Docket No.: A.24-05-020

Exhibit No.:

ALJ: Trevor Pratt

Commissioner: John Reynolds

Date:

Witness: Sean Matlock, Jeff Linam, Alric Oishi

APPLICATION OF BEAR VALLEY ELECTRIC SERVICE, INC. (U 913 E), FOR A CERTIFICATE OF PUBLIC CONVENIENCE TO ACQUIRE, OWN, AND OPERATE THE BEAR VALLEY SOLAR ENERGY AND BATTERY STORAGE PROJECTS AND AUTHORIZE RATEMAKING ASSOCIATED WITH THE STORAGE AND SOLAR ENERGY PROJECTS' CAPITAL INVESTMENT AND OPERATING EXPENSES

REBUTTAL TESTIMONY

PUBLIC VERSION

MAY 30, 2025

BEAR VALLEY ELECTRIC SERVICE

REBUTTAL TESTIMONY

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CHAPTER 1

RESPONSE TO CAL ADVOCATES REPLY TESTIMONY

WITNESSES: SEAN MATLOCK, JEFF LINAM

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CHAPTER 1

I. INTRODUCTION AND BACKGROUND

A. Sean Matlock

1. Q: Please state your name, occupation, and business address.

A: My name is Sean Matlock. I am the Energy Resource Manager at Bear Valley Electric Service, Inc. ("BVES"). My business address is 42020 Garstin Drive, Big Bear Lake, California 92315.

2. Q: Does Exhibit BVES-1, Appendix A, entitled "Qualifications of Witness Sean Matlock" as provided in BVES's May 17, 2024, Prepared Testimony, still accurately summarize your background, education, and experience?

A: Yes, it does.

3. Q: What is the purpose of your rebuttal testimony?

A: My rebuttal testimony responds to the prepared testimony of the Public Advocates Office, Exhibit CA-01 served on May 9, 2025. Specifically, my testimony addresses the benefits and net market value of the Projects (Sections II, III, IV, and VII). I provide the details of my updated calculations in Attachment A (Confidential) – BVES Solar Facility Net Market Value Analysis; Attachment B (Confidential) – BVES Battery Storage Facility Net Market Value Analysis; and Attachment C – Reliability Summary.

B. Jeff Linam

1. Q: Please state your name, occupation, and business address.

A: My name is Jeff Linam. I am the Manager of Regulatory Affairs at Golden State Water Company and I provide regulatory support on behalf of BVES. My business address is 630 East Foothill Blvd, San Dimas, CA 91773.

2. Q: Does Exhibit BVES-1, Appendix A, entitled "Qualifications of Witness Jeff Linam" as provided in BVES's May 17, 2024, Prepared Testimony, still accurately summarize your background, education, and experience?

A: Yes, it does.

3. Q: What is the purpose of your rebuttal testimony?

A: My rebuttal testimony responds to the prepared testimony of the Public Advocates Office, Exhibit CA-01 served on May 9, 2025. Specifically, my testimony addresses the federal tax treatment for the Projects (Section V) and BVES's recommended use of an Allowance for Funds Used During Construction (Section VI). It also addresses BVES's recommended Tier 2 advice letter process for recovery of reasonable cost increases (Section VIII) and addresses Cal Advocates proposed operating expense cap (Section IX).

II. THE PROJECTS WILL PROVIDE CUSTOMERS WITH MULTIPLE BENEFITS AND HAVE A SIGNIFICANT POSITIVE NET MARKET VALUE (WITNESS SEAN MATLOCK)

1. Q: What benefits are the Solar Project and Battery Project (together, the "Projects") expected to provide?

A: The Solar Project will enhance local reliability, reduce dependence on external power sources, and provide price stability for BVES customers. The Solar Project will also support grid reliability and mitigate interruptions from emergency or capacity-constraining situations like wildfires or other situations that may result in a complete or significant loss of power from off-mountain resources. Additionally, the Solar Project is designed to generate approximately 14 gigawatt-per-hour annually, contributing significantly to BVES's Renewable Portfolio Standard ("RPS") compliance.

Similarly, the Battery Project provides significant benefits in terms of reliability and reduced power outage risk. The Battery Project will support local reliability and meet capacity

demands. The Battery Project will allow BVES to self-supply capacity locally and long-term, contributing significantly to BVES meeting local area reliability needs, including ensuring adequate Resource Adequacy capacity.

2. Q: Can you quantify the numerous benefits provided by the Solar Project and Battery Project?

A: While it is difficult to quantify all of the benefits provided by the Projects, BVES provided a net market value analysis in its supplemental testimony. Below, BVES updates its net market value analysis and provides some clarifications in response to Cal Advocates' testimony. *See also* Attachment A (Confidential) – BVES Solar Facility Net Market Value Analysis; Attachment B (Confidential) – BVES Battery Storage Facility Net Market Value Analysis; and Attachment C – Reliability Summary. Cal Advocates raised concerns with BVES' reliability benefit calculation and the inclusion of transmission offset benefits as well.[1] BVES responds to Cal Advocates' concerns below and also explains why reliability benefits and transmission offset benefits should be included in the net market value analysis of the Projects.

A. Benefits, Costs and Net Market Value of the Solar Project

1. Q: What benefits will the Solar Project provide?

A: As detailed in Attachment A, BVES estimates that the Solar Project will afford the following benefits.

Energy Benefits: The solar facility will allow BVES to forgo 14,044 megawatt-hours ("MWhs") of energy purchases resulting in a NPV energy savings of [redacted] This

[1] *See* Ex. CA-01C Public Advocates Office Prepared Testimony (Confidential Version) (May 9, 2025) ("Ex. CA-01C Cal Advocates Testimony") at 1-10: 3 to 1-17:14 .

benefit is based on S&P Global's forecasts of On-Peak annual wholesale spot power prices ($/MWh).[2]

Reliability Benefits: The solar facility will enhance the reliability of the electrical system for residential, commercial, and industrial customers. Power outages incur societal costs that extend well beyond the expenses for the utility company. The Lawrence Berkeley National Laboratory, funded by the Department of Energy, has developed the Interruption Cost Estimate ("ICE") calculator to estimate these costs.[3] BVES justifies the approach to its reliability calculation below. Additionally, BVES used the updated version of the ICE calculator which was released in April 2025 (i.e., ICE calculation 2.0), to calculate the reliability benefits set forth in this testimony. According to the ICE model, the solar facility will provide a NPV reliability benefit of [redacted] over its 30-year lifespan.[4]

Renewable Energy Certificate ("REC") Benefits: Each MWh produced by the solar facility will grant BVES one PCC1 REC. The solar facility enables BVES to supplement part of its RPS REC requirement as stipulated by the CPUC, leading to notable cost savings for ratepayers. Recently, BVES secured a 10-year bundled energy contract, with the PCC1 REC priced at [redacted]. This translates into NPV REC benefit of [redacted]

Transmission Access Charge Benefits (TAC): The solar facility will allow BVES to save on its monthly TAC fee due to reduced reliance on the CAISO grid. For the solar facility, this results in NPV savings of approximately [redacted] over 30 years.

[2] Note that this data was last updated in BVES's supplemental testimony submitted on March 26, 2025. *See* Supplemental Prepared Testimony of Sean Matlock (Confidential Version) (Mar. 26, 2025) ("BVES Supplemental Testimony").

[3] *See* icecalculator.com.

[4] *See* Attachment C – Reliability Summary.

