BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fourth amendment to its 2021 Joint Integrated Resource Plan.	)	Docket No. 22-11032

At a general session of the Public Utilities Commission of Nevada, held at its offices on May 12, 2023.

PRESENT: Chair Hayley Williamson
Commissioner C.J. Manthe
Commissioner Tammy Cordova
Assistant Commission Secretary Trisha Osborne

ORDER

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

I. INTRODUCTION

On November 30, 2022, Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra") (collectively, "NV Energy") filed with the Commission a joint application ("Joint Application"), designated as Docket No. 22-11032, for approval of the fourth amendment to its 2021 Joint Integrated Resource Plan ("2021 Joint IRP"). 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, NAC 704.9005 *et seq*., and Senate Bill 448 (2021) ("SB 448"). 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. Phase I of the Joint Application, specifically NV Energy's request for approval of the Silverhawk Peaking Plant and associated transmission infrastructure, was addressed in a previous Commission Order. This Order addresses the balance of the Joint Application ("Phase II").

II. SUMMARY

The Commission grants in part and denies in part NV Energy's Joint Application as delineated in the order below. The Joint Application included requests to modify the Supply Side, Transmission, and Renewable Plans. In particular, NV Energy's Joint Application focuses on investments to further improve the reliability of NV Energy's system. The Commission accepts NV Energy's plan to contract for additional geothermal resources, procurement of a new phase shift transformer ("PST"), and continued operation of certain generation facilities. The Commission directs NV Energy to provide a more comprehensive plan for the replacement of the Valmy generating station ("Valmy") in a future filing, as well as additional consideration of various transmission requests. Finally, as recommended by most of the intervening parties, the Commission opens an investigatory docket to evaluate recommendations regarding modifications to the electric resource planning process in Nevada.

III. PROCEDURAL HISTORY

- On November 30, 2022, NV Energy filed the Joint Application.
- The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.
- On December 12, 2022, the Commission issued a Notice of Joint Application and Notice of Prehearing Conference.
- On December 16, 2022, the Nevada Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS.

- On December 19, 2022, the Presiding Officer issued Procedural Order No. 1 adopting a procedural schedule and discovery processes.
- On December 20, 2022, the Las Vegas Global Economic Alliance filed comments. That same day, Western Resource Advocates ("WRA") filed a Petition for Leave to Intervene ("PLTI").
- On December 27, 2022, the Commission issued a Notice of Hearing.
- On January 3, 2023, Google LLC ("Google") filed a PLTI.
- On January 4, 2023, Boyd Gaming Corporation, Station Casinos LLC, and Venetian Las Vegas Gaming, LLC ("Southern Nevada Gaming Group" or "SNGG"); Iron Point Solar, LLC ("Iron Point") and Hot Pot Solar, LLC ("Hot Pot"); Wynn Las Vegas, LLC ("Wynn") and Smart Energy Alliance ("SEA"); Nevada Resort Association ("NRA"); Caesars Enterprise Services, LLC ("Caesars"); MGM Resorts International ("MGM") (NRA, Caesars, and MGM, collectively "CMN"); and Interwest Energy Alliance ("Interwest") each filed PLTIs.
- On January 5, 2023, the Presiding Officer issued an Order granting the intervention of WRA.
- On January 6, 2023, the Presiding Officer held a prehearing conference.
- On January 9, 2023, the Presiding Officer issued Procedural Order No. 2.
- On January 11, 2023, Iron Point and Hot Pot filed a supplement to their PLTI.
- On January 13, 2023, the Presiding Officer issued Procedural Order No. 3. That same day Nevada Workers for Clean and Affordable Energy filed a PLTI.
- On January 17, 2023, the Presiding Officer held a continued prehearing conference.
- On January 18, 2023, NV Energy filed a Response to PLTI of Iron Point and Hot Pot.
- On January 20, 2023, the Presiding Officer issued an Order granting the PLTIs of Google, SNGG, Wynn and SEA, NRA, Caesars, MGM and Interwest. That same day, Iron Point and Hot Pot filed a Reply to Response of Nevada Power and Sierra to its PLTI.
- On January 24, 2023, the Presiding Officer held a continued prehearing conference.
- On January 30, 2023, Google, WRA, and Staff filed testimony.
- On January 31, 2023, the Presiding Officer held a continued prehearing conference.

- On February 1, 2023, the Presiding Officer issued an Order granting the PLTIs of Iron Point and Hot Pot and Nevada Workers for Clean and Affordable Energy.

- On February 10, 2023, NV Energy filed rebuttal testimony. That same day, the Presiding Officer issued Procedural Order No. 4.

- On February 14, 2023, the Presiding Officer held a continued prehearing conference.

- On February 15, 2023, Advanced Energy United filed comments.

- On February 16, 2023, the Commission held a hearing. NV Energy, Google, WRA, BCP, and Staff made appearances.

- On February 21, 2023, the Presiding Officer held a continued prehearing conference.

- On March 7, 2023, the Presiding Officer held a continued prehearing conference.

- On March 8, 2023, the Commission issued a Notice of Hearing

- On March 13, 2023, the Commission issued a draft order pertaining to Phase I of the Joint Application. That same day, the Commission issued Procedural Order No. 5.

- On March 16, 2023, the Commission issued an Order granting Phase I of the Joint Application.

- On March 17, 2023, WRA, NV Energy, Staff, Nevada Workers, Caesars, MGM, and NRA filed direct testimony. On that same day, BCP filed a stipulation between NV Energy and BCP to permit BCP to extend BCP's deadline to file direct testimony.

- On March 22, 2023, BCP filed direct testimony.

- On March 31, 2023, NV Energy filed rebuttal testimony.

- On April 4, 2023, the Commission issued Procedural Order No. 6.

- On April 10, 2023, the Presiding Officer held a hearing. On that same day, WRA filed revised direct testimony.

- On April 14, 2023, BCP filed a late-filed exhibit. On that same day, Staff and BCP filed errata to their direct testimony.

IV. AMENDED JOINT APPLICATION

A. Preferred Plan

NV Energy's Position

1. NV Energy provides that the Joint Application seeks: (1) approval of a new fuel and purchase power price forecast; (2) to amend the Generation portion of the Supply Plan with the continued operation of existing turbines at the Clark, Harry Allen, Chuck Lenzie, Silverhawk, Walter M Higgins, Las Vegas, and Sun Peak Generating Stations as well as the Clark Mountain units at the Tracy Generating Station, and the addition of 400 megawatts ("MW") of peaking combustion turbines at the Silverhawk Generating Station; (3) to amend the Renewable portion of the Supply Plan to add a new 120 MW geothermal portfolio long-term power purchase agreement ("PPA") between Sierra and Ormat, a 20 MW new geothermal technology long-term PPA between Sierra and Eavor, and a 200 MW grid-tied battery energy storage system ("BESS") at Valmy ("Valmy BESS"); a waiver of NAC 704.6546 to pass through to customers the full benefit of the investment tax credits ("ITC") for the Valmy BESS and Reid Gardner BESS projects; and (4) to amend the Transmission Plan to add infrastructure necessary for interconnection of the projects presented, to add capacitors at the Humboldt and Maggie Creek substations for static voltage support in the Carlin Trend load pocket, to replace the Bordertown Substation's PST with a new PST at the Hilltop Substation, and secure the necessary line routing studies, substations sites, permitting, land rights, and long lead time materials for several key transmission projects that have been identified in multiple studies to ensure the projects can be built in a timely manner to serve customers' schedules. These items collectively represent NV Energy's preferred plan (the "Preferred Plan"). (Ex. 100 at 12.)

2. NV Energy explains that its Preferred Plan addresses resource adequacy and meets the 16 percent planning reserve margin ("PRM") for each utility, uses the new load forecast presented in the Third Amendment[1], addresses state and federal carbon policy and changes in fuel and purchase power prices, meets or exceeds the renewable portfolio standard ("RPS") in every year, and advances the State's 2050 clean energy goal. (*Id.*) While NV Energy provides that the Preferred Plan is not the least cost plan, NV Energy maintains that the Preferred Plan was selected because it does the most to address resource adequacy without creating long capacity positions. (*Id.* at 11-12.)

3. NV Energy provides that there are several factors driving the need for the Joint Application at this time. (Ex. 114 at 5.) First, NV Energy explains that the updated load forecast presented in NV Energy's Third Amendment showed an increase in load that currently would be served by market capacity. (*Id.*) NV Energy elaborates that delays, shortfalls, and/or cancellations of any approved renewable resources currently under development would increase NV Energy's open capacity positions, cause increased reliance on an uncertain market, and shorten the time period of NV Energy's forecasted RPS compliance periods. (*Id.*) In particular, NV Energy explains that it became aware that the Iron Point and Hot Pot projects would likely not meet their respective planned in-service dates. (*Id.*) NV Energy highlights that these two projects were to provide capacity, energy, and portfolio energy credits ("PC") to both Nevada Power and Sierra. (*Id.* at 5-6.) NV Energy states that these projects were also to provide the voltage support to the Carlin Trend load pocket that is currently provided by coal-fired

[1] Docket No. 22-09006, Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the third amendment to its 2021 Joint Integrated Resource Plan, "Third Amendment".

generation at the Valmy. (*Id.* at 6.) NV Energy outlines that the updated load forecast and the loss of approved projects put increased pressure on the open capacity position. (*Id.*)

4. NV Energy provides that the Preferred Plan excludes the Iron Point and Hot Pot units for the Load and Resources Table and subsequent modeling, and includes the continued operation of most of NV Energy's combustion turbines. (Ex. 114 at 7.) NV Energy explains that these units are an economic source of capacity to improve resource adequacy over the planning period of the Amendment. (*Id.*) NV Energy provides that the Preferred Plan also includes the addition of the Silverhawk Peaking Plant in 2024, adds two new power PPAs for geothermal energy, and adds the Valmy BESS in 2025 as a partial replacement of the Valmy coal plant and to provide dynamic voltage support for the Carlin Trend load pocket in the absence of the Hot Pot and Iron Point projects. (*Id.*) NV Energy elaborates that one PPA is for a portfolio of new and existing geothermal projects for up to 120 MW with various in-service dates and that the other PPA is a 20 MW project using a new geothermal technology, which should reach full output by the end of 2028. (*Id.*) NV Energy maintains that the Valmy BESS relies on the recently passed Inflation Reduction Act ("IRA") by conservatively reflecting a 30 percent ITC for a standalone battery. (*Id.*) NV Energy states that NV Energy will also pursue the additional 10 percent ITC available for installing the Valmy BESS at a retiring coal plant. (*Id.*) In the alternative, NV Energy points to a static synchronous compensator ("STATCOM") that will use new capacitors at the Humboldt and Maggie Creek substations to provide dynamic voltage support for the Valmy area if the Valmy BESS is not approved. (*Id.* at 7-8.)

5. As of the date of this filing, NV Energy states it is uncertain on the timing or future of the Hot Pot and Iron Point projects. (*Id.*) As a result, NV Energy explains that it is being proactive in requesting approval of the BESS to ensure the timely retirement of the Valmy

coal plant. (*Id.*) NV Energy provides it will continue to work with the developers of Hot Pot and Iron Point, and, in the event there is more certainty on timing and price of the projects, NV Energy will make a filing with the Commission to either inform or seek approval of the projects moving forward in relation with the Valmy BESS. (*Id.*)

6. NV Energy states that it is pursuing a limited solution to the capacity needs of Sierra. (*Id.*) NV Energy elaborates that Sierra's growing capacity need, continuing RPS need, and replacement of Valmy capacity are addressed to a limited extent in this Amendment through the addition of geothermal projects, as well as the Valmy BESS. (*Id.*) NV Energy provides that every alternative case put forward in this filing includes incremental placeholder resources for Sierra starting as early as 2025 to address the continuing capacity need. (*Id.* at 8-9.) NV Energy explains that while Nevada Power has incremental placeholder resources in the same time frame, Sierra's need is acute due to its import constraints. (*Id.* at 9.) NV Energy states that the need for near-term placeholders in all cases evaluated indicates that the identified capacity additions are insufficient to satisfy all the needs of the system, notably in northern Nevada. (*Id.*) NV Energy explains that, rather than waiting to file until more northern resource options are identified, which could limit the ability to add resources in 2024 and possibly jeopardize the timely retirement of the Valmy coal plant, NV Energy proposes to acquire sufficient resources at this time to address the voltage support need currently satisfied by Valmy, as well as a portion of the capacity needed by the northern system. (*Id.*) NV Energy states that the BESS project adds both dynamic voltage support and a limited amount of capacity in the Carlin Trend load pocket, and may potentially pair well with future renewable resources in the area. (*Id.*) NV Energy maintains that postponing the selection of a complete solution allows additional time for more northern resource options to become available for evaluation for a more robust solution to Sierra's

capacity needs, including the potential return of the Hot Pot and Iron Point projects. (*Id.*) NV Energy offers that it is NV Energy's intent to bring forward more resources in a future amendment to further address northern Nevada's need in addition to the ongoing overall capacity needs to improve resource adequacy statewide while employing the IRA tax credits on behalf of customers. (*Id.*)

7. Despite NV Energy's request for fossil fuel generation, NV Energy maintains that it is not deviating from its clean energy goals and remains committed to Nevada's sustainability goals. (*Id.* at 10.) NV Energy states that the Preferred Plan achieves and exceeds 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 provides that firm dispatchable resources, which could include — and are modeled as — gas turbines, contribute much more significantly to capacity in 2050 than they do to energy production, resulting in a positive impact on resource adequacy with minimal carbon dioxide emissions. (*Id.*)

8. Relative to the alternative plans, NV Energy explains that the Preferred Plan takes a larger initial step to decrease NV Energy's dependence on market purchases, reducing the risk of higher costs to customers that a larger open capacity position would pose. (*Id.* at 18.) NV Energy explains that the Preferred Plan fills more of NV Energy's near-term open capacity position with the addition of diverse resources — geothermal, combustion turbines, and battery systems – and does so at a reasonable cost. (*Id.*) NV Energy explains that this plan adds additional capacity starting in 2024, reduces the NV Energy's dependence on uncertain market purchases, supplies energy after solar resource output declines in the evening hours, and provides the needed voltage support for the Carlin Trend load pocket to allow the timely retirement of the Valmy coal plant. (*Id.* at 18-19.) NV Energy states that these resources replace some of the

capacity, energy, and renewable credits lost due to the inability of planned resources to meet approved project cost and schedule dates. (*Id.* at 19.)

9. NV Energy states that in its annual review of generating unit retirement dates, new Life Span Analysis Procedure ("LSAP") reports were completed for the majority of NV Energy's generating units. (Ex. 115 at 4.) In most cases, NV Energy provides that it is recommending to continue to operate the generating units another 10 years. (*Id.*) NV Energy offers that the exceptions to the additional 10 years of continued operation are large, combined cycles where the additional 10 years would push their retirement date beyond 2050. (*Id.* at 4-5.) In such cases, due to Nevada's decarbonization goals, NV Energy states the recommendation is to plan for an additional five years of operations. (*Id.* at 5.)

10. NV Energy provides that NRS 704.741(3)(c) contains a requirement for a scenario of low carbon dioxide emissions in triennial IRPs submitted on or before June 1, 2027, that uses sources of supply that result in, by the year 2030, an 80 percent reduction in carbon dioxide emissions from the generation of electricity to meet the demands of customers of the utility as compared to the amount of such emissions in the year 2005, while also meeting the state's 2050 clean energy goal and including the deployment of distributed generation. (Ex. 112. at 11.) NV Energy points out that the July 13, 2022, Order in Docket No. 22-03024[2] specified inclusion of this newly defined scenario in all amendments with supply-side scenarios submitted on or before June 1, 2027, but not required more than once every 12 months. (*Id.*) NV Energy states that the 2005 baseline for carbon dioxide emissions from the generation of electricity to meet the demands of customers of the utility was created using publicly available data in NV Energy's Securities and Exchange Commission 10-K filings, Federal Energy Regulatory

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[2] Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the first amendment to its 2021 Joint Integrated Resource Plan, "First Amendment".

Commission ("FERC") Form 1 filings, and data from the U.S. Environmental Protection Agency's ("EPA") Emissions & Generation Resource Integrated Database. (*Id.* at 12.)

11. NV Energy provides that the Base Case uses an updated long-term resource buildout created in PLEXOS LT to accommodate the new load forecast and removal of the Hot Pot and Iron Point photovoltaic ("PV")/BESS projects. (*Id.* at 13.) NV Energy states that the Base Case includes resources approved in the Commission's July 13, 2022, Order in Docket No. 22-03024. (*Id.*) NV Energy explains that it also incorporates the continued operation of existing generation units requested in this amendment as well as others requested in Sierra's most recent depreciation filing[3], as described in the Generation section of the narrative, as screening of continued operation showed it to be cost effective. (*Id.*) NV Energy provides that the Base Case meets or exceeds the current RPS in every year, meets the 16 percent PRM for each utility, targets NV Energy's contribution to the state's 2050 clean energy goal, and provides the static and dynamic voltage support needed in the Carlin Trend load pocket to allow for the timely retirement of the Valmy coal plant. (*Id.*) NV Energy explains that the Base Case relies heavily on market capacity purchases in 2022-2023, then holds the open position below 1,000 MW in the near term, allowing it to grow to over 2,000 MW at the end of the 30-year study period. (*Id.*)

12. NV Energy explains that the need for near-term placeholders in all cases evaluated indicates that the identified capacity additions are insufficient to satisfy all the needs of the system, notably in northern Nevada. (*Id.*) NV Energy states that, rather than waiting to file until more northern resource options are identified, which could limit the ability to add resources in 2024 and possibly endanger the timely retirement of the Valmy coal plant, NV Energy proposes to acquire sufficient resources at this time to address the voltage support need currently

[3] Docket No. 22-06015, Application of Sierra Pacific Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric operations.

satisfied by the Valmy coal plant, as well as a portion of the capacity needed by the northern system. (*Id.* at 15-16.) NV Energy provides that the remaining northern resource needs will be addressed in a future IRP amendment. (*Id.* at 16.)

13. NV Energy provides that a more robust analysis of options was needed even though a Valmy combustion turbine looked economic at first. (*Id.*) Therefore, NV Energy explains that it decided to delay the final analysis of new CTs in the northern system, eliminating the Valmy combustion turbine from further consideration in the current analysis but continuing evaluation of the BESS project. (*Id.*) NV Energy asserts that the BESS project adds both dynamic voltage support and a limited amount of capacity in the Carlin Trend load pocket and may potentially mesh well with future renewable resources in the area. (*Id.*) NV Energy offers that postponing the selection of a complete solution allows additional time for more northern resource options to become available for evaluation alongside CTs for a more robust solution to Sierra's capacity needs. (*Id.*)

14. NV Energy explains that the initial buildout of the Low Carbon Case was developed using PLEXOS LT. (*Id.* at 17.) NV Energy states that, from the Base Case expansion plan, the amount of renewable energy that achieved the target carbon dioxide emissions reduction was determined. (*Id.*) NV Energy states that this renewable energy requirement was substituted for the 2030 RPS requirement in the Base Case and the PLEXOS LT analysis was repeated. (*Id.*) NV Energy offers that the resulting buildout would then meet 2030 carbon dioxide emissions reduction and the 2050 clean energy goal. (*Id.*)

15. NV Energy states that it selected the Moderate Plan as an alternative plan. (*Id.*) NV Energy explains that the Moderate Plan adds the 120 MW geothermal portfolio, 20 MW AGS project, and the Valmy BESS in northern Nevada along with 400 MW of peaking

combustion turbine in southern Nevada. (*Id.*) NV Energy states that Northern Nevada resources have an expected in-service date in 2025, with the southern Nevada resource expected to be in service by summer 2024. (*Id.*) NV Energy conveys that the Moderate Plan adds additional capacity starting in 2024, reduces NV Energy's dependence on uncertain market purchases, supplies energy after solar resource output declines in the evening hours, and provides the needed voltage support for the Carlin Trend load pocket to allow the timely retirement of the Valmy coal plant. (*Id.* at 17-18.) NV Energy also provides that the Moderate Plan includes placeholder resources as early as 2025, indicating additional needed resources in future IRP filings. (*Id.*)

16. To ensure a diverse set of plans, NV Energy provides that it added an additional case for further analysis — the Limited Plan, a minimalist plan providing a reduced amount of additional capacity. (*Id.* at 18.) NV Energy elaborates that the Limited Plan includes one fewer resource — the Valmy BESS — than the Moderate Plan, relying instead on an increased amount of placeholder resources to be filled later. (*Id.*) NV Energy explains that the Limited Plan achieves the same goals as the Moderate Plan but requires an incremental amount of resources be brought forth in future IRP filings to satisfy the placeholder resources identified. (*Id.*)

17. NV Energy provides that the Low Carbon Case was also chosen as an alternative plan, despite its high cost, to meet the required scenario of low carbon dioxide emissions. (*Id.*) NV Energy states that the Low Carbon Plan adds the geothermal portfolio, AGS project, and the Valmy BESS in northern Nevada. (*Id.*)

18. NV Energy outlines its findings from its present worth of revenue requirement ("PWRR") analyses:

i. The Limited Plan has the lowest 20-year and 30-year PWRR for all load, fuel, market and carbon price scenarios;

ii. The Moderate Plan has the second lowest 20-year and 30-year PWRR for all load, fuel, market and carbon price scenarios;

iii. The Low Carbon Plan has the highest PWRR of the alternative plans in all scenarios;

iv. The significant increase in near-term renewable resources required in the Low Carbon Plan may limit NV Energy and its customers from benefiting from developing technologies and/or from a potential new regional market; and

v. The buildouts for each plan were not modified for the high- and low-economic growth load scenarios. (*Id.* at 22-23.)

19. NV Energy explains that it selected the Moderate Plan as the Preferred Plan and the Limited Plan as the Alternate Plan. (*Id.* at 26.) NV Energy explains that while the alternative plans all provide the required voltage support for the Carlin Trend load pocket, comply with the RPS, and target NV Energy's portion of the state's 2050 clean energy goal, the Moderate Plan achieves the timely addition of new resources. (*Id.*) NV Energy offers that the Moderate Plan adds capacity in 2024 through inclusion of the resource with the earliest commercial operation of any option evaluated. (*Id.*)

20. NV Energy states that, compared to the Moderate Plan, the total environmental costs are about $83 million, or about 1.0 percent, less the Limited Plan and about $1,825 million, or about 22 percent less for the Low Carbon Plan. (Ex. 108 at 24.) NV Energy explains that differences in the social cost of carbon account for the vast majority of the differences in total environmental cost among the three Joint Application plans. (*Id.*) NV Energy provides that the

Moderate Plan and the Limited Plan both have negative economic impacts in Nevada relative to the Base Case, while the Low Carbon Plan generally has positive economic impacts in Nevada relative to the Base Case. (*Id.* at 33.) NV Energy states that, compared to the Moderate Plan, the Limited Plan has a PWSC that is about $184 million, or about 0.5 percent less and the Low Carbon Plan has a PWSC that is about $2,667 million, or about 7.5 percent greater. (*Id.* at 35.) NV Energy states that the results for the Low Carbon Plan reflect the much larger PWRR for the Low Carbon Plan that is not offset by the substantially smaller environmental costs, notably the much lower social costs of carbon. (*Id.*)

21. NV Energy offers that the capital requirements of the Preferred Plan total $11.0 billion and $6.1 billion for Nevada Power and Sierra, respectively. (Ex. 109 at 5.) NV Energy states that for Sierra, capital expenditures for the 2022-2041 period total approximately $6.1 billion for the Preferred Plan and $5.6 billion for the Alternate Plan. (*Id.*) Over the next five years (i.e., 2022-2026), NV Energy provides that capital projections for the Preferred and Alternate Plans are $3.0 billion and $2.5 billion, respectively. (*Id.*) For Nevada Power, NV Energy states capital expenditures over the 2022-2041 period are estimated to total $11.0 billion for either the Preferred or Alternate Plans. (*Id.*) Over the next five years, NV Energy provides that Nevada Power's capital spending projections for the Preferred and Alternate Plans are estimated to be $4.2 billion for each plan. (*Id.*)

22. NV Energy provides that, for both utilities, cash generated from internal operations during the 2022-2041 period is projected to be more than the capital project costs set forth in the capital expense recovery models for the Preferred and Alternate Plans. (*Id.* at 7.) Nevertheless, NV Energy states that additional common equity and debt funding will be required over this period. (*Id.*) To highlight the credit concerns previously articulated in other dockets,

NV Energy states that the financial modeling assumption in this filing is that NV Energy will operate at Staff's recommended capital structure from Sierra's 2022 GRC consisting of a 52.4 percent common equity ratio. (*Id.*) NV Energy asserts that this will require a disproportionate amount of debt financing for this incremental capital to reduce the actual common equity ratio, and the increase in debt financing commensurate with the corresponding decrease in common equity funding, will negatively impact credit metrics. (*Id.* at 7-8.) NV Energy explains that common equity funding will come through internally generated funds, the curtailment of dividends, and, if necessary, the issuance of common equity. (*Id.* at 8.) NV Energy states that it will, however, have a continued need to access external debt financing to fund the capital projects and to refinance maturing debt. (*Id.*)

23. NV Energy states that it will be able to access capital markets in order to finance the Preferred or Alternate Plans, if needed. (*Id.*) NV Energy explains that both utilities have demonstrated the ability to successfully access the debt markets at competitive rates relative to industry peers with similar credit ratings and to attract additional common equity investments from their parent company. (*Id.*) NV Energy notes that the cost of additional capital may be higher if NV Energy's credit ratings are downgraded. (*Id.*)

24. NV Energy states that it developed financial forecasts that reflect Staff's recommendations in Sierra's 2022 GRC. (*Id.* at 9.) NV Energy provides the following assumptions that were incorporated into NV Energy's financial forecasts:

i. A regulatory capital structure containing 52.4 percent common equity ratio for purposes of calculating revenue requirements for both Sierra and Nevada Power;

ii. Repositioning and maintaining a regulatory capital structure over the forecast period of 52.4 percent equity which requires the issuance of about $465 million of additional debt to reduce Sierra's September 30, 2022, equity ratio from 60.0 percent to 52.4 percent. Nevada Power's equity ratio was 52.7 percent as of September 30, 2022; therefore, only about $30.0 million of additional debt was needed to achieve a 52.4 percent common equity ratio;

iii. 9.5 percent allowed return on equity for purposes of calculating Sierra's and Nevada Power's revenue requirements over the forecast period;

iv. General rate case filings occur every three years for each utility with Sierra's first general rate case filing in 2022 and every three years thereafter and Nevada Power's first general rate case filing in 2023 and every three years thereafter;

v. No merger of Sierra with Nevada Power and the associated savings; and

vi. Current interest rate projections that reflect higher borrowing costs prevalent in today's market. (*Id.* at 9-10.)

