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 2025-2044 Triennial	)	Docket No. 24-05041
Integrated Resource Plan and 2025-2027 Energy	)	
Supply Plan.	)	

At a special session of the Public Utilities Commission of Nevada, held at its offices on December 20, 2024.

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

ORDER

TABLE OF CONTENTS

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

I. INTRODUCTION

On May 31, 2024, Nevada Power Company d/b/a NV Energy ("NPC") and Sierra Pacific Power Company d/b/a NV Energy ("SPPC", and collectively with NPC, "NV Energy") filed with the Public Utilities Commission of Nevada ("Commission") a joint application, designated as Docket No. 24-05041 ("Joint Application"), for approval of its 2025-2044 Triennial Integrated Resource Plan ("IRP") and 2025-2027 Energy Supply Plan ("ESP").

On September 4, 2024, NV Energy filed with the Commission a stipulation addressing Phase 1 (ESP) of the IRP ("Phase 1 Stipulation"). On October 2, 2024, the Commission issued an order accepting the Phase 1 Stipulation.

On November 5, 2024, through November 7, 2024, the Commission held a hearing for Phase II addressing the Distributed Resources Plan ("DRP"), Transportation Electrification Plan ("TEP"), and Demand-Side Management Plan ("DSM") of the IRP.

On November 18, 2024, through November 21, 2024, the Commission held a hearing for Phase III addressing the remaining portions of the IRP.

II. PROCEDURAL HISTORY

- On May 31, 2024, NV Energy filed the Joint Application.

- NV Energy filed the Joint Application pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC") Chapters 703 and 704, including, but not limited to NRS 704.741 *et seq*. and NAC 704.9005 *et seq*. Pursuant to NRS 703.190 and NAC 703.527, *et seq*., NV Energy requests that certain information in the Joint Application receive confidential treatment.

- The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.

- On June 10, 2024, the Nevada Attorney General's Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS.

- On June 11, 2024, the Commission issued a Notice of Joint Application and Prehearing Conference.

- On June 12, 2024, Western Resource Advocates ("WRA") filed a petition for leave to intervene ("PLTI").

- On June 17, 2024, Google LLC ("Google") filed a PLTI.

- On June 20, 2024, Vote Solar filed a PLTI.

- On June 25, 2024, Nevada Workers for Clean and Affordable Energy ("NWCAE") filed a PLTI.

- On June 27, 2024, Sierra Club filed a PLTI.

- On July 1, 2024, Advanced Energy United ("United") filed a PLTI.

- On July 2, 2024, Southwest EE Project ("SWEEP") filed a PLTI.

- On July 3, 2024, the Nevada Rural Electric Association ("NREA"); Ormat Nevada Inc. ("Ormat"); Western Power Association ("WPA"); Tract Management Company, LP ("Tract"); Clark County, Nevada ("Clark County"); Wynn Las Vegas, LLC ("Wynn"); Smart Energy Alliance ("SEA"); Interwest Energy Alliance ("IEA" or "Interwest"); Mt. Wheeler Power, Inc. ("MWP"); Boyd Gaming Corporation ("Boyd"), Station Casinos LLC ("Station"), and Venetian Las Vegas Gaming, LLC ("Venetian," together with Boyd and Station, "SNGG"); Microsoft Corporation ("Microsoft"); Solar Energy Industries Association ("SEIA"); Las Vegas Convention and Visitors Authority ("LVCVA"); Caesars Enterprise Services, LLC ("Caesars"), MGM Resorts International ("MGM"), and Nevada Resort Association ("NRA," together with Caesars and MGM, "CMN") Interstate Renewable Energy Council, Inc. ("IREC") each filed a PLTI.

- On July 9, 2024, the Presiding Officer held a prehearing conference. NV Energy, Staff, BCP, WRA, Google, Vote Solar, NWCAE, United, Sierra Club, SWEEP, NREA, Ormat, WPA, Tract, Wynn, SEA, Clark County, IEA, MWP, SNGG, Microsoft, SEIA, LVCVA, NRA, Caesars, MGM, and IREC (collectively, the "Parties") made appearances and discussed a procedural schedule.

- On July 11, 2024, the Presiding Officer issued Procedural Order No. 3. On the same day, NV Energy filed an amendment to the Joint Application.

- On July 15, 2024, the Commission issued a Notice of the Amended Joint Application.

- On July 23, 2024, the Presiding Officer issued an Order on PLTIs, granting the interventions of WRA, Google, Vote Solar, NWCAE, United, Sierra Club, SWEEP, NREA, Ormat, WPA, Tract, Wynn, SEA, Clark County, IEA, MWP, SNGG, Microsoft, SEIA, LVCVA, NRA, Caesars, MGM, and IREC.

- On July 29, 2024, the Commission issued a Notice of Hearing.

- On August 28, 2024, the Presiding Officer issued Procedural Order No. 4, scheduling a consumer session for October 3, 2024. The same day, the Commission issued a Notice of Consumer Session and Notice of Hearings.

- On September 4, 2024, NV Energy, Staff, and BCP filed the Phase 1 Stipulation.

- On September 5, 2024, the Commission issued a Notice of Continued Prehearing Conference. The same day, the Presiding Officer issued Procedural Order No. 5.

- On September 16, 2024, the Presiding Officer held a continued prehearing conference. NV Energy, Staff, BCP, Google, Vote Solar, United, Sierra Club, Ormat, WPA, Tract, Wynn, SEA, Clark County, IEA, SNGG, Microsoft, SEIA, NRA, Caesars, MGM, and IREC made appearances and discussed the Phase 1 Stipulation.

- On September 18, 2024, the Presiding Officer issued Procedural Order No. 6. The same day, the Commission issued a draft order accepting the Phase 1 Stipulation.

- On September 19-20, 2024, NV Energy filed an errata to the Joint Application.

- On September 24, 2024, at an open meeting of the Commission, the Commission voted to accept the Phase 1 Stipulation.

- On September 26, 2024, the Presiding Officer issued Procedural Order No. 7.

- On October 1, 2024, Ormat filed a motion requesting to be excused from the Phase II hearing.

- On October 2, 2024, the Commission issued an Order accepting the Phase 1 Stipulation.

- On October 3, 2024, the Commission held a consumer session.

- On October 4, 2024, Staff, BCP, WRA, Vote Solar, United, SWEEP, SEIA, and IREC each filed direct testimony for the DRP and TEP portions of Phase II. The same day, Google notified the Commission that it would not be filing direct testimony regarding the DRP or TEP portions of Phase II.

- On October 8, 2024, Staff, BCP, WRA, Google, United, and SWEEP each filed direct testimony for the DSM portion of Phase II.

- On October 9, 2024, and October 10, 2024, NV Energy filed an errata to the Amended Joint Application regarding Phase III.

- On October 10, 2024, WRA filed an errata to its Phase II (DSM) direct testimony.

- On October 11, 2024, NV Energy filed a supplement to the October 9-10, 2024, errata.

- On October 17, 2024, MWP filed a motion requesting to be excused from the Phase II hearing.

- On October 18, 2024, Staff, BCP, WRA together with Sierra Club, NWCAE, United, Tract, SEA, MWP, IEA, SEIA, and NRA together with MGM, Caesars, and SNGG filed direct testimony for Phase III. The same day, Google notified the Commission that it would not be filing direct testimony for Phase III. On this same day,

- Also on October 18, 2024, NV Energy filed rebuttal testimony for Phase II (DRP and TEP).

- On October 22, 2024, NV Energy filed rebuttal testimony for Phase II (DSM). The same day, IEA filed an errata to its Phase III direct testimony.

- On October 23, 2024, the Presiding Officer issued Procedural Order No. 8. The same day, Staff filed an errata to its Phase III direct testimony.

- On October 24, 2024, SEA, Wynn, and IEA, each filed a request to be excused from the Phase II hearing.

- On October 28, 2024, the Commission issued an Amended Notice of Hearing.

- On October 29, 2024, Caesars, MGM, and NRA, filed a request to be excused from the Phase II hearing.

- On October 30, 2024, Microsoft, Tract, and WPA each filed a request to be excused from the Phase II hearing.

- On November 4, 2024, NV Energy filed rebuttal testimony for Phase III.

- On November 5, 2024, through November 7, 2024, the Commission held a hearing for Phase II. At the conclusion of the Phase II hearing, on November 7, 2024, SWEEP and Vote Solar orally requested leave to be excused from the Phase III hearing.

- On November 18, 2024, through November 21, 2024, the Commission held a hearing for Phase III.

- On November 22, 2024, the Presiding Officer issued Procedural Order No. 10, permitting legal briefing regarding two questions identified by the Parties at the Phase III hearing.

