Docket No. A.26-01-022

Exhibit No. ____________________

Date August 12, 2026 (Errata, August 17, 2026)

Witness William A. Monsen

DIRECT TESTIMONY OF WILLIAM A. MONSEN
REGARDING MARGINAL COSTS AND REVENUE ALLOCATION
ON BEHALF OF SNOW SUMMIT LLC
IN BEAR VALLEY ELECTRIC SERVICE'S GENERAL RATE CASE
APPLICATION 26-01-022

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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. Are you the same William A. Monsen that previously submitted testimony in this proceeding?

A. Yes. I submitted testimony on behalf of Snow Summit LLC on July 27, 2026.[1] My qualifications are presented in that testimony.

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

A. As a major energy user and single largest customer[2] on the Bear Valley Electric Service, Inc. (BVES) system, Snow Summit is concerned about how various incorrect assumptions in BVES's marginal cost study have resulted in an incorrect revenue allocation.

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[1] "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," July 27, 2026 (Snow Summit RO Testimony).

[2] Snow Summit LLC (Snow Summit) operates two ski resorts: Snow Summit resort and Big Bear Mountain resort. In total, Snow Summit is BVES's entire A5 TOU Primary customer class.

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

A. The purpose of my testimony in this phase of the proceeding is to discuss BVES's proposals regarding marginal costs and revenue allocation in this General Rate Case (GRC) proceeding.[3]

Q. Please summarize your recommendations and conclusions regarding BVES's marginal costs and revenue allocation.

A. In this testimony, Snow Summit presents the impacts of Snow Summit's recommended changes to input assumptions and modeling conventions used by BVES to derive BVES's proposed marginal costs and revenue allocations. In addition, Snow Summit corrects errors in BVES's Marginal Cost of Service model (which is the basis for BVES's marginal costs and revenue allocations). Snow Summit also points out inconsistencies in BVES's Marginal Cost of Service model relative to BVES's testimony.

Snow Summit's Results of Operations (RO) testimony recommended changes to BVES's load forecast for the A5 TOU Primary customer class. In summary, Snow Summit's

[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 submits this testimony related to its concerns regarding BVES's proposed marginal costs, revenue allocation and rate design. Unless otherwise indicated, BVES's testimony is referred to as "BVES Testimony" with an associated volume number.

recommended reductions in the load forecast for the A5 TOU Primary customer class are reasonable because they are based on (1) the fact that BVES projects a significant increase in loads for 2025-2030 during the non-snowmaking months of April-October despite the fact that there have been no changes in equipment or operations at the Snow Summit resort during those months and (2) the clear over-forecasting of loads in 2026 for the A5 TOU Primary class during snowmaking months relative to actual loads.[4]

Application of Snow Summit's load forecast for the A5 TOU Primary customer to BVES's Supply Model reduces BVES's Supply revenue requirements. Applying Snow Summit's recommended load forecast to BVES's Marginal Cost of Service model results in changes to unit marginal costs for Generation (both capacity and energy) and Distribution (both coincident demand and non-coincident demand) as well as changes to how those revised marginal costs are converted into BVES's marginal cost-based cost of service, which is the basis for BVES's revenue allocation based on the Equal Percent of Marginal Cost (EPMC) modeling approach.

Snow Summit also recommends revising other assumptions related to the development of unit marginal Distribution demand costs for both coincident and non-coincident demand. BVES improperly includes the costs of new substation and distribution facilities that were constructed at the request of Snow Summit (and are paid for entirely by Snow Summit through an Added Facilities Agreement) in the development of the unit marginal Distribution costs for coincident and non-coincident demand. Customers other than Snow

[4] The basis for and level of changes are fully described in Snow Summit's RO testimony.

Summit do not bear the cost of those new facilities and, as a result, those customer do not incur any marginal costs associated with those facilities. Snow Summit recommends excluding the cost of the plant additions for the Snow Summit substation and associated equipment from the calculation of the unit marginal Distribution demand costs for coincident and non-coincident demands.

Snow Summit is the only customer on the BVES system that has an interruptible tariff, meaning that Snow Summit can have its loads curtailed by BVES in cases of supply shortages. Because of this, BVES does not apply marginal Generation capacity costs to customers in the A5 TOU Primary customer class in its Marginal Cost of Service calculations. An analogous situation exists regarding marginal increases in distribution equipment based on marginal increases in loads. If the expected loads for the A5 TOU Primary class increase resulting in the need for transmission or distribution equipment, BVES could curtail Snow Summit load and avoid the need for such equipment upgrades. This is well-understood by the Commission. Snow Summit recommends a modest decrease of 5% in the unit marginal Distribution cost for coincident demand for the A5 TOU Primary class to reflect this benefit. Snow Summit also recognizes that this issue has been discussed for years by the larger utilities and, as a result, recommends that BVES establish a stakeholder process to explore this issue further.

Snow Summit's recommended changes result in a more reasonable revenue requirement estimate for BVES. In addition, they provide superior estimates of unit marginal costs and marginal cost-based revenue requirements, which serve as the basis of BVES's

EPMC-based revenue allocation proposal. Even though BVES's revenue allocation proposal relies on only 10% of the EPMC-based revenue allocation, correct marginal costs and a proper marginal cost-based revenue allocations promote the efficient use of electricity. The Commission has found this in countless other proceedings, including in past BVES GRCs.

Q. How is your testimony organized?

A. After this introduction and summary section, Chapter II summarizes the key points of BVES's marginal cost and revenue allocation proposals in this proceeding. Next, Chapter III identifies and proposes corrections to BVES's marginal cost study. Chapter IV presents Snow Summit's proposed revenue allocation based on its recommendations regarding marginal costs. Chapter V provides summary recommendations and conclusions. Following the text of the testimony, there are several attachments that present materials referred to in this testimony.

Q. Does your testimony provide recommended changes to BVES's marginal costs and revenue allocation based on your recommendations?

A. Snow Summit presents approximate changes to BVES's marginal costs and revenue allocation in this testimony. In addition, Snow Summit presents approximate changes to BVES's Supply revenue requirements.

Snow Summit had intended to provide revised calculations of marginal costs and revenue allocation pursuant to its recommendations summarized above. Snow Summit attempted through discovery and informal meetings 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 copies of the models used by BVES to develop its testimony. When Snow Summit ultimately concluded that it would not be able to perform a full analysis of revenue allocation based on Snow Summit's revenue requirements recommendations presented in its prior testimony in this proceeding, Snow Summit requested that BVES evaluate the impact of certain changes to sales forecasts and marginal distribution costs.[5] BVES provided responses to those requests but following additional discovery, Snow Summit found that BVES had not analyzed ALL impacts of the scenarios requested by Snow Summit.[6] As a result, Snow Summit is unable to provide precise revenue requirements based on Snow Summit's recommendations.

Q. Can you provide an example of this issue?

A. Yes. BVES's Supply model has numerous values that are likely tied to loads, but the Supply model does not include formulae for those calculations. Instead, that model has "hard-coded" values. Thus, Snow Summit cannot provide the updated revenue allocations based on the revenue requirements and marginal costs consistent with Snow Summit's recommendations. As a result, this testimony will provide Snow Summit's recommendations for changes to factors affecting BVES's marginal costs and

[5] Snow Summit Data Request Set 8.
[6] BVES Response to Snow Summit Data Request Set 11, Request 6.

approximate estimates of the impacts of changed assumptions on BVES's marginal costs and revenue allocation.

II. BVES's Marginal Cost and Revenue Allocation Proposals

Q. At a high level, please describe BVES's approach for determination of marginal costs and revenue allocation in this proceeding.

A. In this proceeding, BVES uses a two-part weighted-average approach to develop its revenue allocation. The first part (the EPMC method) uses marginal costs for each customer class to develop marginal cost-based revenues for 2027 and then allocates the 2027 total revenue requirement based on the percent of marginal cost-based revenues for each class. The second part (the System Average Percent (SAP) method) applies the same percentage increase for each customer class's current class-average rate for 2026 to derive new class-average rates for 2027 and then multiplies those rates by forecasted sales in 2027 for each class to arrive at class revenue responsibility.

Q. Does BVES use the above approach for its entire revenue requirement?

A, No. BVES applies the above approach separately for its Base revenue requirements and for its Supply revenue requirements.[7]

Q. What costs are included in the Base revenue requirements?

[7] BVES allocates Other Operating Revenues (OOR) to customer classes in its RO models and adds this to the revenue allocation developed using the 90/10 approach.

A. BVES includes its distribution revenue requirements (i.e., distribution demand (coincident), distribution demand (non-coincident), and distribution (customer)) as well as certain capacity-related supply costs in its Base revenue requirements.[8]

Q. What costs are included in the Supply revenue requirements?

A. BVES assigns the variable costs from the Supply model to the Supply revenue requirements.

Q. How does BVES derive the EPMC-based revenue allocation for Base revenue requirements?

A. BVES describes the process as follows: "The EPMC method is applied by functional cost category. For example, demand-related distribution costs are allocated based on demand-related class marginal costs, and customer-related distribution costs are allocated based on customer-related class marginal costs."[9] Based on this approach, BVES claims that it develops unit marginal costs for Generation (energy), Generation (capacity), Distribution demand (coincident), Distribution demand (non-coincident), and Distribution (customer) in its marginal cost of service (MCS) model and applies different determinants to each of these unit marginal costs to develop marginal cost-based revenue requirements for each of these components of the revenue requirements. These marginal cost-based revenue requirements are then reconciled to equal the actual revenue requirement for each component of the revenue requirement.

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[8] BVES MCS Model, tab "RO Inputs," cells J1:J30.
[9] BVES Testimony, Chapter 6, p. 15.

Q. Does BVES in fact use the approach it described in its testimony to develop its EPMC-based revenue allocation?

A. No. Rather than developing actual revenue requirements for each component of its revenue requirements, BVES improperly combines portions of costs of different components. In addition, BVES improperly combines marginal cost-based revenue requirements before reconciliation. In other words, BVES's implementation of its EPMC-based revenue allocation is at odds with BVES's theoretical description of its approach.

Q. Please explain.

A. To develop its total revenue requirements by "component" BVES does the following:

- Distribution (customer): BVES derives this component of its revenue requirement in its RO model.
- Other Operating Revenues: BVES derives this component of its revenue requirement in its RO model.
- Generation: BVES uses the revenue requirements calculated in its Supply model.
- Distribution (demand): BVES derives this by subtraction. It takes the total revenue requirements from its RO model and subtracts the revenue requirements for Distribution (customer), Other Operating Revenues, and Generation and calls this Distribution (demand). In practice, this component of BVES's revenue requirements consists of Distribution (coincident), Distribution (non-coincident), and the fixed Generation costs not captured in the Supply model. Thus, this component combines both Distribution and certain Generation costs.

The following figure[10] presents BVES's approach to developing its components of its revenue requirements:

[10] In order to avoid confusion, any tables taken directly from BVES testimony or workpapers will be called a "figure".