25. NV Energy states that it believes that maintaining the current credit ratings is in the best interest of customers. (*Id.* at 12.) NV Energy explains that a credit rating downgrade will certainly increase NV Energy's cost of debt and cost of equity capital, which in turn will increase the cost to customers. (*Id.*)

Amended Supply Plan – Continued Operation of Existing Generation Units

26. NV Energy requests approval to amend its Supply Plan in order to accommodate the continued operation of existing generation units. (Ex. 100 at 18.) These units and proposed retirement are detailed as follows:

i. Clark Generating Station Unit 4 through 2035;

ii. Clark Generating Station Units 5, 6, and 10 through 2044;

iii. Clark Generating Station Units 7, 8, and 9 through 2043;

iv. Clark Peakers through 2048;

v. Harry Allen Generating Station Units 3 and 4 through 2046;

vi. Harry Allen Generating Station combined cycle units through 2049;

vii. Chuck Lenzie Generating Station through 2046;

viii. Silverhawk Generating Station through 2044;

ix. Higgins Generating Station through 2044;

x. Las Vegas Generating Station through 2049;

xi. Sun Peak Generating Station through 2041;

xii. Clark Mountain units through 2044.

27. NV Energy clarifies that it is not proposing new retirement dates for all of its generating units. (Ex. 115 at 5.) Specifically, NV Energy states that changes are not being proposed for the following units: Brunswick, Tracy 4 and 5 and Valmy 1 and 2. (*Id.*) NV Energy provides that Tracy 4 and 5 currently have an air permit requirement to cease operation at the end of 2031. (*Id.*) NV Energy states that the Valmy Units 1 and 2 are scheduled for retirement and decommissioning at the end of 2025. (*Id.*)

28. Importantly, NV Energy states that these retirement dates are not necessarily the final planning retirement dates. (*Id.*) NV Energy explains that all of NV Energy's units will continue to be reassessed to determine the appropriateness of the existing retirement dates. (*Id.*) NV Energy states that these reviews will be included in a future IRP or IRP amendment in the form of new or revised LSAPs, as appropriate. (*Id.*)

29. NV Energy provides that Nevada's RPS requirement for calendar year 2022 is set at 29 percent of retail sales that will increase to 34 percent in 2024, 42 percent in 2027, and 50 percent in 2030, and remain at 50 percent each calendar year thereafter. (*Id.*)

30. For the RPS renewable plan developed for this amendment, NV Energy uses a model to forecast future PC requirements and PC supplies. (*Id.*) NV Energy states that if, outside the IRP action period, the model indicates that the PC supply is insufficient to meet the RPS, generic placeholder projects are added, as needed, to fill the credit gaps. (*Id.*) NV Energy offers that placeholders have also been added to illustrate the timing and capacity required if NV Energy is to achieve its goal of meeting one hundred percent of its retail load with renewable resources by 2050. (*Id.* at 5-6.)

31. NV Energy provides that the model incorporates all statutory and regulatory limitations, as well as non-RPS PC obligations, in order to calculate the total number of eligible credits available to meet the RPS for each planning year. (*Id.* at 6.) NV Energy states that this total is then compared against the forecast credit requirement to determine whether each company will have sufficient PCs to meet its RPS obligation. (*Id.*)

32. NV Energy provides the following key assumptions that NV Energy incorporates into its modeling:

i. Full compliance with an escalating and compressed RPS schedule: 29 percent in 2022, 34 percent by 2024, 42 percent by 2027 and 50 percent by 2030 pursuant to NRS 704.7821;

ii. Ensuring enough renewable capacity to satisfy a strong and growing demand from the Nevada business community to meet their energy needs from carbon-free, sustainable energy; and

iii. Developing a long-term strategy to build a generating portfolio that can deliver 100 percent carbon-free energy to all customer load needs by 2050. (*Id.*)

33. NV Energy states that the expected PC supply was determined starting with the current portfolio of approved projects, both operating and under development or contemplated NV Energy. (*Id.*) NV Energy provides that the following assumptions are built into the forecast:

i. Existing PPAs expire in accordance with the contract terms and are not automatically renewed;

ii. NV Energy adjusted the expected amount of energy and PCs from renewable facilities for the period of 2022-2025 in cases where the historic generation, based on two or more years of data, consistently varied from that of the contractual or expected supply table. NV Energy states this is consistent with the methodology that NV Energy used for the past several years in developing its IRPs and energy supply plans ("ESPs"). NV Energy states that this adjustment recognizes that options to address underperformance within a shorter planning window are limited. NV Energy states that it also aligns the short-term and long-terms plans;

iii. The projected number of PCs derived from the Renewable Generations incentive programs plateaued in 2020 with the last of the incentivized solar systems now installed. Starting in 2021, the expected number of credits from incentivized rooftop solar is forecasted to begin decreasing by 0.5 percent per year as these systems age and their output slowly begins to decline;

iv. Solar systems placed into service before December 31, 2015, qualify for the solar multiplier, and that systems placed into service after do not qualify;

v. The plan assumes that the percent of annual PC requirements met from demand side management ("DSM") measures are limited to no more than 10 percent of the credit total for 2021 through 2024 before dropping to zero effective 2025.

The plan also assumes, based on current DSM kPC projections, that Sierra may not have a sufficient number of DSM PCs to completely fill the 10 percent cap in 2024;

vi. Surplus PCs are carried forward without limitation and the plan assumes no surplus PC sales;

vii. The plan assumes that generation from both company-owned solar PV systems and PPA projects would be degraded starting the year following the first full year of operation. Geothermal generation would continue to qualify for station usage credits, while all other technologies would no longer qualify;

viii. The plan accounts for all Commission approved and existing NV GreenEnergy Rider ("NGR") and Energy Supply Agreements ("ESAs") as of January 31, 2022, where PCs associated with all or a portion of the output from a renewable facility(s) has been assigned to a customer under the NGR, the Market Price Energy or Large Customer Market Price Energy tariffs, and therefore cannot be used by Nevada Power or Sierra in meeting their RPS credit requirements;

ix. The plan adjusts the retail sales total that is used to calculate the RPS requirement to exclude sales to bundled NGR or ESA customers, and other customers participating in a program of optional pricing that includes the transfer of PCs above that required for RPS compliance in an amount that is equal to the number of credits transferred to or retired on behalf of the participating customers;

x. The plan assumes that the net energy produced by Hoover and allocated to Nevada Power counts towards meeting the RPS;

xi. The plan assumes no changes to the existing statutory and regulatory RPS regime;

xii. The plan includes the North Valley Geothermal PPA, which a 25 MW geothermal plant with an estimated commercial operation date of December 31, 2022. Sierra will be the sole off taker of the energy and PCs. The total number of PCs from this project includes station usage PCs. Certain geothermal station usage, the energy for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine, is eligible for certification under the NRS 704.78215 3(b). Station usage PCs for this facility were estimated at 15 percent of net;

xiii. The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery losses, recognizing that not all of the energy produced by PV arrays paired with energy storage will be delivered real-time to the grid; and

xiv. An adjustment has been added to the model to capture the generation and PCs lost due to curtailment. This adjustment recognizes that as renewable energy becomes the dominant source of generation, there may be times when the transmission system cannot accommodate all the energy being produced making generation curtailment necessary to maintain grid integrity. (*Id.* at 6-8.)

34. Regarding these assumptions being incorporated into NV Energy's modeling, NV Energy provides that the renewable expansion plan developed for short-term planning purposes captures actual historical generation trends based on two or more years of operating data. (*Id.* at 9.) NV Energy provides that it adjusted the supply table based on this historical trend to reflect the most recent operating data after coordinating with internal contract owners to account for potential short-term anomalies. (*Id.*) NV Energy states that historical output trends for Sierra

contracted renewable projects resulted in an adjustment to seven projects, which were all decreases. (*Id.*) In total, NV Energy states that these adjustments lowered the amount of renewable energy by an average of 2.9 percent over the 2022-2024 ESP action period. (*Id.*) NV Energy offers that the same approach for Nevada Power resulted in adjustments to the amount of renewable energy for eight projects, seven decreases and one increase. (*Id.*) In total, NV Energy states that these adjustments lowered the amount of renewable and derived credits by an average 1.7 percent over the 2022-2024 ESP action period. (*Id.*) NV Energy argues that this approach maximizes the reliability and accuracy for the overall energy supply used in short-term planning. (*Id.*)

35. NV Energy provides that Nevada Power exceeded the 2021 RPS requirement of 22 percent ending 2021 with an overall RPS compliance result of 30.1 percent. (*Id.*) NV Energy asserts that Nevada Power is currently positioned to meet its 2022-2025 RPS obligations. (*Id.*) NV Energy explains that there is still the risk that one of the current renewable resources could develop an issue resulting in lost PCs. (*Id.* at 10.) NV Energy states that since NV Energy filed its Annual Compliance filing in April 2022, two projects, Iron Point, a 250-MW solar facility originally scheduled to declare commercial operation in December 2023, and Hot Pot, a 350-MW solar facility originally scheduled to declare commercial operation in December 2024, are no longer expected to reach their contracted commercial operation dates. (*Id.*) NV Energy states that the energy and credits from the two facilities were to be split between Nevada Power and Sierra, so the loss impacts both utilities. (*Id.*)

36. NV Energy states that assuming no production from Iron Point and Hot Pot, and assuming no additional cancelations and/or delays, Nevada Power is forecasted to be compliant to 2032. (*Id.*) To this end, NV Energy provides that Nevada Power will continue to evaluate

existing and pipeline projects and take corrective actions, so that it remains on track to meet all its renewable goals, commitments, and statutory requirements. (*Id.*)

37. NV Energy explains that Sierra exceeded the 2021 RPS requirement of 22 percent ending 2020 with an overall RPS compliance result of 31.9 percent. (*Id.*) NV Energy provides that Sierra is also currently positioned to meet its 2022-2025 RPS obligations. (*Id.*) NV Energy states that the removal of Iron Point and Hot Pot impacted Sierra more than Nevada Power for two reasons; one, Sierra does not have the same amount of backup pipeline capacity as Nevada Power and; two, Sierra faces the same set of ongoing risks involving remaining pipeline projects could be delayed or cancelled; operating projects could experience unexpected outages, and load growth could be higher than projected. (*Id.* at 11.) NV Energy cautions that if no action is taken today, even under the best of scenarios, Sierra could be facing non-compliance as soon as 2030. (*Id.*) Therefore, NV Energy argues that it is imperative that Sierra continue to solicit, vet, and forward proposals for approval. (*Id.*) Conservatively, NV Energy offers it can take four to five years to bring a new project online. (*Id.*)

38. NV Energy argues that the approval of the Ormat Portfolio and Eavor Geothermal projects would benefit Sierra's compliance outlook. (*Id.*) NV Energy maintains that the approval of the two agreements is expected to position Sierra to fully comply with the RPS through 2039. (*Id.*) NV Energy states that the added capacity is insurance against additional pipeline losses and/or delays. (*Id.*) NV Energy provides that it will help replace the energy lost as several Sierra long-term geothermal PPAs are set to expire in the near term. (*Id.*) NV Energy also provides that it would be a significant step in helping Sierra get closer to its goal of providing one hundred percent carbon-free energy to its customers by 2050. (*Id.* at 11-12.)

Ormat Geothermal Portfolio

39. NV Energy requests approval to amend its Supply Plan to allow Sierra to enter into the Ormat PPA for a portfolio of eight geothermal projects with a combined net nameplate rating of 120 MW. (Ex. 100 at 17.) NV Energy provides that commercial operation dates vary for the projects in the portfolio, with the first one expected in December 2024 and the PPA for all projects ending in 2053. (*Id.*) NV Energy states that the PPA has a flat energy price of $69.00 per megawatt-hour ("MWh"). (*Id.*) NV Energy is also requesting to amend its Transmission Plan to expend approximately $33.5 million to construct transmission infrastructure needed to support the interconnection of the geothermal portfolio PPA. (*Id.*)

40. NV Energy states that the Ormat geothermal portfolio was not bid in a renewable energy RFP but was presented as a bi-lateral opportunity to NV Energy in December 2021. (*Id.* at 12.) As part of the analysis conducted for the geothermal portfolio, NV Energy states that its Resource Planning group conducted a PWRR analysis of the geothermal portfolio. (*Id.*) NV Energy further provides that additional due diligence was conducted on the geothermal portfolio that included: (1) status and timing of interconnection, (2) evaluation of site control, (3) status of material permits, (4) review of material equipment for bankability and performance, (5) determination of whether the project development milestone schedule supports contractual commercial operation date, (6) evaluation of development and operating experience of the developer, (7) evaluation of the developer's financial capability, (8) evaluation of developer's jobsite safety performance history, and (9) evaluation of the available water supply. (*Id.* at 12-13.) NV Energy provides that, based on this analysis, no material concerns were raised. (*Id.* at 13.)

41. NV Energy states that Sierra and Ormat executed the geothermal portfolio PPA on May 13, 2022. (*Id.*) NV Energy provides that four of the contracted facilities, totaling 60

MW are existing: Desert Peak 2, Beowawe, Galena 1 (Burdette), and Galena 3. (*Id.*) NV Energy states that when those four PPAs expire, the facilities will remain contracted but under the new, proposed portfolio PPA. (*Id.*) NV Energy provides that the other four facilities are new generators. (*Id.*) NV Energy estimates that the combined portfolio is expected to produce 1,050,346 MWh of renewable energy and associated PCs annually. (*Id.*) NV Energy states that the PPA term will start on the first geothermal facility's commercial operation date (January 1, 2025) and end on December 31, 2053. (*Id.*)

42. In addition to the energy and capacity, NV Energy argues customers will benefit from all associated environmental and renewable energy attributes as the geothermal portfolio will help displace fossil-fueled generation. (*Id.*) NV Energy offers that the geothermal portfolio will also help to close Sierra's open capacity position and provide nighttime renewable energy in support of the zero-carbon goals. (*Id.*) NV Energy maintains that the predictable, around-the-clock generating profile provided by the geothermal portfolio becomes increasingly attractive as it will continue to help avoid exacerbating the solar PV generating peak. (*Id.*) In addition, NV Energy points out that the Legislature established an aspirational goal of achieving by 2050 an amount of energy production from zero-carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State and the geothermal portfolio will help achieve that goal. (*Id.* at 15-16.)

43. NV Energy states that the geothermal portfolio's price of $69 per MWh is approximately 29 percent lower than the last geothermal energy price approved by the Commission in Docket No. 11-08010 for the USG San Emidio geothermal facility of $97.76 per MWh. (*Id.*) NV Energy also provides that the geothermal portfolio's pricing is approximately 9 percent lower than the average geothermal PPA pricing for existing PPAs of $75.99 per MWh.

(*Id.*) NV Energy states that the geothermal portfolio combined with the North Valley PPA that is recently approved by the Commission result in a capacity weighted PPA price of $67 per MWh that is competitive when compared to some planning models that have typically assumed geothermal costs of $87 per MWh. (*Id.*) NV Energy asserts that the geothermal portfolio PPA price is at, near, or below the lower range of levelized cost of energy forecast and recent publicly available geothermal PPA pricing published by National Renewable Energy Laboratory ("NREL"). (*Id.*)

44. NV Energy provides that the opportunity to contract for baseload renewables is not nearly as abundant as solar and could become even more scarce as California also seeks to increase its already substantial stake in geothermal energy, which may create increased demand for Nevada's geothermal resources. (*Id.*)

Eavor Geothermal PPA

45. NV Energy requests approval to amend its Supply Plan to permit Sierra to enter into a PPA for 20 MW (net) AGS resource, the Valmy geothermal project. (Ex. 100 at 17.) NV Energy provides that commercial operation is expected in four phases, beginning December 2026, with a 25-year term at a flat energy price of $70.00 per MWh that will produce up to 170,000 MWh of energy per year. (*Id.* at 17, 19.)

46. NV Energy states that the Valmy Geothermal project bid was not in a renewable energy RFP and instead was the result of bilateral negotiations that began in early 2022 and were concluded in August of 2022. (*Id.*) NV Energy explains that Sierra has been in occasional, informal discussions with Eavor since 2019. (*Id.* at 19.) NV Energy states that Eavor, on behalf of Sierra, acquired the mineral rights beneath Sierra's property via a Bureau of Land Management auction held October 20, 2020. (*Id.*) NV Energy provides that the due diligence

conducted on Valmy Geothermal included: (1) status and timing of interconnection, (2) evaluation of site thermal capability to host geothermal, (3) status of material permits, (4) review of material equipment for bankability and performance, (5) determination of whether the project development milestone schedule supports contractual commercial operation date, (6) evaluation of development and operating experience of the developer, (7) evaluation of the developer's financial capability, (8) evaluation of developer's jobsite safety performance history, and (9) evaluation of the available water supply. (*Id.*) NV Energy provides that, based on this analysis, no material concerns were raised regarding Valmy Geothermal. (*Id.*)

47. NV Energy provides that Sierra and Eavor executed the PPA in November of 2022. (*Id.* at 20.) NV Energy offers that the project is located adjacent to Valmy on land owned by Sierra. (*Id.*)

48. NV Energy states that the Valmy Geothermal project will further NV Energy's efforts to diversify its renewable portfolio, introducing a new and promising technology that may greatly expand the available geothermal generating capacity in Nevada by eliminating the need to find a permeable aquifer. (*Id.* at 22.) NV Energy provides that, unlike traditional geothermal designs which rely on specific, rare geologic formations such as underground rock fractures and the presence of water, Eavor's novel underground design relies mainly on a sufficient underground heat gradient and therefore has the potential for much broader geographic deployment across northern Nevada. (*Id.*) NV Energy explains that the geothermal project is dispatchable and can provide a load-following capability, which will help balance Sierra's renewable energy portfolio, especially considering the solar PV and BESS projects that either recently became commercial or are under development. (*Id.*) NV Energy also provides that Valmy Geothermal also makes productive use of Sierra's land, mineral and other assets at the

retiring, Valmy coal plant while providing valuable locational system reliability benefits to this regional load pocket. (*Id.* at 22-23.)

49. NV Energy notes that the PPA price of $70.00 per MWh for Valmy Geothermal is approximately 28 percent lower than the last geothermal energy price approved by the Commission in Docket No. 11-08010 for the USG San Emidio geothermal facility of $97.76 per MWh. (*Id.* at 23.) NV Energy also notes that the Valmy Geothermal price is also approximately 8 percent lower than the average geothermal PPA pricing for existing PPAs ($75.99 per MWh). (*Id.*) NV Energy asserts that Valmy Geothermal price is competitive when compared to some planning models that have typically assumed geothermal costs of around $86 per MWh. (*Id.*) NV Energy asserts that the Valmy Geothermal PPA price is at, near, or below the lower range of levelized cost of energy forecast and recent publicly available geothermal PPA pricing published by NREL. (*Id.*)

Valmy BESS

50. NV Energy requests approval to amend its Supply Plan to permit Sierra to expend approximately $466 million to purchase, install, and operate a 200 MW, 4-hour, BESS project at Valmy with an in-service date of June 2025. (Ex. 100 at 17.) NV Energy also 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. (*Id.* at 18.) Finally, NV Energy requests approval to amend its Transmission Plan to expend approximately $8 million to construct transmission infrastructure needed to support the interconnection of the Valmy BESS. (*Id.*)

51. NV Energy explains that the Valmy BESS will provide capacity and grid ancillary and reliability services in the Carlin Trend region permitting the retirement of the coal-fired

generation station. (*Id.* at 25.) NV Energy offers that the Valmy BESS provides a new path to support the retirement of the Valmy coal plant given the difficulties and uncertainty surrounding the future of the Iron Point and Hot Pot projects. (*Id.*) NV Energy offers that this project will reduce reliance on market capacity and will help mitigate solar ramping impacts to the system while providing voltage support reactive power to the Carlin Trend region without reliance on coal-fired facilities. (*Id.*)

52. Regarding the Hot Pot and Iron Point projects, NV Energy explains that NV Energy continues discussions with the developer who, due to the recent volatility price increases in the solar and energy storage market, was unable to complete procurement on the schedule and at a price supporting that approved by the Commission in Docket No. 21-06001. (*Id.*) NV Energy provides that, while the proposed Valmy BESS is a partial solution to Sierra's needs, Iron Point and Hot Pot remain strategically located projects that are still viable assets to better address the energy and capacity needs in the region. (*Id.*) As such, NV Energy states that NV Energy and the developer are evaluating several alternatives to deliver one or both projects. (*Id.*) NV Energy offers that NV Energy will return to the Commission with its proposed solution when known. (*Id.*) In the meantime, NV Energy argues that Commission approval of the proposed Valmy BESS is a step towards ending the use of coal at Valmy, and the project will be valuable to Sierra's system and customers regardless of the future of Iron Point and Hot Pot. (*Id.* at 25-26.)

53. NV Energy states that the Valmy BESS will be a grid-tied, 200-MW, 4-hour lithium-iron-phosphate battery located directly adjacent to the Valmy coal plant on property owned by Sierra. (*Id.* at 26.) NV Energy states it will interconnect at the Valmy 345 kV substation. (*Id.*) NV Energy asserts that the project is expected to cost $466 million and will be

eligible for the ITC made available with the IRA. (*Id.*) NV Energy explains that the Valmy BESS was the result of a competitive RFP in the spring of 2022. (*Id.* at 27.) Finally, NV Energy states that it will continue to evaluate the potential for additional ITC credit for siting the Valmy BESS at a retired coal plant. (*Id.*)

54. NV Energy explains that the proposed cost for the Valmy BESS was based on bid results, price intelligence, and engineered budgets for the various parts of scope. (*Id.*) As of the time of this filing, NV Energy states that Sierra has begun negotiations for the BESS battery containers which include the lithium-iron-phosphate batteries, battery management systems, cooling systems, and other direct current electrical equipment. (*Id.*) NV Energy provides that the supplier was selected as the lowest cost, best value supplier, especially, when considering the Lithium index price adjustment. (*Id.*) Due to the price volatility of Lithium Carbonate experienced since the bids were received, NV Energy explains that Sierra chose to move immediately with the selected BESS supplier and notified that supplier and entering negotiations by the thirty (30) day deadline for a price hold in the supplier's offering. (*Id.* at 28-29.) NV Energy provides that the other suppliers did not offer prices without Lithium Index adjusters. (*Id.* at 29.) NV Energy also provides that, at the time of this filing, Sierra also solicited best and final pricing for the two BESS system integrators to finalize project details, procurement of balance of plant equipment, and finalization of project construction contracts. (*Id.*)

Amended Transmission Plan – Static Voltage Support in the Carlin Trend Load Pocket

55. NV Energy requests approval to amend its Transmission Plan to expend approximately $13 million to install capacitor banks at the Humboldt and Maggie Creek substations for static voltage support in the Carlin Trend load pocket. (Ex. 100 at 19.)

