BVES began collecting payments from billing Snow Summit in October 2025.

Actual Cost	AFUDC @ 8.07%	Total Cost
$11,593,344.91	$656,253.24	$12,249,598.15

SWITCH AND FIELD DEVICE AUTOMATION PROJECT AND PARTIAL SAFETY AND TECHNICAL UPGRADES TO MALTBY SUBSTATION PROJECT COSTS

In A.22-08-010, BVES identified the Switch and Field Device Automation project and Partial Safety and Technical Upgrades to Maltby Substation Project as important initiatives in BVES's risk-based decision-making framework and associated mitigation measures.[7]

Recognizing the danger of severe wind conditions contributing to the ignition of fires related to utility infrastructure, the Commission ordered utilities to adopt significant regulations in "Extreme and Very High Fire Threat Zones," and adopted the "Fire Threat Map[8]" published by the California Department of Forestry and Fire Protection's Fire Resources Assessment Program. In 2017, the Commission refined the fire safety map by adopting a High Fire Threat District (HFTD), consisting of three areas: Tier 1, Tier 2, and Tier 3.[9]

The **Switch and Field Device Automation** project is located 100% within HFTD Tier 2. Implementation of this project results in significant mitigation of ignition risk drivers. The Switch and Field Project was divided into three components. The first component was the actual spend for the completed component in 2023 and 2024, as recovered in Advice Letter No. 509-E, filed on February 28, 2025. The second component was the actual spend for the completed component of the project that was operational and used and useful at year-end 2025, plus AFUDC, to be recovered in this advice letter[10]. The third component would be actual spend for the completed component of the project that would be operational and used and useful at year-end 2026. BVES incurred project expenses of $1,191,357.79, plus $12,654.53 in AFUDC at an annual rate of 8.07%, in 2025.

Actual Cost	AFUDC @ 8.07%	Total Cost
$1,191,357.79	$12,654.53	$1,204,012.32

[7] BVES 2023 GRC Decision 25-01-007, pp. 50
[8] The final CPUC Fire Threat Map was submitted to the Commission via a Tier 1 Advice Letter that was adopted by the Commission's Safety and Enforcement Division (SED) on January 19, 2018.
[9] Decision adopting regulations to enhance fire safety in the High Fire-Threat District. D.17-12-024, pp. 2
[10] Settlement Agreement, p. 13

The **Maltby Substation** is located in one of the more densely populated residential areas of Big Bear City on the East end of the BVES service area. These circuits are located in high wind areas. The IntelliRupter switches significantly improves the ability of the circuits to be rapidly de-energized when fault conditions are detected. This significantly reduces the possibility of causing an ignition.[11] The Partial Safety and Technical Upgrades to Maltby Substation Project was operational and used and useful at year-end 2025. BVES incurred project expenses of $2,737,295.84, plus $96,791.80 in AFUDC at an annual rate of 8.07%.

Actual Cost	AFUDC @ 8.07%	Total Cost
$2,737,295.84	$96,791.80	$2,834,087.64

The table below reflects the combined costs and AFUDC for Maltby Substation and 2025 Switch and Field projects:

Actual Cost	AFUDC @ 8.07%	Total Cost
$3,928,653.63	$109,446.33	$4,038,099.96

AUTHORIZED ANNUAL REVENUE REQUIREMENT

The two Advice Letter Projects will increase BVES's authorized annual base revenue requirement for 2026 by $563,560.78, which is an increase of 1.33% from current level. [12] For this reason, BVES is also requesting an update the Base Revenue Requirement Balancing Account. BVES has updated Preliminary Statement V of the tariff book, enclosed herein, to increase the authorized annual base revenue requirement for 2026 by the revenue requirement of the approved capital projects.

REVENUE RECOVERY

As part of the Settlement Agreement, BVES is authorized to file a Tier 2 Advice Letter, requesting implementation of new base rates (rather than a surcharge) to recover costs of the Advice Letter Projects resulting in a corresponding update to the Base Rate Revenue Requirement Balancing Account authorized base rate revenue requirement. The requested cost recovery shall include the construction costs of the project plus AFUDC calculated at the authorized rate of return on rate base, which is 8.07%.[13]

BILL IMPACT

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[11] BVES 2023 GRC Exhibit BVES2, pp. 67

[12] BVES' authorized base revenue requirement is $42,251,834 as shown in the Base Revenue Requirement Balancing Account Preliminary Statement V. The increase to BVES' 2026 authorized base revenue requirement is made up of $168,033.02 and $395,527.76 for the Switch and Field Automation Device Project and Maltby Substation, respectively.