Figure 1: BVES Development of Components of Revenue Requirements

Revenue Requirements	2027
Revenue Requirements (Generation)	16372131.64
Revenue Requirements (Distribution) - Dem	$ 51,301,726
Revenue Requirements (Distribution) - Cust	7,168,714
Revenue Requirements (Other)	1,885,007
Total Revenue Requirements	76,727,578

Revenue Requirements	Total	Customer [1] [2]	Demand
Rate Base			
Plant ($000)	293134.5683	36787.0708	256347.4975
CWIP ($000)	3,031		3,031
Accum. Depr ($000)	(69,813)	-15538.87987	(54,274)
Net Plant ($000)	226,353	21,248	205,104
Other Adjustments ($000)	-19584.61177	-1838.44898	-17746.16279
Rate Base ($000)	206767.914	19409.74194	187358.172
Return on Rate Base ($)	$ 18,919,264	$ 1,775,991	$ 17,143,273
Expenses			
Production, Transmission	17556581.72		17556581.72
Distribution	$ 7,475,857	268676.0693	7,207,181
Customer Acc. + Uncoll	$ 1,476,716	1,476,716	
A&G	$ 13,690,343	901,387	12,788,956
Depreciation	$ 7,202,703	1769099.65	5433603.802
Other Taxes	$ 4,447,821	417,526	4,030,295
Income Taxes	$ 5,958,292	559,317	5,398,974
Revenue Requirements	76727578.23	$ 7,168,714	$ 69,558,865
Other Revenues	-1885006.82		-1885006.82
Supply	(16,372,132)		(16,372,132)
Distribution	$ 58,470,440	7168713.692	$ 51,301,726
		$ 0	$ 1

[1] Plant includes Accounts 368-370 (Transformers, Meters, Services)
[2] Distribution O&M includes Accounts 586, 587, 595, 597

Source: Derived from BVES MCS Model, Tab “RO Inputs.”

Q. Please explain the above figure.

A. The upper left corner of the figure presents BVES's derived revenue requirements by "component." The figure highlighted in yellow is the revenue requirements derived from BVES's Supply model.[11] Also shown is BVES's Distribution (customer) revenue requirements (developed in its own workpaper[12]) and the Other Operating Revenues (derived in BVES's RO models). The revenue requirements for Distribution - Dem is derived in the right half of the figure. The column labeled "Total" presents the derivation of the total revenue requirements ($76,727,578). The column labeled "Customer" presents the total revenue requirements for Distribution (customer), which is equal to $7,168,714. The column labeled "Demand" is the residual revenue requirements ($69,558,865). As can be seen, this column includes expenses for Production, Transmission, Distribution, A&G, Depreciation, Taxes, and other items. To arrive at the value labeled as Distribution-dem, BVES subtracts Other Revenue and Supply revenue requirements from the $69,558,865 to arrive at the value of $51,301,726.

Q. Doesn't subtracting "Supply revenue" remove all Generation costs of Distribution – Dem?

A. No. "Supply" is only the expense portion of Generation costs calculated in the Supply model. There are other costs (e.g., depreciation, taxes, return on rate base) plus the

[11] "CONFIDENTIAL BVES GRC Supply Forecast Model (NO SOLAR) 062426.xlsx." (BVES Supply Model) Calculations performed in tab "Input Loads & Resources." Summary of results in tab "TAB #E1 Supply Expense SUMRY."
[12] BVES MCS Model, tab "MDC-Derivation."

portion of Administrative and General (A&G) cost that is allocated to Generation that are still included in Distribution-Dem.

Q. What is the magnitude of Generation costs that remain in Distribution-Dem?

A. Without additional information from BVES, it is not possible to develop precise values for the amount of generation-related costs that are inappropriately assigned to the Distribution revenue requirements. However, I estimate that approximately $96,000 of production expenses and about $8.5 million of A&G are inappropriately assigned to the Distribution revenue requirement.[13] I cannot provide a precise value for the amount of return, depreciation, and taxes that are incorrectly assigned to distribution demand.

Q. Why do you say that BVES improperly combines marginal cost-based revenues?

A. In the development of marginal cost-based revenues used to derive the EPMC-based revenue allocation, BVES uses the sum of the marginal cost-based revenues for Generation (capacity) and Generation (energy)[14] as the basis for the marginal cost-based revenue that is reconciled against the Supply revenue requirements. In addition, BVES uses the sum of the marginal cost-based revenues for Distribution (coincident) and Distribution (non-coincident)[15] as the basis for the marginal cost-based revenues that is reconciled against Distribution – Dem, which contains generation costs.

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[13] Production expense estimate derived from BVES Model "SEC 2-SOE.xlsm," tab "RO Detail S2." A&G estimate assumes that total A&G (after deduction for Distribution (customer)) is allocated based on % of expenses for Production: $16,372,132/($17,556,582+$7,207,191) * $12,788,956 = $8,455,196. See BVES MCS Model, tab "RO Inputs."

[14] BVES MCS Model, tab "Target Revenues", cells C17:K17.

[15] BVES MCS Model, tab "Target Revenues", cells C25:K25.

Q. How does BVES use these two methods to arrive at its recommended revenue allocation?

A. BVES applies a fixed percentage (10%) to the EPMC-based class revenue requirements and the remainder (90%) to the SAP-based class revenue requirements to arrive at the weighted-average revenue allocation for its Base revenue requirements and its Supply revenue requirements for 2027.

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

A. In its RO Testimony, Snow Summit presented BVES's proposed revenue requirements and revenue allocation by customer class and year.[16] For convenience, that table is reproduced here:

[16] Snow Summit RO Testimony, p. 11.

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 BVES's Marginal Cost of Service (MCS) model, tab "Target Revenues."

As can be seen from the above table, 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.

The following table from Snow Summit's RO testimony[17] presents the change in class-average rates by customer class and year as well as the compound average growth rate (CAGR) over the entire GRC cycle:

Table 2: Percentage Rate Increases Proposed by BVES by Year and Customer Class

	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 MCS model, tab "Target Revenues."

As can be seen from the above table, 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 3.4~~6.3~~% and ~~12.5~~11.9% for each year of the 4-year GRC cycle for all customer classes.

[17] Snow Summit RO Testimony, p. 12.

The following table from Snow Summit's RO testimony[18] presents BVES's revenue fractions by customer class and year:

Table 3: Revenue Allocation Fractions Proposed by BVES

	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 MCS model, tab "Target Revenues." These fractions are w/o OOR.

Revenue fractions are equal to the fraction of BVES's total revenue requirements (excluding Other Operating Revenues) assigned to each customer class by year. As can be seen from the above table, 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, A-5 Primary).

Q. How does BVES propose to develop its revenue allocations in this proceeding?

[18] Snow Summit RO Testimony, p. 13.

A. For 2027, BVES proposes to use a weighted average revenue allocation, with 10% of the revenue allocation based on EPMC and 90% based on SAP.[19] For the attrition years, BVES proposes to use SAP to determine revenue allocation.[20]

Q. How did BVES develop its SAP proposal for the attrition years?

A. As can be seen from Table 3~~Table 3~~ above, BVES's revenue allocation proposal for the attrition years of 2028-2030 does not apply an SAP change to class revenue allocation. This is shown by the fact that the revenue fraction for each class changes by year. Instead, BVES calculates an "SAP change" by comparing the revenue requirements for year "X" with the sum of the class-specific forecasted revenues for year "X" based on assumed sales to each class in year "X" and rates for each class from year "X-1." BVES then applies that same percentage change to the rates for each class from year "X-1" to derive the rates for each class for year "X". BVES then derives the revenue allocation for the year by multiplying the derived class-specific rates for year "X" by the class-specific sales to that class in year "X". BVES uses this process separately for its Base revenue requirements and its Supply costs.

Q. Are there cross-subsidies within BVES's proposed revenue allocation based on BVES's assumed marginal costs in this proceeding?

A. Yes. Cross-subsidies exist when the revenue allocation for a particular class is different from the EPMC-based revenue allocation for that class. Using BVES's marginal costs,

[19] BVES Testimony, Chapter 6, p. 16.
[20] BVES Testimony, Chapter 6, p. 17.

the following table presents the cross-subsidies that exist in BVES's proposed rates in this proceeding and as proposed by BVES in its last GRC:

Table 4: Inter-Class Subsidies in BVES's Proposal Using BVES's Marginal Costs

	BVES 2027	Prior GRC
Residential Permanent Service	(2,584,702) ~~(2,524,770)~~	(3,347,865)
Residential Non-Permanent Service	996,278 ~~934,081~~	1,236,548
General Service - Small (A1)	871,017 ~~1,000,346~~	393,163
General Service - Medium (A2)	53,019 ~~86,100~~	182,278
General Service - Large (A3)	1,298,030 ~~1,325,254~~	384,813
General Service - Time-of-Use (A4-TOU)	725,373 ~~748,581~~	499,329
Time-of-Use Service (A5 TOU Secondary)	(621,966) ~~(621,357)~~	66,812
Time-of-Use Service (A5 TOU Primary)	(684,447) ~~(895,355)~~	520,997
Street Lighting	(52,603) ~~(52,880)~~	63,925
Total	-	0

Sources: BVES 2027 derived from MCS model, tab "Target Revenues." Prior GRC derived from "Direct Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case, Application 22-08,010," May 26, 2023, p. 16.

Q. Do you have any comments about the above table?

A. Yes. The above table presents BVES's own estimates of the cross-subsidies in its current rate proposal and compares those estimates with the cross-subsidies in BVES's prior GRC rate proposal. The most surprising result is that BVES now contends (based on BVES's own marginal costs) that the A5 TOU Primary class (A5-P) is being subsidized by other customer classes whereas in the prior GRC (and for at least the three GRCs prior to this proceeding) BVES's own analysis (relying on BVES's own marginal costs) showed that the A5-P class was subsidizing other customers (e.g., the Permanent Residential class).

