Agenda 22-18 : Item No. 2-A Draft Order for discussion at utility agenda.

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a )
NV Energy and Sierra Pacific Power Company d/b/a )
NV Energy for approval of their 2019-2038 )
Triennial Integrated Resource Plan and 2019-2021 )
Energy Supply Plan. )

Docket No. 18-06003

At a special session of the Public Utilities Commission of Nevada, held at its offices on December 21, 2018.

PRESENT: Chair Ann Wilkinson
Commissioner Ann Pongracz
Commissioner CJ Manthe
Assistant Commissioner Secretary Trisha Osborne

[PROPOSED] ORDER

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

1. INTRODUCTION

Before WILKINSON, ANN, Chair and Presiding Officer.


NV Energy filed the Joint Application pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703 and 704, including, but not limited to NRS 704.741, and NAC 704.9005 through 704.9525. Pursuant to NAC 703.5274, NV Energy requested confidential treatment of information submitted under seal with the Joint Application.

On September 4, 2018, BCP, NV Energy, and Staff filed a partial-party Stipulation resolving all of the issues in Phase I. On September 17, 2018, the Presiding Officer held the Phase I hearing on the Stipulation. The Commission subsequently issued an Order on October 12, 2018, accepting the Stipulation that resolved all issues in Phase I.

On October 5, 2018, NV Energy, Staff, BCP, Sierra Club and NRDC, and NCARE filed a partial-party Stipulation, resolving all issues in Phase II of this Docket. On October 9, 2018, the Presiding Officer held the Phase II hearing on the Stipulation. On November 1, 2018, the Commission issued an Order accepting the Stipulation that resolved all issues in Phase II.

Thereafter, on November 13, 2018, the Commission commenced the hearing on Phase III to address the remaining issues of the Joint Application. The Order that follows addresses all of the Phase III issues, arguments, and evidence in greater detail.

II. SUMMARY

Having thoroughly reviewed the record and applicable law, the Commission accepts the Phase III portions of the Resource Plan (the Supply Plan, the Financial Plan, and the Action Plan), as modified by this Order, and grants the underlying portions of the Joint Application as modified by this Order.
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III. BACKGROUND

An integrated resource plan ("IRP") is a utility's long-term twenty-year plan, which includes an immediate three-year action plan, to meet demand for electric services in an efficient, reliable, and sustainable manner at the lowest reasonable cost to customers. A public utility that supplies electricity in Nevada must submit its resource plan every three years for the Commission's acceptance, rejection, or modification. The components of a resource plan are: (1) a load forecast; (2) a demand side plan; (3) a supply plan; (4) a financial plan; (5) an energy supply plan; and (6) an action plan.¹ A utility's resource plan provides an integrated analysis of the projected need for electricity in the utility's service territory for a forecasted planning period, and the utility's plans for meeting the projected need, including the actions the utility plans to take in the next three years. See, NRS 704.741(1), 704.746, 704.751 and NAC 704.9006, 704.9156, 704.9225.

Once a utility's resource plan is filed, the Commission has statutorily-imposed deadlines of 135 days by which to accept, reject, or modify the utility's energy supply plan, and 210 days by which to accept, reject, or modify all remaining portions of the utility's plan. NRS 704.751. The Commission is required to convene a public hearing on the adequacy of the utility's plan, and thereafter, determine whether: (a) the plan's forecasting methodology is accurate and adequate; (b) the plan includes present and projected reductions in demand resulting from energy efficiency measures; and (c) the plan demonstrates economic, environmental and other benefits to the State and customers of the utility. NRS 704.746.

This year, 2018, marked the first time in which NPC and SPPC filed a Joint Application for Commission approval of NV Energy's Resource Plan. The Commission designated the Joint Application for approval of the 2019-2038 Resource Plan as Docket No. 18-06003. As the cornerstone of the Joint Application, NV Energy seeks approval to add 1,001 megawatts ("MW") of solar resources and 100 MW of energy storage capacity to its generation portfolio. This proceeding commenced on June 1, 2018, involved eleven (11) separate parties represented by legal counsel, and was heard in three separate Phases. Phase I and Phase II were heard and decided by the Commission as evidenced by its orders issued October 12, 2018, and November 1, 2018, respectively.

The following Order addresses all of the Phase III issues, arguments, and evidence in detail.

IV. LEGAL STANDARD

NV Energy filed the Joint Application pursuant to NRS and NAC Chapters 703 and 704, specifically NRS 704.741 et seq. and NAC 704.9005 et seq. (Ex. 2 at 3.) When issuing a decision regarding a utility's Resource Plan application, the Commission's order must include its justification of the preferences given to measures and sources of supply that: (a) provide greatest economic and environmental benefits to the State; (b) are consistent with the IRP statutes; (c) provide levels of service that are adequate and reliable; (d) provide the greatest opportunity for

¹ Senate Bill (SB) 146 (2017) added distributed resources plan ("DRP") as a resource plan component. See, e.g., NRS 704.741(5). On November 21, 2018, the Commission adopted a temporary regulation implementing Senate Bill 146. Docket No. 17-08022; LCB File No. T001-18. Pursuant to Section 3.2 of Senate Bill 146, NV Energy shall file its first DRP on or before April 1, 2019, as an amendment to this joint IRP application.
creating new jobs; and (e) provide diverse electricity supply portfolios and which reduce customer exposure to price volatility for fossil fuels and the potential costs of carbon. The Commission’s order must consider the costs of these measures and sources of supply to the utility’s customers. NRS 704.746, 704.751.

The PUCN may take “[n]otice of judicially cognizable facts and generally recognized technical or scientific facts within the specialized knowledge of the agency,” NRS 233B.123(5), and its final decisions “shall be deemed reasonable and lawful” and have operative effect unless they are set aside by a higher court on review upon a showing of clear error or abuse of discretion. NRS 703.373(9) and (11); see also NRS 703.374(2).

V. PROCEDURAL HISTORY

• On June 1, 2018, NV Energy filed with the Commission a Joint Application, designated as Docket No. 18-06003, for approval of its Resource Plan.

• On June 12, 2018, the Commission issued a Notice of Electric Utilities’ Joint Integrated Resource Plan and Notice of Prehearing Conference.

• The Regulatory Operations Staff of the Commission (“Staff”) participates as a matter of right pursuant to NRS 703.301.

• On June 13, 2018, the Attorney General’s Bureau of Consumer Protection (“BCP”) filed a Notice of Intent to Intervene and participates in this Docket as a matter of right in accordance with provisions of NRS Chapter 228.

• On July 2, 2018, Nevadans for Clean Affordable Reliable Energy (“NCARE”) filed a Petition for Leave to Intervene (“PLTI”).

• On July 3, 2018, Sierra Club and Natural Resources Defense Council (“NRDC”) filed a joint PLTI.


• On July 9, 2018, the Presiding Officer held a prehearing conference at which NV Energy, Staff, BCP, NCARE, Sierra Club, NRDC, Copper Mountain, NextEra, Interwest, NNIEU, SEA, Vote Solar, and Wynn participated. At the prehearing conference, the participants discussed the

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2 NNIEU are EP Minerals, LLC; Heavenly Valley, Limited Partnership; Nevada Cement Company; Nugget Sparks, LLC d/b/a Nugget Casino Resort; Premier Magnesia, LLC; The Ridge Tahoe Property Owners’ Association; Prime Healthcare Services – Reno, LLC d/b/a Saint Mary’s Regional Medical Center, Inc.; Renown Health; and Newmont USA Limited.
PLTI, procedural schedule, and discovery procedures.

- On July 13, 2018, the Presiding Officer issued Procedural Order No. 1, which set the procedural schedule for this Docket and designated the portions of the Resource Plan that are remaining after Phase I (addressing the Energy Supply Plan) and Phase II (addressing the Demand Side Plan) as Phase III of these proceedings.

- On July 18, 2018, the Presiding Officer issued an Order Granting Petitions for Leave to Intervene. The order authorized all entities seeking intervention to participate in Phase III.\(^3\)

- On August 9, 2018, NV Energy filed an errata to its Joint Application.

- On August 14, 2018, the Commission issued a Notice of Hearing.

Phase I:

- On September 4, 2018, BCP, NV Energy, and Staff filed a partial-party Stipulation resolving all the issues in Phase I.

- On September 17, 2018, the Presiding Officer held the Phase I hearing. BCP, NextEra, NNEI, NV Energy, SEA, and Staff made appearances. At the conclusion of the hearing, the Presiding Officer admitted Exhibits 1 through 21 and confidential Exhibits C-1 through C-3 into the record pursuant to NAC 703.730.

- On October 12, 2018, the Commission issued an Order accepting the Stipulation filed on September 4, 2018, that resolved all issues in Phase I.

Phase II:

- On October 5, 2018, NV Energy, Staff, BCP, Sierra Club and NRDC, and NCARE (the "Signatories") filed a partial-party Stipulation, resolving all issues in Phase II of this Docket. The Commission issued Procedural Order No. 2 vacating the first day of the Phase II hearing, October 8, 2018, in light of the Stipulation.

- On October 9, 2018, the Presiding Officer held the Phase II hearing on the Stipulation. BCP, NCARE, NNEI, NV Energy, SEA, Sierra Club and NRDC, and Staff made appearances. At the conclusion of the hearing, the Presiding Officer admitted the Stipulation as Exhibit 22 into the record pursuant to NAC 703.730. SEA filed a letter stating that it did not oppose the Phase II Stipulation and giving its opinion on the structure of Stipulation negotiations.

- On November 1, 2018, the Commission issued an Order accepting the Stipulation filed on October 5, 2018, that resolved all issues in Phase II.

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\(^3\) The Commission granted Sierra Club’s and the NRDC’s PLTI and SEA’s PLTI on the condition that the organizations submit to the Commission documents responsive to NAC 703.595(2)(b), which the organizations subsequently submitted.
Phase III:

- On October 22, 2018, NV Energy filed Prepared Direct Testimony regarding Phase III.

- On November 13-15, 2018, the Presiding Officer held the Phase III hearing. BCP, Copper Mountain, Interwest, NCARE, NextEra, NNIEU, NV Energy, SEA, Staff, and Vote Solar made appearances. At the conclusion of the hearing, the Presiding Officer admitted Exhibits 23 through 66 and confidential Exhibits C-4 through C-8 into the record pursuant to NAC 703.730.


- On November 28, 2018, NV Energy, Staff, and Vote Solar each filed Phase III post-hearing responsive briefs.

VI. PHASE III – REMAINING COMPONENTS OF RESOURCE PLAN

In Phase III of this Docket, NV Energy is requesting the Commission address issues pertaining to the remaining components of its Resource Plan: the Supply Plan, Action Plan, and Financial Plan. In addition, Phase III of this Docket also addresses issues that were properly noticed and necessarily flow from NV Energy’s filing of its Joint Application.

A. Long-Term Fuel and Purchased Power Price Forecasts

Party Positions

NV Energy

1. NV Energy requests approval of the base long-term fuel and purchased power (“FPP”) price forecasts presented in FPP-1 as presenting the best and most accurate information upon which to base long-term planning decisions through the Action Plan\(^4\) period. NV Energy includes FPP-1 in Volume 5 of its Application and filed it under confidential seal because, as NV Energy states, it contains sensitive information that would, if made public, otherwise disadvantage NV Energy by limiting its ability to negotiate with prospective energy suppliers.

\(^4\) “Action plan” means “a detailed specification of the actions a utility intends to undertake to meets its demand and energy requirements during the three years immediately following the year in which its resource plan is filed.” NAC 704.9006.
and impair its ability to achieve favorable pricing and terms and conditions on behalf of customers. (Ex. 2 at 16-17, 22.)

Staff

2. Staff recommends that the Commission approve NV Energy’s long-term FPP price forecasts because they are based upon substantially accurate data and find that the FPP price forecasts are thus appropriate for resource planning decision-making through the Action Plan period. (Ex. 51 at 3.)

Commission Discussion and Findings

3. The Commission approves NV Energy’s base long-term FPP price forecasts as presented in FPP-1 and finds them to be the most accurate information upon which to base NV Energy’s long-term planning decisions through the Action Plan period.

B. NV Energy’s Preferred and Alternative Supply Plans; Early Valmy Unit 1 Retirement; and Power and Capacity Purchase Agreements

Party Positions

NV Energy

4. NV Energy evaluated four alternative supply plans in its IRP: the All Market Case, the Renewable Case, the Low Carbon Case, and the Development Case. NV Energy states that the All Market Case adds two solar photo-voltaic (“PV”) projects to NV Energy’s electricity-production supply: the 200-MW Dodge Flats Solar project and the 101-MW Battle Mountain Solar project located in Washoe and Humboldt counties. NV Energy states that, outside of these supply additions, the All Market Case relies on short-term wholesale power purchases during the Action Plan period to meet demand. (Ex. 4 at 5.)

5. NV Energy states that the Low Carbon Case and Renewable Case are very similar. Both Cases add four additional new solar PV projects to the two projects mentioned in
the All Market Case for a total of six new solar projects. These four additional resources are Fish Spring Ranch Solar (a 100-MW project in northern Nevada); Eagle Shadow Mountain Solar Farm (a 300-MW project in southern Nevada); Copper Mountain Solar 5 (a 250-MW project in southern Nevada); and Techren Solar V (a 50-MW project in southern Nevada). Pursuant to the Power Purchase Agreements (“PPAs”) that NV Energy signed with the developers, these six projects will deliver 1,001 MW of solar energy at historically-low prices. Both the Low Carbon Case and Renewable Case also add three battery storage systems in northern Nevada totaling 100 MW. The battery storage systems are directly tied to the Dodge Flats, Fish Springs Ranch, and Battle Mountain Solar projects, which will provide capacity and flexibility to northern Nevada’s system. (Id.; Ex. 25 at 8-9; Ex. 34 at 18-29.)

6. NV Energy states that the only difference between the Low Carbon Case and the Renewable Case relates to the operation of North Valmy Unit 1 (“Valmy 1”), the 254-MW coal-fired generating unit located in Humboldt County. NV Energy owns a 50-percent interest in this unit (along with Idaho Power Company (“IPC”)), which provides 127 MW of capacity to SPPC’s customers. The Low Carbon Case retires Valmy 1 on December 31, 2021, subject to certain conditions, which, according to NV Energy, help mitigate risk, while the Renewable Case maintains the existing resource planning retirement date of December 31, 2025, for both Valmy 1 and North Valmy Unit 2 (“Valmy 2”). (Ex. 25 at 9-10; Ex. 4 at 5.)

7. Lastly, NV Energy states that the Development Case contains the same six solar and three storage projects as the Renewable Case as well as the retirement of Valmy 1 in 2021. The Development Case adds two additional solar PV projects that provide an additional 299 MW of capacity, both owned and operated by NV Energy. (Ex. 4 at 5.)