[13] Settlement Agreement, pp. 12-13

Table 3 below provides the bill impact on a residential regular customer (Schedule D) and a residential low-income customer (Schedule DLI) bill using 350kWh of energy. Note that the bill impacts reflect change to rates that would become effective on April 1st, 2026, per Commission approval of AL-534-E, Implementation of Base Services Charge and updated rates as authorized by Resolution E-2395.[14]

Estimate Customer Bill Impact

Schedule D	Usage (kWh)	Current Bill	Proposed Bill	Percent Change
Typical Bill	350	$147.61	$149.08	1.00%
Schedule DLI	Usage (kWh)	Current Bill	Proposed Bill	Percent Change
Typical Bill	350	$108.85	$110.02	1.08%

The following workpapers have been provided to Energy Division:
Attachment A: Attachment A- Maltby and 2025 Switch and Field Final

<u>TARIFF CHANGES</u>
See attachment.

<u>TIER DESIGNATION</u>
This advice letter is submitted with a Tier 2 designation, pursuant to D.25-01-007.

<u>EFFECTIVE DATE</u>
BVES respectfully requests this advice letter become effective on April 1, 2026.

<u>NOTICE AND PROTESTS</u>
A protest is a document objecting to the granting in whole or in part of the authority sought in this advice letter. A response is a document that does not object to the authority sought, but nevertheless presents information that the party tendering the response believes would be useful to the Commission in acting on the request.

A protest must be mailed within 20 days of the date the Commission accepts the advice letter for submission. The Calendar is available on the Commission's website at www.cpuc.ca.gov.

A protest must state the facts constituting the grounds for the protest, the effect that approval of the advice letter might have on the protestant, and the reasons the protestant believes the advice letter, or a part of it, is not justified. If the protest requests an evidentiary hearing, the protest must state the facts the protestant would present at

[14] The Commission approved AL-534-E, Implementation of Base Services Charge and updated rates as authorized by Resolution E-2395, on January 26, 2026.

an evidentiary hearing to support its request for whole or partial denial of the advice letter.

The utility must respond to a protest within five days.

All protests and responses should be sent to:
California Public Utilities Commission, Energy Division
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

The protest or correspondence should also be sent via U.S. mail and/or electronically, if possible, to BVES at the addresses shown below on the same date it is delivered to the Commission.

Bear Valley Electric Service, Inc.
Regulatory Affairs
E-mail: RegulatoryAffairs@bvesinc.com

If you have not received a reply to your protest within 10 business days, please contact Alicia Menchaca at (909) 630-5555.

Correspondence:
Any correspondence regarding this compliance filing should be sent by regular mail or e-mail to the attention of:

Jenny Chen
Regulatory Affairs Manager
Bear Valley Electric Service, Inc.
630 E. Foothill Blvd.
San Dimas, California 91773
Email: RegulatoryAffairs@bvesinc.com

The protest shall set forth the grounds upon which it is based and shall be submitted expeditiously. There is no restriction on who may file a protest.

Sincerely,

/s/ Alicia Menchaca
Alicia Menchaca
Rate Analyst, Regulatory Affairs
Bear Valley Electric Service, Inc.

cc: Cheryl Cox, Energy Division

Michael Campbell, California Public Advocates Office
Tamera Godfrey, California Public Advocates Office
Mina Botros, California Public Advocates Office
BVES General Order 96-B Service List