Q. How can you explain such a change in the cross-subsidization for the A5-P class between the prior GRC and this GRC?

A. The only explanation is that the current GRC has hugely different estimates of marginal costs for the A5-P class relative to the prior GRC. The following table compares the fraction of marginal costs[21] by function for the two GRCs:

Table 5: Percentage Change in Marginal Costs Between Prior and Current GRC

		Res. Perm.	Res. Non-Perm.	A1 Comm'l	A2 Comm'l	A3 Comm'l	A4 TOU	A5 Sec.	A5 Pri.	Street Lights	Total
Generation	2027 TY	27%~~27%~~	38%~~38%~~	13%~~13%~~	4%~~4%~~	4%~~4%~~	4%~~4%~~	2%~~2%~~	9%~~9%~~	0%~~0%~~	100%
	2023 TY	32%~~32%~~	38%~~38%~~	12%~~12%~~	5%~~5%~~	5%~~5%~~	3%~~3%~~	0%~~0%~~	6%~~6%~~	0%~~0%~~	100%
	Diff.	-5%~~-5%~~	0%~~0%~~	1%~~1%~~	-1%~~-1%~~	0%~~-1%~~	1%~~1%~~	2%~~2%~~	3%~~3%~~	0%~~0%~~	
Distribution Demand	2027 TY	24%~~24%~~	37%~~38%~~	12%~~11%~~	4%~~4%~~	4%~~4%~~	3%~~3%~~	2%~~2%~~	14%~~14%~~	0%~~0%~~	100%
	2023 TY	32%~~32%~~	41%~~41%~~	12%~~12%~~	5%~~5%~~	4%~~4%~~	2%~~2%~~	0%~~0%~~	4%~~4%~~	0%~~0%~~	100%
	Diff.	-8%~~-8%~~	-3%~~-3%~~	0%~~-1%~~	-1%~~-1%~~	0%~~0%~~	1%~~1%~~	2%~~2%~~	10%~~10%~~	0%~~0%~~	
Distribution Customer	2027 TY	27%~~27%~~	50%~~50%~~	14%~~14%~~	3%~~3%~~	3%~~3%~~	0%~~0%~~	0%~~0%~~	1%~~1%~~	1%~~1%~~	100%
	2023 TY	26%~~26%~~	51%~~51%~~	13%~~13%~~	4%~~4%~~	4%~~4%~~	0%~~0%~~	0%~~0%~~	1%~~1%~~	1%~~1%~~	100%
	Diff.	1%~~1%~~	-1%~~-1%~~	1%~~1%~~	-1%~~-1%~~	-1%~~-1%~~	0%~~0%~~	0%~~0%~~	0%~~0%~~	0%~~0%~~	
Other Operating Revenues	2027 TY	1%~~25%~~	2%~~39%~~	1%~~12%~~	0%~~4%~~	0%~~4%~~	0%~~3%~~	0%~~2%~~	96%~~11%~~	0%~~0%~~	100%
	2023 TY	32%~~32%~~	41%~~41%~~	12%~~12%~~	5%~~5%~~	4%~~4%~~	2%~~2%~~	0%~~0%~~	4%~~4%~~	0%~~0%~~	100%
	Diff.	-31%~~-7%~~	-39%~~-2%~~	-11%~~0%~~	-5%~~-1%~~	-4%~~0%~~	-2%~~1%~~	0%~~2%~~	92%~~7%~~	0%~~0%~~	
Total	2027 TY	25%~~25%~~	39%~~39%~~	12%~~12%~~	4%~~4%~~	4%~~4%~~	3%~~3%~~	2%~~2%~~	12%~~12%~~	0%~~0%~~	100%
	2023 TY	32%~~32%~~	41%~~41%~~	12%~~12%~~	5%~~5%~~	4%~~4%~~	2%~~2%~~	0%~~0%~~	4%~~4%~~	0%~~0%~~	100%
	Diff.	-6%~~-7%~~	-2%~~-2%~~	0%~~0%~~	-1%~~-1%~~	0%~~0%~~	1%~~1%~~	2%~~2%~~	8%~~8%~~	0%~~0%~~	

[21] These fractions are based on the percentage of reconciled revenue requirements based on the percent of marginal cost allocated to each customer class.

The above table compares the percentage of marginal costs for each function (i.e., Generation, Distribution Demand, Distribution Customer, and Other Operating Revenues) for BVES's estimates in this case and in the prior GRC. The highlighted cells show where there are very large changes for the A5-P class. In each of the highlighted cells, BVES's percentage of total marginal costs for the A5-P are greater than in the prior GRC.

Q. Does Snow Summit have concerns with BVES's proposed marginal costs and revenue allocation?

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

III. BVES Should Correct Errors in Its Marginal Cost Study

Q. What is the purpose of this chapter?

A. This chapter addresses BVES's marginal cost study.[22]

Q. How did BVES use the marginal cost study?

A. As discussed in the next chapter, BVES proposes to develop its Base and Supply revenue allocations for 2027 partially on this marginal cost study.

Q. Do you agree with BVES's marginal cost study?

[22] BVES Testimony, Volume 6, pp. 7-14. BVES develops its estimates of marginal costs in its MCS Model.

A. Not entirely. There are several errors in BVES's study. These errors result in incorrect calculation and application of marginal costs, which skew the determination of a marginal cost-based revenue allocation.

Q. What are the impacts of BVES's flawed marginal cost study?

A. As noted above, BVES's marginal cost study in this proceeding resulted in huge changes in marginal cost fractions[23] relative to BVES's prior GRC. Using BVES's incorrect marginal costs results in an incorrect EPMC-based revenue allocation. Since BVES bases its proposed revenue allocation in part on its EPMC-based revenue allocation, the errors in BVES's marginal cost study result in an incorrect revenue allocation.

Q. Please summarize the errors you have identified in BVES's marginal cost study that you address in this testimony.

A. I address two errors that have notable impacts on the marginal cost results:

1. As noted in Snow Summit's RO testimony, BVES's sales and load forecasts for the A5-P customer class are unreasonable. First, BVES's forecast for the snowmaking months (November through March) is significantly higher for 2026 than actual loads for the A5-P class.[24] Second, BVES's forecast for the non-snowmaking months of April-October inexplicably increased in 2025 (and that increase persists in 2026-2030.)[25] By forecasting higher than reasonable sales and

[23] "Marginal cost fractions" are the fraction of total reconciled revenue requirements based on marginal costs. The marginal costs for each function and customer class are applied to the total revenue requirement for each function to arrive at the reconciled revenue requirements based on marginal costs. These reconciled revenue requirements are the basis for BVES's EPMC-based revenue requirements.
[24] Snow Summit RO Testimony, pp. 26 to 28.
[25] Snow Summit RO Testimony, pp. 20 to 23.

loads for the A5-P class, BVES not only overstates its Supply revenue requirements but it also uses unreasonable loads for the determination of marginal costs.[26]

2. BVES improperly includes certain plant costs in its development of its unit marginal costs for transmission and distribution (T&D) (demand). BVES includes plant costs for substations and equipment that are paid for 100 percent by Snow Summit, meaning that there are no marginal costs to other ratepayers associated with those facilities. In addition, the T&D plant costs that BVES includes are not caused by changes in demand, meaning that they are not marginal, resulting in incorrect unit marginal Distribution (demand) costs.

Q. Are the errors you address in this testimony the only errors in its workpapers?

A. They may not be. However, my testimony focuses on the errors summarized above. This does not mean that there are not other errors in BVES's marginal cost study or that Snow Summit necessarily agrees with the remaining assumptions of (and results from) the Marginal Cost of Service study.

Q. What is the significance of the errors in BVES's marginal cost calculations that you address?

A. The development of reasonably accurate marginal costs is critical to establishing the degree to which a utility's rates are based on marginal costs in a manner consistent with longstanding Commission policy. If underlying assumptions and/or calculations within a

[26] Snow Summit's RO Testimony also noted that BVES uses two separate load forecasts in the development of its revenue requirements for supply and for developing marginal costs. Snow Summit RO Testimony, pp. 23 to 26.

utility's marginal cost analysis are unreasonable or simply incorrect, they can result in errors in the marginal costs recommended by the marginal cost study. This would unfairly bias the marginal cost-based revenue allocation as determined by the utility's analysis in favor of one or more customer classes and against other customer classes. It would also result in less efficient use of electricity by customers.

A. BVES's Load Forecasts For A5-P Customers Are Too High, Resulting In Incorrect Unit Marginal Costs

Q. How are BVES's load forecasts used in the determination of unit marginal costs, revenues at marginal costs, and EPMC-based revenue allocation?

A. BVES's Marginal Cost of Service model uses load forecasts in a number of different ways:

- Hourly Marginal Energy Costs: BVES uses its load forecast as the basis for the determination of its Supply revenue requirements. BVES's Supply model takes hourly loads[27] and performs a deterministic "dispatch" of the resources BVES has under its control to meet those loads.[28] The hourly "Total Net Expenditure per Net MWh" from the Supply model is the value that BVES uses as its hourly marginal energy costs in its MCS model. BVES uses the total costs and the total loads by time of use period for the Test Year (2027) and the three attrition years (2028-2030) to derive the unit marginal energy costs by time of use period.

[27] Note that the hourly loads used in the Supply model are capped at 47.4 MW, while the hourly loads used in parts of the MCS model are not capped at this level. Snow Summit has submitted numerous data requests regarding this apparent inconsistency to BVES but BVES claims that there is no inconsistency. See BVES Response to Snow Summit Data Request Set 9, Request 1, BVES Response to Snow Summit Data Request Set 10, Requests 1 and 2, BVES Response to Snow Summit Data Request Set 11, Request 1, BVES Response to Snow Summit Data Request Set 12, Request 1.

[28] The Supply model also calculates other costs, such as BVES's Resource Adequacy and CAISO costs.

- Long Run Unit Transmission and Distribution Marginal Costs: BVES uses a modified version of the so-called "NERA" method for determining the long-run unit transmission and distribution costs (on a $/kW basis).[29] The NERA method uses regressions of cumulative plant additions for transmission, distribution plant, and substation costs against both maximum coincident and maximum non-coincident demands to derive long-run unit transmission and distribution costs. Maximum coincident demand is the maximum demand of all customers in a particular hour of a year. Maximum non-coincident demand is the sum of the maximum hourly demands for each customer class for a year.
- Allocation of Marginal Costs to Customer Classes: In addition to using load forecasts for the determination of unit marginal costs, BVES uses load forecasts to calculate the total costs for each customer class for each category of costs (e.g., generation capacity, generation energy, distribution demand (coincident), distribution demand (non-coincident)). This Marginal Cost of Service relies on different aggregations of loads for different customer classes. These are:
    - Allocation of total marginal energy costs to time of use periods and customer classes using the total loads disaggregated by customer class and time of use periods for the Test Year.
    - Allocation of total marginal generation capacity costs to time of use periods and customer classes using the fraction of total demands disaggregated by time of use period and customer class for the top 100 hours of coincident demand in the Test Year.

[29] BVES Response to Snow Summit Data Request Set 7, Request 7.

- Allocation of unit coincident marginal T&D fixed costs to time of use periods using the fraction of the top 100 hours of coincident demand in the Test Year in each time of use period.
- Allocation of total coincident marginal T&D fixed costs by time periods for each customer class based on the average load by time of use period for each customer class for the Test Year.
- Allocation of total coincident marginal T&D variable costs to customer classes based on annual customer loads for each class.
- Allocation of total non-coincident marginal T&D costs to customer classes based on annual non-coincident demand by customer class.

As can be seen from the above, loads by customer class are a critical part of the development of Marginal Cost of Service for each customer class, which is then used to develop the EPMC-based revenue allocation.

