*Agenda 4-24; Item No. 2B Draft Order for discussion at agenda*

***THIS ORDER IS NOT A FINAL ORDER AND MAY BE SUBSTANTIALLY REVISED PRIOR TO ENTRY OF A FINAL ORDER BY THE PUBLIC UTILITIES COMMISSION OF NEVADA***

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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| Joint Application of Nevada Power Company d/b/a | ) | |
| NV Energy and Sierra Pacific Power Company d/b/a | ) | Docket No. 23-08015 |
| NV Energy for approval of the fifth amendment to its | ) | |
| 2021 Joint Integrated Resource | ) | |
| Plan._______________________________________ | ) | |

At a special session of the Public Utilities Commission of Nevada, held at its offices on March 1, 2024.

PRESENT: Chair Hayley Williamson
Commissioner Tammy Cordova
Commissioner Randy Brown
Assistant Commission Secretary Trisha Osborne

**[PROPOSED] ORDER**

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The Public Utilities Commission of Nevada ("Commission") makes the following findings and conclusions:

## I. INTRODUCTION

On August 22, 2023, Nevada Power Company d/b/a NV Energy ("NPC") and Sierra Pacific Power Company d/b/a NV Energy ("SPPC") (collectively, "NV Energy") filed with the Commission a joint application ("Joint Application"), designated as Docket No. 23-08015, for approval of the fifth amendment to its 2021 Joint Integrated Resource Plan ("IRP").

On January 17, 2024, to January 19, 2024, the Commission held a hearing on the Joint Application.

## II. SUMMARY

The Commission grants in part and modifies in part the Joint Application, as detailed below.

## III. PROCEDURAL HISTORY

- On August 22, 2023, NV Energy filed with the Commission its Joint Application.
- NV Energy filed the Joint Application pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC") Chapters 703 and 704, including, but not limited to, NRS 704.741 and NAC 704.9005 *et seq*. Pursuant to NAC 703.190 and NAC 703.527 *et seq.*, NV Energy requests that certain information contained in its Joint Application receive confidential treatment.
- The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.
- On August 25, 2023, the Nevada Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS.
- On August 25, 2023, NV Energy filed revised versions of Volumes 1 and 2 of the Joint Application redacting confidential information.
- On August 29, 2023, the Commission issued a Notice of Joint Application and Prehearing Conference.
- On August 31, 2023, Google LLC ("Google") filed a Petition for Leave to Intervene ("PLTI").
- On September 5, 2023, Western Resource Advocates ("WRA") filed a PLTI.
- On September 6, 2023, the Commission issued a Procedural Order.

- On September 15, 2023, Staff filed a Motion to Dismiss Prayer No. 8 without Prejudice ("Staff's Motion").

- On September 19, 2023, NV Energy filed the information requested in the September 6, 2023, Procedural Order. That same day, the Nevada Resort Association ("NRA"), Caesars Enterprise Services, LLC ("Caesars"), and MGM Resorts International ("MGM") each filed a PLTI.

- On September 20, 2023, Arevia Power Holdings, LLC ("Arevia"), MSG Las Vegas, LLC ("MSG"), Nevada Workers for Clean and Affordable Energy ("NWCAE"), Advanced Energy United ("AEU"), and Interwest Energy Alliance ("Interwest") each filed a PLTI. Southern Nevada Gaming Group ("SNGG") and Wynn Las Vegas, LLC and Smart Energy Alliance ("Wynn and SEA") each filed a Joint PLTI. WRA filed an Errata to its PLTI. That same day, NV Energy filed an amendment to its Joint Application.

- On September 21, 2023, Sierra Club filed a PLTI and a Notice of Association of Counsel. That same day, the Presiding Officer held a prehearing conference. NV Energy, Staff, BCP, Google, WRA, NRA, Caesars, MGM, Arevia, SNGG, MSG, NWCAE, AEU, Interwest, Wynn and SEA, and Sierra Club made appearances. The Parties discussed the PLTIs, NV Energy's Amendment, a procedural schedule, and the discovery process.

- On September 22, 2023, the Commission issued Procedural Order No. 2 establishing a procedural schedule and discovery processes. That same day, BCP filed a joinder and response to Staff's Motion ("BCP's Joinder and Response") and NV Energy filed a response to Staff's Motion ("NV Energy's Response").

- On September 26, 2023, NV Energy filed a response to each of the PLTIs filed by Wynn and SEA ("NV Energy's Response to Wynn and SEA's Joint PLTI"), MGM ("NV Energy's Response to MGM's PLTI"), Caesars ("NV Energy's Response to Caesars' PLTI"), NRA ("NV Energy's Response to NRA's PLTI"), SNGG ("NV Energy's Response to SNGG's Joint PLTI"), and Sierra Club ("NV Energy's Response to Sierra Club's PLTI"). Staff filed a Response in Support of the Casino Entities PLTIs.

- On September 27, 2023, Wynn and SEA filed a reply to NV Energy's Response to Wynn and SEA's Joint PLTI, MGM filed a reply to NV Energy's Response to MGM's PLTI, Caesars filed a reply to NV Energy's Response to Caesars' PLTI, NRA filed a reply to NV Energy's Response to NRA's PLTI, SNGG filed a reply to NV Energy's Response to SNGG's Joint PLTI, and Sierra Club filed a reply to NV Energy's Response to Sierra Club's PLTI. That same day, the Commission issued an order granting the PLTIs of Caesars, MGM, NRA, SNGG, and Wynn and SEA; and NV Energy filed a Motion to Strike BCP's Joinder and Response ("NV Energy's Motion to Strike").

- On September 28, 2023, the Commission issued an order granting Sierra Club's PLTI.

- On September 29, 2023, the Commission issued an order granting the PLTIs of AEU, Arevia, Google, Interwest, MSG, NWCAE, and WRA. That same day, Staff filed a reply to NV Energy's Response.

- On October 4, 2023, BCP filed a response to NV Energy's Motion to Strike ("BCP's Response to Motion to Strike") and Staff filed a response to NV Energy's Motion to Strike ("Staff's Response to Motion to Strike").

- On October 11, 2023, NV Energy filed a reply to BCP's Response to Motion to Strike and NV Energy filed a letter addressing Staff's Response to Motion to Strike.

- On October 20, 2023, the Presiding Officer issued an order denying Staff's Motion and NV Energy's Motion to Strike.

- On November 2, 2023, and November 7, 2023, the Presiding Officer held discovery dispute conferences.

- On November 9, 2023, the Presiding Officer issued Procedural Order No. 3 directing NV Energy to provide certain information to requesting parties.

- On November 15, 2023, NV Energy filed its Motion.

- On November 20, 2023, Arevia filed a joinder to NV Energy's Motion ("Arevia's Joinder").

- On November 22, 2023, SNGG filed a response to NV Energy's Motion ("SNGG's Response"), Staff filed a response to NV Energy's Motion ("Staff's Response"), Caesars, MGM, and NRA (together "CMN") filed a response to NV Energy's Motion ("CMN's Response"), Sierra Club filed a response to NV Energy's Motion ("Sierra Club's Response"), and Interwest filed a response to NV Energy's Motion ("Interwest's Response").

- On December 1, 2023, NV Energy filed a reply to the Responses filed on November 22, 2023 ("NV Energy's Reply").

- On December 4, 2023, the Commission issued an order granting NV Energy's Motion and setting a briefing schedule addressing the treatment of confidential information at issue in Procedural Order No. 3.

- On December 8, 2023, the Presiding Officer held a continued prehearing conference and issued Revised Procedural Order No. 2.

- On December 11, 2023, NV Energy filed its brief ("NV Energy's Brief"), responsive to the Commission's December 4, 2023, Order.

- On December 14, 2023, NV Energy filed an amendment to its Joint Application.

- On December 18, 2023, in response to the Commission's December 4, 2023, Order and NV Energy's Brief, Staff, CMN, Interwest, SNGG, Wynn and SEA, Arevia, WRA, Sierra Club, and AEU each filed a brief.

- On December 19-20, 2023, Staff, BCP, Interwest, Sierra Club, WRA, CMN and SNGG, MSG, and AEU filed testimony.

- On December 21, 2023, the Commission issued a Notice of Hearing. That same day, CMN filed an errata to its December 18, 2023, brief.

- On December 27, 2023, NV Energy filed a brief in reply to the briefs filed on December 18, 2023.

- On December 29, 2023, the Commission issued an Order addressing the parties' briefs and affirming the November 9, 2023, Procedural Order No. 3. That same day, NV Energy submitted revised confidential portions of its Joint Application pursuant to the December 29, 2023, Order.

- On January 5, 2024, the Presiding Officer issued Procedural Order No. 4 establishing procedures for the hearing.

- On January 8, 2024, NV Energy filed rebuttal testimony. That same day, CMN and SNGG, Sierra Club, and WRA each filed supplemental direct testimony pursuant to the December 8, 2023, Revised Procedural Order No. 2.

- On January 9, 2024, Staff filed an Errata to Swetha Venkat's Direct Testimony, updating certain portions of testimony to reflect the changes presented in NV Energy's December 14, 2023, amendment to its Joint Application.

- On January 12, 2024, NV Energy filed supplemental rebuttal testimony pursuant to the December 8, 2023, Revised Procedural Order No. 2. That same day, the American Institute of Architects and the Nevada Conservation League each filed comments.

- On January 17, 2024, to January 19, 2024, the Commission held a hearing. NV Energy, Staff, BCP, Google, WRA, NRA, Caesars, MGM, SNGG, MSG, AEU, Interwest, Wynn and SEA, and Sierra Club made appearances.

## IV. JOINT APPLICATION

### A. Joint Application Overall Scope and Overall Consideration

**NV Energy's Position**

1. In its Joint Application, NV Energy makes the following requests and prayers for relief:

   I. Approval of the Amendment to the 2021 Joint IRP base long-term fuel and purchased power price forecasts provided in Technical Appendix FPP-1 as presenting the most accurate information upon which to base the planning decisions set forth in the filing.

II. Approval of NV Energy's Preferred Plan, including the resources listed below:

  a. Valmy Generating Station ("Valmy") Units 1 & 2 Repower on Natural Gas

     i. Approval of NV Energy's request to amend its Supply Plan to expend approximately $83 million, SPPC's share of the total project cost shared with Idaho Power Company, to repower existing coal-fired combustion to natural-gas-fired combustion at Valmy, with an in-service date of December, 2025, for Valmy unit 1 and May, 2026, for Valmy unit 2.

     ii. Approval of NV Energy's request to amend its Supply Plan to accommodate the continued operation of the repowered Valmy through 2049.

  b. Sierra Solar Photovoltaic ("PV") & Battery Energy Storage System ("BESS") project (the "Sierra Solar" project)

     i. Approval of NV Energy's request to amend its Supply Plan to expend approximately $734 million, with NPC's share at 60 percent and SPPC's share at 40 percent, to purchase, install, and operate a 400-megawatt ("MW") solar PV project located in Churchill County, Nevada, with an in-service date of April 2027.

     ii. Approval of NV Energy's request to amend its Supply Plan to expend approximately $731 million, with NPC's share at 60 percent and SPPC's share at 40 percent, to purchase, install, and operate a 400-MW, 4-hour, BESS project located in Churchill County, Nevada, with an in-service date of July 2026.

     iii. Approval of NV Energy's request to designate the Sierra Solar project as a critical facility pursuant to NAC 704.9484 and associated accounting treatment in the form of Construction Work in Progress ("CWIP") balances in rate base and project expenses after the in-service date recorded in a regulatory asset account with a carrying charge.

     iv. Waiver of NAC 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the Investment Tax Credit ("ITC") for the Sierra Solar project;

     v. Approval of NV Energy's request to amend its Transmission Plan to expend approximately $71 million to construct transmission infrastructure needed to support the interconnection of the Sierra Solar project.

c. Tracy Units 4/5 ("Tracy 4/5") Continued Operation

i. Approval of NV Energy's request to amend its Supply Plan to accommodate the continued operation of Tracy 4/5 through 2049.

ii. Approval of NV Energy's request to amend its Supply Plan to expend approximately $54 million for compliance with environmental regulations to enable the continued operation of Tracy 4/5 past 2031.

III. Approval of NV Energy's request to amend the Generation Plan for regulatory asset treatment of the decommissioning of coal and coal combustion residuals operations at Valmy.

IV. Approval of NV Energy's request to amend the Renewables Plan to expend funds for the asset purchase of the Crescent Valley project for the future development of a 149-MW PV and 149-MW BESS project known as Crescent Valley Solar located in Lander County, Nevada.

V. Approval of NV Energy's request to amend its Transmission Plan to expend approximately $56 million to construct the Esmeralda 525/230-kilovolt ("kV") transformers.

VI. Approval of NV Energy's request to amend its Transmission Plan to expend approximately $40 million to construct the Amargosa 525/230-kV transformers.

VII. Approval of NV Energy's request to amend its Transmission Plan to construct necessary infrastructure for the Apex Area Master Plan with the following projects:

a. Expend approximately $62 million for Apex Central 230/12-kV Substation;

b. Expend approximately $15 million for Apex East 230/12-kV Substation;

c. Expend $0.22 million for Apex Southeast 230/12-kV Substation constraint study, environmental studies, permitting and land acquisition efforts;

d. Expend $0.17 million for Apex Southwest 230/12-kV Substation constraint study, environmental studies, permitting, and land acquisition efforts.

VIII. Waiver of NAC 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the Valmy BESS project if the Commission approves the project.

IX. Grant the request for confidential treatment of information contained in the Joint Application as described above.

X. Grant such additional other relief as the Commission may deem appropriate and necessary.

(Ex. 100 at 14-17.)

2. NV Energy states that there are several key factors driving the need for this Joint Application at this time. (Ex. 120 at 5.) NV Energy states that the first driver is the need for a solution that allows NV Energy to move forward with the on-time retirement of coal combustion at Valmy by the end of 2025. (*Id.*) NV Energy states that Valmy provides both capacity and critical system support to the Carlin Trend load pocket, and Valmy cannot be retired without a replacement that can provide firm and dispatchable output. (*Id.* at 5-6.)

3. NV Energy states that the second driver is the cancellation of the previously-approved renewable projects that has caused NV Energy to remove multiple renewable energy projects from its resource portfolio. (Ex. 120 at 6.) NV Energy states that this includes the Southern Bighorn Solar PV and BESS project, the Chuckwalla PV/BESS project, and the Hot Pot and Iron Point PV/BESS projects. (*Id.*) NV Energy states that between these four projects, a combined 1,100 MW PV and 795 MW BESS have been canceled since the Third Amendment to the 2018 IRP. (*Id.*) NV Energy states that the loss of these projects presents two significant challenges: the loss of renewable energy generation during daylight hours to contribute to Renewable Portfolio Standard ("RPS") requirements, and the loss of capacity to support resource adequacy in the evening hours after solar energy production has declined. (*Id.*)

4. NV Energy states that the third driver is the continued need to reduce NV Energy's open position. (Ex. 120 at 6.) NV Energy states that NV Energy holds one of the larger

open positions in the Western region, and the strategy to reduce the open position is consistent with actions being taken by other utilities similarly reliant on the market today. (*Id.*) NV Energy states that the Joint Application's proposed resource portfolio would reduce its systemwide open position from 1,092 MW in 2025 to 820 MW in 2026, representing a year-over-year open position decrease from 13 percent to 10 percent of NV Energy's projected net system peak demand. (Ex. 109 at 13.) NV Energy states that without the resources proposed in the Joint Application, the open position in 2026 would be 1,435 MW—17 percent of the projected net system peak demand. (*Id.* at 13-14.) NV Energy states that the 2025 open position is a reduction relative to the open position that NV Energy has held in recent years, and the reduction in 2026 reflects NV Energy's stated intent to further reduce the open position in this Joint Application. (*Id.* at 14.) NV Energy states that a number of recent regional studies have indicated that large portions of the Western Interconnection are currently at risk to experience reliability events. (*Id.* at 18.) NV Energy states that E3 conducted its own study focused on the Desert Southwest and found that significant amounts of new generation capacity will be needed in the next decade. (*Id.*) NV Energy states that in addition, both the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC") continue to issue resource adequacy cautionary statements regarding uncertain availability and deliverability of market capacity and energy. (*Id.*)

5. NV Energy states that, in addition, as NV Energy prepares to participate in the financially-binding phase of the Western Resource Adequacy Program ("WRAP") in summer 2027, NV Energy will need to pass a forward-showing requirement to avoid potentially significant financial penalties. (Ex. 120 at 7.) NV Energy states that, without the addition of new

resources before that time, NV Energy is currently projected to be 1,600 MW deficient for July 2027. (*Id.*)

6. NV Energy states that the fourth driver is NV Energy's intent to continue to advance the state's objectives to become a leading producer and consumer of renewable energy while supporting growth in the state. (Ex. 120 at 7.)

**AEU's Position**

7. AEU states that NV Energy's Joint Application should be rejected either in its entirety or in part. (Ex. 500 at 5, 21.) AEU states that the Valmy repower plan is not adequately supported, its approval via the Joint Application is not necessary, and the issues purportedly addressed by the proposal should instead be examined in the forthcoming 2024 IRP. (*Id.* at 5.) AEU states that to the extent NV Energy includes any of the Joint Application's proposals in that 2024 IRP filing, the Commission should require NV Energy to provide all supporting information in that filing that is currently missing, including: 1) a complete alternative analysis; 2) a low-carbon scenario; and 3) all relevant cost assumption information, including information regarding pipeline capital costs. (*Id.* at 4.) AEU states that if the Commission declines to reject this Joint Application in its entirety, it should reject just the generation and storage proposals in the Joint Application while allowing the transmission-related projects, including the Esmerelda and Amargosa substations and Apex Master Plan, to proceed. (*Id.* at 4, 21.)

8. AEU states that the Joint Application lacks a low-carbon scenario, and that there are significant new proposals including a proposal that would extend the life of several major fossil-fuel-fired assets until 2049. (Ex. 500 at 11.) AEU states that inclusion of a low-carbon scenario is critical to a complete IRP because it allows the Commission and stakeholders to compare a more robust set of IRP options, including at least one that achieves low carbon

dioxide emissions in line with state clean energy goals. (*Id.*) AEU states that it disagrees with NV Energy's assertion that because it conducted a low-carbon analysis for the Fourth Amendment to the 2021 IRP, no such analysis is required in the Joint Application. (*Id.*) AEU states that Commission review of the Joint Application without a low-carbon analysis would undermine the clear intent of state law and regulation, and the Commission should not approve a proposal to repower Valmy or extend Tracy 4/5. (*Id.*)

**Interwest's Position**

9. Interwest states that by bringing these specific resource development requests forward through this Joint Application, NV Energy is avoiding a more fulsome review and consideration that might result from its consideration in the upcoming 2024 IRP process. (Ex. 900 at 35.)

10. Interwest states that NV Energy fails to present and seek solutions within the framework of a fully-developed IRP with Commission-approved scenario development, and NV Energy's resource selection process is not adequately linked to such a fully-developed plan. (Ex. 900 at 7.) Interwest additionally states that NV Energy fails to select resources through a fair, transparent, and predictable request for proposals ("RFP") process designed to test the market for all available resources. (*Id.*) Interwest states, therefore, that NV Energy's resource additions proposed in this docket are unmoored from a regular resource planning process with adequate Commission and stakeholder involvement. (*Id.*) Interwest states that NV Energy presents a limited set of options for the Commission's review that are not rooted in an RFP, and therefore NV Energy's analysis of relative ratepayer costs to implement its preferred resource additions is limited. (*Id.*)

11. Interwest states that NV Energy's resource planning and acquisition process were misaligned because NV Energy coupled the modeling for and identification of a new resource need, and options to fill that need, together with the proposal of a specific resource solution to meet that need. (Ex. 900 at 11.) Interwest explains that, pertaining to NV Energy's Valmy proposal, NV Energy failed to provide the essential resource need information to 2023 open resource RFP bidders, and with the Commission and stakeholders not having the opportunity to review that information before this proceeding, NV Energy's Valmy proposal presumes its underlying modeling and assumptions and ultimate resource selection are optimal. (*Id.* at 12.)

12. Interwest states that the canceled projects at the center of NV Energy's Joint Application are not representative of the history of development trends in the independent power market over time. (Ex. 900 at 25-26.) Interwest states that, although the industry experienced unprecedented challenges in recent years, almost 65 percent (over 20 gigawatts) of clean power projects that first experienced development delays in 2021 were online by the third quarter of 2023. (*Id.* at 25-28.) Interwest additionally states that NV Energy has not shown that it can overcome widespread market challenges with more expediency and at lower cost than an independent power producer can. (*Id.* at 26.) Interwest notes that NV Energy has limited experience developing large-scale solar and BESS projects and has recently failed to meet the targeted commercial operating date of its Dry Lake Solar Project, which consists of 150 MW of solar PV and 100 MW BESS. (*Id.* at 26-27.)

**MSG's Position**

13. MSG states that its Energy Supply Agreement ("ESA") with NV Energy furthers Nevada's sustainability goals in multiple ways, notably by maximizing the amount of direct

sustainable energy consumed by the MSG Sphere, and therefore MSG asks the Commission to approve the portions of the Joint Application that support its ESA. (Ex. 1100 at 2.)

**SNGG and CMN's Position**

14. SNGG and CMN recommend that the Commission reject NV Energy's Joint Application and defer the proposals to the planned 2024 IRP in June 2024 because NV Energy has not shown that the current Joint Application is reasonable and prudent or is the lowest-cost option for ratepayers. (Ex. 700 at 8, 11.) SNGG and CMN state that the Joint Application should not be approved because there is significant uncertainty with respect to NV Energy's ability to place the requested projects in service on the planned timelines and to install the resources at the cost estimated. (Ex. 700 at 4.) SNGG and CMN state that there is uncertainty with respect to the following issues:

a. NV Energy's annual capacity deficiency, given that the load forecast has not been updated, and NV Energy's testimony that it acknowledges load growth;

b. NV Energy's ability to secure access to firm natural gas supply and delivery capacity in a timely manner, to complete the coal-to-gas conversion of Valmy;

c. Alternative firm, dispatchable resources that could be used if NV Energy cannot access natural gas for Valmy as planned;

d. The uncertain probability that NV Energy can bring the Sierra Solar project to commercial operation by 2026 and 2027, and at the estimated cost, given the industry-wide supply-chain challenges;

e. The need for a thorough assessment of other resource options to reduce NV Energy's capacity deficiency which do not have the same supply-chain challenges as solar resources;

f. The lack of detailed project specifications and budget information for the Cresent Valley Solar project.

(Ex. 700 at 3-4.)

15. SNGG and CMN state that NV Energy's preferred repower minimum plan is not reasonable and prudent because of uncertainty related to NV Energy's annual capacity deficiency, whether natural gas would be a firm and dispatchable resource for the Valmy repower project, and the ability to place these projects in service by the planned timelines and within the estimated costs. (Ex. 700 at 4, 5, 8, 10.) SNGG and CMN additionally state that, given the resource adequacy concerns raised in the Joint Application, NV Energy should be required to thoroughly assess what alternatives are available to address the resource adequacy concerns that do not have the same supply-chain issues that the solar industry is experiencing at this time. (*Id.* at 8.)

16. SNGG and CMN note that delaying the current Joint Application until the 2024 IRP would provide NV Energy with more time to support its proposals with additional information to address uncertainties. (Ex. 700 at 10.) SNGG and CMN state that NV Energy's preferred plan is not the lowest-cost option for ratepayers because it has the second lowest present worth of revenue requirement ("PWRR"), and the lowest present worth societal cost ("PWSC") out of the four proposed options. (*Id.* at 11.) Specifically, the 20-year PWRR is $22.1 billion, and the 28-year PWRR is $28.5 billion. (*Id.*) SNGG and CMN note that NV Energy's 20-year PWRR of its preferred plan is $254 million more than NV Energy's repower maximum alternative plan, which is NV Energy's proposed least-cost alternative. (*Id.*) SNGG and CMN also state that the preferred plan's 28-year PWRR is $434 million more expensive than its proposed least-cost alternative. (*Id.*) SNGG and CMN provide that NV Energy's preferred plan would impact ratepayers' base tariff energy rate ("BTGR") ranging anywhere from four to ten percent, and upwards; however, the BTGR impacts that NV Energy has presented may be more substantial because NV Energy used the outdated load forecast information approved in the

Third Amendment to the 2021 IRP. (*Id.* at 13.) SNGG and CMN state that if the Commission approves the Joint Application before further analysis is conducted, then there will be more harm to ratepayers than to NV Energy. (*Id.*) SNGG and CMN state that NV Energy can take on the risk of continuing to pursue these projects now until NV Energy can prove the proposals in the Joint Application are reasonable and prudent and the lowest-cost options for ratepayers. (*Id.* at 13-14.)

**WRA's Position**

17. WRA recommends that the Commission reject NV Energy's Joint Application and defer it to the next full IRP because the Joint Application is inadequate due to NV Energy's greenhouse gas ("GHG") emission reduction backsliding during the 2021 IRP cycle. (Ex. 1600 at 4, 16-17.) WRA states that NV Energy needs to update its emissions forecasts, which should require a full IRP and not the shortened IRP amendment proceedings. (*Id.* at 15.) WRA notes that a full IRP mandates a full regulatory timeline and review that would include a full evaluation of GHG emissions across an entire regulatory timeline accompanied by an updated load forecast with other necessary analysis. (*Id.* at 5.) WRA states that before the Commission can approve the Joint Application, NV Energy needs to account for the difference in GHG emissions for repowering Valmy versus retiring the units as initially planned. (*Id.* at 15-16.) WRA provides that the 2022 Nevada Department of Environmental Protection ("NDEP") report is outdated and only covers actual GHG emissions through 2020 and projection of GHG emissions through 2042. (*Id.* at 15.) WRA notes that this 2022 report did not include the 2021 IRP decision within its assumptions or a Valmy repower; rather, it only included emission reduction assumptions from retiring Valmy. (*Id.*)

18. WRA also recommends that the Commission reform the IRP process because there are current weaknesses in the amendment process and significant changes are needed to maximize the public interest. (Ex. 1600 at 17, 25.) WRA states that investment decisions for large resource procurements should not be fast-tracked in shortened IRP amendment proceedings. (*Id.* at 19, 25.) WRA states that if the Commission approves NV Energy's Joint Application in its entirety, the approved sum could total over $2.364 billion. (*Id.*) WRA provides that the Commission can reform the IRP process by implementing stakeholder access, amendment limits, and modeling best practices. (*Id.* at 23-24.) WRA states that there needs to be amendment limits and a bright line rule denoting what does and does not constitute an amendment to an IRP. (*Id.* at 25.) WRA recognizes that the IRP amendment limitation issue is being addressed in Docket No. 23-07026, but WRA states that the Commission should not approve this substantial resource Joint Application as an amendment before promulgating the new rules. (*Id.*)

**NV Energy's Rebuttal**

19. NV Energy states that it is not logical to fail to address the resource-planning needs that exist today due to an expectation that IRP application regulations may change in the future. (Ex. 137 at 7.) NV Energy states that discussions about the requirements for IRP applications and amendments should be addressed in the IRP Process investigatory docket (Docket No. 23-05013) or the AB524 Rulemaking docket (Docket No. 23-07026). (*Id.*)

20. NV Energy states that the often-repeated notion that filing an amendment rather than a full IRP avoids scrutiny is not supported by the facts. (Ex. 137 at 8.) NV Energy states that the Commission's standard for approval is the same for an amendment or a full IRP. (*Id.*) NV Energy notes that almost five months will pass between the time NV Energy filed the Joint

Application and the hearing, which is similar to the amount of time between the time of filing and the final, third phase, hearing in the latest two full IRPs. (*Id.*) NV Energy states that with the Joint Application proposing supply and transmission projects only, the scope of this IRP amendment is much narrower than a full IRP and, thus, allows the parties to focus on a handful of projects. (*Id.*)

21. NV Energy states that the projects proposed in the Joint Application should not be postponed because of a claimed uncertainty associated with load growth in the future. (Ex. 138 at 3-4.) NV Energy explains that additional load growth will be included as a part of an updated load forecast as part of the 2024 triennial IRP. (*Id.* at 4.) NV Energy states that the current open position is only going to increase and any delays in projects would further exacerbate already existing resource adequacy concerns. (*Id.*) NV Energy states that a clear need for resources is shown in the Joint Application based on the currently-approved load forecast, and any future uncertainty exists only as to the amount of additional demand, which will require incremental resources in the future. (*Id.*)

22. NV Energy states that it did not fail to evaluate resource options other than solar to address resource adequacy concerns. (Ex. 137 at 13.) NV Energy states that it brought forward fossil fuel, solar, and BESS projects which all contribute, to varying degrees, to address the resource adequacy concerns identified in the Joint Application. (*Id.*)

**Commission Discussion and Findings**

23. As a preliminary finding, the Commission does not summarily reject the Joint Application but instead considers each of the prayers for relief and projects requested in the Joint Application individually in this Order. The Commission considers the Joint Application now (as opposed to deferring consideration of the Joint Application's requests to the full IRP that will be

filed this June) for several reasons. First, the Commission requested that NV Energy file a complete Valmy solution in the order addressing the Fourth Amendment to the 2021 IRP. In the order issued on June 12, 2023, in Docket 22-11032, at paragraph 128, the Commission stated:

> As a directive, NV Energy must provide, in a future IRP amendment or the 2024 IRP, whichever comes first, the following related to the retirement of Valmy:
>
> i. A complete solution for the retirement of Valmy;
>
> ii. Comprehensive analysis and comparisons of the financial and economic impacts of each potential solution; and,
>
> iii. Updated information on the federal and state limitations on continued operations of Valmy and associated costs.

Because NV Energy filed a fifth amendment to the 2021 IRP before it filed its 2024 IRP, the Commission will consider the Valmy solution now, as per the Commission's requested timeline.