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
3752-E	PRELIMINARY STATEMENTS BASE REVENUE REQUIREMENT BALANCING ACCOUNT Sheet 1	3591-E
3753-E	PRELIMINARY STATEMENTS BASE REVENUE REQUIREMENT BALANCING ACCOUNT Sheet 2	3592-E
3754-E	Schedule No. A-1 GENERAL SERVICE - SMALL Sheet 1	3728-E
3755-E	Schedule No. A-2 GENERAL SERVICE - MEDIUM Sheet 1	3729-E
3756-E	Schedule No. A-3 GENERAL SERVICE - LARGE Sheet 1	3730-E
3757-E	Schedule No. A-4 TOU GENERAL SERVICE - TIME-OF-USE Sheet 1	3731-E
3758-E	Schedule No. A-5 TOU Primary TIME-OF-USE SERVICE (METERED AT VOLTAGES OF 4,160 KV AND HIGHER) Sheet 1	3732-E
3759-E	Schedule No. A-5 TOU Secondary Time-Of-Use Service (Metered At Voltages less than 4,160 KV) Sheet 1	3733-E
3760-E	Schedule No. D DOMESTIC SERVICE - SINGLE FAMILY ACCOMMODATION Sheet 1	3745-E
3761-E	Schedule No. DE DOMESTIC SERVICE - SINGLE FAMILY ACCOMMODATION (EMPLOYEE) Sheet 1	3746-E
3762-E	Schedule No. DLI CALIFORNIA ALTERNATE RATES FOR ENERGY (CARE) DOMESTIC SERVICE - SINGLE FAMILY ACCOMMODATION Sheet 1	3747-E
3763-E	Schedule No. DM DOMESTIC SERVICE - MULTI-FAMILY ACCOMMODATION Sheet 1	3737-E
3764-E	Schedule No. DMS DOMESTIC SERVICE - MULTI-FAMILY ACCOMMODATION - SUBMETERED Sheet 1	3748-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
3765-E	Schedule No. DMS DOMESTIC SERVICE - MULTI-FAMILY ACCOMMODATION - SUBMETERED Sheet 2	3749-E
3766-E	Schedule No. DO DOMESTIC SERVICE - OTHER Sheet 1	3750-E
3767-E	Schedule No. GSD GENERAL SERVICE - DEMAND Sheet 1	3740-E
3768-E	Schedule No. SL STREET LIGHTING SERVICE Sheet 1	3741-E
3769-E	Schedule No. TOU-EV-1 GENERAL SERVICE TIME-OF-USE ELECTRIC VEHICLE CHARGING Sheet 1	3725-E
3770-E	Schedule No. TOU-EV-2 GENERAL SERVICE TIME-OF-USE ELECTRIC VEHICLE CHARGING Sheet 1	3726-E
3771-E	Schedule No. TOU-EV-3 GENERAL SERVICE TIME-OF-USE ELECTRIC VEHICLE CHARGING Sheet 1	3727-E
3772-E	Table of Contents Sheet 1	3751-E

Excerpt from BVES Preliminary Statement

PRELIMINARY STATEMENTS

A. TERRITORY

That territory in San Bernardino County lying adjacent to Big Bear and Baldwin Lake.

B. CHARACTER OF SERVICE

Service as rendered by this utility is sixty cycle alternating current service of a single phase and three phase type delivered at voltages of 110 and 220 as more specifically set forth in the schedules of rates and in the rules and regulations hereinafter contained.

C. PROCEDURE TO OBTAIN SERVICE

Applicants for service will be required to establish their credit in accordance with the Rules and regulations of this utility.

D. ESTABLISHMENT OF SERVICE

Applicants for service will be required to establish their credit in accordance with the Rules and regulations of this utility.

E. GENERAL

1. All energy supplied by this utility will be measured by means of suitable standard electric meters.
2. All rates herein quoted are not subject to discount except as specifically set forth in the schedules. (T)
3. No discounts are allowed for advances by customers.
4. This utility does not furnish free lamp renewals.
5. No standard riders are employed by this utility.

F. SYMBOLS

Wherever tariff sheets are refilled, changes will be identified by the following symbols:

(C) To signify **changed** listing, rule, or condition which may affect rates or charges.
(D) To signify **discontinued** material, including listing, rate, rule or condition.
(I) To signify **increase.**
(L) To signify material **relocated** from or to another part of tariff schedules with no change in text, rate, rule or condition.
(N) To signify **new** material including listing, rte rule or condition.
(R) To signify **reduction**.
(T) To signify change in wording of **text** but not change in rate rule or condition.

L. SUPPLY ADJUSTMENT MECHANISM

1. The purpose of the Supply-Adjustment Mechanism is to recover in rates the costs related to the Transmission Charge and the Supply Charge, and to have the Supply Adjustment Charge be a charge or a credit when the balance in the Supply Adjustment Balancing Account reflects an under-collection or an over-collection, respectively.