Q. What are your recommended changes to the forecasted loads for the A5-P class?

A. As discussed in Snow Summit's RO testimony, Snow Summit recommends (1) reducing forecasted loads in the snowmaking months by 12.5% for 2026-2030 and (2) to use the average of 2024 and 2025 loads during the non-snowmaking months for the forecasted corresponding monthly loads in 2026-2030. Based on those recommendations, Snow Summit recommends applying the following scalars to BVES's forecasted hourly loads for each month and year:

Table 6: Scalars for Hourly Loads for A5-P Class

Month	2025	2026	2027	2028	2029	2030
1	100.0%	87.5%	87.5%	87.5%	87.5%	87.5%
2	100.0%	87.5%	87.5%	87.5%	87.5%	87.5%
3	100.0%	87.5%	87.5%	87.5%	87.5%	87.5%
4	100.0%	78.5%	78.2%	78.9%	78.9%	78.9%
5	100.0%	88.7%	89.7%	89.6%	89.2%	88.3%
6	100.0%	81.4%	81.5%	80.5%	81.9%	81.9%
7	100.0%	82.9%	88.5%	87.7%	87.8%	82.1%
8	100.0%	82.9%	82.0%	80.1%	81.2%	83.3%
9	100.0%	79.2%	79.5%	82.7%	82.3%	81.6%
10	100.0%	118.9%	124.0%	114.1%	108.5%	107.7%
11	87.5%	87.5%	87.5%	87.5%	87.5%	87.5%
12	87.5%	87.5%	87.5%	87.5%	87.5%	87.5%

As can be seen from the above table, Snow Summit does not recommend reducing BVES's loads in January-October of 2025 since the two new substations serving the Snow Summit resort did not come online until the end of September 2025.

Q. Did you also examine the reasonableness of BVES's load forecasts for other customer classes?

A. No. Snow Summit requested hourly load data from BVES for 2024 to the present for all customer classes but BVES indicated that it "has raw metered reads for 2025 and 2026, but has not gone through class-load study yet. BVES will not be doing the class-load study until the next GRC."[30] Thus, Snow Summit was unable to review the reasonableness of BVES's load forecasts for other customer classes. However, there are

[30] BVES Response to Snow Summit Data Request Set 11, Request 2. See also BVES Response to Snow Summit Data Request Set 10, Request 2. Snow Summit even asked for aggregated monthly loads by customer class once BVES indicated that it hadn't completed its "class load study." BVES refused to provide loads in this aggregated form. BVES Response to Snow Summit Data Request Set 12, Request 3.

likely fewer huge errors in BVES's forecasts for classes other than A5-P since none of the other classes had such significant changes in loads after 2024 (i.e., the installation of the new substations at Snow Summit resort in late September 2025 allowed Snow Summit to purchase significantly greater amounts of energy from BVES than before the substations were installed.)

Q. What are the impacts of your recommended changes in loads for the A5-P class on the various elements of BVES's proposals?

A. The following table summarizes Snow Summit's recommended load forecast for use in BVES's Marginal Cost of Service model[31] by customer class:

Table 7: Snow Summit Recommended Load Forecast (MWh)

	2025	2026	2027	2028	2029	2030
Perm Res	45,910	45,357	44,681	44,103	43,315	42,643
Seas Res	52,688	54,260	55,800	57,625	59,320	61,154
A1	21,801	22,276	22,775	23,186	23,507	23,956
A2	7,409	7,082	7,032	6,737	6,402	6,099
A3	7,442	7,546	7,854	7,475	7,254	7,293
A4	5,761	6,307	7,019	7,619	7,381	6,764
A5-S	2,301	2,295	2,287	2,294	2,294	2,306
A5-P	18,186	20,297	20,081	19,626	19,686	19,758
Street Lt	107	107	106	107	106	107
Total	161,605	165,525	167,635	168,772	169,267	170,078

The following table presents the change in load for the A5-P class resulting from Snow Summit's recommendations:

[31] Snow Summit also derived hourly loads for use in BVES's Supply model based on the modified hourly loads discussed here. The modified hourly loads for the Supply model limited hourly loads for the BVES system to 47.4 MW.

Table 8: Comparison of BVES and Snow Summit Load Forecast for A5-P Class (MWh)

	2025	2026	2027	2028	2029	2030
BVES	19,334	23,271	22,985	22,489	22,568	22,676
Snow Summit	18,186	20,297	20,081	19,626	19,686	19,758
Change	(1,147)	(2,974)	(2,905)	(2,864)	(2,881)	(2,918)

The following table presents Snow Summit's forecast[32] of coincident peak loads used in BVES's Marginal Cost of Service model[33] by customer class:

Table 9: Snow Summit Recommended Coincident Peak Demand Forecast (MW)

	2024	2025	2026	2027	2028	2029	2030
Perm Res	8,797	9,423	9,318	7,763	7,655	7,533	8,763
Seas Res	12,923	14,702	15,072	13,242	13,567	13,934	16,642
A1	4,225	1,796	1,829	1,632	1,662	1,691	1,965
A2	1,248	1,040	997	637	605	580	897
A3	984	771	861	851	818	904	932
A4	684	430	485	481	513	477	485
A5S	456	934	934	834	834	834	934
A5P	12,410	22,389	22,389	25,652	25,652	25,652	22,389
Street Lt	20	25	25	25	25	25	25
System	41,748	51,511	51,912	51,117	51,330	51,629	53,033

The following table compares the forecasts of coincident peak loads from BVES and Snow Summit for the A5-P class based on Snow Summit's revised forecast of hourly loads for the A5-P class:

[32] BVES admitted that the coincident peak demands that it originally presented in its MCS model were incorrect. The coincident peak demands presented in this table have been corrected by Snow Summit (since BVES indicated that it would correct the erroneous coincident peak demands in its rebuttal testimony). See BVES Response to Snow Summit Data Request Set 9, Request 5.

[33] Snow Summit also derived hourly loads for use in BVES's Supply model based on the modified hourly loads discussed here. The modified hourly loads for the Supply model limited hourly loads for the BVES system to 47.4 MW.

Table 10: Comparison of Snow Summit and BVES Forecast of Coincident Peak Demand for A5-P Class (MW)

	2024	2025	2026	2027	2028	2029	2030
Snow Summit	12,410	22,389	22,389	25,652	25,652	25,652	22,389
BVES	12,410	25,588	25,588	29,316	29,316	29,316	25,588
Change	-	(3,198)	(3,198)	(3,665)	(3,665)	(3,665)	(3,198)

The following table presents Snow Summit's forecast of non-coincident maximum loads:

Table 11: Snow Summit Forecast of Maximum Non-Coincident Peak Loads (MW)

	2024	2025	2026	2027	2028	2029	2030
Perm Res	12,220	13,907	13,753	13,556	13,366	13,153	12,933
Seas Res	17,002	19,619	20,112	19,957	20,446	21,000	22,207
A1	6,208	6,905	7,033	7,163	7,293	7,419	7,557
A2	2,097	2,406	2,283	2,286	2,192	2,077	1,988
A3	1,657	1,900	2,122	2,288	2,200	2,431	2,295
A4	1,302	1,273	1,471	1,649	1,808	1,731	1,654
A5S	751	1,134	1,134	1,134	1,134	1,134	1,134
A5P	19,753	29,849	29,849	29,849	29,849	29,849	29,849
Street Lt	40	39	39	39	39	39	39
System	61,030	77,032	77,795	77,920	78,326	78,834	79,656

The following table compares the forecasts of non-coincident maximum loads from BVES and Snow Summit for the A5-P class based on Snow Summit's revised forecast of hourly loads for the A5-P class:

Table 12: Comparison of Snow Summit and BVES Maximum Non-Coincident Loads (MW)

	2024	2025	2026	2027	2028	2029	2030
Snow Summit	19,753	29,849	29,849	29,849	29,849	29,849	29,849
BVES	19,753	34,113	34,113	34,113	34,113	34,113	34,113
Change	-	(4,264)	(4,264)	(4,264)	(4,264)	(4,264)	(4,264)

The following table presents summary statistics about Snow Summit's forecast of the Top 100 maximum coincident peak demands for 2027 based on Snow Summit's revised forecast of hourly loads for the A5-P class:

Table 13: Snow Summit Forecast of Top 100 Maximum Coincident Loads (kW)

Top 100 Hours (Avg. Load)	**# of Hours**	**Top 100 %**	**System Kw**	**Perm Res**	**Seas Res**	**A1**	**A2**	**A3**	**A4**	**A5S**	**A5P**	**Street Lt**	**BVES TOU Period**
Winter TOU - Peak	41	**41.00%**	46,658	8,346	12,380	3,107	1,018	1,105	693	665	19,320	24	W-OnP
Winter TOU - Mid-Peak	25	**25.00%**	44,989	6,702	10,895	2,445	906	919	618	500	21,985	19	W-MP
Winter TOU - Off-Peak	34	**34.00%**	45,084	4,788	10,048	2,437	853	883	706	555	24,790	24	W-OfP
Summer TOU - Peak	-	**0.00%**	-	-	-	-	-	-	-	-	-	-	S-OnP
Summer TOU - Mid-Peak	-	**0.00%**	-	-	-	-	-	-	-	-	-	-	S-MP
Summer TOU - Off-Peak	-	**0.00%**	-	-	-	-	-	-	-	-	-	-	S-OfP

The following table presents the differences between the forecasts of Snow Summit and BVES:

Table 14: Comparison of Snow Summit and BVES Top 100 Loads

Top 100 Hours (Avg. Load)		# of Hours	Top 100 %	System Kw	Perm Res	Seas Res	A1	A2	A3	A4	A5S	A5P	Street Lt
Winter TOU - Peak		2	2.00%	(2,944)	69	128	91	23	24	25	(1)	(3,302)	0
Winter TOU - Mid-Peak		1	1.00%	(3,257)	70	295	112	38	(4)	(2)	1	(3,769)	0
Winter TOU - Off-Peak		(3)	-3.00%	(3,389)	(63)	144	(21)	(5)	(1)	(12)	3	(3,435)	0
Summer TOU - Peak		-	0.00%	-	-	-	-	-	-	-	-	-	-
Summer TOU - Mid-Peak		-	0.00%	-	-	-	-	-	-	-	-	-	-
Summer TOU - Off-Peak		-	0.00%	-	-	-	-	-	-	-	-	-	-

As can be seen from Table 14~~Table 14~~ above, Snow Summit's load forecast results in 2 more hours in the Winter TOU-Peak Period than BVES's forecast (41 vs. 39 hours). The Snow Summit forecast also results in lower average loads for the A5-P class in all Winter TOU periods (e.g., 3,302 kW lower in the Winter Peak period) but slightly higher values in the Winter TOU-Peak and Winter TOU-Mid-Peak periods for most of the other classes (e.g., 69 kW and 70 kW increases for Permanent Residential class in the Winter Peak and Winter Mid-Peak periods.)