24. Second, in filing its Joint Application, NV Energy followed the IRP statutes and regulations in place at the time of the filing, which allow NV Energy to control when it files an IRP amendment.

25. Third, the Commission considers NV Energy's arguments regarding resource adequacy and NV Energy's open position in making its determination to not summarily reject the Joint Application in its entirety. The cancellation of previously-approved renewable energy projects has caused NV Energy to remove multiple renewable energy projects from its resource portfolio, including the Southern Bighorn Solar PV and BESS project, the Chuckwalla PV/BESS project purchase power agreements ("PPAs"), and the NV Energy-owned-and-developed Hot Pot and Iron Point PV/BESS projects. Between these four projects, a combined 1,100 MW PV and 795 MW BESS have been canceled since the Third Amendment to the 2018 IRP. The Commission finds there to be a reasonable need to begin to address the loss of these projects now, so as not to unduly delay addressing resource adequacy in Nevada.

26. However, the Commission is concerned with the piecemeal planning process that is exemplified in the Joint Application. The Fifth Amendment to the 2021 IRP requests more expensive and expansive projects than the initial 2021 IRP itself. NV Energy argues that there is an urgency for approving the projects contained in the Joint Application for RPS compliance needs, resource adequacy needs, and to address its open position, yet addressing these issues in an amendment to a previously-approved IRP is patchwork planning, rather than the holistic planning of addressing these issues in the upcoming full IRP. The Commission balances the less-than-ideal piecemeal planning in this Joint Application because the Commission finds that resource adequacy concerns need to begin to be addressed now; however, the Commission welcomes the changes that will take place to the IRP process under Assembly Bill ("AB") 524 (2023) and looks forward to more holistic resource planning in the future.

27. Finally, regarding several parties' requests to reexamine or discuss the RFP process, the resource procurement and long-term planning processes, and requirements for IRP applications and amendments, the Commission agrees that all of these items need to be reexamined and discussed. The Commission has acknowledged and continues to acknowledge the need for reforms to the IRP process. However, the Commission finds that the best places to discuss any changes to the current IRP process are in the IRP Process investigatory docket (Docket No. 23-05013) and/or the AB 524 Rulemaking docket (Docket No. 23-07026). The Commission finds that it is most efficient for all parties to continue discussions related to any IRP reform and processes in those proceedings.

28. Furthermore, as a Nevada administrative agency, the Commission cannot engage in *ad hoc* rulemaking, meaning that the Commission cannot make any rules of general applicability, and more specifically cannot set general IRP reforms or processes going forward,

outside of a rulemaking docket that follows the procedures set forth in Chapter 233B of the NRS. The Commission opened Docket No. 23-07026 so that it can properly engage in rulemaking for reforming the IRP process in accordance with AB 524.

**B. The Sierra Solar Project**

**i. Project Approval**

**NV Energy's Position**

29. NV Energy seeks approval for ongoing development and construction of a 400-MW solar and 400-MW BESS project known as Sierra Solar. (Ex. 100 at 69.) NV Energy states that the Sierra Solar project will be rate-based, developed by NV Energy, and will be allocated 60 percent to NPC and 40 percent to SPPC. (*Id.* at 95.) NV Energy states that, as a self-developed site, NV Energy would avoid high developer cost premiums, as well as risk of developer termination agreements, while allowing NV Energy to control the use and reuse of the facility more fully for future development phases. (*Id.*) NV Energy states, additionally, that its ownership of the Sierra Solar project will also help optimize utilization of the residual asset life after a typical 25-year contract term for similar assets. (*Id.*)

30. NV Energy states that the Sierra Solar project is in the advanced development stage with site control, executed large generator interconnection agreement ("LGIA"), secured solar panel supply, and project design and permitting underway. (Ex. 100 at 95.) NV Energy states that execution of Phase I at this time will also support efficient execution of future project phases at the same site. (*Id.*) NV Energy states that the land purchase is complete, the LGIA has been fully executed, and a Master Supply Agreement with the solar panel module supplier has been fully executed. (Ex. 115 at 14.)

31. NV Energy states that the Sierra Solar project also supports reduction in market dependence for energy and capacity while supporting the State of Nevada's energy policy goals in Senate Bill ("SB") 358 (2019) and AB 524 (2023). (Ex. 115 at 14.)

32. NV Energy states that the Sierra Solar project is expected to generate approximately 1,142,508 megawatt-hours ("MWh") and 1,086,528 portfolio energy credits ("PECs") annually. (Ex. 115 at 13.) NV Energy states that the Sierra Solar project is proposed to help close SPPC's capacity open position by providing capacity—including peak capacity—to support NV Energy's needs as soon as 2026 and beyond. (*Id.*)

33. NV Energy states that the Sierra Solar project is sited on 6,787 acres of private land owned by SPPC, located in Churchill County approximately 15 miles northeast of Fernley, NV, which is near the load pocket for Northern Nevada in a region of anticipated development. (Ex. 115 at 13.) NV Energy states that development of renewable energy resources at this site will support a master plan development for transmission in the Fernley area. (*Id.*) NV Energy states that the site will likely support expansion to 1,000 MW of solar generating capacity or equivalent or more BESS capacity once the Comstock Meadows to Lantern transmission tie-in is built. (*Id.*) NV Energy states that there is also potential for geothermal development (*Id.*)

34. NV Energy notes that a portion of this project is expected to serve MSG through an ESA that has been filed with the Commission in a separate docket and is currently pending approval. (Ex. 115 at 13.)

35. NV Energy states that the total capital project cost of the Sierra Solar project is estimated to be $1.5 billion, with transmission costs. (Ex. 100 at 97.) NV Energy states, specifically, that it estimates approximately $734 million in project costs without transmission for the solar PV portion and $731 million for the BESS portion. (*Id.*) NV Energy explains that

the Sierra Solar project is expected to provide energy for a 30-year period at a hybrid levelized cost of energy of $86.77 per MWh and will be $38.25 per MWh and $13,622.56 per MW-month when estimated as energy and capacity price separately for comparison purposes. (*Id.*) NV Energy notes that a comparison of the Sierra Solar project relative to solar-plus-storage project proposals received in NV Energy's 2023 RFP is presented in Table REN-5. (*Id.*)

36. NV Energy states that the cost for the Sierra Solar project is competitive. (Ex. 115 at 15.) NV Energy states that the Sierra Solar project's hybrid levelized cost of energy ("LCOE") of $86.77 per MWh is competitive when compared against the solar-plus-storage bids received during NV Energy's Spring 2023 open resource RFP that was issued on January 17, 2023. (Ex. 115 at 15.) NV Energy states that the RFP was issued in response to both a forecasted need for PECs for NV Energy to meet its increasing RPS obligations, as well as to provide cost-effective, long-term resource adequacy and reliability of Nevada's electric system. (*Id.*)

37. NV Energy states that, when assessed separately as energy and capacity costs, the energy price of $38.24 per MWh and capacity cost of $13,622.56 per MW-month are at, near, or below the lower range of LCOE forecast and recent publicly-available solar-plus-storage LCOE pricing published by the National Renewable Energy Laboratory ("NREL"). (Ex. 115 at 15.)

38. NV Energy states that NV Energy's self-build approach offers administrative and regulatory efficiency to negotiate, contract, and operate utility-scale renewable resources on NV Energy's transmission system. (Ex. 115 at 15.)

39. NV Energy states that approval of the Sierra Solar project will help SPPC and NPC meet their RPS requirements. (Ex. 115 at 17.)

**AEU's Position**

40. AEU states that NV Energy's Joint Application should be rejected in its entirety or in part. (Ex. 500 at 5, 21.) AEU states that to the extent NV Energy includes any of the Joint Application's proposals in the 2024 IRP filing, the Commission should require NV Energy to provide all supporting information in that proceeding that is currently missing, including: 1) a complete alternative analysis; 2) a low carbon scenario; and 3) all relevant cost assumption information, including information regarding pipeline capital costs. (*Id.* at 4.) AEU states that if the Commission declines to reject this Joint Application in its entirety, it should reject just the generation and storage proposals in the Joint Application while allowing the transmission-related projects, including the Esmerelda and Amargosa substations and Apex Master Plan, to proceed. (*Id.* at 4, 21.)

41. AEU states that the Joint Application is deeply flawed because it lacks information regarding recent and robust resource solicitations. (Ex. 500 at 18.) AEU claims that NV Energy is not building its proposals from a deep bench of potential projects. (*Id.*) AEU states that NV Energy failed to deliver on its promises in the Fourth Amendment to the IRP, in which NV Energy stated that it was intending to bring forward more resources in a future amendment to address northern Nevada's need in addition to the ongoing capacity needs to improve resource adequacy statewide while employing Inflation Reduction Act ("IRA") tax credits. (*Id.*)

**Interwest's Position**

42. Interwest states that NV Energy used the results from its 2023 open resource RFP to justify utility self-build projects without having established that the 2023 RFP produced a competitive and robust result. (Ex. 900 at 11.) Interwest states that, although NV Energy's estimated LCOE for the Sierra Solar project is lower than the build-transfer agreement ("BTA")

bids it received for the two projects listed in Table REN-5, an RFP conducted in a manner consistent with the principles recommended by Interwest could have attracted a more robust response from additional lower-cost projects. (*Id.* at 13.) Interwest additionally contends that NV Energy's 2023 open-resource RFP was flawed because it did not provide adequately specific information about what NV Energy was seeking in regard to this Joint Application, NV Energy's supply plan, specific resource needs, or procurement targets. (*Id.* at 13-14.) Interwest states that the 2023 open-resource RFP also unfairly limited bids to specific contract structures and the use of NV Energy's approved vendors list. (*Id.* at 14-16.) Interwest also states that potential bidders in the 2023 open resource RFP may have been discouraged by NV Energy's recent history of issuing RFPs that result in little or no procurement and by NV Energy's practice of contracting for resources outside of an RFP process. (*Id.* at 18.) Interwest notes that the most recent RFP issued by NV Energy that resulted in resources being brought forward for the Commission's approval was in 2018, and since then, four major RFPs resulted in no procurement of new resources. (*Id.* at 18-19.) Interwest additionally notes that NV Energy utilized an independent evaluator for its 2018 RFP but has not done so in its following RFPs. (*Id.* at 19-21.)

43. Interwest states that absent a full review of the level of participation in and results of NV Energy's 2023 open resource RFP, which is being used as a benchmark for the evaluation of the costs of this project, the Commission will not be able to evaluate whether the proposed Sierra Solar project is the best available option. (Ex. 900 at 37.) Interwest states that it is concerned that NV Energy's 2021 IRP and RFP were flawed in ways that may have diminished market participation in this solicitation. (*Id.*) Interwest additionally states that it appears that the project costs provided by NV Energy for comparison to its Sierra Solar project were only for

BTA projects originally submitted in response to the original January 2023 RFP and did not include any PPA bids submitted during the July 2023 phase of its 2023 open-resource RFP. (*Id.*)

**MSG's Position**

44. MSG states that the Sphere was designed to be the most sustainable venue in the world. (Ex. 1100 at 3.) MSG states that the ESA will allow Sphere to source power from dedicated solar and battery resources owned and operated by NV Energy. (*Id.* at 3-4.) MSG states that it intends to voluntarily acquire renewable energy credits to mitigate the impact of all non-renewable sources of power under the ESA and ensure that the entire project is ultimately powered by renewable energy. (*Id.* at 4.)

45. MSG states that, despite having the option to take service pursuant to NRS 704B, MSG entered into an ESA with NV Energy on August 21, 2023, which is currently being reviewed and considered in Docket No. 23-08019. (Ex. 1100 at 4.) MSG states that the ESA serves the public interest because MSG will contribute to all public program rates, the ESA will further the efforts of MSG and NV Energy towards achieving Nevada's RPS goals, and the ESA will continue to serve as a template for other large new customers, bringing new investment and employment opportunities to Nevada. (*Id.* at 4-5).

46. MSG states that, if the ESA were delayed, "MSG would be incredibly disappointed not only for its energy future, but also for the entire State of Nevada, and in such event would need to evaluate all of [its] options." (Ex. 1100 at 5.)

**SNGG and CMN's Position**

47. SNGG and CMN state that if the Commission should choose to approve NV Energy's Joint Application, SNGG and CMN recommend the Commission deny the Sierra Solar project and defer it to the upcoming 2024 IRP because further analysis is needed to assess its

benefits. (Ex. 700 at 20.) SNGG and CMN state that construction of solar resources is not the most cost-efficient project at this time due to supply-chain issues with procuring materials. (*Id.* at 18, 19.) SNGG and CMN state that NV Energy's priority should be protecting ratepayers from cost overruns due to delays with labor and material shortages. (*Id.* at 9.) SNGG and CMN provide that NV Energy's requested enhanced ratemaking treatment for the Sierra Solar project could exacerbate the impact of potential cost overruns on ratepayers and cause significant costs. (*Id.*) SNGG and CMN state that NV Energy's proposal for the Sierra Solar project to be a company-owned resource, rather than utilizing a PPA with a developer, means that the project's costs will be included in rate base and earn a return on investment, whereas PPA costs are passed through to customers via the Base Tariff Energy Rate ("BTER") without the additional cost of a return for the utility. (*Id.* at 21.)

48. With regard to NV Energy's argument that company ownership will provide greater control in avoiding problems with meeting deadlines, procuring materials, and bringing the projects to commercial operation by an agreed-upon date, SNGG and CMN state that NV Energy has not shown any evidence that supports the notion that choosing company-owned solar projects over PPAs is better for ratepayers because NV Energy would not be more likely than other solar developers to bring a project to commercial operation in a timely fashion at the estimated cost, given the current industry-wide supply-chain challenges. (*Id.* at 20, 26.) SNGG and CMN state that PPAs meet NV Energy's objectives of transitioning to the use of renewable energy resources and complying with RPS goals while improving capacity deficiencies. (*Id.*) SNGG and CMN add that PPAs are typically less expensive to customers than rate-based resources, too. (*Id.*) SNGG and CMN note that NV Energy has not provided an economic analysis of a mixed PPA and rate-based resource portfolio in this IRP amendment, even though it

could be more advantageous to ratepayers. (*Id.*) SNGG and CMN state that NV Energy has assumed that the existing renewable energy PPAs will expire and has not explored the economics of renewing the existing PPAs instead. (*Id.* at 22.)

49. SNGG and CMN state that even with the Sierra Solar project, NV Energy would still be capacity-deficient in every year from 2024 to 2051 because solar resources alone contribute little to resource adequacy relative to nameplate capacity. (*Id.*) SNGG and CMN explain that NV Energy's supporting data shows that the effective load-carrying capability of the proposed solar resource is approximately one-thirteenth of the nameplate capacity. (*Id.*) SNGG and CMN state that NV Energy does not need the Sierra Solar project to meet State RPS goals because both NPC and SPPC currently exceed the State-mandated RPS requirement and are both compliant until 2029 and 2033, respectively. (*Id.*) SNGG and CMN provide that the addition of renewable resources beyond State RPS requirements is an aspirational goal, and instead NV Energy should work towards balancing renewable energy efforts with ratepayer affordability and resource efficiency and capacity. (*Id.* at 23.) SNGG and CMN note that NV Energy has already spent $81.9 million on the Amargosa Valley Solar Energy Zone land lease auction purchase without Commission approval and proposes another potential $4.4 billion for a full buildout. (*Id.* at 9, 10.)

50. SNGG and CMN add that the Sierra Solar project is not the only option that NV Energy has for providing customers with green energy through the Nevada GreenEnergy Rider ("NGR"), Market Price Energy ("MPE"), and Large Customer Market Price Energy ("LCMPE") programs. (*Id.* at 23-24.) SNGG and CMN state that NV Energy should provide a complete economic comparison of the Sierra Solar project and Option B2 presented in Table REN-5, and

additional detail as to why Option B2 was not more seriously considered, particularly in light of NV Energy's capacity deficiency and clean energy objectives. (*Id.* at 2.)

51. SNGG and CMN note that, as shown in Table Ren-5, Option B2 includes 700 MW of solar capacity and 700 MW of BESS capacity, which is the largest amount of capacity among the projects being compared in the table. (Ex. 701 at 3.) SNGG and CMN state that Option B2 is similar to the Sierra Solar project with respect to the interconnection voltage, the commercial operation date ("COD") for the solar component, and the hybrid LCOE. (*Id.* at 3-4.) SNGG and CMN state that, due to the similarities between the Sierra Solar Project and Option B2, it is not clear why Option B2 was not more seriously considered by NV Energy and included in the alternative resource plans provided in the Joint Application. (*Id.* at 4.) SNGG and CMN therefore state that NV Energy should provide more information as to why the Sierra Solar project was selected rather than Option B2. (*Id.*)

**WRA's Position**

52. WRA states that if the Commission should choose to evaluate the merits of NV Energy's Joint Application as filed, WRA recommends that the Commission approve the Sierra Solar project. (Ex. 1600 at 6.) WRA states that the Sierra Solar project is aligned with State emissions reduction goals because it can be considered a near-one-to-one replacement for the Iron Point and Hot Pot projects, and it would increase renewable energy resources in the state. (*Id.*)

**BCP's Position**

53. BCP offers three options regarding the approval request for the Sierra Solar project:

a. Option 1: Reject the request for the 400-MW Sierra Solar project, reject the request for the Sierra Solar project, and reject the request for the transmission infrastructure needed to support interconnection. Do not preclude NV Energy from requesting these projects in future IRP applications.

b. Option 2: Reject the request to designate the Sierra Solar project as a critical facility and conditionally approve the Sierra Solar project as follows:

1. BESS expenditures above $731 million and above the referenced BESS operations and maintenance ("O&M") expenses in Confidential Exhibit 402 Attachment DAS-20 shall not be subject to cost recovery for ratemaking purposes in a future revenue recovery application;

2. The 400 MW BESS facilities, related O&M, and other expenses be allocated 100 percent to SPPC;

3. Allowance for Funds Used During Construction ("AFUDC") shall not accrue until such time as approval is granted;

4. Approve the request for transmission infrastructure support interconnection estimated at approximately $71 million.

c. Option 3: Reject the request to designate the Sierra Solar project as a critical facility and conditionally approve the Sierra Solar project as follows:

1. Subject to rate-base recovery treatment for the Sierra Solar project facilities, any revenue requirement deficiency including but not limited to O&M expenses which are subject to the ESA sought in Docket No. 23-08019 or any other such agreement sought by NV Energy, shall not be subject to cost recovery from ratepayers for ratemaking purposes;

2. Any solar PV and BESS facility expenditures above $734 and $731 million, respectively, including the referenced annual O&M expenses in the schedule Confidential Exhibit 402 Attachment DAS-20, shall not be subject to cost recovery in any future revenue recovery application;

3. AFUDC shall not accrue until such time as approval is granted.

4. BCP does not object to requests for a 40-percent share allocation to SPPC and a 60-percent share allocation to NPC for the Sierra Solar project.

5. Approve the request for transmission infrastructure to support interconnection estimated at approximately $71 million.

(Ex. 402 at 22-24.)

54. BCP states that using solar PV and BESS resources to close open positions is costly. (Ex. 402 at 7.) BCP states that, for instance, the Amargosa Solar project, which is not contained in the Joint Application but instead will be brought forward in a future IRP application, is estimated to cost $4.4 billion. (Ex. 402 at 10-11.) BCP states that the cost of the project requests in the Joint Application is $2.2 billion. (*Id.* at 9.) BCP states that future resource projects total up to approximately $7.4 billion (without ITC and AFUDC considerations) in the next several years. (*Id.*) BCP states that these projects are defined by discovery responses in this docket. (*Id.*) BCP states that, given large plant additions such as the Greenlink transmission project, adding other large rate base plant additions in the same period could lead to significant near-term rate impacts. (*Id.* at 14.) BCP states that third-party resources procured as PPA-style pricing could smooth out these near-term rate impacts. (*Id.*) BCP states that it prefers PPA-style pricing in securing renewable resources and BESS from either third parties or NV Energy. (*Id.*)

55. BCP states that although approved renewable resources with PPA levelized pricing (NV Energy owned and third-party owned) have recently been canceled due to significant cost increases for solar panels and lithium batteries, this may not be the case going forward because the pricing for such equipment appears to have stabilized. (Ex. 402 at 14.)

56. BCP states that this appears to be the first time an ESA based on levelized pricing will utilize a renewable energy project that is to be a rate base addition. (Ex. 402 at 21.) BCP states that with levelized pricing, the revenue requirement for rate base cost recovery will be larger, which would be unfair to ratepayers as a whole because the selected customer would be paying a lower rate for the Sierra Solar project than the remaining customers. (*Id.*) BCP notes that it is unclear if the remaining customers would be responsible for any revenue requirement deficiency for the selected customer’s load share of the Sierra Solar project. (*Id.*)

57. BCP states that projects with PPA-style pricing (NV Energy owned or third-party owned) can promote retail price stability in addition to protecting reliability, promoting diversity, and fulfilling renewable energy statutory mandates. (Ex. 402 at 20.) BCP states that, in addition, the Sierra Solar project does not provide performance guarantees as does a PPA-style pricing project. (*Id.*) BCP states that there are risks to ratepayers associated with the Sierra Solar project because project cost, decommissioning costs, and ongoing expenses such as O&M expenses are not certain. (*Id.*) BCP states that NV Energy can request recovery of cost overruns for the Sierra Solar project and decommissioning costs in a general rate case as well as varied O&M expenses and added capital over the life of the project. (*Id.*) BCP states that comparing the Sierra Solar project to projects with PPA-type pricing solely on a LCOE basis is not appropriate due to these attributes. (*Id.*) BCP states that NV Energy could have structured the cost recovery of the Sierra Solar project with PPA pricing but chose not to do so. (*Id.*)

58. BCP states that it does not believe that deferring the 400-MW Sierra Solar project to 2028 would affect NV Energy's efforts in complying with the 50-percent RPS mandate to a degree that cannot be mitigated. (Ex. 402 at 21.) BCP states that NV Energy will consider PEC transfers to mitigate any RPS deficiencies. (*Id.*)

**Staff's Position**

59. Staff recommends that the Commission approve the Sierra Solar project, but only if ratepayer cost protections are included. (Ex. 308 at 2.)

60. Staff notes that the estimated $1.536 billion in project costs (roughly $734 million for the PV portion and $731 for the BESS portion) do not include O&M costs. (Ex. 308 at 4.) Staff points to the Greenlink Nevada project as a recent example of the Commission approving a rate-based project at an estimated cost, with an understanding of how that estimated cost will

affect rates, and then watching the project price tag increase past the estimate to potentially be recovered by captive ratepayers. (*Id.* at 4-5.)

61. Staff also states that it is likely that the development of the Sierra Solar project will face cost overruns. (Ex. 308 at 4.) Staff states that it is unknown at this time if the amount of contingency included in the $1.536 billion project cost estimate is adequate to absorb any and all unexpected costs faced during development. (*Id.*) Staff states that NV Energy recognizes that difficulties procuring critical hardware and supply-chain disruptions are not part of doing business in a post-COVID world. (*Id.*) Staff notes that several renewable resource projects, such as Southern Bighorn Solar, Chuckwalla Solar, and BS3 are currently facing delays, shortfalls, or cancelations due to various market conditions surrounding the PV and BESS markets. (*Id.*) Staff also states that both Iron Point and Hot Pot PV plus BESS projects, originally scheduled for commercial operation in December 2023 and 2024, respectively, failed to achieve development milestones that affected the ability of the projects to meet their contractual cost and operational commitments. (*Id.*) Staff states that, contrary to NV Energy's assertion, self-development of projects does not reduce the risk of developer termination as compared to PPAs, as NV Energy is not immune from the exact same supply-chain issues that other developers are facing. (*Id.* at 6.) Staff states that, instead, self-development shifts all risk of cost overruns, underperformance, and delays from a third-party developer to the ratepayers. (*Id.*)

62. Staff states, additionally, that while the $1.536 billion is the number being touted in the Narrative as the project cost, there are the additional, unknown, costs needed to decommission the PV and BESS at the end of their useful lives that would also be borne by ratepayers. (Ex. 308 at 4.) Staff states that, according to a 2021 NREL report, responsible and cost-effective dissolution of PV system hardware at the end of the performance period is an

important business and environmental consideration, and the costs incurred at the end of a PV project life cycle should be considered at the earliest stages of project planning. (*Id.* at 7.)

63. Staff states that it is making its recommendation for rate-based cost-recovery prudency determinations in this IRP Amendment Joint Application because letting NV Energy commence development without Staff's recommended customer cost protections increases the risk that ratepayers would be on the hook for cost overruns and removes the certainty of being compensated for operational delays and performance shortfalls. (Ex. 308 at 8.) Staff states that its recommended customer cost protections afford ratepayers the same cost certainty and cost protections that they receive when NV Energy signs a renewable PPA or when the company develops an NRS 704.752 facility. (*Id.* at 7.) Staff notes that it will still review all of the Sierra Solar project costs in the appropriate general rate case. (*Id.* at 8.) Staff states that if NV Energy wants to add at least $1.536 billion to its rate base, and earn a return on that amount, then it should be the entity bearing the risk of delays and cost overruns, not ratepayers. (*Id.* at 9-10.) Staff also states that it is important to understand that the solar energy and BESS market in Nevada is not barren, and a self-developed, rate-based project is not the last option for NV Energy to obtain renewable energy. (*Id.* at 10.)

64. If the Commission approves the Sierra Solar project, Staff recommends: 1) the cost to construct the Sierra Solar project be capped at the $1.536 billion amount provided in the Narrative, and the O&M amount be capped at the amount included in the calculations of the LCOE and PWRR provided in this filing, and any development cost overruns or unplanned O&M costs be borne by the shareholders and not ratepayers; 2) NV Energy credit ratepayers with daily delay damages if the PV or BESS is not commercially operational by the CODs stated in the Narrative; 3) NV Energy credit ratepayers with liquidated damages if the storage

availability is not maintained and/or there are renewable energy and/or PEC shortfalls; and 4) any and all decommissioning, remediation, and site clean-up costs incurred at the end of the PV's and BESS's useful lives that were not included in the project cost estimate be the responsibility of NV Energy's shareholder and not ratepayers. (Ex. 308 at 9.)

65. Staff states that its first recommended cost protection, capping capital and O&M costs at the amount presented in the Narrative, is similar to the cost protections included in NV Energy's most recently approved PPA. (Ex. 308 at 10.) Staff states that the BS3 PPA stated that the cost per MWh and cost per MW-month were fixed prices and did not contain a clause that the prices may be adjusted upward to account for any cost overruns or unexpected maintenance that were incurred during the development and operation of the facility. (*Id.*)

66. Staff states that its second recommended cost protection, that daily delay damages be credited to ratepayers if the PV or BESS is not commercially operational by the CODs stated in the Narrative, is also similar to the cost protections included in NV Energy's most recently approved PPA with BS3. (Ex. 308 at 10.) Staff states that for each day that BS3 is not commercially operational past its contractual COD, NV Energy, ergo its ratepayers, are afforded daily delay damages according to a specified schedule. (*Id.* at 10-11.) Staff notes that, pursuant to NRS 704.752, although Dry Lake is no longer expected to meet its December 31, 2023, COD, ratepayers cannot receive delay damages but they also cannot be asked to pay for whatever situation is causing the delayed COD. (*Id.* at 11.)

67. Staff states that its third recommended cost protection, that liquidated damages be paid to ratepayers if the storage availability is not maintained and/or there are renewable energy and/or PEC shortfalls, is also similar to the cost protections included in NV Energy's most recently approved PPA with BS3. (Ex. 308 at 11.)

68. Staff states that it is not certain whether its fourth recommended cost protection, that future decommissioning costs should not be recovered from ratepayers, is typically included in PPAs with third parties. (Ex. 308 at 12.) Staff notes, however, that NV Energy included decommissioning and remediation costs in project modeling for its Dry Lake Solar project. (*Id.*) Staff also notes that, based on today's estimated costs of decommissioning PV installations, just the PV portion of the Sierra Solar project could cost between \$114 million and \$176 million to decommission; though Staff recognizes that those costs could decrease as PV recycling and repurposing technologies advance. (*Id.* at 12-13.)

69. Staff states that, regarding the competitiveness of the Sierra Solar project compared to other options presented in the Joint Application, any cost comparison provided in the filing or done through intervenor discovery is only meaningful if the Commission approves Staff's recommendations to have a cap on the cost to construct and operate the Sierra Solar project, as the comparisons use the energy price per MWh, MW-month charges, and hybrid LCOE values that are based on the cost estimates presented in this filing, costs which NV Energy will not commit to abide by. (Ex. 308 at 14.) Staff states that if the Commission does not approve Staff's recommendations, any capital or O&M cost overrun that is allowed to be recovered through rates would render this Joint Application's price comparisons useless and move the price of the Sierra Solar project further away from a market-comparable price. (*Id.*)

70. Staff recommends that the Commission issue a compliance requiring NV Energy to calculate storage availability liquidated damages, and renewable energy and PEC shortfall replacement costs for the Sierra Solar project in accordance with the calculations detailed in BS3's PPA. (Ex. 308 at 16.) Staff states that NV Energy should use BS3's PPA as a template and replace any BS3-specific values with the Sierra Solar project-specific values, to provide

documentation that outlines how the liquidated damages and shortfall replacement costs would be calculated and credited to ratepayers by NV Energy if the Sierra Solar project faces delays or performance issues. (*Id.*) Staff proposes that the same daily delay damages in the BS3 PPA should apply to Sierra Solar. (*Id.* at 17.). Staff states that NV Energy should perform the Sierra Solar project's calculations and credit ratepayers, when applicable, at the same time that it processes its other PPAs' liquidated damages and shortfall replacement amounts. (*Id.*)

71. Staff recommends that the Commission allocate the Sierra Solar project's ownership, energy, capacity, and PECs at 90 percent (360 MW PV and 360 MW BESS) to SPPC and 10 percent (40 MW PV and 40 MW BESS) to NPC. (Ex. 308 at 18.) Staff states that the allocation to NPC is for the purpose of serving MSG if its ESA is approved.[1] (*Id.*) Staff states that if MSG's ESA is denied, Staff recommends that the Commission allocate 100 percent to SPPC. (*Id.* at 19.)