56. NV Energy asserts that Valmy generation is critical to the transmission system reliability in northeastern Nevada. (Ex. 107 at 6.) NV Energy explains that Valmy generation provides both capacity as well as critical voltage support to the over 350 MW Carlin Trend area load pocket. (*Id.*) NV Energy also provides that Valmy generation is also critical due to its location on the transmission grid and the lack of any other substantial company-owned resources in the area. (*Id.*) NV Energy states that it has determined that the plan to replace the Valmy coal plant with the Hot Pot and Iron Point projects is unlikely to go forward. (*Id.*) As such, to allow the timely retirement the Valmy coal plant, NV Energy states that there is a need for the Valmy BESS or a 200 MVAR STATCOM to provide dynamic voltage support in the Carlin Trend area. (*Id.*) NV Energy explains that these new alternatives will also require additional static voltage support in the form of switched capacitor banks. (*Id.*) NV Energy provides that a new 100 MVAR 345 kV capacitor will need to be installed at Humboldt Substation and a new second 18 MVAR 120 kV capacitor bank will be needed at the Maggie Creek 120 kV substation. (*Id.*) NV Energy states that the existing capacitor at Maggie Creek is 12 MVAR and is planned to be resized to 27 MVAR for a total of 45 MVAR. (*Id.*) NV Energy provides that the BESS is NV Energy's preferred mitigation, and is currently being planned to provide voltage support and partially replace existing Valmy capacity. (*Id.*) However, NV Energy notes that both options require a new line bus position on the Valmy 345 kV Substation bus. (*Id.*) NV Energy offers that this new lead line position will allow the Valmy coal plant to continue to operate while the new BESS is constructed and commissioned. (*Id.*)

Associated Transmission Infrastructure

57. NV Energy explains that the proposed transmission system network upgrades will be required to interconnect the resource additions included in the Preferred Plan. (Ex. 107 at 4.)

NV Energy states that the required System Impact Studies ("SIS") and Facility Studies ("FS") for the resource additions in the Preferred Plan have not been completed yet. (*Id.*) Once the SIS and FS are completed, NV Energy provides it may be determined that additional transmission facilities are also required. (*Id.*)

58. NV Energy states that the Preferred Plan includes the addition of the Valmy BESS. (*Id.* at 5.) NV Energy asserts that in order to connect the Valmy BESS will require the addition of a new terminal on the Valmy 345 kV bus so that the Valmy coal plant can continue to operate while the BESS is constructed and commissioned. (*Id.*) NV Energy provides that the estimated cost of the new Valmy terminal is $8 million. (*Id.*)

59. NV Energy provides that the Preferred Plan includes a 120 MW Ormat geothermal portfolio. (*Id.*) NV Energy explains that this will require NV Energy to rebuild the Eagle-Tracy 120 kV #146 line to a higher capacity. (*Id.*) NV Energy estimates the cost for these additions at $33.5 million. (*Id.*) NV Energy notes that there are also additional contingent interconnection terminal facilities that could be required if the prior queued projects do not construct them. (*Id.*)

60. NV Energy states that the 20 MW Eavor geothermal project that is included in the Preferred Plan will require an interconnect to the 25 kV Valmy distribution system. (*Id.*) NV Energy estimates the cost for this interconnection is $100,000. (*Id.*)

61. NV Energy states that the transmission system network upgrades required to interconnect the resource additions will not change if the Alternate Plan is selected. (*Id.*) NV Energy explains that the only difference between the Preferred Plan and the Alternate Plan is that the Alternate Plan does not include the Valmy BESS. (*Id.*) However, NV Energy notes that there is a need for dynamic voltage support at Valmy after the retirement of the Valmy coal plant

which is anticipated to occur at the end of 2025. (*Id.*) NV Energy states that if the Valmy BESS is not installed, it will be necessary to install a 200 megavolt-ampere reactive STATCOM at Valmy. (*Id.*) NV Energy provides that this STATCOM will require the same 345 kV interconnection terminal at Valmy as the BESS. (*Id.*)

Google's Position

62. Google recommends that the Commission postpone its decision on Phase II of the Joint Application until more robust modeling and analysis is completed and provided by NV Energy in a refiled fourth amendment that is reviewed for potential approval by the Commission. (Ex. 500 at 2.)

Nevada Worker's Position

63. Nevada Workers supports the Joint Application. (Ex. 1600 at 3.) Nevada Workers provides that state energy planning must ensure that 1) short term energy supply requirements are fully met and 2) the build-out of energy infrastructure necessary to meet long term load and resource adequacy requirements is begun now. (*Id.*) In particular, Nevada Workers specifically supports the following projects:

i. Hilltop 345 kV PST
ii. Reid Gardner — Harry Allen #3 230 kV line
iii. Fernley Area Master Plan
iv. Silverhawk
v. Valmy BESS with Humboldt Maggie Creek Switched Capacitor
vi. Brooks 230/138 kV Substation
vii. Nevada Solar One Area 230 kV
viii. Apex Area Master Plan
ix. Fort Churchill — Captain Jack 525 kV transmission line

(*Id.* at 3-4.)

64. Nevada Workers points to the extreme heat wave that hit the Western United States, including Nevada, last September, that resulted in record energy demand throughout the West, placing exceptional pressure on the supply of electricity. (*Id.*) Nevada Workers explain

that California declared an energy emergency, which meant California could use energy that had been planned to fulfill the needs of Nevadans, leading to shortages in Nevada. (*Id.*) Nevada Workers explains that a number of factors; including record-breaking temperatures, extreme weather events, severe drought conditions, massive wildfires, and climate change generally; lead to scenarios that strain the electric grid and negatively impact energy infrastructure. (*Id.* at 5.)

65. Nevada Workers explains that the specific projects being pursued by NV Energy will advance Nevada's energy independence by adding key generating resources within the state, including 24/7 geothermal energy capacity, large-scale energy storage to extend availability of renewable energy resources and natural gas units designed to quickly respond to extraordinary energy demand. (*Id.*) Nevada Workers states that the Joint Application will also add more capacity to NV Energy's growing renewable energy portfolio that will ensure Nevada will meet the State's ambitious clean energy goals. (*Id.*)

66. Nevada Workers states that it supports the Valmy BESS with Humboldt Maggie Creek Switched Capacitor project because there is an urgent resource adequacy issue that these projects will help solve. (*Id.*) Nevada Workers also notes that the Valmy BESS project is eligible for federal tax credits under the IRA, which means the cost burden on customers is reduced by federal subsidies. (*Id.*)

67. While Nevada Workers understands that the projects in the Joint Application will lead to increased costs on ratepayers, Nevada Workers maintains that these costs are warranted to ensure safe and reliable electric service in the future. (*Id.* at 8-9.)

Interwest's Position

68. Interwest states that NV Energy did not hold an all-source RFP in this IRP and that the Commission should order NV Energy to do so in the next IRP. (*Id.*) Interwest further

provides three concerns regarding NV Energy's use of a capacity expansion model to review RFP results. (*Id.* at 36.) First, Interwest states that NV Energy did not allow the market to test its assumptions on gas-fired plant extensions but relied on generic units to test its preferred acquisitions. (*Id.*) Second, Interwest states that NV Energy's assumptions in its base case capacity expansion runs did not allow renewable resources to compete to provide capacity to the system and hampered the ability of storage resources to do so. (*Id.*) Third, Interwest states NV Energy contracted for resources outside of the RFPs. (*Id.*) Regarding Interwest's first concern, Interwest states that NV Energy's decision points in this Docket are rooted in it, base case model runs. (*Id.*) Interwest elaborates that no optimized capacity expansion modeling including RFP bids was utilized or, if such modeling occurred, the Commission is kept in the dark as to its results. (*Id.*) Regarding Interwest's second concern, Interwest states that NV Energy's base case model was constrained from considering renewable and storage resource from providing capacity credit to meet the resource need. (*Id.* at 37.) Interwest provides that, contrary to NV Energy's narrative, NV Energy does have sound data on capacity provided by renewables: its Effective Load Carrying Capability ("ELCC") study. (*Id.*) Interwest states NV Energy's approach guaranteed that a new gas-fired unit would be selected to meet the need, because only gas-fire resources were allowed as options. (*Id.*) Additionally, Interwest states that NV Energy makes a request in this case to extend the useful life of approximately 17 gas-fired generators. (*Id.*) Interwest provides that several of these gas-fired units, including the Ft. Churchill Units 1 and 2, Tracy Unit 3, or Clark Unit 4, would raise potential retirement decision for the Commission as soon as 2028 and possibly in the next IRP. (*Id.* at 37-38.) Interwest states that NV Energy's model did not test these retirement decision points, as it is designed to do. (*Id.* at 38.) Instead, Interwest provides, that the plant-life extensions were "baked in" the model as firm decisions. (*Id.*) Interwest argues that if the plant life extensions are granted here, those units will continue to operate absent any modeling on the cost-effectiveness of these decisions and absent market responses. (*Id.*)

69. Interwest provides that it was not correct for NV Energy to exclude renewable resources from being candidate resources in its base case. (*Id.* at 39.) Interwest explains that it is not a best practice to exclude the cheapest and fastest growing technologies in the market from an evaluation that is intended to inform the utility of its options to meet the resource need. (*Id.*) Interwest states that the result of excluding those technologies in the screening process was to limited the ability of the model to accurately create potential resource portfolios based on data available in the market. (*Id.*)

70. Interwest states that NV Energy's RFPs were not set up to provide information and certainty to market participants in the IRP process. (*Id.*) Interwest points out that neither the Spring 2022 or Winter 2023 solicitations mention the ongoing IRP process, the resource adequacy need, or even the level of capacity being sought. (*Id.*) Interwest provides the example that, although the Spring 2022 RFP provides a "Table 2 — RFP Schedule" with dates for filing for PUCN approval, those dates had already passed. (*Id.*)

71. Interwest identifies two issues that Interwest states, if raised in a Phase 1 and prior to an RFP, might lead to a more efficient IRP outcome: (1) NV Energy's approach to renewable contract terms and (2) NV Energy's concerns about the California Independent System Operator ("CAISO") market and its future purchases. (*Id.* at 40-41.) Regarding the contract terms, Interwest provides that, in the Spring 2022 RFP, for bidders submitting PPA proposals, NV Energy provided that the term of such contracts must be thirty-five (35) years. (*Id.* at 41.) Interwest states that that term length is excessive based on the market standard of 15 — 25 years

for wind and solar projects, and 20 years for BESS projects. (*Id.*) Interwest explains that restricting generators to a certain term, versus allowing a range based on the project, is a problematic approach. (*Id.*) Interwest also states that the RFP requires three NV Energy options to purchase at eight, fourteen, and twenty-five years. (*Id.*) Interwest argues that were these provisions available to be reviewed by stakeholders, parties such as Interwest might take issue with them before the Commission. (*Id.*) Regarding NV Energy's concerns about the CAISO market and its future purchases, Interwest states the IRP provides NV Energy's concerns with CAISO purchases as a key driver for its procurement decisions, including the new CT. (*Id.* at 42.) Interwest points out that NV Energy's capacity position shows market purchases dropping approximately 80% (over 1000 MW) in 2024-2028, and regaining most of the purchases by 2030. (*Id.*) Interwest states that the reduction in market capacity is due to new resources coming online, not a reduction from CAISO purchases. (*Id.*) Interwest explains that, for this CAISO uncertainty, a two-phase process would better handle the risk as a future to be explored in a different portfolio outlook, i.e., a "low market purchase" portfolio, rather than presented as fact. (*Id.*) Interwest provides that, in such an event, the risk of CAISO market purchases falling significantly could be considered, but so could a continued market purchase level portfolio using a five-year average, for example, or perhaps a "high market purchase" scenario as a counter balance. (*Id.*) Interwest offers that the goal would be for the Commission to review how the model selects resources under different futures. (*Id.*) Further, Interwest states that, in sensitivity analysis, the production costs could be evaluated with different market price sensitivities, indicating that if CAISO market purchases were available, they might be more costly. (*Id.*)

72. Interwest also holds concerns regarding the geothermal PPAs presented by NV Energy. (*Id.*) Although Interwest states it supports PPAs and geothermal energy, Interwest

provides that it is concerned that even the PPAs in this Docket were executed based on an unsolicited offer made outside of the three RFPs that have been released. (*Id.* at 42-43.) Interwest points out that one red flag here is that NV Energy proposed paying the nearly the same price for a 120 MW unit as a 20 MW unit, implying that NV Energy did not capture economies of scale. (*Id.* at 43.)

WRA's Position

73. WRA states that it holds reservations regarding the process NV Energy has pursued to assess and select resources within its IRP. (Ex. 602 at 7.) WRA provides that, in light of NV Energy's need for replacement renewable energy and capacity, WRA believes it is reasonable for the Commission to approve the Ormat geothermal, Eavor geothermal, and Valmy BESS contracts at this time. (*Id.* at 7-8.) WRA provides that geothermal and BESS resources are effective alternatives for peaking generation, supporting reliability and financial hedging for NV Energy customers during critical periods. (*Id.* at 8.)

74. WRA states that NV Energy utilizes ELCC values for geothermal that NV Energy calibrated based on the historical performance of its existing geothermal fleets. (*Id.*) WRA explains that these assumed values reflect significant degradation associated with ambient derates during the summer peak, which substantially reduces the ELCC values of these resources. (*Id.*) As such, WRA recommends that the Commission should direct NV Energy to assess and value the reliability of the new geothermal resources based on their anticipated performance, including any novel technologies, efficiency upgrades, or ambient environmental condition differences relative to the existing fleet. (*Id.*) WRA provides that NV Energy claims that the AGS Eavor-Loop eliminates or mitigates many of the issues with traditional geothermal and has greater dispatchability than traditional geothermal. (*Id.*) WRA points out that these

attributes are not reflected in NV Energy's current ELCC modeling or reliability accounting efforts. (*Id.*)

75. WRA recommends that the Commission should not approve NV Energy's requests to extend the lifetimes of its existing generation as proposed. (*Id.* at 9.) WRA provides that, while NV Energy has taken significant steps to integrate best practices in resource planning and portfolio modeling, its approach to assessing resource retention is unorthodox and counterproductive. (*Id.*) Specifically, WRA states that NV Energy does not model resource retention or retirement as a consideration within its resource planning modeling exercise. (*Id.*) Instead, WRA states that NV Energy assesses retention through the LSAP. (*Id.*) WRA explains that LSAP includes several steps to determine the operational, economic, and environmental impact of retention of the resource. (*Id.*) WRA states that the LSAP process appears to be separate from, and an exogenous input to, NV Energy's portfolio development process. (*Id.*) WRA offers that, if NV Energy concludes that an existing resource merits extension of its useful life, the resource is not eligible for an early retirement within NV Energy's capacity expansion model. (*Id.*) Specifically, WRA states that NV Energy notes that the PLEXOS LT analysis assumes the continued operation of many existing gas-fired units both in the north and south as cost-effective resources based on economic screenings. (*Id.*) WRA argues this prevents the model from identifying resources which are potentially more cost-effective as candidates to replace the existing generation. (*Id.*)

76. WRA explains that NV Energy's approach is problematic for two reasons. (*Id.*) First, WRA states that, for the consideration of this request, NV Energy's economic screening within the LSAP is less robust than the modeling process it utilizes within its portfolio development process. (*Id.*) WRA offers that the IRP modeling process is far more robust, as it

considers the integrated operations of its entire resource fleet, incorporates stochastic analysis (for economic modeling, though not reliability), and assesses which resource investments are optimal, including potential economic replacements of NV Energy's existing resources. (*Id.* at 10.) Second, WRA provides that forcing the retention of existing thermal units can result in NV Energy retaining excess generation resources when accelerating its near-term build-out of clean energy resources. (*Id.*) WRA states that this outcome is avoidable. (*Id.*) WRA elaborates that, if NV Energy permits its model to consider retirements to offset the new build it is considering in the low-carbon case, NV Energy could arrive at a low-carbon portfolio that meaningfully reduces greenhouse gas emissions without an overabundance of resources and associated costs. (*Id.*) WRA explains that replacing existing fossil fueled generation with new, clean resources is potentially less costly than layering emissions free resources on top of fossil fueled generation. (*Id.*) Given these shortcomings, WRA argues NV Energy's request for extension to the retirement dates of its existing generation should be deferred to a subsequent filing. (*Id.*)

CMN's Position

77. CMN recommends that the Commission either require NV Energy pay ratepayers $75,600,000 of damages if the Commission approves removing Iron Point and Hot Pot from NVE's ESP, or, alternatively, deny the proposal to remove the projects and determine damages later, and deny the Valmy BESS as inadequate. (Ex. 800 at 28-29; Ex. 801 at 28.) CMN states that the Iron Point and Hot Pot projects approved in the Joint 2021 IRP were intended to replace the Valmy coal plant, were approved as though they were third-party PPAs under NRS 704.752, and represented the most significant resources additions for NV Energy at that time. (Ex. 800 at 23-24.) CMN states that under NRS 704.752, NV Energy took on the risk of the projects and committed to delivering energy as contemplated under the PPAs. (*Id.* at 24.) CMN notes that

NV Energy agreed to exclude all Iron Point and Hot Pot's capital investment and expenses from Nevada Power and Sierra's rate base and revenue requirement; however, NV Energy now proposes to remove Iron Point and Hot Pot and replace it with the Valmy BESS system for about the same energy storage price as was proposed for the Iron Point BESS of $466 million. (*Id.* at 25.)

78. CMN states that the Commission approved the Iron Point and Hot Pot PPA subject to specific damages terms, including costs for replacement energy, poor reliability of the BESS, and up to $31,500,000 for Iron Point beginning December 1, 2023, and $44,100,000 for Hot Pot, beginning December 1, 2024, for a total of $66,150,000 after 180 days of failing to reach commercial operation. (*Id.* at 27; Ex. 801 at 27; Tr. at 488.) Based on the NV Energy's proposal to remove the Iron Point and Hot Pot resources, CMN concludes that NV Energy should be liable for these damages under the terms of the approved PPAs because NV Energy has not identified any catastrophic events or natural disasters that would invoke the force majeure terms of the PPA. (Ex. 800 at 24, 28.)

79. CMN recommends that the Commission approve either the South CT or Base Case plans and require NV Energy to conduct an all-source RFP to be included in the next IRP. (*Id.* at 36.) CMN states that NV Energy does not evaluate scenarios to appropriately determine the most viable least cost plan. (*Id.* at 32.) CMN avers that NV Energy performed sensitivity analyses for the Moderate and Limited Plans, but not the South CT or Base Case Plans and was unwilling to provide them when requested to do so via discovery, even though neither the Moderate nor Limited Plans were the least cost options. (*Id.* at 32.) CMN states that the portfolio presented in this Docket is so different from what was approved in the 2021 Joint IRP that no

proper basis exists to determine cost-effectiveness without a comprehensive request for proposal. (*Id.* at 35-36.)

BCP's Position

80. BCP provides that a main goal facing Nevada is the prioritization of resource adequacy in reducing NV Energy's open capacity position. (Ex. 400 at 5.) BCP states the EPA and the U.S. Department of Energy ("DOE") have recently executed a Joint Memorandum on Interagency Communication and Consultation on Electric Reliability. (*Id.* at 6.) BCP explains memorandum provides a framework for interagency cooperation and consultation on electric sector resource adequacy and operational reliability at a time of significant dynamism in the electric sector. (*Id.*) BCP states that the EPA and DOE also anticipate that they will engage in regular outreach and consultation with the FERC when carrying out activities under the memorandum. (*Id.*) Further, BCP states that the memorandum outlines that a reliable and resilient electric power system is indispensable to the national security and economic well-being of the United States. (*Id.*) Accordingly, BCP provides that meeting this challenge will require the shared effort of many entities including but not limited to the FERC-designated Electric Reliability Organization for North America ("NERC"), regional reliability entities, state public utility commissions, developers, owners and operators of generation and transmission resources. (*Id.*)

81. BCP disagrees that this Joint Application includes a diverse set of alternative plans in accordance with the provisions of NAC 704.937(1). (*Id.* at 7.) BCP states that the provisions of NAC 704.937(1) applies to a full triennial IRP not an amendment — in which a three-year action plan is vetted and approved by the Commission. (*Id.*) BCP states that NV Energy has morphed IRP amendments into full triennial IRPs. (*Id.*) BCP explains that providing

a diverse set of alternative plans for consideration is not appropriate for or applicable to an amendment of a previously approved or amended three-year action plan. (*Id.*) BCP states that, in this case, the subject three-year action plan covers the years 2022-2024. (*Id.*)

82. BCP provides that the provisions of NAC 704.9503 (monitoring and amendment of action plan) are specific to an amendment to a previously approved to three-year action plan. (*Id.*) BCP explains that an amendment provides new resources and commitments that were not previously approved as part of the action plan and those which are unable to be secured in accordance with the schedule that is included in the action plan previously approved by the Commission. (*Id.*) Therefore, BCP states that offering a set of alternate plans to select from in an amendment is nonessential but should only be used to as a test comparison in developing which resources and/or commitments should be included in the subject three-year action plan. (*Id.*) BCP maintains that the presented low carbon case in this amendment is not required for an IRP amendment pursuant to NRS § 704.741(3)(c) and is not practical or cost effective at this juncture and only serves as an academic exercise in this case. (*Id.*)

83. BCP has no objection to NV Energy's request for the approval to amend the NV Energy's Action Plan to allow Sierra to enter a PPA for a portfolio of eight geothermal projects with a combined nameplate rating of 120 net MWs with varying commercial operation dates beginning in 2024 and all ending in 2053. (*Id.*)

84. BCP has no objection to NV Energy's request to construct transmission infrastructure required to support the interconnection of the 120 MW geothermal portfolio PPA securitized at an estimated cost of $33.5 million. (*Id.*)

85. BCP has no objection to NV Energy's request to allow Sierra to enter a PPA with Eavor for a net 20 MW AGS resource with commercial operation expected in four phases

beginning in 2026 with a 25-year term at a flat energy price of $70.00 per MWh. (*Id.*) BCP explains that the Eavor technology has been demonstrated in Canada and could further increase the development of geothermal resources within Nevada. (*Id.*)

86. BCP opposes NV Energy's request to expend an approximate $466 million for a the Valmy BESS. (*Id.* at 2-3.) BCP states that NV Energy offers a partial solution regarding the retirement of the Valmy coal plant in 2025, including a limited replacement of the voltage support, and capacity contribution expected from the Iron Point and Hot Pot solar with BESS projects being delayed or potentially not being developed. (*Id.* at 3.) BCP explains that a fifth amendment to the 2021 Joint IRP is expected to be filed this summer and offer a complete solution for the capacity contribution and voltage support commensurate to accommodate a Valmy coal plant retirement. (*Id.*) BCP argues that, based on a reliability and resource adequacy criterion, it is premature to approve the Valmy BESS to retire the Valmy coal plant in 2025, which, if approved, would reduce system reliability by up to 188 MW of capacity (388 MW considering the availability of Valmy Unit 1 during an emergency event which has been dispatched for such events in the last couple of years). (*Id.*) BCP states that it appears that the Valmy coal plant has a flexible window to operate beyond 2025 through 2028 and would comply with forthcoming regional haze and ozone emission requirements. (*Id.*) BCP offers that a retirement date for the Valmy coal plant should be subject to and vetted in the forthcoming fifth amendment. (*Id.*) Further, BCP states that, based on NV Energy's analysis, the Valmy BESS has a higher PWRR, carbon intensity, and Present Worth of Societal Costs ("PWSC") than other options analyzed and tested against the Valmy BESS which are not subject to approval in this case. (*Id.*) BCP explains that increased carbon intensity is apparently due to the BESS inefficiency (i.e. charging and discharging losses) with fossil fuels as modeled. (*Id.*)

87. Based on the previous Commission order in Docket 21-06001, BCP states that the Commission determined that Iron Point and Hot Pot solar with BESS projects were necessary to replace the capacity associated with the Valmy coal plant for a December 31, 2025, retirement date. (*Id.* at 10.) BCP states that that this retirement date could be subject to change via an IRP or IRP amendment. (*Id.*) BCP explains that the Iron Point and Hot Pot solar with BESS projects (600 MW solar, 480 MW BESS) may not be delivered or would not be delivered in time to replace the capacity associated with the Valmy coal plant. (*Id.*) Further, BCP offers that the current market conditions have driven the critical need for resource adequacy which the Western Electric Coordinating Council ("WECC"), NERC, DOE and EPA acknowledge is critical for a reliable and resilient electric power system. (*Id.*) BCP argues that, given that circumstances have changed, it would be prudent to accept that December 31, 2025, is not unequivocally set. (*Id.*) BCP provides that a complete replacement in kind for the capacity and voltage support associated with Valmy within the Carlin Trend load pocket needs to be determined commensurate with setting the Valmy coal plant retirement date. (*Id.*)

88. BCP provides that Sierra's share of the Valmy coal plant is 261 MW. (*Id.*) BCP explains that, under emergency events, Sierra can use Idaho Power Company's share of Unit 1, which would increase available capacity from Valmy to 388 MW. (*Id.* at 10-11.) BCP states that the proposed Valmy BESS project does not replace the capacity associated with the Valmy coal plant. (*Id.* at 11.)