- On December 4, 2024, CMN together with Wynn filed an opening brief ("CMN and Wynn's Brief"); SNGG filed an opening brief ("SNGG's Brief"); BCP filed an opening brief ("BCP's Brief"); and Staff filed an opening brief ("Staff's Brief"). The same day, Google filed a notice that it would not be submitting an opening brief.

- On December 6, 2024, pursuant to Procedural Order No. 10, NV Energy filed a response to the legal briefs filed on December 4, 2024 ("Reply Brief").

III. LEGAL BRIEFING

1. As noted in Section II, above, CMN, Wynn, SNGG, BCP, and Staff (collectively "the Briefing Parties") each filed opening briefs on December 4, 2024, addressing the following two questions:

- Whether the Commission has the authority to determine prudency, or continued prudency, of the Greenlink North, Greenlink West, and Common Ties Projects following the passage of Senate Bill ("SB") 448 (2021) ("Question 1"); and
- Whether NV Energy can request incentives for any Greenlink projects that have been designated as critical facilities in an IRP or if the incentives can only be requested in a general rate case ("Question 2").

(Procedural Order No. 10 at 6.)

2. On December 6, 2024, NV Energy filed its Reply Brief.

CMN and Wynn's Position

3. Regarding Question 1, CMN and Wynn assert that no legal authority exists for the Commission to determine "continued approval" of Greenlink in an IRP proceeding following passage of SB 448, and argue that prudency of cost overruns, including an additional $1.7 billion in Greenlink costs, should be evaluated in a general rate case ("GRC"). (CMN and Wynn Brief at 2-5.) CMN and Wynn further state that NV Energy refused to identify any such authority in response to Staff's discovery requests. (CMN and Wynn Brief at 2-3.) CMN and Wynn assert that SB 448 left the Commission no authority to deny NV Energy's request to construct the Greenlink projects and instead required NV Energy to file a "transmission infrastructure for a clean energy economy plan" ("TICEEP") with the Commission as an amendment to its 2021 IRP, which merely requested that the Commission deem the application "adequate" in that the TICEEP included the information required by statute. (CMN and Wynn Brief at 4.) CMN and Wynn further state that nothing in SB 448 authorizes the Commission to make an IRP prudency determination or authorize or modify the TICEEP, unlike the Commission's authority under

NRS 704.741. (CMN and Wynn Brief at 4.) CMN and Wynn further assert that NV Energy has previously represented to both the Nevada Legislature and the Commission that the prudency determination for Greenlink costs will be made in a GRC. (CMN and Wynn Brief at 2, 5.)

4. As to Question 2, CMN and Wynn argue that, based on NV Energy's CFO's testimony at hearing, the Commission has no idea or estimate of what NV Energy's requested annual revenue requirement increase will be for NPC in its upcoming GRC, with or without the requested CWIP treatment for Greenlink, and NV Energy therefore seeks to bind the Commission through the requested financial incentive without any information about other expenses or the overall size of the rate increase that NPC will seek. (CMN and Wynn's Brief at 5-6.) CMN and Wynn assert that NV Energy's request constitutes improper piecemeal ratemaking harmful to NV Energy's customers and in violation of the Commission's duties, and further asserts that the request is contrary to NV Energy's CEO's representations to the Nevada Legislature. (CMN and Wynn's Brief at 6.) CMN and Wynn state that the Commission's regulations unambiguously require the financial incentives that NV Energy requests to be made in a GRC, as previously recognized by NV Energy's former CFO. (CMN and Wynn's Brief at 6-7.)

SNGG's Position

5. As to Question 1, SNGG asserts that the Commission does not have authority to grant "continued approval" for Greenlink because IRP approval of Greenlink, based on consideration of various factors and data including projected budgets, has already been granted, and any cost overruns are properly considered within the context of a GRC. (SNGG's Brief at 2-3.) SNGG further asserts that NV Energy's request for continued approval of the increased budget is made without regard to the requirements of resource planning because NV Energy has

embedded Greenlink in each of its proposed alternative plans, and NV Energy's request fails to recognize that the Commission has already approved its proposals, including budgets, in the normal course. (SNGG's Brief at 3-4.) SNGG adds that NV Energy intends to proceed with Greenlink no matter the Commission's determination in this Docket, and therefore, there is no viable way to reconsider the prudency associated with the Commission's prior approval in Docket No. 20-07023. (SNGG's Brief at 3-4.) SNGG further states that the Commission approved elements of Greenlink pursuant to a specific statutory mandate in Docket No. 21-06001, and no new application for approval has been submitted, meaning no basis exists for the Commission to revisit the scope of its prior approvals. (SNGG's Brief at 4-5.) SNGG further notes that NV Energy has identified no legal authority for the Commission to consider changes to project budgets after the original project elements and budgets have been satisfied and asserts that NV Energy can only request cost recovery in a GRC once IRP approval is granted. (SNGG's Brief at 5.)

6. Regarding Question 2, SNGG asserts that the Commission is without authority to grant incentives associated with critical facilities in an IRP proceeding because the plain and unambiguous language of NAC 704.9484 authorizes such action only in a GRC. (SNGG's Brief at 5.) SNGG argues that any other interpretation of NAC 704.9484 is contrary to the plain meaning of the regulation and undermines its purpose because the request for incentives, if approved, will increase the revenue requirement outside of a GRC or advice letter filing, as required by NRS 704.100(1)(a). (SNGG's Brief at 5-6.) SNGG further asserts that granting NV Energy's request for critical-facility incentives would violate the prohibition on single issue ratemaking, and notes that NV Energy's former CFO previously acknowledged that such incentives must be sought in a GRC in his testimony in Docket No. 20-07023. (SNGG's Brief at

6.) Finally, SNGG notes that NV Energy's current CEO represented to the Nevada Legislature in 2021 that NV Energy would only recover Greenlink costs in a GRC after project costs were incurred and subject to Commission review in a GRC and asserts that NV Energy's requested incentives would allow recovery of these costs before the project is placed in service. (SNGG's Brief at 7.)

BCP's Position

7. As to Question 1, BCP states that pursuant to NAC 704.9494(6) and the Commission's Order in Docket No. 20-07023, all costs expended to construct Greenlink are subject to a prudency review in a GRC. (BCP's Brief at 1.) BCP further asserts that there is no statutory authority to support NV Energy's request for "continued approval" of Greenlink. (BCP's Brief at 2.) BCP further states that it agrees with Staff's assessment that because the Commission already approved the Greenlink components in Docket Nos. 20-07023 and 21-06001, there is no additional decision for the Commission to make in this Docket. (BCP's Brief at 3.)

8. As to Question 2, BCP argues that NAC 704.9484 unambiguously requires that requests for critical-facility incentives be made in an application to change rates in a GRC. (BCP's Brief at 4.) BCP states that a utility may seek critical-facility designation in an IRP docket, but that any incentives associated with the designation must be sought in a GRC. (BCP's Brief at 4.) BCP states that its interpretation of NAC 704.9484(3) is also supported by policy considerations because the Commission may only fully assess the utility's financial condition to ascertain whether incentives are necessary within the context of a GRC. (BCP's Brief at 4.)

///

///

Staff's Position

9. Regarding Question 1, Staff asserts that the Commission does not have authority to determine continued prudency of any Greenlink projects because SB 448 removed the Commission's discretion to determine prudency of TICEEP plan implementation as a modification of the traditional IRP process, and preserved only the Commission's authority to examine and determine cost-recovery in a GRC after Greenlink North, the Harry Allen to Northwest transmission line ("Harry Allen"), and Greenlink West are constructed. (Staff's Brief at 2.) Staff further states that SB 448 limited the Commission's role to a consistency review of the TICEEP with the requirements of NRS 704.79877. (Staff's Brief at 2.) Staff asserts that although Greenlink West was not explicitly included in the TICEEP, the TICEEP limits Greenlink West because the TICEEP fails to satisfy three requirements of NRS 704.79877 if Greenlink West is not included, and notes that Greenlink North and Harry Allen do not create the mandated 800 megawatts ("MW") of transmission import capacity without construction of Greenlink West. (Staff's Brief at 2-3.) Staff further asserts that SB 448 did not modify the Commission's cost-recovery authority or process, and the concept of "continued prudency" is a fiction created by NV Energy in contradiction of SB 448. (Staff's Brief at 3-4.) Staff also cites NV Energy's CEO's 2021 representations to the Nevada Legislature regarding Greenlink cost-recovery in a GRC and the Greenlink informational update in the Fifth Amendment to the 2021 IRP, which Staff asserts demonstrates that NV Energy has abruptly changed course from its prior position that it would not seek approval of costs outside of a GRC. (Staff's Brief at 4-5.)