72. Staff states that, based on the stated reasons in the Joint Application, it appears that the site was selected to support a specific load-growth area in SPPC's service territory. (Ex. 306 at 19.) Staff states that if NPC ratepayers are being asked to pay for a rate-based renewable resource, then they should also directly receive the local economic and employment benefits that come from having a renewable resource constructed and operated in its service territory. (*Id.*) Staff states that the Sierra Solar project will provide approximately 500 construction jobs over the development periods through 2027 and is expected to provide approximately eight permanent jobs with an average wage of $38 per hour, for an estimated total payroll of more than $16.4 million over 25 years. (*Id.* at 21.) Staff states, therefore, because the site was specifically chosen to benefit load growth in SPPC's service territory, and that ratepayers in SPPC's service territory

[1] Staff notes that MSG's actual load is confidential; however, MSG states that it is comfortable publicly stating that 40 MW would be a large enough size to meet its needs, without compromising the confidentiality of its actual load.

will receive more, if not all, of the local economic benefits from the development of the Sierra Solar project, Staff recommends that the ratepayers receiving these benefits also assume the majority of the cost to build, operate, and maintain the Sierra Solar project. (*Id.*)

73. Staff states that, under its proposed allocation, NPC is forecasted to be non-compliant with the RPS by 2028. (Ex. 306 at 22.) Staff states that, with a four-year timeline to replace a canceled renewable project, there is still time for NV Energy to contract or self-build NPC-dedicated resources before the forecasted 2028 RPS noncompliance date. (*Id.* at 22-23.) Staff notes that NV Energy intends to request approval for renewable energy projects in its 2024 IRP, including the Amargosa Valley Solar Energy Zone project. (*Id.* at 24-25.) Staff states that if NPC does not acquire the necessary PECs for RPS compliance, it could request permission to enter into a Portfolio Credit Exchange Agreement to facilitate PEC loaning between SPPC and NPC. (*Id.* at 23.)

74. Staff explains that the costs associated with a renewable PPA are recovered through different mechanisms than costs associated with an NV Energy-owned and rate-based renewable energy generation facility. (Ex. 302 at 2-3.) Staff states that the difference in the recovery mechanism used can amount to a significant impact on certain customer classes, given the large sums of money that NPC and SPPC are projected to spend on their shares of projects proposed in the Joint Application. (*Id.* at 4-6.) Staff states that, based on the certification filing for NPC's current general rate case, the residential classes would be responsible for approximately 6.15 percent more in cost responsibility for an NV Energy-owned and rate-based renewable resource than for a renewable PPA. (*Id.* at 4.) Staff states that in this scenario, the large industrial class would see a 2.4-percent decrease in cost responsibility. (*Id.*) Staff states that 6.15 percent of the over $1.4 billion in costs that NPC is projected to expend on its share of

projects proposed in the Joint Application amounts to $86 million. (*Id.*) Similarly, Staff states that, based on Statement O from SPPC's latest general rate case, the residential classes would be responsible for approximately 4.91 percent more in cost responsibility for an NV Energy-owned and rate-based renewable resource than for a renewable PPA. (*Id.* at 5.) Staff states that in this scenario, the large industrial class would see a 2.65-percent decrease in cost responsibility. (*Id.*) Staff states that 4.91 percent of the over $800 million in costs that SPPC is projected to expend on its share of projects proposed in the Joint Application amounts to $39 million. (*Id.* at 5-6.)

75. Staff states that NV Energy assumes additional risk by owning its own renewable generation facility rather than entering into a renewable PPA. (Ex. 302 at 7-8.) Staff states that in a PPA, the provider assumes the risk for unforeseen costs and maintenance, and NV Energy's costs are capped pursuant to the PPA. (*Id.* at 7.) Staff explains that when NV Energy owns and operates a renewable energy generation facility, NV Energy is liable for the additional costs which NV Energy can then seek to recover from ratepayers. (*Id.*) Staff states that, similarly, in the instance of a facility not meeting the specified output, NV Energy (and its ratepayers) carry the risk associated with underproduction rather than the provider in a PPA. (*Id.* at 8.)

**NV Energy's Rebuttal**

76. NV Energy states that the Sierra Solar project represents an opportunity to diversify the NV Energy renewable energy portfolio—a portfolio that is currently heavily weighted toward PPAs. (Ex. 141 at 3.) NV Energy explains that, with the Sierra Solar project, NV Energy will diversify its generation portfolio by including company-owned renewables. (*Id.*)

77. NV Energy states that the Joint Application represents an important inflection point in resource planning in Nevada. (Ex. 141 at 2.) NV Energy states that, as Nevada moves beyond just achieving a renewable portfolio standard and begins to increase reliance on

renewable resources for load-serving purposes, it is important to ask what that portfolio of renewable resources should look like from an ownership and control perspective. (*Id.*) NV Energy explains that a third-party that enters into a fixed-priced PPA to provide energy has different motivations versus a utility. (*Id.*) NV Energy states that where the third-party is likely viewing the PPA as a financial instrument, a utility with an obligation to serve customer load will view an energy-generating resource primarily from the perspective of the ability of that resource to contribute to a stable-priced, reliable energy supply resource. (*Id.*) NV Energy states that, under long-established regulatory cost-recovery principles that the Commission has followed for decades, utilities are incentivized to take actions that drive reliability and the long-term viability of the electric generating asset. (*Id.* at 2-3.) NV Energy states that this regulatory model ensures, appropriately, that the utility is motivated first and foremost to deliver critical energy resources to its customers, over other considerations. (*Id.* at 3.) NV Energy states that the same obligations and regulatory oversight processes do not exist for a third party. (*Id.*)

78. NV Energy states that, in this case, the Sierra Solar project represents an opportunity to diversify the NV Energy renewable energy portfolio—a portfolio that is currently heavily weighted toward PPAs. (Ex. 141 at 3.) NV Energy states that, with the Sierra Solar project, NV Energy will diversify its generation portfolio by including company-owned renewables for the reasons described in this and other pieces of testimony submitted in this proceeding. (*Id.*)

79. NV Energy states that the Sierra Solar project serves as an important milestone as NV Energy continues its transition from a thermal generating fleet to a renewable-dominated generation fleet. (Ex. 141 at 13.) NV Energy states that the Sierra Solar project would represent NV Energy's first large, utility-scale, rate-based renewable resource. (*Id.*) NV Energy explains

that approval of the Sierra Solar project as proposed by NV Energy sends a strong message that NV Energy can continue the transition to renewables through a balanced approach that includes both company-owned rate-based renewable resources as well as renewable PPAs. (*Id.* at 13-14.) NV Energy states, however, that if the Commission places conditions on that approval, those conditions will be material to NV Energy's decision-making on whether it would proceed with the project. (*Id.* at 14.) NV Energy states that the establishment of a price cap will send the wrong signal to NV Energy on how it develops renewable energy facilities. (*Id.* at 15.) NV Energy states that, if the Commission decides that fixed-priced generating assets are the expectation going forward, then NV Energy would request that the Commission make that expectation clear on a going-forward basis, versus applying that standard retrospectively to the Sierra Solar project. (*Id.* at 16.)

80. NV Energy requests that the Commission approve the Sierra Solar project as a company-owned project consistent with long-standing generation asset cost recovery. (Ex. 141 at 20.) NV Energy states that if the Commission decides to alter the historic treatment of generation asset cost recovery, NV Energy requests (1) that those new standards not be applied to the Sierra Solar project so that it can move forward, or (2) if the Commission intends to apply those new standards to the Sierra Solar project, that the Commission not approve the Sierra Solar project in this case. (*Id.*) NV Energy states, further, in such an instance, NV Energy request that the Commission clearly articulate the investment recovery model that the Commission intends to implement with respect to renewable generating assets so that NV Energy can properly assess renewable generation to bring forward to the Commission in future IRP proceedings. (*Id.* at 20-21.) NV Energy states that this is imperative to creating a more certain and lower-risk environment that facilitates continued investment in Nevada. (*Id.* at 21.)

81. NV Energy disagrees with Staff's recommendation that the Sierra Solar project incur liquidated damages, storage availability costs, and energy and PEC replacement costs similar to the BS3 PPA. (Ex. 135 at 7.) NV Energy states that the Sierra Solar project, as a rate-based renewable generation resource, should not be treated any different than a traditional company-owned thermal generation resource that does not subject NV Energy's shareholders to any such costs. (*Id.*)

82. NV Energy states that the Commission has never required NV Energy to include liquidated damages, storage availability costs, and energy and PEC replacement costs as part of any rate-based thermal or renewable energy projects in prior regulatory approvals. (Ex. 135 at 7.) NV Energy states that the Sierra Solar project will serve the exact same function as a thermal generation asset, and the need for the generation assets, from the customers' perspective, is the same; therefore, there is no reason to change the regulatory recovery model that focuses on reliability and is subject to review by the Commission. (*Id.*) NV Energy states that, similar to thermal assets, each expense NV Energy incurs for the Sierra Solar project will be reviewed by this Commission through an open process to determine whether that expense was reasonable and prudent. (*Id.* at 8.)

83. NV Energy states that Staff put forward a number of unprecedented cost-limiting recommendations for the Sierra Solar project such as a cost cap, liquidated damages, and ratepayers avoiding costs of decommissioning. (Ex. 139 at 20.) NV Energy states that these cost-limiting measures have not been applied to any other NV Energy rate-based generating asset. (*Id.*) NV Energy states that it is inconsistent for Staff to claim, addressing regulatory treatment, that Sierra Solar is just another utility project and then recommend applying conditions not applied to any other utility-owned project. (*Id.*)

84. NV Energy states that Staff's recommendations demonstrate that Staff seeks to treat NV Energy like a PPA developer and are intended to provide all of the benefits to customers while forcing NV Energy to absorb the costs. (Ex. 139 at 21.) NV Energy explains that, when a project is rate-based rather than developed through a PPA, NV Energy's customers receive a significant benefit because the power at the back-end of the asset life remains the ratepayers' at a significantly lower cost. (*Id.*) NV Energy notes that, unlike in a PPA, customers will get the benefit of any cost savings if the project is completed under budget. (*Id.*)

85. NV Energy states that the cost protections recommended by Staff are not needed because, as a rate-based asset, the Sierra Solar project already has mechanisms that protect customers. (Ex. 139 at 21.) NV Energy explains that, pertaining to the price cap, if NV Energy were to imprudently incur costs bringing the Sierra Solar project to operation, those costs would be evaluated in the general rate case addressing those costs. (*Id.*) NV Energy states, similarly for damages for non-performance, if the Commission found that NV Energy incurred fuel and purchase power costs that it otherwise would not have due to the project being delayed, these costs could be evaluated in a future deferred energy accounting proceeding. (*Id.* at 21-22.)

86. NV Energy states that Staff's recommendation for the Sierra Solar project to be owned 90 percent by SPPC and 10 percent by NPC is reasonable, and NV Energy would still be able to afford the project. (Ex. 139 at 14-15.) NV Energy states that the primary need for the Sierra Solar project is RPS compliance and resource adequacy, but approving the Sierra Solar project would help provide financial stability and credit support for SPPC as it would be taking advantage of the tax credits from the IRA. (*Id.* at 15.) NV Energy notes that the project would also bring benefits to customers by establishing a larger rate base at SPPC that will help its long-term financial stability. (*Id.*)

87. NV Energy states that Staff's calculations relating to the possible rates paid by customers for projects in the Joint Application are premature and speculative. (Ex. 139 at 22.) NV Energy states that, if at the time when the costs from these projects are presented for review in a general rate case, Staff believes that the cost responsibility among classes is inequitable, then Staff can make an argument for a more equitable distribution of the costs. (*Id.*)

88. NV Energy rejects SNGG and CMN's claim that the Sierra Solar project should be denied and resubmitted in the 2024 IRP because NV Energy needs at least 29 percent of its 2023 retail sales to be derived from renewable energy resources, with PECs increasing every year until it reaches 50 percent in 2030, to comply with Nevada's RPS requirements. (Ex. 136 at 2.) NV Energy states that it has received significant load interest from large customers for renewable energy, and therefore it needs the Sierra Solar project to be in service by 2027; otherwise, NV Energy will be in significant noncompliance risk with Nevada's RPS requirements. (*Id.* at 3.) NV Energy explains that resubmitting the Sierra Solar project in the 2024 IRP would likely delay Commission approval until December 2024, instead of March 2024, and as a result delay the Sierra Solar project delivery by a minimum of one year, which could jeopardize suppliers' equipment availability, causing even longer delays. (*Id.* at 4.) NV Energy states that the Sierra Solar project is in an advanced development stage with site control, executed interconnection agreements, an executed supply agreement with the solar panel module and BESS suppliers, and NV Energy is currently negotiating the engineering, procurement, and construction ("EPC") contract. (*Id.* at 5.) NV Energy provides that these development milestones are critical for timely delivery and cost optimization to ensure pricing certainty. (*Id.*) NV Energy also notes that as of November 30, 2023, the costs associated with the Sierra Solar BESS are $711 million, and if the Sierra Solar project is not approved in this Joint Application,

the project costs and schedule could be negatively impacted. (*Id.* at 5.) NV Energy states that it should receive all permits, including its Utility Environmental Protection Act ("UEPA") permit to construct, by December 2024; however, if there are approval delays, then permitting work would need to be paused, resulting in schedule delay and potential cost impacts with fees, consulting, and other related cost increases. (*Id.* at 6-7.) NV Energy provides that most solar PV and BESS projects have a five-to-six-year development to COD cycle, and if the Sierra Solar project is not approved in this Joint Application, then ratepayers would not receive the best project value and would continue to be subject to market pricing volatility associated with purchased power and PECs for the duration that the project is delayed. (*Id.* at 7.)

89. NV Energy also rejects SNGG and CMN's claims regarding uncertainty about NV Energy's ability to bring Sierra Solar to commercial operation on schedule and budget because Sierra Solar is already at an advanced stage with critical development milestones involving project design and permitting. (Ex. 136 at 2, 7.) NV Energy states that NV Energy is currently negotiating the final phase of the EPC contract, and the BESS contract was already executed on December 31, 2023. (*Id.*) NV Energy further provides that because the Sierra Solar project is located on private land controlled by NV Energy, third-party involvement will be mitigated, potential permitting delays will be avoided, and NV Energy will be able to adhere to its schedule. (*Id.* at 7-8.) NV Energy agrees with SNGG and CMN that the Sierra Solar project is not immune to the current supply chain issues, but NV Energy has minimized these issues by controlling cost overruns for ratepayers' interests by procuring major equipment, timely monitoring critical project milestones, and making other related key milestone decisions needed to mitigate supply chain availability, price volatility, inflation, and schedule risks. (*Id.* at 8.) NV Energy states that NV Energy's COD schedule and budget are on track, and NV Energy will

update the Commission on the project's status in the 2024 IRP or a progress report pursuant to NAC 704.9498. (*Id.*) NV Energy disagrees with SNGG and CMN that any additional decommissioning costs need to be included in the Sierra Solar project's initial cost estimate because this is the fifth amendment proceeding, and the Commission has not required NV Energy to include retirement costs for thermal or renewable energy projects in the previous four approvals. (*Id.* at 9, 10.) NV Energy further states that NV Energy did not include these costs in its Joint Application because no decommissioning and remediation requirements currently exist for the Sierra Solar project due to it being constructed on private land, and there is uncertainty around decommissioning costs several decades in the future. (*Id.* at 9.) NV Energy provides that NV Energy consulted with developers, and NV Energy anticipates that these asset costs would be approximately offset by the salvage value of the assets for the Sierra Solar project similar to the practice followed by the PPAs. (*Id.*) NV Energy states that instead of retiring the Sierra Solar project, NV Energy's preferred approach would be to refurbish the plant, perform adequate O&M, correct deficiencies, and repower the plant with new panels and inverters to extend future asset life; therefore, the Sierra Solar project is likely to provide residual value to customers beyond the proposed asset life of 30 years. (*Id.* at 9-10.)

90. NV Energy states that Table REN-5 demonstrates why the Sierra Solar project was chosen over Option B2. (Ex. 142 at 2.) NV Energy states that the Sierra Solar project has a lower LCOE and earlier COD, particularly for the battery component. (*Id.*) NV Energy also states that, with solar panels secured, the Sierra Solar project was further in the development cycle in August of 2023 than Option B2. (*Id.*)

**Commission Discussion and Findings**

91. The Commission approves the Sierra Solar project, with modifications to reflect ratepayer cost protections recommended by Staff, for the reasons outlined below.

92. First, the Commission approves the Sierra Solar project because of the resource adequacy needs created by the cancellation of the previously-approved renewable projects that caused NV Energy to remove multiple renewable projects from its resource portfolio. As previously mentioned in this Order, these projects include the Southern Bighorn Solar PV and BESS project, the Chuckwalla PV/BESS project PPAs, and the Hot Pot and Iron Point PV/BESS projects owned and developed by NV Energy, which total 1,100 MW PV and 795 MW BESS of canceled projects since the Third Amendment to the 2018 IRP. The cancellation of these projects presents two challenges: the loss of renewable generation during daylight hours to contribute to RPS requirements, and the loss of capacity to support resource adequacy in the evening hours after solar production has declined.

93. Furthermore, the Commission is concerned about resource adequacy because of the recent studies suggesting that large portions of the Western Interconnection are currently at risk of experiencing reliability events. E3 conducted its own study focused on the Desert Southwest and found that significant amounts of new generation capacity will be needed in the next decade for resource adequacy. In addition, both NERC and WECC continue to issue resource adequacy cautionary statements regarding uncertain availability and deliverability of market capacity and energy. The Commission takes into consideration the growing concerns for resource adequacy in Nevada and across the Western Interconnection.

94. Since the summer of 2020, the Western United States has continued to experience capacity shortfalls during peak periods of electricity usage. This has resulted in multiple states experiencing emergency energy alerts over the last several years. NERC and WECC have issued

resource adequacy and reliability cautionary statements regarding the uncertain availability and deliverability of market capacity and energy due to stresses on the electric system caused by more frequent and extreme weather, weather-related events, and a changing climate. The Commission highlights that in E3's study, E3 found that across the Western United States, there is evidence that the supply of capacity is becoming increasingly constrained. Multiple recent regional studies indicate that large portions of the Western Interconnection are currently at risk to experience reliability events today, and these studies state that the development of new resources at a rapid pace will be needed to ensure system reliability over the next decade.

95. NV Energy has cited its open position as one of the drivers for the need to approve the Sierra Solar project now, as opposed to waiting for NV Energy to file its full IRP. The Commission mentions the open position here because NV Energy states that it might not build the Sierra Solar project if NV Energy does not agree with Commission modifications to the proposed plan that place conditions on the Sierra Solar project.[2] The Commission finds it troubling that NV Energy is the party raising the urgency and need for the Sierra Solar project now, as opposed to waiting a few months until the full IRP is due in June, yet is also arguing that it might choose not to proceed with the Sierra Solar project due to potential conditions limiting pre-approval of costs to the amounts identified by NV Energy as the basis for the Commission to determine that the project is prudent.. The Commission is persuaded that there is a resource adequacy need necessitating consideration of the Sierra Solar project now and is troubled by the suggestion that this need may be ignored unless NV Energy gets the terms that it desires for the Sierra Solar project. The Commission reminds NV Energy that it has an obligation to provide



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[2] *See, i.e.,* Tr. at 708, where NV Energy states the following: "…if that's where the Commission is hung up, that if there has to be an upper limit on price…if the Commission, for whatever reason in this case, feels like it has to have an upper limit on costs, we'll assess if we think it's reasonable and whether we can move forward with the project or not."

safe, reliable service, which, based on NV Energy's representations in this proceeding, includes following its own recommendation to close some of its open position with urgency.

96. The Commission has an obligation to balance the interests of NV Energy's ratepayers and shareholders. Because the Sierra Solar project, as proposed, does not have the ratepayer protections of a PPA, or the protections that would exist if the project had been brought forward under NRS 704.752 as a company-owned resource styled as a PPA for cost-recovery purposes, the Commission cannot at this time find that the project as proposed represents a prudent course of action. Based on the available information and known alternative approaches that limit the risks to ratepayers of cost-overruns, delays, non-performance, and unknown decommissioning costs, the Commission can only determine that it would be prudent to move forward with the Sierra Solar project if ratepayer and shareholder interests are balanced through a modification to NV Energy's proposal ensuring that appropriate protections are in place for this first-of-its-kind rate-based project, particularly in light of the recent project failures noted above, of which the company-owned-and-developed Hot Pot and Iron Point projects comprised more than half of the combined 1,100 MW PV and 795 MW BESS canceled renewable resource capacity.

97. The Commission finds that Staff's recommended conditions for the Sierra Solar project are reasonable and necessary. First, the Sierra Solar project is costly, the most expensive project ever proposed to be built or owned by NV Energy, and even with the Sierra Solar project's proposed price tag, its actual costs are unknown at this time. The estimated $1.536 billion Sierra Solar project costs (roughly $734 million for the PV portion and $731 million for the BESS portion) do not include O&M costs. NV Energy could not and would not provide any final cost estimate for the Sierra Solar project and, in fact, when asked at hearing if there was any

upper limit of cost that NV Energy could agree to not overrun, would not commit to any upper limit number.

98. NV Energy acknowledges that the Sierra Solar project is costly and may not be cheaper than a PPA-style project, either NV Energy owned or third-party owned. At hearing, NV Energy stated, "[i]f you're looking at purely price, and price is your number one concern, don't approve a Company-owned asset." (Tr. at 702.) NV Energy argues that there are factors other than price that need to be considered that benefit ratepayers in terms of reliability and sustainability, but NV Energy offered limited explanation and no quantification of those benefits in this docket.[3] NV Energy mentions the favorable dispatchability and curtailment of the Sierra Solar project and the theoretical ability to save decommissioning costs as other factors besides price to consider when evaluating the Sierra Solar project.[4] The Commission acknowledges these as potential benefits of the Sierra Solar project and can weigh these factors when considering the Sierra Solar project, but finds it difficult to do so against the costs of the Sierra Solar project, because NV Energy did not quantify these benefits or provide evidence for how to weigh or offset the cost of the Sierra Solar project against these benefits. NV Energy also failed to explain why a company-owned, PPA-style resource brought under NRS 704.752 would not

[3] *See* Tr. at 720-721:
Q from the Commission: "so those other values [other than price], I don't recollect any meaningful discussion or quantification of any of them in this filing. Is there a way to quantify some of the other benefits or other factors that you've alluded to?"
A from NV Energy: "Yes, I don't want to say you couldn't, I assume you could, just as you suspect. My testimony tries to provide a narrative on what some of those considerations could be. You're right, I don't offer a quantification on those. That is certainly something the Company could look at on a going-forward basis, to recognize that's part of our responsibility, and that's something the Commission is looking for, and something we could provide in future filings."
[4] *See* Tr. at 876: When asked about decommissioning costs and that being a benefit to ratepayers NV Energy stated the following: "…we're going to try to continue the operation of that facility past its expected life, just like we do on our thermal units."
Q from party: "you'll try, but you don't have any experience in doing that; correct?"
A from NV Energy: "Not on renewable units."
Q from party: "So you can't tell this Commission the likelihood of your success, or the cost of doing that; correct?"
A from NV Energy: "What I'm pointing out is an intent, not a fact."

provide the same operational control benefits as the rate-base proposal, or why the terms of a PPA with a third party could not include provisions that enable equivalent operational flexibility to a rate-base project.

99. With cost as a driving consideration for the Commission to consider with the Sierra Solar project, the Commission is concerned about the potential for cost overruns. As Staff points out, the Greenlink Nevada project is a recent example of the Commission approving a rate-based project at an estimated cost, with an understanding of how that estimated cost will affect rates, and then watching the project price tag increase past the estimate to, potentially, be recovered by captive ratepayers. Greenlink Nevada is overbudget in excess of $400 million dollars.

100. The Commission also agrees with Staff when Staff states that it is likely that the development of the Sierra Solar project will face cost overruns. The Commission finds that it is unknown at this time if the amount of contingency included in the $1.536-billion project cost estimate is adequate to absorb any and all unexpected costs faced during development. The Commission notes that several renewable resource projects, such as Southern Bighorn Solar, Chuckwalla Solar, and BS3 are currently facing delays, shortfalls, or cancelations due to various market conditions surrounding the PV and BESS markets. Furthermore, both Iron Point and Hot Pot PV plus BESS projects, originally scheduled to declare commercial operation in December 2023 and 2024, respectively, failed to achieve development milestones that affected the ability of the projects to meet their contractual cost and operational commitments. The Commission acknowledges that NV Energy has completed the land purchase, the LGIA, and a Master Supply Agreement with the solar panel module supplier to try and mitigate delays and cost overruns for the Sierra Solar project. However, as NV Energy acknowledges, these steps may not fully

mitigate or prevent delays and cost overruns.[5] Most importantly, the Commission finds that NV Energy self-development projects that are rate-based, like the Sierra Solar project, shift all risk of cost overruns, underperformance, and delays from a third-party developer to the ratepayers. Unlike Hot Pot and Iron Point and the PPA model in general, if the Sierra Solar project faces delays and cost overruns, there is no mechanism like canceling a contract or reconsidering whether the pricing is reasonable and the project remains prudent before having to pay for the costs. While the Commission can disallow imprudently-incurred and unreasonable costs in a general rate case, the Commission has limited ability to disallow prudently-incurred but unforeseen costs in a general rate case.

101. Additionally, the Commission finds that while $1.536 billion is the number being touted in the Narrative as the project cost, there are additional, unknown, costs needed to decommission the PV and BESS at the end of their useful lives that would also be borne by ratepayers. According to a 2021 NREL report, responsible and cost-effective dissolution of PV system hardware at the end of the performance period is an important business and environmental consideration, and the costs incurred at the end of a PV project life cycle should be considered at the earliest stages of project planning.

102. The Commission accepts and approves Staff's recommendation for limiting a prudency determination to the estimated costs that NV Energy has identified as supporting the selection of the Sierra Solar project over alternative projects/approaches. In this instance, letting NV Energy commence development without the recommended customer cost protections increases the risk that ratepayers would be on the hook for cost overruns and removes the

[5] NV Energy states, "So what we've done to mitigate those delays, is we've sourced our panels from the United States. That's one mitigation strategy we've done. Now again, does that solve everything? Probably not. I don't know. But we've done everything we can." (Tr. at 892.)

certainty of being compensated for operational delays and performance shortfalls. The Commission notes that NV Energy could have structured the cost recovery of the Sierra Solar project with PPA pricing but chose not to do so.

103. The Commission is concerned with the cost recovery model proposed for the Sierra Solar project which, compared to a PPA type of model, appears to shift risks from the project owner (whether a third party or NV Energy) to ratepayers while simultaneously being more expensive. NV Energy's assertion that the rate-based cost recovery method is important for the sake of "balance" is not persuasive, as NV Energy has not presented sufficient evidence to demonstrate what is an appropriate balance. Therefore, without being able to clearly illustrate how the rate-base cost recovery method provides benefits to ratepayers that only exist under that cost-recovery method, burdening ratepayers with increased risk and cost appears unnecessary and imprudent.

104. The Commission finds that Staff's recommended customer cost protections afford ratepayers the same cost certainty and protections that they receive when NV Energy signs a renewable PPA or when NV Energy develops an NRS 704.752 facility. The Commission notes that it will still review all of the Sierra Solar project costs in the appropriate general rate case.

105. The Commission adopts Staff's recommendations establishing the following conditions and limits on planned costs that the Commission finds prudent for purposes of resource-planning approval: 1) the cost to construct the Sierra Solar project is capped at the $1.536 billion amount provided in the Narrative, and the O&M amount is capped at the amount included in the calculations of the LCOE and PWRR provided in this filing; 2) NV Energy will credit ratepayers with daily delay damages if the PV or BESS is not commercially operational by the CODs stated in the Narrative; 3) NV Energy will credit ratepayers with liquidated damages if

the storage availability is not maintained and/or there are renewable energy and/or PEC shortfalls; and 4) the approval of the Sierra Solar project does not include any decommissioning, remediation, and site clean-up costs incurred at the end of the PV's and BESS's useful lives that were not included in the project cost estimate.

106. The first condition of cost protection, capping capital and O&M costs at the amount presented in the Narrative, is similar to the cost protections included in NV Energy's most recently approved PPA. The BS3 PPA stated that the cost per MWh and cost per MW-month were fixed prices and did not contain a clause that the prices may be adjusted upward to account for any cost overruns or unexpected maintenance that were incurred during the development and operation of the facility. Importantly, the cost cap includes an approximately 9-15 percent contingency[6] already built in for cost overruns. The Commission disagrees with NV Energy's assertion that 20 or 24 percent is an appropriate band for a cost cap for potential cost overruns and instead finds reasonable the 9-15 percent contingency amount already built into the Sierra Solar project in NV Energy's Narrative.

107. The second condition of cost protection, that daily delay damages will be credited to ratepayers if the PV or BESS is not commercially operational by the CODs stated in the Narrative, is also similar to the cost protections included in NV Energy's most recently approved PPA with BS3. For each day that BS3 is not commercially operational past its contractual COD, NV Energy and its ratepayers are afforded daily delay damages according to a specified schedule. Pursuant to NRS 704.752, although Dry Lake did not meet its December 31, 2023, COD, ratepayers do not receive delay damages, but they also cannot be asked to pay for whatever situation is causing the delayed COD.

