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

[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.

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[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?

[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

ATTACHMENT 3

EXCERPTS FROM DOCUMENTS REFERENCED IN TESTIMONY