89. BCP states that, on March 15, 2023, the EPA has finalized the Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards. (*Id.*) BCP explains that this final rule requires NOx emissions reductions from power plants and industrial resources that pollute across state lines, including Nevada. (*Id.*) BCP also provides that EPA adopted several

changes to the final rule to address reliability concerns. (*Id.* at 12.) BCP offers that the final rule provides greater compliance flexibility for power plants by deferring backstop emission rate requirements for plants with generating capacity greater than 100 MW that currently do not have state-of-the-art controls, such as selective catalytic reduction controls, until no later than 2030. (*Id.*) BCP maintains that this standard applies to the Valmy coal plant. (*Id.*) Further, BCP states that the final rule enhances the availability of allowances allowing plant owners to "bank" allowances at a higher level through 2030. (*Id.*) In particular, BCP explains that the rule provides greater certainty for grid operators and power companies by establishing a predictable minimum quantity of allowances through 2029. (*Id.*) Additionally, BCP states that the rule ensures that no unit incurs a penalty under the backstop emission rate requirements solely because of limited unavoidable emissions. (*Id.*) In light of this information, BCP offers that it appears that the Valmy coal plant may have a flexible window to operate beyond 2025 through 2028. (*Id.*) To be clear, BCP does not advocate that the Valmy coal plant be retired in 2028 or any date at this juncture. (*Id.*) Instead, BCP provides that the Valmy coal plant retirement date should be vetted and determined by the Commission based on a plan that provides for a complete replacement of capacity and voltage support associated with Valmy expected to be inclusive of the fifth amendment this summer. (*Id.*)

90. BCP explains that NV Energy offered a comparison to a 200 MW combustion turbine of equal capacity along with a 200 MVAR STATCOM facility of equal voltage support, shown in Figure EA-4 of the Joint Application. (*Id.* at 13.) BCP states that NV Energy provides that the Valmy BESS employ a conservative 30 percent ITC. (*Id.*) However, BCP states that upon review of the PWRR values, the Joint Application is based on the capital expense recovery work sheets with a 40 percent ITC. (*Id.*)

91. BCP provides that Figure EA-19 of the Joint Application reveals that the Valmy BESS would be notably more carbon intensive between 2025 through 2033 as modeled. (*Id.* at 15-16.) BCP explains that this is likely due to the energy loss associated with the inefficiency of charging and discharging the BESS facility with fossil fuels and/or purchased power generated by fossil fuels as modeled. (*Id.* at 16.) BCP points out that similar results are represented in Figure NERA-3 of carbon dioxide emissions and the respective PWSC values in Figures NERA-9 and NERA-10. (*Id.*)

Staff's Position

92. Staff recommends that the Commission approve the proposed PPAs with Ormat and Eavor. (Ex. 309 at 1.) Staff states that the Ormat PPA is comprised of:

i. Energy from four existing geothermal facilities and four new geothermal facilities;
ii. A combined capacity of between 105 and 135 MWs;
iii. A term beginning in January 2025 and expiring on December 31, 2053;
iv. An energy cost of $69.00 per MW-hour.

93. Staff also states that the Eavor contract for a new geothermal facility will be for a capacity of 16 to 20 MWs, 25 years beginning on December 31, 2026, and $70.00 per MW-hour. (*Id.* at 2.)

94. Staff states that NV Energy did not take into consideration potential delays, shortfalls or cancellations in its RPS forecast, which was unexpected due to the fact that NV Energy has publicly stated that several PPAs will not meet the contracted commercial operation date, including the already-approved Iron Point and Hot Pot projects. (*Id.* at 5-6.) Given the stated delays, Staff avers that NV Energy should have included the delays should have been

modeled in the RPS forecasts. (*Id.* at 6.) As a result, Staff requested NV Energy run additional compliance forecasts, one with the proposed geothermal PPA's not approved and one with the proposed PPAs approved, which NV Energy did. (*Id.*) As a result of the studies incorporating the noted delays and cancellations, Staff concludes that the approval of the proposed geothermal PPAs will hedge against additional delays or cancellations, support NV Energy meeting its RPS requirements, give NV Energy more dispatchable resources, and, while the cost of new geothermal resources may be lower in the future, the cost does not support denial of the proposed PPAs. (*Id.* at 7.)

95. Staff recommends that the Commission approve NV Energy's request to rebuild 21 miles of the existing Eagle-East Tracy 120 kilovolt ("kV") #146 line to provide transmission services for Ormat's geothermal portfolio for $33.5 million. (Ex. 302 at 1-2.) Staff states that Ormat's proposed geothermal portfolio consists of eight existing and new geothermal plants, including the existing Beowawe, Galena 1, Galena 3, and Desert Peak 2 plants and the new North Valley 2, Pinto, Lone Mountain, and Gerlach. (*Id.* at 2.)

96. Staff recommends that the Commission deny the request to purchase, install, and operate the Valmy BESS at the estimated cost of $474 million, including transmission upgrades. (Ex. 313 at 2.) Staff further recommends that the Commission order NV Energy file a life assessment plan outline for the future of the Valmy plant site, specifically analyzing whether both the Valmy coal plant units should be retired in 2025, and what NV Energy's plans are regarding meeting Sierra's capacity and energy needs. (*Id.*) Staff asserts that this could be accomplished through a potential upcoming amendment to include a full range of alternatives. (Tr. at 806.) Staff notes that it supported the Silverhawk combustion turbines as "insurance policies" for summer peak capacity concerns, but that Staff cannot support the proposed "half-a-

billion dollar" Valmy BESS without a comprehensive, carefully thought-out plan to address capacity issues over the next 5-10 years. (Ex. 313 at 4.) Staff further suggests that the Joint Application is "essentially throwing out the Preferred Plan [from the previously approved IRP] and replacing it with a new plan" and proposing a project that was not proposed in the 2021 Joint IRP. (Tr. at 766; 803-04.) Staff avers that the changes in the Joint Application greatly modify the Preferred Plan from what was approved in the 2021 Joint IRP and fail to provide a comprehensive replacement plan. (*Id.* at 766-67.) Staff concludes that NV Energy should have simply filed a new, full plan to restart the resource planning process. (*Id.* at 788.)

97. Staff acknowledges that under the most recent SIP that there is a federally enforceable mandatory closure date of December 2028 for both Valmy coal plant units. (Ex. 313 at 5.) Staff also expresses concern over NV Energy maintaining a voluntary closure date of 2025 for the Valmy coal plant and that NV Energy disavows responsibility for any ensuring reliability issues. (*Id.*) In short, Staff acknowledges that there is a need for capacity replacement near the existing the Valmy coal plant, but believes that the BESS is a "quick, reactionary decision due to delays/setbacks" in the Iron Point and Hot Pot projects. (*Id.* at 5 and 8.)

98. Without the required information being included in this filing, Staff posits that Iron Point and Hot Pot projects have been removed from NV Energy's Preferred Plan because of issues relating to cost and or in-service dates. (*Id.* at 7.) In comparing the Iron Point and Hot Pot resources to the proposed BESS, Staff alleges that "[t]here is no comparing what the Commission approved in the 2021 IRP [600 MWs of new solar resources and 480 MWs of new battery storage] and what NV Energy" proposed here – a 200 MW stand-alone BESS. (*Id.* at 8.) Staff states that the BESS is an insufficient replacement for the existing the Valmy coal plant in terms of reliability, NV Energy's operating experience, and energy. (*Id.* at 9.) Staff further states

that the proposed BESS would be 188 MWs short of the current capacity of the Valmy coal plant, i.e. the Valmy coal plant can produce 388 MWs of power and the BESS could deliver 200 MWs (where 388 minus 200 equals 188.) (*Id.* at 17.) Staff also states that the Joint Application does not have adequate information to approve the Valmy BESS, specifically because of the issues surrounding Iron Point and Hot Pot projects. (Tr. at 763-64.)

99. Staff further states that the Joint Application does not have enough justification or analysis as to why Iron Point and Hot Pot could not continue to be good resources, even if they cost more or take longer to bring online. (Ex. 313 at 9-10.) Staff states that there may be other projects that could replace the Valmy coal plant, but those have not been proposed to the Commission, such as a new natural gas power plant at Valmy. (*Id.* at 11.) Staff also notes that Nevada Gold Mines began construction on a new 200 MW solar PV project that may offset the immediate need for the proposed BESS because the project could provide energy and voltage support that NV Energy could pay for as needed or available. (*Id.* at 18-19.) Staff also describes how the Nevada Gold Mine project reduces the need for the reliability benefits that the proposed BESS could address. (*Id.* at 19.)

100. Staff recommends that the Commission deny NV Energy's request to amend its Transmission Plan to construct the transmission infrastructure associated with the Valmy BESS. (*Id.* at 2.) Consistent with Staff's position that the Commission should deny the Valmy BESS, Staff recommends the Commission also deny the proposed transmission upgrades. (*Id.*)

101. Staff recommends that the Commission approve NV Energy's proposed unit retirement dates with the exception of the Chuck Lenzie, Silverhawk, Higgins, and Clark units. (*Id.* at 28.) Staff recommends that the Chuck Lenzie retirement date be extended an additional 3 years beyond what NV Energy proposed, to 2049, and that the Silverhawk and Higgins units

have their retirement dates extended by 5 years, each, as well. (*Id.* at 29.) Staff states that these units should continue to run through 2049 for a variety of reasons, including:

i. The Legislature set the start of 2050 as the year Nevada should achieve net-zero carbon;

ii. The Higgins unit is within Las Vegas and does not rely on the existing 500 kV transmission system to import energy;

iii. The Lenzie units represent 1,200 MWs of generation and were recently upgraded to increase the output capacity;

iv. The existing Silverhawk unit will be collocated with the recently approved Silverhawk Peaking units which will benefit from full time staffing required for the exiting unit, and was also recently the subject of upgrade to increase its output, and;

v. The Clark unit, like the Higgins unit, does not rely on rely on the existing 500 kV transmission system to import energy and are quick-start, fast-ramping units that will balance future reliance on intermittent resources. (*Id.* at 29-30.)

102. Staff notes that existing planning processes, such as the Western Electricity Coordinating Council, rely on information, such as planned retirement dates, to reach long-term policy and planning decisions. (*Id.* at 30-31.) Staff also suggests that rates will continue to increase in future general rate cases, so extending the life of these units will provide ratepayers with rate relief in the 2049 and 2050 rate cycles. (*Id.* at 31.)

103. Staff recommends that the Commission deny NV Energy's request to install capacitor banks at the Humboldt and Maggie Creek substations for static voltage support in the Carlin Trend load pocket. (*Id.* at 20.) Staff states that with the pending retirement of the Valmy

coal plant and the Iron Point and Hot Pot projects, and the operational characteristics of the proposed BESS, NV Energy proposed adding capacitors at the Humboldt Substation and Maggie Creek bus. (*Id.*) Staff notes that because the the Valmy coal plant is still operational, the capacitors are just another "piecemeal" solution to the bigger issue of the Valmy coal plant retirement without a meaningful solution in place. (*Id.*) Staff avers that the capacitor banks are part of a "stop-gap" measure that includes the Valmy BESS system and that the projects should not be approved in whole or in part until NV Energy does a more thorough assessment of system reliability needs that takes into consideration Nevada Gold Mine's new generation facility. (*Id.*)

104. Staff recommends the Commission require NV Energy to work with the Nevada Department of Environmental Protection ("NDEP") to determine whether the Tracy units 4 and 5 can continue to operate, rather than retire in 2031. (*Id.* at 21.) Staff states that Tracy units 4 and 5 are highly efficient 100 MW combined cycle natural gas units that recently received $11 million of new investment and, as a result, should continue running to meet the energy needs of the Northern Nevada, especially the growing energy needs at the Tahoe-Reno Industrial Complex. (*Id.* at 21.) Staff avers that NV Energy made a unilateral decision to not perform any environmental upgrade controls on Tracy units 4 and 5, creating a legally enforceable retirement date of 2031 due to NDEP's SIP. (*Id.* at 22.) Staff states that NV Energy's decision circumvented the Commission's IRP process and denied the Commission the opportunity to weigh in on whether or not it would make more sense to upgrade an existing unit, rather than retire it. (*Id.*) Staff notes that NV Energy did not reevaluate the Tracy units at the "10-year-to-go mark" in its LSAP, per the requirements of NAC 704.9355 and NV Energy's own LSAP process, and instead just used the 35 year "sticker life" without any additional analysis, even though the units could operate for up to 20 more years. (*Id.* at 23, 25.) Staff also provides that NV Energy

indicated through the discovery process that the necessary upgrades to continue running the Tracy units would cost between $8 million and $20 million. (*Id.* at 24.) Staff states that the estimated cost of upgrades to continue running the 100 MW units is substantially cheaper than the cost of fully replacing those units, even though NV Energy failed to provide a PWRR on the estimates. (*Id.*) Staff also provides that, while the interaction between the timing of the SIP process and the required upgrades for the Tracy units may need further analysis, NV Energy has represented through its engineering reports that the Tracy units could be upgraded by 2028. (*Id.* at 27.) Staff proposes that to avoid any more such forced retirements that removes resource planning decisions from the Commission's purview, the Commission should require NV Energy to work with NDEP in amending the SIP to allow upgrades to the Tracy units. (*Id.* at 28.) Staff also proposes the Commission require NV Energy explain why it chose not to upgrade the Tracy units without Commission input. (*Id.*)

105. Staff recommends the Commission find that NV Energy has met the regulatory requirements for evaluating environmental costs and economic impacts for the three alternative plans. (Ex. 305 at 2.) Staff also recommends that the Commission require NV Energy to justify and support continued use of various processes in the resource plan models including the following:

i. The impact placeholders have on comparing alternative plans;

ii. Configuration of power generation facilities in PLEXOS; and,

iii. Manual adjustments to the PLEXOS model. (*Id.*)

106. Regarding placeholder use in NV Energy's planning process, Staff recommends the Commission require NV Energy review and document placeholder use in comparable resource planning plans at other utilities and in academic and policy literature, bring the findings

to Staff, and then implement any relevant findings in future IRP filings. (*Id.* at 13.) Staff proposes a review of how placeholders operate in the IRP process because placeholders confound the effects of potential resource additions, impose uncertainty on the robustness of NV Energy's analyses, and negatively impact comparisons between plans. (*Id.* at 10-11; also see Ex. 307 at 5-6; Tr. at 714-15.) Staff concludes that the reliance on placeholders does not yield the most robust analysis of alternative plans and that more analysis of how placeholders interact with proposed projects would result in more meaningful comparisons between plans. (Ex. 305 at 11-12.)

107. Staff recommends the Commission require NV Energy to adopt endogenous configuration of all power generation facilities in PLEXOS and not just renewable resources and battery facilities. (*Id.* at 13.) Staff states that renewable resources and battery facilities are currently endogenously configured in PLEXOS in 1 MW increments to optimize size, ratio between generation and storage facilities, and style of resource (e.g. solar PV plus BESS or standalone BESS) to achieve an optimal economic outcome. (*Id.* at 14.) Staff notes that no other power generation facilities are endogenously configured and that if they were, proposed projects could be improved (scale, location, timing, technology, etc.), allow for more meaningful comparisons, and more customized. (*Id.*)

108. Staff finally recommends the Commission require NV Energy justify and support any manual adjustments made to the PLEXOS model. (*Id.* at 16.) Staff avers that NV Energy makes various manual changes to the PLEXOS model to meet "reliability and RPS obligations," including adjustments regarding the PRM, RPS compliance, keeping resource availability for each utility below its respective load plus PRM, and locating new resources to match load distribution. (*Id.* at 16.) Staff states that, when queried, NV Energy provided no academic or

policy literature, industry practice, or numerical techniques for making such adjustments. (*Id.* at 16-17.) Staff suggests that by doing a comprehensive review of academic or policy literature, industry practice, or numerical techniques for making such adjustments, NV Energy could enhance its simulations and allow for more meaningful comparisons between alternatives. (*Id.* at 18.)

109. Staff also recommends the Commission direct NV Energy to develop, demonstrate, and deploy cost-effective solutions for voluminous or proprietary materials. (*Id.* at 18.) Staff states that, during discovery, NV Energy indicated that certain files could not be provided because of the "hundreds of thousands of calculations", large amount of data, and proprietary nature of the information. (*Id.* at 18-19.) Staff suggests that NV Energy should propose a solution in future filings to ensure that parties have access to all documents that would otherwise be too voluminous to provide and protect proprietary interests. (*Id.* at 19.)

NV Energy's Rebuttal

110. NV Energy rejects CMN's assertion that the Commission should wait for NV Energy to complete an all-source RFP. (Ex. 128 at 7.) NV Energy explains that its original filing contained sufficient comparisons of the costs of the geothermal PPAs and the Valmy BESS. (*Id.*) Furthermore, NV Energy provides that an all-source RFP was recently issued. (*Id.*) NV Energy states that there were no bids for geothermal projects, highlighting the limited availability of valuable round-the-clock renewable generation. (*Id.*) NV Energy states that it did receive bids for grid-tied BESS, similar to the proposed Valmy BESS, confirming the price for the Valmy BESS is in line with similar recently received RFP proposals. (*Id.*)

111. In response to Staff's opposition to the Valmy BESS, NV Energy argues that it is important the Commission approve the Valmy BESS at this time. (*Id.* at 8.) NV Energy explains

that this project has a summer 2025 COD pending Commission approval in this filing, which supports long lead-time procurement, with known BESS costs and delivery, and interconnection agreements in progress that support the COD. (*Id.*) NV Energy warns that delay of approval would suspend development activities, which would negatively impact the project schedule and potentially increase the cost of the BESS. (*Id.*) NV Energy further provides that, if brought forward in a future amendment, the Valmy BESS COD would be pushed out approximately one year to mid-2026, the BESS and other suppliers would not hold their production queue positions, and today's pricing would be at risk. (*Id.*) While NV Energy states it is important that a comprehensive plan be implemented for Valmy, building the plan takes time and planning without action does not resolve rapidly approaching resource needs. (*Id.*) NV Energy offers that, by the end of 2025, NV Energy will have gained significant BESS operational experience. (*Id.*) NV Energy states that it will be able to leverage the experience gained from operating Chukar BESS and from approximately two years of operating the Reid Gardner BESS and Dry Lake BESS that will allow the Companies to ensure Valmy BESS can provide capacity and reliability service for the area in short order. (*Id.*) NV Energy states that the Valmy BESS could also be expanded in the future to add additional storage should the forthcoming comprehensive plan for the region call for it. (*Id.* at 8-9.) NV Energy provides that the Valmy coal plant could continue to operate in a limited manner, with restrictions, if required for system reliability. (Ex. 127 at 8.)

112. NV Energy disagrees with WRA's argument that the Commission should defer its decision making until the LSAP is reformed. (Ex. 127 at 2.) NV Energy counters that the Commission has successfully relied upon the LSAP since its adoption in 2009. (*Id.*) NV Energy offers the LSAP is a detailed economic analysis that examines the remaining economic useful life of a generating unit and the costs of continued operation versus the economic benefit derived

from using the unit in its needed mode of operation. (*Id.* at 3.) NV Energy states that economic analysis provided in the LSAP is the same production cost analysis for market alternatives, using PROMOD or Plexos, that is used in all of NV Energy's resource planning modeling. (*Id.*)

113. NV Energy clarifies that when a generating unit's life is identified in the LSAP, that unit's life does not remain permanent or static. (*Id.* at 4.) NV Energy explains that within the LSAP is a required reassessment methodology. (*Id.*) NV Energy states that the reassessment criteria requires that all units are examined at least annually in the budget planning process and, once a triggering event occurs, a full LSAP is generated, and that information is provided to the Commission in public filings for review. (*Id.*) NV Energy highlights that a number of NV Energy's generating units have seen several changes in their lives through the LSAP as a result of triggering events, such as changes in environmental regulations, or the necessity for major investments in the units. (*Id.*)

114. NV Energy provides that Staff recommends that NV Energy complete an LSAP for Tracy units 4 and 5, and Valmy, and begin work with the NDEP to modify the SIP. (*Id.*) NV Energy agrees with Staff's recommendations that LSAP analyses are needed to review the remaining lives of these units. (*Id.*) NV Energy explains that the recent changes in energy markets and EPA's new Ozone Transport Rule are both triggering events under the LSAP and warrant the need for an LSAP. (*Id.*) NV Energy states it has already begun developing the LSAPs and will be ready to file them in its next IRP filing. (*Id.*) Additionally, NV Energy states it has commenced discussions with the NDEP regarding the potential for SIP modifications. (*Id.*)

115. NV Energy disagrees with Staff's recommendation regarding the retirement dates for the Clark Peaking units, Lenzie combined cycle blocks 1 and 2, Harry Allen combined cycle, and the Silverhawk combined cycle should be changed to 2049. (*Id.* at 10.) First, NV Energy

states that the LSAP should be used for retirement dates and continuing the life beyond that examined in the LSAP runs the risk of failing to identify impacts beyond those addressed in the analysis. (*Id.*) Second, NV Energy explains that planning to retire such a large amount of generation all in one year may be problematic since all of the generating capacity would need to be replaced at once instead of through a more phased approach over a number of years. (*Id.*) Although the economics of continuing to run these units have not been examined in an LSAP, NV Energy explains the maintenance strategies and the Long-Term Service Agreements provide a method for systematic replacement of components, and therefore, operation of the units could theoretically be continually extended. (*Id.*)

116. NV Energy rejects Intervenor recommendations that NV Energy use PLEXOS LT rather than an LSAP to determine unit retirement dates. (Ex. 126 at 3.) NV Energy explains that PLEXOS LT is a capacity expansion model which samples periods of time in its analysis. (*Id.*) NV Energy states that it does not have the detail of a production cost model. (*Id.*) NV Energy also states that, while PLEXOS LT can analyze retirement dates, it is not as rigorous as the current LSAP. (*Id.*)

117. NV Energy explains that NV Energy's resource adequacy assessment will definitely change if it joins the Western Resource Adequacy Program ("WRAP"), but the changes will not be as significant as suggested by WRA. (*Id.* at 11.) NV Energy provides that WRAP will require NV Energy to show near-term monthly resource sufficiency. (*Id.* at 12.) NV Energy states that it already assesses monthly sufficiency over peak periods in its ESP. (*Id.*) NV Energy explains that it is likely NV Energy will have to expand the monthly look to cover non-peak periods, but the transition should not be impactful. (*Id.*)

Commission Discussion and Findings

Amended Supply Plan – Continued Operation of Existing Generation Units

118. The Commission modifies the plan regarding NV Energy's request to amend the Supply Plan to accommodate the continued operation of existing generation units. NV Energy utilized the LSAP to evaluate and determine the economic useful lives of the generating units. These generating units have a demonstrated history of providing reliable service at a reasonable cost and will remain a useful tool for consideration in future IRPs as NV Energy continues to provide reliable service while making the necessary investments to achieve the environmental goals established in NRS 445B.380. The Commission agrees with Staff that it is important that NV Energy's analysis in future IRPs not limit consideration of potential resources to achieve the environmental goals at a reasonable cost.

119. NV Energy had requested the following retirement dates:

a. Clark Generating Station unit 4 through 2035;
b. Clark Generating Station units 5, 6, and 10 through 2044;
c. Clark Generating Station units 7, 8, and 9 through 2043;
d. Clark Peakers through 2048;
e. Harry Allen Generating Station units 3 and 4 though 2046;
f. Harry Allen Generating Station combined cycle units through 2049;
g. Chuck Lenzie Generating Station through 2046;
h. Silverhawk Generating Station through 2044;
i. Higgins Generating Station through 2044;
j. Las Vegas Generating Station through 2049;
k. Sun Peak Generating Station through 2041;
l. Clark Mountain units through 2044.

120. The Commission modifies NV Energy's request to approve the following retirement dates:

a. Clark Generating Station Unit 4 through 2035;
b. Clark Generating Station Units 5, 6, and 10 through 2044;
c. Clark Generating Station Units 7, 8, and 9 through 2043;
d. Clark Peakers through 2049;
e. Harry Allen Generating Station Units 3, and 4 though 2046;
f. Harry Allen Generating Station combined cycle units through 2049;
g. Chuck Lenzie Generating Station through 2049;
h. Silverhawk Generating Station through 2049;
i. Higgins Generating Station through 2049;
j. Las Vegas Generating Station through 2049;
k. Sun Peak Generating Station through 2041;
l. Clark Mountain units through 2044.

121. NV Energy acknowledged that the generation units could continue to run to Staff's proposed retirement dates, and the PWRR analysis indicates that continued operation of the generation units is economic through the retirement dates proposed by Staff. At a time when planning to meet the energy needs of customers is more complex, the Commission believes that all cost-effective options which also allow NV Energy to meet state environmental requirements should be modeled and considered.