[6] At hearing, NV Energy stated that the $1.536 billion cost estimate NV Energy provided for the Sierra Solar project includes a contingency estimate in project costs that is "about 9 percent," lower than 15 percent. (Tr. at 993.)

108. The third condition for cost protection, that liquidated damages will be paid to ratepayers if the storage availability is not maintained and/or there are renewable energy and/or PEC shortfalls, is also similar to the cost protections included in NV Energy's most recently approved PPA with BS3.

109. The fourth condition for cost protection, that future decommissioning costs not be included in this IRP approval, is not analogous to a typical term in PPAs with third parties, but PPA pricing typically does not include any obligation for the utility or its ratepayers to cover decommissioning costs that are not already captured in the PPA's fixed pricing. NV Energy included decommissioning and remediation costs in project modeling for its Dry Lake Solar project, and based on today's estimated costs of decommissioning PV installations, just the PV portion of the Sierra Solar project could cost between $114 million and $176 million to decommission, though the Commission agrees with Staff that those costs could decrease as PV recycling and repurposing technologies advance.

110. The Commission finds that, regarding the competitiveness of the Sierra Solar project compared to other options presented in the Joint Application, any cost comparison provided in the filing or done through intervenor discovery is only meaningful if the Commission approves Staff's recommendations to have a cap on the cost to construct and operate the Sierra Solar project, as the comparisons use the energy price per MWh, MW-month charges, and hybrid LCOE values that are based on the cost estimates presented in this filing, costs which NV Energy will not commit to abide by. In the absence of the Commission's modification to the Joint Application's proposed open-ended costs for the Sierra Solar project, any capital or O&M cost overrun would render the Joint Application's price comparisons useless and move the price of the Sierra Solar project further away from a market-comparable price.

111. The Commission issues a compliance requiring NV Energy to calculate storage availability liquidated damages and renewable energy and PEC shortfall replacement costs for the Sierra Solar project in accordance with the calculations detailed in BS3's PPA. NV Energy should use BS3's PPA as a template and replace any BS3-specific values with Sierra-Solar-specific values to provide documentation that outlines how the liquidated damages and shortfall replacement costs would be calculated and credited to ratepayers by NV Energy if the Sierra Solar project faces delays or performance issues. The Commission finds that the same daily delay damages in the BS3 PPA should apply to the Sierra Solar project. NV Energy should perform the Sierra Solar project's calculations and credit ratepayers, when applicable, at the same time that it processes its other PPAs' liquidated damages and shortfall replacement amounts.

112. The Commission is not persuaded by NV Energy's argument that the Sierra Solar project should be compared to historical approvals of thermal resources and not compared to approved renewable resources for the purposes of cost recovery. The Commission finds that the Sierra Solar project is appropriately compared to other renewable projects, which thus far have been predominantly PPA-style, because the Sierra Solar project will operate like other renewable resources and not like thermal generation resources. For instance, the angle and availability of the sun affects solar energy facilities but not natural gas plants. There are no fuel considerations for a solar energy facility, as there are with a gas plant. The maintenance of a gas plant is different than that of a solar field or BESS. Renewable energy projects bring RPS compliance with them but some variability, while thermal projects deliver the exact opposite—no RPS compliance potential but less variability. Thermal projects are not subject to the unique PV and BESS supply chain issues that solar projects have faced. NV Energy has a proven track record

of developing thermal resources, but much less so with renewable energy projects.[7] For all of these reasons, the Commission finds that the appropriate cost-recovery comparison and paradigm for the Sierra Solar project should reflect how the Commission evaluates renewable energy projects rather than thermal resources.

113. The Commission also finds uncompelling NV Energy's argument that restricting the scope of pre-approved costs for the Sierra Solar project somehow amounts to the creation of a new standard. The current and historical standard for resource-planning remains the same: prudence. NV Energy conflates the cost-recovery that occurs in a general rate case with the predetermination of the prudence of costs in an IRP proceeding. In an IRP proceeding, the Commission's approval of a plan essentially establishes a presumption that the costs associated with reasonably executing the plan were prudently incurred; thus, when the utility seeks recovery of the pre-approved costs in a general rate case, the utility's burden for demonstrating prudence is lower than it would be for costs that did not receive such pre-approval. Here, the Commission's modifications simply identify the scope of what the Commission can reasonably determine is prudent based on the known and knowable information at this time. The Commission is not making a final determination as to whether NV Energy may recover additional costs in a future rate case; however, for costs associated with the Sierra Solar project, any amounts beyond the costs pre-approved here would require a demonstration of prudence that NV Energy failed to make in this case.

114. The Commission notes that costs associated with a renewable PPA are recovered through different mechanisms than costs associated with an NV Energy-owned and rate-based

[7] For example, as noted during the hearing, the following NV Energy-developed renewable energy projects were subject either to cost overruns or delays: Jean Airport Flow Battery, Iron Point, Hot Pot, Dry Lake Solar, Carson Lake Geothermal, China Mountain Wind.

renewable generation facility. The difference in the recovery mechanism used can amount to a significant impact on certain customer classes, given the large sums of money that NPC and SPPC are projected to spend on their shares of projects proposed in the Joint Application.

115. The Commission allocates the Sierra Solar project's ownership, energy, capacity, and PECs at 90 percent (360 MW PV and 360 MW BESS) to SPPC and 10 percent (40 MW PV and 40 MW BESS) to NPC. (Ex. 308 at 18.) The Commission finds that the Sierra Solar project site was selected to support a specific load growth area in SPPC's service territory, justifying the allocation of the majority of costs to SPPC. However, under its proposed allocation, NPC is forecasted to be non-compliant with the RPS by 2028. With a four-year timeline to replace a canceled renewable project, there is still time for NV Energy to contract or self-build NPC-dedicated resources before the forecasted 2028 RPS noncompliance date. NV Energy intends to request approval for renewable projects in its 2024 IRP, including the Amargosa Valley Solar Energy Zone project. However, if NPC does not acquire the necessary PECs for RPS compliance, it could request permission to enter into a Portfolio Credit Exchange Agreement to facilitate PEC loaning between SPPC and NPC, at which point the Commission would also reconsider the 90/10 cost split between SPPC and NPC to reflect any benefit to NPC with RPS compliance.

116. The Commission notes that this appears to be the first time that an ESA based on levelized pricing will use a renewable energy project that is to be a rate-base addition. The Commission also notes that, with levelized pricing, the revenue requirement for rate-base cost recovery may be larger, which would be unfair to ratepayers as a whole because the ESA customer would be paying a lower rate for the Sierra Solar project than the remaining customers. It is unclear to the Commission whether the remaining customers would be responsible for any

revenue requirement deficiency for the ESA customer's load-share of the Sierra Solar project. The Commission flags this issue here, which will be fully addressed in the ESA docket, Docket No. 23-08019.

### ii. Critical Facilities Designation/Regulatory Asset Treatment

**NV Energy's Position**

117. NV Energy requests that the Sierra Solar project receive the critical facility designation pursuant to NAC 704.9484. (Ex. 100 at 97.) NAC 704.9484 defines "critical facility" and lists the following criteria, among others, that qualifies a facility for the designation: Develops renewable energy resources; fulfills statutory mandates. (*Id.*)

118. NV Energy states that the Sierra Solar project is the first solar and BESS project developed by NV Energy in northern Nevada. (Ex. 115 at 16.) NV Energy states that the Sierra Solar project will provide NV Energy's customers the benefits from all associated environmental and renewable energy attributes as the company-owned solar plus storage resource will help reduce dependency on fossil-fueled generation and the volatile wholesale market, promote diversity of supply side resources and retail price stability, and protect reliability. (Ex. 100 at 97-98.) NV Energy states, in addition, the Sierra Solar project contributes to NV Energy's RPS compliance and achieving the state-wide goal of zero net carbon by 2050. (*Id.* at 98.) NV Energy therefore states that it fulfills the statutory RPS mandate. (*Id.*)

119. NV Energy states that the Sierra Solar project develops renewable energy resources as it represents a new chapter of renewable energy development as a 400 MW solar resource paired with a large dispatchable 400 MW BESS. (Ex. 100 at 98.)

120. NV Energy states that the Sierra Solar project adds diversity of supply as a renewable resource capable of providing energy during daytime, evening, and nighttime hours.

(Ex. 100 at 98.) NV Energy states that it reduces the open capacity position via a large dispatchable BESS, larger than any BESS currently in NV Energy's portfolio, available in the net-peak evening hours after solar production has dropped off. (*Id.*)

121. NV Energy states that it continues to face supply issues with existing resources. (Ex. 115 at 17.) NV Energy states that it also has renewable energy supply obligations per the existing green tariff programs like NV Energy GreenEnergy Rider and ESAs. (*Id.*) NV Energy states that any resource pipeline cancellation, existing resource underperformance for another PPA or company-owned resources and ability to procure future resources may present additional challenges to RPS compliance. (*Id.*) NV Energy states that these statutory and contractual obligations continue to be met by the same pool of NV Energy's renewable energy resources and are affected by renewable resources cancelations or delays. (*Id.*) NV Energy states that the Sierra Solar project's commercial operation in the 2026 and 2027 timeframes is critical for fulfilling future RPS compliance obligations in the face of uncertainty about the developers' ability to deliver contracted and approved renewable projects. (*Id.*) NV Energy states that therefore, the Sierra Solar project is a critical facility required for continued fulfillment of a statutory mandate. (*Id.*)

122. NV Energy also states that the location of this project is ideal to protect and enhance system reliability. (Ex. 100 at 98.) NV Energy states that the generation will be in close proximity to the Tahoe Reno Industrial Center, Fernley, and Fallon areas which have experienced large amounts of load growth and are forecast to continue to see extensive load growth. (*Id.*) NV Energy explains that having generation located close to the load reduces system losses and improves system reliability. (*Id.*)

123. NV Energy states that if Commission designates the Sierra Solar project as a critical facility, NV Energy requests to be allowed to:

a. include the CWIP balances from the Sierra Solar project in rate base for general rate cases (or any other recovery mechanism or filing that would allow NV Energy to update the CWIP balance in rate base, which may or may not be in place today, such as a capital recovery mechanism that NV Energy may file in the future) prior to the unit being placed into service; and

b. include the Sierra Solar project expenses, depreciation and O&M expenses, after the in-service date and until included in rates, in a regulatory asset with carrying charges.

(Ex. 100 at 99.). NV Energy states that it is requesting this cost accounting treatment because constructing the Sierra Solar project will involve significant construction expenditures and, without CWIP, no cost recovery until the project is in rate base and has gone through a general rate case. (*Id.*) NV Energy explains that these large expenditures without contemporaneous cost recovery are detrimental to NV Energy's financial condition, particularly SPPC's. (*Id.*) NV Energy states that CWIP in rate base treatment has traditionally been a solution for this circumstance. (*Id.*)

**SNGG and CMN's Position**

124. SNGG and CMN recommend that if the Commission approves the Sierra Solar project in this proceeding, then it should not be designated as a critical facility. (Ex. 700 at 4.) SNGG and CMN state that to receive a critical facility designation, a resource must protect reliability, promote diversity of supply and demand side resources, develop renewable energy resources, fulfill statutory mandates, and promote retail price stability. (*Id.* at 27.) SNGG and CMN state that the Sierra Solar project should not qualify as a critical facility because solar resources do little to protect reliability and it provides little capacity relative to nameplate and thus does not significantly improve resource adequacy. (*Id.*) SNGG and CMN provide that even though the Sierra Solar project would contribute to the state's goal of achieving net zero carbon

emissions by 2050, this is not a statutory mandate and the Sierra Solar project is not required for RPS compliance at this time. (*Id.*) SNGG and CMN note that critical facilities can receive incentives like an enhanced return on equity for the life of the facility, inclusion in rates of CWIP, and costs incurred to construct the designated Critical Facility can be recorded to a regulatory asset. (*Id.* at 28.) SNGG and CMN provide that NV Energy is not currently requesting an enhanced ROE, however, it is requesting to include CWIP balances in rate base for general rate cases and depreciation and O&M expenses after the in-service date and until included in rates in a regulatory asset with carry charges. (*Id.*) SNGG and CMN state that NV Energy has not quantified the cost of this enhanced ratemaking nor advised on any benefits to ratepayers. (*Id.* at 29.)

125. SNGG and CMN recommend that if the Sierra Solar project is approved and designated a critical facility and NV Energy is granted a regulatory asset for depreciation and O&M, then the regulatory asset should be adjusted to reflect deferred taxes for costs not yet recovered in rates. (Ex. 700 at 4-5.) SNGG and CMN state that if a regulatory asset is established, in which NV Energy can record O&M and depreciation expense incurred after the in-service date until those costs can be included in rates, then SNGG and CMN recommend the carrying charge be set to the after-tax rate of return, rather than the pre-tax rate of return. (*Id.* at 30.) SNGG and CMN provide that this is because the net carry amount outlay to NV Energy during the deferral period will be based on the after-tax amount of the deferred costs. (*Id.*) SNGG and CMN note that the after-tax amount will be the regulatory asset carrying balance, but the full O&M costs and carrying charge will be included in the regulatory asset amortization. (*Id.*)

**BCP's Position**

126. BCP states that this is not the proper proceeding for NV Energy to request critical facility incentives such as CWIP and regulatory asset treatment. (Ex. 401 at 9.) BCP states that, pursuant to NAC 704.9484(3), any incentives associated with a critical facility designation must be requested in a general rate case. (*Id.*)

127. BCP recommends, if the Commission approves the Sierra Solar project, that the Commission reject NV Energy's request to make the Sierra Solar project a critical facility to be compliant with NAC 704 because NV Energy did not structure the Sierra Solar project's cost recovery as PPA-style pricing. (Ex. 402 at 20.) BCP provides that PPA-style pricing helps stabilize retail prices in addition to protecting reliability, promoting diversity, fulfilling RPS mandates, and can provide performance guarantees. (*Id.*) BCP notes that NV Energy's current application for the Sierra Solar project does not promote retail price stability to the same degree as PPA-style pricing because the Sierra Solar project will be treated as rate base plant. (*Id.*) BCP provides that the Sierra Solar project does not provide performance guarantees and ratepayers are exposed to uncertain risks due to project costs, decommissioning costs, and ongoing O&M expenses. (*Id.*) BCP states that, as proposed, NV Energy can request recovery of cost overruns and decommissioning costs for the Sierra Solar project in a general rate case as well as varied O&M expenses and added capital over the life of the project." (*Id.*) BCP states that for cost recovery, PPA style pricing is not a front end loaded revenue requirement mechanism like rate base plant additions. (*Id.* at 13.)

128. BCP recommends that the Commission reject NV Energy's request for CWIP balances in rate base and project expenses after the in-service date recorded in a regulatory asset with a carrying charge to comply with NAC 704.9484(3) because NV Energy's calculations demonstrate that the most pertinent credit ratio of forecasted funds from operations

("FFO")/Debt is sufficient throughout the analysis period through 2033. (Ex. 402 at 20; Ex. 401 at 22.) BCP states that NV Energy's analysis shows that the critical facility ratemaking treatment is not needed. (Ex. 401 at 13.) BCP also recommends that the FFO to debt ratios reflect the MSG-transaction ESA revenues, which should improve the FFO/Debt ratios. (*Id.* at 21, 22.)

**Staff's Position**

129. Staff recommends that the Commission deny NV Energy's request to designate the Sierra Solar project as a critical facility pursuant to NAC 704.9484. (Ex. 307 at 8.)

130. Staff states that NV Energy loosely applies the criteria in NAC 704.9884(2). (Ex. 307 at 9.) Staff states that under NV Energy's rationale, every single renewable energy facility would qualify as a critical facility. (*Id.*) Staff notes however, that the Commission has only deemed two generating facilities as critical (the Lenzie and Tracy combined cycles) under a specific and unique set of circumstances. (*Id.*) Staff states that the circumstances regarding the Sierra Solar project are completely different from those when the Commission granted critical facility status for the Lenzie and Tracy combined cycles because there are currently many available in-state supply options. (*Id.* at 10.) Staff points to the robust response to NV Energy's 2023 open resource RFP as well as the fact that NV Energy is pursuing additional NV Energy-owned renewable energy projects. (*Id.*) Staff states that the Commission has and should continue to grant critical facility designation in only the most unique of circumstances, and the Sierra Solar project does not rise to that level. (*Id.*)

131. Staff recommends that the Commission reject NV Energy's request to include CWIP in rate base. (Ex. 306 at 5.) Staff states that there is nothing unique with respect to the

Sierra Solar project that, on its own, would warrant including CWIP in rate base to be collected from ratepayers before the project goes into service. (*Id.* at 6.)

132. Staff acknowledges that large amounts of spending, especially debt spending without some increase in revenue, could negatively impact various financial metrics. (Ex. 306 at 6.) Staff states that this negative impact could be reduced by NV Energy entering into PPAs or BTAs rather than electing to build the entirety of the project with company funds, equity, and debt. (*Id.* at 7.) Staff states that NV Energy may also file general rate cases on a more regular basis to reduce the regulatory lag. (*Id.* at 7-8.) Staff states that, before the Commission should grant an incentive request like having ratepayers pay for utility owned equipment before it becomes used and useful, it should ensure that all other options have been evaluated including using PPAs or other ownership models that can reduce the time delay for recovery of expenses while still providing benefits to both shareholders and ratepayers. (*Id.* at 8.)

133. Staff also acknowledges that the Commission has previously authorized CWIP in rate base in the past when both NPC and SPPC were beginning to recover from the Western Energy Crisis and beginning to build new internal generation resources. (Ex. 306 at 8.) Staff states that, at the time, neither SPPC or NPC's debt rating was considered investment grade and the use of the CWIP in rate base was one tool the Commission used to help improve those credit ratings and build the new generation needed. (*Id.*) Staff states that NPC and SPPC are both in a more stable financial conditions and have much improved credit ratings. (*Id.*)

134. Staff recommends that the Commission reject NV Energy's request for regulatory asset treatment of project expenses after the in-service date of the Sierra Solar project. (Ex. 306 at 2.) Staff states that, notwithstanding the Commission's determination on whether or not to designate the Sierra Solar project as a critical facility, nothing regarding the Sierra Solar project

itself differentiates it from any other utility project that is completed and placed into service during the normal course of business. (*Id.* at 2-3.)

135. Staff explains that any project owned by the utility would incur similar costs once it is placed into service and becomes used and useful. (Ex. 306 at 3.) Staff states that, as part of the first general rate case that occurs after the project is placed into service the cost of the project, less any depreciation incurred since it went into service and the costs related to operating and maintaining the functioning plant would be included in the revenue requirement and used to set rates to be charged to ratepayers. (*Id.*) Staff states that without the incentive treatment offered by the use of the regulatory asset, the company would not recover the depreciation nor the O&M expenses that occur during the interim period. (*Id.*) Staff states that this is part of the concept known as regulatory lag. (*Id.*)

136. Staff states that, because both the PV and BESS are eligible for tax credits through the Investment Tax Credit or the Production Tax Credit, if the Commission allows NV Energy to record costs in a regulatory asset, NV Energy should also be required to record the applicable tax credits as an offset to the regulatory asset or in a regulatory liability account. (Ex. 306 at 4.)

137. Staff also disagrees with NV Energy's request that regulatory asset accounts established for the Sierra Solar project should accrue carry charges. (Ex. 306 at 4.) Staff states, if the Commission were to allow depreciation and O&M costs to be recovered from ratepayers through a regulatory asset, that process alone provides a benefit to the utility; adding a carrying charge in addition to that benefit would be unreasonable. (*Id.*)

**NV Energy's Rebuttal**

138. NV Energy states that the Sierra Solar project meets four of the five items listed in NAC 704.9484 (of which only one is required). (Ex. 139 at 3-4.) NV Energy states, specifically, the project promotes diversity in supply as NV Energy only has 35 MWs of owned solar capacity; it is a renewable energy facility; it helps fulfill a specific statutory mandate for meeting RPS requirements; and it helps promote price stability as it is not dependent on unknown flexibility of commodity prices, such as natural gas. (*Id.* at 4.) NV Energy states, therefore, the project does qualify for critical facility designation under NAC 704.9484. (*Id.*) NV Energy states that Staff and BCP's focus on the financial position of NV Energy appears to be an attempt to create new requirements for critical facility designation that go beyond what the regulation requires. (*Id.*) NV Energy states that, while financial distress might be an additional reason why critical facility designation may be appropriate, it is not a requirement. (*Id.*)

139. NV Energy states that it is appropriate for NV Energy to request the critical facility designation to help maintain financial support during the course of large builds, particularly when the request meets the criteria identified in NAC 704.9484(2), as it does here. (Ex. 139 at 4.). NV Energy states that the critical facility designation will protect NV Energy's financial status as it works through a period of significant capital investment. (*Id.* at 4-5.)

140. NV Energy states that this is the appropriate time to request critical facilities designation pursuant to NAC 704.9484(3) which contemplates a request for critical facility designation prior to a request that the incentive associated with that facility be included in rates in a general rate case. (Ex. 139 at 10.) NV Energy states that it is only asking for approval to designate the Sierra Solar project as a critical facility in this docket and identify incentives for Commission's consideration, it is not asking for the incentive to be in rates at this time. (*Id.*) NV Energy explains that recovery would be brought forward in a different docket. (*Id.*)

141. NV Energy states that there is no guarantee on the action of the rating agencies, related to NV Energy being issued a downgrade, which is why NV Energy is requesting critical facility designation for the Sierra Solar project to support the financial position of NV Energy and minimize the potential for a rating downgrade. (Ex. 139 at 10-11.)

142. NV Energy states that between the Financial Plan and Mike Behrens' direct testimony in the NV Energy's Joint Application, as well as NV Energy's data requests responses, there is sufficient evidence to see there is a financial benefit for the project to have the critical facility designation. (Ex.139 at 12.)

143. NV Energy states that SNGG and CMN are incorrect in asserting that this project does not significantly improve resource adequacy or provides little nameplate capacity. (Ex. 139 at 13.) NV Energy explains that a 400 MW solar and battery project is a large-scale project that will provide material generation to address resource adequacy concerns. (*Id.*) NV Energy also disagrees with SNGG and CMN that the project does not provide any RPS benefit. (*Id.*) NV Energy states that renewable projects take years to plan and build and can be subject to unanticipated delays so having the Sierra Solar project in development will provide a material benefit to NV Energy's RPS compliance by providing protection against a deficiency or delay in another renewable resource. (*Id.*)

144. NV Energy states that, though the project does qualify for critical facility designation under the Commission's regulations, NV Energy can afford to build the Sierra Solar project without the critical facility designation, even if approved at 90 percent ownership for SPPC and 10 percent ownership for NPC as proposed by Staff. (Ex. 139 at 14.)

145. NV Energy disagrees with Staff's recommendation to deny CWIP in rate base as Staff incorrectly characterizes building the Sierra Solar project as normal course of business and

uses that characterization as reason to deny NV Energy's request for CWIP in rate base. (Ex. 139 at 8.) NV Energy also states that the alternate recovery mechanisms proposed by Staff would not adequately compensate NV Energy, would still create regulatory lag, and would create uncertainty about future Commission decisions. (*Id.* at 8-9.)

146. NV Energy states that the assertion that that this project is not any different than any other in the normal course of NV Energy's business is misplaced. (Ex. 139 at 6.) NV Energy states that, while it is ultimately a rate-based generation plus storage project, "normal course of business" projects would be more in the area of distribution, capital maintenance, and transformers, not a large, new generating facility that would be the first rate-based utility-scale solar project owned by NV Energy. (*Id.*)

147. NV Energy agrees that load growth helps mitigate the effects of regulatory lag, but that load growth only compensates for the lag that might be associated with the costs to bring service to the new customer, such as the distribution line. (Ex. 139 at 6-7.) NV Energy states that for large generating projects like the Sierra Solar project, the new facility's depreciation expense would be significantly greater than the revenue from new customer load growth. (*Id.* at 7.)

148. NV Energy states, in contrast to Staff's assertion that depreciation and O&M expenses do not normally earn a return as that has historically been the treatment approved by the Commission, this situation is different because the regulatory asset is being requested on something that is not yet in rates, i.e. the regulatory lag. (Ex. 139 at 7.) NV Energy states, therefore, the depreciation and O&M expense incurred before the next general rate case represent a portion of a cost for a capital investment which NV Energy would never get the opportunity to recover or even earn a return on. (*Id.*) NV Energy explains that allowing the depreciation and

O&M expenses to go into a regulatory asset allows NV Energy to recover the cost of the asset and the carry would represent a return NV Energy never had an opportunity to earn on that portion of the investment that would be depreciated before the next general rate case to get the value in rate base. (*Id.*)

149. NV Energy disagrees with SNGG and CMN's recommendation to use an after-tax rate of return for the carrying charge is a regulatory asset is allowed for the critical facility designation for the Sierra Solar project. (Ex. 130 at 4.) NV Energy states that this particular regulatory asset is not any different from any other regulatory asset that NV Energy would establish and there is no need to account for the tax impacts of this regulatory asset differently than all of the other regulatory assets on NV Energy's balance sheet. (*Id.*)

**Commission Discussion and Findings**

150. The Commission denies NV Energy's request to designate the Sierra Solar project as a critical facility pursuant to NAC 704.9484. The Commission finds that NV Energy loosely applies the criteria in NAC 704.9484(2) when it requests critical facility treatment for the Sierra Solar project. The Commission agrees with Staff that, under NV Energy's rationale, every single renewable energy facility would qualify as a critical facility. The Commission has only deemed two generating facilities as critical (the Lenzie and Tracy combined cycles) under a specific and unique set of circumstances that do not apply to the Sierra Solar project. The circumstances regarding the Sierra Solar project are completely different from those when the Commission granted critical facility status for the Lenzie and Tracy combined cycles because there are currently many available in-state supply options.

151. The Commission rejects NV Energy's request to include CWIP in rate base. The Commission finds that there is nothing unique with respect to the Sierra Solar project that, on its

own, would warrant including CWIP in rate base to be collected from ratepayers before the project goes into service.

152. The Commission acknowledges that large amounts of spending, especially debt spending without some increase in revenue, could negatively affect various financial metrics. However, the Commission finds that this negative impact could be reduced by NV Energy entering into PPAs or BTAs rather than electing to build the entirety of the project with company funds, equity, and debt. NV Energy may also file general rate cases on a more regular basis to reduce the regulatory lag.

153. The Commission rejects NV Energy's request for regulatory asset treatment of project expenses after the in-service date of the Sierra Solar project. The Commission finds that nothing regarding the Sierra Solar project itself differentiates it from any other utility project that is completed and placed into service during the normal course of business. The Commission finds that any project owned by NV Energy would incur similar costs once it is placed into service and becomes used and useful. The Commission notes that, as part of the first general rate case that occurs after the project is placed into service the cost of the project, less any depreciation incurred since it went into service and the costs related to operating and maintaining the functioning plant would be included in the revenue requirement and used to set rates to be charged to ratepayers. Without the incentive treatment offered by the use of the regulatory asset, NV Energy would not recover the depreciation nor the O&M expenses that occur during the interim period, which is normal regulatory lag.

**C. Valmy Units 1 and 2**

**i. Repower**

**NV Energy's Position**

154. NV Energy states that its Joint Application provides a complete solution to support the timely retirement of coal generation at Valmy and the need for voltage support and available around-the-clock generation in the Carlin trend load pocket. (Ex. 120 at 3.) NV Energy states that Valmy provides both capacity and critical system support to the Carlin Trend load pocket, and the units cannot be retired without a replacement that can provide firm and dispatchable output. (*Id.* at 5-6.)

155. NV Energy requests approval to complete the conversion of the existing Valmy coal-fired units 1 and 2 to operate on natural gas and complete the retirement of coal-fired operations at Valmy. (Ex. 100 at 59.) NV Energy states that the project scope will include replacement of the coal-fired burner equipment on the existing boilers with burners and controls that will allow the units to operate on natural gas. (*Id.*) NV Energy states, additionally, the conversion to natural gas is expected to require the installation of additional NOx controls such as selective catalytic reduction ("SCR") or selective catalytic reduction ("SNCR"). (*Id.*) NV Energy also states that, to prepare the units for long-term operation on natural gas, major outages would be completed on the units to bring all of the equipment to a state that would allow for continued operations. (*Id.*)

156. NV Energy states that, while it is requesting approval of natural gas, or fossil generation, NV Energy is not deviating from its clean energy goals. (Ex. 120 at 8.) NV Energy states that by eliminating coal from the existing resource portfolio, NV Energy continues to deliver on its commitment to reduce carbon emissions, (*Id.*) NV Energy states that its Preferred Plan achieves and exceed the RPS in all years, and, as in recent IRP filings, targets NV Energy's proportionate share of the state's 2050 clean energy goal. (*Id.*) NV Energy states that firm dispatchable resources, which are modeled today as gas turbines, contribute much more

significantly to firm capacity in 2050 in the Preferred Plan than they do to energy production, resulting in a positive impact on resource adequacy with minimal potential carbon dioxide emissions. (*Id.* at 9.)