5 PPA prices range from $21.55 per megawatt-hour (“MWh”) for Copper Mountain 5 output to $29.96 per MWh for Fish Springs Ranch output. (Ex. 34 at 18-26.)
8. NV Energy requests approval of the Low Carbon Case, which NV Energy identifies as its Preferred Plan. NV Energy identifies the Renewable Case as its Alternative Plan. NV Energy contends that the Low Carbon Case increases renewable energy capacity and production, reduces natural gas capacity and production, and all but eliminates coal-fired capacity and production by 2023. NV Energy selected the Low Carbon Case as the Preferred Plan because it advances Nevada’s energy policy, delivers the services that customers value, and fits closely with NV Energy’s corporate business strategy. In addition to its short-term goal of doubling renewable resources by 2023, NV Energy has a longer-term aspirational goal to deliver 100 percent renewable energy to customers. NV Energy states that the Low Carbon Case is the next logical step in advancing Nevada’s energy goals and NV Energy’s strategy to deliver the services its customers value. According to NV Energy, the Low Carbon Case reduces NV Energy’s impact on the environment and reduces its generation fleet’s carbon intensity while producing significant economic benefits. Notably, both the Low Carbon Case and Renewable Case involve an estimated $2.175 billion progressive investment in Nevada, provide an estimated 1,785 construction jobs, and approximately 76 long-term jobs. (Ex. 25 at 8-15; Ex. 11 at 7-8.)

9. To implement the Low Carbon Case, NV Energy proposes a conditional, early retirement of Valmy 1 on December 31, 2022. NV Energy subjects the early retirement to six conditions. First, there must be demonstrative evidence that the three new northern PV projects and associated storage projects will achieve commercial operation by June 2022. Second, NV Energy must have adequate capacity to serve customer load, which will be determined using specific metrics.⁶ Third, NV Energy must have sufficient access to economic capacity and

⁶ These metrics include: (1) for any given hour, an increase in the Loss of Load Probability ("LOLP") by more than 100 percent would trigger the re-evaluation of the Valmy 1 retirement; (2) any megawatt-hour increase in Expected Unserved Energy ("EUE") under the Valmy 1 retirement scenario would trigger a re-evaluation of the retirement;
energy in western markets to mitigate cost pressure and alleviate a reduction in flexibility associated with not having power available from Valmy 1. Fourth, a transmission area load of 2,800 MW will trigger a re-evaluation of retirement of Valmy 1. Fifth, accounting treatment regarding decommissioning Valmy 1 must be consistent with other retired NV Energy generation assets. Specifically, the costs of decommissioning Valmy 1 will be tracked and placed into a regulatory asset, and a carrying charge equal to SPPC’s currently-approved cost of capital would apply. Upon completion of decommissioning, the balance in the regulatory asset will be placed into rate base. Seventh, the accounting treatment regarding undepreciated book value of Valmy 1 must be consistent with the tracking accounting treatment authorized in prior dockets. Specifically, the undepreciated book value of Valmy 1 will be placed into a regulatory asset where it would not earn a carrying charge. SPPC will amortize the regulatory asset balance using the depreciation rate for Valmy 1 until the balance is included in SPPC’s revenue requirement. NV Energy includes these conditions in its Low Carbon Case because the planning environment in which it operates is becoming increasingly fractured and uncertain due to things like not knowing where new or existing distribution-only service customers are acquiring their network resources or how they will be delivered to the distribution system. NV Energy identifies this uncertainty as the reason these conditions must be met before Valmy 1 is retired. (Ex. 2 at 23-24; Ex 25 at 17-20; Tr. at 136.)

10. NV Energy states that it has not committed to retiring Valmy 1 early because the unit provides flexibility and critical load reliability and service to northern Nevada. NV Energy

and (3) the Loss of Load Expectation ("LOLE") does not exceed the one day in 10 years criterion. (Ex. 2 at 23 of 260.)

7 At the hearing, NV Energy clarified that it will incur only a minimal decommissioning expense prior to the retirement of both Valmy units. (Tr. at 136-37.)
predicts that, with the addition of the northern Nevada PPAs outlined above, as well as battery storage systems, NV Energy should be able to retire Valmy 1 by the end of 2021 without compromising service ability and reliability. However, NV Energy identifies a gap between its long-term planning tools and the tools needed to predict real-time operating conditions. Thus, NV Energy recognizes a need to confirm its ability to safely retire Valmy 1 with additional, real-time analysis as 2021 approaches. To bridge the gap, NV Energy is currently investigating upgrades to the tools resource planners use to assess system performance. (Ex. 25 at 17-19; 23-24.)

11. NV Energy indicates that, while transmission planning issues exist, reliability is paramount, and Valmy 1 is key to reliability within the constrained northern Nevada transmission system. According to NV Energy, under the current system configuration, the operation of generation interconnected at the Valmy substation is critical. NV Energy further contends that generation located within the constrained portion of the northern Nevada transmission system provides essential ancillary services and allows NV Energy to maintain import capability. NV Energy references the disaggregation of centralized transmission planning processes as further complicating the reliability calculus. NV Energy notes that, at this point in the planning process, the location, attributes, and operating characteristics of the generation that would meet energy supply needs of potential load growth are not required to be identified by potential NRS Chapter 704B customers until the customer actually files a request with the Commission to exit bundled electric service under NRS Chapter 704B. Consequently, transmission needs are not known with certainty, thereby increasing the difficulty in determining whether generation at Valmy needs to stay interconnected. NV Energy further states that, because transmission additions in Nevada often require a long lead time (seven to ten years), if a
supply deficiency were projected, NV Energy would need to take action to add or maintain
generation interconnected at the Valmy substation. NV Energy expresses awareness that it needs
to be vigilant and reassess real-time operation conditions and load growth as 2021 approaches.
Nevertheless, NV Energy concludes that the Low Carbon Case allows NV Energy to maintain
reliability and ensure prudent decisions. (Ex. 56 at 7-10.)

12. NV Energy acknowledges the Renewable Case, not the Low Carbon Case, is
actually the lowest-cost case NV Energy analyzed, and it has essentially the same impact on
Nevada’s economy as the Low Carbon Case. NV Energy recommends that, if the Commission
does not believe that the conditions identified for the early retirement of Valmy 1 are necessary
to adequately ensure reliable operations, then the Commission should select the Renewable Case.
(Ex. 25 at 17.)

NCARE

13. NCARE recommends approval of NV Energy’s Low Carbon Case due to the
plan’s environmental benefits. However, NCARE limits its recommended approval to the
following elements of the Low Carbon Case: the early retirement of Valmy 1; the addition of
1,001 MW of renewable energy sourced from the six new solar PPAs and three co-located
battery storage projects; and approval to construct the network upgrades necessary to
interconnect the six new PPAs to NV Energy’s transmission system. NCARE contends that
these actions reduce carbon emissions, as well as emissions of criteria pollutants. NCARE notes
that, when comparing carbon emissions among the four Cases under the No Carbon Price
Scenario, the emission benefits of the Low Carbon Case exceed those of the All Market Case;
the emissions benefits of the Renewables and Development Cases are similar to the Low Carbon
Case. As another benefit of the Low Carbon Case, NCARE identifies increased resource
diversity, which provides environmental benefits and mitigates potential risk to rising natural gas prices in the future. Conversely, NCARE recognizes that the All Market Case relies more heavily on natural gas. (Ex. 37 at 4-8.)

14. NCARE also urges the Commission to consider environmental impacts and climate change in this proceeding because these impacts will result in damages and costs to Nevadans, including threats to life, infrastructure, food, livelihoods, ecosystems and future costs of complying with carbon regulations. NCARE supports the Low Carbon Case because it reduces emissions and thereby mitigates risk of the most severe impacts of climate change. Additionally, regarding social costs and benefits, NCARE notes that the present worth of the environmental costs included in the Present Worth of Societal Costs ("PWSC") of the Low Carbon Case is nearly half a billion dollars less than the All Market Case. At the same time, NCARE concedes that the present worth of the environmental costs included in the PWSC of the Renewable Case is similar to the Low Carbon Case. (Id. at 13-14.)

15. NCARE also offers recommendations for improving NV Energy's IRP process as it relates to emissions because, as NCARE argues, the current process does not do enough to reduce carbon emissions over the next 20 years. NCARE observes that, after 2024, NV Energy's carbon emissions cease declining, then plateau, and then actually begin to rise due to natural gas investments. According to NCARE, a "true" low-carbon portfolio would identify a set of clean energy resources needed to meet long-term emission reduction goals, including resources added outside of the Action Plan period, and would allow for a continued reduction in carbon emissions beyond the Action Plan period rather than a plateau. NCARE recommends that the Commission direct NV Energy, in its next IRP, to develop a true low-carbon portfolio that reduces emissions
consistent with science, including an evaluation of low-carbon resources over the 20-year planning horizon. (Id. at 18-29; 34.)

16. NCARE outlines some changes to NV Energy’s presentation of resource portfolios that, in NCARE’s opinion, would improve the Commission’s evaluation of those portfolios and achieve the goals of Senate Bill (“SB”) 65 (2017). NCARE recommends that, in addition to what SB 65 requires, NV Energy include a clear presentation of the emissions associated with each of the proposed portfolios and a graph presenting carbon emissions associated with each of the four portfolios over the 20- or 30-year period. NCARE also recommends that NV Energy include a graphical representation of its fuel mix over time, reflecting energy balance under the Low Carbon Case, in addition to a table showing the projected fuel mix that is required by SB 65. NCARE contends that additional changes to the IRP’s analysis could help better inform Commission decisions relating to carbon emissions. Noting the regulation adopted to implement SB 65, NCARE argues that NV Energy should calculate the PWSC using the social cost of carbon in each year of the portfolio. In years where NV Energy models a compliance cost in the Present Worth of Revenue Requirement (“PWRR”), the value added to calculate the PWSC should be the difference between the social cost of carbon and the compliance cost modeled. Accordingly, NCARE recommends that the Commission direct NV Energy to present a more comprehensive set of information in the IRP summary on fuel diversity and carbon emissions, and present an analysis of the cost of carbon emissions, particularly social costs, that is consistent with the Commission’s regulation implementing SB 65. (Id. at 29-34.)

SEA
17. SEA critiques NV Energy's IRP for failing to properly account for customers departing NV Energy's system under NRS 704B, and, thus, finds NV Energy's request for additional generation resources unnecessary and economically burdensome to ratepayers. SEA considers both of NV Energy's resource plans unrealistic because they fail to recognize pending load departures under NRS 704B and the preference of large-load customers to purchase from the market. SEA acknowledges that NV Energy assumes that some amount of load will depart, but only in 2019. SEA finds NV Energy's resource plans defective also because they do not consider the ability of new, large, single-load customers to select an alternative energy provider, thus producing a dramatically overstated and aggressive load forecast. SEA further states that NV Energy's assumption that each new load will select the utility as its preferred energy supplier is unreasonable, given NV Energy's rates. SEA states that NV Energy should consider 704B customers in its IRP and that the pool of existing eligible 704B customers should serve as a basis for the capacity that may be freed up due to departures. Additionally, SEA recommends that NV Energy be prohibited from including any new large loads in its forecast, except those that have explicitly contracted to take service from NV Energy. SEA thus recommends the Commission not approve NV Energy's request for additional generation. (Ex. 54 at 2-5.)

Vote Solar

18. Vote Solar recommends that the Commission not approve the Low Carbon Case in total, but approve parts of the Case that have been demonstrated to be cost-effective, specifically, the six solar PV and three storage projects. Vote Solar argues that NV Energy's Low Carbon Case does not demonstrate that the open position\(^8\) and fossil generation included in

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\(^8\) The "open position" is defined as any value resulting from the peak load, net of demand-side and private generation resources, plus planning reserves that is greater than the sum of the peak capacities for all of the available supply-side resources. (Ex. 28 at 8.)
the Low Carbon Case are lower-cost and lower-risk for meeting customer needs than a plan that includes greater utilization of solar and storage and retirement of additional fossil fuel units. Vote Solar states that NV Energy’s proposal to add 1,001 MW of new solar resources is insufficient to demonstrate that the Low Carbon Case results in the lowest-cost, least-risk option because all of the considered Cases include either the 1,001 MW of solar resources contained in the Low Carbon Case or a subset of those resources. Vote Solar observes that none of the Cases considered retiring Valmy 1 earlier than 2021 or Valmy 2 earlier than 2025 or considered earlier retirement of gas units. According to Vote Solar, NV Energy’s analysis lacks cases that add more solar PPAs at the current low prices, retire fossil fuel generation sooner, or both. (Ex 40 at 19-20; Tr. at 361-62.)

19. Vote Solar acknowledges that NV Energy’s proposal is a step in the right direction but argues that more can and should be done to transition away from fossil fuels. Vote Solar notes that retiring Valmy 1 early appears to result in more overall coal generation than if it were retired with Valmy 2 as Valmy 2 would need to make up for any reduced coal-burn at Valmy 1. Vote Solar states that, moreover, NV Energy has not calculated any cases reflecting accelerated retirement of any other coal or gas-fired generation resources. NV Energy seeks to extend the lives of eight gas-fired combustion turbines. Vote Solar argues that NV Energy’s simplistic analysis conducted to justify this proposal does not take into account the possibility of replacing capacity gas units with solar generation or storage that provides both capacity and energy. Vote Solar states that replacing gas units with solar will have a lower overall net cost than the market purchases NV Energy used in its analysis, potentially lower than the existing operating costs of the gas plants. Vote Solar contends that the replacement solar PV should provide an energy value over its life that exceeds the cost, even before adding the capacity value
of avoiding operation and maintenance and other costs to keep old gas plants open. (Ex. 40 at 23-27.)

20. Vote Solar contends that NV Energy and its customers would also benefit economically from additional solar generation even after adding the 1,001 MW of new solar PPAs proposed in its plan. Vote Solar sees no reason why the current downward trend of solar prices will reverse in the near term, yet NV Energy’s assumed future solar prices are inconsistent with the history of solar costs and solar PPA pricing, which has shown a steep and steady decline. Vote Solar states that another benefit of replacing Valmy with solar-plus-storage is one that NV Energy recognized: connect solar PV directly at North Valmy or within the Carson Trend to provide dynamic reactive compensation in the event that the TS Power Plant is unable to operate after 2023. Vote Solar identifies additional potential low-cost solar PV generation beyond 1,001 MW. NV Energy received bids totaling 3,774 MW of renewable energy capacity and 797 MW of battery storage capacity in its 2018 request for proposals (“RFP”), but only 1,001 MW were selected. Moreover, NV Energy received proposals for 450 MW of qualified facility (“QF”) resources in 2017, but only two proposals—totaling 50 MW—were awarded. The RFP in 2017 stated that bids should be priced below the long-term avoided cost (“LTAC”), so Vote Solar argues that most, if not all, of the QF bids totaling 450 MW should have come in under the projected marginal cost of energy and capacity over the 25-year contract term solicited. (Id. at 27-34.)