Eavor Geothermal PPA and Ormat Geothermal Portfolio

122. The Commission accepts NV Energy's amendment of the Supply Plan to allow Sierra to enter into PPAs for a portfolio of geothermal projects with a combined nameplate rating

of 120 MW (net). In addition, the Commission accepts NV Energy's amendment of the Transmission Plan to expend approximately $33.5 million to construct the transmission infrastructure needed to support the interconnection of the geothermal projects. These geothermal projects will assist Sierra in retiring the Valmy coal plant by providing non-intermittent renewable replacement capacity, energy and ancillary services at a reasonable cost. The PPAs will support NV Energy in providing dispatchable resources, and are renewable, which assists NV Energy in meeting the RPS. NV Energy identified a need for additional renewable resources, and these PPAs are a reasonable resource to fill the identified need.

Valmy BESS

123. The Commission rejects NV Energy's request for approval of $466 million to acquire the Valmy BESS. NV Energy stated that the Valmy BESS cannot provide sufficient capacity and voltage support to replace the current resource upon the retirement of the Valmy coal plant. Further, no evaluation or determination has occurred that the previously approved Hot Pot and Iron Point projects, which were sufficient to provide capacity and voltage support in the Valmy region, are no longer available.

124. In NV Energy's 2021 Joint IRP, NV Energy proposed, and the Commission accepted a plan that included the Hot Pot and Iron Point solar plus battery storage projects. These projects were able to fulfill several needs on NV Energy's system, including the ability to retire the Valmy coal plant while maintaining adequate capacity and voltage support.

125. In this Docket, NV Energy requested approval of the Valmy BESS to address the same capacity and voltage support need for which the Hot Pot and Iron Point projects had been approved in the 2021 Joint IRP. NV Energy removed Hot Pot and Iron Point from the loads and resources table and stated that Hot Pot and Iron Point could no longer be expected to fulfill the

needs of the system for which it was approved in Docket No. 21-06001. However, the Commission was unable to evaluate that statement as NV Energy provided limited evidence regarding the status of Hot Pot and Iron Point, and NV Energy made no request for relief in this docket regarding the status of Hot Pot and Iron Point.

126. NV Energy also indicated that it would file a fifth amendment to its resource plan in the summer of 2023, which would include additional details regarding the status of Hot Pot and Iron Point, and a request for a complete solution to the capacity and voltage support issues upon the retirement of the Valmy coal plant. Accordingly, the Commission will be able to conduct a comprehensive review of the viability of the Hot Pot and Iron Point projects later this summer. At that time, the Commission will be able to make an informed decision on a comprehensive resource plan that will ensure system reliability at the time of the Valmy coal plant retirement. The Commission finds it premature and unreasonable to approve the $466 million Valmy BESS investment as a cost-effective replacement for the Valmy coal plant without all the necessary facts.

127. The retirement of the Valmy coal plant by the previously approved date of 2025 is a significant priority for this Commission. System reliability is paramount.

128. 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 the Valmy coal plant:

i. A complete solution for the retirement of the Valmy coal plant;

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 the Valmy coal plant and associated costs.

129. Several parties raised questions about the status of the Hot Pot and Iron Point projects that NV Energy was not able to answer. It is critical that this Commission review NV Energy's decision regarding the continued viability of Hot Pot and Iron Point and evaluate whether NV Energy or its customers are entitled to damages or costs due to the projects' status. As an additional directive, NV Energy must provide in a future IRP amendment, or the 2024 IRP an update on the status of the Hot Pot and Iron Point projects, including adequate detail to allow the Commission to review whether continuing with Hot Pot and Iron Point, or another solution to the retirement of the Valmy coal plant, is the most cost-effective and reasonable resource decision.

Amended Transmission Plan – Static Voltage Support in the Carlin Trend Load Pocket

130. The Commission rejects NV Energy's request to amend the Transmission Plan for $13 million to install capacitor banks at the Humboldt and Maggie Creek substations for static voltage support in the Carlin Trend load pocket. As discussed above, the Commission rejected the Valmy BESS, and directs NV Energy to provide a complete solution for the retirement of the Valmy coal plant in a future application. Therefore, any additional investment in the Carlin Trend load pocket should be evaluated in that future filing.

Associated Transmission Infrastructure

131. The Commission rejects NV Energy's request for $8 million to construct transmission infrastructure to support interconnection of the Valmy BESS due to the Commission's rejection of the Valmy BESS. The transmission interconnection is not necessary without the construction of the Valmy BESS.

B. Base Fuel and Purchased Power Price Forecast

NV Energy's Position

132. NV Energy requests approval of the Joint Application 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. (Ex. 100 at 17.)

133. NV Energy explains that resource adequacy risks for the state of Nevada, and the Western region as a whole, have been evolving since the summer of 2020. (Ex. 111 at 3.) NV Energy elaborates that significant regional heat events have occurred for three consecutive summers and risks for the Western region have continued to change for a number of reasons including shifts in weather and a rapidly changing resource mix. (*Id.*) NV Energy provides that these factors have led to reduced market liquidity, increased market prices, and supply curtailments. (*Id.*) NV Energy states that these concerns are expected to continue into the future as climate-related events such as record temperatures, wildfire, and drought no longer appear to be isolated incidents. (*Id.*) NV Energy points out that the 2021 Western Assessment of Resource Adequacy, published by the WECC on February 1, 2021, identified changes on the Western system affecting the reliability of imports and urged entities to act. (*Id.* at 4.) NV Energy provides that the most recent update to the report, published on November 1, 2022, reported similar findings and highlighted more severe weather events, continued reliability concerns for the Western Interconnection, and identified both availability and deliverability concerns related to regional reliance on imports. (*Id.*) As stated in the First Amendment, NV Energy points out that many fossil and other baseload power plant retirements have recently occurred. (*Id.*) NV Energy provides that approximately 23 gigawatts ("GW") of resources retired in the Western Interconnection over the past decade with approximately 18 GW of those retirements being coal or natural gas resources. (*Id.*) NV Energy states that the WECC reports indicate the planned

retirement of an additional 26 GW of mostly coal and natural gas resources by 2032. (*Id.*) NV Energy also points to a June 2021 California Public Utilities Commission order in Docket No. R.20-05-003 which required procurement of 11,500 MW of specifically non-fossil resources by the end of 2026. (*Id.*) NV Energy warns that these changes could dramatically affect the resource mix in the region and the availability of market capacity. (*Id.*) NV Energy further provides that these concerns are compounded by the rule changes already implemented or being discussed by CAISO. (*Id.*)

134. NV Energy argues that CAISO rule changes will increase market risk going forward. (*Id.* at 5.) NV Energy explains that market concerns continue to be compounded by CAISO's change in day-ahead export priorities implemented in the summer of 2021, and its ongoing wheel-through initiative. (*Id.*) NV Energy states that the change in export priorities allows CAISO to adjust day-ahead export schedules to zero with potentially less than an hour's notice on whether the energy will flow. (*Id.*) NV Energy provides that the changes to wheel-through priorities allow CAISO to prioritize use of Northwest imports to serve CAISO load, precluding short-term (less than 45-day) firm energy from being wheeled through California. (*Id.*) NV Energy provides that these two items impact both NV Energy and Open Access Transmission Tariff customers in Nevada. (*Id.*) NV Energy points out FERC issued an order extending the wheel-through policies approved for the summer of 2021 through May of 2024 and directed CAISO to report on progress towards a long-term approach. (*Id.*) NV Energy highlights that CAISO issued its straw proposal on July 29, 2022, with a final proposal expected to be ready around February 2023. (*Id.*) Accordingly, NV Energy offers that there is significant uncertainty as to what wheel-through rules will be adopted and, most significantly, what will be the amount of transmission capacity CAISO will claim on behalf of its native load. (*Id.*) NV Energy

explains that both of these items add significant risk to the market as a whole as the liquidity in the real-time hourly power market has been reduced significantly as more entities have joined the energy imbalance market. (*Id.*)

135. NV Energy also provides that supply curtailments have increased risk for NV Energy. (*Id.*) NV Energy states that it has experienced major supply curtailment events that have led to emergency conditions. (*Id.*) NV Energy points to August 18, 2020, when NV Energy experienced significant curtailments with the largest curtailment occurring in hour ending 19 with curtailments of 1,243 MW. (*Id.* at 5-6.) NV Energy states that this led to NV Energy entering a Level 3 Energy Emergency Alert ("EEA"), which is the highest level of emergency and means load shed is imminent. (*Id.* at 6.) NV Energy also provides July 9, 2021 as another example of when NV Energy experienced significant curtailments totaling 1,406 MW in hour ending 20. (*Id.*) NV Energy explains that this scenario once again led to NV Energy entering an EEA Level 3 situation. (*Id.*) NV energy explains that, while the summer of 2022 featured lower volumes of supply curtailments, there was still in excess of 300 MW of curtailments during the critical hours during the September heat wave. (*Id.*) NV Energy highlights that supply curtailments of this size highlight the risk of relying so heavily on market purchases. (*Id.*)

136. NV Energy argues that adding in-system generating resources, specifically resources that are available after solar resources drop off in the evening hours, will reduce NV Energy's open position and thus its reliance on market capacity purchases. (*Id.*) NV Energy explains that this will help mitigate uncertainty surrounding climate change, wildfires, western resource retirements, and the impact of CAISO rule changes. (*Id.*) NV Energy states that, as seen in recent summers, events in the West resulted in significant supply curtailments for NV Energy. (*Id.*) NV Energy points out that in-system generating resources would not be subject to

curtailment and could continue providing energy to Nevada customers even when issues such as regional heat waves and wildfires occur. (*Id.*)

137. NV Energy provides that it is taking additional actions to address resource adequacy. (*Id.* at 7.) NV Energy states that it has been actively participating in Phase 3A of the WRAP and is planning to participate in Phase 3B beginning on January 1, 2023. (*Id.*) NV Energy explains that this new phase will commence a transitional period into the binding phase. (*Id.*) NV Energy highlights that the Northwest Power Pool d/b/a Western Power Pool ("WPP") recently submitted a tariff filing to the FERC under Docket No. ER22-2762. (*Id.*)

138. NV Energy clarifies that coal price forecast, provided in the Fuel and Purchased Power Price Forecasts in this Joint Application, was updated due to higher observed market quotes used in the short-term forecast and an updated market forecast from S&P Global Market Intelligence. (*Id.*) NV Energy also provides that the coal market has experienced a significant drop in liquidity, which was primarily driven by increased demand both domestically and internationally. (*Id.* at 7-8.) NV Energy offers that minimal volumes of acceptable quality coal are available for 2023-2024. (*Id.* at 8.)

139. NV Energy provides that it has developed Mid and High Carbon Price Forecasts based on input from NV Energy's consultant, NERA. (Ex. 120 at 8.) NV Energy states that NERA concluded that it is no longer appropriate to model a cap-and-trade program at least for the federal policy that is likely to be in place in the near and medium terms. (*Id.*) Instead, for the Joint Application, NV Energy states NERA considers it appropriate to assume that federal climate policy affecting fossil fuel prices will be based on the IRA and to evaluate the resulting effects on fossil fuel prices. (*Id.*) NV Energy explains that NERA developed assessments of price impacts to natural gas and coal fuels resulting from changes in demand for these fuels due

to the IRA provisions based upon this existing modeling information. (*Id.*) NV Energy states that the effects of Mid and High carbon price adjustors on fossil fuels are stated as annual percentage adjustments to wholesale fossil fuel prices. (*Id.*)

140. NV Energy provides that WoodMac's regional power price forecast represents day-ahead firm energy prices; however, NV Energy states it does not explicitly include the full cost of new capacity additions that would be required to ensure resource adequacy over the forecast period. (*Id.* at 9.) Therefore, NV Energy states that it prepares a capacity price forecast for market purchases to supplement the regional power price forecast from WoodMac. (*Id.*) NV Energy explains that the regional price forecast is used by the PROMOD model to economically dispatch market purchases against internal generation, while the capacity price forecast (dollars per kilowatt-year) is multiplied by NV Energy's open capacity position as an additional fixed fuel and purchased power cost. (*Id.*)

141. Regarding its long-term capacity price forecast, NV Energy states that, as part of its Long-Term Outlook ("LTO"), WoodMac prepared an estimate of the levelized cost of new entry ("CONE") for the installed cost of future combined cycle generation. (*Id.*) NV Energy explains that the CONE is an estimate of the annual fixed costs associated with owning and operating a new generating facility (i.e., exclusive of variable costs such as fuel and emissions). (*Id.*) NV Energy provides that the CONE was used to compute a long-term capacity price forecast. (*Id.*) NV Energy states annual capacity prices (in dollars per kilowatt-year) were calculated as the difference between the CONE and the net energy margins reflected in the wholesale power price forecast (i.e., spark spreads). (*Id.*)

142. NV Energy provides that it has followed the F&PP price forecast provision from Docket No. 22-03024 pertaining to the use of high and base price F&PP forecasts. (*Id.* at 10.)

NV Energy states that, since the high price F&PP forecast filed in the First Amendment is lower than the base price F&PP forecast filed in this Docket, the base price F&PP forecast was used for production cost modeling. (*Id.*)

143. NV Energy states that the increased customer demand shown in the 2022 base load forecast and the loss of the Iron Point and Hot Pot projects create a need for increased resources or market purchases. (Ex. 112 at 6.) NV Energy explains that the First Amendment reduced reliance on market capacity purchases due to concerns about uncertain availability and deliverability. (*Id.*) NV Energy offers that these concerns persist and therefore this amendment continues to focus on further reducing reliance on market capacity purchases. (*Id.*) NV Energy states that replacing lost resources, addressing a new load forecast, and reducing reliance on uncertain market availability and deliverability may all be deemed to be actions that improve resource adequacy in this amendment. (*Id.*)

144. NV Energy provides that the economic analysis for this amendment uses the 2022 base load forecast presented in Docket 22-09006, addresses updated fuel and purchase power price forecasts including expectations for the impact of federal carbon policy, meets or exceeds the RPS in every year, targets NV Energy's contribution to the state's 2050 clean energy goal, meets the 16 percent PRM for each utility, and includes required reserves to be held for OATT customers. (*Id.* at 9.) NV Energy also provides that the economic analysis includes the assumption that the Iron Point and Hot Pot PV/BESS projects cannot be delivered on the schedule approved in the 2021 Joint IRP. (*Id.*)

WRA's Position

145. WRA states that NV Energy's response to WRA concerns regarding the continued applicability of its PRM and ELCC studies focused almost exclusively on asserting

that its load forecast, which had been revised between the 2021 Joint IRP Load Forecast and the Revised Load Forecast approved in Docket No. 22-09006, had not changed materially. (Ex. 602. at 20.) WRA states that NV Energy asserted that its peak load forecast had grown by only 107 MW or 1.4 percent in 2023. (*Id.*) WRA argues that this assertion is both factually incorrect and would be insufficient, even if true, to assert that NV Energy's load forecast had not changed materially. (*Id.*) WRA states that NV Energy's assertion regarding its 2023 peak load growth is factually incorrect because WRA states that NV Energy's workpapers provide a significantly larger estimate of the change in NV Energy's peak load. (*Id.* at 21.) Specifically, WRA explains that the workpaper indicates that peak load has grown by 292 MW (or 3.8 percent) in 2023, occurring at hour 4768, July Hour 16 [day not listed], which appears to be the peak hour across the system for 2023. (*Id.*) WRA maintains that this 3.8 percent growth is consistent with the data table provided in the System Ranked Data tab. (*Id.*) WRA states that, because NV Energy's reliability requirement is set strictly as a multiplier of its gross peak load, this result means that NV Energy would need to procure resources equivalent to an additional 4.4 percent of its July peak to meet its 16 percent PRM under the new load forecast because under a 16 percent PRM, the 3.8 percent load growth translates to a 4.4 percent increase in reliability requirement. (*Id.*)

146. WRA states that whether or not NV Energy's 2023 peak load forecast grew by 1.4 or 3.8 percent is a significant question in any reliability analysis, but it is far from the only information that would bear on the applicability of NV Energy's outdated reliability studies. (*Id.* at 22.) For context, WRA explains that NV Energy's reliability accounting framework is an annual structure which requires it procure resources solely as a function of its gross peak load, which occurs in July; yet the resources it procures must assure reliability across the full modeling horizon in all hours and all months of the year. (*Id.*) WRA offers that, despite having a lower

gross peak, September has emerged as a significant period of reliability concern, driven by a growing risk of extreme weather, earlier sunsets, reduced hydroelectric availability, and wildfire risk. (*Id.*) As such, WRA provides that a robust analysis, such as that performed for the PRM study, will surface the reliability events across all at-risk months, condensing a textured summer of reliability risk into a single value. (*Id.*) WRA points out that NV Energy asserts that the PRM is durable to load forecast changes so long as the load shape does not change. (*Id.*) WRA offers that, while the assertion that load shape is more impactful than load magnitude is directionally correct, NV Energy's load forecast results in substantial changes to the texture underlying the reliability analysis, as load changes across the summer are far from uniform in coming years. (*Id.*) WRA illustrates that, in 2023, NV Energy's revised load forecast adds 3.8 percent to July while September's peak load declines by 0.8 percent. (*Id.* at 22-23.) However, WRA provides that, by 2025, this trend has flipped — September's revised load forecast adds 4.7 percent while July adds only 3.5 percent. (*Id.* at 23.) WRA warns that this could result in NV Energy pursuing only enough additional resources to cover the 3.5 percent load growth in July and not the full 4.7 percent needed to cover the additional reliability risk in September. (*Id.*) WRA argues that September's reliability risk is invisible to NV Energy's simplified reliability compliance framework. (*Id.*)

CMN's Position

147. CMN states that it is reasonable for NV Energy to rely on market purchases to serve some portion of its load because all proposed Plans rely on the market for some amount of load, the reliance is reasonable given each utility's peak load, and the South CT and Base Case both has a lower PWRR than the Preferred or Alternate Plans. (Ex. 800 at 34-35.) CMN

concludes that reliance on market purchases is more cost-effective than acquiring the Valmy BESS or entering in the geothermal PPAs. (*Id.* at 35.)

BCP's Position

148. BCP has no objection to NV Energy's request for the approval of the 2021 Joint IRP base long-term fuel and purchased power price forecast as presenting the most accurate information upon which to base planning decisions set forth in the filing. (Ex. 400 at 2.)

Staff's Position

149. Staff recommends the Commission find that NV Energy's development and consideration of the three resource expansion plans, PWRR and PWSC analyses, and Financial Plan meet regulatory requirements. (Ex. 307 at 1.) Staff does note that the PWRR may be slightly understated because NV Energy is relying on an ITC rate of 40 percent for the proposed Valmy BESS facility, but it likely only qualifies for 30 percent. (*Id.* at 9-10.)

NV Energy's Rebuttal

150. NV Energy rejects CMN's position that NV Energy may rely on market purchases to serve load requirements. (Ex. 124 at 2.) NV Energy explains that relying on market purchases is a high-risk proposition for the residents of Nevada. (*Id.*) NV Energy further provides that market purchases that may be delivered during critical hours is exactly the reason resource adequacy issues arose starting in the summer of 2020. (*Id.*)

151. NV Energy also rejects WRA's position that identifying bilateral trades is a core goal of the WRAP program and new trade opportunities will be available due to the WRAP. (*Id.* at 4.) NV Energy argues WRA incorrectly labels the WRAP as a marketplace designed to identify trading partners. (*Id.*) NV Energy explains that the core goal of the WRAP is in fact to provide a standardized regional resource adequacy program to support reliability efforts in the

West. (*Id.*) NV Energy elaborates that WRAP members do not have visibility into other participants' long-term portfolios, which are supplied confidentially to the WRAP program administrator, and the bilateral trades referenced by WRA will only be executed on a short-term (day-ahead) basis within the WRAP program. (*Id.*)

152. NV Energy provides that, while WRA states that modifications to the CAISO wheel-through priorities will reduce the risk of NV Energy relying on regional resources, the fact remains the CAISO can still curtail users of its transmission system even if it is registered as high-priority transmission service. (*Id.* at 5.)

Commission Discussion and Findings

153. The Commission accepts NV Energy's new base long-term fuel and purchased power price forecasts included in Technical Appendix FPP-1. NV Energy's price forecasts were not opposed by any party to the proceeding. NV Energy presented five different price forecasts, including three different carbon scenarios. These forecasts used reasonable methodologies and present substantially accurate data upon which to base the resource planning decisions set forth in the Joint Application.

C. Amended Transmission Plan – Hilltop Substation PST

NV Energy's Position

154. NV Energy requests approval to amend its Transmission Plan to expend approximately $21.2 million to replace the Bordertown Substation's PST with a new PST at the Hilltop Substation. (Ex. 100 at 19.)

155. NV Energy states that the Bordertown 345 kV Substation PST will need to be replaced with a new 345 kV PST at Hilltop Substation. (Ex. 107 at 7.) NV Energy explains that the current location of the PST at Bordertown Substation has the potential to restrict import

capability from Hilltop Substation by 100 MW when the Fish Springs solar facility's generation is at the maximum output of 100 MW. (*Id.*) NV Energy states that this restriction is mitigated by the Hilltop Substation PST project. (*Id.*) NV Energy provides that the Bordertown Substation PST limits power flow on the Hilltop-Fort Sage-Bordertown 345 kV line to 300 MVA. (*Id.*) NV Energy explains that there are six large generation interconnections ("LGI") that would require the Hilltop Substation PST as mitigation, totaling 1,365 MW of proposed generation. (*Id.*) NV Energy estimates the cost of the Hilltop Substation PST to be $21.2 million. (*Id.*)

156. NV Energy states that it is seeing an increase in the number of requests for LGIs and requests for service for large load additions. (*Id.*) NV Energy explains that many of these requests require service within a few years, however, the necessary transmission system upgrades can take 5 to 10 years, or more, to permit and construct. (*Id.*) NV Energy elaborates that to have the required transmission additions available when they are needed to accommodate these generator interconnections and load additions, it is necessary to begin permitting and right of way acquisition well in advance of the anticipated in-service date. (*Id.*) NV Energy states that, while it is impossible to predict which generation interconnections and loads will materialize, the requested transmission projects have been selected for approval of the initial phases because they have been identified in multiple studies and deemed most beneficial to the transmission system overall, and are consistent with area master plans for native load growth. (*Id.* at 7-8.) NV Energy provides that these transmission projects will require multiple years to secure the necessary line routing studies, substations sites, permitting and land rights ahead of the in-service dates. (*Id.* at 8.) When more surety is attained regarding the specific generation and loads, NV Energy states that the projects will be submitted in an IRP filing for approval of the balance of estimated project expenditures. (*Id.*) With this partial approval approach, NV

Energy states that the projects can be built in a timely manner on an as needed basis to better serve customers' schedules. (*Id.*) NV Energy argues that this approach also minimizes the financial exposure for customers while allowing projects that are critical to Nevada's economic development goals to be developed in a timely manner. (*Id.*)

157. NV Energy states that construction of the Comstock Meadows — West Tracy 345 kV line and the Comstock Meadows substation was previously approved by the Commission in Docket No. 19-05003. (*Id.* at 8.) NV Energy explains that, as described in the Tracy Area Master Plan in that docket, the need for this new line was based on the total load in the Tahoe-Reno Industrial Center ("TRIC") area reaching 300 MW. (*Id.*) NV Energy provides that the area load has not reached this level currently but is forecast to exceed this level by 2024. (*Id.*) NV Energy states that the current planned in-service date is October of 2024. (*Id.*) NV Energy explains that the Comstock Meadows — West Tracy 345 kV line also must be in service prior to the Greenlink West being completed. (*Id.* at 8-9.) NV Energy notes that this will prevent the overload of the existing Comstock Meadows 120 kV lines when, as part of Greenlink West project, the Ft. Churchill — Comstock Meadows 345 kV line is completed. (*Id.* at 9.) At that time, NV Energy asserts that power must have a low impedance path going north to the existing 345 kV system in the event of loss of the Mira Loma — Ft. Churchill 345 kV line. (*Id.*) NV Energy also provides that the Comstock Meadows — West Tracy 345 kV line will aid in moving new generation to the TRIC and Reno load pockets. (*Id.*)

Nevada Worker's Position

158. Nevada Workers supports the Hilltop 345 kV PST. (Ex. 1600 at 6.)

Staff's Position

159. Staff also alleges that the Bordertown PST to Hilltop PST replacement project is part of the "piecemeal" approach to planning because NV Energy is requesting the $22 million upgrade to interconnect the Fish Springs solar facility after the Fish Springs PPA was approved. (Ex. 306 at 3.) Staff states that the $22 million appears to be directly caused by approval of the Fish Springs Project. (*Id.*)

160. Staff recommends the Commission approve the replacement of the 345 kV PST at the Bordertown Substation with a new 345 kV PST at the Hilltop Substation to remove a potential limit on the import capability of the line in light of six new large generator interconnections on the Hilltop Substation. (*Id.* at 2.) Staff further recommends that the remaining cost of the Bordertown PST be removed from rate base and placed in plant held for future use because NV Energy has no need for a spare PST and has operated for 25 years without a spare. (*Id.* at 3.) Staff also states that it was unaware of the requirement for the additional PST until this filing and that if the PST had been requested in the underlying 2018 docket, the information may have changed its recommendation at that time. (Tr. at 699.) Staff notes that the replacement will require a new transformer because the old one cannot be moved because of the need for continual phase shifting capabilities. (Ex. 306 at 2.)