157. NV Energy states that, while it is true it did not support the refueling of Valmy in the 2021 IRP, system conditions and resource options have changed since that time and the refueling option is now an economic and reliable option. (Ex. 120 at 9.) NV Energy states that, per a new transmission study, there is a need not only for voltage support for the Carlin Trend area, but also the availability of around-the clock generation without runtime limitations to be located at or near Valmy. (*Id.*) NV Energy states that since a firm dispatchable resource is needed to resolve the Carlin Trend's post contingency voltage issues, an intermittent resource such as a solar/BESS pairing would not suffice, nor would a stand-alone BESS, as it does not have sufficient output duration by itself to support the Carlin Trend area. (*Id.*) NV Energy states that, while the transmission study shows, when Greenlink West is completed, the continued must-run at Valmy would no longer be required, there will likely still be periods when generation is required as loads continue to increase in northern Nevada. (*Id.* at 10.) NV Energy states that this leaves two feasible options to support the retirement of coal generation at Valmy and to support the continuing need for a firm dispatchable resource: the refueling of Valmy to burn natural gas, or the construction of new natural gas-fired peaking units at the Valmy site. (*Id.*) NV Energy states that in evaluating the refuel option, the cost is approximately $270 million lower than the peaking units and would allow NV Energy to eliminate coal combustion from its fleet by the end of 2025. (*Id.*) NV Energy states that the earliest peaking units could be installed is estimated to be May 31, 2027, which would require continued existence of the coal-fired units for a minimum of 17 additional months. (*Id.*) Additionally, if there were any delays in the

installation of the peaking units, system reliability could be at a risk as the existing coal generation would be severely limited for the summer months in 2027 due to updated environmental restrictions. (*Id.*)

158. NV Energy states that the project and continued operation costs assumes that Idaho Power Company will continue to participate in Valmy with its 50 percent ownership, sharing 50 percent of the output and cost. (Ex. 100 at 59.) NV Energy states that it has been in thorough discussion with Idaho Power Company regarding its continued participation in Valmy. (Ex. 120 at 10.) NV Energy states that Idaho Power Company has a 50 percent ownership share in Valmy and has the first right to participate in the repower project up to its 50 percent ownership share. (*Id.*) NV Energy states that Idaho Power Company has continued to indicate its plans of retaining 50 percent ownership of Valmy and participating in the repower project, and it is expected to request approval of such in an IRP filing. NV Energy states that the Valmy Life Span Analysis Process ("LSAP") Update also studied a scenario where Idaho Power Company does not participate in the coal to gas conversion and exists Valmy. (*Id.*) NV Energy states that the analysis shows that this scenario is cost effective for SPPC, but since Idaho Power Company has expressed interest in maintaining its interest and operation of its share, this alternative was not studied outside the LSAP. (*Id.*) NV Energy proposes to provide status updates and a potential compliance filing relative to Idaho Power Company's status in continued ownership in the Valmy conversion. (*Id.*)

159. NV Energy states that the project assumes that the gas conversion of Valmy unit 1 will be completed in the fall of 2025 with the outage starting after the peak season of 2025. (Ex. 100 at 59.) NV Energy states that during the Unit 1 outage, Unit 2 would continue to operate on coal in support of the transmission system must-run requirement. (*Id.*) NV Energy states that the

outage to complete the conversion to natural gas operations would be completed by December 31, 2025, to allow coal-fired operation at Valmy to cease. (*Id.*) NV Energy states that once the Unit 1 outage is complete and Unit 1 is capable of operation on natural gas, it would take over the must-run support and the Unit 2 outage would begin, with both units being converted to natural gas operation by June 1, 2026. (*Id.*)

160. NV Energy states that the total cost of the Valmy conversion to natural gas is estimated at $166 million, with SPPC's 50 percent share being approximately $83 million. (Ex. 100 at 60.) NV Energy states that the cost estimate includes capital improvements necessary for the continued operation of the Valmy units to prepare for operation from the current retirement date of 2025 through 2049. (*Id.*)

**AEU's Position**

161. AEU states that the Commission should order a fresh solicitation targeted to the Valmy need. (Ex. 500 at 5.) AEU suggests that this solicitation process could take one of two forms: 1) order NV Energy to perform a solicitation targeted to the Valmy need now; or 2) use the 2024 IRP to develop a comprehensive statement of need that can form the basis for an all-source RFP at the conclusion of the 2024 IRP process. (*Id.* at 4.) AEU states that NV Energy could then evaluate those bids and put together a proposed portfolio as the first amendment to the 2024 IRP. (*Id.*)

162. AEU states that it opposes NV Energy's proposal to convert the existing coal fueled plant at Valmy to a natural gas fueled plant. (Ex. 500 at 5.) AEU states that the proposal should be rejected for the following reasons: 1) the proposal is inconsistent with prior NV Energy commitments and Commission directives, and NV Energy's broader Joint Application also fails to comply with key Commission requirements; 2) the costs and risks associated with

the repower proposal cannot be meaningfully analyzed at this time; and 3) the short-term and long-term needs cited in support of the Valmy Repower "station" could be met with combinations of other options that were not examined. (*Id.*)

163. AEU further states that NV Energy's Valmy proposal is inconsistent with its longstanding commitment to retire the Valmy plant by 2025 and Commission directives regarding Valmy retirement. (Ex. 500 at 5.) AEU states that NV Energy's Joint Application fails to satisfy the requirement for a complete analysis of alternative solutions to Valmy retirement. (*Id.*) AEU states that NV Energy's Joint Application also fails to provide a low carbon scenario. (*Id.*) AEU states that the Order in Docket No. 22-11032 made clear the Commission's intentions to conduct a comprehensive evaluation of its options to effectuate the retirement of Valmy. (*Id.* at 6.)

164. AEU states that the Commission issued a directive in Docket No. 22-11032 that NV Energy, in a future resource plan amendment or the 2024 IRP, whichever comes first, NV Energy must provide the following related to the retirement of the coal-fired Valmy generated units: 1) a complete solution for the retirement of Valmy; 2) comprehensive analysis and comparisons of the financial and economic impacts of each potential solutions; and 3) updated information on the federal and state limitations on continued operations. (Ex. 500 at 7.) AEU states that the specific language in these findings and orders is significant and should not be ignored as the Commission now considers the Joint Application. (*Id.* at 7.) AEU further asserts that a retirement of coal combustion is not Commission ordered and is NV Energy's attempt to redefine prior Commission orders to fit its preferred solution. (*Id.* at 7.)

165. AEU states that NV Energy limits the scope and content of its solutions analysis through successive discussions of options with inconsistent criteria and methodology through the

supply plan, Valmy LSAP analysis, and alternative plan analysis. (Ex. 500 at 8.) AEU states that it does not believe these analyses are presented in sufficient detail to allow for rigorous Commission and stakeholder review. (*Id.*) AEU states that NV Energy failed to discuss various individual components that together could potentially form a complete solution to Valmy retirement, such as: 1) the continued operation of Valmy until the in-service of Greenlink West in late 2026; 2) the continued operation of the TS Power Plant; 3) combination of Valmy PV/BESS and the Sierra Solar project; and 4) additional recent project proposals. (*Id.*)

166. AEU states that it does not believe the Commission has a complete picture of the new pipeline capital costs or the fuel price assumptions associated with the Valmy proposal. (Ex. 500 at 12.) AEU also states that the costs associated with the necessary buildout to Ruby Pipeline for the natural gas repowering at Valmy have not been provided either in the Joint Application or in the information received under the protective agreement. (*Id.*) AEU states that without this information, stakeholders in the Joint Application cannot fully analyze this proposal. (*Id.*) AEU states that the Ruby Pipeline itself bears project risk as it has previously been in bankruptcy and its future is uncertain. (*Id.*)

167. AEU states that it does not agree with NV Energy's position that the Carlin Trend load pocket requires around-the-clock generation. (Ex. 500 at 16.) AEU states that around-the-clock generation is not a recognized utility resource planning term. (*Id.*) AEU states that the around-the-clock generation rubric encompasses a range of recognized planning constraints and objectives, which may be accomplished by a broader array of technologies. (*Id.*) AEU states that the resources necessary to address these needs include both active and reactive power, voltage support, fast-start capability, and long-duration capacity. (*Id.*) AEU states that these needs can be met with existing renewable energy technologies and energy storage, non-generating

resources and advanced transmission technologies and imported power. (*Id.*) AEU further states that it disagrees with NV Energy's position that there is a long-term need for the Valmy repower proposal. (*Id.* at 16-17.)

168. AEU further states that the Commission does not have adequate information to decide on the Valmy proposal currently, and there is no short- or long-term need to repower this fossil asset for 24 years. (Ex. 500 at 18.) AEU states that the Valmy proposal is not ripe for review given the uncertainty of Idaho Power's participation in the repower proposal, and Idaho Power's IRP is pending before the Idaho Public Utilities Commission. (*Id.*) AEU states that if Idaho Power does not participate in the Valmy repower proposal, NV Energy's costs and risks would be substantially different, and yet an analysis of those costs and risks are not present in the Joint Application. (*Id.*)

**Sierra Club's Position**

169. Sierra Club recommends that the Commission reject the Joint Application as it pertains to Valmy Units 1 and 2 because NV Energy has failed to show adequate analysis to support its assertion that $NO_x$-reducing equipment and SCR will be required under the Good Neighbor Plan to maintain must-run status during the ozone season (May through September). (Ex. 1400 at 9.) Sierra Club also states that spending $82.6 million on gas conversion, SCR installation, and continued operations at Valmy is concerning because there are other viable options for Valmy that are fairer to the ratepayer. (*Id.* at 20-21.) Sierra Club provides that NV Energy notes in the narrative: "it is 'reasonably anticipated' that coal-fired must-run operation at Valmy could likely be sustained through the 2026 ozone season without SCR installation." (*Id.* at 9.) Sierra Club states that NV Energy's schedule for gas conversion and SCR at Valmy could be

pushed back one year from completion in May 2026 to completion in May 2027 to facilitate further study of these alternative options. (*Id.* at 9.)

170. Sierra Club states that NV Energy's 2023 Valmy LSAP Update looks at the cost of only four different Valmy scenarios. (Ex. 1400 at 16.) Sierra Club states that two scenarios assess the cost of a portfolio that converts the existing Valmy units to gas, with different allocations between NV Energy and Idaho Power Company. (*Id.*) Sierra Club provides that a third scenario assesses the cost of replacing Valmy with new simple cycle combustion turbines. (*Id.*) Sierra Club states that the fourth scenario assesses the cost of replacing Valmy with solar plus BESS. (*Id.*) Sierra Club states that the LSAP indicates that keeping Valmy online and converting the plant to gas with SCR is expected to be less expensive than either of the two other replacement scenarios considered. (*Id.*) Sierra Club states that the solar plus BESS scenario appears significantly more expensive than the other options, however, it is not clear whether NV Energy included a realistic estimate of the value of renewable energy market sales, or unrealistically assumed that any renewable energy generation in excess of retail load would be curtailed. (*Id.*) Sierra Club also states that NV Energy evaluated only two alternative scenarios to the Valmy gas conversion, and these do not represent the full range of alternatives to NV Energy's plan; this study does not optimize a resource portfolio to find the lowest-cost alternative to continued operation of, and investment in, Valmy. (*Id.* at 17.)

171. Sierra Club recommends that NV Energy provide the Commission with a report showing the potential lower capital costs associated with retiring the Valmy plant earlier than 2049. (Ex. 1400 at 24.) Sierra Club provides that NV Energy's updated transmission reliability study, the 2023 Valmy Must Run Study ("Must Run Study"), indicates that the transmission system can withstand the retirement of Valmy, but not until Greenlink West is completed. (*Id.* at

9.) Sierra Club states that the Must Run Study further indicates that once Greenlink West is in service, it will resolve many of the identified reliability issues with retiring Valmy. (*Id.* at 14.) Sierra Club notes that Greenlink West is currently planned for service in May 2027 and Greenlink North is expected in December 2028. (*Id.* at 15.) Sierra Club states that the Must Run Study provides insight into the grid in 2025 and 2027 but it does not support NV Energy's plans to run Valmy through 2049 because, as soon as Greenlink North is in service in 2028, the study shows no further transmission system issues resulting from the Valmy retirement. (*Id.*)

172. Sierra Club recommends reducing the operating timeframe of Valmy, and instead of operating it through 2049 retire both Valmy units in 2027 or 2028, after Greenlink West and Greenlink North are in service. (Ex. 1400 at 22.) Sierra Club states that retiring Valmy then will avoid making investments in gas conversion, continuing operations, and SCR, since Valmy will become less important for system reliability after Geenlink North is in place. (*Id.* at 22, 24.) Sierra Club notes that capital expenditures for continued operation through 2049, at $32.25 million, are a substantial part of NV Energy's proposal. (*Id.* at 22.)

173. Sierra Club provides that NV Energy could retire one Valmy unit in 2025 or otherwise place a unit on standby until Greenlink West and Greenlink North are in place in May 2027 and December 2028. (Ex. 1400 Testimony at 23.) Sierra Club states that NV Energy could maintain control of two sources of generation near Carlin Trend after retiring one Valmy unit by negotiating a deal with Newmont for NV Energy to operate Newmont Mining Company's TS Power Plant ("TSPP") until Greenlink North is in place. (*Id.*) Sierra Club recommends that NV Energy provide the Commission with a report on the potential for demand response, customer-sited backup generation or storage, negotiations with Newmont for operation of TSPP until new transmission resources are in place, and other options to avoid costs associated with long-term

operation of both Valmy units. (*Id.* at 25.) Sierra Club states that NV Energy did not evaluate a plan without Valmy 1 in its Key Decision Report ("KDR"), despite the savings that could be achieved by avoiding investment in Valmy 1. (*Id.* at 17.)

174. Sierra Club states that according to the Nevada Regional Haze State Implementation Plan ("SIP"), SNCR is a cheaper solution than SCR as the cost of SNCR is one-tenth the cost of SCR for Valmy. (Ex. 1400 at 9.) Sierra Club states that NV Energy has not analyzed SNCR to see if it would be an adequate alternative to use instead of SCR. (*Id.*) Sierra Club recommends that NV Energy provide the Commission with a report on installing SNCR instead of SCR at one or both Valmy units to minimize costs for ratepayers while meeting Good Neighbor Plan and NERC reliability requirements. (*Id.* at 25.) Sierra Club provides that updating the 2023 Valmy Must Run Study to assess whether the Valmy units could be placed on standby during off-peak months in 2026-2028 could help reduce Valmy's $NO_x$ emissions during the ozone season enough to comply with the Good Neighbor Plan without SCR installation; the current 2023 Must Run Study did not assess off-peak months. (*Id.* at 23.)

**SNGG and CMN's Position**

175. SNGG and CMN state that they are concerned with NV Energy's ability to place the Valmy conversion project in service by the planned timelines and to install these resources at the projected costs. (Ex. 700 at 4.) SNGG and CMN provide that, according to NV Energy, Pinyon Pipeline, LLC, a new pipeline affiliated with Ruby Pipeline, has proposed a lateral that will supply natural gas to Valmy to support this project. *(Id.* at 14.) SNGG and CMN note, however, that NV Energy does not appear to have any current transportation service agreements ("TSAs") with Ruby Pipeline or Pinyon Pipeline. (*Id.* at 15.)

**WRA's Position**

176. WRA states that if the Commission should choose to evaluate the merits of NV Energy's Joint Application as filed, WRA recommends that the Commission deny the Valmy conversion and repower without prejudice. (Ex. 1600 at 6.) WRA notes this action would not prevent NV Energy from refiling itsValmy conversion and repower proposal in a 2024 IRP application after a full regulatory and GHG emissions evaluation have been completed. (*Id.*) WRA provides that approval of a new thermal generation resource stands in direct opposition to statutory emissions-reduction goals for the state. (*Id.*)

177. WRA recommends that the Commission robustly interrogate and asses the linkage between the Valmy retirement and the broader need for firm generation on SPPC's system. (Ex. 1601 at 43.) WRA states that gaps between NV Energy's resource needs and its process for resource procurement need to be resolved. (*Id.* at 38.) WRA notes that NV Energy indicates that once Greenlink West is in service it will resolve many of the identified reliability issues in northern Nevada, but it is not certain to eliminate the must-run requirement for Valmy. (*Id.* at 6.) WRA provides that NV Energy has not adequately supported the need for around-the-clock generation at or near the Valmy units after Greenlink West is completed with its Must-Run Study. (*Id.* at 10-11.) WRA states that NV Energy's transmission analysis did not include analysis of a firm, non-use-limited generation solution or whether additional criteria might further stress the conclusion that an aging, long-start resource such as the Valmy conversion would be a reliable solution. (*Id.* at 11.) WRA states that any reliability concerns with Greenlink West would be applicable to load growth and the lack of dispatchable resources on the whole SPPC system, not just with retiring Valmy. (*Id.*) WRA notes that the late identification of the need for firm generation reflects the failure of the IRP process to produce a sufficiently rigorous

analysis for SPPC's system, illustrating a need to more regularly and thoroughly analyze reliability risk with more granular transmission topology. (*Id.* at 12.)

178. WRA recommends that the Commission require NV Energy to analyze and explore the viability of a geothermal resource as all or part of the Valmy solution prior to moving forward with the proposed gas repower because of the economic and policy benefits. (Ex. 1601 at 5.) WRA states that it is unclear why NV Energy did not evaluate geothermal as a Valmy replacement because, according to a study by the U.S. Department of Energy's 2014 Pacific Northwest National Laboratory, Valmy has the best characteristics of any coal resource in the nation for geothermal augmentation or replacement. (*Id.* at 13-14.) WRA provides that geothermal replacement is a viable solution because the Valmy units are in a geothermal-rich resource area and geothermal resources provide continuous generation. (*Id.* at 14.) WRA notes that continuous generation could reduce import levels and risks that NV Energy is trying to resolve with the proposed repower at Valmy. (*Id.*) WRA states that a geothermal resource would help with the significant flat industrial loads on SPPC's system. (*Id.* at 16.) WRA notes that gas conversion or replacement are not well-suited for continuous efficient operation due to their lack of secondary cycles and consequent elevated heat rates, and both expose NV Energy and their customers to fuel price risk. (*Id.*) WRA provides that geothermal may be a cost-effective solution because it is a renewable energy resource and although the capital investment of a geothermal resource is significantly higher than a gas conversion, a geothermal resource provides firm capacity with a high-capacity factor as an emissions-free renewable energy resource. (*Id.* at 15.) WRA states that NV Energy can invest in a geothermal resource and in turn solve the Valmy technical need and current and future RPS needs. (*Id.*) WRA notes that if NV Energy goes through with the Valmy gas repower instead, then it will have to develop other

renewable energy resources to comply with statutory obligations. (*Id.*) WRA provides that their preliminary economic screening of a geothermal option suggests a ballpark figure that it can be constructed and operated for approximately 65 percent of the cost that would be required for the combined coal-to gas conversion with an equivalent level of other resources producing an equivalent quantity of renewable energy. (*Id.* at 28-29.) WRA notes that economic incentives also include the 40 percent federal Investment Tax Credit for renewable energy resources. (*Id.* at 15.) WRA states that if further investigation shows that Valmy would not be suitable for geothermal, it is highly likely that, with sufficient lead time and market direction, commercial developers of geothermal resources could find sufficient capacity to provide much if not all of the generating capacity needed for the Valmy retirement. (*Id.* at 22.)

179. WRA also recommends that the Commission direct NV Energy to address its use of an incorrect heat rate value in its gas conversion analysis, which underestimates fuel consumption by 20-30 percent. (Ex. 1601 at 5.) WRA states that an error of this magnitude can have significant implications over the life of a 28-year resource. (*Id.* at 33.) WRA states that it does not know what data input NV Energy used to calculate the heat rate value, but it does not appear that NV Energy included actual performance and efficiencies when modeling the options. (*Id.* at 33.) WRA provides that the 2023 heat rate data provided in discovery is considerately different than the 2018 high load baseline. (*Id.*) WRA notes that incorrect heat rate data could significantly underestimate ratepayers' fuel price exposure. (*Id.* at 16.)

**BCP's Position**

180. BCP states that NV Energy's proposed conversion of the Valmy units from coal generation to natural gas seems to be the best solution for the Carlin Trend load pocket. (Ex. 402 at 17.) BCP notes that while natural gas peaking units could be an alternative option, new

peaking units could not be placed into service until 2027 and are approximately $270 million more expensive than the repowering of the Valmy units. (*Id.* at 17-18.) BCP states that a Valmy unit operating under a must-run procedure is required to ensure a firm dispatchable resource can mitigate unacceptable low voltage in the Carlin Trend area. (*Id.*) BCP states that a standalone Valmy BESS option does not have sufficient output duration to serve load and support voltage issues during transmission outage events until starting an existing Valmy unit, which requires approximately twenty-four hours to place in-service. (*Id.* at 18.) BCP recommends the Commission approve only $50.4 million, not to exceed $55.4 million, of SPPC's share of the estimated $83 million necessary for the engineering, procurement, and construction and SCR installation improvements to the Valmy units because NV Energy's request for capital projects for continued operation estimated at approximately $32.25 million is not needed at this time. (*Id.* at 3, 15, 19.) BCP states that this decision will not preclude NV Energy from requesting the $32.25 million later during the 2024 full IRP. (*Id.* at 19.) BCP notes that the Valmy conversion will maintain SPPC's 261 MW share of the resource capacity. (*Id.* at 18.) BCP provides that the December 2025 and May 2026 repowering in-service dates will remove NV Energy's final coal-generation source from its portfolio. (*Id.* at 15.) BCP states that this conversion will reduce carbon emissions by approximately 50 percent. (*Id.* at 18.) BCP recommends that the Commission therefore approve the continued operation of the repowered Valmy through 2049 to comply with the state RPS mandate. (*Id.* at 19.)

181. BCP recommends that the Commission reject NV Energy's proposed $419 million 200-MW Valmy BESS project in the Carlin Trend region because the Valmy repowering is a better solution. (Ex. 402 at 30.) BCP states that NV Energy's current application does not describe the full scope of the December 2025 Valmy BESS project in sufficient detail. (*Id.*) BCP

states that NV Energy does not include the transmission facilities to interconnect the Valmy BESS project. (*Id.*) BCP states again that a standalone Valmy unit is not a viable option and therefore the best solution for NV Energy is to repower both Valmy units because a standalone Valmy BESS option does not have sufficient output duration to serve load and support voltage issues during transmission outage events to support the Carlin Trend area until starting an existing Valmy unit. (*Id.*) BCP notes that there currently is uncertainty of solar development success in the Carlin Trend region and a Valmy BESS or similar solar project would be a better option after further determination of the solar development viability in Carlin Trend. (*Id.* at 31.) BCP states that if the Commission determines a BESS project is warranted in this case, the 400 MW Sierra Solar BESS would be a better option given its close proximity to the Tahoe Regional Industrial Center, Fernley, and Fallon because these areas are experiencing large amounts of load growth. (*Id.*)

**Staff's Position**

182. Staff recommends that the Commission approve NV Energy's request to repower Valmy from coal to natural gas. (Ex. 309 at 5.) Staff states, however, the Commission should not approve the $83 million amount requested because the actual cost estimate to convert the Valmy units to natural gas and to install the required SCR is only $50.43 million. (*Id.*)

183. Staff states that the Carlin Trend load pocket constraint is a real condition and so is the must-run requirement on the generators located in that load pocket. (Ex. 309 at 8.) Staff states that in the three near miss years out of the last four years (2020, 2021, and 2022), NV Energy was on the verge of having to declare a system emergency and potentially curtail loads during the peak summer months because of available capacity concerns. (*Id.*) Staff therefore states that retiring any existing internal generation capacity that helped avoid those load

curtailments is a risky endeavor, especially given the load growth NV Energy is experiencing and the delays NV Energy has seen with previously contracted renewable energy resources coming on-line. (*Id.*) Staff states that NV Energy has also committed itself to High Voltage Distribution agreements as well as WRAP requirements that will require the production of the Valmy units to satisfy. (*Id.* at 8-9.)

184. Staff states that the load pocket constraint NV Energy has outlined is likely to improve in the future such that the Valmy units may not need to be run as much as perhaps NV Energy is alluding to in this filing. (Ex. 309 at 9.) Staff states that additional resources in the Carlin Trend load pocket will be added tools that will allow the Valmy units to operate less during non-peak load periods. (*Id.* at 10.) Staff also states that the partnership with Idaho Power Company in the Valmy units will allow NV Energy to use Idaho Power Company running its half of the Valmy units to aid with the local reliability situation in the Carlin Trend versus NV Energy always needing to run its share of the two units. (*Id.* at 10-11.)

185. Staff states that with NV Energy forecasting to spend between \$5 and \$10 billion on renewable energy projects over the next five to seven years, squeezing out some value from existing resources is imperative in order to keep customer rates in a reasonable and affordable range. (Ex. 309 at 12.) Staff notes that NV Energy estimates that it will cost over \$630 million to build the 149 MW solar and 4-hour BESS Crescent Valley solar PV project. (*Id.* at 13.) Staff states that this cost shows the value of spending \$50 million in new capital to maintain NV Energy's 261 MW shares of Valmy. (*Id.*)

186. Staff states that converting the coal units to natural gas provides an immediate 50 percent reduction in carbon. (Ex. 309 at 14.) Staff states, additionally, with NV Energy

proposing to extend the retirement date until 2049, the conversion does not impact the Nevada's goal of achieving its net zero carbon goal by 2050. (*Id.*)

187. Staff states that the cost estimate to convert the Valmy units to natural gas and install the SCR pollution control equipment is only $100.846 million, with NV Energy's cost share being $50.430 million. (Ex. 309 at 20.) Staff states that this is the amount Staff is recommending be approved. (*Id.*) Staff states that the remaining amount requested by NV Energy, for "capital projects for continued operation," is just a placeholder amount associated with upgrades that may be needed at some point in the future in order for the Valmy units to operate out until the end of 2049. (*Id.*) Staff states that NV Energy has acknowledged that it has no specific details regarding these upgrades and when they will be needed. (*Id.*) Staff therefore states that if and when additional Valmy capital expenditures are needed, those projects can either be included in a future IRP filing or presented after they are done in a general rate case proceeding. (*Id.*)

**NV Energy's Rebuttal**

188. NV Energy disagrees with the recommendation to order a fresh solicitation targeted to the Valmy need. (Ex. 138 at 8.) NV Energy states that a fresh solicitation for different projects at Valmy would make it impossible to retire Valmy coal generation on time and would extend the life of coal. (*Id.*)

189. NV Energy disagrees that continued operations capital should not be approved at this time. (Ex. 133 at 3-4.) NV Energy explains that as a unit approaches its retirement date, less investment is made in the unit and the O&M strategy shifts from investing in the long-term operations of the units to only completing the maintenance and capital projects necessary for a unit to run to its retirement date. (*Id.* at 4.) NV Energy states that the Valmy units have seen

their major outages delayed since it did not make sense to complete significant outages with only a few years of operations left. (*Id.*) NV Energy states that its generation engineering team conducted a detailed survey of the Valmy plant records and interviewed plant personnel to identify the projects needed to operate the units past 2025. (*Id.* at 5.) NV Energy explains that these projects are those that would normally have been completed during the planned outages that were postponed or canceled due to the impending retirement of the units. (*Id.*) NV Energy states that the units could feasibly operate beyond 2025, but safe and reliable operations would be a great concern without the completion of these projects. (*Id.*) NV Energy states that it included the continued operations projects in the LSAP analysis because they provide a complete picture of the cost to continuing to operate these units beyond their currently approved retirement date as the conversion and emissions controls projects are not the only costs that would be incurred to operate these units until 2049. (*Id.* at 6.)

190. NV Energy states that, if the Commission agrees with Staff and BCP's recommendation to deny the continuing operations capital projects spending, NV Energy recommends that the Commission approve its request to continue operations of the Valmy Units 1 and 2 beyond their currently planned retirement date of 2025, and amend the Supply Plan to operate the units through 2049 by converting them to operate on natural gas and add emissions controls, at a cost of up to $50.43 million (SPPC's 50 percent share), because the Commission will have the opportunity to review the prudency of the investments for the natural gas conversion, emissions controls, and continuing operations capital in future general rate cases. (Ex. 133 at 24-25; Ex. 132 at 4.)

191. NV Energy explains that SCRs were used for planning purposes, understanding the final selection of NOx controls will be determined as part of updates to the Regional Haze

Analysis, Federal Good Neighbor Plan, and permitting. (Ex. 132 at 3.) NV Energy states that SCRs were selected for planning purposes as they would be the most stringent control evaluated under Regional Haze for Valmy. (*Id.*)

192. NV Energy states that the final determination of suitable controls under the Regional Haze Rule will be assessed through an updated four-factor analysis for both Valmy Units, in which both SNCR and SCR will be evaluated. (Ex. 132 at 6.) NV Energy states that NDEP will select the appropriate level of controls considering cost effectiveness with respect to the Regional Haze Rule and incorporate those into the SIP for Regional Haze for Environmental Protection Agency ("EPA") approval. (*Id.*) NV Energy notes that the installation of SNCRs on the Valmy Units would limit operation under the Federal Good Neighbor Plan, if implemented, during the ozone season as NOx allowances would be based on unit operations and a NOx emissions rate commensurate with SCRs. (*Id.* at 7.)

193. NV Energy states that the various individual components proposed by AEU could not form a complete solution to the Valmy retirement. (Ex. 137 at 12.) NV Energy states that the majority of options presented by AEU do not provide voltage support and available around-the-clock generation requirements in the Carlin Trend load pocket after Greenlink West is in service. (*Id.*) NV Energy states that options that that could not accommodate potentially recurring generation needs in this location, as discussed in the Transmission Section of the narrative were not evaluated. (*Id.*)

194. NV Energy states that the Valmy LSAP analysis does not provide only summary metrics of the economic analysis. (Ex. 137 at 10.) NV Energy notes that for each scenario evaluated in the Valmy LSAP, the summary of production cost output for the economic analyses are provided in Technical Appendix ECON-4, the Loads and Resources tables are provided in

Technical Appendix ECON-5, the capital projects are presented in Technical Appendix ECON-6, and the present worth of revenue requirement is provided in Technical Appendix ECON-7. (*Id.*)

195. NV Energy disagrees that it did not provide sufficient analysis for the Valmy conversion project. (Ex. 133 at 7-8.) NV Energy explains that its LSAP analysis for the Valmy units is a Commission-approved process that has been used in this and previous filings to review retirement decisions for generating units and recommend either retirement or continued operation of NV Energy's generating units. (*Id.* at 8.) NV Energy describes the LSAP as a detailed economic analysis that examines the remaining economic useful life of a generating unit, examining the costs of continued operation versus the economic benefit derived from using the unit in its needed mode of operation. (*Id.*) NV Energy states that the LSAP showed that the conversion of the Valmy units to operate on natural gas is the best option that economically addresses the system support requirements. (*Id.* at 9.)