BCP

21. BCP recommends that the Commission reject NV Energy’s Low Carbon Case and instead approve its Renewable Case, with the availability of Valmy 1 and 2 through 2025. BCP states that, as NV Energy recognizes, Valmy 1 is critical in ensuring system reliability in
northern Nevada. BCP notes that NV Energy recognizes that it does not have the right analytical tools to ensure system reliability after an early retirement date for Valmy 1. Moreover, despite NV Energy conditioning the early retirement of Valmy 1 on, among other things, the metrics of loss of load probability, and proposing that it will re-evaluate the early retirement date of Valmy 1 (if approved), such reliability metrics have never been applied to a re-evaluation of a Commission-approved retirement of a generating facility. BCP further observes that, under NV Energy’s proposed re-evaluation process, NV Energy can, on its own, claw back the Commission’s approval. Given the uncertainties, BCP believes it is bad policy for the Commission to approve Valmy 1’s early retirement with the ability to have its approval reversed through a future compliance filing by NV Energy. BCP cautions that, if the Commission were to approve the early retirement and NV Energy determines not to retire Valmy 1 through a re-evaluation and compliance filing, there could be heated opposition from other parties in future filings. (Ex. 43 at 2-8.)

22. BCP identifies major uncertainties affecting NV Energy’s resource planning period, which NV Energy recognizes. First, BCP recognizes a high level of uncertainty with the accelerating load growth in the Tracy Area of the northern system and notes that NV Energy has received an unprecedented number of customer load requests, with loads in excess of 1,449 MW. Second, BCP identifies the uncertainty surrounding the operation of Newmont’s 200 MW TS Power Plant co-located with North Valmy within the Carlin/Elko load pocket of the northern system. Newmont has approval to depart from NV Energy’s bundled electric service under the provisions of NRS 704B. BCP notes that NV Energy stated it may continue to operate Valmy 1 if, in 2021, it becomes known that Newmont will not operate its TS Power Plant. Third, BCP references the negotiations between NV Energy and IPC to address uncertainties associated with
an end to IPC’s participation in the operation of Valmy 1 in 2019. BCP also states that, regarding the transmission area load growth of 2,800 MW that will trigger a re-evaluation of early Valmy 1 retirement under NV Energy’s Low Carbon Case, both Valmy 1 and the proposed 401 MW of solar PV generation with 100 MW of paired battery storage may be necessary to maintain the northern transmission load capability of 2,800 MW. Thus, according to BCP, early retirement of Valmy 1 would create system reliability issues. Stated differently, BCP finds that the early Valmy 1 retirement would lower the system reliability and flexibility with or without the proposed 401 MW of PV solar generation and 100 MW of battery storage. (Id. at 9-12; 28)

23. BCP observes that the driving factor for the Low Carbon Case costing $22 million more than the Renewable Case is the cost of replacement capacity for the lost capacity of Valmy 1 between 2022 and 2025. According to BCP’s calculations, this additional cost could result in an increase of up to seven percent to the Base Tariff Energy Rate (“BTER”) of SPPC’s customers between 2022 and 2025. BCP notes that another cost incorporated in the Low Carbon Case is the cost associated with NV Energy’s request that costs to isolate and make safe Valmy 1 upon retirement be placed into a regulatory asset as a decommissioning cost. BCP estimates the present value of this cost at $1.65 million, resulting in the Low Carbon Case costing approximately $23.7 million more than the Renewable Case. This increased cost would solely burden SPPC’s ratepayers. BCP observes that the early retirement of Valmy 1 also does not reduce the overall impact on the environment; environmental impact is equal between the Low Carbon and Renewable Cases. BCP contends that both the Low Carbon Case and the Renewable Case comply with Nevada’s energy policy, despite the Renewable Case not retiring Valmy 1 early. (Id. at 16-19; 24-26.)
24. BCP argues that the fact of the matter is that NV Energy does not know whether the new PPAs adequately replace Valmy 1’s capacity in the event of the early retirement. BCP states that NV Energy must acquire the tools necessary to conduct such an analysis. BCP supports the Renewable Case because it better manages the relationship between mitigating risk, minimizing cost, and maximizing reliability in accordance with NAC 704.948(2).\(^9\) According to BCP, the Low Carbon Case is less in accordance with this requirement. (Id. at 29.)

**Staff**

25. Staff recommends that the Commission reject NV Energy’s Low Carbon Case as its Preferred Plan and reject its request for approval to conditionally retire Valmy 1 early. Staff recommends that the Commission instead approve NV Energy’s Alternative Plan, the Renewable Case, with one modification: order both Valmy 1 and 2 to be permanently retired no later than December 31, 2025. (Ex. 46 at 2-3.)

26. Staff notes that the amount of carbon emissions resulting from the Low Carbon and Renewable Cases are essentially the same. Staff conducted a PROMOD\(^{10}\) analysis to quantify the difference between carbon emissions of the Renewable Case and Low Carbon Case. Staff found that the Low Carbon Case actually has higher carbon emissions than the Renewable Case. Staff states that, after presenting these findings to NV Energy, NV Energy stated that PROMOD only accounts for carbon emissions from internal generation and does not include emissions from market purchases. Staff observes that the global analysis of emissions, prepared

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\(^9\) NAC 704.948 requires a utility to analyze its resource planning decisions, taking into account its assessment of risk and identifying risks with respect to costs, reliability, finances, the volatility of the price of purchased power and fuel, and any other uncertainties the utility identifies.

\(^{10}\) "PROMOD" is an economic production cost model that NV Energy uses to evaluate its alternative supply plans over the planning period. PROMOD simulates the operation of the electric system and computes production costs (fuel, purchased power, variable and fixed costs to operate) by performing hourly, chronological economic unit commitment and dispatch of NPC’s and SPPC’s electric production resources and market purchases to satisfy hourly load requirements in a least-cost solution over the planning period. (Ex.28 at 9.)
by NERA (National Economic Research Associates) Economic Consulting ("NERA"), shows that the two Cases have nearly identical carbon emissions.\textsuperscript{11} Thus, Staff concludes that the Low Carbon Case results in no appreciable decrease in carbon emissions along with less system reliability and higher cost to ratepayers. (Id. at 5-6.)

27. According to Staff, the Renewable Case is the lowest-cost option. Staff states that, according to PROMOD output reports, the PWRR of the Renewable and Low Carbon Cases appear identical in years 2019 through 2021. Then, beginning in 2021, immediately after the proposed retirement of Valmy 1, and running through 2025, the Low Carbon Case has a higher PWRR in each of the four years. The cumulative total of the higher PWRR is approximately $22 million when compared to the Renewable Case. After 2025, the PWRR is essentially the same in both cases, and the $22 million difference remains constant through the rest of the 30-year analysis. Staff states that a deeper look into the data provided shows that the vast majority of the $22 million higher PWRR for the Low Carbon Case is in the forecasted BTER and in SPPC’s service territory only, which is substantial in terms of SPPC’s rates. (Id. at 8-9.)

28. Staff supports the Renewable Case because it allows adequate planning time for an unconditional and seamless retirement of both Valmy 1 and 2, with no additional environmental impact, and at the least cost. Staff’s recommendation allows NV Energy seven years to plan for and complete the elimination of the two remaining coal-fired Valmy Units. Staff finds no quantifiable benefits associated with retiring Valmy 1 early, and, under the Low Carbon Case, Staff finds NV Energy’s early retirement proposal so heavily-conditioned that Staff cannot reliably say that the early retirement would actually occur. According to Staff, NV Energy’s early retirement conditions are decidedly fluid and therefore challenging and much less

\textsuperscript{11} Environmental Costs and Economic Impacts of the 2018 Integrated Resource Plan Report prepared by NERA for NV Energy appears as attachment ECON-12 in Exhibit 17.
desirable from a resource planning and a public relations perspective. Staff finds the 2,800-MW transmission area load cap is one of the most troubling conditions. The total control area load is within a range of 2,100-2,200 MW. The load growth in the Tahoe-Reno Industrial Center has resulted in proposed load requests of over 1,449 MW already, which, combined with the current transmission area peak load, would surpass the 2,800-MW limit and cause NV Energy to potentially not retire Valmy 1 early. Staff warns that, if NV Energy’s proposal is approved, the high-tech companies deciding whether to locate in Nevada could be the very loads that trigger the abandonment of the utilities’ plan to close the coal unit. Staff notes that NV Energy’s conditional retirement plan could end up being out of line with Nevada’s energy and economic development policies. (Id. at 5-7, 10-14.)

29. Staff lists the following benefits of the Renewable Case over the Low Carbon Case: a firm commitment to retire Valmy, more transparency for Valmy’s retirement, an opportunity to get the current Valmy regulatory asset into rates, less risk, better transmission system planning, and a guaranteed end to utility-owned coal-fired generation in Nevada. (Id at 15-21.)

30. Regarding the opportunity to place Valmy regulatory asset into rates, Staff states that the stipulation in Docket 16-06006, SPCC’s most recent general rate case, placed Valmy 1 depreciation expenses—approximately $7.2 million annually—into a regulatory asset, with carrying charges. Current ratepayers are thus not paying for it. Staff’s recommendation would bring these costs back into rates in the 2019 general rate case, and the Valmy plants will be close to being paid off in 2025. (Id. at 17.)

31. Regarding ending utility-owned coal generation in Nevada, Staff states that, in 2013, in Docket 13-06002, the Commission changed the Valmy 1 retirement date from 2021 to
2025 partially because salvage operation for Valmy 1 cannot commence without Valmy 2 salvage operation. Since that time, the Idaho Public Utilities Commission ordered IPC to make efforts to stop coal burning by December 31, 2019, for Valmy 1 and by December 31, 2025, for Valmy 2. Because NV Energy cannot meet the 2019 deadline regardless of what happens in this Docket, Staff opines that the next best scenario is to match the second deadline that its partner has been ordered to meet. Staff notes that such an action would also be a recognition that the two Valmy units are so intertwined that actual decommissioning will not begin until 2025 and guarantee a definitive end to utility-owned coal burning in Nevada. (Ex. 46 at 18.)

32. Regarding there being less financial and legal risk with approving a permanent shutdown of both Valmy units in 2025, Staff states that it identified a potential significant financial risk associated with the early retirement of Valmy 1. Specifically, if NV Energy retires Valmy 1 in 2021 and follows through on its plan not to lay off any Valmy station employees, IPC is likely to question paying its share of the payroll of the retained employees. Staff cautions that this could leave NV Energy having to pay 100 percent of the salaries. Staff notes that the Low Carbon Case does not account for this potential cost. (Id. at 18-19.)

33. Regarding better transmission system reliability, Staff states that NV Energy admits that Valmy 1 is the key to reliability and maintaining import capacity under the current configuration. Staff notes that the Renewable Case allows more time to accommodate or reconfigure the system with new renewables that may come to fruition before Valmy 1 shuts down in 2025. Moreover, Staff identifies a transmission-related reliability issue in the Carlin/Elko load pocket. If the constrained 345-kV feeder line is undergoing maintenance, either Valmy or the Newmont coal plant must be operating. Newmont’s contract expires in 2023.
Staff observes that the Renewable Plan allows time to implement reliability measures if Newmont does not renew its contract. (Id. at 21-22.)

34. Staff notes that, four months prior to filing its IRP, NV Energy filed an updated Life Span Analysis Process ("LSAP") in Docket No. 16-07001 that compared the base case of retiring Valmy 1 in 2025 with an early retirement in 2019. In that case, NV Energy’s analysis showed that it would be $17 million cheaper on a five-year PWRR basis to retire Valmy 1 in 2019. A similar analysis performed four months later now shows that it would be $22 million more costly to retire Valmy 1 over a similar period of time. Staff contends that the nearly $40-million swing is an illustration that more time is necessary to achieve the best solution. (Id. at 23.)

35. Staff also suggests that, if the Commission approves Staff’s recommendation to adopt NV Energy’s Renewable Case instead of the Low Carbon Case, the Commission should deny, as moot, the special accounting treatment requested by NV Energy because, under the Renewable Case, Valmy 1 would not conditionally close early and thus no special accounting treatment is necessary. However, if the Commission authorizes the early shutdown of Valmy 1, Staff supports granting SPPC’s request for special accounting treatment because SPPC’s proposed accounting treatment is consistent with prior accounting treatment of the retirement of other NV Energy generating facilities. (Ex. 47 at 3-4.)

36. Regarding the PPAs, Staff states that the RFP requirements and criteria used to score and rank the bids for the PPAs were made transparent to the bidders, and the evaluation of the bids was conducted in an unbiased manner. Staff does not have any reason to recommend rejecting any of the PPAs. According to Staff, the final shortlist bids were competitively priced and provide a Renewable Portfolio Standard ("RPS") benefit to ratepayers. Without signing
these contracts, Staff notes that it is unlikely SPPC would meet its RPS requirement in 2022. Furthermore, Staff identifies a potential for NPC’s existing renewable facilities to underperform and reduce the number of years before noncompliance. (Ex. 55 at 8.)

37. Staff recommends that the Commission find that all four of NV Energy’s proposed long-term resource expansion plans meet regulatory requirements. All plans meet future demand on the system, meet or exceed the current RPS, and the Renewable, Low Carbon, and Development Cases are all low-carbon-intensity plans, satisfying NAC 704.9355 and 704.937. (Ex. 50 at 3-5.)

38. Staff recommends that the Commission find that the following cost estimates are acceptable for evaluating the resource expansion plans, as they are reasonable and/or comply with Nevada law: NV Energy’s carbon dioxide cost estimates, social costs of carbon, environmental costs of other air emissions, additional costs of water consumption, and economic benefits/impacts of resource expansion plans to Nevada. Staff states that NV Energy developed a reasonable range of carbon prices and appropriately contemplated national cap-and-trade regulations in estimating the PWRP for each of the plans. Further, Staff finds NV Energy’s estimates of the social costs of carbon acceptable because NV Energy followed Commission regulation LCB File No. R060-18 and, while estimates are too wide to conduct meaningful comparative analysis, they were developed based on information available today and are a result of the many uncertainties surrounding this issue. Staff finds NV Energy’s environmental cost estimates also acceptable because the methodologies are the same as in previous proceedings and are sound, and the resulting dollar amounts of the costs are very small. Thus, Staff finds it highly unlikely that a change in value of the environmental cost of non-carbon air emissions would affect NV Energy’s selection of its Preferred and Alternative Plans. (ld. at 5, 9-11.)
39. Staff also finds acceptable NV Energy’s estimates of environmental costs of water and land-use because, while no environmental costs were calculated for water quality, solid waste disposal and land use, the NERA Report sufficiently discusses the topic. Staff states that, moreover, the methodology and data regarding environmental costs of additional water look appropriate, and it is highly unlikely a change in the costs of additional water consumption would affect NV Energy’s selection of a plan due to the insignificant dollar amounts of additional water consumption relative to environmental costs and the PWRRs. Staff states that NV Energy’s estimates of net economic impacts of each resource plan to the State of Nevada are also acceptable, as the estimates comply with NAC 704.9357. (Id. at 11-15.)