2. The monthly charges for service otherwise applicable under each of the utility's rate schedules shall include: -a) the Transmission Charge, b) the Supply Charge and c) the Supply Adjustment Charge. The Supply Charge and the Transmission Charge shall be expressed in terms of a cents-per-kilowatt-hour charge or a dollars-per-kilowatt charge depending upon the nature of the charge and the applicable rate schedule. The Supply Adjustment Charge shall be expressed in terms of a cents-per-kilowatt-hour charge or credit.

   a. The Transmission Charge shall be designed to recover the most recently adopted estimate of costs to the utility for California Independent System Operator Corporation services, transmission services, ancillary services, system protection services, capacity charges, all SCE transmission charges, option premiums, and schedule dispatch charges (collectively, Transmission Costs).
   b. The Supply Charge shall be designed to recover the most recently adopted estimate of the costs to the utility of purchasing electricity,-fuel, renewable energy credits (RECs) and imbalance energy (collectively, Supply Costs).
   c. The Supply Adjustment Charge shall be designed to recover or return, respectively, any under-collection or over-collection balance in the Supply Adjustment Balancing Account.

3. A Supply Adjustment Balancing Account (Balancing Account) shall be maintained to record the difference between the accumulated billings of the Transmission Charge, the Supply Charge and the Supply Adjustment Charge, and the accumulated accruedTransmission Costs and Supply Costs. Monthly entries to the Balancing Account will be determined from the following calculations:
   a. Accumulated billings during the month from Transmission Charge, Supply Charge and Supply Adjustment Charge;
   b. Less the adjustment to reflect the current adopted rate for franchise fees and uncollectibles;
   c. Less-accrued Transmission Costs;
   d. Less accrued Supply Costs;
   e. Plus any refunds for Supply Costs or Transmission Costs previously reflected in the Balancing Account;
   f. Plus or minus interest expense, depending upon whether there is an under-collection or over-collection in the Balancing Account; such interest shall be calculated based upon the average of the beginning and ending monthly balance in the Balancing Account multiplied by the 90-day commercial paper rate for the month;
   g. Less an adjustment, if any, for the direct payment of refunds to customers;
   h. Less any costs related to the purchase of RECs;
   i. Plus any proceeds from the sale of RECs;

(Continued)

L. SUPPLY ADJUSTMENT MECHANISIM (continued)

j. Less any power purchase payments provided to eligible Net Energy Metering customers for energy produced by on-site generation in excess of consumption over a 12-month period; power purchase payments may include additional compensation for renewable attributes where applicable; and
k. The accumulated accrual cost of Supply Costs shall be trued-up on a monthly basis.

If the above calculation produces a positive amount (over-collection), such amount shall be credited to the Balancing Account. If the calculation produces a negative amount (under-collection), such amount shall be debited to the Balancing Account.

4. The utility may make periodic Advice Letter filings to revise the Supply Adjustment Charge to reflect the most current status of the Balancing Account. BVES shall file a Tier 1 Advice Letter request to eliminate such cumulative balance over a twelve-month period via a debit/collection or credit/refund tariff in the event the cumulative balance (either an under-collection or an over-collection) in the Supply Adjustment Balancing Account is plus or minus $500,000. (N)

5. Not more often than once per year, the utility may file an application to revise the Transmission Charge and/or Supply Charge to recover in rates the most current estimates of its Transmission Costs and/or Supply Costs.

V. BASE REVENUE REQUIREMENT BALANCING ACCOUNT

Bear Valley Electric Service, Inc. ("BVES") shall maintain the Base Revenue Requirement Balancing Account ("BRRBA") as follows. (T)

1. PURPOSE:
The purpose of the BRRBA is to record the difference between BVES adopted Base Revenue Requirements and the recorded revenues from base rates.

2. APPLICABILITY
The BRRBA shall apply to all customers base rate revenues.

3. RATES
Base rates are electric rates and related adjustments. Adjustments are required to amortize under-collections or over-collection in the BRRBA as authorized by the Commission from time to time.