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Greenhouse Gas ("GHG") Benefits: Due to the reduction of energy purchases made possible by the solar facility, BVES will reduce its energy transaction by 14,044,000 kWh per year. According to the GHG Equivalencies Calculator by the EPA, zip code 92315, this results in an annual reduction of 7,083 metric tons of CO_2. This results in a NPV GHG benefit of [redacted] This benefit is based on S&P Global's latest forecasts of allowance prices for the California-Quebec GHG Trading Program ($/metric ton).[5]

2. Q: What is the Net Present Value of the Solar Project's benefits?

A: Based on the above-listed benefits, BVES calculates that the total Net Present Value of the Solar Project's benefits amount to [redacted]

NPV Benefits	Amount
Energy Benefits	$ [redacted]
Reliabilty Benefits	$
REC Benefit	$
Transmission Access Charge Benefits	$
GHG Benefits	$
Total Benefits	**$**

3. Q: What is the Net Present Value of the Solar Project's costs?

A: BVES estimates that the total cost of the solar facility over the life of the Project includes the NPV Subtotal Capital & Operating Cost of [redacted].[6]

[5] Note that while the Battery Project also provides GHG benefits as detailed below, the calculation was not included in the Battery Project NMV calculation. One of the clear benefits of energy storage is the flexibility to use the battery at any time of the day. Thus, it is difficult to calculate the exact GHG benefit of the Battery Project when preserving the flexibility benefit.

[6] Note that, contrary to Cal Advocates' assertions, our calculation of the NPV Cost does NOT include the ITC in the final value. The ITC was subtracted off the rate base in Appendix A on the "Cashflow Summary" tab in cells D45 - AG45. The ITC line item was intended to be illustrative only. *See e.g.,* Confidential BVES Supplemental Testimony of Sean Matlock, Appendix A (BVES Solar Facility Analysis) (Mar. 26, 2025).

NPV Costs	Amount
Total NPV Costs	[redacted]
Total Costs	[redacted]

Note: The NPV Cost does not include the ITC

4. Q: Based on the net market value, does the Solar Project provide a net benefit to its customers?

A: Yes. Contrary to Cal Advocates' claim, the total net market value of the Solar Project is the net difference between NPV benefits and NPV costs. BVES calculates that the total net market value is [redacted]

NPV Benefits	$ [redacted]
NPV Costs	$
Net Market Value	**$**

B. Benefits, Costs, and Net Market Value of the Battery Project

1. Q: What benefits will the Battery Project provide?

A: As detailed in Attachment B, BVES estimates that the Battery Project will afford the following benefits.

RA Benefits: The battery will reduce BVES's RA obligation by 5,000 kWh during peak hours resulting in NPV RA savings worth [redacted] This benefit is based on S&P Global's forecast for summer year capacity prices ($/kW-year).[7]

Energy Benefits: The battery will allow BVES to forgo 7,300 MWh of energy purchases during peak hours resulting in NPV energy savings of [redacted]. This benefit is based on S&P Global's forecasts of On-Peak annual wholesale spot power prices ($/MWh).[8]

[7] Note that this data was last updated in BVES's supplemental testimony submitted in March 2025. *See* Confidential BVES Supplemental Testimony of Sean Matlock, Appendix B (Updated BVES Battery Storage Facility Analysis) (Mar. 26, 2025).

[8] *Id.*

Reliability Benefit: The battery will enhance the reliability of the electrical system for residential, commercial, and industrial customers. Power outages incur societal costs that extend well beyond the expenses for the utility company. According to the ICE model, the battery will provide a NPV reliability benefit of [redacted] over its 20-year lifespan.[9]

Transmission Off-Set Benefits:[10] As detailed below, transmission offset benefits are appropriate to include within the net market value calculations of the Projects. In Q4 2024, BVES completed the Radford Rebuild Project. The Radford Line, a bare wire sub-transmission line operating at 34.5 kV with an 8 MW capacity, consists of 95 wood poles. The line connects to the Southern California Edison ("SCE") Bear Valley Line and ascends the mountain through the San Bernardino National Forest in San Bernardino County, reaching Big Bear Lake where it connects to the Village Substation. The U.S. Forest Service has jurisdictional control over most of the area the Radford Line traverses. Approximately 90% of the line is located in the High Fire Threat District ("HFTD") Tier 3 (extreme risk) as defined in GO 95, with the remaining 10% in HFTD Tier 2 (elevated risk). The Radford Line is constructed on steep slopes with high tree and vegetation density.

The total project cost was approximately [redacted] for 3.1 circuit miles, or [redacted] per mile. Using this cost estimate to project the rebuild to the nearest SCE substation, the cost for BVES to pay SCE to rebuild a pole line and add capacity to the Big Bear Valley is approximately [redacted] (20 miles multiplied by [redacted].

[9] *See* Attachment C – Reliability Summary.

[10] Note that the Solar Project, if built as a standalone project, would also provide transmission off-set benefits. However, to avoid double counting transmission off-set benefits for the combined Projects, BVES is only including the transmission off-set benefits for the Battery Project for purposes of the net market value calculation.

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Transmission Access Charge Benefits (TAC): The battery will allow BVES to save on its monthly TAC fee due to reduced reliance on the CAISO grid. For the battery, this results in NPV savings of approximately [redacted] over 20 years.

2. Q: What is the Net Present Value of the Battery Project's benefits?

A: Based on the above-listed benefits, BVES calculates that the NPV of the Battery Project's benefits amounts to [redacted].

NPV Benefits	Amount
RA Benefits	$ [redacted]
Energy Benefits	$
Reliabilty Benefits	$
Transmission Off Set Cost	$
Transmission Access Charge Benefits	$
Total Benefits	**$**

3. Q: What is the Net Present Value of the Battery Project's costs?

A: BVES estimates that total cost of the battery over the life of the Project includes the NPV Subtotal Capital & Operating Cost of [redacted].[11]

NPV Costs	Amount
Total NPV Costs	$ [redacted]
Total Costs	**$** [redacted]
Note: The NPV Cost does not include the ITC	

4. Q: Based on the Net Market Value, does the Battery Project provide a net benefit to its customers?

[11] Appendix B, Summary Tab, Cell D14. Note that, Contrary to Cal Advocates' assertion, the NPV Cost does *not* include the ITC in the final value. The ITC is subtracted off the rate base in the "Cashflow Summary" tab in cells D45 - W45.

A: Yes. Contrary to Cal Advocates' claim, the total net market value of the battery is the net difference between NPV benefits and NPV costs. The total net market value is [redacted].