40. Staff recommends that the Commission find that NV Energy’s Renewable Case is the least-cost option among its four plans when evaluated with PWRR and PWSC, and is consistently a lower-cost option than the Low Carbon Case, with and without considering the illustrative social cost of carbon included in PWSC calculations. Staff notes that the Renewable Case’s PWRRs are about $22 million lower than those of the Low Carbon Case while the Renewable Case’s PWSCs are $22-$24 million lower than the Low Carbon Case’s PWSCs. Staff sees no discernable differences in the economic impacts between the Renewable Case and Low Carbon Case. (Id. at 15-17.)

NV Energy Rebuttal

41. NV Energy recommends that the Commission reject SEA’s recommendation to deny approval of the Low Carbon Case based on alleged inaccuracies in the long-term load forecast. NV Energy notes that, in accepting the stipulation in Phase I of these proceedings on October 12, 2018, the Commission determined that NV Energy’s load forecast is based on
substantially accurate data, is adequately documented, justified, demonstrated and defended, and
is appropriate for making resource planning decisions. (Ex. 62 at 5-6.)

42. NV Energy recommends that the Commission reject concerns by NCARE
regarding the formulation of alternative plans. NV Energy states that it uses placeholders to
allow for analysis of different supply-side options and maintain consistency between
placeholders so that assumptions about the future do not influence the selection of a supply-side
plan. NV Energy states that it only includes placeholders for resources for which it is not
seeking a determination of prudence, and they essentially represent future decisions that must be
made and will be evaluated in future IRPs. According to NV Energy, it has maintained
consistent placeholders across resource plans to make it easier to compare financial and societal
cost impacts of action plan decisions in one case against those in another. Additionally, NV
Energy states that the Low Carbon and Renewable Cases do not only ensure compliance with
Nevada’s RPS; both plans provide amounts of renewable energy and portfolio credits that exceed
the RPS. (Id. at 43-46.)

43. NV Energy disagrees with Staff’s recommendation to permanently retire Valmy 1
and 2 no later than December 31, 2025, unless the Commission’s order includes conditions that
allow for reconsideration similar to what NV Energy provided in its request to retire Valmy 1
early. NV Energy states that Staff and NV Energy acknowledge uncertainties regarding retiring
Valmy 1 early, but Staff’s proposal creates a predetermined outcome as the best solution to
remove that uncertainty. Staff’s proposal would preclude NV Energy and the State from
pursuing options tomorrow that may be superior to those known today. NV Energy states that,
as part of this Docket, it has not studied the feasibility of eventually converting both Valmy
Units to natural gas. But, if the Commission adopts Staff’s recommendation, NV Energy would
be precluded from ever examining that option. NV Energy states that it does not seek approval for the retirement of Valmy 2 in this Docket. December 31, 2025, is the retirement date used for the retirement of Valmy 2 in the Low Carbon Case. (Ex. 61 at 3-5.)

44. NV Energy also disagrees with BCP’s proposal to disregard considering early retirement of Valmy 1 and instead focus only on the LSAP process to determine the retirement dates of Valmy. NV Energy states that, unlike Staff’s recommendation, BCP’s recommendation does not eliminate options for future consideration. However, the LSAP process cannot yield a deterministic outcome for North Valmy for the Commission to consider at this time or in the near future. NV Energy states that it could make arguments about future states—markets, policies, technology—to support a retirement date outcome, but each of those can be argued by any stakeholder, leaving the Commission to consider arguments for and against each of those future states. NV Energy reminds that it has instead presented to all stakeholders the very conditions—which all parties can agree to—that need to occur to support an early retirement date for Valmy 1. (Id. at 5-6.)

45. Regarding NV Energy’s apparent need for new transmission reliability assessment tools, NV Energy states that its transmission planning group is constantly looking at new software tools and new methods of analysis to look at different sensitivities and scenarios. NV Energy posits that it does not believe that it is necessary for the Commission to order NV Energy to address its need for reliability assessment tools, as meeting those requirements is something that NV Energy can take up on its own. (Tr. at 549-50.)

**Commission Discussion and Findings**

46. Pursuant to NRS 704.746(5), the Commission must give preference to the measures and sources of supply that:
(a) Provide the greatest economic and environmental benefits to the State;
(b) Are consistent with the provisions of this section;
(c) Provide levels of service that are adequate and reliable;
(d) Provide the greatest opportunity for the creation of new jobs in this State; and
(e) Provide for diverse electricity supply portfolios and which reduce customer exposure
to the price volatility of fossil fuels and the potential costs of carbon.

47. The Legislature also tasked the Commission with considering the cost of such
measures and sources of supply to the customers of an electric utility. The Low Carbon Case
strikes an appropriate balance between the factors that the Commission must consider. While the
Low Carbon Case is not the least-cost case, the Low Carbon Case is nonetheless a low-cost case
when compared to the Development and All Market Cases. The Low Carbon Case saves
customers between $35 million and $52 million in the 10-year PWRR analysis. (Ex. 28 at 10.)
The 30-year PWRR analysis shows a savings of $29 million versus the Development Case and
$155 million versus the All Market Case. (Id., Ex. 11 at 155.) The Commission acknowledges
that the Low Carbon Case does show a higher PWRR than the Renewable Case of approximately
$22 million between 2022 and 2025, with the difference largely attributable to the open position
costs associated with the early retirement of Valmy 1. (Ex. 46 at 8-9; Ex. 11 at 155.) However,
the Low Carbon Case provides for the retirement of Valmy 1 in 2021 only if the conditions set
forth by NV Energy are met.\textsuperscript{12}

48. The Low Carbon Case best advances Nevada’s clean energy goals by including
1,001 MW of renewable PPAs and 100 MW of storage paired with the early retirement of Valmy
1. As discussed in detail below, the conditions set forth by NV Energy provide a sufficient level
of assurance that the retirement of Valmy 1 will not adversely affect the reliability of NV

\textsuperscript{12} Analysis of PWSC, defined as the sum of the PWRR and environmental costs (air emissions and additional water
costs), closely tracks the results of the PWRR analysis with the Low Carbon Case comparing favorably against the
All Market and Development Cases and demonstrating higher costs versus the Renewable Case. (Ex. 11 at 176-78.)
Energy’s system and that any cost pressure on SPPC’s customers will be evaluated and considered prior to the retirement of Valmy 1.

49. The Renewable, Low Carbon, and Development Cases all provide sizeable opportunities for the creation of new jobs in Nevada. The Low Carbon and Renewable Cases involve an estimated $2.175-billion investment in Nevada and provide an estimated 1,785 construction jobs and approximately 76 long-term jobs. (Ex. 11 at 156.) Because the Development Case includes construction of two additional solar resources totaling 299 MW, it creates even greater job opportunities. (Id. at 184, 187.) However, this increased economic activity comes at a price of $20 million in increased annual expenditures over the 30-year planning horizon. (Id. at 179-87.)

50. All three progressive Cases diversify NV Energy’s electricity supply portfolios and reduce customer exposure to the price volatility of fossil fuels and potential costs of carbon by increasing the number of PV solar resources and storage units and reducing the share of fossil-fuel generation in the total electricity production. (See, e.g., Ex. 25 at 10-14.)

51. The Low Carbon Case, when paired with the conditions NV Energy sets forth for the retirement of Valmy 1 in 2021, adequately addresses reliability and service criteria. Staff, BCP, and NV Energy agree that Valmy 1 is the key to reliability and maintaining import capability within SPPC’s service territory. The Commission shares the concerns raised by Staff and BCP regarding reliability intertwined with the early retirement of Valmy 1. NV Energy has taken reliability into consideration in recommending the Low Carbon Case. NV Energy has done so through the conditions it places on the early retirement of Valmy 1, which provide
adequate safeguards that reliability will be evaluated and considered prior to a final
determination that Valmy 1 will be retired.13

52. The Commission adopts NV Energy’s stated conditions for the early retirement of
Valmy 1 on December 31, 2021. The conditions address reliability concerns and cost concerns
while also ensuring that the accounting treatment of Valmy 1 retirement costs is consistent with
the treatment approved by the Commission for other recent retirements. First, there must be
demonstrative evidence that the three new northern PV projects and associated storage projects
will achieve commercial operation by June 2022. Second, NV Energy must have adequate
capacity to serve customer load, which will be determined using the metrics specified by NV
Energy. Third, using the criteria proposed by NV Energy, there must be sufficient access to
capacity and energy in western markets to mitigate cost pressure and alleviate a reduction in
flexibility associated with not having power available from Valmy 1. Fourth, a transmission area
load of 2,800 MW will trigger a re-evaluation of retirement of Valmy 1. Fifth, accounting
treatment regarding decommissioning Valmy 1 must be consistent with other retired NV Energy
generation assets. Sixth, the accounting treatment regarding undepreciated book value must be
consistent with the tracking accounting treatment authorized in prior dockets. (Ex. 2 at 23-24;
Ex 25 at 17-20.)

53. The Commission expects that NV Energy will closely monitor the feasibility of
retiring Valmy 1 early. As reflected in the conditions set forth by NV Energy and adopted by the
Commission, cost and reliability concerns are paramount. In that vein, the Commission requires

13 The Commission notes that NV Energy acknowledges that it may currently lack the necessary modeling tools to
comprehensively assess electric system reliability in the emerging environment of disaggregation of centralized
transmission planning processes. However, NV Energy represented to the Commission through pre-filed testimony
and during the hearing that it has the ability to, and will, address the issue without further Commission action at this
time. (Ex. 25 at 23-24; Tr. at 550.)
that NV Energy keep the Commission apprised of the status of the reliability- and cost-related conditions and, therefore, NV Energy's outlook on the early retirement of Valmy 1. At a minimum, NV Energy must provide an update to the Commission on the reliability and cost conditions in its report on the progress of the action plan made pursuant to NAC 704.9498. If NV Energy indicates that any condition is likely to delay the retirement of Valmy 1 beyond December 31, 2021, NV Energy must discuss whether it plans to file an amendment to its IRP to reflect the altered retirement and, if not, state the reasons for that decision. 14

54. Regarding the accounting conditions (Conditions 5 and 6) set forth by NV Energy, the Commission determines that the costs of decommissioning Valmy 1 will be tracked and placed into a regulatory asset, and a carrying charge equal to SPPC's currently-approved cost of capital will be applied. Upon completion of decommissioning, the balance in the regulatory asset will be placed into rate base. Also, upon its retirement, the undepreciated book value of Valmy 1 will be placed into a regulatory asset where it will not earn a carrying charge. SPPC will amortize the regulatory asset balance using the depreciation rate for Valmy 1 at the time of its retirement until it is included in SPPC's revenue requirement. When the balance in the regulatory asset is included in revenue requirement, it will be placed into rate base. SPPC will apply in an appropriate future proceeding to collect the balances associated with the regulatory assets over an amortization period subject to Commission review and approval.

55. The Commission appreciates NCARE's concerns regarding the selection of placeholders in the Cases laid out by NV Energy. These placeholders demonstrate an increase in gas generation and a decrease in renewable generation over the resource plan period. Although NV Energy is not seeking approval for any of these resources in this Docket and generally keeps

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14 NV Energy remains obligated in any case to monitor and amend its action plan pursuant to NAC 704.9503.
placeholders identical among various Plans to provide a fair and more accurate comparison, the Commission encourages NV Energy to select placeholders in future resource filings that more accurately reflect the general policy of this State toward more renewable generation and energy efficiency as well as NV Energy’s own aspirational goals of supplying an ever-greater percentage of energy from renewable sources.

56. The Commission is not persuaded by Vote Solar’s arguments that NV Energy must essentially refile its resource plan to include plan options with a greater number of renewable and storage resources. The Commission notes that the Preferred and Alternative Cases contain an unprecedented increase in renewable generation and large-scale utility storage. Decarbonization of Nevada generation is an important, but not the sole, factor the Commission must consider in approving a resource plan. It is a responsibility of this Commission to also keep electric rates affordable for Nevada residents and businesses and to ensure a reliable operation of the State’s electric system. NRS 704.746(5). The Development Case demonstrates that an addition of renewable resources to the Low Carbon and Renewable Cases considerably increases ratepayer costs. (Ex. 11 at 155.)

57. The Commission always welcomes a robust debate and meaningful, constructive, participation in its proceedings. SEA meaningfully participated in this Docket by cross-examining witnesses and filing its own expert witness testimony. However, the Commission finds that the testimony proffered by SEA in Phase III of this Docket pertained to load forecast issues already adjudicated in Phase I of this Docket. In issuing the Order dated October 12, 2018, the Commission adopted the Phase I stipulating parties’ load forecast after giving SEA an opportunity to present its own witness(es) and question the stipulating parties’ witness. (October 12, 2018, Order at 8-11.).
C. Power Purchase and Capacity Purchase Agreement Cost Allocation

Party Positions

NV Energy

58. NV Energy states that the production cost modeling related to the six new PPAs assigns the cost of each PPA to NPC and SPPC based on the projects’ locations—the costs of the three northern Nevada PPAs are assigned to SPPC, and the costs of the three southern PPAs are assigned to NPC. NV Energy states that the Commission could take a different approach, however. The Commission has the option of blending the prices of all of the PPAs to create an average price and then allocate costs based on each utility’s energy consumption. NV Energy contends that this latter approach optimizes the portfolio of contracts for all of NV Energy’s customers and could be more consistent with the process embodied by SB 146, requiring joint planning for the benefit of all customers. NV Energy states that, alternatively, the Commission could directly assign the costs to the contracting utility and rely on the joint dispatch process to account for the exchange of energy between NPC and SPPC. (Ex. 25 at 15-16.)

Staff

59. Staff agrees with NV Energy that the costs of all six PPAs should be shared between SPPC and NPC instead of being directly assigned to each company that signed the PPA. However, because the generation from the six solar projects will be utilized by either NPC or SPPC through joint dispatch, Staff opposes tracking which MWh came from which PPA to allocate each PPA’s cost between the companies, as suggested by NV Energy. Staff notes that both NPC and SPPC have stated the amount of generation each needs by signing their respective contracts. Accordingly, Staff recommends that the costs from all six PPAs be allocated to NPC and SPPC based upon the production ratio calculated as the amount of MWhs produced under
each company’s PPA divided by the total MWhs production from all six PPAs. Under this methodology, and in line with projected production, approximately 40 percent of the costs would be allocated to SPPC and 60 percent allocated to NPC.\textsuperscript{15} Additionally, a set ratio would share the risk of any solar facility not meeting its commercial operation date or underperforming, as both companies would receive less total generation and share in the total cost reduction. Staff argues that using a production ratio to allocate the costs avoids picking winners and losers among NPC’s and SPPC’s ratepayers (i.e., who gets the lowest cost PPAs), which is a fair result considering that all of the bids were solicited in the same RFP and were seemingly assigned to each company based upon its physical location. (Ex. 55 at 9-11.)

60. Staff contends that the cost of the Capacity Purchase Agreements (“CPAs”) for the three storage projects should be allocated between the companies instead of being solely SPPC’s cost. Staff notes that, unlike the generation from the solar facilities, which are must-take non-dispatchable resources, the storage systems can be dispatched as needed for the benefit of either company. Therefore, under the joint system planning, Staff champions allocating the costs to either company accordingly. (Id. at 11.)