Commission Discussion and Findings

161. The Commission accepts NV Energy's request to amend the Transmission Plan to invest $21.2 million to replace the Bordertown Substation PST with a new PST at the Hilltop Substation. The new PST can partially alleviate any restriction on import capacity caused by the current facilities, thereby contributing to the reliability of the system. The new PST is a reasonable investment for the increased reliability

162. The Commission further accepts Staff's recommendation that NV Energy remove any remaining costs from rate base associated with the current PST at Bordertown Substation and place those costs into Account 105, Plant Held for Future Use. No evidence was provided that both the PST at Bordertown and the PST at Hilltop are necessary to achieve reliable service. Accordingly, the Bordertown PST should no longer be in rate base since it is not necessary for reliable service.

D. Transmission Project Expenditures

NV Energy's Position

163. NV Energy requests approval to amend its Transmission Plan to make the following expenditures to begin initial phases, including constraint siting studies, environmental studies, permitting, right of way purchases and land acquisitions, for the listed transmission projects:

i. Expend $1.00 million for Reid Gardner to Harry Allen #3 230 kV Line;
ii. Expend $1.50 million for Nevada Solar One Area;
iii. Expend $2.10 million for Brooks 230/138 kV Substation;
iv. Expend $0.77 million for the Apex Area Master Plan;
v. Expend $5.50 million for the Fernley Area Master Plan;
vi. Expend $0.15 million for Buffalo Mountain 345/120 kV Substation;
vii. Expend $9.30 million for Amargosa Valley — Bighorn — El Dorado Valley 525 kV line;
viii. Expend $34.8 million for Fort Churchill — Captain Jack 525 kV line. (Ex. 100 at 19.)

164. NV Energy explains that, while it is impossible to predict which generation interconnections and loads will materialize, the above transmission projects were prudently selected for approval of the initial phases because they have been identified in multiple studies and deemed most beneficial to the transmission system overall and are consistent with area master plans for native load growth. (*Id.* at 126.) NV Energy provides that these transmission projects will require multiple years to secure the necessary line routing studies, substations sites, permitting, land rights and long lead time materials ahead of the in-service dates. (*Id.*) NV Energy offers that, at the time more surety is attained regarding the specific generation and loads, the projects will be submitted in an IRP filing for approval of the balance of estimated project expenditures. (*Id.*) NV Energy states that, with approval to begin pre-construction efforts, specific projects can be maintained as an alternative and built in a timely manner when needed to better serve customers' schedules. (*Id.*)

Google's Position

165. Google recommends that NV Energy should be required to work with regional planners on the design of the Fort Churchill — Captain Jack 525 kV transmission line as a condition of Commission approval to spend $34.80 million sought by NV Energy to permit and study the line. (Ex 501 at 2.)

166. Google recommends that NV Energy should be required to perform IRP model simulations that examine the impacts of the proposed Fort Churchill — Captain Jack 525 kV transmission line and include those simulations as sensitivities in a refiled fourth amendment. (*Id.*)

167. Google states that NV Energy did not consider the potential impacts of the Fort Churchill – Captain Jack 525 kV transmission line in its IRP modeling as NV Energy

represented that there is insufficient information to include an economic analysis of the Fort Churchill — Captain Jack 525 kV line in its filing. (*Id.*) Google maintains that the Fort Churchill – Captain Jack transmission line has the potential to dramatically alter power flows in the West. (*Id.* at 13.) Google states that participation of regional stakeholders at the conceptual stage could improve the design and substantially increase the value of the project. (*Id.*) Thus, Google argues that collaboration now is critical to achieving the ultimate goal of an integrated Western market. (*Id.*) Google recommends that NV Energy should be required to work with regional planners as a condition of Commission approval of the $34.80 million sought by the Company to permit and study the line. (*Id.*)

Nevada Worker's Position

168. Nevada Workers supports the Hilltop 345 kV PST, the Reid Gardner — Harry Allen #3 230 kV line, and the Fernley Area Master Plan because Nevada Workers provides that these three projects are vital for NV Energy to meet Nevada's growing energy demand, as well as federal and state requirements. (Ex. 1600. at 6.) Nevada Workers provides that the Hilltop project is part of Greenlink. (*Id.*) Further, Nevada Workers states that the Fernley Area Master Plan is necessary to meet expected significant increase in new load due to significant commercial and industrial growth planned for this area. (*Id.*) Nevada Workers also provide that action on the Reid Gardner – Harry Allen Line is needed now because the 2026 in service date is fast-approaching and this project will help meet energy demand. (*Id.*)

169. Nevada Workers supports the Brooks 230/138 kV Substation and the Nevada Solar One Area 230 kV projects because these projects will support NV Energy efforts to continue to build-out its renewable energy and meet Nevada clean energy goals. (*Id.* at 7.) Nevada Workers provides that the Brooks project in particular will ensure there is adequate

energy supply for future load growth in the northern Las Vegas valley, which continues to see population increases. (*Id.*) Additionally, Nevada Workers state that the Nevada Solar One project is necessary because of demand for interconnection in the area south of Las Vegas, near Boulder City. (*Id.*) Nevada Workers points out that these types of projects take careful planning. (*Id.*)

170. Nevada Workers supports the Apex Area Master Plan proposed by NV Energy. (*Id.*) Nevada Workers explains that the northern area of the Las Vegas Valley continues to grow as is evident in the industrial and commercial expansion seen at Apex. (*Id.*) Nevada Workers state that recent approval of a second water line and sewer treatment plant in Apex Industrial Park will allow for full development of the remaining property. (*Id.*) Nevada Workers state that, for the expected added load of 2,000 MW, NV Energy must begin planning and constructing needed infrastructure. (*Id.*)

171. Nevada Workers supports the approval of the Fort Churchill — Captain Jack 525 kV transmission line because it is a strategic priority to make certain there is sufficient connection between Nevada and the Northwest to enable the State to meet it clean energy goals as well as provide excess energy to the Northwest. (*Id.*) Also, Nevada Workers provides that this transmission project will position the state to participate in a regional power organization that was directed by the Legislature in Senate Bill 448 in 2021. (*Id.*) Nevada workers argues that the cost of $34.8 million will be worth it because this project will provide long term energy and resource adequacy, as well as opportunity for sale of excess renewable energy to help California, Oregon and Washington meet their clean energy goals. (*Id.*)

CMN's Position

172. CMN recommends that the Commission deny all expenditures associated with the eight new transmission projects because the majority of the funds would not be expended until after the conclusion of the Joint 2021 IRP action plan, the funds are associated with projects that have not been reviewed for prudency, the proposed purpose to interconnect large generators in unjustified, and NV Energy did not provide adequate analyses to support the projects. (Ex. 800 at 9-13.) CMN states that NV Energy will not expend the majority of the $55,120,000 on the eight transmission projects until after the current action plan has expired, with 99% of the Fort Churchill — Captain Jack 525 kV transmission line expenses occurring after 2024. (*Id.* at 10.) CMN also states that the proposed transmission lines must be reviewed as part of a comprehensive Supply Plan to determine the prudency of the proposals. (*Id.* at 11.) CMN concludes that without a comprehensive update to the Transmission Plan, the project pre-construction expenditures cannot be approved. (*Id.*) CMN also notes that while several of the projects are proposed to be developed for large generator interconnections, generally large generators are liable for the cost of those projects unless ratepayers receive the benefits of the new generation. (*Id.* at 12.) CMN also notes that NV Energy did not provide a dollar-weighted cost allocation calculation for the projects between its two service territories. (*Id.* at 13; Tr. at 477.)

173. CMN states that in discovery NV Energy represented that the cost of the Fort Churchill — Captain Jack 525 kV transmission line was estimated at $1.1 billion, which, according to CMN's estimates, could expand to over $1.5 billion due to inflation and other increases. (*Id.* at 14.) CMN also notes that the Fort Churchill — Captain Jack 525 kV transmission line had no economic analysis performed on it, it was previously rejected as a

viable option by NV Energy in Docket 20-07023[4], and was not analyzed in interregional planning. (*Id.* at 14-16.)

BCP's Position

174. BCP does not object to NV Energy's proposal for the transmission infrastructure for the Fernley Area Master Plan, estimated to be approximately $5.5 million. (Ex. 400 at 4.) BCP states that NV Energy is requesting approval of transmission infrastructure, in part, for the NV Energy's 1,000 MW Ceresola Energy Center for a start date of May 1, 2025. (*Id.* at 18.) BCP holds concerns that NV Energy is requesting approval for transmission infrastructure for a NV Energy-owned 1,000 MW generation project when there is no mention or description of the project in the supply side sections of the Joint Application. (*Id.*) BCP maintains that it is disconcerting that the transmission side will request approval prior to committing any funds for land purchases or right-of-way easements when the generation side follows a different standard. (*Id.*)

175. BCP opposes NV Energy's request to begin initial phases, including constraint siting studies, environmental studies, permitting, right of way and land purchases for a Amargosa Valley - Bighorn - El Dorado Valley 525 kV line. (*Id.*) BCP provides that the Commission should order NV Energy to have all development cost items be securitized by the large generator interconnection agreements as a condition when such a project is brought back in an IRP for approval. (*Id.*) BCP states that the demand for the Amargosa Valley - Bighorn - El Dorado Valley 525 kV line is predominantly from entities outside Nevada to allow for 1,000 to 2,500 MW development of renewables. (*Id.*) BCP further provides that NV Energy's Joint Application

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[4] Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fourth amendment to its 2018 Joint Integrated Resource Plan to update and modify the renewable portion of the Supply-Side Action Plan and the Transmission Action Plan.

does not provide an estimated cost for the project and does not provide detail on certain renewable projects for which the line is intended deliver power to other states. (*Id.* at 20.)

176. BCP argues that ratepayers should not be subject to take on the risk of NV Energy's request for $9.4 million in development costs, including land purchases and right-of-way easements. (*Id.* at 20.)

177. BCP opposes NV Energy's request to begin initial phases, including constraint siting studies, environmental studies, permitting, right-of-way and land purchases for a Fort Churchill - Captain Jack 525 kV line estimated at $34.8 million. (*Id.*) BCP states that NV Energy's request for the $34.8 million to begin development activities for the a Fort Churchill - Captain Jack 525 kV line has not been sufficiently supported by NV Energy. (*Id.* at 21.) BCP notes that there is only a page and half of text devoted in support in its Joint Application for the request of $34.8 million to begin development activities and, therefore lacks a thorough description of need and any estimated cost for the line. (*Id.*) BCP further points out that this request pales in comparison to the volumes of information and data including proposed allocations between Sierra and Nevada Power for the Greenlink Nevada 525 kV lines – which were vetted and litigated at length before the Commission in Docket No. 20-07023. (*Id.*) Given the lack of support at this juncture, BCP concludes that ratepayers should not be burdened with the risk of $34.8 million to being development activities including land purchases and right-of-way easements. (*Id.*)

Staff's Position

178. Staff also recommends that the Commission deny NV Energy's request to spend $34.8 million and $9.3 million for permitting and land acquisition associated with the Fort Churchill - Captain Jack 525 kV transmission line and Armargosa Valley-Bighorn-El Dorado

Valley 525 kV transmission line. (Ex. 313 at 31, 36.) Staff states that the Fort Churchill - Captain Jack 525 kV transmission line should be denied because NV Energy is "only six years away from joining" a regional transmission organization ("RTO") and that, as a result, any new project should be subject to regional planning activities and cost allocation. (*Id.* at 32.) Staff also states that last time this project was proposed in Docket 20-07023, NV Energy rejected it based on NV Energy's own scoring rubric and did not provide any updated analysis to change that score. (*Id.* at 32-33.) Staff also points out that the Greenlink Project will cost $3 billion and has yet to receive permits; as a result, adding another billion-dollar-plus transmission project is premature. (*Id.* at 33.) Staff further states that NV Energy "appears to have plans" to build and own thousands of MWs of new, company-owned generation in Nevada that will reduce the need for this type of transmission. (*Id.*) Staff notes that NV Energy did not propose a cost allocation for the initial cost of $35 million or the total cost of the project between jurisdictions. (*Id.*) Finally, Staff also noted that during rebuttal testimony, NV Energy significantly adjusted the price and scope for the Fort Churchill - Captain Jack 525 kV transmission line, which raised concerns about the project. (Tr. at 810-11.)

179. Staff states that the Armargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line has similar issues as the Captain Jack line, including adding more transmission when Greenlink is not yet permitted, the high cost of the proposed line, and no cost-allocation was proposed. (*Id.* at 36-37.) Staff notes that NV Energy justified the Armargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line in its filing by stating that Greenlink West line is already fully subscribed and the Armargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line will address that congestion; however, Staff suggests that the Armargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line be put on hold until transmission

service and interconnection agreements are executed. (*Id.* at 37.) Staff admits that the Commission should approve the Armargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line over the Fort Churchill - Captain Jack 525 kV transmission line because the Armargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line is fully within Nevada (i.e. intrastate and not part of RTO planning). (*Id.*)

180. Staff recommends approval NV Energy's request to amend its Transmission Plan to begin making the expenditures for the initial phases including constraint siting studies, environmental studies, permitting, right-of-way purchases, and land acquisitions for the following projects:

i. Reid Gardner to Harry Allen #3 230 kV line ($1.00 million);

ii. Nevada Solar One Area ($1.50 million);

iii. Brooks 230/138 kV substation ($2.10 million);

iv. Apex Area Master Plan new 525/230/12 kV substation ($0.77 million);

v. Fernley Area Master Plan ($5.50 million), and;

vi. Buffalo Mountain 345/120 kV substation ($0.15 million). (Ex. 306 at 1-2.)

181. Staff states that the costs for each of these projects will be reviewed in the next associated general rate case filing and, where appropriate, allocated based on large generator interconnection agreements. (*Id.* at 6.)

NV Energy's Rebuttal

182. In response to Intervenor inquiries, NV Energy provides that NV Energy has not included the Ft. Churchill—Captain Jack 525 kV transmission line in the regional planning process yet because it is premature to do so at this time. (Ex. 130 at 2.) NV Energy reiterates that it is requesting Commission approval for expenditures to begin only the initial phases of the

project, including constraint siting studies, environmental studies, permitting, right of way purchases and land acquisitions. (*Id.*) NV Energy clarifies that it has not requested Commission approval to construct the project, but instead to investigate whether it is a viable project. (*Id.*)

183. In response to Intervenor recommendations to not approve the funding requested for the Ft. Churchill—Captain Jack 525 kV transmission line, NV Energy states that if the Commission finds that it is not appropriate to fully approve permitting and land acquisition for the project at this time, then NV Energy recommends that the Commission approve the action plan budget of $400,000 for the project. (*Id.* at 5.) NV Energy explains that this would allow NV Energy to continue with routing and constraint studies, preliminary engineering, and environmental studies during the action plan period. (*Id.*) NV also provides that the Amargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line has been identified as a necessary system upgrade in the System Impact Study for Transmission Service Requests ("TSR"). (*Id.*) NV Energy similarly provides that if the Commission finds that it is not appropriate to fully approve permitting and land acquisition for the project at this time, then NV Energy recommends that the Commission approve the action plan budget of $400,000 for the Amargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line. (*Id.* at 6.)

184. While Staff recommends that the Commission should prioritize the Amargosa Valley-Bighorn-El Dorado Valley 525 kV transmission line between the two transmission projects, NV Energy disagrees and highlights the importance of the Ft. Churchill—Captain Jack 525 kV transmission line. (*Id.*) NV Energy explains that the Ft. Churchill—Captain Jack 525 kV transmission line would provide a direct interconnection to the Pacific Northwest, allowing access to a totally new market. (*Id.*) Further, NV Energy provides that this will provide access to

a geographically and resource diverse set of new renewable resources and allow the regional exchange of resources. (*Id.*)

Commission Discussion and Findings

185. The Commission approves, as Staff recommends, NV Energy's request to amend its Transmission Plan to begin making the expenditures for the initial phases including constraint siting studies, environmental studies, right-of-way purchases, land acquisitions, and permitting for the following projects:

i. Reid Gardner to Harry Allen #3 230 kV line ($1.00 million);

ii. Nevada Solar One Area ($1.50 million);

iii. Brooks 230/138 kV substation ($2.10 million);

iv. Apex Area Master Plan new 525/230/12 kV substation ($0.77 million);

v. Fernley Area Master Plan ($5.50 million), and;

vi. Buffalo Mountain 345/120 kV substation ($0.15 million).

The Commission agrees with Staff that these projects are needed to help NV Energy continue to meet its obligation to support load growth, allow for large generator interconnections, and/or alleviate system overloads. The costs will be reviewed and accounted for during the next general rate case to ensure that large generator interconnection agreement customers contribute their share.

186. The Commission rejects NV Energy's request without prejudice to amend its Transmission Plan with planning for (1) Fort Churchill to Captain Jack ($34.9 million, or $400,000 as stated in rebuttal), and (2) Amargosa Valley to Big Horn to El Dorado Valley ($9.3 million, or $400,000 as stated in rebuttal). The Commission rejects these projects as inadequately developed for resource planning approval at this time.

187. As discussed further elsewhere in this Order, many parties raised concerns about the effective integration of the pieces of the resource planning process. Integrated resource planning is focused on maintaining reliability of the system while managing costs. Transmission is an important part of this planning process, and transmission projects often have long multi-step processes to completion. As part of ensuring reliable service, NV Energy must continually monitor future transmission needs and evaluate opportunities. Once NV Energy has determined a need, and potential viable projects, the need and related projects can be evaluated as part of an IRP filing.

188. The two projects were introduced with budgets that were subsequently reduced in rebuttal to $400,000 each, to begin the initial phases. Questions for the two projects about the benefits of the lines, the potential buyers and sellers, and the interplay with the regional planning process, were not adequately answered by NV Energy at the hearing. Any, or all, of these projects may ultimately be appropriate for NV Energy to pursue to completion. However, the requests in this case are premature given that the investigation of potential projects can and should occur prior to seeking resource plan approval.

189. NV Energy can make the necessary expenditures to begin studies and explore permitting for these types of transmission projects, prior to seeking Commission approval through a resource plan amendment. NV Energy acknowledged that investigation of the viability of transmission projects should occur prior to seeking resource plan approval. Integrated resource planning is not only to be utilized on a piecemeal basis for regulatory risk management. NV Energy must file a triennial IRP in 2024 with a comprehensive transmission plan, which will allow NV Energy the opportunity to present a robust and integrated analysis of the needs of the transmission system going forward.

E. Waiver of Separate-Entity Accounting Method

NV Energy's Position

190. NV Energy requests that the Commission grant NV Energy a waiver of NAC 704.6546. (Ex. 119 at 3.) NV Energy explains that NAC 704.6546 requires the use of the separate company method in computing income taxes for each utility. (*Id.*) NV Energy states that this regulation ensures that any benefits or detriments of consolidation are not considered at the utility level. (*Id.*) NV Energy provides that the IRA was passed into law on August 16, 2022, and it brought several benefits to Nevada Power and Sierra. (*Id.* at 4.) Specifically, NV Energy outlines that the Valmy BESS requested in this IRP amendment and the Reid Gardner BESS requested in the First Amendment will be eligible for significant tax credits, potentially up to 40 percent ITC. (*Id.*) NV Energy further provides that the projects also qualify for accelerated tax depreciation deductions with a five-year life. (*Id.*) NV Energy argues that receiving a waiver of the separate company method would allow the tax credits of the IRA to pass directly to customers when incurred rather than some point in the future. (*Id.*)

191. NV Energy cautions that it will not be able to monetize the tax benefits when they are generated if NV Energy continues to use the separate-entity method. (*Id.*) Instead, NV Energy offers Nevada Power and Sierra will have tax credit carryforward balances that will take years to utilize. (*Id.*) NV Energy explains that it is prevented from monetizing the tax benefits immediately because each utility must generate enough taxable income on its own to absorb the tax depreciation and credits generated each year. (*Id.*) NV Energy elaborates that, since the benefits are substantial, it will take several years to fully utilize all the tax benefits. (*Id.*) NV Energy states that, under the separate-entity method, any unused tax credit carryforward balances

will be recorded on the balance sheet as a deferred tax asset and will be included in rate base. (*Id.* at 5.) NV Energy offers that this rate base increase will increase revenue requirement. (*Id.*)

192. NV Energy explains that credits generated on Sierra's tax return are not truly unused because Berkshire Hathaway Energy ("BHE") will use the credits on its consolidated tax return. (*Id.*) NV Energy elaborates that BHE will then pay cash to NV Energy Inc. to compensate Nevada Power and Sierra for the use of the losses and credits. (*Id.*) However, NV Energy points out that the requirement to use the separate-entity method prohibits the utilities from recognizing the receipt of the cash and use of the tax attributes at the utility level. (*Id.*)

193. In NV Energy's request for a waiver of NAC 704.6546, NV Energy proposes that it be permitted to account for the receipt of the BHE tax cash payments and reduce the tax asset balances, thus monetizing the tax attributes at the utility level. (*Id.* at 6.) NV Energy asserts that this would eliminate the tax credit carryforward asset balances and thus reduce rate base because the monetization of the credit would ultimately flow from BHE to Sierra and Nevada Power for each respective BESS. (*Id.*) NV Energy explains that the receipt of the cash at the utility level will reduce the carry forward balances that increase rate base thus lowering rate base and allowing the customer to benefit from the credits. (*Id.*) NV Energy provides that it cannot simply leave the tax asset balance out of the calculation of the rate base. (*Id.*) NV Energy explains that the credit carryforward balances are directly related to fixed assets that are included in rate base and to leave them out would violate NAC 704.6546 regarding the calculation of rate base. (*Id.*)

194. NV Energy explains that, in order for the Commission to waive NAC 704.6546, NAC 704.0097 requires three prongs for a deviation from the regulation:

i. First, there must be good cause for the deviation. NV Energy states this is satisfied because the monetization of the tax credits generated benefits customers by reducing rate base, thereby reducing revenue requirement;

ii. Second, there must be a specific reference to each provision of the chapter from which deviation is requested. NV Energy states that the sole specific reference is to NAC 704.6546;

iii. Finally, the deviation must be in the public interest and not contrary to statute. NV Energy provides that the deviation from the requirement for separate entity tax accounting is in the public interest because it lowers Sierra's and Nevada Power's revenue requirements. Further, NV Energy states that the requested deviation is not contrary to statute. (*Id.* at 7-8.)

195. NV Energy explains that it will be opting out of normalization for the Valmy BESS and Reid Gardner BESS projects. (*Id.* at 8.) NV Energy states that this will not change the accounting for the projects but will allow the ITC benefits to reduce revenue requirement sooner than under the normalization requirements. (*Id.*) NV Energy provides that, with normalization, the ITC is recaptured onto the books of Nevada Power and Sierra and amortized as a reduction of income tax expense over the book life of the underlying asset. (*Id.*) NV Energy states that there is no adjustment to the rate base. (*Id.*) NV Energy explains that, without normalization, the treatment is the same except there is a rate base adjustment by the net of two accounts: account 255 capitalized ITC credit carryforward and account 190 unutilized ITC credit carryforward. (*Id.*) NV Energy asserts that the result is that rate base is adjusted for any amount of credits both generated and utilized by NV Energy. (*Id.*) NV Energy offers that if it is granted the waiver of NAC 704.6546, the account 190 unutilized ITC credit carryforward will be zero. (*Id.*) Thus, NV

Energy concludes that the full benefit of the ITC credits generated will reduce rate base and benefit the customers. (*Id.*)

CMN's Position

196. CMN recommends that the Commission approve NV Energy's proposal to not normalize the ITC, require flow-through tax accounting, and place the benefits of the ITC into a regulatory liability account to ensure that ratepayers receive the full value of the ITC plus carry. (Ex. 800 at 22-23.) CMN states that NV Energy is proposing single-entity accounting to take advantage of the changes in the ITC pursuant to the IRA, avoid normalization of the ITC, and pass the value of the associated tax credits to customers on a normalized basis over the life of the projects, rather than on a flow-through basis. (*Id.* at 18.) CMN states that the single-entity accounting is required to receive the full benefits of these projects because neither Sierra nor Nevada Power have sufficient taxable currently to utilize the ITCs, lessening the support for building the projects. (*Id.* at 19.) CMN states that Sierra and Nevada Power's are unable to use the ITC as a carryforward due to how NVE files its taxes as a subsidiary of BHE. (*Id.* at 20.) However, CMN states that NV Energy can receive payments from BHE without the proposed waiver, and that the waiver may prevent NV Energy from capturing other tax benefits unless the waiver is modified to apply to all tax attributes that NV Energy cannot utilize on a stand-alone basis that BHE will reimburse NV Energy for. (*Id.* at 21-22.)