Q. What is the impact of Snow Summit's proposed load forecast on the supply revenue requirements?

A. The following table presents Snow Summit's estimate of Supply revenue requirements by customer class for 2027:

Table 15: Impact of Snow Summit Load Forecast Recommendation on Supply Costs ($)

	BVES	Snow Summit	Snow Summit - BVES
Residential Permanent	4,375,801 ~~4,375,801~~	4,307,802 ~~4,308,692~~	(67,999) ~~(67,109)~~
Residential Non-Permanent	5,464,204 ~~5,464,204~~	5,381,906 ~~5,383,002~~	(82,298) ~~(81,202)~~
A1 Commercial	2,050,344 ~~2,050,344~~	2,019,038 ~~2,019,455~~	(31,306) ~~(30,889)~~
A2 Commercial	536,427 ~~536,427~~	528,357 ~~528,463~~	(8,070) ~~(7,964)~~
A3 Commercial	779,769 ~~779,769~~	767,510 ~~767,670~~	(12,259) ~~(12,099)~~
A4 TOU	716,684 ~~716,684~~	705,187 ~~705,336~~	(11,497) ~~(11,348)~~
A5 Secondary	212,544 ~~212,544~~	209,160 ~~209,202~~	(3,384) ~~(3,342)~~
A5 Primary	2,227,803 ~~2,227,803~~	2,175,630 ~~2,172,768~~	(52,174) ~~(55,035)~~
Street Lighting	8,556 ~~8,556~~	8,419 ~~8,421~~	(137) ~~(135)~~
Total	16,372,132 ~~16,372,132~~	16,103,009 ~~16,103,009~~	(269,123) ~~(269,123)~~

As can be seen from the above table, using more reasonable load forecasts for the A5-P class results in a reduction in the supply revenue requirement of $269,123.

Q. How did you derive the change in supply revenue requirements?

A. I input Snow Summit's recommended hourly loads into BVES's supply model (capping loads at 47.4 MW). I did not change any of BVES's assumptions regarding the cost or availability of different supply options.

Q. Do you have any concerns about Snow Summit's estimate of Supply revenue requirements?

A. Yes. BVES's Supply model has several assumptions that are "hard-wired" but that likely change with changes to load forecasts. These include:

- Quantity and price of Renewable Energy Credits (RECs) that BVES must purchase
- The Resource Adequacy (RA) capacity charge paid by BVES

- Fees paid to the California Independent System Operator (CAISO)
- Charges paid by BVES for transmission access and options
- The amount of energy either supplied or consumed each hour by BVES's proposed battery project

Because these charges did not vary in BVES's Supply model with revised loads, they are likely incorrect in Snow Summit's estimate of supply revenue requirements. However, since Snow Summit's load forecast is lower than BVES's forecast for the A5-P class and for the BVES system, I would expect that the Supply revenue requirements would be slightly less than presented in Table 15~~Table 15~~ above.

Q. What are the impacts of Snow Summit's revised load forecast for the A5-P class on marginal costs?

A. The following table compares the unit generation marginal costs by TOU period for Snow Summit and BVES:

Table 16: Comparison of Generation Unit Marginal Costs ($/kW-yr)

Snow Summit				BVES				Change (SS - BVES)		
Generation MC ($/kW)	312.38	% Top 100 Hrs		Generation MC ($/kW)	312.38	% Top 100 Hrs		Generation MC ($/kW)	-	% Top 100 Hrs
Winter Peak	128.08	41%		Winter Peak	121.83	39%		Winter Peak	6.25	2%
Winter Mid-Peak	78.10	25%		Winter Mid-Peak	74.97	24%		Winter Mid-Peak	3.12	1%
Winter Off-Peak	106.21	34%		Winter Off-Peak	115.58	37%		Winter Off-Peak	(9.37)	-3%
Summer Peak	-	0%		Summer Peak	-	0%		Summer Peak	-	0%
Summer Mid-Peak	-	0%		Summer Mid-Peak	-	0%		Summer Mid-Peak	-	0%
Summer Off-Peak	-	0%		Summer Off-Peak	-	0%		Summer Off-Peak	-	0%

As seen from the above table, a greater percentage of the unit generation marginal costs are assigned to the winter peak (41% vs. 39%) and the winter mid-peak (25% v. 24%) periods using Snow Summit's load forecast.

The following table compares the unit marginal energy costs by TOU period for Snow Summit and BVES:

Table 17: Comparison of Snow Summit and BVES Unit Marginal Energy Costs ($/MWh)

	Based on 2027-2030 Supply Forecast		
Generation Marginal Energy Costs	**Snow Summit**	**BVES**	**Change**
Winter Peak	56.42	57.31	(0.89)
Winter Mid-Peak	67.69	68.21	(0.51)
Winter Off-Peak	66.67	68.46	(1.79)
Summer Peak	47.51	47.50	0.01
Summer Mid-Peak	68.90	68.76	0.14
Summer Off-Peak	62.57	62.54	0.03

As can be seen from the above table, the unit marginal energy costs for the winter TOU periods are slightly lower based on Snow Summit's load forecast than BVES's estimates (e.g., $56.42/MWh vs. $57.31/MWh in the Winter Peak period.) In addition, the unit marginal energy costs for the summer TOU periods are slightly higher using Snow Summit's load forecast.

Q. Does Snow Summit's revised load forecast affect BVES's estimate of unit customer-related marginal distribution costs?

A. No.

Q. Does Snow Summit's load forecast affect the unit marginal costs for Distribution (coincident and non-coincident)?

A. Yes. The revised load forecast changes these unit marginal costs as well. However, as discussed below, Snow Summit has other recommended changes to the determination of the unit marginal costs for coincident and non-coincident demand-based Distribution. Therefore, Snow Summit will present those revised marginal costs in the next section.

B. BVES Improperly Calculates Marginal Distribution Demand Costs

Q. How did BVES develop unit marginal Distribution demand costs?

A. BVES performed several regressions where the independent variables are system coincident peak demand or system non-coincident peak demand and the dependent variables are cumulative (1) net "transmission" additions, (2) net "distribution" additions, and (3) net "distribution" substation additions. These linear regressions used five years of historic data and five years of forecast data. The resulting "slope" for each regression is used to develop marginal Distribution demand costs for customers taking service on A-5 Primary as well as the rest of BVES's customers.[34]

Q. What is the basis of this approach for determination of unit marginal costs for Distribution demand?

A. This method was originally developed by the National Economic Research Associates in the 1970s when marginal cost-based ratemaking was in its infancy.

[34] BVES MCS Model, tabs "MDD-Plant_Inv" and "MDD-A5P."

Q. What period of data is used with the NERA method for estimating unit marginal Distribution demand costs?

A. 15 years of time-series data is used with this method. NERA's method uses 10 years of historic data and 5 years of forecast data.

Q. How many years of data did BVES use in the development of these unit marginal cost estimates?

A. BVES used 10 years of costs: 5 years of historic data (2021-2025) and 5 years of forecast data (2026-2030).[35]

Q. Does BVES make any adjustments to the regression results to arrive at its final estimates of unit marginal Distribution demand costs?

A. Yes. BVES applies an arbitrary 50% reduction to the regression results developed using BVES's implementation of the NERA method to arrive at its final unit marginal Distribution demand costs for T&D and for substations.[36]

1. BVES Improperly Assigns Marginal Distribution Demand Costs to A5-P Customers Despite Those Customers Being Interruptible Pursuant to BVES's Tariff

Q. Does BVES assign marginal Distribution demand costs to customers in the A5-P class?

A. Yes.

Q. Is this appropriate?

[35] BVES MCR model, tabs "MDD-Plant_Inv" and "MDD-A5P."

[36] BVES Response to Snow Summit Data Request Set 9, Request 2.

A. No. Customers in the A5-P class can have their loads interrupted if needed by BVES. There does not appear to be a limit on the number of times that BVES can interrupt these customers but BVES can only interrupt A5-P customer load to respond to situations where it would not have sufficient generation capacity to meet all loads. Thus, if customers in the A5-P class wish to increase their usage by a small amount and, as a result, cause the need for additional transmission or distribution facilities to deliver that incremental demand, BVES could choose to curtail the incremental load, thereby avoiding the need for some of those incremental facilities.

Q. Have other utilities used this sort of approach to avoid construction of new facilities?

A. Yes. Utilities implement demand-side management programs to avoid construction of new generation facilities. Demand-side resources are used to allow utilities to avoid the construction of new distribution facilities.[37] The Commission has a long-term and extensive effort to properly value the costs avoided as a result of demand-side resources.[38]

Q. Does BVES value the ability of A5-P customers to avoid construction of new facilities in its ratemaking process?

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[37] See Rulemaking (R.) 21-06-017. the Distribution Planning Process Improvements and the Distribution Investment Deferral Framework, which is "an ongoing annual process to identify, review, and select opportunities for competitively sourced distributed energy resources to defer or avoid utility traditional distribution capital investments. DERs as alternatives to traditional grid investments are commonly referred to as non-wires alternatives." https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning

[38] See R.22-11-013. See also the Commission's website related to the development and enhancement of the Avoided Cost Calculator: https://www.cpuc.ca.gov/dercosteffectiveness

A. Yes. BVES does not assign unit marginal Generation capacity costs to customers in the A5-P customer class in the development of its EPMC-based revenue allocation. It appears that BVES does this since a small increase in demand by customers in the A5-P class will not trigger the need for new generation supplies.

Q. How is this analogous to avoiding construction of new distribution substations?

A. BVES has two sources of electric supply: generation within its service territory and imported energy from Southern California Edison Company (SCE) through substations that interconnect BVES's system to SCE. While BVES is attempting to construct new in-area generation, this has proven difficult (e.g., the failed solar project that caused BVES to revise its revenue requirements, marginal cost, and revenue allocation proposals in this proceeding). Absent additional in-area generation, the only way for BVES to increase supply for its customers is through increased distribution substation capacity between BVES and SCE. By using additional curtailment of load to the A5-P class, BVES could defer such distribution substation expansion projects.

Q. How might the ability of BVES to curtail load for A5-P customers change the assignment of marginal Distribution demand costs to the A5-P class?

A. BVES's "unit marginal Distribution demand cost" for the A5-P class is based on two sets of costs: (1) transmission plant excluding substations and (2) distribution plant categorized as substations.[39] It is possible that BVES could rely on curtailment to avoid a portion of new distribution substation capacity.

[39] BVES MCS Model, tab "MDD-A5P."

Q. Have you estimated the fraction of capital additions to distribution substations that might be avoided through curtailment of A5-P customer load?

A. No. This analysis would require an in-depth understanding of BVES's distribution planning process. It would also require discussions with stakeholders (e.g., Snow Summit, BVES, ratepayer advocates) to balance the amount of additional curtailment that might occur against the benefits of that additional curtailment.

Q. Would the avoidance of distribution costs apply to marginal T&D costs for both coincident and non-coincident demands?

A. No. This is only applicable to coincident distribution demand costs. Since customers in the A5-P class would consume some amount of power throughout the year, their marginal non-coincident distribution demand costs are non-zero.

Q. What do you recommend?

A. There is clearly a benefit that the A5-P class provides to BVES in terms of avoidance of additional distribution substation investments. However, the magnitude of that benefit is uncertain. Snow Summit recommends that the marginal Distribution capacity costs for coincident demand be reduced in this proceeding by a nominal amount (e.g., 5%) to account for that benefit.[40] Snow Summit also recommends that the Commission order BVES to convene a stakeholder group to determine the avoided Distribution demand costs provided by the A5-P class.

[40] Snow Summit did not include this recommended reduction in the unit marginal Distribution demand (coincident) costs that it presents in this testimony.