196. NV Energy disagrees with AEU's assertion that the Valmy conversion project cannot be meaningfully analyzed because the information regarding the proposed natural gas supply lateral had not been provided in the Joint Application. (Ex. 133 at 10.) NV Energy states that high level details regarding the gas supply were provided in the Joint Application and additional details were provided in response to data requests. (*Id.*)

197. NV Energy disagrees that the Valmy conversion project does not comply with explicit Commission directives regarding the Valmy retirement. (Ex. 133 at 10.) NV Energy states that the retirement of Valmy has always been aimed at eliminating coal generation from NV Energy's portfolio. (Ex. 138 at 7.) NV Energy states that, at no point was it stated that the retirement of the Valmy plant meant the removal of fossil generation from the Valmy location

forever. (*Id.*) NV Energy state that any long long-term planning solutions must balance emissions, reliability, and cost, and the Valmy conversion proposes a solution to significantly lower carbon emissions by retiring coal generation while ensuring continued reliability for the benefit of customers. (*Id.*)

198. NV Energy interprets the Commission's directive to be aimed at reducing emissions by ending coal-fired generation, not necessarily ending all fossil-fired generation at Valmy, while maintaining a reliable and economic electrical system in Nevada. (Ex. 133 at 11.) NV Energy points to previous Commission orders (in Docket Nos. 22-11032, 21-06001, and 21-06002) and the legislative mandates of SB 123 to highlight the interests in the elimination of coal-fired electric generation while still recognizing the importance of generation at the Valmy site to support system conditions. (*Id.* at 11-12.) NV Energy states that, even if the Commission's previous position was that the Valmy coal-fired generation should retire in 2025, the intent of the LSAP process is to regularly review the retirement decisions, so it is prudent for NV Energy and the Commission to review the decision at this time. (*Id.* at 13-14.)

199. NV Energy explains that its 2023 open resource RFP did not restrict any specific resource type, such as geothermal, nor resource location or point of interconnection. (Ex. 135 at 6.) NV Energy states, however, only one bid was received for a geothermal portfolio resource with no projects in the Valmy region. (*Id.*) NV Energy states that it will continue to pursue geothermal resources and will continue to put forth good faith efforts in renegotiating geothermal PPAs that are set to expire throughout the planning period. (*Id.*) NV Energy states that, regardless of these efforts, these resources are either not in the same region as Valmy or not to scale in time to support the December 31, 2025, Valmy coal retirement date. (*Id.*)

200. NV Energy disagrees with the concerns raised by SNGG and CMN pertaining to the supply of natural gas for the operation of Valmy following the Valmy conversion. (Ex. 133 at 2, 14.) NV Energy states that it has executed precedent agreements with Ruby Pipeline Ruby Pipeline and Pinyon Pipeline. (*Id.* at 15.) NV Energy provides that these agreements state that Ruby Pipeline and Pinyon Pipeline will make reasonable efforts to obtain any required permits or prior authorization to site, construct, place into service, maintain, or operate the new pipeline facilities and prior to the facilities' in-service date NV Energy will execute TSAs with Ruby Pipeline and Pinyon Pipeline. (*Id.*) NV Energy states that Pinyon Pipeline requested approval to build the new lateral by filing a Certificate of Public Convenience and Necessity with the Commission on December 29, 2023. (*Id.*) NV Energy notes that its natural gas procurement strategy would remain unchanged due to the addition of Valmy. (Ex. 138 at 5.) NV Energy states that all costs related to the Valmy conversion, including costs associated with the new Ruby Pipeline lateral, were included as a part of the modeling results that were put forth in the filing. (*Id.* at 8.)

201. NV Energy rejects WRA's claim that NV Energy has used an incorrect heat rate in the Valmy gas conversion estimate. (Ex. 133 at 2.) NV Energy states that the heat rate curve was not changed because the design for the converted units is not available until an engineering design is completed. (*Id.* at 18.) NV Energy states that it is reasonable to assume that the units will operate similarly after they are converted to operate on natural gas, and the heat rate will not change dramatically when the Valmy units are converted. (*Id.* at 18, 19.) NV Energy provides that NV Energy analyzed the best generation options for the Valmy conversion after the LSAP process. (*Id.* at 19.) NV Energy explains that NV Energy used the best available information when evaluating the conversion options and took into consideration updates to transmission

topology, retail and unbundled customers' load growth, and market conditions. (*Id.* at 19-20.) NV Energy states that a delay in the approval of a Valmy solution could necessitate the continued use of coal at Valmy or else jeopardize the continued reliable operation of the northern system. (*Id.* at 20.)

202. NV Energy disagrees with Sierra Club and explains that its LSAP process is adequate, reasonable, and reliable when analyzing and comparing Valmy retirement options. (Ex. 133 at 21.) NV Energy provides that the Valmy LSAP analysis only included scenarios that addressed the transmission system needs identified in the Transmission Section of the narrative, with the exception of the scenario that replaced Valmy with Hot Pot for illustrative purposes, despite the fact that this scenario cannot reliably provide transmission support in all hours if generation is required after Valmy is retired. (*Id.*) NV Energy provides that it did assess the transmission system requirements prior to creating the Valmy LSAP scenarios, despite Sierra Club stating that NV Energy did not. (*Id.*) NV Energy states that the LSAP process has proven valuable in examining the changing system and environmental regulations conditions because when one of the triggering events occur, such as system operating requirements, a new LSAP is completed. (*Id.*)

203. NV Energy disagrees that the Valmy analysis should be updated to consider making investment in only one Valmy unit because the need for both Valmy units has already been evaluated. (Ex. 134 at 10.) NV Energy states that when the Newmont TSPP is not online, both Valmy units must be in Reliability Must Run status. (*Id.*)

204. NV Energy also disagrees with Sierra Club's two recommendations to retire one Valmy unit in 2025 or put one unit in standby and to install SNCR instead of SCR. (Ex. 133 at 22.) NV Energy explains that if one unit is retired, the units can no longer support the system

contingencies during any kind of outage or if the one remaining unit trips offline. (*Id.*) NV Energy further explains that the standby unit would not meet the Good Neighbor rule requirements because it would still operate on coal if it was called out of standby mode and in turn would exceed acceptable emission limits. (*Id.*) NV Energy states that there would be increased costs and issues with maintaining a standby Valmy unit that is not expected to normally operate. (*Id.*) NV Energy explains that installation of an SNCR may only allow limited operating hours during the ozone season under the Good Neighbor Rule regulations and that summer operation of these units could be critical for these units to support customer needs for energy when solar and renewables are not available and, if operating hours are limited, these units would not be available to support the customers. (*Id.* at 22-23.) NV Energy provides that using SCR installation at Valmy was the most cost conservative scenario and final determination of the required environmental controls will be made through updates to the Regional Haze Rule permitting. (*Id.* at 23.)

205. NV Energy disagrees that Valmy generation is only needed for reliability in the Carlin Trend load pocket before Greenlink West and Greenlink North are in service. (Ex. 134 at 8.) NV Energy states that the need for generation and/or reactive support in the Carlin Trend area will depend on the amount of load growth that occurs in northern Nevada and how the transmission system is loaded after the Greenlink projects are in service. (*Id.*)

206. NV Energy states that, while the Valmy conversion project will provide critical voltage control support in the short term, Sierra Club fails to discuss the long-term value of the capacity and energy that would be made available from the project. (Ex. 138 at 9.) NV Energy explains that it is facing a significant capacity shortfall and are working to reduce their open

position as required for participation in WRAP, a future day-ahead market, and/or a future regional transmission organization ("RTO"). (*Id.* at 9-10.)

**Commission Discussion and Findings**

207. The Commission approves NV Energy's request to repower Valmy from coal to natural gas, to continue operations of Valmy units 1 and 2 beyond their currently-planned retirement date of 2025, and to amend the Supply Plan to operate the units through 2049 by converting the Valmy units to operate on natural gas and add emissions controls. However, the Commission does not approve the $83 million amount requested because the actual cost estimate to convert Valmy to natural gas and to install the required SCR is only $50.43 million. The Commission approves $50.43 million to convert Valmy to natural gas.

208. The Commission disagrees with recommendations to order a fresh solicitation targeted to Valmy, as a fresh solicitation for different projects at Valmy would make it impossible to retire Valmy coal generation on time and would extend the life of coal.

209. The Commission finds that the Carlin Trend load pocket constraint is a real condition and so is the must-run requirement on the generators located in that load pocket. As Staff points out, in the three near-miss years out of the last four years (2020, 2021, and 2022), NV Energy was on the verge of having to declare a system emergency and potentially curtail loads during the peak summer months because of available capacity concerns. Therefore, the Commission finds that retiring any existing internal generation capacity that helped avoid those load curtailments is a risky endeavor, especially given the load growth NV Energy is experiencing and the delays NV Energy has seen with previously-contracted renewable energy resources coming on-line. WECC and NERC have issued reports that warn of resource adequacy issues across the Western United States, particularly in the summer months. The

Commission finds that, without Valmy, there is a high probability Nevada would have experienced rolling blackouts three out of the last four years. The Commission finds that, for reliability reasons, NV Energy needs to be able to operate Valmy to maintain available capacity and meet summer demand. NV Energy has also committed itself to High Voltage Distribution agreements as well as WRAP requirements that will require the production of Valmy to satisfy.

210. The Commission finds that the load pocket constraint NV Energy has outlined is likely to improve in the future such that Valmy may not need to be run as much as NV Energy is alluding to in this filing, as outlined by Staff. The Commission finds that additional resources in the Carlin Trend load pocket will be added tools that will allow Valmy to operate less during non-peak load periods. Furthermore, the partnership with Idaho Power Company in Valmy will allow NV Energy to use Idaho Power Company running its half of Valmy to aid with the local reliability situation in the Carlin Trend versus NV Energy always needing to run its share of the two units.

211. The Commission reiterates Staff's point that NV Energy is forecasting to spend between $5 and $10 billion on renewable energy projects over the next five to seven years, and accessing the existing Valmy units 1 & 2 resources is beneficial to keep customer rates in a reasonable and affordable range.

212. Importantly, the Commission highlights that converting the coal units to natural gas provides an immediate 50 percent reduction in carbon. Additionally, with the retirement date extended until 2049, the coal-to-gas conversion does not affect Nevada's goal of achieving its net-zero carbon goal by 2050. While NV Energy is requesting approval of natural gas, NV Energy is not deviating from its clean energy goals.

213. The Commission finds that, per the new transmission study, there is a need not only for voltage support for the Carlin Trend area, but also the availability of around-the-clock generation without runtime limitations to be located at or near Valmy. Because a firm dispatchable resource is needed to resolve the Carlin Trend load pocket's post contingency voltage issues, an intermittent resource such as a solar/BESS pairing would not suffice, nor would a stand-alone BESS, as it does not have sufficient output duration by itself to support the Carlin Trend area. While the transmission study shows that when Greenlink West is completed the continued must-run at Valmy will no longer be required, there will likely still be periods when generation is required as loads continue to increase in northern Nevada. As NV Energy notes, this leaves two feasible options to support the retirement of coal generation at Valmy and to support the continuing need for a firm dispatchable resource: the refueling of Valmy to burn natural gas, or the construction of new natural gas-fired peaking units at the Valmy site. The Commission finds that the refuel option is approximately $270 million lower than the peaking units and would allow NV Energy to eliminate coal combustion from its fleet by the end of 2025.

214. Going forward and to continue to look towards decarbonization, the Commission desires to receive updates regarding the potential for geothermal resources in the Valmy region. In the latest RFP, only one bid was received for a geothermal portfolio resource with no projects in the Valmy region. However, NV Energy states that it will continue to pursue geothermal resources and will continue to put forth good-faith efforts in renegotiating geothermal PPAs that are set to expire throughout the planning period. As a directive, the Commission asks for updates regarding geothermal resources in the Valmy region.

215. The cost estimate to convert the Valmy units to natural gas and install the SCR pollution control equipment is $100.846 million, with NV Energy's cost share being $50.43

million. The Commission approves NV Energy's cost share at $50.43 million. The Commission finds that the remaining amount requested by NV Energy, for "capital projects for continued operation," is just a placeholder amount associated with upgrades that may be needed at some point in the future in order for Valmy to operate out until the end of 2049. NV Energy has acknowledged that it has no specific details regarding these upgrades and when they will be needed. If and when additional Valmy capital expenditures are needed, those projects can either be included in a future IRP filing or presented in a general rate case proceeding once they have been completed and placed in service.

216. Regarding the use of SCRs and NOx controls, the Commission finds that NV Energy used SCRs used for planning purposes for Valmy, understanding the final selection of NOx controls will be determined as part of updates to the Regional Haze Analysis, Federal Good Neighbor Plan, and permitting. SCRs were selected for planning purposes as they would be the most stringent control evaluated under Regional Haze for Valmy. The final determination of suitable controls under the Regional Haze Rule will be assessed through an updated four-factor analysis for both Valmy units, in which both SNCR and SCR will be evaluated. NDEP will select the appropriate level of controls considering cost effectiveness with respect to the Regional Haze Rule and incorporate those into the SIP for Regional Haze for EPA approval.

217. Regarding the Valmy LSAP, the Commission finds that the Valmy LSAP analysis does not provide only summary metrics of the economic analysis. The Commission notes that, for each scenario evaluated in the Valmy LSAP, the summary of production cost output for the economic analyses are provided in Technical Appendix ECON-4, the Loads and Resources tables are provided in Technical Appendix ECON-5, the capital projects are presented in Technical Appendix ECON-6, and the PWRR is provided in Technical Appendix ECON-7.

The Commission finds that the LSAP showed that the conversion of Valmy to operate on natural gas is the best option that economically addresses the system support requirements.

218. Regarding the supply of natural gas to Valmy, the Commission disagrees with the concerns raised by SNGG and CMN pertaining to the supply of natural gas for the operation of Valmy following the Valmy conversion. NV Energy has executed precedent agreements with Ruby Pipeline and Pinyon Pipeline, and these agreements state that Ruby Pipeline and Pinyon Pipeline will make reasonable efforts to obtain any required permits or prior authorization to site, construct, place into service, maintain, or operate the new pipeline facilities and prior to the facilities' in-service date NV Energy will execute TSAs with Ruby Pipeline and Pinyon Pipeline. Pinyon Pipeline requested approval to build the new lateral by filing a Certificate of Public Convenience and Necessity with the Commission on December 29, 2023. The Commission notes that NV Energy's natural gas procurement strategy will remain unchanged due to the addition of Valmy.

219. The Commission disagrees with Sierra Club that the Valmy analysis should be updated to consider making investment in only one Valmy unit because the need for both Valmy units has already been evaluated. When the Newmont TSPP is not online, both Valmy units must be in Reliability Must Run status. The Commission also disagrees with Sierra Club's recommendations to retire one Valmy unit in 2025 or put one unit in standby and to install SNCR instead of SCR. If one unit is retired, the units can no longer support the system contingencies during any kind of outage or if the one remaining unit trips offline. Furthermore, the standby unit would not meet the Good Neighbor rule requirements because it would still operate on coal if it was called out of standby mode and in turn would exceed acceptable emission limits. There would also be increased costs and issues with maintaining a standby

Valmy unit that is not expected to normally operate. Furthermore, installation of an SNCR may only allow limited operating hours during the ozone season under the Good Neighbor Rule regulations and summer operation of these units could be critical for these units to support customer needs for energy.

**ii. Regulatory Asset Treatment**

**NV Energy's Position**

220. NV Energy requests approval to amend its Generation Plan for regulatory asset treatment of the decommissioning of coal and coal combustion residuals operations at Valmy. (Ex. 100 at 16.)

221. NV Energy states that the costs for the retirement of coal operations at Valmy are not included in the project costs presented above and would be collected and recovered through a regulatory asset similar to the retirement of other coal facilities within NV Energy's fleet. (Ex. 100 at 62.) NV Energy explains that the undepreciated net book value ("NBV") for assets that are retired, and the related stranded inventory will also be included in the regulatory asset account. (*Id.*)

**SNGG and CMN's Position**

222. SNGG and CMN state that NV Energy must demonstrate that it has a viable dispatchable and firm resource to replace the Valmy resource before it is allowed to remove the coal-related cost from plant-in-service and record it in a regulatory asset. (Ex. 700 at 17.) SNGG and CMN state that it is not opposed to NV Energy's request for this regulatory asset, if NV Energy demonstrates that the coal retirement is prudent (*Id.*) However, SNGG and CMN state that there should be no return on the remaining net book value component of the regulatory asset, consistent with prior Commission orders. (*Id.*) SNGG and CMN state that, in addition, to the

extent that retirement of the coal-related facilities does not coincide with the implementation of new rates from a future general rate case, then a regulatory liability should be established to track Valmy coal-related costs that are included in customer rates, but that will be avoided after retirement of the coal resource. (*Id.*) SNGG and CMN state that these would include non-fuel O&M expenses, depreciation expense, property taxes, and working capital (coal inventory and material and supplies. (*Id.* at 17-18.) SNGG and CMN state that this regulatory liability should be used to offer the regulatory asset balance that would need to be recovered from customers. (*Id.* at 18.)

**Staff's Position**

223. Staff recommends that the Commission approve NV Energy's request for regulatory asset treatment for the retirement and decommissioning of Valmy coal assets with appropriate offsets. (Ex. 306 at 9.) Staff states that, as part of the Valmy conversion, SPPC will retire assets currently in service at Valmy that would not be needed or useful after the conversion, and SPPC is requesting that the NBV and decommissioning/removal cost be recorded in a regulatory asset account for recovery in a future general rate case. (*Id.*) Staff agrees with this request but recommends that the Commission require that the NBV placed into the regulatory asset at the time of retirement continue to amortize by the currently authorized depreciation rate throughout the rate effective period. (*Id.* at 10.)

224. Staff states that, if the NBV does not amortize, SPPC will in effect over-collect depreciation expense in revenue. (Ex. 306 at 10.) Staff explains that when Valmy assets are retired, they will no longer depreciate for accounting purposes, however, ratepayers would still be paying rates based on the full depreciation of the Valmy assets until new rates are set in a general rate case. (*Id.*)

225. Staff also states that, to the extent current O&M is no longer required, there should be some level of O&M credit in the regulatory asset account, or a separate regulatory liability account set up to reflect those costs that are no longer required. (Ex. 306 at 10.) Staff explains that there should also be some level of O&M expense that would cease to occur once the coal operations have ended though ratepayers would still be paying those expenses as part of the current rates. (*Id.*) Staff states, additionally, SPPC currently records some costs related to coal handling, including maintenance, in its deferred accounts that are recovered through the BTER; Staff states that these costs should not now become general rate costs and recorded in a regulatory asset account during this transition period. (*Id.*)

**NV Energy's Rebuttal**

226. NV Energy disagrees that there will be some level of O&M that would no longer occur and therefore be credited in the regulatory asset account. (Ex. 139 at 15.) NV Energy sates that, while Valmy will not be operating as a coal plant anymore, it will still be operating and, therefore, will still incur O&M costs. (*Id.* at 15.) NV Energy explains that if the O&M level related to Valmy was credited into the regulatory asset, SPPC would not be able to recover the O&M costs for Valmy as it transitions to natural gas. (*Id.*)

227. NV Energy also disagrees that a regulatory liability should be established for coal related costs that are in rates, such as non-fuel O&M, depreciation, property taxes, and working capital. (Ex. 139 at 16.) NV Energy states that this recommendation ignores the fact that there will still be ongoing costs at the facility as it relates to non-fuel expense, such as O&M, property taxes, working capital, and even depreciation. (*Id.*) NV Energy states that the depreciation should remain in rates and not be credited to the regulatory asset to help offset the regulatory lag for depreciation of the additional capital investment that will be spent to convert the facilities to

natural gas. (*Id.*). NV Energy explains that NV Energy's proposal is to move the NBV of the non-continuing coal related items to the regulatory asset as well as any decommissioning costs. (*Id.*) NV Energy states that there is no need to move any other costs as it will represent the ongoing costs the of natural gas facility as there will still be O&M, property tax, depreciation, and working capital for the ongoing facility. (*Id.*)

**Commission Discussion and Findings**

228. The Commission approves NV Energy's request for regulatory asset treatment for the retirement and decommissioning of Valmy coal assets with appropriate offsets, as recommended by Staff. As part of the Valmy conversion, SPPC will retire assets currently in service at the Valmy site that would not be needed or useful after the conversion, and SPPC is requesting that the NBV and decommissioning/removal cost be recorded in a regulatory asset account for recovery in a future general rate case. The Commission approves this request but also requires that the NBV placed into the regulatory asset at the time of retirement continue to be amortized by the currently authorized depreciation rate throughout the rate effective period.

229. The Commission finds that, if the NBV does not amortize, SPPC will in effect over-collect depreciation expense in revenue. When Valmy assets are retired, they will no longer depreciate for accounting purposes, however, ratepayers would still be paying rates based on the full depreciation of the Valmy assets until new rates are set in a general rate case.

230. Furthermore, the Commission finds that, to the extent current O&M is no longer required, there should be some level of O&M credit in the regulatory asset account, or a separate regulatory liability account set up to reflect those costs that are no longer required. The Commission finds that there will be some level of O&M expense that will cease to occur once the coal operations have ended though ratepayers would still be paying those expenses as part of

the current rates. Additionally, SPPC currently records some costs related to coal handling, including maintenance, in its deferred accounts that are recovered through the BTER these costs should not now become general rate costs and recorded in a regulatory asset account during this transition period.

**D. Tracy 4/5**

**NV Energy's Position**

231. NV Energy requests approval for the continued operation of Tracy 4/5 through 2049 and approval of $54 million in capital expenditures necessary for the continued operation of the units. NV Energy states that its LSAP determined it was economically prudent to continue operation of the Tracy 4/5 beyond their current 2031 retirement date, through 2049, with the required installation of an SCR system. (Ex. 100 at 63.) NV Energy states that operation beyond 2031 would also require capital investment for continued operation. (*Id.*)

232. NV Energy states that the LSAP analysis assumes that the SCR would be installed and operational in 2027. (Ex. 100 at 63.) NV Energy explains that, although major project costs would not be incurred until after the Action Plan period of the 2021 IRP, SPPC is requesting approval of the permitting and analysis costs for the continued operation of the units, such that modification to the SIP and subsequent revisions to the Title V air permit can commence. (*Id.*)

233. NV Energy states that the total cost of the Tracy 4/5 SCR project is estimated at $54 million, without AFUDC. (Ex. 100 at 64.) NV Energy states that the project costs are estimated at this time since the engineering and design would not begin until after the permitting and modification to the SIP are completed. (*Id.*) NV Energy states that much of the continuing operations capital was modeled to occur during a 2031 major outage on the unit, but these costs could be completed during an earlier outage if necessary. (*Id.*)

234. NV Energy states that, under the Regional Haze Rule, NDEP revised Tracy's Title V permit to include the legally enforceable retirement date for Tracy 4/5 of December 31, 2031, and filed the SIP addressing the specific elements required in the Regional Haze Rule with the EPA in August 2022. (Ex. 113 at 6.) NV Energy states that proceeding with revaluating Tracy 4/5 assuming continued operations and installation of NOx controls, subject to SIP revision and permit modification, would allow for compliance with the Regional Haze Rule. (*Id.* at 6-7.) NV Energy states that it is engaging NDEP to amend the SIP for regional haze and Title V permit for Tracy 4/5 to allow for continued operation with NOx controls. (*Id.* at 7.)

**Interwest's Position**

235. Interwest recommends that NV Energy change its approach to modeling to allow for its capacity expansion models to identify opportunities for new resources to displace existing resources and provide for their economic retirement. (Ex. 900 at 38.) Interwest states that if they were to be implemented it would be appropriate to apply that type of analysis to the question of whether investments to extend the operating life of Tracy 4/5 are economic given other available resources considered in the capacity expansion planning model. (*Id.*) Interwest states that such analyses would be even better if informed by the results of predictable resource procurements attracting diverse bid portfolios that offer alternatives to the continued operation of existing plants like Tracy 4/5. (*Id.*)

**Sierra Club's Position**

236. Sierra Club recommends that the Commission reject NV Energy's Joint Application as it pertains to SCR installation at Tracy 4/5 and continued operation of those units through 2049 because the marginal benefits shown do not outweigh the increased carbon emissions and associated risks of a significant investment in Tracy 4/5. (Ex. 1400 at 29.) Sierra

Club states that NV Energy has not demonstrated that it is in the best interest of ratepayers to install SCR at Tracy 4/5 at this time, nor to extend the 27-year-old units' operating lives to 2049. (*Id.*)

237. Sierra Club states that there is no urgent need to install SCR because NV Energy can meet Good Neighbor Plan requirements at Tracy 4/5 through reduced dispatch or installation of much less expensive SNCR technology; either approach would avoid a significant capital outlay of $12 million for SCR. (Ex. 1400 at 29.) Sierra Club provides that NV Energy's previous planned retirement date for Tracy 4/5 coincides with the EPA's Clean Air Act Title V air quality permit, which imposes a federally enforceable retirement date of December 31, 2031. (*Id.* at 26.) Sierra Club notes that extending the retirement date to 2049 is 18 years beyond the previously planned 2031 retirement date. (*Id.*) Sierra Club states that with a 2031 planned retirement date, there is plenty of time for NV Energy to carefully consider this decision and observe whether the units' economic considerations improve or decline. (*Id.* at 29.) Sierra Club states that, regarding the Nevada Regional Haze Program, NV Energy has the option of including a plan for reduced dispatch and/or SNCR installation at Tracy 4/5 in an amended SIP or retiring the Tracy 4/5 in 2031 as currently required. (*Id.*)

238. Sierra Club states that the economic analysis of SCR installation and operation of Tracy 4/5 through 2049 shows a marginally expected benefit. (Ex. 1400 at 4.) Sierra Club provides the expected cost of SCR installation at Tracy 4/5 is $12 million, and the expected cost of capital expenditures for continuing operation through 2049 is $41.5 million. (*Id.* at 26.) Sierra Club states that the Tracy 4/5 LSAP considers only two scenarios: retirement of Tracy 4/5 in 2031 or continued operation through 2049 with SCR installation. (*Id.* at 27.) Sierra Club notes that the study indicates that installing SCR and running the units through 2049 is marginally less

expensive than retiring Tracy 4/5 in December 2031. (*Id.* at 26.) Sierra Club states that installing SCR at Tracy 4/5 at this time is unnecessary and risky because of the marginal economics of keeping the units online. (*Id.* at 28.) Sierra Club states that if SCR is installed as planned, and then additional unexpected expenses occur or gas prices increase more than expected, it will be too late to avoid the cost of SCR installation and save that money for ratepayers by retiring Tracy 4/5 in 2031 as initially planned. (*Id.*) Sierra Club also notes that should the economics of the units tilt strongly in favor of retirement after the installation of SCR, the cost of the SCR would become a stranded asset potentially borne by ratepayers. (*Id.*) Sierra Club provides that additional expenses could also occur because of the age of the 27-year-old plant, or because of future carbon regulation. (*Id.*) Sierra Club states that customers will be more likely to benefit from investments in new, clean generation instead of investment in an older combined cycle generator that is nearing the end of its design life. (*Id.*)

**BCP's Position**

239. BCP recommends the Commission approve NV Energy's request to accommodate the continued operation of Tracy 4/5 through 2049 because it is a benefit to ratepayers. (Ex. 400 at 2, 3.) BCP states that the continued operation of Tracy 4/5 is both a financial benefit and a benefit because of the certainty of a company owned and operated resource relative to volatile market purchases. (*Id.* at 3.) BCP recommends the Commission deny NV Energy's request to expend approximately $54 million for compliance with environmental regulations to enable the continued operation of Tracy 4/5 past 2031 and only approve the $12 million required for SCR installation because this project would remove the legal barrier to Tracy 4/5's continued operation beyond December 2031. (*Id.* at 3, 4.) BCP states that the other nine projects related to reliability and performance are not necessary at this time

because the 2027 date is arbitrary and is not based upon physical inspection of the unit, nor does NV Energy provide a business case explaining why performing these projects in 2027 is a benefit to ratepayers. (*Id.* at 4-5.)

**Staff's Position**

240. Staff recommends that the Commission approve NV Energy's request for the continued operation of Tracy 4/5 in Prayer for Relief item 2(c)(i) but approve only approximately $12 million of the $54 million NV Energy requests in Prayer for Relief item 2(c)(ii). (Ex. 305 at 1.)

241. Staff states that it is necessary for NV Energy to continue to have all of its conventional generation fleet available, including Tracy 4/5. (Ex. 305 at 3.) Staff notes that NV Energy has experienced resource adequacy "close calls" three out of the last four summer peak load seasons, which shows the usefulness of internal generation capacity. (*Id.* at 3-5.)

242. Staff additionally states that the continued operation of Tracy 4/5 is a crucial component of efforts to maintain reliable service while continuing to work towards Nevada's 2030 RPS requirement and towards Nevada's goal of zero net carbon by 2050. (Ex. 305 at 5.) Staff states that, as Nevada moves towards its net zero goal and as the amount of electricity generated from conventional sources declines, it is important to maintain al of the conventional capacity Nevada has as an insurance policy against the inevitable hiccups that will be experienced. (*Id.*) Staff notes that, while there are many possible pathways to net zero carbon emissions, the most prudent pathway is a balanced approach that prioritizes an orderly transition while also aiming to preserve enough capacity to assure grid reliability and resource adequacy. (*Id.* at 6.) Staff states that, if a prudent, orderly transition is pursued, net zero carbon will be

achieved by 2050, without reliability issues or NV Energy having to curtail loads due to a lack of resources. (*Id.*)

243. Additionally, Staff finds that the continued operation of Tracy 4/5 fits within a reliable framework towards achieving net zero carbon without loss of load because: the Tracy 4/5 unit is an efficient unit that produces relatively low-cost electricity; NV Energy's request includes the installation of an SCR onto the combustion turbine which will reduce the unit's emissions; the Tracy 4/5 is connected to the grid immediately adjacent to northern Nevada's fastest growing industrial load pocket, the Tahoe Reno Industrial Center; and the continued operation will protect against potential unforeseen weather events or setbacks in the development of new renewable resources. (Ex. 305 at 7-9.)