10. As to Question 2, Staff asserts that utilities may request financial incentives in IRPs, but NV Energy is barred from doing so for Greenlink North and Harry Allen because SB 448 contemplates that such incentives would only be reviewed by the Commission in a GRC,

and because the stipulation in Docket No. 21-06001 requires that a request for incentives for Greenlink North and Harry Allen "must include all financial impacts associated with such a request, including a rate impact analysis that specifies the rate impact of any such proposal on each rate class" which Staff asserts is a function of a GRC, and which NV Energy did not provide in this Docket. (Staff's Brief at 6.) Therefore, Staff asserts that NV Energy is precluded from requesting incentives for Greenlink North and Harry Allen by the terms of the stipulation in Docket No. 21-06001. (Staff's Brief at 6.) Staff states, as to Greenlink West, the Commission should maintain its decision in Docket No. 20-07023 denying critical facility status because Greenlink West remains necessary in the normal course of business. (Staff's Brief at 6-7.) Staff further notes that NV Energy's request for financial incentives in this IRP runs contrary to NV Energy's representations in Docket No. 20-07023 in which NV Energy's former CFO expressly recognized that such incentives must be sought in a GRC. (Staff's Brief at 7.)

NV Energy's Response

11. As to Question 1, NV Energy asserts that Staff's Brief misapprehends how the TICEEP elements of SB 448 fit within the general IRP framework, and states that the Commission's decisions in Docket Nos. 20-07023 and 21-06001 already designated the Greenlink projects as prudent investments with the Commission retaining jurisdiction for continued determinations of prudency. (NV Energy's Reply Brief at 1-2.) [1]

12. NV Energy asserts that, pursuant to NRS 703.110(3), any project that is approved by the Commission following the IRP process is deemed "a prudent investment," and the utility may then recover all just and reasonable costs for the project in a GRC. (NV Energy's Reply

[1] NV Energy asserts that Staff is the only party to have addressed the jurisdictional issue raised and that CMN and Wynn, SNGG, and BCP relied only on arguments asserted in the testimony of Staff's witness Adam Danise. (NV Energy's Reply Brief at 2, fn 1.)

Brief at 2-3.) NV Energy identifies the Sierra Solar photovoltaic ("PV") and Battery Energy Storage System ("BESS") project, Valmy coal-retirement and gas-repower project, and Tracy units 4/5 emission controls project in Docket No. 23-08015 as illustrative of this principle. (NV Energy's Reply Brief at 3.) NV Energy concludes that because the Greenlink projects went through the IRP process, they received resource planning approvals. (NV Energy's Reply Brief at 3.) NV Energy asserts that Staff recognizes that the Greenlink projects received resource planning approvals, and states that Staff's conclusion that the TICEEP projects did not receive a prudency determination is not supported by the relevant sections of the NRS or past Commission practice. (NV Energy's Reply Brief at 3-4, citing Ex. 313 at 23.)

13. NV Energy argues that SB 448 required it to file the TICEEP as a resource plan amendment and required the Commission to accept an adequate plan under NRS 704.751. (NV Energy's Reply Brief at 4.) NV Energy asserts that its IRP Amendment and subsequent Commission acceptance of the TICEEP projects under NRS 704.751(8) resulted in a determination of prudency "under the plain language of NRS 704.110, subsection 3: a project accepted under NRS 704.751 is a 'prudent investment.'" (NV Energy's Reply Brief at 4.) NV Energy asserts that, therefore, SB 448 may be harmonized with the Commission's general IRP approval process. (NV Energy's Reply Brief at 4.)

14. NV Energy further asserts that it filed the TICEEP as an amendment to the then-pending IRP, thereby satisfying the statutory mandate, and the Commission had the authority to deem any portion of the TICEEP inadequate in which case NV Energy would have had the option to accept the Commission's modification curing the inadequacy or withdraw the TICEEP. (NV Energy's Reply Brief at 4.) NV Energy asserts that the Commission's authority in this respect "mirrors" the Commission's general IRP authority under NRS 704.751(1) and (2) and

NRS 704.7321. (NV Energy's Reply Brief at 4.) NV Energy concludes that upon entry of the Commission's January 26, 2022, order accepting the TICEEP stipulation, the TICEEP projects (Greenlink North and Harry Allen) were deemed prudent investments, and the Commission therefore had, and has, jurisdiction to determine their prudency. (NV Energy's Reply Brief at 5.) NV Energy notes that CMN and Wynn, SNGG, BCP, and Staff argue that the Commission should review the Greenlink costs in a GRC, and states that the Commission has authority to review the Greenlink costs for reasonableness and prudency in a GRC pursuant to NRS 704.110(3). (NV Energy's Reply Brief at 5.)

15. NV Energy further states that the Commission maintains resource planning authority for Greenlink because NRS 704.79879 and NRS 704.7988 permit the Commission to consider a TICEEP amendment and modify the Plan, and NAC 704.9494(3) reflects the Commission's continuous authority over the Plan. (NV Energy's Reply Brief at 5.)

16. NV Energy asserts that CMN and Wynn's argument that NV Energy did not cite legal authority to justify continuing jurisdiction is misplaced because NV Energy cited NRS and NAC provisions, including NRS 704.741, NRS 704.751, and NRS 704.79877, as authority for seeking continued approval in its response to Staff's inquiry. (NV Energy's Reply Brief at 5-6, citing Ex. 313 attachments AED 13, AED 14.) NV Energy concludes that the Commission may grant continued approval for the Greenlink projects under NRS 704.751, at which point the Greenlink projects will be deemed a prudent investment with the indicated budgets. (NV Energy's Reply Brief at 6.)

17. As to Question 2, NV Energy asserts that Commission precedent over the past 20 years is to approve critical-facility incentives in an IRP. (NV Energy's Reply Brief at 6.) NV Energy states that NAC 704.9484 is included under the "Resource Planning" section of the

regulations, which indicates that critical facility designation and related incentives should be sought in an IRP. (NV Energy's Reply Brief at 7.) NV Energy asserts that it identified two such occasions in the Joint Application, Docket Nos. 04-6030 and 05-8004, and identifies several other examples of the Commission granting critical facility incentives in IRP dockets in its brief. (NV Energy's Reply Brief at 7-8.) NV Energy notes that the Commission is not bound by *stare decisis* but asserts that these examples conclusively demonstrate that the Commission can and does designate critical facility incentives in IRP proceedings. (NV Energy's Reply Brief at 7.) NV Energy further argues that the Commission's language in its March 27, 2014, Order in Docket No. 13-12040 supports NV Energy's position that critical-facilities incentives, including a regulatory asset, can be requested outside of a GRC. (NV Energy's Reply Brief at 8.)

18. NV Energy further asserts that Staff's Brief omits relevant language from NRS 704.79877(3) and misrepresents NRS 704.79878, and that the complete language of NRS 704.79877(3) supports NV Energy's request for construction work in progress ("CWIP") because the statute addresses cost recovery and financial incentives before the TICEEP is placed in service, which is distinguishable from traditional ratemaking procedure. (NV Energy's Reply Brief at 9.) NV Energy argues that NRS 704.79878(2) does not limit financial-incentive review to a GRC, but instead places a conditional requirement on NV Energy to propose a rate-mitigation mechanism "with the last sentence contemplating Commission incentive consideration."

19. NV Energy asserts that the stipulation in Docket No. 21-06001 speaks for itself, and by its own terms does not require that "future proceedings" addressing TICEEP financial incentives only be GRCs. (NV Energy's Reply Brief at 9.)

20. NV Energy argues that it addressed the issue of a CWIP rate-impact analysis by "rate class" on rebuttal, and provided the rate-impact analysis by rate class rather than by rate schedule, and asserts that it has done so in numerous previous IRPs. (NV Energy's Reply Brief at 10.) NV Energy asserts that the Commission recognizes this distinction, citing Docket Nos. 22-11032 and 21-06036. (NV Energy's Reply Brief at 10.)

21. Finally, NV Energy states that the briefing parties' reliance on NV Energy's former CFO Michael Cole's testimony in Docket No. 20-07023 is misplaced because no inconsistency exists. (NV Energy's Reply Brief at 10.) NV Energy asserts that Mr. Cole's testimony in Docket No. 20-07023 merely sought to preserve NV Energy's ability to seek incentives in a future filing and recognized that customer rates cannot be adjusted in an IRP proceeding pursuant to NAC 704.9484(3), but states that NAC 704.9484(3) does not preclude it from seeking an incentive without inclusion in rates in an IRP. (NV Energy's Reply Brief at 10.)