4. AUTHORIZED BASE RATE REVENUE REQUIREMENTS
BVES's authorized annual base rate revenue requirements for the years 2023, 2024, 2025, and 2026 as reflected in the Settlement Agreement approved by the Commission in D.25-01-007, and in addition reflect the annual revenue requirement for the approved capital projects in advice letter 509-E and 540-E, are set forth below: (C)

The annual revenue requirements are set forth below:	
Year	Annual Revenue Requirement
2023	$33,051,872
2024	$35,251,872
2025	$39,593,248
2026	$42,815,395

(I)

The authorized monthly revenue requirement shall be apportioned on a monthly basis using the following percentage allocation:

Sales MWh by Month	Month
Jan	10.66%
Feb	9.14%
Mar	8.54%
Apr	7.27%
May	7.00%
Jun	7.29%
Jul	8.06%
Aug	7.79%
Sep	7.29%
Oct	7.56%
Nov	8.44%
Dec	10.97%

(Continued)

PRELIMINARY STATEMENTS
BASE REVENUE REQUIREMENT BALANCING ACCOUNT

V. BASE REVENUE REQUIREMENT BALANCING ACCOUNT (continued)

5. ADJUSTMENTS TO THE REVENUE REQUIREMENT
The annual revenue requirement levels in Section 4 may be adjusted, if needed, by an update as a result of changes to BVES' allocation of GSWC's (i) General Office cost, (ii) common plant cost or (iii) employee pension and benefit costs, each as approved by the Commission in GSWC water operations application filed before the Commission, or by some other appropriate proceeding that establishes a new BVES base rate revenue requirement or an addition to the BVES base rate revenue requirement shown in Section 4. The annual revenue requirement levels in Section 4 also may be adjusted, if needed, by an update as a result of the disposition of balances in the Pension Balancing Account, or advice letter filings regarding the completion and placement into commercial operation of the (i) Radford Line (ii) the Switch and Field Device Automation Project and (iii) Maltby Substation Project. (C)

6. TRANSFERS AND ADJUSTMENTS TO THE BRRBA BALANCE
From time to time the Commission may find that an amortization of a base rate memorandum or balancing account it authorized has run for the required number of months but that there remains an unamortized over- or under- collected balance at the end of the amortization period. The unamortized balances for such accounts may be transferred to the balance in the BRRBA if the costs covered by the account are base rate related costs. Additionally, pursuant to Ordering Paragraph #11 of D.24-05-028, BVES will record any over- or under-collection of revenues by income-graduated fixed charges as a separate line-item.

7. ACCOUNTING PROCEDURES:
BVES shall maintain the BRRBA by making entries at the end of each month as follow:

a. Recorded monthly base rate revenues.
b. Apportioned monthly allocation of the authorized annual base rate revenue requirement as described in Section 4.
c. Total net BRRBA balance: 7.a. minus 7.b.
d. BVES shall apply interest to the average net balance in the BRRBA account at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month as reported in the Federal Reserve Statistical Release, H.15, or its successor publication. Accumulated interest will be included in the amount on which interest is charged, but will be identified as a separate component of the BRRBA account.

8. EFFECTIVE DATE
As reflected in the Settlement Agreement approved by the Commission in D.25-01-007, the revenue requirements for 2023, 2024, 2025, and 2026 are effective as of January 1, 2023, January 1 2024, January 1, 2025, and January 1, 2026, respectively.

9. ACCOUNT DISPOSITION
The disposition of the balance in the BRRBA at the close of each year, plus any transfers or adjustments authorized to be made to the BRRBA, will be addressed by BVES in a Tier 2 Advice Letter filing if the amount of the under- or over-collection is equal to or greater than 5% of the revenue requirement established for the previous twelve months. Should such a trigger be met, BVES may file the required advice letter with the necessary amortization charge expected to amortize the balance over the next twelve months.

Excerpts from Liberty Utilities (CalPeco) Preliminary Statements

PRELIMINARY STATEMENT
(Continued)

8. BASE REVENUE REQUIREMENT BALANCING ACCOUNT

Liberty Utilities (CalPeco Electric) LLC ("Liberty") shall maintain the Base Revenue Requirement Balancing Account (BRRBA).

A. Purpose

The purpose of the BRRBA is to record the difference between Liberty's authorized annual Base Rate revenue requirements and the annual recorded revenue from Base Rates.

B. Applicability

The BRRBA is applicable to all rate schedules.

C. Base Rates

Base Rates are electric rates and related adjustments. Adjustments are required to amortize under-collections or over-collections in the BRRBA authorized by the Commission from time to time.

D. Monthly Base Rate Revenue Requirement

Liberty's annual authorized Base Rate revenue requirements shall be converted to monthly Base Rate revenue requirements by dividing the annual authorized Base Rate revenue requirement by 12.