2. BVES Improperly Includes Non-Marginal Costs in the Development of Its Unit Marginal Distribution Demand Costs

Q. What are marginal Distribution demand costs?

A. BVES states: "Marginal distribution demand costs represent the incremental cost in transmission and distribution facilities to serve incremental peak demands. The incremental cost includes transmission, distribution, and substation investments."[41]

Q. How does BVES calculate its unit marginal costs for Distribution demand?

A. BVES uses several steps to calculate marginal costs for Distribution demand:

- It calculates the change in total investment in its sub-transmission system (i.e., 34.5 kV) and its other distribution facilities (except for final line transformers) relative to changes in its total coincident and non-coincident demand for 10 years (five historical and five forecast years). These steps yield the unit marginal costs of sub-transmission and distribution caused by both coincident and non-coincident peak demands.
- It uses 100% of the unit marginal cost of sub-transmission and 50% of the unit marginal cost of distribution driven by coincident peak demands as caused by customers' coincident demands; it also uses 50% of the unit marginal cost of distribution caused by non-coincident demands as being caused by customers' non-coincident demands.
- For the A-5 Primary customers, BVES uses a slightly different approach: it determines the unit marginal cost of sub-transmission lines and distribution

[41] BVES Testimony, Chapter 6, p. 10.

substations based on the coincident peak demands on the system to develop the unit marginal Distribution cost (coincident) and assigns those to A-5 P's coincident demands; it then assumes that 50% of the marginal cost of distribution substations based on non-coincident demands are caused by A-5 Primary customers and assigns those unit marginal Distribution costs (non-coincident) to A5-P's non-coincident demands.

Q. What is the basis of BVES's assumed transmission and distribution investments for these calculations?

A. Snow Summit understands that BVES uses its historic and forecast net plant additions plus Construction Work in Progress (CWIP) to arrive at the annual investments.[42] These investments include both conventional investments in T&D facilities (e.g., substations, poles, wire) resulting from increases in demand as well as investments made as part of BVES's wildfire mitigation efforts.

Q. Does this series of investments include the substations and other distribution facilities for which Snow Summit pays 100 percent of the costs pursuant to an Added Facilities Agreement?

A. Yes. As discussed elsewhere, Snow Summit pays 100% of the costs of substations and distribution equipment that were constructed by BVES pursuant to Snow Summit's Added Facilities Agreement with BVES.

[42] BVES MCS Model, tab "Plant."

a) BVES Improperly Includes Costs of Substations and Other Distribution Equipment For Which Snow Summit Pays 100 Percent of the Costs

Q. What are the costs associated with the substations and other distribution equipment for which Snow Summit pays 100 percent of the costs pursuant to an Added Facilities Agreement?

A. These projects are covered under BVES's Project C-023: Snow Summit Project. The following table summarizes the costs associated with this project:

Table 18: Plant Additions for Snow Summit Project

							Plant Additions					
Project ID	**Project Name**	**Recurring Projects Flag =1**	**In Service Year**	**FERC Account**	**Percentage of Cost**	**Actual Spend End of 2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
C-023	Snow Summit Project	0	2025	362	75%	4,809,911	8,707,673	-	-	-	-	-
C-023	Snow Summit Project	0	2025	366	15%	961,982	1,741,535	-	-	-	-	-
C-023	Snow Summit Project	0	2025	367	10%	641,322	1,161,023	-	-	-	-	-

Source: Excerpt from BVES Model "SEC7-~~8~~8-9-UPIS Reserve RB_Filing.xlsx," tab "Forecasted Additions by Pro WS4"

As can be seen from the above table, BVES has plant additions of approximately $8.7 million, $1.7 million, and $1.2 million in 2025 for FERC Accounts 362, 366, and 367, respectively.[43] These costs were recorded as plant additions in 2025 when the Snow Summit project came online.

Q. Are these the values that BVES includes in the development of its distribution demand costs?

[43] FERC Account 362 is the FERC account for substation costs.

A. These are approximately equal to the values used by BVES in its regression analysis. BVES modifies its plant additions to account for retirements and other adjustments. However, BVES does not perform those modifications on a per-project basis, so it is not possible for me to develop precise estimates of those adjustments. Snow Summit expects that the adjustments are small.

Q. Why is it inappropriate for BVES to include these costs in its assessment of the marginal Distribution demand costs?

A. The costs for the Snow Summit Project are not costs borne by any ratepayer except for Snow Summit pursuant to the Added Facilities Agreement.[44] Stated differently, the *marginal* Distribution demand cost of the Snow Summit Project for other ratepayers is $0. Because other customers bear no net costs for those facilities, it is improper to include those costs in the development of unit marginal Distribution demand costs.

Q. What do you recommend?

A. BVES should remove the costs of the Snow Summit Project from the data used in its regression analysis to determine unit marginal Distribution demand costs.

Q. Should BVES remove these costs from its rate base?

A. BVES models the Snow Summit Project in its RO model as any other T&D addition. In addition, BVES includes the payments made by Snow Summit in its calculation of revenue requirements and deducts the costs paid by Snow Summit from costs that are

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[44] Even though the Added Facilities Agreement is between BVES and the Snow Summit resort, Snow Summit is the only customer in the A5-P class.

assigned to all customer classes under BVES's normal ratemaking treatment of capital projects. Because of this netting, it is appropriate to include the costs of the Snow Summit Project in BVES's revenue requirements calculation since it is ultimately netted out of revenue requirements.

3. Impacts of Snow Summit Assumptions on Marginal Distribution Demand Costs

Q. Do Snow Summit's recommended changes to BVES's load forecast for the A5-P class and the removal of the Snow Summit substation have an impact on unit marginal Distribution demand costs?

A. Yes. The following sections present those impacts.

a) Marginal Distribution Demand (Coincident)

Q. What are the impacts on marginal Distribution demand costs (for coincident demands) associated with Snow Summit's proposed changes to load forecast and removing the Snow Summit substation from the calculation of marginal costs?

A. As noted above, Snow Summit recommends changes in the load forecast for the A5-P class. Those changes result in a change in coincident and non-coincident demands. Both coincident and non-coincident demands affect the calculation of the unit marginal cost for Distribution demand (coincident and non-coincident). Removing the costs of the Snow Summit distribution substation and other facilities paid for entirely by Snow Summit also changes the unit marginal costs. Thus, there are three separate cases: (1) changing the load forecast and including the Snow Summit facilities in the calculation of unit marginal

Distribution demand costs, (2) removing the Snow Summit facilities from the calculation of unit marginal Distribution demand costs and using BVES's load forecast, and (3) changing the load forecast and removing the Snow Summit facilities from the calculation of unit marginal Distribution demand costs. Each is presented below:

Table 19: Comparison of Unit Marginal Distribution (Coincident) Values Including Snow Summit Substations and Using Snow Summit Loads ($/kW)

Snow Summit					BVES					Change (SS - BVES)			
	System	**A-5P**				System	A-5P				System	A-5P	
Coincident Distribution MC ($/kW)	**972.06**	**190.49**	**% Top 100 Hrs**		Coincident Distribution MC ($/kW)	760.05	149.24	% Top 100 Hrs		Coincident Distribution MC ($/kW)	212.01	41.25	% Top 100 Hrs
Winter Peak	398.54	78.10	41.00%		Winter Peak	296.42	58.20	39.00%		Winter Peak	102.12	19.90	2.00%
Winter Mid-Peak	243.01	47.62	25.00%		Winter Mid-Peak	182.41	35.82	24.00%		Winter Mid-Peak	60.60	11.81	1.00%
Winter Off-Peak	330.50	64.77	34.00%		Winter Off-Peak	281.22	55.22	37.00%		Winter Off-Peak	49.28	9.55	-3.00%
Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%
Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%
Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%

Table 20: Comparison of Unit Marginal Distribution (Coincident) Values Removing Snow Summit Substations and Using BVES Loads ($/kW)

Snow Summit					BVES					Change (SS - BVES)			
	System	**A-5P**				System	A-5P				System	A-5P	
Coincident Distribution MC ($/kW)	707.78	104.44	% Top 100 Hrs		Coincident Distribution MC ($/kW)	760.05	149.24	% Top 100 Hrs		Coincident Distribution MC ($/kW)	(52.27)	(44.80)	% Top 100 Hrs
Winter Peak	276.04	40.73	39.00%		Winter Peak	296.42	58.20	39.00%		Winter Peak	(20.38)	(17.47)	0.00%
Winter Mid-Peak	169.87	25.07	24.00%		Winter Mid-Peak	182.41	35.82	24.00%		Winter Mid-Peak	(12.54)	(10.75)	0.00%
Winter Off-Peak	261.88	38.64	37.00%		Winter Off-Peak	281.22	55.22	37.00%		Winter Off-Peak	(19.34)	(16.58)	0.00%
Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%
Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%
Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%

Table 21: Comparison of Unit Marginal Distribution (Coincident) Values Removing Snow Summit Substations and Using Snow Summit Loads ($/kW)

Snow Summit					BVES					Change (SS - BVES)			
	System	**A-5P**				System	A-5P				System	A-5P	
Coincident Distribution MC ($/kW)	904.49	133.51	% Top 100 Hrs		Coincident Distribution MC ($/kW)	760.05	149.24	% Top 100 Hrs		Coincident Distribution MC ($/kW)	144.44	(15.73)	% Top 100 Hrs
Winter Peak	370.84	54.74	41.00%		Winter Peak	296.42	58.20	39.00%		Winter Peak	74.42	(3.46)	2.00%
Winter Mid-Peak	226.12	33.38	25.00%		Winter Mid-Peak	182.41	35.82	24.00%		Winter Mid-Peak	43.71	(2.44)	1.00%
Winter Off-Peak	307.53	45.39	34.00%		Winter Off-Peak	281.22	55.22	37.00%		Winter Off-Peak	26.31	(9.82)	-3.00%
Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%
Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%
Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%

The following is seen from the above tables:

- Using Snow Summit Load Only: As seen in Table 19~~Table 19~~, using the Snow Summit load forecast alone results in a significant increase in the unit marginal cost for Distribution (coincident): for system, this increases from $760/kW to $962/kW and for A5-P, this increases from $149/kW to $190/kW. This also increases the allocation of cost in the winter on-peak and mid-peak period by 2% and 1%, respectively, while decreasing the allocation to the winter off-peak period by 3%.
- Removing Snow Summit Substation Only: As seen in Table 20~~Table 20~~, removing the Snow Summit substation while using the BVES load forecast results in a decrease in the unit marginal cost for Distribution (coincident): for system, this decreases from $760/kW to $708/kW and for A5-P, this decreases from $149/kW to $104/kW. This keeps the allocation of costs based on the Top 100 hours the same as assumed by BVES.
- Use Snow Summit Loads and Remove Snow Summit Substation: As seen in Table 21~~Table 21~~, using the Snow Summit load forecast and removing the Snow Summit substation results in a significant increase in the unit marginal cost for Distribution (coincident) for system (from $760/kW to $904/kW) and a decrease for A5-P (from $149/kW to $134/kW.) This also increases the allocation of cost in the winter on-peak and mid-peak period by 2% and 1%, respectively, while decreasing the allocation to the winter off-peak period by 3%.

b) Marginal Distribution Demand (non-coincident)

Q. What are the impacts of Snow Summit's assumptions on unit marginal Distribution demand costs based on non-coincident loads?