Commission Discussion and Findings

22. Having reviewed and considered the evidence on the record and the arguments set forth in CMN and Wynn's Brief, SNGG's Brief, BCP's Brief, Staff's Brief, and NV Energy's Reply Brief, the Commission approves critical-facility designation for Greenlink West, does not approve, accept, or issue continued approval for the Greenlink Nevada Project, and declines to issue Construction Work In Progress ("CWIP") at this time, as NV Energy's request for CWIP is appropriately placed in a GRC and not in this IRP.[2] The Commission fully addresses all of its legal findings and other issues regarding the Greenlink Nevada Project in subsection Z of Phase 3 of this Order.

---

[2] Insofar as the parties raise other arguments not specifically addressed in this Order, the Commission has considered the same and concludes that they are not determinative of the Commission's conclusions as stated herein.

IV. AMENDED JOINT APPLICATION: PHASE II

A. Distributed Resources Plan ("DRP") Prayers for Relief Generally

NV Energy's Position

23. NV Energy requests that the Commission approve the DRP as compliant with NAC 704.9237 and determine that, pursuant to NAC 704.9494(5), the elements contained in the DRP are prudent. (Ex. 117 at 300.) NV Energy requests that the Commission find the following:

1. The summary describing the results of the February 5, 2024, stakeholder meeting are in compliance with NAC 704.9237(3)(e);
2. The discussion of the effect of Net Energy Metering ("NEM") systems on the reliability of the distribution system is in compliance with NRS 704.741(3)(d);
3. The load and DER forecasting has been prudently performed in compliance with NAC 704.9237(2)(f), subject to the request to waive the following certain provisions of this regulation:

> NAC 704.9237(2)(f) states that the DRP must "Be developed by a utility using a forecast of net distribution system load and distributes resources. The forecast must be for a period of not less than 6 years, beginning with the year after the distributed resource plan is filed. The net distribution system load and distributed resources forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types." NV Energy states that it utilized the latest available net distribution feeder, substation transformer, and transmission forecasts to determine the constraints on the transmission and distribution systems. However, NV Energy states that all distributed resource types as defined in NAC 704.90583 are not yet represented in those forecasts and NV Energy has disaggregated system-level private solar PV and electric vehicle forecasts down to the substation and feeder levels.
>
> NV Energy states that is consultant, E3, produced geolocational forecasts for DERs at the census block level and NV Energy translated some of that data to its distribution feeder and incorporated it into the non-wires alternatives ("NWA") analyses. NV Energy states that it will integrate the Forecasting Anywhere results for all DER types into its planning, forecasting, and analyses associated with the DRP as appropriate over the next year ahead of

the planned filing of an update to the DRP on or before September 1, 2025, to close this compliance gap.

4. The HCA has been prudently performed in compliance with NAC 704.9237(3)(b), subject to the following request to waive certain aspects of the regulation:

   NAC 704.9237(3)(b) states that the DRP must include a hosting capacity analysis ('HCA') of the distribution system evaluated 'under normal conditions and planned and unplanned contingency conditions.' NV Energy states that it discussed the issue of performing HCA under contingency conditions internally and initially concluded that any contingencies analyzed would need to be limited in scope to ensure that the number of cases analyzed do not create an untenable situation in terms of being able to complete the analysis, especially considering the monthly update and annual full-system update processes already take an entire month and an entire quarter to be completed, respectively, with current processes and resources. NV Energy states that it will continue to investigate how other utilities may be approaching this issue to ascertain if there are any techniques that can be applied to ensure that the analytical process would not be made impractical by the addition of contingency conditions.

5. The general network access ("GNA") for the distribution system has been prudently performed in compliance with NAC 704.9237(3)(a). This includes the following elements:

   a. The identification of distribution constraints and projects;
   b. The NWA analyses;
   c. The locational net benefit analysis ("LNBA"); and
   d. The traditional wired upgrade projects and NWA solutions recommendations.

6. The GNA for the transmission system has been prudently performed in compliance with NAC 704.9237(3)(a). This includes the following elements:

   a. The identification of transmission constraints and projects;
   b. The NWA analyses;
   c. The LNBA; and
   d. The traditional wired upgrade projects and NWA solutions recommendations.

7. The LNBA for the distribution and transmission systems has been prudently performed;
8. The NWAs and utility infrastructure upgrade solutions recommendations are prudent and in compliance with NAC 704.9237(3)(c);
9. The identification of barriers to the deployment of DERs and solutions to them are in compliance with NAC 704.9237(2)(e);
10. The summary explaining how DERs have affected the need for supply-side resources in the resource planning process is in compliance with NAC 704.9237(3)(d);
11. The identification of existing programs approved by the Commission that address the deployment of DERs and the methods of effectively coordinating these programs to maximize the locational benefits and minimize the incremental costs of DERs is in compliance with NAC 704.9237(2)(c);
12. The development and deployment of a publicly accessible web portal that provides maps and accessible electronic data is in compliance with NAC 704.9237(5);
13. The identification of any incremental utility investment or expenditure necessary to integrate cost-effective distributed resources is in compliance with NAC 704.9237(2)(d);
14. The Transportation Electrification Plan ("TEP") is in compliance with the requirements of NAC 704.9237(3)(g), and the programs and budgets requested within the TEP meet the objective of NRS 704.7867 and also meet the requirements of SB 448 (2019) Section 14 (2)(a)-(e);

15. That, as part of the TEP, NV Energy met the Stipulated compliance Items 2 and 3 as outlined in Docket No. 23-09002 and the four required Transportation Electrification Stakeholder meetings as required by NRS 704.7867(3);
16. Pursuant to NRS 704.7867(2)(d), NV Energy also requests approval of the proposed revisions to the schedule No. ESB-V2G, Electric School Bus V2G Trial tariffs provided in the 2024 Joint IRP Application Exhibit E;
17. The Technical Appendix submitted with the DRP is in compliance with NAC 704.9237(3)(f);
18. The following requests and directives be approved:
    a. Docket No. 21-06001—Directive 15 (stakeholder process to consider and address the concerns raised in intervener testimony in Docket No. 21-06001);
    b. Docket No. 23-02001—Directives 4,5,6 (energy storage system ("ESS") and system peak data, electric vehicle ("EV") charging station use data, and EV infrastructure deployment ("EVID") and ESS programs post-installation survey data);
19. The request for $300,000 to investigate and develop an NWA Tariffed-On-Bill pilot program with stakeholders; and
20. The request for approval of the size and type of the Utility Owned Community Solar ("UOCS") and Solar for A; ("S4A") fixed supply-side placeholder resources.

(Ex. 117 at 300-302.)

Commission Discussion and Findings

24. The Commission reviewed the DRP and evidence in this Docket. Weighing the relevant evidence, the Commission finds that, absent a finding to the contrary in this order below, NV Energy has met the applicable provisions of NAC 704.9237, NRS 704.741, NRS 704.751, NRS 704.7867. The Commission finds that, pursuant to NAC 704.9494(5), the

elements contained in the DRP are prudent, except as explicitly discussed and outlined further below. In the sections below, the Commission makes specific findings regarding certain elements of the DRP that either parties raise as issues or that the Commission raises as issues for further discussion and findings.

25. Additionally, the Commission finds that NV Energy has met the directives from Docket No. 23-02001 and Docket No. 23-09002, but not from Docket No. 21-06001, as discussed and outlined further below in this Order.

B. Rule 9 Load Study and Output Methodology

NV Energy's Position

26. NV Energy states that a load study is:

> [T]he process within NV Energy's Distribution Planning department in response to a request for new or additional load on the electric distribution system and generally considers the rating, past peak loading, current load forecast, and remaining reserved load on the distribution feeder(s) and distribution substation transformer(s) that the load may be added to. The aforementioned peak loading values are updated annually in September, but the forecast and reserved load data are refreshed on a daily basis to reflect any changes in those values.

(Ex. 2001 at 4 citing NV Energy's Response to IREC's Third Data Request, Question 3-05(A) (August 30, 2024).)

IREC's Position

27. IREC recommends the Commission order NV Energy to use a dependable PV output methodology in the Rule 9 load study process to increase the capacity of the distribution system to host new loads and avoid distribution system upgrades. (Ex. 2001 at 3.)