61. Staff proposes that the storage capacity cost allocation be similar to how the cost of a short-term power purchase is allocated between SPPC and NPC using the Joint Dispatch Agreement (“JDA”).\textsuperscript{16} Staff explains that, for short-term power purchases, each company is allocated a percentage of the MWhs, capacity costs, and the energy costs associated with such purchases equal to the company’s native load for the hours in which the purchase was made

\textsuperscript{15} Staff clarified that the proposal for the 40/60 split applies to the entire cost of the solar PPAs, not just the energy cost component. (Tr. at 527.)

\textsuperscript{16} The JDA is the long-term agreement between SPPC and NPC that governs joint dispatch transactions using the One Nevada Line and calculates and allocates the costs and savings of such transactions. (Ex. 55 at 11.)
divided by the sum of both companies’ native loads for such hours. Regarding storage capacity payment allocation, instead of using the hours when the purchase was made, Staff proposes that the companies would use the hours in which the storage systems are dispatching. (Id. at 11.)

**NV Energy Rebuttal**

62. NV energy recommends that the Commission accept Staff’s proposed adjustments to the allocation of energy costs associated with the six PPAs in the Low Carbon Case and Renewable Case because it is not unreasonable. NV Energy’s understanding of Staff’s proposal is that SPPC’s customers would be responsible for 40 percent of energy costs delivered by each of the six counterparties, and NPC’s customers would be responsible for 60 percent; each company would pay each of the counterparties to the three contacts into which it entered. Differences between cash expenditures and costs would be addressed through the JDA. (Ex. 62 at 25.)

63. NV Energy states that there are two benefits to Staff’s proposal. First, blending the costs diversifies the counterparty and asset risk for NPC and SPPC. Second, Staff’s recommendation recognizes the basic premise of joint planning: optimize assets. NV Energy also recognizes that blending costs of the PPAs also allows NPC and SPPC to capture economies of scale. NV Energy identifies several options for implementing this allocation methodology: the underlying PPAs could be amended or assigned, making both NPC and SPPC jointly and severally responsible for the total amount of energy delivered under the PPA; the PPAs could be partially assigned; the companies can use a “related power purchase agreement” to provide a mechanism for selling energy between NPC and SPPC; or an addendum could be added to the JDA addressing allocation costs for each of the PPAs. NV Energy recommends that the
Commission allow NV Energy to work with Staff and its PPA counterparties to determine the best implementation approach. (*ld. at 26-27.*)

64. NV Energy recommends that the Commission reject Staff’s recommendation regarding the allocation of capacity costs under the three CPAs. NV Energy states that it is unclear what it means to have “the storage systems” dispatching. NV Energy explains that a battery’s cycle involves both charging and discharging. Because the charging component can be used to manage imbalances between generation and production load, an hour in which the battery is charging can be an hour in which the storage system is dispatching. Second, NV Energy identifies complications associated with Staff’s methodology during a month in which the storage system is not dispatched because the monthly charges under the CPAs are fixed. A method for recording CPA charges to the deferred energy accounts when the storage systems are not dispatching is thus required. Third, NV Energy questions how these jointly and severally controlled capacity assets would be reflected in the loads and resources table submitted in a resource plan. (*ld. at 28.*)

65. NV Energy does not disagree with the concept of joint and several control of the CPA resource and allocation of costs. But it entered into the CPAs based on an assessment of SPPC’s supply-side capacity needs. While Staff’s recommendation is consistent with joint planning principles, NV Energy points to the lack of adequate operational experience to assess the best methodology for allocating the capacity costs associated with the CPAs. NV Energy identifies alternative proposals to equitably adjust the CPA costs based on actual operational experience and use of the systems. First, the costs of the CPAs could flow through to SPPC’s deferred energy account. After operational experience is gained, the JDA could be modified to reallocate costs. Second, the Commission could establish an initial allocation based on the
companies’ current respective open positions. Third, establish jointly-controlled capacity that would be reflected on a joint-controlled loads and resources table, without allocation to either utility. NV Energy states that this option would require Staff, BCP, NV Energy, and other stakeholders to work together to identify an appropriate allocation methodology before the storage systems are placed into commercial operation. (Id. at 29-32.)

**Commission Discussion and Findings**

**PPA Costs Allocation**

66. The Commission accepts Staff’s “production ratio” methodology to allocate PPA costs. Under that methodology, the cost of each PPA will be allocated based on the ratio of the MWhs produced by each of the six solar projects divided by the total MWhs produced by the projects. Under the current production projections, the three solar resources contracted by SPPC will produce approximately 40 percent of the total output of the six projects, and the three solar resources contracted to NPC will produce 60 percent of the total output. Accordingly, SPPC will carry approximately 40 percent of the six PPAs’ costs, and NPC will carry the remaining 60 percent of the costs. This approach cures the inequities that result from relatively higher-priced PPAs contracted by SPPC and lower-priced PPAs contracted by NPC. In addition, as stated in NV Energy’s rebuttal, this approach diversifies risks and is more consistent with the joint dispatch principles than the traditional method of each utility carrying the costs of contracted PPAs. The Commission directs NV Energy to work with Staff and other interested parties to determine the most efficient, least-cost means of implementing Staff’s proposal. The Commission directs the parties to file the selected option for implementing the “production ratio” methodology within 90 days of the issuance of this Order. In addition to providing support for the selected option, the filing must address:
a) how the PPA costs can be accurately identified through filings such as Federal Energy Regulatory Commission ("FERC") Form 1 and the Deferred Energy Accounting Adjustment applications;

b) the effect on the companies’ BTER and Deferred Energy Accounting Adjustment ("DEAA") rate calculations;

c) the effect on the companies’ credit metrics and the respective debt structure;

d) the effect on the calculation of impact fees payable by NRS 704B departing customers; and

e) whether the capacity benefits associated with each of the six PRAs will remain with the utility that entered into the PPA.

67. Further, in formulating the responsive compliance filing, the parties must take into account that the sole intent behind the Commission’s adoption of the “production ratio” methodology is to “blend” the varying PPA pricing to ensure that both SPPC’s and NPC’s customers are treated fairly and benefit from the same low prices offered by the six projects. Whatever “production ratio” implementation mechanism the parties recommend, the allocation methodology ultimately emerging from this Docket must also account for the sharing and assignment of the costs and benefits associated with the six projects under the JDA. In other words, the implementation mechanism proposed by the parties must consider the JDA principles of benefits and costs sharing. The six PPAs have operational, planning, and accounting impacts on both Companies. Each of these impacts needs to be considered and evaluated in any proposed allocation methodology.

CPA Costs Allocation

68. The Commission declines to re-allocate the CPA costs pursuant to the methodology recommended by Staff. All three energy storage projects are located in SPPC’s service territory, contracted to SPPC, and were secured to provide capacity to SPPC’s customers. Therefore, SPPC must bear the full costs of the CPAs. However, to the extent NPC will derive benefits from the storage projects, if any, it must also bear the costs associated with the benefits.
The JDA mechanism provides the necessary tools to account for such benefits and assign costs. In the event the parties determine that the current JDA is unable to accommodate the necessary accounting of the storage projects’ benefits and costs, the parties shall offer solutions to amend the JDA in the PPA Costs Allocation compliance filing delineated in paragraphs 66-67.

D. Network Upgrades for Power Purchase Agreements

Party Positions

NV Energy

69. NV Energy requests approval for network upgrades necessary for some of the PPA projects identified in its Low Carbon, Renewable, and Development Cases. NV Energy states that the upgrades will be necessary to interconnect the following projects to NV Energy’s transmission system: Dodge Flat Solar; Fish Spring Ranch; Eagle Shadow Mountain Solar Farm; and Copper Mountain 5. The costs of the upgrades for each project are $12.565 million, $2.38 million, $550,000, and $7.4 million, respectively. (Ex. 2 at 26.)

NCARE

70. NCARE supports approval of these network upgrades. (Ex. 37 at 5-6.)

BCP

71. BCP recommends that the Commission approve the requested network upgrades. (Ex. 43 at 3.)

Staff

72. Staff recommends that the Commission approve NV Energy’s requested network upgrades to interconnect the renewable energy projects. No transmission network upgrades are necessary to interconnect the Battle Mountain Solar and Techren V projects into NV Energy’s transmission system. While it has no concerns regarding the requested network upgrades for these projects, Staff highlights that the costs of the upgrades are just estimates: actual
construction costs could be higher or lower than provided estimates. Even though Staff recommends that the PPA pricing for each resource be blended in accordance with its “production ratio” method, Staff recommends that these transmission network upgrade costs be allocated to the ratepayers of the utility that executed the PPA. Staff states that it believes this to be the simplest and most reasonable approach given that the cost of the two transmission systems (NPC and SPPC) are still allocated separately to each set of native load customers in each utility’s general rate case proceedings. (Ex. 48 at 3-7; Tr. at 438-39.)

**Commission Discussion and Findings**

73. The Commission approves NV Energy’s requested network upgrades to interconnect the applicable renewable energy PPA projects into NV Energy’s transmission system, as these upgrades are necessary to acquire the benefits of the Dodge Flat Solar, Fish Spring Ranch, Eagle Shadow Mountain Solar Farm, and Copper Mountain 5 PPAs. The cost estimates for these upgrades are appropriate; no party challenged or questioned NV Energy’s cost estimates. The costs for these upgrades shall be assigned to utility customers based upon the location of the resource; that is, upgrade costs for the resources located in SPPC’s service territory shall be assigned to SPPC’s retail customers, and upgrade costs for the resources located in NPC’s service territory shall be assigned to NPC’s retail customers. The Commission agrees with Staff that this approach is reasonable given that these are transmission network upgrades, and the cost of NPC’s and SPPC’s transmission systems remain allocated separately to each utility’s customers.

**E. NV Energy’s Membership in WestConnect**

**Party Positions**

**NV Energy**
74. NV Energy requests approval to continue NPC’s and SPPC’s involvement and membership in WestConnect. The Action Plan budget to continue membership is $225,000 annually in 2019, 2020, and 2021 for a total cost of $675,000. (Ex. 2 at 26.)

75. NV Energy states that it has participated in transmission planning activities associated with WestConnect since the 2015 formation of the organization, pursuant to the requirements in FERC Order No. 1000. NV Energy explains that WestConnect has a FERC-approved Planning Participation Agreement setting forth the rights and obligations of members who pay dues to WestConnect, stakeholders who participate in WestConnect open activities, and the Planning Management Committee that steers WestConnect. (Ex. 11 at 124.)

BCP

76. BCP has no objection to approval of NV Energy’s request to continue involvement and membership in WestConnect. (Ex. 43 at 3.)

Staff

77. Staff supports NV Energy’s continued involvement and membership in WestConnect and recommends that the Commission approve NV Energy’s request to spend up to $675,000 to continue its membership. (Ex. 49 at 2.)

Commission Discussion and Findings

78. The Commission finds that NV Energy’s request to expend $225,000 annually in 2019, 2020, and 2021 for a total cost of $675,000 to continue its membership in WestConnect is reasonable. Accordingly, the Commission approves NPC’s request to continue its involvement and membership in WestConnect at the requested budget level.

F. Arden-McDonald Transmission Line

Party Positions
NV Energy

79. NV Energy requests approval to reconductor a 1.45-mile segment of the Arden to McDonald 230-kV transmission line at a cost of $720,000. NV Energy states that this upgrade is necessary to mitigate a potential North American Electric Reliability Corporation ("NERC") violation identified as a result of the previously-approved McDonald 230/138-kV Substation upgrade. NV Energy states that, after the Commission approved installation of the McDonald Substation, additional analysis identified an overload on the 230-kV transmission line, which occurs under high import conditions in the southern system. (Ex. 2 at 26; Ex. 56 at 6-7; Ex. 16 at 162-171.)

Vote Solar

80. Vote Solar contends that NV Energy has not justified the need for the 230-kV transmission line from Arden to McDonald and that there is no analysis in the application of non-wires alternatives. Through an information request to NV Energy, Vote Solar acquired analyses for near-term building of solar-plus-storage to mitigate the need for transmission facilities.\(^{17}\) Vote Solar posits that a non-wires solution only costs more than a wired solution if the cost of the non-wired solution, less the generation capacity and energy values it provides, costs more than the wires solution. Vote Solar states that NV Energy’s analysis incorrectly assumes that solar non-wire alternatives would provide only a transmission benefit, and fails to recognize generation capacity and energy benefits from a solar solution. Vote Solar recommends that the Commission reject the project unless and until NV Energy demonstrates that it is more cost-effective than a non-wires alternative ("NWA"). (Ex. 40 at 35-37, 39.)

BCP

\(^{17}\) NV Energy’s response to Vote Solar’s pertinent information request was submitted into the record as Exhibit 59.
81. BCP has no objections to approval of NV Energy’s request to reconductor the 1.45 mile segment of the Arden to McDonald 230kV transmission line. (Ex. 43 at 3.)

Staff

82. Staff recommends that the Commission approve NV Energy’s $720,000 expense associated with upgrading a 1.45-mile segment of the Arden to McDonald 230-kV transmission line. According to Staff, NV Energy has demonstrated that the upgrade is necessary to mitigate potential NERC violations and that the costs of the upgrades are reasonable. Following the McDonald 230 kV transformer installation, an overload condition would occur under high import conditions in the southern system. This upgrade would avoid that issue and will support increased load capacity and increased customer load requirements in the area. (Ex. 49 at 2-3; Tr. at 434-35.)

NV Energy Rebuttal

83. NV Energy states that IRP statutes and regulations do not require analysis of NWAs for new projects and that Vote Solar fails to point to any statute or regulation supporting such an obligation. Nevertheless, NV Energy looked at NWAs for the Arden to McDonald 230-kV line before proposing the reconductor project. NV Energy explains that the project did not meet the initial screening requirements for a full NWA analysis for three reasons. First, reconductoring needs to be completed by May 31, 2019, coincident with the installation of the remainder of the previously-approved McDonald transformer equipment and facilities. It is not feasible to defer or replace reconductoring the pertinent segment of the Arden to McDonald transmission line with a NWA in time to meet the timing required to alleviate the reliability issue. Second, the constraint driving the need to reconductor is reliability. Reduction or shift of local load onto the 138-kV line served by the McDonald transformer would not mitigate the
reliability issue being addressed by the proposed project. Third, preliminary results from the NWA analysis prepared for the original McDonald 230/138-kV transformer project were used to eliminate the cost of an NWA to the reconductoring project, and the result was cost-prohibitive. (Ex. 58 at 2-4.)

Commission Discussion and Findings

84. The Commission approves NV Energy’s request to reconductor a 1.45-mile segment of the Arden to McDonald 230-kV transmission line at a cost of $720,000, as this upgrade is necessary to prevent potential NERC violations due to overload conditions in the southern system. Additionally, the upgrade is necessary to support the increased load capacity on the transmission system, given the rapid increase in customer load requirements in that area. NV Energy considered NWAs for this project but reasonably found that the project failed to meet screening requirements for a full NWA analysis.