A. As with the impacts of Snow Summit's assumptions on unit marginal Distribution demand cost based on coincident loads, there are three scenarios to examine: (1) changing load forecast as recommended by Snow Summit and including the new Snow Summit facilities in the calculation of unit marginal Distribution demand costs, (2) removing the Snow Summit facilities from the calculation of unit marginal Distribution demand costs and using BVES's load forecast, and (3) using Snow Summit's load forecast and removing the Snow Summit facilities. Each is presented below:

Table 22: Comparison of Unit Marginal Distribution Costs (Non-Coincident) Including Snow Summit Substations and Using Snow Summit Loads ($/kW)

	Non-Coincident ($/kW)	
	System	A-5P
Snow Summit	577.30	106.70
BVES	473.56	87.59
Change	103.74	19.11

As seen from the above table, using the Snow Summit load forecast results in significant increases in the unit marginal costs: from $473.57/kW to $577.30/kW for system and from $87.59/kW to $106.70/kW for the A5-P class.

Table 23: Comparison of Unit Marginal Distribution Costs (Non-Coincident) Removing Snow Summit Substations and Using BVES Loads ($/kW)

	Non-Coincident ($/kW)	
	System	**A-5P**
Snow Summit	439.10	58.39
BVES	473.56	87.59
Change	(34.46)	(29.20)

As seen from the above table, removing the Snow Summit substations and using the BVES load forecast for A5-P results in a decrease in the unit marginal Distribution costs: from $473.57/kW to $439.10/kW for system and from $87.59/kW to $58.39/kW for the A5-P class.

Table 24: Comparison of Unit Marginal Distribution Costs (Non-Coincident) Removing Snow Summit Substations and Using Snow Summit Loads ($/kW)

	Non-Coincident ($/kW)	
	System	**A-5P**
Snow Summit	534.86	71.15
BVES	473.56	87.59
Change	61.30	(16.43)

As seen from the above table, removing the Snow Summit substations and using the Snow Summit load forecast results in an increases in the unit marginal costs for system: from $473.57/kW to $534.86/kW. It also results in a decrease in the unit marginal costs for the A5-P class from $87.59/kW to $71.15/kW.

IV. BVES Should Revise Its Revenue Allocation to Incorporate More Appropriate Marginal Costs and Other

Assumptions Recommended by Snow Summit

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

A. This chapter present the impacts of Snow Summit's recommended marginal costs and other assumptions on BVES's revenue allocation.

A. BVES's Revenue Allocation Proposal

Q. Please describe BVES's revenue allocation proposal.

A. In its revenue allocation proposal for 2027, BVES takes a small step in the direction of marginal cost-based revenue allocation. BVES proposes to use a hybrid approach to revenue allocation for the Test Year, where it will use a weighted-average revenue allocation based 10% on EPMC and 90% on SAP.[45]

For years 2028-2030, BVES proposes to use a completely different revenue allocation scheme than it uses for 2027. Instead of basing the revenue allocation in 2028-2030 on marginal costs at all, BVES uses SAP to allocate the change in revenue requirements in 2028-2030 relative to the revenue requirements in 2027.[46] By doing this, BVES effectively locks in any cross-subsidies that would exist in the 2027 revenue allocation for the remaining three years of the GRC cycle.[47]

[45] BVES Testimony, Volume 6, p. 16.
[46] BVES Testimony, Volume 6, p. 17.
[47] To develop its "SAP" proposal, BVES uses the formula: rates in year X = rates in year X-1 * [revenue requirement in year X / (rates in year X-1 * sales in year X)].

The following table presents BVES's proposed revenue allocation fractions for each customer class and year:

Table 25: BVES's Revenue Allocation Proposal (Percent of Total Excluding OOR)

Revenue Allocation Fractions by Year and Customer Class					
	Current	Proposed	Proposed	Proposed	Proposed
	2026	2027	2028	2029	2030
Residential Permanent Service	23.0%	22.3%	21.7%	21.1%	20.7%
Residential Non-Permanent Service	39.8%	40.9%	41.8%	42.8%	43.7%
General Service - Small (A1)	13.4%	13.5%	13.7%	13.8%	14.0%
General Service - Medium (A2)	4.1%	3.9%	3.7%	3.5%	3.3%
General Service - Large (A3)	5.8%	5.8%	5.5%	5.4%	5.3%
General Service - Time-of-Use (A4-TOU)	3.6%	3.8%	4.1%	3.9%	3.6%
Time-of-Use Service (A5 TOU Secondary)	1.0%	1.0%	1.0%	1.0%	1.0%
Time-of-Use Service (A5 TOU Primary)	9.1%	8.6%	8.5%	8.3%	8.3%
Street Lighting	0.1%	0.1%	0.1%	0.1%	0.1%
Total less OOR	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Derived from BVES MCS Model, tab "Target Revenues"

Q. Why does BVES recommend its hybrid approach for revenue allocation in 2023?

A. BVES states that "The Company's proposal strikes an appropriate balance of the rate design principles."[48]

Q. What does BVES say about its recommendation to use its SAP approach for revenue allocation in 2028-2030?

[48] BVES Testimony, Volume 6, p. 16.

A. BVES states that "The Company proposes to establish revenue targets in 2028-2030 based on the SAP method. The SAP method would be applied independently to Base and Supply revenues."[49]

B. Snow Summit Revenue Allocation Proposal

Q. Please describe how Snow Summit developed its revenue allocation proposal.

A. As described previously, Snow Summit examined and proposed modifications to specific assumptions used by BVES in the development of its marginal costs. The modified assumptions resulted in changes to BVES's unit marginal costs as well as certain factors used to determine the Marginal Cost of Service. Snow Summit then applied the modified assumptions to the MCS model used by BVES to develop its revenue allocation proposal.

Q. Did Snow Summit make any changes to BVES's assumptions that were in the MCS model prior to applying its changed assumptions?

A. Yes. As mentioned previously, in response to a Snow Summit data request, BVES admitted that it had used incorrect values for its coincident peak demands.[50] Since BVES did not plan to send out a modified MCS model correcting this error prior to when BVES submits its rebuttal testimony, Snow Summit revised the base assumptions used to properly calculate annual coincident peak demands. This correction to BVES's modeling resulted in a change in BVES's proposed revenue allocation.

[49] BVES Testimony, Volume 6, p. 17.
[50] BVES Response to Snow Summit Data Request Set 9, Request 5.

Q. Did you revise BVES's revenue requirements consistent with your recommendation in Snow Summit's prior testimony regarding revenue requirements?

A. I did calculate new Supply revenue requirements based on Snow Summit's proposed changes to loads for the A5-P class. As noted above, Snow Summit's Supply revenue requirements is likely high because BVES's Supply model had certain values that should have changed with changes in loads but did not because BVES had hard-coded those values in its model.

Q. In Snow Summit's RO testimony, Snow Summit recommended changing BVES's capital structure and return on equity. Did you reflect that recommendation in the updated revenue requirements or calculation of marginal costs in this testimony?

A. No. I did not calculate new revenue requirements assuming Snow Summit's recommended capital structure and return on equity.[51] In addition, I did not use Snow Summit's recommended values for capital structure or return on equity in the development of marginal costs.[52]

Q. Please present your revised revenue allocation.

A. The following tables presents Snow Summit's proposed revenue allocation for 2027:

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[51] Snow Summit RO Testimony, pp. 18-19.

[52] BVES's cost of capital is used in the development of its Real Economic Carrying Charge (RECC) and other assumptions in BVES's MCS model. See BVES MCS Model, tab "Common_Inputs."

Table 26: Snow Summit Revenue Allocation ($)

	Supply Revenue Requirements			Base Revenue Requirements			Total Revenue Requirements		
	BVES	Snow Summit	Change	BVES	Snow Summit	Change	BVES	Snow Summit	Change
Residential Permanent	4,375,801 ~~4,375,801~~	4,307,802 ~~4,308,692~~	(67,999) ~~(67,109)~~	12,301,375 ~~12,301,375~~	12,424,945 ~~12,426,167~~	123,569 ~~124,792~~	16,677,176 ~~16,677,176~~	16,732,747 ~~16,734,859~~	55,570 ~~57,683~~
Residential Non-Permanent	5,464,204 ~~5,464,204~~	5,381,906 ~~5,383,002~~	(82,298) ~~(81,202)~~	25,141,413 ~~25,141,413~~	25,369,356 ~~25,371,931~~	227,943 ~~230,518~~	30,605,617 ~~30,605,617~~	30,751,262 ~~30,754,933~~	145,645 ~~149,316~~
A1 Commercial	2,050,344 ~~2,050,344~~	2,019,038 ~~2,019,455~~	(31,306) ~~(30,889)~~	8,086,240 ~~8,086,240~~	8,153,939 ~~8,154,772~~	67,698 ~~68,532~~	10,136,584 ~~10,136,584~~	10,172,976 ~~10,174,227~~	36,392 ~~37,643~~
A2 Commercial	536,427 ~~536,427~~	528,357 ~~528,463~~	(8,070)~~(7,964)~~	2,396,826 ~~2,396,826~~	2,417,972 ~~2,418,218~~	21,146 ~~21,392~~	2,933,253 ~~2,933,253~~	2,946,329 ~~2,946,682~~	13,076 ~~13,429~~
A3 Commercial	779,769 ~~779,769~~	767,510 ~~767,670~~	(12,259) ~~(12,099)~~	3,546,647 ~~3,546,647~~	3,572,623 ~~3,572,998~~	25,976 ~~26,351~~	4,326,416 ~~4,326,416~~	4,340,133 ~~4,340,668~~	13,717 ~~14,252~~
A4 TOU	716,684 ~~716,684~~	705,187 ~~705,336~~	(11,497) ~~(11,348)~~	2,125,992 ~~2,125,992~~	2,142,118 ~~2,142,342~~	16,127 ~~16,350~~	2,842,676 ~~2,842,676~~	2,847,305 ~~2,847,677~~	4,630 ~~5,002~~
A5 Secondary	212,544 ~~212,544~~	209,160 ~~209,202~~	(3,384)~~(3,342)~~	572,070 ~~572,070~~	580,088 ~~580,140~~	8,018 ~~8,070~~	784,614 ~~784,614~~	789,248 ~~789,342~~	4,634 ~~4,728~~
A5 Primary	2,227,803 ~~2,227,803~~	2,175,630 ~~2,172,768~~	(52,174) ~~(55,035)~~	4,223,864 ~~4,223,864~~	4,002,006 ~~3,996,471~~	(221,859)~~(227,393)~~	6,451,668 ~~6,451,668~~	6,177,636 ~~6,169,240~~	(274,032) ~~(282,428)~~
Street Lighting	8,556 ~~8,556~~	8,419 ~~8,421~~	(137)~~(135)~~	76,012 ~~76,012~~	76,516 ~~76,523~~	504 ~~511~~	84,568 ~~84,568~~	84,935 ~~84,944~~	368 ~~376~~
Total	16,372,132 ~~16,372,132~~	16,103,009 ~~16,103,009~~	(269,123) ~~(269,123)~~	58,470,440 ~~58,470,440~~	58,739,563 ~~58,739,563~~	269,123 ~~269,123~~	74,842,571 ~~74,842,571~~	74,842,571 ~~74,842,571~~	- ~~—~~