28. IREC states that it understands that when evaluating new service requests, NV Energy assumes no output from existing distributed resource generation. (Ex. 2001 at 4.) IREC asserts that this assumption is unreasonable and states its expectation that peak loads occur in the

daytime on most of NV Energy's feeders, and it is reasonable to assume that a PV system has some level of output during daytime hours. (Ex. 2001 at 4.) IREC further asserts that failure to consider daytime PV output could subject customers seeking to connect new loads to unnecessary studies and upgrade costs through the Rule 9 process. (Ex. 2001 at 5.) IREC recommends that NV Energy instead use a dependable PV output methodology for Rule 9 evaluations, including load studies, which will enable NV Energy to integrate solar energy more effectively into the planning process and avoid grid upgrades when distributed energy resources ("DERs") can reliably serve peak load on a feeder. (Ex. 2001 at 5.)

29. IREC recommends that the Commission order NV Energy to adopt a methodology similar to that utilized by Southern California Edison ("SCE"), which IREC submits is sound, or host a workshop for interested persons to discuss a proposed methodology and implementation. (Ex. 2001 at 5-6 and Attachment MM-2.)

NV Energy's Rebuttal

30. NV Energy responds that it does not assume no output from existing distributed generation when evaluating new service requests. (Ex. 163 at 17.) NV Energy states that when evaluating the electric distribution system for available capacity, any relevant existing distributed generation is assumed to be generating as it was during the most recent peak loading of the relevant facilities was established. (Ex. 163 at 17.)

31. NV Energy states that, given this clarification, IREC's recommendation on this issue is likely unnecessary. (Ex. 163 at 18.) NV Energy further states, however, that if this issue is still relevant, the Commission should not order NV Energy to adopt a dependable PV methodology similar to SCE's, but NV Energy would instead be agreeable to hosting a workshop to discuss whether adoption of the dependable PV output concept would be appropriate and necessary. (Ex. 163 at 18.)

Commission Discussion and Findings

32. The Commission finds that a workshop hosted by NV Energy would be the most beneficial path forward on the issue of dependable PV output methodology in the Rule 9 load study. Interested parties agree that this procedure would be beneficial, and NV Energy is agreeable to hosting a workshop to discuss whether adoption of the dependable PV output concept would be appropriate and necessary. The Commission directs NV Energy to host a workshop within three months of the issuance of this order regarding PV output methodology, including an evaluation of SCE's methodology.

C. Rule 9 Process

NV Energy's Position

33. NV Energy states that Rule 9 specifies how projects are designed, constructed, inspected, paid for, owned, and taxed. (Ex. 117 at 268.) NV Energy further states that Rule 9 governs how the total costs and responsibilities for the construction and modification of line extensions are allocated between the utility and applicants based on factors including a project's size, duration, and risk, with the goal to balance these factors in an efficient and equitable manner. (Ex. 117 at 268-269; Ex. 152 at 2-3.) NV Energy states that the elements contained in the DRP are prudent and are compliant with NAC 704.9237 (Ex. 152 at 9.)

IREC's Position

34. IREC recognizes that energization is governed by NV Energy's Rule 9 which establishes timelines and allocates costs and responsibilities among customers and NV Energy. (Ex. 2000 at 13.) IREC asserts that anticipated higher energy demand will result in more Rule 9 applications, which must be managed through clear, efficient, and reliable energization processes. (Ex. 2000 at 13-14.) IREC states that during discovery NV Energy provided general data on average timelines for standard and non-standard projects for 2024. (Ex. 2000 at 16.)

IREC asserts that this data demonstrates that for standard projects NV Energy is meeting timelines for step 1 (delivering a planning memo and cost estimate) and step 3 (designating a project coordinator) but is not meeting timelines for step 6 (delivering an updated cost estimate after completion of the pre-design meeting) or step 8 (delivering the final agreement and cost estimate to the customer.) (Ex. 2000 at 16.) IREC further states that non-standard projects have longer timelines for each step than standard projects. (Ex. 2000 at 18-19.)

35. IREC concludes that NV Energy is not complying with timelines established in Rule 9, though not to an extreme degree. (Ex. 2000 at 19.) IREC states, however, that EV growth and other DERs will increase Rule 9 applications and recommends that current delays in the Rule 9 process be addressed now, which IREC asserts NV Energy has failed to do. (Ex. 2000 at 19.)

36. IREC recommends that the Commission order NV Energy to broadly engage stakeholders regarding the Rule 9 process, including medium- and heavy-duty vehicle ("MHDEV") energization. (Ex. 2000 at 25.) Specifically, IREC requests that the Commission order NV Energy to host at least three in-depth public workshops devoted to Rule 9 and the energization process to gather customer input, including areas of improvement and suggested solutions for increased effectiveness. (Ex. 2000 at 25-26.)

37. IREC recommends that such workshops should occur after an outreach effort conducted by NV Energy to ensure that relevant MHDEV stakeholders are aware of and able to attend the workshop. (Ex. 2000 at 25.) IREC further recommends that at least one workshop be dedicated specifically to the needs of MHDEV customers and include discussion of the use of the hosting capacity analysis in enabling flexible loads. (Ex. 2000 at 25.) IREC further recommends that, once the workshops are complete, NV Energy should use the information from stakeholders

to prepare an Energization Report to be submitted with NV Energy's 2025 DRP update covering (i) timelines for processing Rule 9 applications, and (ii) additional processes, tools, or other refinements to internal processes, customer engagement, and/or the tariff necessary to accelerate transportation electrification. (Ex. 2000 at 26-29.) IREC submits that the Commission should require NV Energy to file an energization timeline update as part of its annual DRP update including a narrative summary of developments over the preceding year. (Ex. 2000 at 29-30.)

38. IREC further states that the California Public Utilities Commission ("CPUC") may direct Pacific Gas & Electric and other California utilities to incorporate HCA into its internal energization processes, and states that it is interested in working with NV Energy to explore how the HCA may be used as part of the process for evaluating new loads. (Ex. 2000 at 38.) IREC recommends that the Commission require NV Energy to begin evaluating how the HCA may be incorporated into the load review process. (Ex. 2000 at 39.)

NV Energy's Rebuttal

39. NV Energy states that it disagrees with IREC's recommendation that the Commission require NV Energy to begin a process to evaluate how the HCA may be used to inform the load application process. (Ex. 163 at 25.) NV Energy notes IREC's statement that it is unaware of any states that currently use the HCA in the new load study process and recommends that the more prudent course is to observe developments in California on this subject before considering any action in Nevada. (Ex. 163 at 25.)

40. NV Energy states that it disagrees with various requests for Commission order made by IREC. (Ex. 163 at 26-27). Specifically, NV Energy states that the Commission should not issue an order establishing a goal that NV Energy allow new generation interconnection and load energization requests using hourly profiles, nor require NV Energy to submit a plan to provide 576-hour results in the HCA by the DRP 2026 update in its 2025 DRP update. (Ex. 163

at 26.) NV Energy states that it is, however, amenable to discussing this subject with interested parties and report on this process in the September 1, 2025 DRP update. (Ex. 163 at 26.)

41. NV Energy states that the Commission should not require it to begin evaluating how the HCA may be incorporated into the load review process and submits that the prudent course is to observe the CPUC's actions and assess the results of that effort before considering further action on the subject. (Ex. 163 at 25.)

42. NV Energy responds that while it has not proposed a specific MHDEV program, MHDEVs could be included in the fleet and Transit Electrification Grant offerings if the customer's fleet consists of these vehicle types. (Ex. 158 at 15.)

Commission Discussion and Findings

43. The Commission finds reasonable IREC's recommendations for a Rule 9 stakeholder group and orders NV Energy to broadly engage stakeholders regarding the Rule 9 process, including MHDEV energization. Specifically, the Commission orders NV Energy to host at least four in-depth public workshops devoted to Rule 9 and the energization process to gather customer input, including areas of improvement and suggested solutions for increased effectiveness on achieving the customer's requested in-service date.

44. The Commission finds that these workshops shall occur after an outreach effort conducted by NV Energy to ensure that relevant stakeholders are aware of and able to attend the workshops. Once the workshops are complete, NV Energy shall use the information from stakeholders to prepare an Energization Report to be submitted with NV Energy's 2025 DRP update covering (i) timelines for processing Rule 9 applications and (ii) additional processes, tools, Staffing requirements, or other refinements to internal processes, customer engagement, and/or the tariff necessary to achieve the customer's requested in-service date.

45. The Commission notes that Phase III also contains Rule 9 recommendations and Commission discussions and findings. The workshops outlined here will be the same workshops discussed further in Phase III.

D. DRP Portal

NV Energy's Position

46. NV Energy states that Section 6 of Ex. 117 discusses the publicly accessible DRP web portal ("DRP Portal") and any updates. (Ex. 152 at 15.) NV Energy asserts these activities meet the requirements of NAC 704.9237(5). (Ex. 152 at 15.)