197. CMN supports NV Energy's proposal to opt-out of normalization of the ITC, but does not agree with normalizing the value of the ITC to rate payers because such a normalization will diminish the value of the tax benefits in favor of shareholders. (*Id.* at 22-23.)

NV Energy's Rebuttal

198. NV Energy rejects CMN's assertion that NV Energy is not proposing to maximize benefits under the ITC. (Ex. 125 at 3.) Specifically, NV Energy provides that the accounting proposed by NV Energy provides for a regulatory liability to be established for the full amount of the ITC generated and utilized by the consolidated group. (*Id.*) NV Energy explains that the liability then reduces rate base in year one and is amortized into operations and management ("O&M") expense as a reduction of tax expense over the book life of the asset. (*Id.*) NV Energy elaborates that the full benefit of the ITC generated is used to reduce revenue requirement through a combination of reduced income tax expense (amortization) and reduced rate base. (*Id.*) NV Energy concludes that this creates the same impact to customers as if the book basis of the asset was reduced by the ITC in the year placed in service. (*Id.*)

199. NV Explains that it proposed a different ITC treatment for Hot Pot and Iron Point versus the Valmy and Reid Gardner BESS projects because the Hot Pot and Iron Point projects used a pricing mechanism that did not include rate base. (*Id.* at 4.) Rather, NV Energy states it determined a separate rate for the power from the project that would be used for the life of the project. (*Id.*) In this case, NV Energy explains that the Valmy and Reid Gardner BESS projects are included in general rates and thus in rate base. (*Id.*) As such, NV Energy asserts that the use of the regulatory liability for the ITC balance as a rate base reduction in the year placed in service provides the same benefit as reduction of tax expense did in the Hot Pot and Iron Point projects. (*Id.*)

200. NV Energy disagrees with CMN's assertion that when using a normalization method of accounting, ratepayers will recognize a rate base benefit through the creation of a deferred tax liability. (*Id.*) NV Energy explains that a rate base adjustment is only allowed if NV Energy can opt out of normalization (*Id.*) NV Energy provides that if there is no ability to opt

out of normalization, then utilities can either reduce tax expense through amortization of ITC benefits or reduce rate base but not both. (*Id.* at 5.)

201. NV Energy also rejects CMN's assertion that a waiver to opt out of normalization is not required because NV Energy will still receive renumeration for the ITCs in its intercompany payments with BHE. (*Id.*) NV Energy explains that due to the requirement to use separate company accounting for income taxes at the utilities, the cash is not able to be paid to the utilities through intercompany or other tax accounts to reimburse the utilities for the use of the tax attributes. (*Id.*)

Commission Discussion and Findings

202. The Commission accepts NV Energy's request for a deviation from NAC 704.6546 pursuant to NAC 704.0097, as related to the accounting for the Reid Gardner BESS. Granting the deviation provides ratepayers the most benefits related to the Reid Gardner BESS ITC calculations. The Commission also accepts NV Energy's proposed accounting for the ITC. The Commission contemporaneously rejects NV Energy's request for approval of the Valmy BESS in this Order, therefore, no deviation applicable to the Valmy BESS is necessary.

203. NAC 704.6546 provides generally that for ratemaking purposes, any timing differences must be normalized at the applicable current income tax rate. The regulation also provides that any deferred income tax associated with items in rate base must likewise be included in the calculation of rate base. NV Energy identified the regulation for deviation as NAC 704.6546, and the Commission finds that the deviation is in the public interest and is not contrary to statute. The IRA provides for significant ITC opportunities for which the previously approved Reid Gardner BESS qualify. Absent a waiver from the regulation, the ITC annual amortization amount would be recognized in a general rate case and be calculated over the book

life of the asset. The unused portion of the ITC would be carried forward, be treated as an increase to rate base, and reduced as the ITC is amortized. (*See* Ex. 100 at 23-24.)

204. The IRA allows NV Energy to pass through to the customer the full value of the ITC by opting out of normalization, and this deviation allows NV Energy to take advantage of that opt out. As explained by NV Energy (Ex. 125 at 3-4), doing so allows for both the amortization (reduction) to rate revenues and reduction to rate base for the unamortized portion of the ITC. The fiscal impact is significant – for the Reid Gardner BESS this will total approximately $98.7 million.

205. No parties disagreed that the waiver should be granted – even CMN, if it was applied holistically to all applicable tax items. The proposed accounting treatment described in testimony and at hearing was also supported by Staff. (Tr. at 665) The tax accounting is proper, and while there may be merit in applying the waiver to other tax items, this is not the venue to do so.

F. IRP Process Reforms

Google's Position

206. Google recommends that NV Energy should be required to perform model simulations in all future IRPs and any current and future amendments to its 2021 IRP to examine the energy, capacity, and transmission impacts of: (a) joining the WRAP — which it has already committed to join; (b) joining a day-ahead market — which it intends to join by the first quarter of 2025; and (c) its statutory requirement to join a RTO by 2030. (Ex. 501 at 2.) Google provides that the results of these analyses should be incorporated in a refiled fourth amendment. (*Id.*)

207. Google recommends that the Commission should provide a forum or mechanism (such as a new docket) to consider IRP process reforms that are raised and considered, but not resolved, in the IRP sessions led by the utility prior to the filing of an IRP or IRP amendment. (*Id.* at 3.) Google provides that this docket could also be used to consider broader IRP reforms. (*Id.*)

208. Google recommends that, as part of the preparation of a refiled fourth amendment, and in all future IRP proceedings, NV Energy should be required to give Staff and stakeholders free access to its IRP models and tools, including software, in order to better understand the assumptions that drive NV Energy's Preferred Plan and to allow alternatives to be modelled and proposed by stakeholders for the Commission's consideration. (*Id.*) The recent settlement to share certain confidential IRP information between NV Energy and certain parties could offer a template for ensuring that confidential information remains secure. (*Id.*)

209. Google expresses concerns that NV Energy did not consider planned participation in regional market constructs in its IRP modeling which Google argues NV Energy should be required to do so. (*Id.* at 6.) Google expands that NV Energy's IRP modeling did not consider its statutory requirement to join an RTO by 2030, nor did it consider any incremental activities it will take prior to 2030 toward joining an RTO such as joining the WRAP or a day-ahead market. (*Id.* at 7.) Google provides that NV Energy has made the commitment to join WRAP and a day-ahead market in some capacity and thus joining the WRAP and a day-ahead market will have a material impact on the NV Energy's forecasted resource needs. (*Id.* at 8.)

210. Accordingly, Google argues that the Joint Application should reflect NV Energy's decision to join these markets and delineate how the utility has evaluated these impacts in the context of other resource decisions it has proposed. (*Id.*) In addition, Google argues that NV

Energy should be required to present alternative scenarios reflecting various potential RTO footprints that may be available in 2030. (*Id.*) While Google explains that the details of whether and what form an RTO may take by 2030 are uncertain, Google maintains that 2030 is firmly within the IRP planning horizon. (*Id.*) Google concludes that a major potential change should be analyzed in the IRP process. (*Id.*)

211. Google explains that RTO-related activities should be reflected in the IRP because the incorporation of RTO activities in NV Energy's IRP comports with potential future policy recommendations of the Regional Transmission Coordination Task Force, of which NV Energy is a member and which the Commission participates in a non-voting capacity. (*Id.*) Further, Google explains that the exclusion of RTO activities from resource planning could result in an overestimation of needed resources. (*Id.*) Google outlines that prudent resource planning must take into account efficiencies and the resources that will be available to the utility through regionally integrated transmission operation and wholesale electricity markets. (*Id.*) As such, Google argues that the failure to do so could result in increased costs and a reduction in the benefits of joining an RTO. (*Id.*)

212. While Google points out that NV Energy claims it is still investigating its participation in WRAP, a day-ahead market, and an RTO, and does not have sufficient information to determine if joining these organizations would materially impact its needs for additional resources, Google argues that these justifications to exclude these impacts from NV Energy's analysis are not credible. (*Id.* at 10.) More specifically, Google argues that regional models are available to study the benefits of regional markets and RTOs, which could be used to inform or adjust NV Energy's IRP modeling. (*Id.*) Google concludes that, to the extent that NV Energy has sufficient knowledge to make a reasonable estimate of the impact of joining the

WRAP, a day-ahead market, or an RTO, it should be included in the modeling of an IRP or an IRP Amendment. (*Id.*)

213. Google states that NV Energy is gathering substantial amounts of information through its participation in planning groups for RTO-related activities. (*Id.*) Google provides that NV Energy likely has access to preliminary results of the cost-benefit study being performed for the Western Markets Exploratory Group ("WMEG") by the consulting firm E3. (*Id.*) Further, Google states that through NV Energy's discussions in CAISO and Southwest Power Pool stakeholder groups regarding a day-ahead market, NV Energy has access to information that will allow it to make a reasonable estimate of the benefits of joining these organizations. (*Id.*) Moreover, Google provides that NV Energy can and should be doing its own modeling to assess the benefits. (*Id.* at 10-11.) In sum, Google argues that NV Energy now has or should have sufficient information to include the benefits of joining the WRAP, a day-ahead market, and an RTO in its IRP. (*Id.* at 11.) Google warns that failing to do so could bias the IRP towards excessive resource investment in generation assets. (*Id.*)

214. Google states that the Commission encourages entities to meet and discuss potential IRP process improvements through IRP sessions led by NV Energy. (*Id.* at 14.) However, Google provides that these IRP sessions, as currently structured, are not the appropriate forum to raise and discuss IRP process improvements. (*Id.*) Google explains that if NV Energy modified the structure of these sessions to allow for proposed IRP process reforms to be raised and discussed, then this forum could be adapted for this purpose. (*Id.*) Accordingly, Google recommends that the Commission should order NV Energy to allow for full discussion of IRP process reforms in these sessions. (*Id.*) For potential disputes that could not be resolved in

the sessions, Google states that the Commission would need to provide a mechanism or forum, such as a new docket, to consider IRP process reforms that could not be resolved. (*Id.*)

215. Google recommends that NV Energy should be directed by the Commission to allow stakeholders to access its IRP models at no cost in order to improve transparency, allow stakeholders and the Commission to better understand the assumptions that drive NV Energy's Preferred Plan, and to allow stakeholders to model alternatives for the Commission's consideration. (*Id.* at 15.) Google explains that greater access to NV Energy models will increase confidence in NV Energy's modeling and can bring to the fore new and creative ideas for resource planning. (*Id.*) Google provides the examples of other state regulatory bodies adopting similar procedures with the utilities under their jurisdictions. (*Id.* at 15-16.)

Interwest's Position

216. Interwest recommends that the Commission create a two-phase process in the next IRP with Commission decisions at the conclusion of each phase. (Ex. 700 at 7.) For Phase 1, Interwest explains the Commission should approve a resource adequacy constraint, approve modeling assumptions including policy constraints and bid evaluation parameters of an all-source RFP, including approving scenarios to meet policy goal including utility ownership targets or acquisitions, and approve bid portfolios to be examined in Phase 2. (*Id.*) Interwest clarifies that, if utility-owned generation projects are presented in Phase 1, those should be tested against the all-source RFP in Phase 2. (*Id.*) Regarding Phase 2, Interwest provides that, within a certain timeframe following NV Energy's receipt of bids, the Commission should require NV Energy to present a Phase 2 report populating bid portfolios approved in Phase 1 with resources for Commission review and approval. (*Id.*) Further, within this proposed Phase 2, Interwest

provides that the Commission should approve a resource portfolio to be acquired based on the results of the all-source RFP. (*Id.*)

217. Interwest goes on to recommend that the Commission should require additional phases if updates or amendments are required, or otherwise require annual reporting updates ahead of the next IRP. (*Id.*) Interwest explains that additional phases should follow a truncated Phase 1 and 2 process. (*Id.*)

218. Interwest recommends that the Commission incorporate an all-source RFP prior to resource acquisition approval. (*Id.* at 8.) Interwest explains that, in an all-source RFP, the "base case" is an informational exercise that begins a discussion on modeling parameters for bid evaluation by which all types of technologies compete to provide capacity and energy to the system. (*Id.*) Interwest recommends providing clear direction to the independent power producer market on the resource need, bid evaluation, and acquisition approval process in the RFP. (*Id.*) Interwest further recommends using the capacity expansion and production cost models to create optimized resource portfolios as outlined in Phase 1. (*Id.*) Interwest states that the Commission should require NV Energy to present to the Commission a preferred portfolio. (*Id.*) Interwest supports a process through which portfolios are crafted and refined with stakeholder input prior to the IRP filing. (*Id.*)

219. Interwest points to an IRP best practices evaluation published by Energy Innovation, et. al. as providing a high-level framework for IRPs. (*Id.* at 10.) Specifically, Interwest cites four objectives from the best practices evaluation published by Energy Innovation, et. al. (*Id.*) These four objectives are listed below:

(1) Regulators should use the resource planning process to determine the technology-neutral procurement need.

(2) Regulators should require utilities to conduct a competitive, all-source procurement process, with robust bid evaluation.

(3) Regulators should conduct advance review and approval of procurement assumptions and terms.

(4) Regulators should renew procedures to ensure that utility ownership of generation is not at odds with competitive bidding. (*Id.*)

220. Interwest also points to a publication from the Rocky Mountain Institute ("RMI") titled "Reimagining Resource Planning" which found that a comprehensive IRP practice is to establish a common set of assumptions and evidence that can be used to assess which near- and long-term options can meet system needs and achieve desired utility performance across multiple objectives. (*Id.* at 11.) Interwest explains that the RMI and Energy Innovation reports are just two among several that conclude that using advanced review of modeling assumptions prior to an RFP, and incorporating the all-source RFP as the critical element of the IRP, the resulting competitive all-source solicitations produce robust, low-cost bids that benefit ratepayers and manage utility risk. (*Id.*)

221. Interwest identifies several risks inherent to an IRP including resource adequacy, constraints on transmission, gas pipeline capacity, and greenhouse gas emissions risk. (*Id.*) Interwest provides that IRPs can help to avoid the opposite risk of over-building supply or creating stranded assets. (*Id.*) Interwest goes on to provide that IRPs can manage cost and risk to strike a balance of utility-owned generation and PPA projects. (*Id.*) Interwest explains that, in recent years, several utilities have experienced massive construction cost overruns for large utility-owned generation projects. (*Id.*) Interwest offers that IRPs can reduce this risk through the diversification of ownership, technology, or timing. (*Id.*)

222. Interwest maintains that a two-phase process can implement best practices to effectuate a significant impact on IRP outcomes. (*Id.*) Interwest explains that the first phase of

an IRP can also set transparent acquisition targets for the RFP that assist NV Energy, the Commission, and market participants to understand the process. (*Id.* at 14.) Additionally, Interwest provides that if new transmission investments are contemplated during the resource acquisition period, those investments should be considered in Phase 1 so that they are made available to the market in the RFP. (*Id.*)

223. Interwest explains that in a two-phase process, bids supply the candidate resources to the capacity expansion model during the resource acquisition period, and generic units are solely used as placeholders in the outside years. (*Id.*) Interwest provides that using an all-source RFP where renewable energy can provide capacity to the system in line with the utility's approved ELCC studies lets different generation types compete on a level playing field. (*Id.*) Thus, Interwest provides that using Phase 2 to evaluate and incorporate the results of an RFP, including proposals for both PPAs and UOG, provides direct and current market data for the Commission to examine to fill the resource adequacy need. (*Id.*) Interwest states that these factors allow for a robust and transparent Phase 2 analysis that can give regulators confidence that the projects selected satisfy both resource adequacy and transmission need in a cost-effective and reliable manner with real projects. (*Id.*)

224. Interwest states that the benefits of reviewing modeling characteristics in a Phase 1 are that the assumptions in the base case can be tested without the pressure of generation units already presented for approval. (*Id.*) Interwest explains that if done in advance of resource acquisition, the base case can be modified, if the Commission determines it necessary, ahead of an RFP and without having to decide on utility proposals for new generation. (*Id.*) Interwest elaborates that, importantly, this doesn't preclude a utility from presenting a utility-owned generation proposal in Phase 1, but the approval of such a proposal should be evaluated against

proposals from the market. (*Id.* at 14-15.) Interwest states that vetting modeling assumptions in Phase 1 also provides transparency and stakeholder buy-in. (*Id.* at 15.) Interwest also states that the capacity expansion model can then be leveraged for its primary purpose in Phase 2. (*Id.*)

225. Interwest provides that the purpose of a Phase 2 process is the all-source RFP. (*Id.*) Interwest states that the Phase 2 process can be truncated where most modeling issues are decided in Phase 1, including the parameters of the utility's bid evaluation and presentation to the Commission. (*Id.*) In that respect, Interwest explains that the decision can focus on cost, reliability, and which of the portfolios best meets the resource need. (*Id.*) Interwest points to the 2016 Public Service Company of Colorado IRP in Colorado, which led to an RFP in 2017 and resource acquisitions decided in 2018, as a good example of a two-phase IRP. (*Id.*)

226. Regarding the current IRP process before the Commission, Interwest explains that NV Energy issued three utility-scale RFPs during the pendency of the 2021 IRP – which contains four phases and four amendments. (*Id.* at 26.) Interwest states that NV Energy issued a Spring 2022 RFP, a 2022 "PURPA RFP" seeking resources from 50 — 100 MW, and a Winter 2023 RFP. (*Id.*) Further, Interwest states that the Phase 1 order in this case finds that NV Energy testified it held two additional RFPs in 2020. (*Id.*) Interwest points out that NV Energy stated no projects were selected from either 2020 or 2022 RFPs. (*Id.*) Interwest argues none of these RFPs were approved in any Phase or amendment order. (*Id.* at 27.) Interwest provides that out of the five RFPs held since 2020, the sum of projects from those RFPs that will help fill the capacity position NV Energy started this proceeding with in 2021 is low – only 66 MW. (*Id.*) Interwest states that while NV Energy provided its reasoning both for launching the RFPs and for its decisions not to contract, the decisions are made in NV Energy's discretion separate and apart from the many phases of this ongoing IRP and without supporting data presented to the

Commission. (*Id.*) Interwest states that, in the interim, NV Energy has pursued self-build options at Silverhawk, and executed PPAs with IPP projects outside of the RFP process. (*Id.*)

227. From the current IRP process before the Commission, Interwest provides three primary concerns. (*Id.*) First, Interwest states that there is a disconnect between the Commission's exercise of its IRP jurisdiction on the one hand, and RFPs conducted by the utility on the other. (*Id.*) Interwest explains that this means that the process of soliciting and evaluating new resources, arguably the primary purpose of the IRP, has limited or even zero examination in the IRP, even as multiple RFPs take place in parallel. (*Id.*) Interwest states that, while NV Energy's subject matter experts are no doubt capable and the utility has the best insight into its resource needs, there is a stark disconnect. (*Id.*) Interwest argues that if RFPs are not considered in the IRP process except as individual projects, they may be randomly put forward during a three-year litigation process at the utility's sole discretion, then there is less information exchange, less transparency into what the market can provide, and ultimately weakened decision-making that may not be reflective of the ratepayers' best interest. (*Id.*) Interwest states that, while Phase II tackled some modeling inputs, in no phase were the modeling assumptions or detailed results of bid evaluations ever put forward for the Commission to review. (*Id.* at 28.) Interwest argues that it is a lost opportunity for these RFPs to be taking place in the shadow of the IRP decisions rather than being guided by them. (*Id.*)

228. Second, Interwest explains that RFP bidders have no certainty their bids will ever be analyzed or brought before the Commission, despite the terms of the RFPs that list exact decision dates. (*Id.*) Interwest provides that such RFP bid data sits in NV Energy's database, ostensibly for later use. (*Id.*) Interwest states that the RFP process is ambiguous, unpredictable, and uncertain from the market's perspective. (*Id.*)

229. Third, Interwest states that, for parties like Interwest, and more importantly the Commission, Staff, consumer representatives, and other stakeholders, there has been constant IRP litigation during the IRP period. (*Id.*) Interwest provides that there is no finality whether the next IRP phase or amendment comes on the heels of the last, overlapping at times, with later phases undoing earlier phases. (*Id.*) Interwest explains that this makes the whole process opaque and leaves little chance for parties to review whether the IRP as a whole produces the best results for ratepayers. (*Id.*)

230. Interwest offers that this IRP process creates uncertainty which leads to risk. (*Id.*) Interwest provides independent power producers may have participated in several RFPs without seeing any be concluded. (*Id.*) Interwest states that NV Energy says projects from older RFPs may be brought forward in the future. (*Id.*) Interwest provides that it is likely that all 2020 bids, and likely even 2022 bids, can no longer honor their pricing from the time the bids were submitted. (*Id.*) Further, Interwest states that the Commission's diligence is hampered by not reviewing resources via its primary risk management tool, the capacity expansion model. (*Id.* at 29.) Instead, Interwest states that resources have been acquired at different times via different applications, all within this three-year window before the process starts again. (*Id.*) Interwest explains that when a project goes wrong due to the overwhelming global market forces of 2021-2022, for example, there is little evidence to support what could have been, or what can still be done, as an alternative. (*Id.*) Interwest offers that this gives NV Energy the controlling ability to suggest a course correction, absent things like back-up bids, wait lists, or bid refresh opportunities. (*Id.*)

231. Interwest states that NV Energy did not use its capacity expansion model to identify and fill the capacity need in this IRP. (*Id.*) Interwest elaborates that, while NV Energy

ran its model, it did not fill the capacity need and did not follow the model's initial results. (*Id.*) Interwest states that the Preferred Plan's open capacity position is not mentioned in the 2022 or 2023 RFPs, which means that bidders are not aware of the market conditions created by NV Energy's resource need. (*Id.*) Interwest maintains that NV Energy's alternatives then do not fill the resource need but leave "placeholder" capacity as soon as 2025. (*Id.*)

232. Interwest states that there are due process benefits that would result from moving to a two-phase process in the next IRP. (*Id.* at 31.) Interwest states that this will benefit stakeholders and the public interest. (*Id.*) First, Interwest explains that parties will be able to comment on modeling and bid evaluation before-the-fact to assist Commission evaluation. (*Id.*) Second, Interwest states parties will be able to integrate information from the RFP bids submitted, assisting the Commission's evaluation of the market results as against NV Energy's proposals, if any. (*Id.*) Interwest provides that the result is likely to be a more robust and transparent review that in turn leads to ratepayer savings through competitive pressure and an optimized portfolio. (*Id.*)

233. Interwest concludes that where all-source procurements are initiated with explicit determinations of need rather than a technology specification, set regulatory approval processes, and transparent evaluation, the market for generation projects can provide robust responses to all-source RFPs. (*Id.* at 35.) Interwest offers that the primary function of the capacity expansion model is leveraged to evaluate multiple technologies on multiple criteria. (*Id.*) Interwest further states that the optimum mix of solar, wind, storage, and gas resources is more effectively selected based on actual bids, rather than in a generic evaluation or single-source RFPs. (*Id.*) Interwest provides that benefits regulators and ratepayers compared to an after-the-fact review that creates a number of problems, most notably that there is limited ability to review the utility's

options. (*Id.*) Interwest maintains that the all-source RFP provides hard data on competitively bid alternatives and therefore allows for a more informed and cost-effective decision-making process benefitting the Commission, the consumer, and providing confidence to the generation market in Nevada. (*Id.*)

WRA's Position

234. WRA states that NV Energy's recent IRP process reforms have aligned its process with best practices for regional utilities of similar size and with similar decarbonization policy requirements. (Ex. 602 at 12.) However, WRA provides that NV Energy's process has a critical gap in its approach that omits the final step of an ex-post assessment of the reliability of its resource portfolios using sophisticated reliability modeling software. (*Id.*) WRA explains that this omission means that NV Energy is out of step with regional utilities. (*Id.*) WRA further provides that the omission also introduces significant and unnecessary reliability risk for Nevada. (*Id.*) WRA states that NV Energy's current approach relies heavily on the development of ex ante reliability parameters—specifically PRM, ELCC, and other resource counting rules—to determine reliability compliance. (*Id.*) WRA explains that this simplification, without an ex-post review, is inconsistent with how other neighboring utilities ensure their selected portfolios are reliable. (*Id.*) WRA argues that it also introduces two dynamics that erode confidence in NV Energy's reliability assessment. (*Id.*) First, WRA states that NV Energy's current modeling may miss critical reliability dynamics. (*Id.*) Second, WRA states that NV Energy's static representation of modeling quickly loses fidelity as real-world conditions change. (*Id.*) WRA provides that an ex-post reliability check using modeling software is critical to avoiding such problems and is consistent with how other similar utilities in the west ensure their systems are reliable through IRP planning. (*Id.*)

235. WRA elaborates that simplified reliability assessment using capacity expansion modeling, paired with static reliability parameters, can miss critical portfolio dynamics and risks, which are not effectively represented in a capacity expansion model. (*Id.* at 12-13.) WRA provides that these risks are articulated well in the 2021 IRP filing of neighboring utility, PacifiCorp. (*Id.* at 13.) WRA states that PacifiCorp highlighted that PLEXOS LT relies on a limited, simplified representation of reliability dynamics as a necessary tradeoff to support the complex optimization necessary to assess resource alternatives. (*Id.*) WRA offers that this well-documented problem can be solved through ex post modeling, often referred to as "roundtrip modeling," which consists of a final reliability check to assess the integrated operations of the selected portfolio using a production cost modeling software like PLEXOS ST. (*Id.*)

236. WRA states that, since the static reliability analysis performed by Energy and Environmental Economics ("E3") on behalf of NV Energy was completed in 2020 and 2021, a wide range of input parameters have changed, including NV Energy's load forecast, its portfolio mix, its expectation of available market purchases from neighboring regions, and the availability of its hydroelectric resources. (*Id.* at 13-14.) WRA points out that NV Energy's consultant, E3, has warned that if one or more of these factors change substantially, then the ELCC for a resource can change and the ELCC values in this study should be revisited. (*Id.* at 14.) Similarly, WRA also points to NV Energy's PRM Study which provided that number of future changes – which may include fundamental changes in the shape of NV Energy's load, major changes in the resource portfolio, and improved understanding of impacts of climate change on extreme weather events that affect system reliability – may eventually require NV Energy to revisit its PRM requirement. (*Id.*) WRA concludes that the inclusion of an ex-post reliability assessment within the modeling process is a best practice and is sufficient to test the reliability of

the IRP at a level of robustness similar to a full refresh of NV Energy's out-of-date PRM and ELCC studies. (*Id.* at 14-15.)