NPV Benefits	$	[redacted]
NPV Costs	$	
Net Market Value	**$**	

C. Benefits, Costs, and Net Market Value of the Projects

1. Q: What is the Net Present Value of the Projects' benefits?

A: Based on the values above, the NPV of the benefits of the Combined Projects is [redacted]

NPV Benefits	**Solar Project**	**Battery Project**	**Combined Projects**
Energy Benefits	[redacted]		
RA Benefits			
Reliability Benefits			
REC Benefit			
Transmission Off-Set Cost			
Transmission Access Charge Benefits			
GHG Benefits			
Total Benefits			

2. Q: What is the Net Present Value of the Projects' costs?

A: The NPV of the costs of the Projects is [redacted]

NPV Costs	**Solar Project**	**Battery Project**	**Combined Projects**
Total NPV Costs	[redacted]		
Total Costs			

3. Q: Based on the Net Market Value, do the Project together provide a net benefit to its customers?

A: Yes. The total net market value of the Projects is [redacted]

	Solar Project	Battery Project	Combined Projects
NPV Benefits	[redacted]		
NPV Costs			
Net Market Value			

III. THE PROJECTS WILL PROVIDE SIGNIFICANT COST SAVINGS BY AVOIDING THE NEED FOR EXPENSIVE TRANSMISSION CAPACITY UPGRADES (WITNESS SEAN MATLOCK)

1. Q: Why should the Commission account for avoided transmission capacity upgrade costs when evaluating the Projects?

A: BVES is a small utility that provides electric service to the isolated mountain communities of Big Bear Valley. BVES meets the majority of its energy requirements by purchasing wholesale power from outside its service territory. BVES also owns and operates one natural gas-gas fired generation plant – the Bear Valley Power Plant ("BVPP") – which is the only local generation within BVES's service territory.

BVES currently provides approximately 138,000 MWhs of retail sales for electric service to approximately 25,000 residential and commercial customers. The California Energy Commission's Integrated Energy Policy Report forecasts a steady 10,000 MWh increase in BVES's load and energy demand through 2035.

BVES's service territory is indirectly connected to the CAISO via only two SCE transmission lines. However, the transmission lines connecting Big Bear Valley to the wholesale market are capacity limited. On SCE's transmission system, BVES faces a limited import capacity of 39 MW. BVES has consistently hit this threshold with its existing load, relying on the 8.4 MW Bear Valley Power Plant to supply the remaining load demand and bringing total system capacity to 47.4 MW. There is insufficient transmission capacity to deliver the amount of energy that BVES will need to meet its increasing load. Therefore, in order to procure sufficient energy from the wholesale markets, BVES would have to obtain significant transmission capacity upgrades.

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As described above, BVES estimates that such transmission upgrades will cost more than [redacted][12] Indeed, even studying the costs of transmission upgrades can cost millions of dollars. Because the cost and challenge of obtaining transmission capacity upgrades are so significant, BVES has sought more effective solutions, such as the Solar Project and Battery Project. The only alternative to paying for transmission capacity upgrades is for BVES to build more local generation resources to meet its growing energy needs. This is precisely what gave rise to the present Application. It is therefore appropriate to consider these avoided transmission upgrade costs when considering the net market value and cost-effectiveness of the proposed Projects.

2. Q: What is your response to Cal Advocates' argument that transmission offset benefits should be excluded from the Projects' net market value?

A: In urging the Commission to disregard BVES's calculation of transmission off-set benefits, Cal Advocates fundamentally misunderstands the options available to BVES and BVES's reason for pursuing this Application.[13]

Cal Advocates argues that – because BVES acknowledges that transmission upgrades are a disfavored solution due to high cost and difficulty – the Commission should disregard transmission upgrades as an alternative to the proposed Projects and should not consider the benefits of avoiding transmission upgrade costs when evaluating the proposed Projects.[14] Cal Advocates argument incorrectly assumes that BVES has the option to do nothing to address its

[12] The estimated costs for BVES transmission improvements are informed by a recently completed 34 kV sub-transmission project undertaken by BVES in similar mountainous terrain. Based on this precedent, the cost to reconstruct comparable sub-transmission infrastructure is approximately [redacted] per mile. These facilities operate at the same voltage level as those within the nearby SCE system, located approximately 20 miles from the BVES service area.

[13] Ex/ CA-01 Cal Advocates Testimony at 1-10:23-24 (Public Version).

[14] Ex/ CA-01C Cal Advocates Testimony at 1-10:23 to 1-12:15.

capacity constraints. That is incorrect. If BVES is not granted approval to build new local resources to meet its growing energy demands, it will have to pay for the transmission upgrades to address import capacity limitations or it will be unable to meet its customers' load requirements. Failure to account for the transmission upgrade costs ignores the alternative to the Projects. Thus, it is appropriate to consider such avoided costs when evaluating the benefits and value of the Projects.

3. Q: Do transmission capacity upgrades address BVES' reliability needs?

A: Cal Advocates argues that the Commission should not consider transmission upgrades as an alternative to the proposed Projects because transmission upgrades will not satisfy BVES's reliability needs.[15] However, such statement oversimplifies the issue. Transmission upgrades *would* address the import capacity limitations on BVES's system. The upgrades would enable BVES to provide adequate energy supply to address its growing customer needs. However, transmission upgrades *would not* provide the same reliability benefits that local resources, such as the Projects, provide (e.g., grid reliability and interruption mitigation in emergency or capacity-constraining situations). The additional reliability benefits provided by the Projects serve to justify BVES's Application for their approval, but additional benefits do not negate the transmission capacity upgrade alternative.

4. Q: If we remove the transmission off-set benefit from the net market value calculation, does that make the Projects NMV calculation negative?

A: No. While BVES opposes Cal Advocates' recommendation that the transmission off-set benefits be left out of the Projects' NPV calculation, inclusion of the transmission off-set benefits is not necessary to demonstrate the cost effectiveness of the Projects. BVES has already left the transmission off-set benefits out of its net market value calculation for

[15] Ex/ CA-01C Cal Advocates Testimony at 1-11:8-9 and 1-12:12-15.

the Solar Project, in order to not duplicate that benefit when combined with the Battery Project. The Solar Project's net market value is [redacted] If the transmission off-set benefits are removed from the Battery Project, the Battery Project's net market value is still [redacted] If the transmission off-set benefits value are removed from the Projects, the Projects' net market value is still [redacted].

IV. THE PROJECTS WILL PROVIDE SIGNIFICANT RELIABILITY BENEFITS TO CUSTOMERS (WITNESS SEAN MATLOCK)

1. Q: Why should the Commission account for reliability benefits when evaluating the Projects?

A: Maintaining a high level of electric reliability provides measurable economic benefits to the communities served by BVES. Use of the Lawrence Berkeley National Laboratory's ICE calculator, demonstrates that even brief power outages can result in thousands to millions of dollars in lost economic activity, depending on the duration and customer types impacted. For example, a one-hour outage affecting commercial and industrial customers in a small community can result in an estimated economic loss of tens of thousands of dollars. These real and quantifiable impacts underscore the importance of continued investment in grid resilience and modernization. Every avoided outage helps preserve local productivity, support essential services, and strengthen overall economic stability.

According to 2022 U.S. Census data,[16] the Big Bear Valley region generates approximately $235 million in annual retail sales. This figure highlights the critical role that electric reliability plays in supporting the local economy. Disruptions in power service can have

[16] *See* census.gov.

measurable and immediate economic consequences, particularly for retail, tourism, and small business sectors that are sensitive to power availability.

2. Q: Can you explain BVES's approach to calculating reliability benefits for the Projects?

A: BVES's approach to calculating reliability benefits is based on the following principles. *First,* reliability calculations should be done using a trusted, independent third-party model. BVES utilized the ICE calculator, created by the Lawrence Berkeley National Laboratory with funding by the Department of Energy, to calculate the reliability benefits of the Projects. In addition to the inherent robustness of the ICE calculator, the calculator has been approved for use by the Commission. For example, in the risk-based decision framework proceeding, the Commission adopted the ICE calculator as the default approach for investor-owned utilities to quantify reliability impacts, stating that its use increases "clarity, transparency and usefulness".[17]

Second, the model should consider various factors such as project resource type, geography, number of customers, and industry-recognized reliability measures like Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI"). The ICE calculator includes all of these factors, along with additional variables, in its model.