IREC's Position

47. IREC states that the DRP Portal includes significant data about the location and characteristics of NV Energy's distribution system that is not the output of any specific analysis and recommends that the Commission order NV Energy to publish additional information which can be used by customers seeking to site and design new DERs. (Ex. 2001 at 6-7.) IREC asserts that additional information will enable customers to improve designs and locations for DERs without requiring NV Energy Staff to respond to unique requests from potential applicants. (Ex. 2001 at 7.)

48. IREC recommends that NV Energy publish the following additional feeder and substation data on the DRP Portal to inform customers of system sizing and potential upgrade avoidance:

1. Feeder type: radial, network, spot, mesh, etc.;
2. Number of phases;
3. Substation transformer the feeder connects to;
4. Substation transformer's nameplate rating;
5. Number of substation transformers and whether a bus-tie exists;
6. Service transformer rating.

(Ex. 2001 at 7).

49. IREC further states that publishing additional HCA data on the DRP Portal on a weekly basis will provide customers information about significant changes since the most recent HCA update, which IREC submits may be used by customers to make a rough estimate of the likelihood that a new interconnection or load request will require study or upgrades. (Ex. 2001 at 9.) IREC recommends that the DRP Portal provide the following additional data on a weekly basis: 1) Connected Load (MW) after HCA performed; 2) Connected DER (MW) after HCA performed; 3) Queued Load (MW) after HCA performed; and 4) Queued DER (MW) after HCA performed. (Ex. 2001 at 9.)

50. IREC further recommends that NV Energy provide a catch-all notes field in the DRP Portal to permit NV Energy engineers to provide any unique or relevant information to assist guiding new load or generation interconnection applicants. (Ex. 2001 at 10.)

51. IREC also states that it supports NV Energy's plan to review redaction criteria for its distribution feeder system to align with other states and utilities where appropriate, thereby reducing the number of redacted feeders on the DRP Portal. (Ex. 2000 at 34-35.) IREC states that it recommends NV Energy explain the purpose of each redaction criterion and how it applies to each piece of data at issue, then explain to interested parties how the publication of the relevant hosting capacity data would be adverse to grid security or risk exposing customer information. (Ex. 2000 at 36.) IREC further recommends that the Commission require NV Energy to host at least one public workshop to discuss the proposed redaction criteria, with suggested procedures regarding advanced notice of the proposed criteria. (Ex. 2000 at 36-37.)

NV Energy's Rebuttal

52. NV Energy responds that it disagrees with IREC's recommendation that certain data regarding the distribution system on the DRP Portal should be updated on a weekly basis because IREC has not analyzed the feasibility, effort, time, and cost required to achieve the

requested update frequency, nor the potential benefits which may justify the requested updates. (Ex. 163 at 21.) NV Energy further states that simply because another state updates its information on a daily basis does not justify IREC's request. (Ex. 163 at 21.)

53. NV Energy states that while it had intended to reduce the frequency of its monthly HCA updates from nine times per year to four times per year to manage its existing workload and resources, it is agreeable to maintaining the current HCA update schedule as requested by IREC. (Ex. 163 at 22-23.) NV Energy further states that it does not agree with IREC's recommendation that the Commission order NV Energy to update its HCA 12 times per year because it still takes NV Energy the entire first quarter of each year to complete its full system HCA update. (Ex. 163 at 23.) NV Energy is agreeable to further discussion on this issue with interested stakeholders. (Ex. 163 at 23-24.)

54. NV Energy states that it disagrees with IREC's recommendation that the Commission require NV Energy to hold at least one public workshop discussing proposed HCA data redaction criteria but is agreeable to discussing such criteria with interested parties. (Ex. 163 at 24.) NV Energy further states that it finds the following items identified by IREC reasonable for such discussion: i) an explanation of the purpose of each criterion; (ii) an analysis of how the publication of hosting capacity data meeting that criterion makes the grid less secure; and (iii) a discussion, including citations, of whether the CPUC, other state commissions, or relevant federal authorities allow the redaction of similar information. (Ex. 163 at 24 citing Ex. 2000 at 36.)

Commission Discussion and Findings

55. The Commission finds that the DRP Portal and updates description meet the requirements of NAC 704.9237(5). The Commission declines to adopt IREC's recommendation that certain data regarding the distribution system on the DRP Portal should be updated on a

weekly basis because no party has analyzed the feasibility, effort, time, and cost required to achieve the requested update frequency, nor the potential benefits which may justify the requested updates.

56. The Commission declines to order NV Energy to update its HCA 12 times per year because it takes NV Energy the entire first quarter of each year to complete its full system HCA update. The Commission notes NV Energy's agreement to further discussion regarding the HCA update schedule and finds that NV Energy shall engage with interested stakeholders regarding HCA updates, data redaction, and other state and federal authorities' HCA programs, but the Commission at this time declines to require the discussion to take place in a formal public workshop.

E. Net Energy Metering ("NEM") Reliability

NV Energy's Position

57. NV Energy asserts that at current penetration levels, it has yet to identify discernable effects of NEM systems on the reliability of NV Energy's distribution system. (Ex. 117 at 26; Ex. 152 at 9.) NV Energy includes within the DRP a discussion of the effect of NEM systems on its distribution system reliability. (Ex. 117 at 26-28.) NV Energy requests that, as part of a determination that the elements of the DRP are in compliance with NAC 704.9237, that the Commission determine that the discussion of the effect of NEM systems on the reliability of the distribution system in Section 2.F of the DRP is in compliance with NRS 704.741(3)(d). (Ex. 117 at 300.)

Staff's Position

58. Staff recommends that the Commission order NV Energy to propose NEM reliability impact thresholds, related tracking, and Rule 15 or another tariff revision to ensure there are no negative distribution system impacts with incremental NEM penetration in NV

Energy's next IRP or IRP amendment filing after NV Energy obtains stakeholder input during the planned 2025 Rule 15 workshops. (Ex. 302 at 2, 11-13.)

NV Energy's Rebuttal

59. NV Energy generally agrees with Staff's recommendation. (Ex. 163 at 3.) NV Energy, however, states that while it is agreeable to working with Staff to establish the relevant thresholds, plan, communication protocol, and tariff revisions, it requests that the topic be restricted to NEM's potential effect on the reliability of the distribution system only, stating that this is what NRS 704.741(3)(d) is limited to. (Ex. 163 at 12-13.) NV Energy further responds that the communication protocol suggested by Staff be limited to prospective or new NEM customers to prevent confusion or negative reaction from existing customers. (Ex. 163 at 13.)

Commission Discussion and Findings

60. First, the Commission finds that the NEM elements of the DRP are in compliance with NAC 704.9237, and the Commission finds that the discussion of the effect of NEM systems on the reliability of the distribution system in Section 2.F of the DRP is in compliance with NRS 704.741(3)(d). Second, the Commission orders NV Energy to propose NEM reliability impact thresholds, related tracking, and Rule 15 or another tariff revision to ensure that there are no negative distribution system impacts with incremental NEM penetration in NV Energy's next IRP or IRP amendment filing after NV Energy obtains stakeholder input during the planned 2025 Rule 15 workshops. NV Energy shall work with Staff and other interested stakeholders to establish the relevant thresholds, plan, communication protocol (for existing and future or potential NEM customers), and tariff revisions. The Commission restricts these discussions to NEM's potential effect on the reliability of the distribution system only, pursuant to NRS 704.741(3)(d).

///

F. Rule 15: Generation Interconnection Procedure

NV Energy's Position

61. NV Energy states that it expected to file an updated Rule 15 with the Commission this summer but asserts that it understands the vested interests of stakeholders in Rule 15, as well as the stakeholders' expectation to be a part of the updating process as opposed to simply following NV Energy's ultimate filing with the Commission. (Ex. 117 at 233.) NV Energy states that it expects to hold at least two meetings with interested stakeholders to solicit specific issues from them during this process. (Ex. 117 at 233.)

IREC's Position

62. IREC states that it agrees with NV Energy that a collaborative stakeholder process should occur before NV Energy proposes specific revisions to Rule 15, but states that two meetings are insufficient for the process to cover the many subjects which NV Energy proposes to include in its revision. (Ex. 2000 at 45.) IREC states that it anticipates the working group process will require one year to adequately address each subject at issue in detail. (Ex. 2000 at 46.) IREC recommends that the Commission order NV Energy to convene a working group no later than April 1, 2025, hold meetings at least monthly, and file proposed revisions to Rule 15 within 12 months of convening the working group. (Ex. 2000 at 46.)