244. Staff supports NV Energy's request for approximately $12 million for the installation of an SCR to reduce the emissions of the Tracy 4/5, however, Staff recommends that the Commission deny any other requested Tracy 4/5 investments (amounting to approximately $42 million), as they are not properly supported by NV Energy in the Joint Application. (Ex. 305 at 9.) Staff states that NV Energy's Joint Application (in technical appendix GEN-4) merely names projects and lists dollar amounts with no further support for these projects. (*Id.*) Staff further states that, upon request for an engineering and economic perspective justifying the projects, NV Energy responded that those analyses had not been completed and would be performed in the future. (*Id.*) Staff states that, without detailed support and justification at this stage, NV Energy is seeking a "blank prudency check" for these projects going into the next general rate case which will subvert the proper assessment and procedure for evaluating these projects. (*Id.* at 9-10.)

**NV Energy's Rebuttal**

245. NV Energy disagrees that continued operations capital should not be approved at this time. (Ex. 133 at 3-4.) NV Energy explains that as a unit approaches its retirement date, less investment is made in the unit and the O&M strategy shifts from investing in the long-term operations of the units to only completing the maintenance and capital projects necessary for a unit to run to its retirement date. (*Id.* at 4.) NV Energy states that for Tracy 4/5, NV Energy listed nine major projects that it expects to be needed to continue operating beyond 2031. (*Id.* at 4.) NV Energy explains that most of these projects would be scheduled for the next planned turbine outage in 2027, since the only time this work could be completed is during an extended unit outage (*Id.*) NV Energy states that it included the continued operations projects in the LSAP analysis because they provide a complete picture of the cost to continuing to operate these units beyond their currently approved retirement date as the emissions controls projects are not the only costs that would be incurred to operate these units until 2049. (*Id.* at 6.)

246. NV Energy disagrees with Sierra Club's recommendation for the Commission to reject the Tracy 4/5 SCR installation due to inadequate analysis. (Ex. 133 at 2, 20.) NV Energy explains that NV Energy's LSAP process is adequate, reasonable, and reliable when analyzing and comparing whether to invest and continue operation of Tracy 4/5. (*Id.* at 21.)

247. NV Energy provides that it better for both ratepayers' and NV Energy's energy needs to invest in Tracy 4/5 because the LSAP was used to examine whether it is better to run Tracy 4/5 until 2031 and retire or invest in emissions controls and other projects. (Ex. 133 at 23.) NV Energy states that equipment such as SCR catalyst materials can have 18-24 month lead times and things like engineering and design are needed in advance of ordering in and installing SCRs, therefore, it takes longer than three months to install SCR. (*Id.* at 23-24.) NV Energy explains that timely approval of the Tracy 4/5 emission controls and continued operation projects

is also needed at this time to allow NDEP to revise the SIP for Regional Haze and complete the other permitting activities needed for ongoing operation of these units. (*Id.* at 24.) NV Energy provides that if the Commission denies the continuing operations capital project spending, then NV Energy recommends that the Commission approve NV Energy's request to continue Tracy 4/5 operations beyond its currently planned 2031 retirement date, and amend the supply side plan to operate Tracy 4/5 through 2049 by adding emissions controls, up to $12 million for Tracy 4/5, because the Commission will have the opportunity to review the prudency of the investments for the emissions controls and continuing operations capital in future general rate cases. (*Id.* at 24-25.)

248. NV Energy states that the Regional Haze Rule requires evaluation of emission controls to determine technical feasibility and cost effectiveness. (Ex. 132 at 8.) NV Energy states that the revised four factor analysis will re-assess the cost effectiveness of the two previously identified control options, Dry Low NOx ("DLN") combustion and SCR, based on continued operation. (*Id.*) NV Energy explains that SNCR was previously determined not to be a technically feasible control option for Tracy 4/5 during the original analysis and SCR was determined to be more cost-effective than DLN combustion. (*Id.*) NV Energy states that continued operation of Tracy 4/5 beyond 2031 will be contemplated in the amended four-factor analysis and NOx controls will require installation in a reasonable timeframe to be determined by NDEP. (*Id.*)

**Commission Discussion and Findings**

249. The Commission approves NV Energy's request to continue Tracy 4/5 operations beyond its currently planned 2031 retirement date and NV Energy's request to amend the supply

side plan to operate Tracy 4/5 through 2049 by adding up to $12 million for Tracy 4/5 emissions controls, as recommended by BCP and Staff.

250. The Commission finds that it is necessary for NV Energy to continue to have all of its conventional generation fleet available, including Tracy 4/5. NV Energy has experienced resource adequacy "close calls" three out of the last four summer peak load seasons, which shows the usefulness of internal generation capacity.

251. The Commission finds that, additionally, the continued operation of Tracy 4/5 is a crucial component of efforts to maintain reliable service while continuing to work towards Nevada's 2030 RPS requirement and towards Nevada's goal of zero net carbon by 2050. As Nevada moves towards its net zero goal and as the amount of electricity generated from conventional sources declines, it is important to maintain all of the conventional capacity Nevada has during the transition. While there are many possible pathways to net zero carbon emissions, the most prudent pathway is a balanced approach that prioritizes an orderly transition while also aiming to preserve enough capacity to assure grid reliability and resource adequacy. As Staff notes, if a prudent, orderly transition is pursued, net zero carbon will be achieved by 2050, without reliability issues or NV Energy having to curtail loads due to a lack of resources.

252. Additionally, the Commission finds that the continued operation of Tracy 4/5 fits within a reliable framework towards achieving net zero carbon without loss of load because of the following reasons: Tracy 4/5 is an efficient unit that produces relatively low-cost electricity; NV Energy's request includes the installation of an SCR onto the combustion turbine which will reduce Tracy 4/5's emissions; Tracy 4/5 is connected to the grid immediately adjacent to northern Nevada's fastest growing industrial load pocket, the Tahoe Reno Industrial Center; and

the continued operation will protect against potential unforeseen weather events or setbacks in the development of new renewable resources.

253. The Commission approves NV Energy's request for approximately $12 million for the installation of an SCR to reduce the emissions of Tracy 4/5, however, the Commission denies any other requested Tracy Unit 4/5 investments (amounting to approximately $42 million), as they are not properly supported by NV Energy in the Joint Application. NV Energy's Joint Application (in technical appendix GEN-4) merely names projects and lists dollar amounts with no further support for these projects. Furthermore, upon Staff's request for an engineering and economic perspective justifying the projects, NV Energy responded that those analyses had not been completed and would be performed in the future. The Commission finds that, without detailed support and justification at this stage, NV Energy is seeking a "blank prudency check" for these projects going into the next general rate case which will subvert the proper assessment and procedure for evaluating these projects.

**E. Crescent Valley Solar**

**NV Energy's Position**

254. NV Energy seeks approval to purchase development assets under an Asset Purchase Agreement ("APA") for future development of a 149 MW solar and 149 MW BESS project known as Crescent Valley Solar. (Ex. 100 at 69; Ex. 115 at 20.) NV Energy states that Crescent Valley Solar is located in SPPC's service territory, approximately 46 miles southeast from Valmy. (*Id.*) NV Energy states that the project site and the development APA consist of 1,280 acres on private land leased from two landowners, and is located in Lander County, Nevada. (*Id.*)

255. NV Energy states that it has been in negotiations with the developer to acquire the project assets and has reached an agreement on a purchase price. (Ex. 100 at 101.) NV Energy states that the APA was executed on May 26, 2023, and NV Energy is continuing their due diligence for the project development. (*Id.*) NV Energy states that, due to NV Energy's large open capacity position and anticipated customer load growth in its service territory, NV Energy is requesting approval to purchase the Crescent Valley Solar project assets at this time in order to secure the project when it became available. (*Id.*)

256. NV Energy states that it seeks approval to purchase development assets under an APA from Invenergy, LLC for several reasons, including:

a. The preferred plan in this IRP amendment filing identifies a need for 10,390 MW of BESS capacity with 16,580 MW of solar PV through 2050. Based on due diligence, NV Energy believes that up to 149 MW of solar PV and 149 MW of BESS capacity can be developed at the Crescent Valley site.

b. The LGIA has been executed for this site.

c. SPPC needs PECs.

d. The project development status is mature and therefore supports an earlier COD compared to a new project.

e. Crescent Valley supports NV Energy's renewables and storage self-development pipeline that helps support customer needs with the best value resources.

f. Market signals indicate that the project may be acquired by other interested parties if not acquired by NV Energy at this time.

g. Property values are expected to continue to increase through the remainder of 2023 and beyond.

(Ex. 115 at 20-21.)

257. NV Energy states that the Crescent Valley Solar project was bid in NV Energy's 2018 Fall Renewable Energy RFP, and again in NV Energy's 2022 Spring Renewable Energy RFP. (Ex. 115 at 22.)

258. NV Energy states that SPPC and Invenergy executed the APA in May 2023. (Ex. 115 at 22.) NV Energy states that the agreement is for the purchase of the project assets including all agreements and permits secured by Invenergy. (*Id.*) NV Energy states that, if the APA is approved, SPPC would become the project developer and complete any remaining development activities. (*Id.*) NV Energy states that the APA does not include, and NV Energy does not seek approval of, construction of the renewable and storage project itself. (*Id.*) NV Energy states that it would seek approval of the project in a later filing after completing further design, cost estimating and development activities and would provide in that filing, detailed project costs, performance and schedule. (*Id.*)

**AEU's Position**

259. AEU states that NV Energy's Joint Application should be rejected in its entirety or in part. (Ex. 500 at 5, 21.) AEU states that to the extent NV Energy includes any of the Joint Application's proposals in that 2024 IRP filing, the Commission should require NV Energy to provide all supporting information in that proceeding that is currently missing, including: 1) a complete alternative analysis; 2) a low carbon scenario; and 3) all relevant cost assumption information, including information regarding pipeline capital costs. (*Id.* at 4.) AEU states that if the Commission declines to reject this Joint Application in its entirety, it should reject just the generation and storage proposals in the Joint Application while allowing the transmission-related projects, including the Esmerelda and Amargosa substations and Apex Master Plan, to proceed. (*Id.* at 4, 21.)

260. AEU states that the Joint Application is deeply flawed because of the lack of recent and robust resource solicitations. (Ex. 500 at 18.) AEU claims that NV Energy is not building its proposals from a deep bench of potential projects. (*Id.*) AEU states that NV Energy

failed to deliver on its promises in the Fourth Amendment to the IRP, in which NV Energy stated that it was intending to bring forward more resources in a future amendment to address northern Nevada's need in addition to the ongoing capacity needs to improve resource adequacy statewide while employing IRA tax credits. (*Id.*)

**Interwest's Position**

261. Interwest states that NV Energy's request for authorization for its purchase of pre-development assets for its Crescent Valley Solar Project represents piecemeal acquisition that does not allow for robust participation and consideration of all possible options. (Ex. 900 at 38.)

**SNGG and CMN's Position**

262. SNGG and CMN recommend that the Commission deny approval of the APA at this time because NV Energy has not yet completed a detailed estimate of project costs, performance, and schedule, therefore, approval would be premature at this time. (Ex. 700 at 32.)

**BCP's Position**

263. BCP recommends that the Commission reject the APA for the Crescent Valley Solar project. (Ex. 402 at 4.) BCP notes the estimated costs associated with the future project are approximately $630 million and assumes SPPC owning 100 percent of the project rights, however, the COD has not been determined at this time. (*Id.* at 24-25.) BCP states that NV Energy is not compliant with the requirements of NAC 704.9489(1)(h) which requires that an action plan include the expected time for construction of project facilities including the major milestones of construction. (*Id.* at 25.) BCP states that the Crescent Valley APA is more appropriate as request in the June 2024 IRP, when the complete project description can be provided, including a more accurate cost estimate, construction schedule, and commercial operation date. (*Id.*)

**Staff's Position**

264. Staff recommends that the Commission deny NV Energy's request to expend the requested amount for the purchase of the Crescent Valley Solar project. (Ex. 307 at 10.) Staff acknowledges that NV Energy has an open position and will additionally require large additions of solar PV capacity and BESS capacity to maintain reliability, comply with the RPS, and achieve Nevada's 2050 clean energy goals. (*Id.* at 11-12.) Staff states, however, the Crescent Valley Solar project will not materially provide capacity to help close NV Energy's open position as it would only contribute approximately 28 MW from the solar PV and approximately 120 MW from the BESS of peak summer capacity. (*Id.* at 12.)

265. Staff states that if the Commission were to approve the Crescent Valley Solar project APA, the Commission would be put in a position of having to approve the entire Crescent Valley Solar project because NV Energy's expenditures thus far would have already been deemed prudent. (Ex. 307 at 12.) Staff states that if the Commission were to deny the Crescent Valley Solar project but approve the Crescent Valley Solar project APA, NV Energy would recover the costs of the APA from ratepayers without any corresponding benefit to ratepayers, unless NV Energy could sell Crescent Valley Solar's assets for more than they purchased them. (*Id.*) Staff states, therefore, NV Energy is, in a subtle way, requesting the Commission approval for the entire $630 million for the entirety of the project. (*Id.*) Staff notes that if the Commission does not approve the APA in this docket, NV Energy is able to terminate the APA. (*Id.*)

266. Staff states that NV Energy has other options, including the Sierra Solar project, the Amargosa Valley Solar Energy Zone, and private renewable energy developers, to meet the need that the Crescent Valley Solar project aims to fill. (Ex. 307 at 13-14.)

**NV Energy's Rebuttal**

267. NV Energy disagrees that the Crescent Valley APA should not be approved at this time. (Ex. 135 at 8.) NV Energy states that it plans to prepare a similar comparison to that included in Technical Appendix REN-5 for all project options being brought forward in the subsequent filing plus any PPA options from the most recent RFP. (*Id.* at 10.) NV Energy states that this should address intervener interests that the project(s) delivering best customer value are brought forward for the Commission's approval. (*Id.*)

268. NV Energy states that, if the Commission approves the Crescent Valley APA in this Joint Application, the Commission would not be required to approve the entire Crescent Valley project because NV Energy can pursue an APA divestment if the Commission does not approve the entire project in a subsequent filing. (Ex. 135 at 10.) NV Energy states, additionally, the Commission may issue a directive that the APA sales' upside would provide a benefit to the ratepayers without any downside impacting the customers. (*Id.*)

**Commission Discussion and Findings**

269. The Commission denies NV Energy's request to expend the requested amount for the Crescent Valley Solar project and rejects approval of the APA for the Crescent Valley Solar project. The Commission rejects approval of the Crescent Valley Solar project APA and expenses at this time because the Commission finds the Crescent Valley Solar project approval request premature at this point, considering NV Energy is going to file a full IRP in June in which NV Energy can bring forward the Crescent Valley Solar project for consideration as a part of the full IRP and not in piecemeal fashion in this Joint Application.

270. The Commission finds that the Crescent Valley Solar project differs from the Sierra Solar project for several reasons and is thus being treated differently by the Commission.

First, the Crescent Valley Solar project is in its nascency, as compared to the much further along Sierra Solar project. Second, the Commission is concerned that, by approving the Crescent Valley Solar project APA, the Commission would be put in a position of having to approve the entire Crescent Valley Solar project. Third, NV Energy can proceed with the Crescent Vallet Solar project without a prudency determination in this docket. NV Energy maintains that the APA is highly marketable (easy to divest) to other developers and that the land value will continue to increase. The Commission finds that NV Energy can enter the APA with very little risk and with the potential to make money if NV Energy divests without a prudency determination in this docket. NV Energy may bring the Crescent Valley Solar project back in the full IRP so as to be compared to other potential resources.

**F. Transmission Plan**

**NV Energy's Position**

271. NV Energy requests approval for network upgrades required to interconnect and deliver the Joint Application's Preferred Plan's new generation resources, fulfill interconnection and transmission service requests under the NV Energy Open Access Transmission Tariff, and meet load service obligations in a timely manner. (Ex. 100 at 110.) NV Energy states that the Sierra Solar project will require transmission network upgrades including a new collector substation called Lantern 345 kV substation. (Ex. 116 at 4.) NV Energy states that the new substation will be connected via a line fold of the existing Valmy-East Tracy 345 kV line #3422. (*Id.*) NV Energy states that the estimated cost for Lantern substation is $46.2 million. (*Id.*)

272. NV Energy states that the location of the Sierra Solar project is ideal to protect and enhance system reliability. (Ex. 116 at 5.) NV Energy states that this generation will be connected to the existing Valmy-East Tracy 345 kV line #3422 at the proposed Lantern

substation. (*Id.*) NV Energy states that the generation will be in close proximity to the Tahoe Reno Industrial Center, Fernley and Fallon areas which have experienced large amounts of load growth and are forecast to continue to see extensive load growth. (*Id.*) NV Energy states that having generation located close to the load reduces system losses and improves system reliability. (*Id.*)

273. NV Energy states that the Commission approved the construction of the Esmeralda and Amargosa 525 kV substations in Docket No. 20-07023. (Ex. 100 at 113.) NV Energy states that it has received numerous applications for interconnection on the Greenlink West, at Esmeralda substation totaling more than 9,900 MW (with 5,500 MW at 230 kV and 4,400 MW at 525 kV) and at Amargosa substation totaling 4,958 MW (with 1,408 MW at 230 kV and 3,550 MW at 525 kV). (*Id.*) NV Energy states that it is responsible for the cost of the 230 kV facilities required to interconnect the new generation with the various developers. (*Id.* at 113-114.) NV Energy states that, to minimize costs through economies of scale and accommodate timely interconnection of renewable resources, NV Energy proposes to aggregate the acquisition of construction services and long-lead equipment for the Greenlink West substation facilities' 525/230 kV transformers with the ongoing procurements. (*Id.* at 114.) NV Energy requests Commission approval to construct the Greenlink West substation facilities' two 525/230 kV transformers simultaneously with the 525 kV switching yards at each location. (*Id.*) NV Energy states that the lead times for transformers, breakers, insulators, and switches have nearly doubled over the past two years. (Ex. 116 at 6.) NV Energy states that postponing acquisition of long-lead equipment and construction of the 230 kV buildout would increase costs and delay interconnection of renewable resources two years or more. (*Id.*) NV Energy requests approval to amend its Transmission Plan to expend approximately $40 million to construct the

Amargosa 525/230 kV Transformers. (Ex. 100 at 16.) NV Energy requests approval to amend its Transmission Plan to expend approximately $56 million to construct the Esmeralda 525/230 kV Transformers. (*Id.*)

274. NV Energy states that NPC has received numerous applications for load service in the Apex area for warehousing, manufacturing, data centers, and mixed use. (Ex. 100 at 117.) NV Energy states that the Apex area has the potential for substantial load and generation growth. (Ex. 116 at 7.) NV Energy states that the City of North Las Vegas is collaborating with developers in the Apex area and the city is developing water and sewer projects as well as new roadways to aid in the economic growth of the area. (*Id.*) NV Energy explains that several potential load additions ranging from 15 MW to 460 MW have inquired about electric service in this location. (*Id.*) NV Energy states that, currently, there is no distribution capacity to accommodate these new loads. (*Id.*) NV Energy notes that the Apex Area Master Plan was strategically planned to allow multiple substations to be placed along a proposed 230 kV loop and phased in as load materializes. NV Energy states that, based on the current Rule 9 agreements that have been signed, it is necessary to start the Apex Central substation construction project as soon as possible to meet the customers' 2025 in-service dates. (Ex. 116 at 7.) NV Energy states that there is no distribution capacity remaining from the existing substations that could be allocated to these new distribution loads. (*Id.*) NV Energy requests approval to amend its Transmission Plan to expend approximately $62 million for Apex Central 230/12 kV Substation; to expend approximately $15 million for Apex East 230/12 kV Substation; to expend $0.22 million for Apex Southeast 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts; and to expend $0.17 million for

Apex Southwest 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts. (Ex. 100 at 16-17.)

**AEU's Position**

275. AEU states that the Commission should allow the transmission-related projects, including the Esmerelda and Amargosa substations and Apex Master Plan, to proceed. (Ex. 500 at 21.)

**BCP's Position**

276. BCP recommends the Commission administer the approval of the Esmeralda and Amargosa 525/230 kV transformer network upgrades as follows: (1) grant approval when it is demonstrated with a compliance filing that the approximate $96 million of project costs are securitized by executed LGIAs, and (2) AFUDC shall not accrue until such time this approval is granted. (Ex. 402 at 3-4.) BCP states that NV Energy has already committed expenditures towards the Esmeralda and Amargosa transformer projects without prior approval from the Commission by ordering breakers, disconnect switches, and transformers December, 2022, through May, 2023. (*Id.* at 28.) BCP notes that NV Energy is planning to aggregate the construction of the 525/230 kV transformer facilities with the Esmaralda and Amargosa substations to achieve construction cost synergies. (*Id.*) BCP states that although this course of action seems reasonable because the Commission has approved these substations as part of the Greenlink West project, requesting Commission approval after project funds have been expended is problematic in the regulatory process. (*Id.*) BCP states that a more reasonable solution would be for NV Energy to submit a compliance filing with the necessary executed LGIAs that securitize these network upgrades. (*Id.*)

**Staff's Position**

*Apex Area*

277. Staff recommends that the Commission approve NV Energy's request to amend the Transmission Plan with the following four expansions to the Apex Area Master Plan:

h. $61.385 million to construct necessary infrastructure for Apex Central 230/12 kV Substation;

i. $15.5 million to construct necessary infrastructure for Apex East 230/12 kV Substation;

j. $221,000 for Apex Southeast 230/12 kV Substation constraint and environmental studies, permitting and land acquisition efforts; and

k. $168,000 for Apex Southwest 230/12 kV Substation constraint and environmental studies, permitting and land acquisition efforts.

(Ex. 303 at 1-2.)

278. Staff states that, although it understands the growth potential for the Apex area and supports the proposed projects, Staff has not seen NV Energy optimally coordinating the electrical infrastructure investments in these master plan areas with the customers' loads infrastructure that are being developed concurrently. (Ex. 303 at 5.) Staff states, for example, in SPPC's latest general rate case filing in Docket No. 22-06014, NV Energy was constructing extensive electrical infrastructure in the Tracy Area Master Plan to serve the customers' expected loads; however, when the COVID-19 pandemic took effect, many of these loads planned for the Tracy area slowed down and/or got deferred. (*Id.*) Staff states, despite that, NV Energy did not slow down its infrastructure investments and, as a result, in the 2022 SPPC general rate case filing, there was significant excess electrical infrastructure installed compared to the actual customers load that was completed in the area. (*Id.*)

279. Staff states, therefore, it must be incumbent on NV Energy to monitor the customers' load infrastructure being developed concurrently in the Apex area and if construction and/or load growth slows down or is delayed, NV Energy needs to consider delaying its

infrastructure investments. (Ex. 303 at 5.) Staff states that there should not be another situation where NV Energy does not adjust its infrastructure construction, while their customers have altered their plans, resulting in excess built-out and potential unnecessary rate pressure on other customers. (*Id.*)

*Esmeralda Substation*

280. Staff recommends that the Commission deny NV Energy's request to amend its Transmission Plan, Prayer for Relief Item 5, to expend approximately $56 million to construct the Esmeralda 525/230 kV transformers. (Ex. 304 at 2.)

281. Staff states that it is under the impression that NV Energy has already started this project. (Ex. 304 at 2.) Staff understands that NV Energy has already ordered all the major equipment needed for the project, NV Energy has started the request for proposal for construction of the project and is performing technical reviews of the proposals, and NV Energy is planning to award the construction contract in January 2024. (*Id.*) Staff contends, therefore, that this project should be reviewed for prudency during the appropriate general rate case proceeding. (*Id.*)

282. Staff states that, given that NV Energy has started and committed to the project, seeking Commission approval in this IRP amendment is not appropriate since there is nothing to approve. (Ex. 304 at 3.) Staff states that NV Energy is undermining the purpose of resource planning approval by not allowing the Commission, Staff, and interveners an opportunity to vet the projects before NV Energy ordered equipment and issued an RFP. (*Id.*)

*Amargosa Substation*

283. Staff recommends that the Commission deny NV Energy's request to amend the Transmission Plan, Prayer for Relief Item 6, to expend approximately $50 million to construct the Amargosa 525/230 kV transformers. (Ex. 304 at 3.)

284. Staff states that it is under the impression that NV Energy has already started this project. (Ex. 304 at 4.) Staff understands that NV Energy has already ordered all the major equipment needed for the project, NV Energy has started the request for proposal for construction of the project and is performing technical reviews of the proposals, and NV Energy is planning to award the construction contract in January 2024. (*Id* at 5.) Staff contends, therefore, that this project should be reviewed for prudency during the appropriate general rate case proceeding. (*Id.*) Staff states that, given that NV Energy has started and committed to the project, seeking Commission approval in this IRP amendment is not appropriate since there is nothing to approve. (*Id.*) Staff states that NV Energy is undermining the purpose of resource planning approval by not allowing the Commission, Staff, and interveners an opportunity to vet the projects before NV Energy ordered equipment and issued an RFP. (*Id.*)

285. Additionally, Staff states that with the planned development of the Amargosa Solar Project, NV Energy has secured 1200 MW of transmission rights on the 525 kV side of this proposed substation. (Ex. 304 at 4.) Staff explains, therefore, there will not likely be sufficient availability for other generation interconnects in the que to connect on the proposed 230 kV side of this substation. (*Id.*)

286. Staff states that the Amargosa Substation should only be brought forward once there is a better understanding of the Armargosa solar facility NV Energy has essentially already committed to build. (Ex. 304 at 4.) Staff states that, without knowing the impact of the Amargosa Solar project on the Greenlink West Transmission Line or the Amargosa Substation

capacity, Staff cannot analyze or understand the need for the 525/230 kV transformer and breaker addition. (*Id.* at 6.)

*Sierra Solar Transmission*

287. Staff recommends that the Commission approve NV Energy's request to expend approximately $70.5 million to construct transmission infrastructure to interconnect Phase 1 of the Sierra Solar project. (Ex. 307 at 6.)

288. Staff notes that NV Energy is seeking Commission approval to construct transmission facilities as part of a 700 MW LGIA (between NV Energy's merchant function and NV Energy's transmission function) that are necessary to interconnect the 400 MW Sierra Solar project in the instant docket. (Ex. 307 at 7.) Staff states that, because the $70.5 million infrastructure is associated with a 700 MW interconnection and with NV Energy only building 400 MW associated with Sierra Solar Phase 1, there may be transmission assets that are capable of interconnecting more than 400 MW of generating capacity. (*Id.* at 7-8.) Staff states that if that is the case, it may be appropriate to put some of the interconnection costs into "plant held for future use" when the project is brought for recovery in a future general rate case proceeding. (*Id.* at 8.)

**NV Energy's Rebuttal**

289. NV Energy disagrees that there is not adequate capacity at Amargosa Substation to afford a 230-kV interconnection due to the Amargosa Solar Project. (Ex. 134 at 3.) NV Energy explains that the substation equipment will be rated for 3,500 megavolt-amperes ("MVA"). (*Id.*) NV Energy states, additionally, as transmission facilities are placed in service such as Greenlink North, SWIP North, and series compensation of ON Line, these transfer

capabilities will increase. (*Id.*) NV Energy also notes that a generator dropping remedial action scheme could also be installed to allow higher levels of generation. (*Id.*)

290. NV Energy states that in the 2023 Spring generation interconnection cluster, NV Energy received 14 interconnection requests at Esmeralda 230 kV substation totaling 5,850 MW and 3 interconnection requests at Amargosa 230 kV substation totaling 1,408 MW. (Ex. 134 at 3.) NV Energy states that, although LGIA have not been executed yet and the interconnection customers have not posted security for the required transmission system network upgrades, NV Energy is proposing the 230-kV projects now in order to construct the 230-kV substation facilities at the same time as the 525-kV facilities are being constructed. (*Id.* at 4.) NV Energy notes that this would reduce the cost of the 230-kV facilities by approximately $10 million because NV Energy will have crews working in the substation and the substation will still be de-energized so the crews will not need to work around energized equipment which is safer and less expensive. (*Id.*) NV Energy notes that if approval were requested after the LGIAs are executed, constructing the 230-kV facilities at the same time as the 525-kV facilities would not be possible, and thus, will incur higher costs and a delayed in-service date. (*Id.* at 4-6.)

291. NV Energy disagrees with Staff's assertion that NV Energy has essentially started the projects and there is nothing for the Commission to approve. (Ex. 134 at 5.) NV Energy states that the lead time for large power transformers is two years or more so NV Energy had to place orders to reserve their production slots to have the necessary 525/230 kV transformers available when substation construction is scheduled to begin. (*Id.*) NV Energy notes that it specified cancellation options in the request for proposals and can cancel the two 525/230 kV transformers if NV Energy does not receive Commission approval for the projects. (*Id.*) NV Energy states that it does not intend to move forward without Commission approval and will

very likely cancel the equipment orders if the Commission denies its request for 525/230 kV buildout at Amargosa and Esmeralda substations. (*Id.*)

**Commission Discussion and Findings**

*Apex Area*

292. The Commission approves NV Energy's request to amend its Transmission Plan to expend approximately $62 million for Apex Central 230/12 kV Substation; to expend approximately $15 million for Apex East 230/12 kV Substation; to expend $0.22 million for Apex Southeast 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts; and to expend $0.17 million for Apex Southwest 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts. NPC has received numerous applications for load service in the Apex area for warehousing, manufacturing, data centers, and mixed use. The Commission finds that the Apex area has the potential for substantial load and generation growth. As NV Energy explains, several potential load additions ranging from 15 MW to 460 MW have inquired about electric service in this location. The Commission notes that the Apex Area Master Plan was strategically planned to allow multiple substations to be placed along a proposed 230-kV loop and phased in as load materializes. The Commission finds that, based on the current Rule 9 agreements that have been signed, it is necessary to start the Apex Central substation construction project as soon as possible to meet the customers' 2025 in-service dates. There is no distribution capacity remaining from the existing substations that could be allocated to these new distribution loads. For these reasons, the Commission approves NV Energy's Apex area requests.