Third, model inputs should include low and high interruption years to account for variability between years. As explained below, BVES proposes to use the average reliability benefit calculation based on three years to account for years with both high and low interruptions.

[17] D.22-12-027, at 57 (Finding of Fact 13).

Finally, while unnecessary to calculate a reasonable reliability benefit amount, BVES also took a more conservative approach by only calculating the reliability benefits for mitigation of transmission line disruptions, without including the additional benefits of the Projects mitigating local distribution line disruptions. I discuss these final two principles below.

3. Q: What is your response to Cal Advocates' assertions regarding BVES's use of the Lawrence Berkeley National Laboratory's ICE Calculator?

A: Cal Advocates incorrectly argues that BVES's data is not representative of BVES's longer-term outage risk because it inappropriately included interruption data from the year 2022, "which was an extraordinary year when BVES suffered its largest SCE-caused outage in the last ten years."[18] It is important to note that year-over-year metrics such as the SAIDI and the SAIFI can vary significantly depending on external factors. Thus, utilizing an average of BVES's recent experience is an appropriate way to identify recent experiences while also accounting for variability between years.

Further, BVES's experience in 2022 was not an outlier as implied by Cal Advocates. As you can see from the table below, 2025 SAIDI numbers are already over double the 2022 total numbers even though we are only in May of 2025. The 2025 numbers are due to major events such as the SCE Public Safety Power Shutoff that occurred earlier in the year (compare the 2022 SAIDI value of 272.40 to the current 2025 SAIDI value of 640.06 in the table below). These types of events are outside of BVES's direct control.

[18] Ex. CA-01C Cal Advocates Testimony at 1-15:14 to 1-16:1.

Year	SAIDI	SAIFI
2021	114.71	1.35
2022	272.40	4.06
2023	128.77	2.12
2024	152.08	4.42
2025	640.06	0.85
Average	**261.61**	**2.56**

Lastly, as provided below, BVES calculated the reliability benefit for multiple individual years. Even if you only consider a low interruption year, the reliability benefits are still significant.

4. Q: Did BVES use three years of interruptions instead of one year in its initial reliability calculation as alleged by Cal Advocates?

A: No. Cal Advocates mischaracterizes BVES as having incorrectly input three years of interruption data into the ICE calculator, rather than one year of interruptions.[19] In its previous filing, BVES used the average of four years (2021-2024) of SAIDI and SAIFI data and input those averages into the ICE calculator, i.e., it did not use the cumulative SAIDI or SAIFI amounts for those years. BVES chose this initial approach because using a multi-year average to calculate reliability impacts offers a more accurate and balanced representation of a utility's performance over time compared to relying on a single year of data. Single-year metrics can be heavily influenced by atypical events such as severe weather, wildfires, or Public Safety Power Shutoff events. A multi-year average smooths out these irregularities, providing a more stable and comprehensive view of trends, system performance, and areas for improvement. This approach supports more informed regulatory decisions and ensures that planning and investment strategies are based on consistent, long-term data rather than isolated incidents.

[19] Ex. CA-01C Cal Advocates Testimony at 1-15:9-11.

Subsequently, and in response to inquiries by Cal Advocates, BVES evaluated the reliability benefits of individual years 2021, 2022, and 2023. This allowed BVES to show the significant reliability benefits of the Projects both in a range of higher and lower interruption years. BVES then combined the outputs for all three years into a three-year average (versus averaging the inputs prior to running the model). As noted above, using a multi-year average offers a more accurate and balanced representation of a utility's performance over time compared to relying on a single year of data. Based on the average values from 2021-2023, the total projected reliability benefits over the lifetime of the Projects amount to [redacted][20] Moreover, it is worth noting that the total average reliability benefits value would be even *higher* if BVES included data from year 2024 and 2025.

NPV of Total Lifetime Reliability Benefits ($)			
Year	**Battery**	**Solar**	**Hybrid**
2021	[redacted]		
2022			
2023			
Average Total Benefits			

NPV of Annual Reliability Benefits ($)			
Year	**Battery**	**Solar**	**Hybrid**
2021	[redacted]		
2022			
2023			
Average Annual Benefits			

5. Q: What flexibility does BVES have to utilize the Battery Project to meet reliability needs?

[20] *See* Attachment C – Reliability Summary.

A: BVES has the flexibility to utilize the Battery Project at different times and in different ways according to where it determines the best need. For example, BVES can deploy the battery during peak periods to mitigate price volatility. However, it can also prioritize reserving the battery to meet reliability needs, as needed. It is therefore incorrect to portray the Battery Project as necessarily being unavailable for reliability purposes for a significant portion of each day.[21]

6. Q: What is your response to Cal Advocates' assertion that BVES incorrectly assumes the Projects will mitigate all of BVES distribution level outages?

A: Cal Advocates argues that the Projects will not mitigate all SCE-supply outages, because "[d]uring scenarios in which BVES's *distribution* system experiences an outage, the Solar and Battery Projects would not be able to provide service to at least some of BVES's customers until the problem within the distribution system is resolved."[22] Cal Advocates also argues that, because the Battery Project will "enable . . . only 'a portion' of the system in an islanded configuration when microgrid distribution control systems have been configured."[23] Cal Advocates fundamentally misunderstands the data presented.

BVES only evaluated the reliability benefits of mitigating SCE-caused (i.e. *transmission* level) outages. Benefits from the mitigation of BVES distribution-level outages are not included in BVES's reliability value calculation. As Cal Advocates points out, the Projects likely *would* be able to provide some reliability coverage for distribution-level outages. These *additional* benefits are not included in BVES's reliability benefits calculation as BVES took a

[21] *See* Ex. CA-01 Cal Advocates Testimony at 2-9:5-14.

[22] Ex. CA-01 Cal Advocates Testimony at 1-16:16 to 1-17:3 (emphasis added).

[23] Ex. CA-01 Cal Advocates Testimony at 2-8:14-16.

conservative approach to its calculation. Additionally, calculating when there may be overlap between a transmission outage and distribution outage would be difficult, if not impossible to calculate as transmission outages create distribution system impacts.

7. Q: What is your response to Cal Advocates' assertions that the Projects cannot provide reliability benefits at all hours of the day?

A: Cal Advocates suggests that BVES overstates the Solar Project's reliability benefits because "BVES has not demonstrated that the standalone Solar Project would be able to provide service to its customers at times of greatest need," and that BVES overstates the Battery Project's reliability value because the Battery Project will not be able to provide reliability benefits "for a significant portion of each day" after it has been discharged.[24] Again, Cal Advocates misunderstands BVES's reliability calculations.

BVES's reliability value calculations are derived from the Lawrence Berkeley National Laboratory' ICE calculator. The ICE calculator accounts for the type of resource in question (i.e. a solar facility and a battery facility) and adjusts its reliability calculations according to resource-specific characteristics. Therefore, limitations such as the hours in which a solar facility generates and the availability of a battery resource after discharge are already accounted for in the ICE calculations.

The ICE reliability benefits calculations may be approximations, but they are supported by Commission precedent and sufficiently accurate for the purposes of demonstrating the cost-effectiveness of the Projects and supporting approval of this Application.

8. Q: Is it reasonable to assign no reliability benefit to the Projects?

[24] Ex. CA-01 Cal Advocates Testimony, at 2-7:21-23 and 2-9:13-14.