E. Adjustments to the Annual Authorized Base Rate Revenue Requirement

The annual authorized Base Rate revenue requirement levels may be adjusted, if needed, by an update as a result of a Commission decision, order, or resolution that changes the annual Base Rate revenue requirement of Liberty that:

1) has been issued regarding a CalPeco application or advice letter, or
2) has been issued in another Commission proceeding that establishes for Liberty a new annual Base Rate revenue requirement or an addition to the annual Base Rate revenue requirement.

PRELIMINARY STATEMENT
(Continued)

8. BASE REVENUE REQUIREMENT BALANCING ACCOUNT (continued)

F. Accounting Procedures

Liberty shall maintain the BRRBA by making entries at the end of each month as follows:

a. Base Rate revenues recorded during the month;
b. Monthly Base Rate revenue requirement as described in Section D;
c. Total net BRRBA balance equals (2) minus (1).
d. Liberty shall apply interest to the average net balance in the BRRBA account at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month as reported in the Federal Reserve Statistical Release, H.15, or its successor publication. Accumulated interest will be included in the amount on which interest is accrued, but will be identified as a separate component of the BRRBA account.

G. Effective Date

The BRRBA is effective as of January 1, 2013.

H. Account Disposition

The disposition of the balance in the BRRBA on September 30, 2017 will be addressed by Liberty in a Tier 2 Advice Letter filing to be made no later than October 31, 2017. Provided, however, Liberty shall make such a Tier 2 Advice Letter filing only if the amount of the under- or over- collection in the BRRBA Account is +/-5% of the authorized Base Rate revenue requirement corresponding to the preceding fifteen months. Should such a trigger be met, Liberty shall file the required Tier 2 Advice Letter filing and shall include in the filing the amortization rate to amortize the balance over the next twelve months beginning October 1, 2017.

The disposition of the balance in the BRRBA on September 30 of every subsequent calendar year will be addressed by Liberty in a Tier 2 Advice Letter filing to be made no later than October 31 of that calendar year. Provided, however, Liberty shall make such a Tier 2 Advice Letter filing only if the amount of the under- or over-collection in the BRRBA Account is +/- 5% of the authorized revenue requirement corresponding to the preceding twelve month period. Should such a trigger be met, Liberty shall file the required Tier 2 Advice Letter filing and shall include in the filing the amortization rate to amortize the balance over the next twelve months beginning January 1 of each year.

PRELIMINARY STATEMENT
(Continued)

9. POST-TEST YEAR ADJUSTMENT MECHANISM (PTAM)

A. Purpose

The purpose of this mechanism is to revise Base Rates in any year in which new Base Rates do not become effective as result of a Commission decision in response to a Liberty General Rate Case application.

B. Applicability

The PTAM is applicable to all rate schedules.

C. Attrition Rate Factor Component:

The Attrition Rate Factor will be based on the current year's September Global Insight U.S. Economic Outlook forecast for the Consumer Price Index, minus a 0.5% productivity factor (but will not be less than zero).

D. Major Plant Additions Component

For purposes of the PTAM, a "Major Plant Addition" includes any capital project closed to plant-in-service that exceeds $4 million in a calendar year. The revenue requirement associated with a Major Plant Addition would also include the California portion of operation and maintenance expenses, depreciation and property taxes. Liberty shall file a Tier 1 advice letter providing notice of a planned Major Plant Addition prior to seeking any PTAM adjustment as described in Section F associated with that Major Plant Addition.

E. Effective Date

The PTAM is effective as of January 1, 2013.

F. Revision Date

Liberty shall file a Tier 2 advice letter containing the PTAM adjustment no later than October 15 of the calendar year prior to the calendar year Liberty will be requesting that the new PTAM rates become effective. New PTAM rates will be effective January 1 of each calendar year following such an advice letter filing.

PRELIMINARY STATEMENT
(Continued)

5. GENERAL

A. Measurement

Measurement of Electric Energy: All electric energy as supplied by the Liberty Utilities (CalPeco Electric) LLC ("Liberty") to its customers shall be measured by means of suitable standard electric meters, except energy delivered under street lighting tariffs on a rate-per-lamp basis, and energy, estimated from load and operating time data, for highway sign lighting, traffic control, and other installations where metering is impractical.

B. Discounts

No discounts are allowed from bills, or minimum charges, except as specifically provided in certain schedules.