85. Vote Solar’s position focuses heavily on the need for NV Energy to demonstrate that reconductoring the transmission line is more cost-effective than an NWA, particularly a solar-plus-storage alternative. The Commission appreciates Vote Solar’s advocacy for prudent financial decision-making. However, Vote Solar has not convincingly demonstrated to the Commission that NV Energy’s decision to expend $720,000 to upgrade the transmission line—to, importantly, avoid transmission line overload and NERC violations—is financially imprudent, particularly in light of the company already finding an NWA to be “cost prohibitive.” (Ex. 52 at 4.) Moreover, cost is only one factor to consider: NV Energy also considers reliability and timing constrains in its NWA analysis. Vote Solar has not convincingly articulated to the Commission how an NWA would adequately address the evident transmission reliability concerns or the timing constraints surrounding this project.
86. Accordingly, the Commission rejects Vote Solar’s recommendation and approves NV Energy’s request.

G. NV Energy’s Request to Deviate from NAC 704.9496

Party Positions

NV Energy

87. NV Energy states that NAC 704.9492 and 704.9496 require a multi-step process to determine NV Energy’s LTAC rates. NV Energy requests a deviation from NAC 704.9496 so that it can instead establish its LTAC rates in a single step by using the current pricing from the highest-cost 50-MW bid selected in the recent 2018 Renewable RFP—the Techren V Project—to cap NV Energy’s administratively-determined LTAC. NV Energy states that the 50-MW limit on availability of LTAC rates was derived based upon the results of the Techren V contract, i.e., the use of that contract as the comparable product. NV Energy states that the limit was proposed pursuant to NAC 704.9492(5) and states that it believes that this limit represents an alternative source of energy, i.e., a representation of what is available to NV Energy. NV Energy further states that the LTAC rates would be available for up to 50 MW of renewable resources in each of NV Energy’s service territories, for a total limit of 100 MW, and that the LTAC contracts with QFs would be for up to 25 years. According to NV Energy, its requested deviation from NAC 704.9496 and using Techren V pricing to cap its LTAC rates serves the public interest in at least two respects. First, it allows NV Energy to have a price that reflects the current market conditions. Second, NV Energy avoids the costs and time delays associated with issuing another RFP. (Ex. 2 at 19-22, 26; Ex. 11 at 194; Tr. at 141-44, 150-51, 233, 606-07, 649-51.)

88. NV Energy states that, pursuant to NAC 704.9492, it calculated estimated LTAC rates based on the Low Carbon Case as its Preferred Plan. NV Energy used two methods to
calculate the LTAC: uncapped LTAC and capped LTAC. The uncapped methodology is based on the combination of capacity costs and marginal energy costs under the Preferred Plan. The capped methodology uses the Techren V pricing to selectively reduce the hourly marginal energy costs with added capacity derived from the uncapped methodology. NV Energy contends that its capped LTAC methodology is consistent with the purpose of the LTAC calculation—to reflect the utility’s next-best alternative for serving the demanded MW of capacity and energy. (Ex. 11 at 189-94.)

**Vote Solar**

89. Vote Solar asserts that NV Energy’s proposal does not comply with the Public Utilities Regulatory Policies Act (“PURPA”) because the cumulative limit on availability of LTAC rates and the capping of the LTAC rates based on the Techren V bid are contrary to federal law. (Ex. 40 at 4-5.) At the same time, Vote Solar does not take issue with NV Energy’s uncapped LTAC rates methodology. (Tr. at 365.)

90. Vote Solar states that, under PURPA, a qualifying facility (“QF”) has the right to sell its output subject to a long-term contract or legally enforceable obligation (“LEO”) at LTAC rates. Vote Solar contends that cumulative caps have been rejected by FERC because they violate PURPA. Vote Solar notes that the ability to sell output pursuant to a short-term avoided cost tariff does not remove a QF’s right to sell pursuant to an LEO or long-term contract at LTAC rates. (Ex. 40 at 5-9.)

91. Vote Solar states that, under PURPA, utilities must purchase energy and capacity from QFs at the avoided cost rate, which is the price that the utility would have paid for energy or capacity, but for the purchase from the QF. Vote Solar states that, when making an avoided cost determination, the utility must look at the marginal cost of all generation sources that the
utility would utilize if it does not buy the output from a QF. Vote Solar contends that, contrary to NV Energy’s assertion that Techren V reflects the next-best alternative for serving the next demanded MW of capacity and energy, NV Energy’s IRP shows that solar generation is not the marginal resource for energy or capacity. Rather, Vote Solar notes, it shows that NV Energy considers gas generation, not a solar PPA, to be the marginal energy and capacity resource. In other words, the Techren V bid price is not NV Energy’s avoided cost. Furthermore, Vote Solar observes that an analysis of NV Energy’s 2017 PURPA solicitation shows that soliciting bids from QFs produces bids under the marginal energy and capacity costs that will be displaced by QF generation. Vote Solar argues that, because the bidding was limited to a subset of QFs, rather than procuring all generation through competitive bidding, the results of the bid do not reflect the marginal energy and capacity cost displaced by new QF generation and do not meet the definition of avoided cost. (*Id.* at 9-14.)

92. Vote Solar states that NV Energy’s position in the 2017 bidding process—as if all QFs must win the bidding process to receive a contract and as if NV Energy has discretion in selecting which bidder can receive a contract—violated PURPA because it restricted a QF’s ability to receive a long-term contract or LEO at LTAC rates. Vote Solar states that this process, and the cumulative cap, also deprives ratepayers of the opportunity to benefit from renewable generation at costs no higher than what NV Energy would have incurred without that generation. (*Id.* at 14-16.)

93. Vote Solar states that, even if the Techren V bid reflected the marginal energy and capacity resource, the incremental cost of Techren V would be the PPA price during all hours, not just hours where it is lower than the calculated, uncapped LTAC. Vote Solar argues that the
Techren V PPA cannot be used on an hour-by-hour basis as a price cap because the PPA requires NV Energy to take generation at all hours, not on an hour-by-hour basis. (Id. at 16.)

94. Vote Solar contends that, by averaging all of the hours in the month to determine the average monthly LTAC rates, instead of averaging the hours during which solar generation occurs, NV Energy is acting contrary to NAC 704.9492(3), which requires NV Energy to provide on- and off-peak costs. Furthermore, Vote Solar states that monthly averaging undervalues solar generation because generation from solar QFs is highest during daytime summer hours, which have higher avoided costs. Accordingly, Vote Solar recommends that the Commission reject NV Energy’s proposal regarding LTAC and waive any requirement in the Commission’s rules that conflict with federal law. (Id. at 16-17, 39.)

Staff

95. Staff supports NV Energy’s request to deviate from NAC 704.9496(5). Staff does not see a major issue with capping the LTAC rates based upon the highest bid received by NV Energy in its 2018 Renewable RFP. Staff notes that, given the recent decline in solar PV prices, there is a good chance that there could be 50-MW projects that can meet or beat the LTAC rates that NPC and SPPC have proposed here. So it is possible that there could be 1,051 MW total of new renewable energy contracts resulting from this case, and not just the 1,001 MW explicitly outlined in the filing. Staff recommends that the Commission approve NV Energy’s request to make the LTAC rates available for up to 50 MW of renewable resource for contracts up to 25 years in duration. (Ex. 48, at 9-10; Tr. at 439-40, 500.)

NV Energy Rebuttal

96. NV Energy states that it has complied with NAC 704.9492 and 704.9496 by calculating LTAC rates based on a blend of resources in the Low Carbon Case and then capping
the resources based on a similar market resource. NV Energy argues that a gas-fired combustion
turbine should not be used as a proxy for marginal energy and capacity costs because the
Commission has abandoned the proxy method for determining LTACs and that, furthermore,
FERC has found that the LTAC should be based on the blend of resources that the utility might
procure. (Ex. 62 at 33-37.)

97. NV Energy contends that FERC gives “wide latitude” to state commissions to
establish their avoided cost methodologies. Furthermore, NV Energy states that 18 C.F.R.
292.304(e) and 18 C.F.R. 292.304(c)(3)(ii) allow for state commissions to consider other factors
when setting avoided cost rates, including, but not limited to, the various technologies and their
supply characteristics, the length and duration of the contract, and the availability of capacity or
energy from a QF during peak periods. NV Energy notes that no federal regulation requires the
utility to pay rates for purchases that are above the utility’s avoided cost. (Id. at 37-39.)

98. NV Energy observes that the Commission rejected SPPC’s capped LTAC in 2016
because that cap was based on a 100-MW solar contract. NV Energy states that the Commission
found that using a 100-MW solar project with financing to cap rates for 25-MW QFs, which do
not have the same financial benefits, was improper. Therefore, in this filing, NV Energy has
fixed this deficiency by using a 50-MW block for the capped LTAC. (Id. at 39.)

99. NV Energy contends that the averaging of hourly avoided costs across a month is
not unreasonable as it follows the Commission’s regulations, which do a good job of capturing
the costs of energy and capacity of the blend of resources set forth in NV Energy’s Low Carbon
Case. (Id. at 39-40.)

100. NV Energy asserts that the 50-MW block of capacity reserved for QFs seeking
LTAC rates is compliant with Nevada regulations and does not violate PURPA because it is not
an absolute cap that stops QFs from obtaining a long-term contract or LEO beyond 50 MW. NV Energy states that, under PURPA, not all QFs are entitled to the same avoided cost rates, as the rates may vary based on the value of the capacity and cost differences. NV Energy also notes that FERC has allowed states to maintain alternative programs with capacity caps, so long as QFs have the opportunity to enter into LEOs or long-term contracts at avoided cost rates. NV Energy states that, if Vote Solar believes the Commission’s regulations are inconsistent with PURPA, it should challenge the regulations themselves, not the implementation of them. *(Id. at 41-42.)*

**Commission Discussion and Findings**

101. The Commission grants the requested deviation from the requirements of NAC 704.9496 and allows NV Energy to cap its administratively-determined LTAC rates using the pricing from the Techren V project. Good cause for the deviation exists, and the deviation is in the public interest. Granting the deviation eliminates the protracted process outlined in subsections (5) and (6) of NAC 704.9496. Using results from the 2018 RFP and avoiding the solicitation process ultimately saves ratepayers money and makes the LTAC rates available to QFs earlier. The Commission also grants the deviation because using the results of a competitive bidding process to establish LTAC rates without awarding QF contracts based on that solicitation is more consistent with NAC 704.9496 and federal law than using the solicitation contemplated in NAC 704.9496 to not only set LTAC rates but to also award QF contracts to the winning bids.

102. Additionally, the Commission grants the deviation because the pricing of Techren V substantially represents, and is therefore suitable to establish, NV Energy’s long-term avoided costs. The Techren V PPA is a 25-year contract for the purchase of all energy and capacity associated with the 50-MW project. *(Ex. 11 at 81-83; Ex. 15 at 1-154.)* The PPA provides for a
base price of $29.89 per MWh with no escalation. (Ex. 11 at 82.) NV Energy entered into the
PPA as a result of a competitive solicitation. (Id. at 62-83.) The Commission’s regulations
define “long-term avoided cost” as the incremental costs of electric energy or capacity, or both,
to a utility which, but for the purchase of electric energy or capacity from one or more qualifying
facilities, the utility would generate itself or purchase from another source over a period
exceeding 1 year. (NAC 704.9111.) Under the current market conditions and considering NV
Energy’s existing generation portfolio, the Commission finds it reasonable to presume that NV
Energy would seek to close a 50-MW, 100-MW combined, open long-term position with a non-
utility solar resource PPA, but for the purchase of electric energy or capacity from a QF. The
Commission has no evidence before it indicating that a competitive solicitation for a 50-MW
non-utility-owned long-term solar PPA would produce a winning bid substantially different from
the Techren V PPA. Accordingly, the Techren V PPA substantially represents NV Energy’s
long-term avoided costs.

103. Because the Techren V pricing is a result of an actual competitive solicitation and
because the Techren V project would itself qualify as a QF, using the Techren V PPA to cap the
LTAC rates is also consistent with the 18 C.F.R. 292.304(a) mandates that the rates “[b]e just
and reasonable to the electric consumer of the electric utility … and … [n]ot discriminate against
qualifying cogeneration and small power production facilities.” To be clear, the Techren V PPA
does not, in and of itself, represent NV Energy’s avoided costs. The uncapped LTAC rates were
originally calculated using NV Energy’s forecasted capacity costs and hourly marginal energy
costs under the Low Carbon Case as filed. (Ex. 11 at 189.) Pursuant to NAC 704.9496, NV
Energy will now recalculate its uncapped LTAC rates based on the orders issued in this Docket
and cap those rates with the combined energy and capacity pricing of the Techren V resource.
104. Finally, the Commission finds that the requested deviation is not contrary to statute.

105. NAC 704.9492 requires the utility to “specify its proposed limits concerning the availability of the rates for long-term avoided cost.” Pursuant to the regulation, NV Energy proposed a 50-MW per utility, 100-MW combined, limit on availability of LTAC rates. NV Energy has not established in this proceeding the grounds for limiting LTAC rates availability to a 100-MW combined cap. The Commission finds that the proposed 50-MW per utility, 100-MW combined, LTAC rates availability represents the first tranche of LTAC rates available for QF contracts up to 25 years in duration. Once this first tranche is filled, NV Energy shall make a filing with the Commission with proposed re-calculated LTAC rates. NV Energy will have an opportunity in that filing to propose and support limits on availability of LTAC rates.

106. Considering that a number of legal arguments raised in these proceedings discuss the interplay between Nevada regulations and federal law, the Commission deems it appropriate to open an investigatory docket to evaluate whether Nevada’s regulations, specifically NAC 704.9492 and 704.9496, are fully consistent with federal PURPA authorities. The investigation will include an analysis of changes to federal PURPA authorities, including federal court and FERC decisions interpreting implementation of PURPA, that have occurred since the Commission’s latest rulemaking addressing LTAC rates in Docket No. 02-5030.

H. Life Span Analysis Process: NV Energy’s Request to Extend Retirement Dates of Natural Gas Generation Units

Party Positions

NV Energy

107. NV Energy requests approval to change the retirement dates for the following natural gas generation units: Clark Peaker Unit 4, Clark Mountain Units 3 and 4, Fort Churchill
Unit 1, Sun Peak Units 3, 4, and 5, and Harry Allen Unit 3. NV Energy requests to extend the retirement date for Clark Peaker Unit 4 from 2020 to 2030, Clark Mountain Units 3 and 4 from 2024 to 2034, Fort Churchill Unit 1 from 2025 to 2028, Sun Peak Units 3-5 from 2026 to 2031, and Harry Allen Unit 3 from 2025 to 2035. NV Energy states that all of the units are in good operating condition and are expected to primarily provide capacity service, energy service, or peaking operational service. NV Energy explains that these requests are based on its LSAP. This process assigns generating units a retirement date and provides for periodic reassessment of those dates. Various criteria for reassessment are analyzed and specified, and various options are subsequently developed, including the option to invest to meet or move the retirement date. NV Energy states that it performed LSAPs on each of the units mentioned above, and those LSAPs indicate that there are no known approved or pending environmental regulations that would materially affect the units, and they are currently operating reliably and are expected to continue to do so in the foreseeable future. (Ex. 35 at 5-7, Ex. 11 at 239, 254, 269, 285, 299.)