A: No. As detailed above, there are significant reliability benefits attributed to both Projects. Further BVES's approach to its reliability calculation is reasonable and supported by Commission precedent. Cal Advocates also acknowledges that "some reliability benefits may be reasonable to attribute to either or both Projects" despite it attributing zero reliability benefits for the Projects in its net market value analysis.[25] For all of the reasons set forth above, providing zero reliability benefits to the Projects' net market value calculation as suggested by Cal Advocates is unreasonable and unsupported.

V. BVES'S TAX BENEFITS STRATEGY MAXIMIZES THE BENEFITS THAT ACCRUE TO RATEPAYERS (WITNESS JEFF LINAM)

1. Q: Please describe BVES's approach to Federal tax benefits.

A: As detailed in the Application, BVES is committed to maximizing tax incentives for the benefit of its customers.[26] BVES's approach to federal tax benefits includes three elements:

(1) BVES will seek to maximize the tax credits available at the time the Projects are placed into service.[27]

(2) The Solar Battery Tax Memorandum Account ("SBTMA") is a critical element for ensuring that all of the tax benefits are tracked and returned to customers in a timely fashion.

[25] Ex. CA-01C Cal Advocates Testimony, at 1-13:6-7.

[26] *See* Application, at 27.

[27] The EPC contracts also contains provisions that support the Projects' ability to claim additional adders within the Inflation Reduction Act, such as th [redacted]

(3) BVES will ensure that the revenue requirement reflects the full impact of the tax credits at the time the projects are placed into service via the process proposed in the Application[28] and any costs tracked in the SBTMA are returned to customers.

2. Q: Why does the memorandum account approach proposed by BVES provide the most benefits for ratepayers?

A: As addressed in more detail below, the final determination of tax benefits will not be fully known until the Projects are completed and ready to be placed into service. These include, but are not limited to, the ITC percentage, the costs to which the credit applies, the receipt of the tax benefits and future tax law provisions. The SBTMA allows the tax benefits to be tracked in the interim until the Projects are completed, tax benefits are known and the revenue requirement can reflect the final tax benefits. The SBTMA can also address timing differences between the tax benefits being realized and when reflected in rates.

3. Q: What is your response to Cal Advocates' recommendation that the Projects' Maximum Reasonable Cost ("MRC") be capped at the sum of BVES's March 2025 forecasted MRCs net of the expected 30 percent ITC?

A: The approach is unnecessary and creates unnecessary administrative hurdles. Instead, the MRC for each Project should be set based on construction and initial operation costs as previously proposed by BVES.[29] BVES will then maximize the tax incentives and apply those tax incentives through the SBTMA. As discussed above, the SBTMA is the best approach to track and provide the tax benefits associated with the projects to customers. The

[28] *See* Application, at 44 (requesting authorization to file a Tier 1 advice letter at the completion of the Solar Project's construction to initiate cost recovery for its investment in and the costs to operate the Solar Project, as a UOG asset, plus and AFUDC).

[29] *See* Application, at 2-3; *see also* BVES Supplemental Testimony at 1-8:8-9.

SBTMA allows the tax benefits to be tracked in the interim until the projects are completed, tax benefits are known and the revenue requirement can reflect the final tax benefits.

However, if the Commission wishes to accept Cal Advocates' recommendation and adjust the rate base for the Projects by an assumed the 30% of the capital costs, then the following conditions must apply:

a) Approval of the SBTMA would still be necessary to track differences between when the tax benefits are realized. The SBTMA would also be necessary to track any differences in the tax incentives should the actual incentives be higher or lower than anticipated or as a result of changes in the tax law.

b) The ITC must be applied to only the project costs that are considered includable costs for purposes of determining the tax credit. This is addressed in the rebuttal testimony of Alric Oishi.[30] Based on current law, both the Solar Project and Battery Project will qualify for the 30% credit assuming completion in late 2026.

c) BVES is not expected to have sufficient taxable income to monetize the credit in the initial years of the projects. As discussed in the rebuttal testimony of Alric Oishi, this will result in a deferred tax asset being recorded on the balance sheet.[31]

d) Cal Advocates' recommendation that the tax credit for the Projects be treated as a flow-through deduction be rejected. As explained by Witness Alric Oishi, adoption of the flow-through recommendation results in a normalization violation.

e) Acceptance of Cal Advocates' position on the adjustment to rate base must include a condition that if there is a change in Federal tax law that impacts BVES's ability to take

[30] *See* Ch. 2 Rebuttal Testimony of Alric Oishi.

[31] *See* Ch. 2 Rebuttal Testimony of Alric Oishi.

the full 30% ITC credit, the impact should be recorded to the SBTMA and addressed in the next general rate case. As illustrated above, even without tax incentives, the Projects provide significant benefits for BVES's customers, thus such approach is reasonable.

4. Q: What is your response to Cal Advocates' contention that BVES includes ITC benefits in its net market value calculations?

A: Cal Advocates misunderstands BVES's revenue and net market value calculations. The direct and supplemental testimony has consistently excluded the tax benefits from the revenue requirement calculations. For the direct testimony, the financial models for Solar Project and Battery Project were provided with the testimony as Appendix B and Appendix C, respectively. For the supplemental testimony, the financial models for Solar Project and Battery Project were provided with the testimony as Appendix A and B, respectively. In all of the financial models, the ITC was estimated for illustrative purposes as 30% of the asset sale price. This is the cost of the Solar Project and Battery Project based on the EPC price from EDF. However, the net present value and net market value calculations exclude the estimated benefits associated with tax credits. Furthermore, the cash flow calculations also exclude the tax benefits that would accrue to customers; although there is a line for the estimated ITC benefits, it is for illustrative purposes only.

5. Q: If federal tax incentives are not included in the net market value calculation, will the net market value be negative for either of the Projects?

A: No. As explained above, none of BVES's net market value calculations include federal tax credits. Even without the inclusion of the tax benefits, each project has a significantly high net market value calculation, which means that even without any tax credits, the Projects provide a net benefit to ratepayers. BVES is committed to maximizing the tax incentives

available for the Projects but such additional customers savings are on top of the already clear benefits of both Projects.

VI. THE COMMISSION SHOULD APPROVE AN ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (WITNESS JEFF LINAM)

1. Q: Please clarify BVES's testimony with respect to the allowance for funds used during construction.

A: BVES's proposal to include an Allowance for Funds Used During Construction ("AFUDC") for the Solar Project and Battery Project is based on the process that has been approved by the Commission for similar projects. In Decision ("D.") 19-08-027, the Commission granted BVES's request to recover the Pineknot Substation Project and the Grid Modernization Project costs, plus an AFUDC through a Tier 1 advice letter filing. In D.25-01-007, the Commission approved BVES's settlement with Cal Advocates to recover the Partial Safety and Technical Upgrades to Maltby Substation Project, Radford Line Project, Advanced Metering Infrastructure Project and the Switch and Field Device Automation Project, plus AFUDC, upon completion and placement into commercial operation.