6. ENERGY COST ADJUSTMENT CLAUSE (ECAC)

A. Purpose

The purpose of the Energy Cost Adjustment Clause (ECAC) is to reflect in rates: (1) the cost of fuel and purchased power, and (2) certain other energy-related costs.

B. Applicability

The Energy Cost Adjustment Clause is applicable to all rate schedules.

C. Revision Date

The Revision Date for calculating the Energy Cost Adjustment Clause Billing Factors (ECACBFs) will be January 1 or on such other dates as **(T)**
the Commission may authorize. **(T)**

Applications for ECACBF revisions calculated in accordance with the provisions described herein shall be filed with the California Public Utilities Commission annually on July 1. **(T)**

(Continued)

PRELIMINARY STATEMENT
(Continued)

6. ENERGY COST ADJUSTMENT CLAUSE (ECAC) (continued)

C. Revision Date (continued)

Liberty shall propose revisions to the ECACBFs calculated in accordance with the provisions herein. **(T)** **(T)**

(T) The Company shall submit an application for changes to the ECACBFs only if a change to total ECAC revenues of +/-5 % occurs as a result of the combination of revisions to the:

i. Offset Rate based on the new fuel and purchased power forecast for the Forecast Period; and

ii. Balancing Rate to amortize any projected over- or under-collection balance in the Energy Cost Adjustment Account as of the Revision Date.

The revised ECACBFs shall be applied to bills for service rendered on and after the Revision Date and shall continue thereafter until the next revised ECACBFs become effective.

D. Forecast Period

The Forecast Period for calculating the ECACBFs shall be the twelve calendar month period commencing with the Revision Date.

E. Interest Rate

The Interest Rate to be applied to the Energy Cost Adjustment Account shall be 1/12 of the interest rate on Commercial Paper, for the previous month as published in the Federal Reserve Statistical Release, H. 15. Should publication of the interest rate on Commercial Paper (prime, 3 months) be discontinued, interest will so accrue at the rate of 1/12 of the most recent month's interest rate on Commercial Paper, which most closely approximates the rate that was discontinued, and which is published in the Federal Reserve Statistical Release, H. 15, or its successor publication.

(**Continued)**

PRELIMINARY STATEMENT
(Continued)

6. ENERGY COST ADJUSTMENT CLAUSE (ECAC) (continued)

F. Franchise Fees and Uncollectible Accounts Expense Factor

The Franchise Fees and Uncollectible Accounts Expense Factor shall be the rate derived from the Commission's decision in the Company's most recent General Rate Case proceeding to provide for Franchise Fees and Uncollectible Accounts Expense.

G. Energy Cost Adjustment Clause Billing Factor

The ECACBFs shall become effective for service on and after each Revision Date and continuing thereafter until the next ECACBFs become effective in accordance herewith. The ECACBF for each rate component provided in Section L shall be set in the amount of the algebraic sum of the Offset Rate and the Balancing Rate corresponding to that component, multiplied by the Franchise Fees and Uncollectible Accounts Expense Factor, and carried to the nearest $0.00001 per kilowatthour.

(1) The system Offset Rate is calculated based on dividing the Fuel and Purchased Power Cost by either the total system kilowatt-hours sales or the demand billing determinants, as appropriate, estimated for the Forecast Period. The Offset Rate for each applicable component varies according to legislative and CPUC requirements for Liberty's tier structure and time-of-use considerations.

(2) The Balancing Rate, as determined in Section I, shall be an amount per kilowatt-hour of sales necessary to amortize the accumulated balance in the Energy Cost Adjustment Account, included as a subaccount in CPUC Account Nos. 186 and 557 and maintained as described in Section J.

H. Fuel and Purchased Power Cost

(1) The estimated Fuel and Purchased Power Cost shall be equal to:

(a) The volumes of diesel fuel to be used for electric generation during the Forecast Period expressed in gallons and multiplied by the Current Average Diesel Price as set forth in Section I.2, plus

(b) The total purchases of electric capacity, transmission services, and energy including variable wheeling, estimated to be made from each source during the Forecast Period multiplied by their respective latest tariff, contract, or delivered price forecasted to be in effect during the Forecast Period, plus

PRELIMINARY STATEMENT
(Continued)

6. ENERGY COST ADJUSTMENT CLAUSE (ECAC) (continued)

H. Fuel and Purchased Power Cost (continued)

(1) The estimated Fuel and Purchased Power Cost shall be equal to: (continued)

(c) The carrying costs of fuel inventory equal to the product of the following estimated items for the Forecast Period: (1) the average monthly number of gallons of diesel fuel in inventory, (2) the average inventory price per gallon, and (3) the Interest Rate.