Vote Solar

108. Vote Solar recommends that NV Energy’s LSAP process be expanded to consider not just life extensions, but also the possibility for replacement of older, less-efficient units with cleaner, zero-carbon-emitting resources at utility, community, or rooftop scales. Vote Solar states that this analysis should be part of future IRP and Distributed Resource Plan submittals. (Ex. 49 at 27.)

Staff

109. Staff recommends that the Commission approve NV Energy’s request to change the retirement dates, with two caveats. First, the new retirement date for Harry Allen Unit 3 should be 2036 instead of 2035, which will coincide with the retirement date for Harry Allen
Unit 4. Second, NPC and SPPC should adjust the depreciation expenses associated with these retirement date changes in their next general rate cases. (Ex. 46 at 2.)

110. Staff explains that Harry Allen Units 3 and 4 are immediately adjacent to each other and are interlaced with common equipment, wiring, piping, and share one grid connection. Staff asserts that it would therefore be a logistical challenge and less cost-effective to decommission and make safe Harry Allen Unit 3 without affecting operation of Unit 4. From a resource planning perspective, it makes more sense to plan for the loss and subsequent replacement of the capacity of both Harry Allen Units 3 and 4 simultaneously. (Id. at 26.)

111. With regard to the second condition, Staff clarifies that it is not asking for a full depreciation study: it is just asking that the depreciation rates for these units with life extensions be updated. Staff recommends that, if the Commission approves the new retirement dates, the Commission include this requirement in its Order. (Id.)

**NV Energy Rebuttal**

112. NV Energy states that it agrees with Staff’s recommendation to retire Harry Allen Unit 3 in 2036. (Tr. at 291.)

**Commission Discussion and Findings**

113. Having reviewed the corresponding LSAPs, the Commission approves NV Energy’s requested changes in retirement dates for Clark Peaker Unit 4, Clark Mountain Units 3 and 4, Fort Churchill Unit 1, Sun Peak Units 3, 4, and 5, and Harry Allen Unit 3, with one exception. For the reasons articulated by Staff, the Commission extends the retirement date of Harry Allen Unit 3 to 2036, instead of 2035, to coincide with the Harry Allen Unit 4 retirement date. NPC and SPPC shall adjust the depreciation rates associated with these retirement date changes in each company’s next respective general rate case.
114. The Commission appreciates Vote Solar’s recommendation to expand LSAP to consider replacing older fossil-fuel generators with cleaner resources, but the Commission rejects the proposal because such considerations are better addressed outside of an LSAP. The scope of an LSAP is narrow: it contains a thorough and regularly-conducted analysis of various environmental and reliability criteria that determine whether NV Energy should keep or change the retirement date for a given generating unit. It is therefore more appropriate for NV Energy to conduct any analysis for replacing generation units outside of a process that is reserved specifically for analyzing retirement of generation units. The Commission agrees with Vote Solar that, in future resource plan submissions, NV Energy should consider a full range of economic and viable resource options including those suggested by Vote Solar.

I. One Nevada Line Cost Allocation

Background

115. The One Nevada Line (“ON Line”) is a 500-kilovolt (“kV”) transmission project that interconnects SPPC’s 345-kV transmission system with NPC’s 500-kV transmission system. (Ex. 52 at 3.) The Commission determined an original cost allocation for the ON Line at 95 percent to NPC and 5 percent to SPPC in 2016. (See, Docket No. 10-02009, Order dated July 30, 2010, at para. 450.) As contemplated in the Commission’s December 29, 2017, Order in Docket Nos. 17-06003 and 17-06004, the Commission’s June 12, 2018, Notice in the instant Docket stated that parties wishing to revisit the allocation of costs of the ON Line between NPC and SPPC may have the opportunity to do so in this proceeding.

Party Positions

NV Energy

116. NV Energy did not propose any change to the current ON Line cost allocation, under which NPC pays 95 percent of the costs and SPPC pays 5 percent of the costs. (Tr. at 182-
83.) NV Energy states that, in terms of resolving planning uncertainty, it would be beneficial to have a fixed allocation of the ON Line. (Tr. at 246-47.) NV Energy also states that the cost allocation of ON Line has not factored into any past PPA decisions. (Tr. at 246.)

**NNIEU**

117. NNIEU supports maintaining the current 95 percent to NPC, 5 percent to SPPC ON Line cost allocation and sees no need to change the current allocation. NNIEU states that the fact that NV Energy, after considering the propriety of the current allocation for both of its utilities, did not propose an alternative allocation is significant. NNIEU states that it is important to remember that the allocation discussed here is in fact a shared participation in a fixed long-term capital cost investment. NNIEU agrees with NV Energy witness James Doubek who, in Docket No. 15-07004, stated, among other things, that “the investment decisions and associated cost sharing are made based on the best available information at the time and should only be changed in rare situations.” (Ex. 39 at 4-5 *(quoting Docket No. 15-07004, Ex. 89, Prepared Rebuttal Testimony of James Doubek at 9).*

118. NNIEU argues that, in evaluating a potential allocation change, the most important criterion is whether the proposed increase in percentage of ON Line capital cost assigned to SPPC is financially justified by the value SPPC ratepayers receive from increased ON Line utilization. Importantly, ON Line investment was driven primarily by NPC’s need to access geothermal power in northern Nevada, and at the time ON Line investment was being considered, Staff and BCP thought that SPPC ratepayers should have no or only minor responsibility for its costs. The benefit of ON Line utilization to SPPC ratepayers can be determined by comparing the delivered cost of electricity from sources in southern Nevada
utilizing ON Line with the delivered cost of electricity from sources which do not require ON Line. *(Id. at 5-6.)*

**Staff**

119. Staff proposes to permanently reallocate the costs of ON Line to 80 percent NPC and 20 percent SPPC beginning on January 1, 2019, and recommends that the Commission make the accounting adjustments necessary to implement this change. In Staff’s opinion, the reallocation should be based on transmission import capacity benefits to SPPC and joint dispatch savings rather than the changing cost of renewable resources. NPC’s customers also benefit from the increased import capability of SPPC’s electric system that is attributed to the installation and operation of the ON Line. *(Ex. 52 at 2-6; Tr. at 479, 487-88.)*

120. In its proposal, Staff explains that ON Line provided SPPC with approximately 250 to 300 MW of increased import capacity. Staff highlights that the Falcon to Gonder transmission project, which was granted approval in SPPC’s 1998 IRP, also increased SPPC’s import capacity by 250 to 300 MW. Staff proposes using this project as a proxy/benchmark to value the import capacity that ON Line provided to SPPC. The Falcon to Gonder project cost SPPC approximately $128 million, once the price is adjusted to 2013 dollars. This amount represents approximately 20 percent of the $623 million NV Energy recorded on its books for ON Line in 2013. Staff concludes that it is therefore reasonable to allocate to SPPC 20 percent of the cost of ON Line going forward. *(Ex. 52 at 7-9.)*

121. Staff provides estimated annual Joint Dispatch savings that have accrued to SPPC and NPC over the past three years as a result of ON Line being constructed. Staff highlights that, although the dollar benefits of joint dispatch have fluctuated over the past three years, the ratio of benefits between NPC and SPPC have been relatively constant around 80/20 percent. Staff
suggests that this is another data point that could potentially be used to justify an 80/20 cost allocation between NPC and SPPC. *(Id. at 8-9.)*

122. Staff posits that the ON Line cost allocation should not be based on load ratio energy share or system peak allocation because the ON Line project was not built for this purpose. Instead, the project was built to help NPC comply with the RPS. To reallocate the cost of the ON Line based upon a load ratio share or system peak allocation method would be to conclude that the ON Line project was built to serve each utility equally or to meet each utility’s peak load requirements and that is just not the case. Furthermore, SPPC allocates its transmission costs using a 12-month coincidental peak (“CP”) allocation methodology, while NPC use a 4 summer month CP allocation. Staff explains that this causes the transmission systems to be accounted for separately in retail rates and, as Staff opines, is another reason that the ON Line allocation should not be based on load ratio energy share or system peak allocation. Staff acknowledges that, in previous dockets where ON Line cost allocation was addressed, the Commission never identified a CP methodology as one of the factors that should be considered in ON Line cost allocation. *(Id. at 9-10; Tr. at 481.)*

123. Staff acknowledges that, in past orders, the Commission identified cost allocation factors that should be considered when allocating ON Line costs between NPC and SPPC. Those include: joint dispatch benefits, third-party transactions, joint planning benefits, and capacity used for renewable energy exchanges. *(Tr. at 486, 490.)*

124. Staff emphasizes that, if the Commission approves the change in cost allocation for the ON Line project, the allocation should not be revisited in a future proceeding. Utilities and customers need to begin planning for and using the transmission system without worrying that a contract signed or resource run could cause another ON Line cost reallocation. Staff states
that, based on the information that is in the record, it does not believe that there is any other
information that the Commission needs to make a final cost allocation of ON Line. (Ex. 52 at 9-
10; see Tr. at 492-93.)

125. Staff recommends that, if the ON Line costs are reallocated, SPPC and NPC
establish regulatory asset and regulatory liability accounts. Staff explains that SPPC would
establish a regulatory asset account because it will pay a new cost that is not in rates, and NPC
would establish a regulatory liability account to receive SPPC’s payments and to accumulate the
dollars associated with NPC’s cost responsibility for the change in ON Line cost allocation.
These accounts would facilitate the intercompany payments/receipt of cost amounts for the re-
allocated plant, associated depreciation expense, carrying charges, and any other incidental
charges related to the cost reallocation. (Ex. 52 at 12; Ex. 47 at 5-6.)

126. Staff recommends that, if the ON Line costs are reallocated, the Commission
issue a directive for SPPC and NPC to make a filing with the Commission that illustrates how
NPC and SPPC propose to account for the reallocation of costs, including proposed account
numbers and journal entries. (Ex. 47 at 5.)

NV Energy Rebuttal

127. NV Energy states that it can accept Staff’s recommendation to reallocate the costs
of ON Line to 80 percent NPC and 20 percent SPPC. According to NV Energy, it now has
several years of operational data related to ON Line. NV Energy states that, in addition to the
joint dispatch savings highlighted by Staff, the CP methodology is a potentially relevant method
for allocating transmission system costs, but NV Energy does not recommend that the
Commission establish a specific CP methodology as a basis for allocating transmission system
costs. (Ex. 62 at 7-9, 12.)
128. NV Energy notes that FERC uses the CP methodology. NV Energy explains that there are two types of CP systems: a 4-CP system, where there are four months with peaks that are statistically different than the other eight months, and a 12-CP system, where the peaks are not statistically different over the entire 12 months. NV Energy applied the three tests specified by FERC and found that SPPC’s system, NPC’s system, and NV Energy’s system are all biased towards a 4-CP system. NV Energy states that the results show that the 80 percent/20 percent allocation is more consistent with a 4-CP methodology than with a 12-CP methodology and that this is true using either total load or only native load. (Id. at 9–15.)

129. With respect to Staff’s argument that SPPC retain a 12-CP methodology, NV Energy contends that, based on the tests run, it is not clear whether SPPC is best categorized as a 12-CP system. NV Energy asserts that, accordingly, this proceeding is not the appropriate forum in which to permanently require a 12-CP cost allocation in SPPC’s revenue requirement. (Id. at 14.)

130. NV Energy states that it owns 25 percent of ON Line and leases the rest from Great Basin Transmission Company (“GBT”). NV Energy asserts that, accordingly, the Commission needs to evaluate a number of different cost factors when reallocating the ON Line cost. (Id. at 15.)

131. NV Energy states that, based on the 80/20 cost allocation split, the depreciation expense for NPC would decrease by $469,000, and SPPC’s would increase by $412,000. (Id. at 16.)

132. NV Energy proposes that a reallocation of ON Line capital O&M expenses be facilitated by a change in legal ownership on January 1, 2019, by NPC selling 15.79 percent of its plant balance to SPPC at a price of $20.1 million based on NPC’s net book value, resulting in
no financial gain or loss. NV Energy posits that this change of legal ownership would avoid a violation of tax normalization rules and that this change in legal ownership is necessary to ensure that the Average Rate Assumption Method ("ARAM") is calculated correctly. As NV Energy explains, the ARAM is calculated differently for NPC and SPPC due to different depreciation rates. The tax loss on the transfer of assets will result in a tax reduction for NPC and deferred taxes to be established on SPPC’s books. Additionally, the excess deferred tax balances will transfer from NPC to SPPC and will be included in SPPC’s calculation of ARAM. (Id. at 16-18.)

133. NV Energy states that the reallocation will increase SPPC’s monthly ON Line lease expense by $6.8 million. NV Energy states that if GRT does not want to update the agreement to reflect the reallocation, the $6.8 million will be accounted for in NPC and SPPC’s intercompany agreement. (Ex. 62 at 18.)

134. NV Energy recommends that other O&M expenses currently allocated as 95 percent/ 5 percent be reallocated to 80 percent/ 20 percent if the reallocation is accepted. NV Energy also recommends that the regulatory asset balances for lease payments after ON Line was placed in service, but before the payments were captured in rates, not be reallocated. (Id. at 19.)

135. NV Energy recommends that if the Commission reallocates ON Line costs, instead of establishing regulatory asset and liabilities to account for revenue requirement changes, the tax rate reduction riders ("TRRR") be amended creating a larger TRRRR credit for NPC and a smaller credit for SPPC. NV Energy states that this adjustment does not reflect the exact dollar decrease for NPC because revenue requirement changes between NPC and SPPC are not symmetrical due to different jurisdictional rates, depreciation rates, and authorized returns. (Id. at 20.)
136. NV Energy explains that the proposed adjusted TRRR for NPC and SPPC was also calculated to ensure that the revenue adjustment was allocated equitably to the customer classes and that customers who do not qualify for the TRRR or do not pay state jurisdictional costs were removed from the calculation. (Id. at 20-24.)

**Commission Discussion and Findings**

137. For the reasons discussed below, the Commission declines to reallocate the costs of ON Line between NPC’s and SPPC’s retail service customers at this time. As explained in more detail below, the Commission directs NV Energy to submit to the Commission by May 19, 2019, an application that directly and solely addresses ON Line cost reallocation.

138. The Commission declines to reallocate the costs of ON Line at this time because the record lacks evidence sufficient to support a permanent and fair reallocation of ON Line costs between NPC’s and SPPC’s retail service customers. The Commission has repeatedly indicated that the allocation of costs for ON Line is subject to change from the current 95 percent NPC/5 percent SPPC allocation. (See Docket No. 10-02009, Order dated July 30, 2010, at para. 451 (“[t]he Commission further finds that the ON Line project allocation approved in this proceeding is subject to potential future modification to reflect significant changes in conditions that may occur over the project’s depreciable life . . .” (emphasis added)); see also Docket Nos. 15-06065, 15-07004, and 15-08011, Modified Final Order dated Feb. 12, 2016, at para. 298 (“[t]he Commission’s 2010 order made clear that the current 95/5 allocation is subject to potential future modifications . . .”).)