While Cal Advocates did not oppose BVES's AFUDC request, there are several statements in Cal Advocates' testimony that BVES would like to address. *First*, Cal Advocates refers to BVES's AFUDC proposal as an "undetermined" amount. This is correct, and by necessity. It is not feasible to calculate exact funds used during construction, as those numbers are subject to continual change. Instead, BVES seeks the Commission's approval of an AFUDC *formula,* as have been approved in other instances cited above. BVES did provide an example calculation using some illustrative inputs to Cal Advocates in response to a data request, but given

that the actual input values cannot be determined at this time, the calculation was illustrative only.[32] BVES's proposal to include AFUDC at the time the Projects are placed into service is consistent with the process approved by the Commission for similar projects. BVES did address in the testimony[33] that the payment structure with EDF is designed to limit BVES customer cost exposure by limiting payments under the contract to specific milestones with [redacted] of the payments held until mechanical completion.

Second, Cal Advocates pointed out that BVES's supplemental testimony spreadsheet for the Battery Project included an estimate for AFUDC. This inclusion was made in error. BVES had added in an estimate for AFDUC for illustrative purposes in response to a data request. BVES has removed the illustrative AFUDC calculation from the net market value calculation spreadsheet to avoid any confusion. For consistency, the revenue requirement for the Battery Project should have been presented exclusive of AFUDC. BVES's proposal is to include AFUDC when the Projects are proposed to be included in rates.

VII. THE PROPOSED PROJECTS PROVIDE A COST EFFECTIVE MEANS OF ADDRESSING BVES'S PEAK DEMAND, REGULATORY OBLIGATIONS, AND GHG REDUCTIONS (WITNESS SEAN MATLOCK)

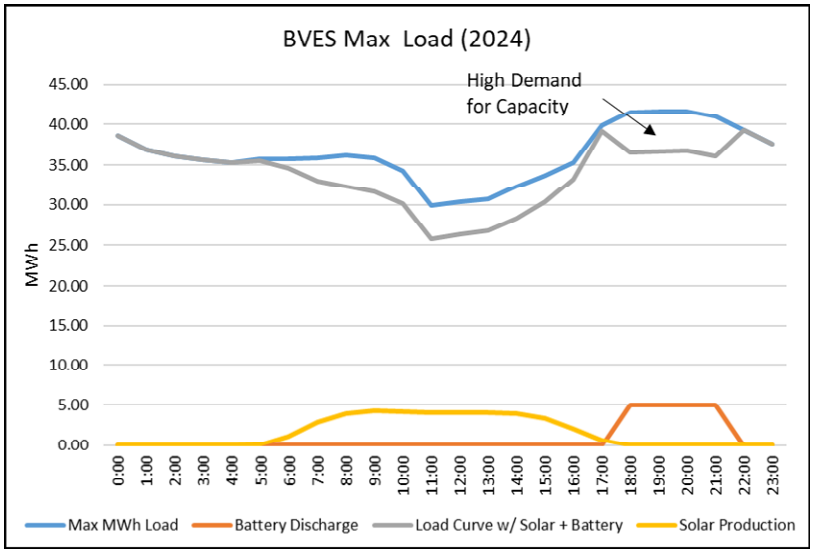
A. The Proposed Projects Will Help BVES Meet Peak Demand

1. Q: Please explain how the Projects will help provide energy during peak demand.

[32] *See* Ex. CA-01C Cal Advocates Testimony, Confidential Attach. 2, BVES response to Cal Advocates DR-002, Q.1.a.

[33] Exh. BVES-1C, Ratemaking, Direct Testimony of Jeffrey T. Linam, Chapter 3 ("Ch. 3 Testimony of Jeff Linam") at 3-8:7-13 (Confidential Version).

A: Cal Advocates argues that the proposed Projects will not provide energy when it is most needed.[34] During evening hours, especially in winter, Big Bear's demand peaks due to tourism, necessitating more capacity. The Battery Project will help shift load to when capacity is most needed. The graph below shows 2024's hourly peak load, highlighting evening peaks when solar power is unavailable.



Furthermore, while the Solar Project cannot produce during evening periods, BVES can utilize policy tools to shift demand. For example, EV charging is forecasted to contribute to increasing load demand. BVES can utilize rate design to incentivize EV charging during off peak hours and during solar production hours.

B. The Proposed Projects Provide the Most Effective Means of Addressing BVES's Regulatory Obligations

1. Q: Can BVES meet all of its regulatory obligations with PCC3 RECs as alleged by Cal Advocates?

[34] Ex. CA-01 Cal Advocates Testimony, at 2-7:19-23 ("BVES' load peaks on winter evenings, and BVES has not demonstrated that the Solar Project is capable of generating during those winter evening periods. Therefore, BVES has not demonstrated that the standalone Solar Project would be able to provide service to its customers at times of greatest need."); *id.* at 2-9: 13-14 ("the Battery Project would not be available for reliability purposes for a significant portion of each day.").

A: No. Both BVES's RPS and Integrated Resource Plan ("IRP") highlight the critical importance of investing in local solar and battery storage resources—particularly in light of the recent Reliable and Clean Power Procurement Program proceeding, which is consolidating RPS and IRP planning requirements. As a small investor-owned utility operating within the CAISO balancing authority, BVES serves a relatively limited customer base and faces unique challenges in securing RPS- and IRP-eligible resources. Local resource development is essential for aligning with BVES's long-term planning goals and offers clear reliability and resiliency benefits to the Big Bear Valley community. Resources such as local solar and energy storage facilities provide critical grid support, mitigate the risk of external supply disruptions, and enhance BVES's ability to meet future policy mandates.

While BVES and other small or multi-jurisdictional utilities in California are permitted to meet their RPS compliance obligations using PCC3 RECs, no such carve out exists for IRP GHG reduction purposes. PCC3 RECs are not recognized in the IRP GHG reduction models. This limitation highlights the need for BVES to develop or procure PCC1 RECs from certified in-state facilities.

Furthermore, of the procurement credited towards an RPS compliance period, at least 65% of such procurement must come from long-term contracts (10 years or longer) or owned facilities. As BVES will own the solar facility, all output from that facility will qualify towards the 65% long-term contracting requirement.

Establishing a local solar project will enable BVES to generate PCC1 RECs and offer the greatest level of flexibility in meeting both RPS and IRP program requirements. This strategy ensures regulatory compliance while delivering long-term economic and environmental benefits to the community.

2. Q: Please explain why purchasing PCC3 RECs is not more cost effective than pursuing the Solar Project.

A: Cal Advocates argues that the Solar Project is not cost effective because it would be cheaper for BVES to meet its remaining RPS requirements through unbundled RECs.[35] This argument disregards the fact that BVES must procure additional energy in order to meet its load forecast. As discussed above, BVES has two options: invest more than [redacted] in transmission capacity upgrades in order to be able to procure necessary energy from the CAISO markets, or build local resources to meet BVES's energy needs. Upgrading the transmission corridor will cost significantly more than building the Solar Project. The cost savings from purchasing PCC3 RECs to meet RPS requirements does little to make the transmission upgrade option more cost effective. It is far more cost effective to build the Solar Project to meet BVES's energy needs and simultaneously meet BVES's RPS and IRP obligations with the same project.