Note: Does not include Other Operating Revenues

Table 27: Snow Summit Changes in Revenue Allocation from Revenue at Present Rates (%)

	Supply Revenue Requirements			Base Revenue Requirements			Total Revenue Requirements		
	BVES	Snow Summit	Change	BVES	Snow Summit	Change	BVES	Snow Summit	Change
Residential Permanent	-10.1% ~~-10.1%~~	-11.5% ~~-11.5%~~	-1.4% ~~-1.4%~~	30.2%~~30.2%~~	31.5%~~31.5%~~	1.3%~~1.3%~~	18.2%~~16.5%~~	18.7%~~16.9%~~	0.6%~~0.4%~~
Residential Non-Permanent	-8.8% ~~-8.8%~~	-10.2% ~~-10.2%~~	-1.4% ~~-1.4%~~	26.3%~~26.3%~~	27.4%~~27.4%~~	1.1%~~1.2%~~	16.2%~~18.2%~~	16.6%~~18.7%~~	0.4%~~0.6%~~
A1 Commercial	-10.1% ~~-10.1%~~	-11.5% ~~-11.5%~~	-1.4% ~~-1.4%~~	25.5%~~25.5%~~	26.5%~~26.5%~~	1.1%~~1.1%~~	18.1%~~16.2%~~	18.6%~~16.6%~~	0.5%~~0.4%~~
A2 Commercial	-7.8% ~~-7.8%~~	-9.2% ~~-9.1%~~	-1.4% ~~-1.4%~~	26.0%~~26.0%~~	27.1%~~27.1%~~	1.1%~~1.1%~~	14.6%~~18.1%~~	15.0%~~18.6%~~	0.4%~~0.5%~~
A3 Commercial	-10.8% ~~-10.8%~~	-12.2% ~~-12.2%~~	-1.4% ~~-1.4%~~	22.3%~~22.3%~~	23.2%~~23.2%~~	0.9%~~0.9%~~	12.0%~~14.6%~~	12.2%~~15.0%~~	0.2%~~0.4%~~
A4 TOU	-11.8% ~~-11.8%~~	-13.2% ~~-13.2%~~	-1.4% ~~-1.4%~~	23.1%~~23.1%~~	24.1%~~24.1%~~	0.9%~~0.9%~~	24.7%~~12.0%~~	25.4%~~12.2%~~	0.7%~~0.2%~~
A5 Secondary	-6.6% ~~-6.6%~~	-8.0% ~~-8.0%~~	-1.5% ~~-1.5%~~	42.4%~~42.4%~~	44.4%~~44.4%~~	2.0%~~2.0%~~	12.0%~~24.7%~~	7.3%~~25.4%~~	-4.8%~~0.8%~~
A5 Primary	-13.6% ~~-13.4%~~	-15.6% ~~-15.6%~~	-2.0% ~~-2.1%~~	32.8%~~33.0%~~	25.8%~~25.8%~~	-7.0% ~~-7.2%~~	31.1%~~12.2%~~	31.6%~~7.3%~~	0.6% ~~-4.9%~~

Street Lighting	-5.7%~~-5.7%~~	-7.2%~~-7.2%~~	-1.5%~~-1.5%~~	37.1%~~37.1%~~	38.0%~~38.0%~~	0.9%~~0.9%~~	16.6%~~31.1%~~	16.6%~~31.6%~~	0.0%~~0.6%~~
Total	-10.2%~~-10.1%~~	-11.6%~~-11.6%~~	-1.5%~~-1.5%~~	27.2%~~27.2%~~	27.8%~~27.8%~~	0.6%~~0.6%~~	18.2%~~16.6%~~	18.7%~~16.6%~~	0.6%~~0.0%~~

Note: Does not reflect changes in Other Operating Revenues

Q. What assumptions did you use in the development of Snow Summit's revenue allocation?

A. I used Snow Summit's revised forecast of loads for the A5-P customer class. In addition, I excluded the Snow Summit substation and associated distribution equipment from the net plant additions used in the calculations of unit marginal Distribution demand costs. As noted above, using the revised forecast for the loads for the A5-P customer class affects the calculation of BVES's unit marginal costs as well as the Supply revenue requirement.

Q. Please present Snow Summit's proposed revenue allocation for the Test Year and attrition years.

A. The following table presents Snow Summit's proposed revenue allocation for 2026-2030:

Table 28: Snow Summit Revenue Allocation for 2027-2030 ($)

Base and Supply Revenue Targets	**2026**	**2027**	**2028**	**2029**	**2030**
Residential Permanent Service	14,530,082	16,732,747	17,269,719	17,642,727	18,681,888
Residential Non-Permanent Service	25,141,698	30,751,262	33,239,774	35,808,465	39,555,602
General Service - Small (A1)	8,466,164	10,172,976	10,871,901	11,556,975	12,646,139
General Service - Medium (A2)	2,606,700	2,946,329	2,944,380	2,928,591	2,985,875
General Service - Large (A3)	3,644,683	4,340,133	4,361,082	4,466,700	4,824,964
General Service - Time-of-Use (A4-TOU)	2,280,931	2,847,305	3,235,460	3,267,581	3,214,802
Time-of-Use Service (A5 TOU Secondary)	629,322	789,248	825,844	856,497	921,599
Time-of-Use Service (A5 TOU Primary)	5,749,203	6,177,636	6,436,587	6,616,690	7,125,912
Street Lighting	64,529	84,935	89,407	94,199	100,980
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

Q. What are the average revenue requirements per kWh sales for each class and year?

A. The following table presents the average revenue requirements per kWh sales:[53]

Table 29: Snow Summit Revenue Requirements per kWh Sales ($/kWh)

Average Revenue per kWh Sales	2026	2027	2028	2029	2030
Residential Permanent Service	0.377	0.441	0.462	0.479	0.515
Residential Non-Permanent Service	0.537	0.638	0.670	0.701	0.752
General Service - Small (A1)	0.446	0.520	0.545	0.569	0.611
General Service - Medium (A2)	0.435	0.515	0.541	0.566	0.607
General Service - Large (A3)	0.498	0.573	0.601	0.629	0.675
General Service - Time-of-Use (A4-TOU)	0.411	0.461	0.483	0.501	0.539
Time-of-Use Service (A5 TOU Secondary)	0.290	0.363	0.380	0.394	0.424
Time-of-Use Service (A5 TOU Primary)	0.310	0.333	0.347	0.357	0.385
Street Lighting	0.691	0.910	0.958	1.009	1.082

The following table presents the annual change in revenue requirements per kWh sales based on the above table:

Table 30: Snow Summit Annual Change in Revenue Requirements per kWh Sales (%)

Average Revenue per kWh Sales	2027	2028	2029	2030
Residential Permanent Service	16.9%	4.7%	3.8%	7.6%
Residential Non-Permanent Service	18.7%	5.0%	4.6%	7.4%
General Service - Small (A1)	16.6%	4.9%	4.4%	7.4%
General Service - Medium (A2)	18.6%	5.0%	4.6%	7.4%
General Service - Large (A3)	15.0%	5.0%	4.6%	7.4%
General Service - Time-of-Use (A4-TOU)	12.2%	4.7%	3.9%	7.6%
Time-of-Use Service (A5 TOU Secondary)	25.4%	4.6%	3.7%	7.6%
Time-of-Use Service (A5 TOU Primary)	7.3%	4.3%	2.8%	7.8%
Street Lighting	31.6%	5.3%	5.4%	7.2%

Q. Why should the Commission adopt Snow Summit's recommended revenue allocation?

[53] BVES's MCS model has hard-coded sales values for 2027-2030. Snow Summit estimated sales for each customer class based on its proposed load forecast and the implied loss factors in BVES's sales and load forecasts for each class.

A. As discussed above, BVES's forecast of loads for the A5-P customer class is unreasonable. Snow Summit revised that forecast to reflect the likely loads during the non-snowmaking months, which BVES forecast to inexplicably increase in 2025 relative to 2024 (and which remain unreasonably high in 2026-2030). To correct this error, Snow Summit recommended using the average of loads for 2024 (based on actual data) and 2025 (based on BVES's forecast) as the basis for loads during the non-snowmaking months for 2026-2030. This is a reasonable adjustment since Snow Summit has not installed new equipment or changed operations during its non-snowmaking months.[54]

Snow Summit also adjusted BVES's forecasted loads for the A5-P class during snowmaking months. Snow Summit examined the actual loads in the snowmaking months for the A5-P class in 2026 and found that BVES's forecast for 2026 was approximately 25% higher than actual loads. To correct this error, Snow Summit conservatively adjusted BVES's loads in the snowmaking months downward by 12.5% (i.e., only half of the forecast error seen in 2026). This is also a conservative and reasonable adjustment.[55]

Snow Summit had planned to examine the BVES load forecasts for other customer classes as well but BVES did not provide monthly loads for 2025 or 2026 for other customer classes, as Snow Summit requested. The Commission should be less concerned about the potential for huge forecasting errors in the loads for other customer classes

[54] Snow Summit RO Testimony, p. 7.
[55] Snow Summit RO Testimony, pp. 26-28.

since there were not the same type of major changes in loads for those classes between 2024 and the forecast years of 2025-2030 as were seen for the A5-P class.

The Commission should also adopt Snow Summit's recommended changes to the calculation of unit marginal Distribution demand cost. Snow Summit is paying 100% of the costs for the substations and distribution equipment associated with the new Snow Summit Substations, meaning that the marginal cost of that equipment is zero for other customer classes.

Snow Summit's recommended changes result in a more reasonable revenue requirement estimate for BVES. In addition, they provide superior estimates of unit marginal costs and marginal cost-based revenue requirements, which serve as the basis of BVES's EPMC-based revenue allocation proposal. Even though BVES's revenue allocation proposal relies on only 10% of the EPMC-based revenue allocation, correct marginal costs and a proper marginal cost-based revenue allocations promote the efficient use of electricity. The Commission has found this in countless other proceedings, including in past BVES GRCs.

V. Recommendations and Conclusion

Q. What is your overall recommendation?

A. The Commission should adopt Snow Summit's recommendations regarding revisions to BVES's revenue requirements, marginal costs and revenue allocation. In addition, the

Commission should order BVES to undertake a stakeholder process to examine the distribution capacity costs avoided by interruptible customers.

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.

136. CPUC Application 26-01-022
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 26-010-022. July 27, 2026.

ATTACHMENT 2

DATA REQUEST RESPONSES REFERENCED IN TESTIMONY