139. The Commission has also previously identified various factors that it believes should be considered when evaluating the reallocation of ON Line costs. In consolidated Docket Nos. 15-06065, 15-07004, and 15-08011, after recognizing that the proponents of cost
reallocation in those dockets failed to justify changing the ON Line allocation at that time, the
Commission stated that “[p]roposals to adjust the cost allocation, if any at all, would be better
assessed after additional experience with the commercial operation of ON Line coupled with a
review of the benefits ...” (Comm’n Modified Final Order dated Feb. 12, 2016 at para. 298.)
The Commission listed examples of such benefits as “including but not limited to: capacity for
renewable energy transfers – both North and South; joint dispatch; joint planning; and third party
transactions[].” (Id.)

140. The instant proceeding demonstrates that NV Energy has acquired the additional
experience necessary to better assess ON Line costs. Indeed, according to NV Energy, it “now
has several years of operational data related to the ON Line.” (Ex. 62 at 8.) However, while the
Commission appreciates the parties’ efforts, the record here fails to provide the Commission with
enough information to properly analyze the benefit factors it believes should be considered in the
ON Line cost allocation.

141. Regarding the amount of ON Line transmission capacity that each utility needs to
receive renewable energy, the record indicates that NPC requires approximately 571 MW of
capacity to receive renewable energy from the north, and SPPC requires approximately 376 MW
of capacity to receive renewable energy from the south. (See Ex. 44 at § 2.) But, based on the
record, the Commission remains uncertain how it should weigh this factor against the other
factors it identified.

142. Regarding joint dispatch benefits, Staff states that “the ratio of the benefits
between the two companies have been relatively constant around 80/20 percent” and that this
“could potentially be used to justify an 80/20 cost allocation between NPC and SPPC.” (Ex. 52 at
9.) NV Energy states that its ON Line data indicates this same information. (Ex. 62 at 8.) While
NV Energy recognizes that “[t]his is the type of actual operational data the Commission identified as relevant to making allocations decisions in 2015,” (Id.), this is only one of the four factors that the Commission identified. No party indicated what weight the Commission should give joint dispatch benefits in reallocating the costs of ON Line in relation to the other benefit factors.

143. Regarding joint planning benefits, it appears that Staff did not consider this factor in its cost allocation analysis. (See Tr. at 490-91.) NV Energy indicates that ON Line cost reallocation would affect NPC’s and SPPC’s joint planning decision-making. (See Tr. at 242-47.) NV Energy does not advise, however, how joint planning would weigh in the ON Line cost allocation. (Tr. at 632.) The Commission therefore remains uncertain exactly how reallocation would or should affect joint planning or what weight the Commission should give this factor in determining cost reallocation in relation to the other identified factors.

144. Regarding third-party transactions, NV Energy indicates that “point-to-point-transactions” (i.e. third-party transactions) between NPC and SPPC affect retail rates in the respective service territories. Specifically, revenue from point-to-point transactions that require use of ON Line capacity is credited to the retail service area that takes delivery in such a transaction. (Tr. at 631.) How this process affects the cost allocation of ON Line, whether this process would need to change, and to what extent such information should be considered and weighed in a reallocation analysis remains unknown to the Commission based on the record, however.

145. Staff identified a fifth factor for the first time in this proceeding: transmission import benefits that ON Line provides to SPPC’s system. According to Staff, the ON Line project increased SPPC’s total import capability from 1,000 MW to approximately 1,300 MW.
While Staff’s analysis focuses on the increased benefits to SPPC, Staff also recognizes that NPC may benefit from this increased import capacity into SPPC’s system. (Tr. at 487-88.) The Commission appreciates Staff identifying this new factor, which the Commission finds warrants consideration in an ON Line cost allocation analysis. However, to what extent increased import capacity benefits affect both systems, and how those benefits should be weighed against the other factors in estimating a proper ON Line cost reallocation, remains unknown to the Commission.

146. Notably, NNEIU argues that “[t]he most important, if not only, criteria [for the Commission to consider] is whether a proposed increase in the percentage of ON Line capital cost assigned to [SPPC] is financially justified by the value [SRPC] rate-payers will receive from increased ON Line utilization.” (Ex. 39 at 5.) If NNEIU believes that this criteria should carry great weight in determining ON Line cost allocation, the Commission invites NNEIU, and any other party, to further demonstrate whether and to what extent this factor should control the issue when weighed against the other factors that the Commission has identified.

147. Both Staff and NV Energy address the option of allocating ON Line costs based upon each utility’s customer group contribution to the coincident peak, i.e. the CP method. The Commission refrains from adopting this method in any cost allocation approach. As Staff states, to do so would assume that the ON Line was built to serve NPC and SPPC equally. (Ex. 52 at 9.) Furthermore, despite Staff characterizing SPPC’s transmission system as a 12-CP system in its cost allocation analysis, as NV Energy shows, it remains unclear whether this characterization is appropriate.
148. Given the foregoing, the Commission directs NV Energy to submit to the Commission, by May 19, 2019,\(^1\) an application that directly and solely addresses ON Line cost allocation. In its application, NV Energy shall provide the Commission with a recommended permanent ON Line cost allocation to eliminate any potential planning uncertainty and regulatory burdens associated with continually changing the ON Line cost allocation. NV Energy’s application shall include data and analysis to support its proposal, and shall include an analysis of at least the following five benefit factors: capacity used for renewable energy exchanged between NPC and SPPC, joint dispatch benefits, joint planning benefits, third-party transactions, and import capacity benefits. NV Energy shall also make recommendations for the weight the Commission should attribute to each benefit factor. Should NV Energy propose a reallocation of ON Line costs, any such proposal shall be reflected in SPPC’s 2019 general rate case application.

J. Approval of NV Energy’s Financial Plan

Party Positions

NV Energy

149. NV Energy provides the financial information and assumptions used to develop its Financial Plan in Section 4 of Volume 11 of its Joint Application. (Ex. 11 at 196-216 of 309.)\(^2\)

150. NV Energy notes that attributes of the IRP could potentially have a negative impact on the companies’ credit ratings or financing costs. NV Energy states that its

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\(^1\) This due date aligns with NV Energy’s due date for filing with the Commission a joint application seeking approval of a replacement JDA governing transactions utilizing the ON Line, in accordance with ordering paragraph 15 in the Commission’s Modified Final Order dated September 11, 2015 in Docket No. 15-03001.

\(^2\) NV Energy filed an errata to its Financial Plan on August 9, 2018. Nothing in the errata materially alters the analysis, results, or conclusions drawn by the Financial Plan.
creditworthiness has improved over the past five years, but credit quality can be affected by the funding requirements associated with capital expenditures and financial commitments created by PPAs and CPAs. NV Energy cautions that, if executed, the PPAs detailed in this Joint IRP are expected to negatively affect credit quality unless mitigated by other actions. NV Energy expects to be able to mitigate this impact through prudent financial management. (Ex. 26 at 5-7.)

**BCP**

151. BCP states that the impact of the imputed debt related to the six PPAs will not be realized until SPPC’s 2022 general rate case and NPC’s 2023 general rate case. BCP contends that this provides NV Energy with time to manage the impact of the incremental imputed debt proposed in this filing. (Ex. 45 at 11.)

152. BCP recommends that the Commission refrain from pre-endorsing any implied range of higher equity ratios. BCP states that the Commission unequivocally expects NV Energy to manage its capital structure and that the determination of prudence will be examined in future rate cases. BCP acknowledges that NV Energy’s rebuttal testimony addresses BCP’s concern with respect to an implied higher or lower equity ratio. (*Id.*; Tr. at 389.)

**Staff**

153. Staff recommends that the Commission find that the financial information and assumptions used by NV Energy to develop its Financial Plan meet regulatory requirements. Staff states that NV Energy’s Financial Plan provides and explains assumptions and methodologies used to develop the Preferred and Alternative Plans pursuant to NAC 704.9401. The results of the Financial Plan show that NPC and SPPC will generate cash, from operations during the 2019-2038 planning period, in excess of funding the capital projects included for the Preferred and Alternative Plans. Staff notes NV Energy’s concern regarding the impact that the
six new PPAs (if approved) would have on credit metrics and ratings. Staff explains that major credit rating agencies treat, to various degrees, such long-term financial obligations as debt-like items. Staff notes that NV Energy acknowledges that such treatments will negatively affect certain credit metrics and may affect NPC’s and SPPC’s current investment grade rating.

According to Staff, the Commission does not need to act on this matter in this proceeding. Staff observes that, pursuant to the Stipulation in Phase I, NV Energy has agreed to closely monitor this issue and notify the Commission of a credit quality issue. (Ex. 50 at 18-19.)

**NV Energy Rebuttal**

154. NV Energy notes that the PPAs proposed in this Docket represent contractual commitments having a notional value of about $1.9 billion. NV Energy contends that, given the magnitude of these contractual commitments compared to the companies’ overall capitalization, the decisions made in this Docket will affect the companies’ credit metrics and customers in a way that is not dissimilar to the impact from a direct investment in the solar facilities. NV Energy states that, if the reasonable decision to enter into the six PPAs and three CPAs degrades credit metrics and yields higher overall costs, it may result in higher equity returns or equity levels in future general rate review filings. (Ex. 60 at 3-4.)

155. NV Energy acknowledges that it has not asked the Commission to pre-approve an increase in the equity layer. NV Energy recognizes that there are tools available to it and the Commission to mitigate the potential that PPAs with significant notional value will increase the cost of borrowing for the companies. (Id. at 6.)

**Commission Discussion and Findings**

156. The Commission adopts Staff’s recommendation as NV Energy’s Financial Plan satisfies NAC 704.9401. A “financial plan” means “a plan that demonstrates the financial
impact of the preferred plan of a utility on the utility and its customers.” NAC 704.9069. NAC 704.9401 states:

1. The assumptions and methodologies for modeling used to develop the utility’s financial plan must be described in the resource plan of the utility. The following estimated financial information for the preferred plan must be included in the financial plan:

   (a) Present worth of revenue requirements.
   (b) Nominal revenue requirements by year.
   (c) Average system rates per kilowatt-hour by year.
   (d) Total rate base by year.
   (e) Financial results attributed to the risk management strategy of the utility.

2. The financial assumptions used by the utility to develop its supply plan must be stated in the financial plan. The following items must be stated for each year in the financial plan:

   (a) The general rate of inflation.
   (b) The AFUDC rates used in the supply plan.
   (c) The cost of capital rates used in the supply plan.
   (d) The discount rates used in the calculations to determine present worth.
   (e) The tax rates used in the supply plan.
   (f) Other assumptions used in the supply plan.

NV Energy includes this information on pages 196-216 of Exhibit 11, wherein NV Energy specifies that it analyzed the financial impact of both the Preferred and Alternative Plans “from the perspective of several customer and company-financial impacts . . .” Accordingly, the Commission finds that NV Energy’s Financial Plan satisfies the applicable regulatory requirements.

K. **NV Energy’s Requests for Confidential Treatment**

157. Pursuant to NAC 703.5274, NV Energy requests that the Commission grant confidential treatment to certain information within its Joint Application and that the information remain confidential for a period of five years. NV Energy’s request pertains to information regarding NV Energy’s load forecasts, fuel and purchased power price forecasts, gas premiums,
operational data, transmission infrastructure, forecasted financial data, and renewable projects data. According to NV Energy, the information for which it requests confidential treatment qualifies for such treatment because it contains customer-specific information; derives independent economic value from not being generally known; discloses NV Energy’s internal views, expectations, and analysis of relevant markets or costs; or contains commercially sensitive and/or trade secret information. NV Energy requests that this information remain confidential for a period of five years. (Ex. 2 at 15-19, 28.)

158. Under NRS 703.190, the Commission shall, upon receipt of a request from a public utility, prohibit the disclosure of any applicable information in the possession of the Commission concerning the public utility if the Commission determines that the information would otherwise be entitled to protection as a trade secret or confidential commercial information. Upon making such a determination, the Commission shall establish the period during which the information must not be disclosed.

159. The Commission has reviewed the information for which NV Energy seeks confidential treatment and agrees with NV Energy’s stated reasons as to why the information qualifies for such treatment. The information for which NV Energy seeks confidential treatment shall remain confidential for a period of five years.

**VII. ORDER, COMPLIANCES & DIRECTIVES**

THEREFORE, it is ORDERED that:

1. The Supply Plan, the Financial Plan, and the Action Plan portions of the Integrated Resource Plan are ACCEPTED AS MODIFIED by this Order.

2021 Energy Supply Plan, designated as Docket No. 18-06003, are GRANTED AS MODIFIED by this Order.

3. The Assistant Commission Secretary SHALL OPEN a new investigatory docket to evaluate whether Nevada regulations, specifically Nevada Administrative Code sections 704.9492 and 704.9496, are fully consistent with federal Public Utility Regulatory Policies Act authorities.

Compliances

4. Consistent with paragraphs 66 and 67 of this Order, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall work with the Regulatory Operations Staff and other interested parties to determine the most efficient, least-cost means of implementing the Regulatory Operation Staff's "production ratio" methodology to allocate Power Purchase Agreement costs. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, Staff, and other interested parties shall file the selected implementation option, and supporting information, within 90 days of the issuance of this Order.

Directives

5. Consistent with paragraph 53 of this Order, NV Energy shall closely monitor the feasibility of retiring North Valley Unit 1 early and keep the Public Utilities Commission of Nevada apprised of the outlook on early retirement. NV Energy shall, at a minimum, provide an update on reliability and cost conditions in its report on the progress of the action plan submitted pursuant to Nevada Administrative Code 704.9498.

6. Consistent with paragraph 105 of this Order, once the first 50-MW-per-utility tranche of Long Term Avoided Cost rates available for qualified facility contracts is filled,
Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file with the Public Utilities Commission of Nevada proposed recalculate Long Term Avoided Cost Rates.

7. Consistent with paragraph 113 of this Order, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, in each utility’s next general rate case, shall adjust the depreciation expenses associated with the retirement date changes of Clark Peaker Unit 4, Clark Mountain Units 3 and 4, Fort Churchill Unit 1, Sun Peak Units 3, 4, and 5, and Harry Allen Unit 3.

8. Consistent with paragraph 148 of this Order, by May 19, 2019, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file with the Public Utilities Commission of Nevada an application addressing cost allocation of the One Nevada Line.

9. All arguments of the parties raised in these proceedings not expressly addressed herein have been considered and either rejected or found to be non-essential for further discussion in this Order.

10. The Commission may correct any errors that have occurred in the drafting or issuance of this Order without further proceedings.

By the Commission,

ANN WILKINSON, Chair and Presiding Officer

ANN PONGRACZ, Commissioner
CJ MANTHE, Commissioner

Attest: ______________

TRISHA OSBORNE,  
Assistant Commission Secretary

Dated: Carson City, Nevada

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(SEAL)