C. The Proposed Projects Reduce GHG Emissions

1. Q: Describe the Solar Project's impact on GHG emissions in the Big Bear Valley area.

A: The Solar Project will lower GHG emissions in the Big Bear Valley area and help meet California's overall GHG emissions reduction targets. During operation, the Solar Project will directly reduce GHG emissions by providing power with no GHG emissions and reducing the number of hours that BVES must run its BVPP gas-fired generator to provide local power. Further, operation of the Solar Project will allow BVES to reduce the amount of energy purchased through power purchase agreements, including any purchases from GHG-emitting

[35] *Id.,* at 2-6:10-12.

resources. Carbon emissions reduction benefits are estimated to be [redacted] on average per year over the life of the Solar Project.[36]

2. Q: Describe the Solar Project's impact on GHG emissions in the Big Bear Valley area.

A: Overall, the Battery Project, in addition to the Solar Project, showcases a shift towards a more sustainable resource mix and support BVES in achieving its decarbonization goals. The Battery Project will lower GHG emissions in the Big Bear Valley area and help meet California's overall GHG emissions reduction targets. Operation of the Battery Project will allow BVES to reduce the amount of energy purchased through power purchase agreements, including any purchases from GHG-emitting resources. The Battery Project also provide BVES with the flexibility to further reduce emissions through market participation if the asset is charged during periods of high renewable energy output on the CAISO grid and discharged during periods of demand on the BVES system when renewable energy is less available on the CAISO grid. The Battery Project may also reduce the number of hours the BVPP is used, further reducing GHG emissions.

3. Q: Do you agree with Cal Advocates assertion that the Battery Project and the Projects together will increase GHG emissions?

A: No. Adding a Solar Project and Battery Project to the BVES system will not increase GHG emissions. I disagree with Cal Advocates' argument that the Battery Project and combined Projects will increase GHG emissions to the extent the battery is charged from SCE-supplied grid system power or the BVPP, due to "round-trip efficiency losses from the battery."[37]

[36] *See* Appendix B, BVES Solar Facility Analysis, Summary Tab (average of annual "Monetized CO2 Savings" in column AL).

[37] Ex. CA-01 Cal Advocates at 2-9:18-20.

First, while round-trip efficiency losses exist, this does not inherently translate to increased GHG emissions. If a battery is charged during low-emission periods and displaces generation during high-emission periods (e.g., peaker plants or high marginal emissions hours), the overall GHG impact can be net beneficial even with efficiency losses.

Second, Cal Advocates also fails to account for the local reliability benefits provided by the Battery Project. The Battery Project can provide critical capacity during peak periods and reduce the need for high-emission local generation (such by the Bear Valley Power Plant) or from customer-sited emergency diesel backup. The presence of a battery allows for more flexible operation of local generation, potentially reducing its run time and increasing its efficiency.

For the Projects together, the Battery Project is expected to primarily charge during the Solar Project's generation hours when the solar output may exceed local load. This minimizes the reliance on SCE grid-supplied power and provides a firm, dispatchable renewable resource that can serve evening peaks and reduce fossil demand. If charging from the grid, operational strategies can be implemented to avoid charging during high-emission periods. It is unlikely that the Battery Project would charge from the Bear Valley Power Plant, except under exigent circumstances.

Far from increasing GHG emissions, the Solar and Battery Projects are key tools for reducing GHG emissions, enabling higher renewable penetration, and enhancing local reliability.

VIII. THE COMMISSION SHOULD PERMIT RATE RECOVERY FOR REASONABLE COST INCREASES THROUGH A TIER 2 ADVICE LETTER PROCESS (WITNESS JEFF LINAM)

1. Q: Does Cal Advocates provide any justification for why the use of a Tier 2 Advice Letter process for cost recovery is inappropriate?

A: No. Cal Advocates argues that BVES's proposal to request recovery for any increase in the MRC via a Tier 2 advice letter is not reasonable, citing potential increases in costs.[38] Cal Advocates' argument is flawed. Public Utilities Code Section 399.14(c), requires BVES to demonstrate an (1) actual cost increase, (2) that cost increase is reasonable and prudent, and (3) that present or future public convenience and necessity require construction at increased cost. Cal Advocates identifies reasons that may cause the Projects' costs to increase above the MRC, but does not provide evidence that such cost increases would be unreasonable or would undermine the necessity of the Projects. Moreover, nowhere does Cal Advocates explain why Public Utilities Code 399.14(c) cannot be satisfied via a Tier 2 advice letter process.

The Tier 2 Advice Letter process will provide Cal Advocates and Energy Division with opportunity to review costs. A Tier 2 advice letter allows for a 30-day review period whereby both Cal Advocates and Energy Division have the ability to review all applicable costs to ensure that they were reasonable and prudently incurred prior to granting recovery through customer rates. In fact, the Commission has a recent history of approving advice letters establishing recovery for project costs incurred by BVES that were outside of rates.[39] Additionally, should the Commission need more than the 30 days to review the additional costs incurred, Energy Division has the discretion to suspend the advice letter to allow for additional review time. An advice letter is also a more efficient and cost-effective process for both the Commission and BVES than a separate and duplicative application as Cal Advocates proposes.

[38] *Id.,* at 1-19:16 to 1-20:9 (Confidential Version).

[39] *See* BVES Tier 2 Advice Letter 509-E Request for Recovery of Radford Line and Switch and Field Capital Projects, effective April 1, 2025 (Feb. 28, 2025); BVES Advice Letter 455-E Request for Recovery of Authorized Grid Modernization Project and Increase Base Revenue Requirement, effective November 15, 2022 (Oct. 12, 2022).

2. Q: What additional complications arise when using the longer and less efficient General Rate Case or separate Application approach?

A: If BVES needs to seek recovery of costs above the MRC in its general rate case or through a separate application, BVES would incur additional carrying costs and associated reasonable return on its investment, over the period between when the Project has been constructed and when it ultimately gets included in rates for recovery. Given that the timing of a general rate case filing may not coincide with the timing of the completion of a project, and that a separate application can take anywhere from 18 months to 24 months to conclude, the following additional costs would accrue and need to be recovered: (a) Allowance for Funds Used During Construction, and (b) a full rate of return post construction, until the costs are in rates on any additional costs incurred above the MRC that are ultimately determined by the Commission to be reasonable and prudent.

IX. THE COMMISSION SHOULD APPROVE BVES'S PROPOSAL FOR THE PROJECTS' OPERATING EXPENSES (WITNESS JEFF LINAM)

1. Q: What is BVES' proposal to the Projects' operating expenses?

A: As detailed in the Application, BVES requests that the Commission authorize BVES to include the Projects' operating expenses in its adjusted revenue requirement, which represent the annual and incremental costs associated with operating the Projects over their useful lives.[40] Such approach would wrap the operating expenses of the Projects into BVES's overall operations and maintenance costs. Any future operations and maintenance costs beyond this rate cycle will be evaluated and scrutinized as part of BVES general rates cases.

[40] *See* Application, at 28 and 36.

2. Q: Why should BVES's approach be approved over Cal Advocates' recommendation that the Projects' operating expenses be capped at the forecasted amounts?

A: BVES's approach to wrap the Projects' operating expenses into its overall operations and maintenance costs is more appropriate. While Cal Advocates includes a recommendation that the operating expenses be capped at the forecasted amounts in its overview, it does not provide any justifications for the approach in its testimony.[41] Treating the Projects' operating expenses separately than BVES's other operations and maintenance expenses presents administrative hurdles with little to no benefit. BVES provided an estimate (in 2024 dollars) for the first year of operating expenses for each Project in its Application.[42] To the extent there are any concerns over future year operating expenses, such concerns are more appropriated addressed in the general rate case. Imposing an expense cap for 20 and 30 years for the battery and solar projects, respectively, is not only unreasonable and administratively challenging but it is also counter to how the Commission treats BVES's other operating expenses. This extends to cases similar to this application, where the Commission has approved capital projects outside of a general rate case.[43] In the settlement to Liberty Utilities' (CalPeco Electric) application to finance, construct, own and operate the Luning Solar Project (A.21-04-006) and approved by the Commission in D.23-08-032, Cal Advocates agreed to authorize Liberty to recover costs

[41] Ex. CA-01 Cal Advocates Testimony, at 3-3:19-21.