237. WRA explains that roundtrip modeling refers to a final step in the modeling process to assess whether the integrated portfolio, once developed, operates in a manner consistent with the expectations of the capacity expansion model used to generate the portfolio and the PRM and ELCC parameters established in ex ante studies. (*Id.* at 15.) More specifically, WRA explains that roundtrip modeling refers to the inclusion of an ex post probabilistic modeling run that assesses whether the portfolio in question passes a specific reliability threshold, such as the 1-day-in-ten-years Loss of Load Expectation standard approved by the Commission for NV Energy. (*Id.*) WRA provides that roundtrip modeling enables the utility to update key parameters such as load forecast changes that may have arisen following the development of static parameters developed in ELCC or PRM studies which may no longer be applicable. (*Id.* at 16.) WRA offers that the vast majority of western utilities incorporate roundtrip modeling as an integral final step in their portfolio development processes. (*Id.*) While WRA concedes NV Energy would need to modify its current PLEXOS model to perform a probabilistic reliability assessment, WRA argues that this step is not unreasonable or overly burdensome for a utility of the size and resources of NV Energy. (*Id.*) WRA points out that NV Energy is the only utility among the 15 largest within WECC which does not currently incorporate, or is not actively considering the incorporation of, roundtrip modeling within its IRP process. (*Id.* at 19.)

238. WRA provides that NV Energy's current PRM-based process does not capture load forecast changes occurring in critical hours (i.e. September evenings) which are separate from the one peak load hour of the year. (*Id.* at 24.) Without reform, WRA warns that NV

Energy and the Commission may perceive full reliability compliance for the July-based PRM analysis despite significant reliability risk lurking in a revised September. (*Id.*) WRA explains that this effect is also illustrated in the hourly load shape changes present for the peak days in NV Energy's workpaper, which show significant growth in mid-day load in the revised forecast relative to peak and overnight load growth. (*Id.*) As a result, WRA highlight NV Energy's mid-day loads on peak summer days grow by as much as 7 percent, while its evening and overnight loads grow by 3-4 percent. (*Id.*)

239. WRA cautions that NV Energy's current practice of relying solely on static reliability parameters introduces significant risk of reliability events for NV Energy customers. (*Id.* at 25.) WRA states that it is reasonable to conclude that, in 2025, NV Energy will not meet the Commission's directed reliability standard of 0.1 loss of load expectation if it procures reliability resources based solely on the change to its annual peak load occurring in July, as the faster, decoupled growth in September under the revised load forecast is not accounted for in NV Energy's reliability accounting framework. (*Id.* at 26.) However, WRA warns that this result should be corroborated with a robust, probabilistic reliability analysis. (*Id.*) WRA notes that NV Energy's current software, specifically the PLEXOS suite, is fully capable of performing the necessary reliability analysis with some setup and parameterization. (*Id.*)

240. WRA provides that NV Energy currently accredits thermal and hydroelectric resources at their full installed capacity ("ICAP"), which significantly overstates their reliability contributions relative to other methods such as unforced capacity ("UCAP") or ELCC. (*Id.*) WRA points out that, while NV Energy takes the partial step of incorporating forced outages into its reliability modeling for thermal resources, these limits are not reflected in its resource accreditation for compliance with the PRM. (*Id.* at 27.) WRA provides that this represents a

significant gap when resources are substituted in the portfolio and is another risk that could be ameliorated through ex post reliability modeling. (*Id.*) WRA states that NV Energy's current approach introduces three policy concerns. (*Id.*) First, WRA states that the failure to represent thermal limitations in its reliability accreditation prevents NV Energy from accurately assessing the costs and benefits of thermal retention through the LSAP process. (*Id.*) Second, WRA states that the failure to represent thermal limitations in its reliability accreditation prevents NV Energy from accurately comparing the cost of competing reliability resources on equal footing. (*Id.*) Third, WRA states that the failure to represent thermal limitations in its reliability accreditation has the potential to introduce reliability risk when ICAP thermal replaces ELCC resources, which increases the risk of insufficient resources and adds to the risk of outages. (*Id.*)

241. WRA explains that the WRAP program will require utilities to account for thermal resources using a UCAP methodology, which provides a better estimate of how resources can contribute to resource adequacy. (*Id.*) WRA offers that UCAP accounts for historical forced outage events and relative to NV Energy's current practice of accounting for its thermal fleet at its installed capacity, UCAP is a significant improvement. (*Id.* at 27-28.) However, WRA states, considering NV Energy's reliance on thermal resources for reliability, and in recognition of the extreme conditions NV Energy's thermal fleet may face during a severe west-wide heat event, NV Energy should consider an enhanced assessment of its thermal fleet risk using ELCC methods, including the risk of correlated outages driven by extreme heat and ambient derates which may exceed values observed in the historical data used to populate the UCAP assessment. (*Id.* at 28.) WRA states that the WRAP will require specific capacity accreditation processes for run-of-river and storage hydro, which NV Energy should apply to its contracted hydro resources rather than modeling and accrediting them as firm capacity. (*Id.*)

242. WRA states NV Energy replaces resources measured in perfect capacity (ELCC) with resources measured in installed capacity, introducing a differential between its target reliability standard and expected reliability standard based on the revised portfolio. (*Id.*) WRA argues that this inherently erodes the link between NV Energy's modeled reserve margin and the actual expected performance of its resource fleet. (*Id.*) As a result, WRA provides that NV Energy's approach decouples its portfolio from the Commission's adopted reliability standard. (*Id.*) WRA notes that NV Energy's current modeling and accreditation practices are not consistent with the accounting requirements it will face under the WRAP. (*Id.* at 28-29.)

243. WRA points out that the FERC recently issued a ruling approving the WRAP tariff and setting in motion the initial implementation of the WRAP program. (*Id.* at 29.) In light of this ruling, WRA highlights three key implications for NV Energy's resource planning efforts. (*Id.*) First, WRA states that WRAP participation will bring binding resource sufficiency requirements and penalties for non-compliance that NV Energy must plan to meet with eligible resources. (*Id.*) Second, WRA states that WRAP will provide greater transparency and liquidity to the regional resource market, enabling NV Energy to more effectively solicit capacity resources from across the western region. (*Id.* at 30.) Third, WRA states that WRAP will establish standardized resource accreditation and reliability need determination across the region, which should be integrated into NV Energy's state-level resource planning. (*Id.*)

244. WRA provides that, presuming NV Energy moves forward with participation in the WRAP, NV Energy will face binding compliance obligations for resource procurement using standardized measures across the West. (*Id.*) WRA states that NV Energy and the Commission will need to be more proactive and forward-looking to ensure NV Energy has sufficient resources to meet the WRAP requirements and ensure sufficient resources to provide for

reliability and effective financial hedging for NV Energy customers. (*Id.*) To achieve this, WRA states that NV Energy and the Commission must evolve the IRP process to reduce reliance on just-in-time procurement. (*Id.*) Further, WRA states that it is reasonable to expect that certain WRAP members will have excess capacity available for resale to short utilities like NV Energy. (*Id.*) WRA argues that NV Energy should immediately undertake efforts to leverage this opportunity to identify what resources are available and what requirements must be met for NV Energy to procure and show regional resources as part of its WRAP compliance. (*Id.* at 30-31.)

245. WRA provides that NV Energy's reliability position management will need to evolve in several ways to align with the requirements of the WRAP program. (*Id.* at 31.) Regarding PRM, WRA states that WRAP establishes the reliability requirement for Load Responsible Entities ("LRE") as a specific PRM applied to the peak load forecast based on the LRE's P50 load forecast and thus NV Energy may need to change its current 16 percent PRM to align with the WRAP results. (*Id.*) WRA states that WRAP will require LREs to show sufficiency on a monthly basis and thus NV Energy will need to transition from an annual resource planning framework. (*Id.*) WRA states that WRAP will utilize monthly, regional ELCC values and thus NV Energy will need to align its solar, wind, and storage resource accreditation with WRAP monthly ELCC results. (*Id.*) WRA states that WRAP will utilize a specific methodology for determining the Qualified Capacity Contribution of hydroelectric and thermal resources and thus NV Energy will need to align its hydroelectric and thermal resource methodologies with WRAP rules. (*Id.* at 31-32.) WRA provides that each of the alignments listed above will bring NV Energy's modeling processes more closely in line with industry best practices. (*Id.* at 32.)

246. WRA provides that, while NV Energy has appropriately transitioned much of its portfolio development process to industry standard modeling methods, WRA states NV Energy's process excludes consideration of the optionality of retention or retirement of its existing resources. (*Id.* at 32-33.) Instead, WRA explains the model is constrained to retain these existing resources until the end dates determined exogenously through the LSAP. (*Id.* at 33.) WRA argues that this approach precludes NV Energy's portfolio modeling exercise from identifying or assessing early retirements for any of its existing generation, even if more cost-effective resource alternatives may exist. (*Id.*) WRA offers that NV Energy should allow its capacity expansion model to operate without this constraint to evaluate whether older fossil fueled resources could be cost-effectively replaced. (*Id.*) WRA explains that the net effect of NV Energy's current modeling approach is to make portfolios with more aggressive resource build-outs look artificially worse because of the forced retention of older generation. (*Id.*) WRA states that, while this problem arises because of the modeling limitations NV Energy selected, the utility frames this problem as the fault of the resource buildout. (*Id.*) WRA provides that, to the extent NV Energy's model identifies resources for retirement, NV Energy has the capability to perform multiple model runs which include and exclude resources to assess the intuition of the Capacity Expansion model and more robustly test the portfolio using Production Cost Modeling. (*Id.* at 34.) However, WRA warns that locking in these resources as a baseline assumption which is not tested in the modeling is not a best practice and risks significantly overestimating the cost of the low carbon case resource build-out. (*Id.*) WRA recommends that NV Energy should re-assess the low-carbon case and provide a revised portfolio for Commission consideration in its next IRP amendment filing. (*Id.*)

247. WRA argues that NV Energy's existing process for filing its triennial IRP and making substantial revisions through amendments limits regulatory review and stakeholder engagement. (*Id.*) WRA offers that directing NV Energy to improve its modeling process (in alignment with recommendations above) and to provide significantly more notice to the Commission and stakeholders prior to major resource investments will reduce the risk of rushed, just-in-time requests for urgent capacity. (*Id.* at 35.) WRA recommends that the Commission should direct NV Energy to provide the Commission and stakeholders with significantly more notice when NV Energy is actively considering resource procurements or changes to its Action Plan. (*Id.*)

248. WRA provides that the current IRP process blends the modeling and procurement decisions into one suite of choices before the Commission. (*Id.* at 36.) WRA states that a preferred approach would separate modeling and portfolio development with generic resources into one phase of the IRP process, and procurement approvals, preferably stemming from approved generic resource approvals, into a separate, subsequent phase. (*Id.*) WRA provides a possible three-step framework for this process. (*Id.*) For the first step, WRA recommends providing generic assumptions and portfolio results for Commission and stakeholder review and Commission approval of a supply-side plan in the initial phase of the triennial IRP. (*Id.*) For the second step, WRA recommends conducting a competitive all-source solicitation, open to both proposed build transfer agreements and PPAs, using the approved modeling assumptions from the IRP. (*Id.*) For the third and final step, WRA recommends filing preferred and alternative portfolios with the Commission for review and approval in a second phase of the IRP, which could be conducted on an expedited basis. (*Id.*)

BCP's Position

249. BCP states that the Commission, in prior orders, has expressed concern regarding the substantial financial commitments for a project prior to seeking approval in an IRP application. (Ex. 400 at 16.) BCP points out that in the consolidated dockets, Docket 08-05014 and Docket 08-05015, the Commission specifically outlined that:

> "The Commission shares BCP's concerns regarding [Nevada Power Company's] decision to proceed construction and equipment procurement prior to applying for resource planning approval for the Harry Allen CC. ... [t]he Commission finds that in the future, [Nevada Power Company] shall file amendments as soon as practicable when circumstances, such as substantial financial commitments, warrant an amendment, rather than presenting the Commission with an amendment after substantial financial commitments have been made." (*Id.* at 18-19; Dockets 08-05014 and 08-05015, Order ¶ 52.)

250. BCP recommends that the Commission order NV Energy to file for approval as soon as practicable prior to making substantial financial commitments for any project development tasks or risk cost recovery from ratepayers. (*Id.* at 17.) More specifically, BCP recommends that the Commission issue an order that addresses NV Energy's practice of making financial commitments for any development task prior to seeking approval in an IRP or an amendment. (*Id.* at 19.)

Staff's Position

251. Staff recommends the Commission direct NV Energy to include in future IRP or IRP amendment filings an explanation and roadmap detailing how the IRP or IRP amendment fulfills the goals or initiatives or aligns with the projects proposed in the strategic operating plan ("SOP"). (Ex. 311 at 1.) Staff states that NV Energy's SOPs present its top goals, priorities, and initiatives for the next one and ten years and then implements them through the IRP. (*Id.*) After reviewing the SOP as compared to the Financial Plan included with, Staff found that "large inconsistencies" between the two. (*Id.* at 2.) Staff states that as a result of these inconsistencies, the SOP and the analysis in this Docket are not aligned, nor did the 2023 SOP inform the

Commission's long-term planning in this Docket. (*Id.* 3.) As a result of this disconnect, Staff posits that the proposed projects are presented to the Commission in a compartmentalized manner to prevent the Commission from getting a holistic view of all possible resources and alternatives. (*Id.*) Staff refers to several projects proposed in this Docket that are presented outside of the larger context of the SOP and NV Energy's Action Plan Progress Report, which also provided information that was not aligned with this Docket. (*Id.* at 4.)

252. Staff states that the SOP lists a variety of resources that NV Energy is actively pursuing are not presented or otherwise discussed in the IRP, creating a "piecemeal, just in time planning and "crisis driven"" approach that effectively precludes the Commission from approving resources that can meet legislated energy policies or engaging in true long-term planning. (*Id.* at 6.) Staff proposes that, to solve these problems, NV Energy should include a discussion of the actions, goals, plans, and projects from the SOP in all IRP and IRP amendments, and include all projects NV Energy is pursuing as placeholder projects. (*Id.* at 7.)

NV Energy's Rebuttal

253. In response to BCP's assertion that NV Energy should file for approval prior to making significant expenses supporting new projects or else risk cost recovery, NV Energy states that a requirement to make a filing for Commission approval of each project development expenditure could delay project schedules and/or potentially result in lost site acquisition or equipment procurement opportunities. (Ex. 128 at 10.) NV Energy argues that, based on the record of Commission project approval to date, it can be surmised that NV Energy has a well-functioning RFP process and has successfully demonstrated to the Commission, in multiple filings, through its comparisons to RFP results and other project cost benchmarking, that the proposed projects were cost-effective, prudent portfolio additions. (*Id.* at 12.)

254. NV Energy also takes issue with WRA's suggestion which NV Energy states implies that NV Energy should provide notice to the Commission every time it considers new unit options at any of its facilities. (Ex. 127 at 5.) NV Energy offers that it regularly considers new unit options as part of normal planning processes. (*Id.*) Were NV Energy required to provide the Commission formal notice every time NV Energy was studying the need and viability of new units, the Commission would be administratively burdened and overwhelmed with irrelevant information (*Id.* at 5-6.) NV Energy maintains that, consistent with NRS 704.741 and its accompanying regulations, it is not until NV Energy has fully vetted and screened potential project viability and need, and have performed a full analysis, that it presents those projects to the Commission for approval. (*Id.* at 6.)

255. NV Energy argues that it is important for NV Energy to have the ability to file amendments to its Commission-approved joint resource plan during interim periods between filing the next triennial IRP. (Ex. 131 at 8.) NV Energy offers that this is why the statutes and regulations specifically contemplate amendments. (*Id.*) NV Energy explains that it is important to have an avenue to address challenges not anticipated during the joint resource plan filing review process. (*Id.*) NV Energy elaborates that being able to address in real-time the ever-changing energy landscape is critical and prudent to effectively run a utility and fulfill our obligation to serve. (*Id.*) In response to WRA's recommendations to alter the IRP process, NV Energy states that, if WRA believes that changes should be made to any of the Commission's IRP regulations, WRA should follow the procedures outlined in NAC 703.546. (*Id.*)

256. NV Energy states that it appears that Google wants NV Energy to independently conduct sessions to reform the electric utility IRP process, separate and apart from the

Commission's established rulemaking process. (*Id.* at 11.) However, NV Energy states that only the Legislature and the Commission may change electric utility IRP process. (*Id.*)

257. NV Energy generally responds to Intervenor assertions that seek to alter the IRP process. (*Id.* at 12.) Specifically, NV Energy provides that Intervenors are attempting to collaterally reject this Amendment by criticizing the process for filing and reviewing electric utility resource plans and amendments. (*Id.*) NV Energy states that Intervenor recommendations do not appear to be for the overall benefit of NV Energy's customers, but instead to effectuate these Intervenors' special interests. (*Id.*) Further, NV Energy provides that these Intervenor recommendations will limit NV Energy's ability to quickly respond to critical needs as they arise by adding unnecessary layers of filings and the requisite approvals, delaying the time by which NV Energy can implement plans to provide reliable service at just and reasonable rates for customers we are obligated to serve. (*Id.*)

258. NV Energy concludes that it does not believe that there is a need to reform the IRP statutes or regulations at this time. (*Id.* at 13.) NV Energy requests that the Commission reject the proposals as inappropriate given the scope of this proceeding. (*Id.* at 19.) NV Energy provides that it will support the Commission's encouragement to the parties from phase one of this docket to meet and confer by committing to notifying, when practicable, when initiation of a triennial filing has begun, or when circumstances cause the planning of an amendment to begin. (*Id.*)

Commission Discussion and Findings

259. Several intervenors – including WRA, Google, Interwest and CMN – recommended broad reforms to NV Energy's IRP and resource procurement processes. WRA (Ex. 602) suggests "structural reforms" to NVE's IRP and Interwest (Ex 700-701) similarly

proposes NV Energy adopt a two-stage IRP such as Public Service Company of Colorado uses in Colorado. Google also suggests NV Energy improve its IRP processes to better share data and modelling, including proprietary information. Like Google and Interwest, CMN (Ex. 800-801) recommends that the Commission require NV Energy to hold comprehensive all-source RFPs for new resources before approving any new resources, explaining that neither Alternate nor Moderate Plans proposed could be shown to be least cost, least risk of all available options. CMN asserts that additional sensitivity analysis and more comprehensive economic analysis of the Plans is necessary to show cost-effectiveness of a preferred portfolio.

260. The intervenors raise reasonable concerns with stakeholders' ability to evaluate NV Energy's IRP. However, while Google, Interwest, WRA, CMN and Staff pose helpful questions, the parties may not yet have all the right answers to the issues that arose in this Docket. Parties have identified modelling weaknesses, IRP process failures, transparency gaps, and stakeholder engagement concerns. However, the Commission does not find that a comprehensive overhaul of Nevada's electric resource planning is warranted in this Docket.

261. NV Energy's needs and operations are changing, and the planning processes used by NV Energy must adapt. It is more efficient to accommodate new needs preemptively rather than addressing changes after issues become acute. Walk, jog, run applies here as well. For instance, while Google's recommendation to model the impacts of joining a market/RTO was premature in this IRP Amendment, NV Energy will eventually need to reflect the impacts of RTO participation given the requirement to join such a market in SB448. As the current IRP process does not contemplate any kind of regional planning impacts and such an undertaking is likely both data intensive and complex, discussing how NV Energy might go about modelling the impacts of a regional market on its resource portfolio is reasonable to start well in advance.

262. The Commission supports NV Energy's suggestion in the hearing (Tr. at 1227:25-1228:23) to improve the navigability of the IRP filings via inclusion of additional indexes and visual aids as a reasonable improvement. IRPs are necessarily complex filings and the proposal to include a flow chart of some kind to show readers the order of modelling and data analysis are helpful improvements. Similarly, NV Energy's suggestion to host an informal meeting or workshop for stakeholders prior to the next IRP is valuable. There are many newer stakeholder groups as well as individual technical experts with differing experience. The Commission appreciates NV Energy's proposal to increase understanding, capacity building, and knowledge sharing among stakeholders.

263. Further, NV Energy's system is growing more complex, as NV Energy addresses (1) increasing renewable procurement, rather than dispatchable fossil generation resources to meet the RPS; (2) using new and complex modelling software to conduct production cost modelling, and (3) contemplating participation in new regional programs for resource adequacy and trading in multi-state day-ahead markets. These are topics worthy of additional discussion among the full set of stakeholders. To include the Commission in the discussion and maximize transparency, the Commission will open an investigatory docket and host at least two formal workshops on potential improvements to the IRP.

264. The first workshop in 2023 will provide stakeholders an opportunity to discuss more near-term improvements to NV Energy's resource planning, including possible discussion of changes that might smooth the processing of the 2024 IRP. Workshop topics should include many of the topics raised in this docket, including but not limited to the following:

i. Better accounting for net peak load and increasing load across the year, rather than just at the July summer peak, particularly by ensuring generation resources match load at all times in the year via ELCC or similar analyses;

ii. Possible improvements to modelling assumptions, methodologies and data sharing, selection;

iii. Role of sensitivity analyses or side cases in resource planning and options for making the IRP more robust for unforeseen portfolio changes and disruptive exogenous events; and,

iv. Process discussions to ensure clear links from each discrete step – economic, production cost, LSAP and other modelling, RFPs, and thence to selected resource portfolios.

265. The Commission will schedule additional workshops as necessary to consider other productive updates to IRPs. Additionally, NV Energy is already participating in the non-binding seasons of WPP's WRAP. Therefore, NV Energy must adapt the IRP to meet the Nevada resource adequacy standards and WRAP's forward showing with the attendant, discrete assumptions for PRMs, resource counting, etc. Therefore, as a directive, the Commission Secretary shall open a new Investigatory Docket related to examining process, modelling, and analytical improvements to NV Energy's resource planning.

THEREFORE, it is ORDERED:

1. Phase 2 of the Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fourth amendment to its 2021 Joint Integrated Resource Plan in Docket No. 22-11032 is granted in part and denied in part, as modified by this Order.

2. The Commission accepts in part, deems inadequate in part, and modifies the fourth amendment to Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy's 2021 Joint Integrated Resource Plan, as provided by and consistent with this Order.

Directives:

3. In a future resource plan amendment or the 2024 integrated resource plan, NV Energy must provide an update on the status of the Hot Pot and Iron Point projects, including adequate detail to allow the Commission to review whether continuing with Hot Pot and Iron Point, or another solution to the retirement of the Valmy generating units, is the most cost-effective and reasonable resource decision.

4. In a future resource plan amendment or the 2024 integrated resource plan, whichever comes first, NV Energy must provide the following related to the retirement of the coal-fired Valmy generating units:

a. A complete solution for the retirement of the Valmy coal plant;

b. Comprehensive analysis and comparisons of the financial and economic impacts of each potential solution; and,

c. Updated information on the federal and state limitations on continued operations of Valmy and associated costs.

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5. The Commission Secretary shall open a new Investigatory Docket related to examining process, modelling, and analytical improvements to NV Energy's resource planning.

By the Commission,

HAYLEY WILLIAMSON, Chair

C.J. MANTHE, Commissioner

TAMMY CORDOVA,
Commissioner and Presiding Officer

Attest:
TRISHA OSBORNE,
Assistant Commission Secretary

PUBLIC UTILITIES COMMISSION PUC OF NEVADA

Dated: Carson City, Nevada

5/12/23

(SEAL)