*Esmeralda and Amargosa*

293. The Commission approves NV Energy's request to amend its Transmission Plan, Prayer for Relief Item 5, to expend approximately $56 million to construct the Esmeralda 525/230 kV transformers and approves NV Energy's request to amend the Transmission Plan, Prayer for Relief Item 6, to expend approximately $50 million to construct the Amargosa 525/230 kV transformers. The Commission finds that the costs for Amargosa and Esmerelda transformers related to the 230-kV portion of the projects shall be recorded to plant held for future use until the 230-kV facilities are serving additional customer load or related large generator interconnection agreements are entered into that would make use of this equipment, whichever comes first.

294. NV Energy has received numerous applications for interconnection on the Greenlink West, at Esmeralda substation totaling more than 9,900 MW (with 5,500 MW at 230 kV and 4,400 MW at 525 kV) and at Amargosa substation totaling 4,958 MW (with 1,408 MW at 230 kV and 3,550 MW at 525 kV). The Commission finds that, to minimize costs through economies of scale and accommodate timely interconnection of renewable resources, NV Energy is approved to aggregate the acquisition of construction services and long-lead equipment for the Greenlink West substation facilities' 525/230 kV transformers with the ongoing procurements. As NV Energy notes, this would reduce the cost of the 230-kV facilities by approximately $10 million because NV Energy will have crews working in the substation and the substation will still be de-energized so the crews will not need to work around energized equipment which is safer and less expensive. The Commission notes that the lead times for transformers, breakers, insulators, and switches have nearly doubled over the past two years. The Commission finds that postponing acquisition of long-lead equipment and construction of the 230-kV buildout would increase costs and delay interconnection of renewable resources by two or more years.

*Sierra Solar*

295. The Commission approves NV Energy's request to expend approximately $70.5 million to construct transmission infrastructure to interconnect Phase 1 of the Sierra Solar project.

296. The transmission facilities are a part of a 700-MW LGIA that are necessary to interconnect the 400-MW Sierra project in the instant docket. Because the $70.5 million infrastructure is associated with a 700-MW interconnection and with NV Energy only building 400 MW associated with Sierra Solar Phase 1, there may be transmission assets that are capable of interconnecting more than 400 MW of generating capacity. If that is the case, the Commission finds that interconnection costs exceeding what would be necessary to implement infrastructure associated with 400 MW to be used for Sierra Solar Phase 1 shall be recorded to plant held for future use until additional phases of Sierra Solar are approved or a large generator interconnection agreement is entered into with a different developer that would make use of this infrastructure, whichever comes first

**G. Waivers of NAC 704.6546**

**NV Energy's Position**

297. NV Energy requests waiver of NAC 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the 400 MW Sierra Solar BESS project. (Ex. 100 at 15.)

298. NV Energy requests a waiver of NAC 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the Valmy BESS project if the Commission approves the project. (Ex. 100 at 16.)

299. NV Energy states that the Sierra Solar BESS project is eligible for tax credits under the IRA. (Ex. 100 at 106.) NV Energy states that if the Valmy BESS project were to move forward, it would also be eligible for tax credits under the IRA. (*Id.*) NV Energy explains that the IRA provides a 30 percent ITC for battery storage projects and allows NV Energy to pass through to the customer the full benefit of those credits by opting out of normalization. (*Id.* at 106-107.) NV Energy states that it intends to opt out of the ITC normalization for the Sierra Solar BESS project and, in the event approved, for the Valmy BESS project as well. (*Id.* at 107.) NV Energy therefore requests a waiver of NAC 704.6546, use of separate-entity method by utility members of consolidated group, to take full advantage of those tax benefits. (*Id.*)

300. NV Energy explains that if the waiver request for NAC 704.6546 is granted, the account 190 unutilized ITC credit carry forward would be zero. (Ex. 100 at 107.) NV Energy states, thus, the full benefit of the ITC credits generated would reduce rate base and benefit the customers. (*Id.*) NV Energy states, accordingly, the deviation from NAC 704.6546 is for good cause, is in the public interest, and is not contrary to statute. (*Id.*)

**BCP's Position**

301. BCP recommends that the Commission grant the requested waiver from NAC 704.6546 for the Sierra Solar project and allow NV Energy to calculate taxes on a consolidated basis to take full advantage of the tax benefits generated by this project. (Ex. 401 at 19-20.) BCP also recommends, however, that the Commission require NV Energy to demonstrate on an annual basis that ratepayers are being fully compensated for the tax benefits that are being generating at the utility level. (*Id.* at 20, 22.)

**Staff's Position**

302. Staff recommends that the Commission approve NV Energy's request for a waiver of NAC 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the Sierra Solar BESS project (Ex. 306 at 11.) Staff states that, by taking advantage of the normalization opt out provision of the IRA, NV Energy is able to effectively lower the cost to ratepayers for the BESS by creating a Regulatory Liability account in the amount of the ITC credit that offsets the rate base impact of the project. (*Id.* at 12.) Staff states that this lowers not only the net depreciation expense, by use of an amortization credit, it also lowers the overall rate base which also helps to reduce the revenue requirement. (*Id.*) Staff explains that a waiver of NAC 704.6546 is required to effectuate the realize this benefit. (*Id.*)

303. Staff recommends that the Commission reject NV Energy's request for a waiver of 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the Valmy BESS project (Ex. 306 at 12.)

304. Staff notes that it disapproves of the Valmy BESS project as Staff recommends that the Commission approve the Valmy coal conversion project. (Ex. 306 at 13.) Staff states, therefore, that NV Energy's request is hypothetical at this point since the project itself is not even being requested for approval as part of the preferred plan. (*Id.*) Staff states that the Commission should not grant a waiver of a regulation unless there is a valid current reason to do so and should not allow NV Energy to use a waiver as it pleases at some unspecified point in the future. (*Id.*) Staff notes that there is also a question about eligibility for the normalization opt out provision of the IRA for projects that begin construction after December 31, 2024, which creates uncertainty about granting this waiver for a future project. (*Id.*)

**NV Energy's Rebuttal**

305. NV Energy disagrees with BCP's recommendation for an annual accounting of the tax benefits that develop from the waiver because all the tax information is already provided with each general rate case that NV Energy files and is easily identified as a simple journal entry to debit the net operating loss account and credit cash. (Ex. 130 at 2-3.) NV Energy explains that, in Docket No. 22-11032, the Commission granted a similar waiver of NAC 704.6546 for the Reid Gardner BESS and no additional accounting requirement was deemed necessary. (*Id.* at 3.)

306. NV Energy states that it is not requesting a hypothetical or conditional waiver for Valmy BESS, as Staff describes. (Ex. 130 at 3.) NV Energy states that it only seeks a waiver of NAC 704.6546 for Valmy BESS if that project is approved in this Joint Application. (*Id.*)

**Commission Discussion and Findings**

307. The Commission approves NV Energy's request for a waiver of NAC 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the Sierra Solar BESS project. The Commission finds that, by taking advantage of the normalization opt-out provision of the IRA, NV Energy is able to effectively lower the cost to ratepayers for the BESS by creating a regulatory liability account in the amount of the ITC credit that offsets the rate base impact of the project. This lowers not only the net depreciation expense, by use of an amortization credit, it also lowers the overall rate base which also helps to reduce the revenue requirement. The Commission finds that a waiver of NAC 704.6546 is required to effectuate this benefit.

308. The Commission also agrees with NV Energy that the tax benefit detail is provided with each general rate case and it is not necessary to provide an annual accounting as proposed by BCP.

309. A waiver of NAC 704.6546 for Valmy BESS is moot as the Commission is not approving a Valmy BESS project. The Valmy BESS project was discussed in the filing as an alternative to the preferred Valmy coal conversion project, which is approved in this Order, thereby obviating a waiver for Valmy BESS.

**H. Fuel and Purchased Power ("FPP") Price Forecasts**

**NV Energy's Position**

310. NV Energy requests approval of the Fifth Amendment to the 2021 Joint IRP base long-term FPP price forecasts provided in Technical Appendix FPP-1 as presenting the most accurate information upon which to base the planning decisions set forth in the filing. (Ex. 100 at 15.)

**Staff's Position**

311. Staff recommends that the Commission approve the Joint Application base long-term FPP price forecasts as they are based upon substantially accurate data and are therefore appropriate for resource planning decision making purposes. (Ex. 300 at 1.) Staff states that the methodologies NV Energy used to develop its FPP price forecasts are reasonable. (*Id.* at 2-6.)

**Commission Discussion and Findings**

312. The Commission approves the Joint Application base long-term FPP price forecasts as they are based upon substantially accurate data and are therefore appropriate for resource planning decision making purposes. The Commission finds that the methodologies NV Energy used to develop its FPP price forecasts are reasonable. Staff supports this finding, and no party objects.

**I. Financial Plan**

**NV Energy's Position**

313. NV Energy states that Commission regulations require NV Energy to rank power supply options on the basis of the PWRR and the PWSC. (Ex. 100 at 180.) NV Energy explains that the PWSC of a resource plan is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…" (*Id.*) NV Energy states that environmental costs are defined by the Commission as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan." (*Id.*) NV Energy provides its analysis of environmental costs and "net economic benefits" in Section 8, Chapter G of the Narrative in the Joint Application. (*Id.* at 180-199.)

314. NV Energy further provides its Financial Plan at Section 9 of the Narrative in the Joint Application. (Ex. 100 at 200.) NV Energy states that the Financial Plan section summarizes the results of the analysis of financial impacts of the Preferred, Alternate, and No Repower Plans presented in the Joint Application. (*Id.*) NV Energy states that the Financial Plan for both NPC and SPPC spans a 20-year period (2022-2041) and analyzes these three scenarios from the perspective of customers and NV Energy using several financial metrics as mandated by NAC 704.9401(1). (*Id.*)

**Staff's Position**

315. Staff recommends that the Commission find that NV Energy's development and consideration of the four resource plans are sufficient for the purposes of the economic analysis and are consistent with the relevant resource planning regulations. (Ex. 301 at 2.) Staff states that each of the plans presented by NV Energy provide a complete solution for the timely retirement of coal combustion at Valmy, available around-the-clock generation in the Carlin Trend load pocket, reduce NV Energy's open position, meet the current RPS, meet the 16

percent planning reserve margin ("PRM") for each company, and target NV Energy's proportionate contribution to Nevada's 2050 clean energy goal, and contain both conventional and renewable placeholders. (*Id.* at 3.)

316. Staff recommends that the Commission find that NV Energy's economic analysis, including the PWRR and PWSC analysis, is consistent with the relevant resource planning regulations. (Ex. 301 at 7.)

317. Staff recommends that the Commission find that NV Energy's Financial Plan is consistent with the relevant resource planning regulations. (Ex. 301 at 15.) Staff states that the Financial Plan, provided in Volume 1, presents NV Energy's analysis of the financial impact of the Preferred and Alternate Plans on both NPC and SPPC. (*Id.*) Staff states that NV Energy provided the financial information and assumptions used to develop their Financial Plan as required by NAC 704.9401. (*Id.* at 15-16.) Staff states that, like previous financial plans, NV Energy provided its analysis of the following financial information for the Preferred and Alternate Plans over the 20-year period, 2022-2041: capital expenditures, external financing requirements, total rate base, electric revenue requirement, impacts on average system cost, and impacts on credit metrics. (*Id.* at 16.) Staff states, additionally, in this Joint Application, NV Energy added customer rate impact analysis of the projects proposed for approval in the instant filing to the Financial Plan, due to the Commission's requested customer rate impact analyses in recent IRP amendments, including Docket Nos. 22-09006 and 22-11032. (*Id.*) Staff states that the Commission also requested a rate impact analysis in the Procedural Order issued on September 6, 2023, showing the combined rate impacts of proposed and approved investments from the instant docket, Docket Nos. 23-03003 (NDPP Plan), 23-03004 (NDPP Cost Recovery), 21-06001 (2021 IRP), 22-03024 (First Amendment to the 2021 IRP), 22-09006 (Third

Amendment to the 2021 IRP), 22-11032 (Fourth Amendment to the 2021 IRP), and 20-07023 (Fourth Amendment to the 2018 IRP). (*Id.*)

318. Staff notes that, because the Financial Plan and rate impact analysis incorporate NV Energy's proposed 60/40 (NPC/SPPC) split, the results of both the Financial Plan and rate impact analysis would likely be affected, as the capital expenditures required for SPPC and NPC would be different under Staff's proposed split. (Ex. 301 at 22.) Staff states that, in response to data requests, NV Energy provided the effects on certain financial metrics between 2023- 2028 of five different scenarios, including a scenario that removes the Sierra Solar project, and four different ownership allocations: a 100 percent allocation to SPPC, a 100 percent allocation to NPC, NV Energy's proposed 60/40 split, and Staff's proposed 90/10 split; provided by Staff as Confidential Attachment SV-5. (*Id.*)

319. Staff recommends that the Commission find that the PWRR, PWSC, and Financial Analysis cannot be reasonably relied upon to evaluate the costs associated with NV Energy's proposed plans and order NV Energy to include reasonably known projects as placeholders and to reflect more accurate pricing/cost structures for its renewable placeholders. (Ex. 301 at 24.) Staff states that the analyses incorporate placeholder assumptions, the cost of which ultimately flows through the PWRR, PWSC, and financial analyses, that appear to diverge from the actual planning that NV Energy is doing, and accordingly do not represent the costs associated with NV Energy's actual resource planning. (*Id.*)

320. Staff states that NV Energy's economic analysis did not include placeholders that reflect resources that had been requested in the Joint Application or that have already expended funds. (Ex. 301 at 24.) Specifically, Staff states that the Crescent Valley Solar project and Amargosa Valley Solar Energy Zone project were not included as placeholders despite NV

Energy having performed various stages of planning for each of them. (*Id.* at 24-25.) Staff states that NV Energy included Solar PV and BESS placeholders in 2027 and beyond, however, Staff states that the size of the placeholders shown in the anticipated completion year for Crescent Valley Solar and Amargosa Valley Solar Energy Zone are not reflective of the actual projects. (*Id.* at 25-26.)

321. Staff states that, at a minimum, a project for which an agreement, such as an APA, is in place, a land acquisition and/or permitting has been completed, and any project that NV Energy plans on seeking approval in the three-year action plan period should be considered a reasonably known project and included as a placeholder in the economic analysis. (Ex. 301 at 27.)

322. Staff also states that the PWRR and PWSC analyses and Financial Plan cannot be reasonably relied upon because NV Energy uses renewable placeholders that are modeled using renewable PPA pricing, not modeled as capital projects. (Ex. 301 at 27-28.) Staff states that it is not appropriate for NV Energy to use renewable PPA pricing for all renewable placeholders given that NV Energy has been requesting more NV Energy-owned projects in recent IRPs and IRP amendments. (*Id.* at 28.) Staff explains that the price for PPA resources is known and fixed at the time of Commission approval, whereas NV Energy-owned project may be subject to cost overruns and are recovered through the BTGR for which NV Energy earns a return on their investment. (*Id.*) Staff states that, to the extent that more future projects are NV Energy-owned, and thus require more capital expenditures, the economic and financial analyses likely understate the costs of the placeholders and total costs associated with NV Energy's plans. (*Id.* at 29.)

323. Staff sates, therefore, the PWRR and PWSC analyses and Financial Plan are not representative of NV Energy's actual planning and cannot be reasonably relied upon to evaluate

these plans because it appears that a significant chunk of cost information is missing. (Ex. 301 at 29.)

**NV Energy's Rebuttal**

324. NV Energy disagrees that the Financial Plan should not be relied on, but notes that Staff affirms that the Financial Plan is consistent with the relevant resource planning regulations, and NV Energy agrees with this assessment. (Ex. 139 at 19.) NV Energy states that while there may be room for improvement to better align the IRP financial analysis with NV Energy's business plan, the analysis still is in line with the applicable requirements and NV Energy's previous filings. (*Id.*) NV Energy notes that the IRP and business plan do have some similarities, but they serve two different purposes and NV Energy is currently evaluating how to best make the financial analysis align with NV Energy's business plan for the 2024 IRP filing. (*Id.*)

325. NV Energy disagrees with Staff's recommendation that "reasonably known" future projects be included in NV Energy's economic analyses because NV Energy already includes future resources in their analyses to the extent that is appropriate. (Ex. 137 at 19.) NV Energy states that the potential future resources proposed by Staff are beyond the action plan period with size, timing, and cost subject to change as the system needs change. (*Id.*) NV Energy states that its use of placeholder resources in its plans reflects the fact that system needs will likely change in future filings and the placeholder resources stemming from the most recent least cost capacity expansion buildout are the best representation available at this time. (*Id.*) NV Energy further explains that PPA-style pricing is assumed for all placeholders so the PWRR and PWSC are not influenced by assuming one recovery structure when another one might be used. (*Id.*)

326. NV Energy also notes that, because size, timing, and associated cost of any reasonably known future projects are subject to change as the system needs change, if these projects were inserted in lieu of generic placeholder resources, the representation of these reasonably known future projects would necessarily vary between the Alternative Plans depending on the proposed projects in each plan. (Ex. 137 at 19.)

**Commission Discussion and Findings**

327. The Commission finds that NV Energy's development and consideration of the four resource plans are sufficient for the purposes of the economic analysis and are consistent with the relevant resource planning regulations. The Commission agrees with Staff that each of the plans presented by NV Energy provide a complete solution for the timely retirement of coal combustion at Valmy, available around-the-clock generation in the Carlin Trend load pocket, reduce NV Energy's open position, meet the current RPS, meet the 16 percent PRM for each company, and target NV Energy's proportionate contribution to Nevada's 2050 clean energy goal, and contain both conventional and renewable placeholders.

328. The Commission finds that NV Energy's economic analysis, including the PWRR and PWSC analysis, is consistent with the relevant resource planning regulations.

329. The Commission finds that NV Energy's Financial Plan is consistent with the relevant resource planning regulations. The Financial Plan, provided in Volume 1, presents NV Energy's analysis of the financial impact of the Preferred and Alternate Plans on both NPC and SPPC. The Commission finds that NV Energy provided the financial information and assumptions used to develop their Financial Plan as required by NAC 704.9401. Like previous financial plans, NV Energy provided its analysis of the following financial information for the Preferred and Alternate Plans over the 20-year period, 2022-2041: capital expenditures, external

financing requirements, total rate base, electric revenue requirement, impacts on average system cost, and impacts on credit metrics. Additionally, in this Joint Application, NV Energy added customer rate impact analysis of the projects proposed for approval to the Financial Plan, due to the Commission's requested customer rate impact analyses in recent IRP amendments, including Docket Nos. 22-09006 and 22-11032. The Commission also requested a rate impact analysis in the Procedural Order issued on September 6, 2023, showing the combined rate impacts of proposed and approved investments from the instant docket, Docket Nos. 23-03003 (NDPP Plan), 23-03004 (NDPP Cost Recovery), 21-06001 (2021 IRP), 22-03024 (First Amendment to the 2021 IRP), 22-09006 (Third Amendment to the 2021 IRP), 22-11032 (Fourth Amendment to the 2021 IRP), and 20-07023 (Fourth Amendment to the 2018 IRP).

330. The Commission finds that, because the Financial Plan and rate impact analysis incorporate NV Energy's proposed 60/40 (NPC/SPPC) split of the Sierra Solar Project, the results of both the Financial Plan and rate impact analysis are affected, as the capital expenditures required for SPPC and NPC are different in this Order.

331. While prepared consistent with the relevant resource planning regulations, the Commission is concerned with the degree to which the PWRR, PWSC, and Financial Analysis can be reasonably relied upon to evaluate the costs associated with NV Energy's proposed plans and orders NV Energy to include reasonably known projects as placeholders and to reflect more accurate pricing/cost structures for its renewable placeholders. The analyses incorporate placeholder assumptions, the cost of which ultimately flows through the PWRR, PWSC, and financial analyses, that appear to diverge from the actual planning that NV Energy is doing, and accordingly would not represent the costs associated with NV Energy's actual resource planning.

332. The Commission finds that NV Energy's economic analysis did not include placeholders that reflect resources that had been requested in the Joint Application or for which funds have already been expended. Specifically, the Crescent Valley Solar project and Amargosa Valley Solar Energy Zone project were not included as placeholders despite NV Energy having performed various stages of planning for each of them. NV Energy included Solar PV and BESS placeholders in 2027 and beyond; however, the size of the placeholders shown in the anticipated completion year for Crescent Valley Solar and Amargosa Valley Solar Energy Zone are not reflective of the actual projects.

333. The Commission finds that, at a minimum, a project for which an agreement, such as an APA, is in place, a land acquisition and/or permitting has been completed, and any project that NV Energy plans on seeking approval in the three-year action plan period should be considered a reasonably known project and included as a placeholder in the economic analysis.

334. Furthermore, the Commission finds that the PWRR and PWSC analyses and Financial Plan may not be reasonably relied upon because NV Energy uses renewable placeholders that are modeled using renewable PPA pricing, not modeled as capital projects. The Commission finds that is not appropriate for NV Energy to use renewable PPA pricing for all renewable placeholders given that NV Energy has been requesting more NV Energy-owned projects in recent IRPs and IRP amendments. The price for PPA resources is known and fixed at the time of Commission approval, whereas, NV Energy-owned projects may be subject to cost overruns and are recovered through the BTGR for which NV Energy earns a return on its investment. The Commission finds that, to the extent that more future projects are NV Energy-owned, and thus require more capital expenditures, the economic and financial analyses likely understate the costs of the placeholders and total costs associated with NV Energy's plans.

335. Accordingly, the Commission finds that the PWRR and PWSC analyses and Financial Plan may not best represent NV Energy's actual planning. NV Energy is directed to provide one version of each of its plans in the upcoming IRP with placeholders adjusted as discussed above for projects in progress or requested and to reflect anticipated NV Energy-owned projects. NV Energy may also provide versions using its current placeholder methodology for comparative purposes.

**J. Western Power Pool ("WPP")/WRAP Participation**

**NV Energy's Position**

336. NV Energy states that the WRAP continues to be developed with NV Energy participating in the latest phase of development (3B) that began on January 1, 2023. (Ex. 120 at 12.) NV Energy states that there are currently 22 entities that are participating in the WRAP, which makes the total WRAP footprint more than 57,000 MW. (*Id.*) NV Energy states that the first binding season has been pushed back from Summer 2025 to Summer 2026, due to a lack of participation, and NV Energy has elected to go binding in the Winter 2026/2027 season, which will allow NV Energy additional time to continue to add resources in order to pass the forward-showing requirement for the Summer 2027 season. (*Id.*)

337. NV Energy states that regional resource adequacy is important for every entity in the West, including NV Energy. (Ex. 120 at 13.) NV Energy states that, historically, every entity has planned for itself with many entities relying on the market to meet some of their load requirements. (*Id.)* NV Energy states that this is one of the major contributing factors to the resource adequacy issues that have presented themselves over the past several summers. (*Id.*) NV Energy states that the WRAP is the first regional reliability planning and compliance program in the history of the West. (*Id.*) NV Energy states that with the majority of the entities

in the West now planning to participate in the WRAP, every utility will be required to be resource sufficient, thus increasing resource adequacy for the region as a whole. (*Id.*)

338. NV Energy states that it will face binding compliance obligations for participation. (Ex. 120 at 13.) NV Energy states that failure to meet these requirements could result in significant financial penalties. (*Id.*)

339. NV Energy states that membership in WRAP is expected to require participants to show they have generation capacity to meet 100 percent of a monthly 1 in 2 peak (P50) forecasted demand plus the sub regional Planning Reserve Margin that is determined through regional modeling. (Ex. 120 at 15-16.) NV Energy states that this will be done through a forward showing program that occurs 7 months in advance of each binding season. (*Id.* at 16.) NV Energy states that if a participant fails to pass this forward-showing requirement, it will be assessed a deficiency charge. (*Id.*) NV Energy states that, without additional resources, NV Energy will fail to meet this requirement by more than 1,600 MW for the summer of 2027. (*Id.*) NV Energy states that the need for new resources continues throughout the study period due to growing customer demand. (*Id.*)

**BCP's Position**

340. BCP states that, given the status of the energy markets, NV Energy's open positions, and the risk of being charged penalties for resource deficiency for the summer 2027 season, it would be prudent for NV Energy to defer its binding winter 2026-2027 season election to the winter 2027-2028 season. (Ex. 402 at 6.) BCP notes that this deferral would provide NV Energy an additional year to meet the WRAP resource adequacy requirements. (*Id.*)

**Staff's Position**

341. Staff recommends that the Commission order NV Energy to send written notice to the WPP to defer their WRAP financially binding season from winter 2026-2027 to winter 2027-2028. (Ex. 307 at 2.) Staff states that NV Energy may have entered the winter 2026-2027 WRAP financially binding season without Commission approval. (*Id.* at 3.) Staff states that NAC 704.9503(1)(e) requires an electric utility to amend its action plan if the utility makes a commitment for an option that was not available at the time the action plan was approved. (*Id.*) Staff states NV Energy's commitment to join WRAP's winter 2026-2027 financial binding season was not available and evaluated at the time the action plan was approved. (*Id.* at 3-4.) Staff notes that committing to WRAP's 2026 winter binding season may require billions of dollars for NV Energy to become resource adequate in time to meet WRAP's resource adequacy requirements by late 2026, for the summer 2027 financially binding season, or face significant penalties and/or be barred from accessing any excess capacity that may be available in WRAP during system emergencies. (*Id.* at 4.) Staff states that NV Energy's forecasted open position for the summer of 2027, with or without Commission approval for the requests in this docket, would subject NV Energy to substantial penalties that could be passed onto ratepayers. (*Id.*)

342. Staff supports NV Energy joining WRAP but contends that NV Energy should defer their binding season one year, to winter 2027-2028, which is the last season for a participant to elect to join the binding phase. (Ex. 307 at 5.) Staff notes that NV Energy has until October 31, 2024, to provide written notice to WPP to elect to defer. (*Id.*). Staff states that, with the October 31, 2024, deadline, this Joint Application will be the Commission's last opportunity to weigh in on whether the binding participation in the WRAP should be deferred, absent opening and expediting an investigatory docket. (*Id.*)

**NV Energy's Rebuttal**

343. NV Energy agrees that the WRAP is an important development for the western region and that regional coordination through the program is needed to ensure reliable service. (Ex. 138 at 10.) NV Energy states that, while earlier participation would enable NV Energy to experience this regional coordination at an earlier date, it is reasonable to consider a deferred entry as a binding participant to protect against potential financial penalties. (*Id.*)

**Commission Discussion and Findings**

344. The Commission supports NV Energy joining WRAP, but orders NV Energy to send written notice to the WPP to defer its WRAP financially binding season from winter 2026-2027 to winter 2027-2028. The Commission finds that committing to WRAP's 2026 winter binding season may require billions of dollars for NV Energy to become resource adequate in time to meet WRAP's resource adequacy requirements by late 2026, for the summer 2027 financially binding season, or face significant penalties and/or be barred from accessing any excess capacity that may be available in WRAP during system emergencies. NV Energy's forecasted open position for the summer of 2027, with or without Commission approval for the requests in this docket, would subject NV Energy to substantial penalties that could be passed onto ratepayers.

345. The Commission finds that NV Energy should defer its binding season one year, to winter 2027-2028, which is the last season for a participant to elect to join the binding phase. The Commission notes that NV Energy does not find it unreasonable to consider a deferred entry as a binding participant to protect against potential financial penalties.

THEREFORE, it is ORDERED:

1. The Joint Application is Granted in Part and Modified in Part, as delineated in this Order.

**Compliances:**

2. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall calculate storage availability liquidated damages, and renewable energy and Portfolio Energy Credit shortfall replacement costs for the Sierra Solar project in accordance with the calculations detailed in BS3's Power Purchase Agreement. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall use BS3's Power Purchase Agreement as a template and replace any BS3 specific values with the Sierra Solar project specific values, to provide documentation that outlines how the liquidated damages and shortfall replacement costs would be calculated and credited to ratepayers by Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy if the Sierra Solar project faces delays or performance issues. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall perform the Sierra Solar project's calculations and credit ratepayers, when applicable, at the same time that it processes its other Power Purchase Agreements' liquidated damages and shortfall replacement amounts.

3. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall provide status updates to the Commission relative to Idaho Power Company's status in continued ownership in the Valmy conversion.

4. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file the information requested in paragraph 9 a. of the Procedural Order dated September 6, 2023, updated for the findings in this Order.

**Directives:**

5. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall provide updates to the Commission regarding geothermal resources and development in the Valmy region.

6. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall provide one version of each of its plans in the upcoming Integrated Resource Plan with placeholders adjusted as discussed in this Order for projects in progress or requested and to reflect anticipated NV Energy-owned projects. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy may also provide versions using its current placeholder methodology for comparative purposes.

By the Commission,

______________________________
HAYLEY WILLIAMSON, Chair and Presiding Officer

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TAMMY CORDOVA, Commissioner

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RANDY BROWN, Commissioner

Attest: ______________________________
TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada

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(SEAL)