[42] *See* Application, at 28 and 36.

[43] *See* D.19-08-028 and D.25-01-007. In D.19-08-027, the Commission approved BVES's request to recover the Pineknot Substation Project and the Grid Modernization Project costs through a Tier 1 advice letter project. Operating costs for these projects were included in BVES's Test Year 2023 GRC (A.22-08-010). D.25-01-007 approved a settlement with Cal Advocates to recover costs for several projects through separate Tier 2 advice letter filings. Operating costs for these projects will be included in BVES's Test Year 2027 general rate case to be filed in January 2026.

associated with the operation of the Project as general rates during the Project's operating life.[44] Therefore, the Commission should reject Cal Advocates proposal to cap the operating costs for these projects for the next 20 to 30 years.

X. CONCLUSION

1. Q: Does this conclude this portion of your testimony?

A: Yes, it does.

[44] D.23-08-032, Attachment A, at 6.

APPLICATION OF BEAR VALLEY ELECTRIC SERVICE, INC. (U 913 E), FOR A CERTIFICATE OF PUBLIC CONVENIENCE TO ACQUIRE, OWN, AND OPERATE THE BEAR VALLEY SOLAR ENERGY AND BATTERY STORAGE PROJECTS AND AUTHORIZE RATEMAKING ASSOCIATED WITH THE STORAGE AND SOLAR ENERGY PROJECTS' CAPITAL INVESTMENT AND OPERATING EXPENSES

REBUTTAL TESTIMONY OF

ALRIC OISHI

CHAPTER 2

TAX TREATMENT

PUBLIC VERSION

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BEAR VALLEY ELECTRIC SERVICES

CHAPTER 2

TAX TREATMENT

I. INTRODUCTION

1. Q: Please state your name, occupation, and business address

A: My name is Alric Oishi. I am the Director of Tax for the Golden State Water Company and its subsidiaries. My business address is 601 E. Foothill Blvd, San Dimas, CA 91773.

2. Q: Does Chapter 2, Appendix A, entitled "Qualifications of Witness Alric Oishi" accurately summarize your background, education, and experience?

A: Yes, it does.

3. Q: What is the purpose of your rebuttal testimony?

A: My rebuttal testimony responds to the prepared testimony of the Public Advocates Office, Exhibit CA-01 served on May 9, 2025. Specifically, my testimony addresses Cal Advocates' tax related recommendations related to ratemaking for ITC.

II. TAX TREATMENT

1. Q: Is the ratemaking for the ITC related to the Solar Project or the ITC related to the Battery Project subject to any federal income tax law restrictions?

A: Yes, ITC claimed on public utility property is subject to the normalization requirements of the Internal Revenue Code ("Code") and the associated Treasury regulations. These rules have been interpreted by the Internal Revenue Service in numerous private letter rulings.

2. Q: What are the consequences of a utility not complying with the ITC normalization requirements?

A: A utility that does not comply with the ITC normalization requirements in its ratemaking or regulatory reporting is either not eligible for the ITC or may be required to recapture the ITC (i.e., pay additional federal income tax liability equal to some or all of the amount of the tax credit claimed).

3. Q: Can BVES opt-out of the normalization rules for the Projects?

A: No. BVES analyzed the normalization rules for the two Projects. As detailed below, BVES cannot opt-out of the normalization rules for either Project without causing a normalization violation.

4. Q: Can you explain why the Solar Project and Battery Project are ineligible for the normalization opt-out option that Cal Advocates recommends?

A.: In its testimony Cal Advocates references an opt-out election that, under certain circumstances, allows utilities to use flow-through accounting of the ITC.[45] The statutory wording related to the scope of the opt-out election is very specific. The election is limited to "energy storage technology" as defined in Code Section 48(c)(6) with a maximum capacity of more than 500 kilowatt hours. Code Section 48(c)(6) defines the term "energy storage technology" to mean (i) property (other than property primarily used in the transportation of goods or individuals and not for the production of electricity) which receives, stores, and delivers energy for conversion to electricity (or, in the case of hydrogen, which stores energy), and has a nameplate capacity of not less than 5 kilowatt hours, and (ii) thermal energy storage property. The "energy storage technology" definition referenced by the statutory election also states that the term "energy storage technology" shall not include any property the construction of which begins after December 31, 2024.

[45] Ex. CA-01 Cal Advocates Testimony, at 1-18:6-13.

Given that the definition does not include power generation facilities, the election is not available for the Solar Project. Additionally, the Battery Project did not begin construction before December 31, 2024. Thus, the Battery Project is also ineligible for the election referenced by Cal Advocates under tax law as currently enacted.

5. Q: How do the ITC normalization requirements apply to the ITC claimed with respect to the Solar Project and Battery Project?

A: The rules pursuant to former Code Section 46(f)(1) (i.e., "Option 1") apply. Under these rules, ITC may reduce rate base with such rate base reduction restored no less rapidly than ratably over the life of the asset (as reflected in regulatory depreciation). Amortization of the ITC may not reduce recoverable income tax expense or otherwise reduce the revenue requirement. The rate base reduction may not occur until the ITC is utilized or realized on a tax return. In other words, ITC that is carried forward may not immediately be reflected in setting rates. ITC reflected in rates is also subject to the consistency requirements of former Code Section 46(f)(10). These rules could apply to limit the amount of ITC reflected in rates, for example, if a portion of the plant costs are not included in rate base or reflected in regulatory depreciation expense.

6. Q: In determining the ITC to be claimed for the solar and battery project, does the ITC rate apply to all project costs?

A: No. The ITC must be applied to only the project costs that are considered includable costs for purposes of determining the tax credit. While the ITC will apply to the acquired assets from EDF, there are certain costs like land, AFUDC and certain interconnection costs that are excluded from the determination of the ITC.

7. Q: In your opinion, will BVES have sufficient taxable income to monetize the ITC in the initial year of the projects?

A: No. Due to the size of the ITC, BVES is not expected to have sufficient taxable income in the initial year of the projects to recognize the credit. This will result in a deferred tax asset being recorded on the balance sheet for BVES.

III. CONCLUSION

1. Q: Does this conclude this portion of your testimony?

A: Yes, it does.

APPENDIX A

Qualification of Witness Alric Oishi

Q1. Please state your name and business address.

My name is Alric Oishi. My business address is 601 E. Foothill Blvd, San Dimas, CA 91773.

Q2. By whom are you employed and in what capacity.

I am employed by Golden State Water Company as the Director of Tax. As Director of Tax, I oversee all aspects of tax compliance and income tax reporting for American States Water Company and its wholly owned subsidiaries Golden State Water Company, Bear Valley Electric Service, Inc. and American States Utility Services. I have been at Golden State Water Company for one year. Prior to Golden State Water Company, I worked in aerospace and in grocery wholesale distribution in similar roles and in public accounting serving a variety of industries.

Q3. Briefly state your educational background and experience.

I hold a Bachelor of Arts degree in Economics from the University of California at Los Angeles and a Masters in Business Taxation from the University of Southern California. I am a Certified Public Accountant in the State of California and have 30 years of experience in accounting, tax compliance and financial statement preparation.