(2) The Current Average Diesel Price shall be the estimated average cost in dollars per gallon from inventory computed at the end of each month of the Forecast Period, using estimated replacement price of such fuel for the Forecast Period and the estimated additions and withdrawals in each month.
J.

I. Balancing Rate

The Balancing Rate shall be determined by dividing (1) the estimated balance in the Energy Cost Adjustment Account as of the Revision Date by (2) the estimated kilowatt-hour sales or demand billing determinants applicable to the amortization period set by the Commission in the decision approving the change in ECACBF.

J. Energy Cost Adjustment Account

The Company shall maintain an Energy Cost Adjustment Account. Entries shall be made to this account at the end of each month as follows:

(1) A debit entry (credit entry, if negative) equal to:

(a) The recorded Fuel and Purchased Power Cost, less the cost of fuel for economy or surplus sales, for the month.

(b) Less the amount of recorded Offset Rate revenue during the month reduced by the Franchise Fees and Uncollectible Accounts Expense.

PRELIMINARY STATEMENT
(Continued)

6. ENERGY COST ADJUSTMENT CLAUSE (ECAC) (continued)

J. Energy Cost Adjustment Account (continued)

(2) A credit entry (debit entry, if negative) equal to the amount of recorded Balancing Rate revenue during the month reduced by the Franchise Fees and Uncollectible Accounts Expense.

(3) A credit entry equal to the amount of any cash refunds, including associated interest, received from its fuel or purchased power suppliers on and after the Revision Date and applicable to retail energy sales.

(4) A debit entry (credit entry, if negative) equal to the average of the beginning and ending balance multiplied by the Interest Rate.

K. Billing Factors

The following factors are in effect for the period shown:

Energy Cost Adjustment Clause Billing Factor $/kWh

	Residential	
	D-1, DS-1, DM-1 Baseline	D-1, DS-1, DM-1 Excess
Offset	0.05953 **(I)**	0.05953 **(I)**
Balancing	0.03892	0.03892
Total	0.09845 **(I)**	0.09845 **(I)**

	Commercial			
	A-1	A-2 Winter	A-2 Summer	PA
Offset	0.05953 **(I)**	0.05953 **(I)**	0.05953 **(I)**	0.05953 **(I)**
Balancing	0.03892 **(I)**	0.03892 **(I)**	0.03892 **(I)**	0.03892 **(I)**
Total	0.09845 **(I)**	0.09845 **(I)**	0.09845 **(I)**	0.09845 **(I)**

(continued)

PRELIMINARY STATEMENT
(Continued)

6. ENERGY COST ADJUSTMENT CLAUSE (ECAC) (continued)

K. Billing Factors (continued)

	Commercial				
	A-3 On-Peak Winter	A-3 Mid-Peak Winter	A-3 Off-Peak Winter	A-3 On-Peak Summer	A-3 Off-Peak Summer
Offset	0.05953 **(I)**	0.05953 **(I)**	0.05953 **(I)**	0.05953 **(I)**	0.05953 **(I)**
Balancing	0.03892	0.03892	0.03892	0.03892	0.03892
Total	0.09845 **(I)**	0.09845 **(I)**	0.09845 **(I)**	0.09845 **(I)**	0.09845 **(I)**

	SL (per bulb) 5,800 Lumens	SL (per bulb) 9,500 Lumens	SL (per bulb) 22,000 Lumens
Offset	1.73 **(I)**	2.44 **(I)**	4.70
Balancing	1.13	1.60	3.07
Total	2.86 **(I)**	4.04 **(I)**	7.77

	OL (per bulb) 5,800 Lumens	OL (per bulb) 9,500 Lumens	OL (per bulb) 16,000 Lumens	OL (per bulb) 22,000 Lumens
Offset	1.73 **(I)**	2.44 **(I)**	3.99 **(I)**	5.06 **(I)**
Balancing	1.13	1.60	2.61	3.31
Total	2.86 **(I)**	4.04 **(I)**	6.60 **(I)**	8.37 **(I)**