63. IREC further states that the Commission should order the working group to consider, and NV Energy's ultimate Rule 15 revision filing to address, the following:

a. The HCA's role in streamlining the interconnection process and evaluation to determine which initial review screens are commonly failed and/or could be replaced by the more precise evaluation found in the HCA and examination of NV Energy's supplemental review process (Ex. 2000 at 46 47);

b. Modernizing the screening and study processes to recognize recent developments, including the use of acceptable export controls as described in the *Toolkit and*

Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage to incorporate best practices for export controls in Rule 15 (Ex. 2000 at 46-49);

c. The *Decision Options Matrix for IEEE 1547 ™-2018 Adoption* which IREC notes NV Energy has rightly acknowledged, but which IREC states it is uniquely positioned to guide NV Energy through the process of adopting as IREC engineers assisted in developing IEEE 1547-2018 and has developed tools for guidance and best practices for this subject. (Ex. 2001 at 11-14); and

d. The voltage variation evaluation recommendations found in IEEE 1547-2018, including the magnitude DER output change and threshold percentage which IREC asserts will permit more DERs to interconnect to the grid under the 3% voltage change measure as opposed to NV Energy's existing 2.5% standard (Ex. 2001 at 14-15.)

NV Energy's Rebuttal

64. NV Energy replies that because it did not make any request of the Commission regarding Rule 15, it believes IREC's recommendation on the subject is irrelevant and more appropriately addressed within a filing by NV Energy requesting approval of an update to Rule 15. (Ex. 163 at 27; Ex. 163 at 32-33.) NV Energy further states that while it agrees that it is time to move forward with updating Rule 15 and that this should likely take place in 2025, it does not agree that it should be required to do so. (Ex. 163 at 35.)

65. NV Energy agrees with IREC's recommendation that NV Energy should alter its current 2.5 percent (3V) voltage variation criterion in the HCA to 3.0 percent (3.6V) as contained in IEEE 1547-2018. (Ex. 163 at 4, 35-36.)

Commission Discussion and Findings

66. Because of the need to update Rule 15, and because the Rule 15 update process will likely be lengthy and include issues tangential to or not included in this IRP, the Commission finds that NV Energy shall schedule public meetings to update Rule 15 with all interested stakeholders. The Commission finds that IREC's list of potential Rule 15 topics is best addressed in the Rule 15 update workshops and future docket itself and not in this IRP due

to the need for more information and input from stakeholders to inform the future filing. The Commission orders NV Energy to start the Rule 15 update process with meetings with interested stakeholders, with a formal filing due by January 1, 2026. The formal filing shall include an update on the topics outlined above by IREC including why or why not these items were addressed in the meetings and formal filing.

67. Finally, the Commission finds it reasonable and in the public interest to order NV Energy to alter its current 2.5 percent (3V) voltage variation criterion in the HCA to 3.0 percent (3.6V) as contained in IEEE 1547-2018 because this change will permit more DERs to interconnect to the grid under the three percent voltage change measure. NV Energy and IREC agree with this recommendation.

G. HCA

NV Energy's Position

68. NV Energy requests that the Commission find that the DRP and included HCA were prudently performed in compliance with NAC 704.9237(3)(b), subject to NV Energy's request to waive the requirement that the HCA include an evaluation under normal conditions and planned and unplanned contingency conditions. (Ex. 152 at 9, 12-14; Ex. 117 at 300, 302-303.)

IREC's Position

69. IREC recommends that the Commission require NV Energy to continue to improve the HCA so that it can be used to help efficiently direct load and generation projects to locations on the grid where upgrades will not be required. (Ex. 2000 at 30.) IREC opposes NV Energy's request to decrease the frequency of its HCA updates and instead proposes monthly updates, supports NV Energy's proposal to reduce the amount of redaction in the DRP Portal with additional recommended actions to accomplish this goal, and recommends that the

Commission establish a goal to allow new generation interconnection applications and load energization requests based on hourly profiles and for NV Energy to provide 576-hour HCA results. (Ex. 2000 at 30.)

70. IREC states that NV Energy agreed, as part of the stipulation in the 2019 DRP, that achievement of "real-time" HCA data, as the term "real time" is used in NAC 704.9237(3)(b) "shall include updates in a period of time shorter than monthly." (Ex. 2000 at 31.) IREC further states that NV Energy's current practice is to update the hosting capacity of the entire system on the first quarter of each year, followed by monthly updates of a significant portion of the total distribution feeders for the remainder of the year. (Ex. 2000 at 31.)

71. IREC asserts that NV Energy's proposal conflicts with NV Energy's obligations under the NAC and would substantially impair the usefulness of the HCA. (Ex. 2000 at 33.) Instead, IREC recommends the Commission order NV Energy to increase the frequency of its updates to at least once per month because this proposed frequency would comport with the definition of "real time" included in the 2019 DRP stipulation, and because the HCA's benefits depend on accurate and up-to-date results. (Ex. 2000 at 33.) IREC also recommends that the Commission establish a process to require NV Energy to go beyond monthly updates. (Ex. 2000 at 33.)

Vote Solar's Position

72. Vote Solar recognizes that NV Energy has provided an HCA which purports to reflect normal system operating conditions and seeks a waiver from NAC 704.9237(3)(b) which also requires NV Energy to provide an HCA under contingency conditions. (Ex. 1300 at 49-50.) Vote Solar asserts that NV Energy's HCA is fundamentally flawed because it overstates actual PV generation capacity. (Ex. 1300 at 50-52.) Vote Solar states that NV Energy's assumptions on this subject are concerning because they result in nearly half of all feeder sections at or near

capacity and implies that NV Energy will deny interconnection or require lengthy review and costs of new solar customers. (Ex. 1300 at 52.) Vote Solar recommends that the Commission order NV Energy to utilize actual daily solar generation curves in the HCA, taking into account the orientation, tilt angle, and any shading of rooftop systems across its territories. (Ex. 1300 at 5.)

Staff's Position

73. Staff recommends that the Commission find that the DRP meets the requirements of NRS 704.741 and NAC 704.9237 and order, as directives, that NV Energy in the September 1, 2025 DRP update 1) integrate geolocational forecasts for all DER types, and 2) include an evaluation of the contingency conditions addition in the HCA. (Ex. 302 at 1-2, 4-5.)

74. Staff states that NV Energy completed the HCA under normal operating conditions, but not under planned or unplanned contingency conditions. (Ex. 302 at 5.) Staff further states that NV Energy acknowledged in discovery that it would monitor developments regarding HCA operational flexibility in California to determine the potential applicability to NV Energy's HCA. (Ex. 302 at 5.) Staff notes that the CPUC) is not expected to issue findings on this subject until during or after second quarter 2025. (Ex. 302 at 5.) Staff therefore recommends that the Commission direct NV Energy to include an evaluation of the contingency conditions' addition in the HCA in the September 1, 2025 DRP update once the CPUC's final findings are available. (Ex. 302 at 2, 4-5.)

NV Energy's Rebuttal

75. NV Energy responds to IREC's position, stating that it did not request that the Commission approve a reduction in the frequency of its monthly HCA updates, but notes that it is agreeable to maintaining the current HCA update schedule. (Ex. 163 at 22.) NV Energy further states, however, that it disagrees with IREC's recommendation that the Commission

order NV Energy to update the HCA monthly (12 times per year), but is agreeable to a discussion of the feasibility, effort, time, cost, and trade-offs which may be required to achieve IREC's suggested update frequency. (Ex. 163 at 23-24.)

76. NV Energy disagrees with Vote Solar's contention that the HCA is fundamentally flawed due to its assumption for solar PV in the analysis because NV Energy is aware that the output of solar PV systems is variable over the course of a day and a year and asserts that its assumptions in this regard are an acceptably conservative planning level for purposes of estimating incremental hosting capacity of a feeder section. (Ex. 163 at 30.) NV Energy asserts that this assumption ensures "that no practical limits should need to be placed on solar PV operation and that results are valid for any level of output up to fill rated output." (Ex. 163 at 30 citing Ex. 117 at 42.)

77. NV Energy agrees with Staff's recommendation that the Commission direct NV Energy to include an evaluation of the contingency conditions addition in NV Energy's HCA in NV Energy's next DRP update on or before September 1, 2025. (Ex. 163 at 3-4.) NV Energy states, however, that final findings in the CPUC's Resolution E-5260 are not necessary and it will therefore close this compliance gap ahead of the September 1, 2025 DRP update. (Ex. 163 at 15.) Accordingly, NV Energy is agreeable to Staff's recommended directive on this issue but suggests that any such directive need not reference the California action. (Ex. 163 at 15.)

Commission Discussion and Findings

78. First, the Commission finds that the DRP was prudently performed in compliance with NAC 704.9237(3)(b). The Commission finds that the DRP meets the requirements of NRS 704.741 and NAC 704.9237 subject to NV Energy's request to waive the requirement that the HCA include an evaluation under normal conditions and planned and unplanned contingency

conditions. The Commission notes that NV Energy is agreeable to maintaining the current HCA update schedule.

79. Second, the Commission declines to adopt IREC's recommendation that the Commission order NV Energy to update the HCA monthly (12 times per year), but the Commission does support discussion between NV Energy and interested stakeholders regarding the feasibility, effort, time, cost, and trade-offs which may be required to achieve IREC's suggested update frequency. The Commission finds that more information is needed regarding the feasibility, time, cost, and trade-offs before the Commission orders NV Energy to update the HCA update frequency, which may be filed in a future docket.

80. Third, the Commission disagrees with Vote Solar's contention that the HCA is fundamentally flawed due to its assumption for solar PV in the analysis because NV Energy is aware that the output of solar PV systems is variable over the course of a day and a year, and NV Energy's assumptions in this regard are an acceptably conservative planning level for purposes of estimating incremental hosting capacity of a feeder section. The Commission finds that the assumption ensures that no practical limits need to be placed on solar PV operation and that results are valid for any level of output up to fill rated output.

81. Finally, the Commission directs NV Energy to include an evaluation of the contingency conditions in NV Energy's HCA in NV Energy's next DRP update on or before September 1, 2025, including the findings in the CPUC's Resolution E-5260, as recommended by Staff.

///

///

///

H. NWA Project Tariffed-On-Bill ("TOB") Pilot

NV Energy's Position

82. NV Energy proposes a phase-gated approach to investigate, develop, and evaluate a new NWA TOB financing mechanism to support the deployment of NWAs. (Ex. 145 at 7-8; Ex. 117 at 213.) NV Energy asserts that this financing method is growing in the industry and contemplates equipment installed and financed by the utility, registered with the premises and associated meter, and monthly payments are made by the current customer of the premises until the equipment is fully paid off. (Ex. 117 at 213.)

83. NV Energy requests that the Commission approve a budget of $300,000 for the initial phase investigation and customer research. (Ex. 117 at 214.)

SEIA's Position

84. SEIA recommends that the Commission deny Section 8 of NV Energy's DRP, which proposes to spend $300,000 of ratepayer funds for investigating a TOB financing program because this activity is outside NV Energy's core service provision. (Ex. 1800 at 3, 7.) SEIA explains that NV Energy's current proposal, while designated a pilot program, is not actually a pilot program; but instead, NV Energy is seeking authorization from the Commission to investigate the implementation of a future pilot TOB program. (Ex. 1800 at 3.) SEIA states that after NV Energy performs the investigation, it will return to the Commission seeking authorization to implement the pilot program, based on its investigation. (Ex. 1800 at 3-4.)

85. SEIA states that NV Energy proposes to fund the initial implementation pilot, if it moves forward beyond the investigation phase, with its own capital, earning an authorized return on its investment in the upfront costs of improvements at customers' homes and businesses, yet

the rate of return ("ROR") has not been determined and NV Energy will request the Commission to review and authorize the ROR in a subsequent tariff filing. (Ex. 1800 at 4.)

86. SEIA states that it is not necessary nor reasonable for NV Energy to spend $300,000 of ratepayer funds to investigate a strategy to increase deployment of DERs. (Ex. 1800 at 5.) SEIA explains that a robust, competitive market already exists across Nevada to meet customer demand for DERs and deliver benefits to NV Energy's high potential NWA areas, without spending ratepayer funds to further investigate a TOB program. (Ex. 1800 at 5.) SEIA also explains that the Commission should not authorize NV Energy to provide customers with a service that is already being efficiently provided by the market. (Ex. 1800 at 5.) SEIA states that there are already significant government incentives and grants that efficiently and cost-effectively meet NV Energy's goals, such as the Nevada Clean Energy Fund ("NCEF") and the Nevada Governor's Office of Energy. (Ex. 1800 at 6.)

87. SEIA states that if the Commission does grant the investigation proposal then the Commission should direct NV Energy to also evaluate non-utility-provided financing options, competitive service solicitations, and third-party program administrators if it authorizes NV Energy's investigation because incorporating financing options beyond NV Energy's capital in the TOB investigation could result in lower costs to program participants, mitigate concerns about the appropriate role for the utility, and would leverage the expertise and capital of private lenders. (Ex. 1800 at 7-8.)

SWEEP's Position

88. SWEEP recommends that the Commission approve NV Energy's TOB financing pilot proposal because this concept removes barriers to energy efficiency ("EE") and

DERs by providing low-cost financing that is tied to the building premise and can be helpful for renters and income-qualified ratepayers. (Ex. 1602 at 4, 12.)

WRA's Position

89. WRA recommends that the Commission require NV Energy to develop a broader TOB financing product for all customers rather than limiting it to a small field demonstration for NWA projects. (Ex. 1201 at 22.) WRA states that NV Energy can provide increased demand-side program incentives for customers in NWA project areas before applying a TOB financing package to encourage participation in areas where the grid faces constraints. (Ex. 1201 at 22.) WRA states that NV Energy should act swiftly to remove the barriers customers encounter when participating in programs for distributed resources that support the utility's policies and Nevada's clean energy goals. (Ex. 1201 at 22.)

90. WRA states that NV Energy's proposed TOB pilot program is not extended to all customers; it is limited to single-family homes, mobile homes, multi-family homes, and commercial properties within designated NWA project areas. (Ex. 1201 at 20.)

91. WRA argues that there are no set plans to offer customers a TOB financing program outside of NWA project areas. (Ex. 1201 at 21.) WRA states that NV Energy's proposed TOB pilot program will develop gradually with limited customer participation. (Ex. 1201 at 21.) WRA states that it will take at least 2 years for the first customer to take advantage of TOB financing, particularly in areas facing grid constraints. (Ex. 1201 at 21.) WRA acknowledges that NV Energy must establish terms and conditions, train NV Energy Staff, and secure large-scale financing; however, WRA states that TOB financing is not a new concept. (Ex. 1201 at 21.) WRA states that utilities have offered various forms of on-bill financing that NV Energy can leverage. (Ex. 1201 at 21.)

Staff's Position

92. Staff states that it recommends the Commission deny NV Energy's request for $300,000 to investigate and develop an NWA TOB pilot program at this time because additional evaluation information is required for budgetary approval, including: operation and maintenance, capital parts replacement, warranty, insurance, fire risk mitigation, lack of performance and other applicable costs over the asset lives of the NWA measures and the party who will be responsible for each of the foregoing costs. (Ex. 302 at 2, 6-7.) Staff further states that it is not opposed to the NWA TOB pilot program in theory, which Staff states could provide bill savings while providing operational benefits from the installed NWAs, provided the program is designed and implemented effectively. (Ex. 302 at 7.) Staff concludes, however, that it does not recommend budgetary approval without the additional detail identified above. (Ex. 302 at 7.)

NV Energy's Rebuttal

93. NV Energy responds that the proposed phase-gated NWA TOB pilot program in the DRP is intended to begin with stakeholder involvement and investigation in 2025 leading to a controlled test and field demonstration for inclusion in the 2025 annual DRP update and implementation in 2026 and 2027. (Ex. 165 at 15.) NV Energy asserts that Staff, WRA, and SWEEP support the concept, and WRA and SWEEP in fact propose that the TOB concept be expanded to all customers. (Ex. 165 at 16.) NV Energy states that it has proposed an investigatory process specifically to address the issues and questions identified by SEIA. (Ex. 165 at 16.)

94. NV Energy states that, while it could move forward without budgetary approval at any time, it has requested budget approval for transparency to interested stakeholders and will utilize the budgetary request for expert consultants to facilitate stakeholder engagement and program design. (Ex. 165 at 16-17.)

Commission Discussion and Findings

95. The Commission denies NV Energy's request for $300,000 to investigate and develop an NWA TOB pilot program at this time because additional evaluation information is required for budgetary approval, including: operations and maintenance (O&M), capital parts replacement, warranty, insurance, fire risk mitigation, lack of performance and other applicable costs over the asset lives of the NWA measures, and information regarding the party who will be responsible for each of the foregoing costs. The Commission is not opposed to the concept of an NWA TOB pilot program, which, as interveners and Staff note, could provide bill savings while providing operational benefits from the installed NWAs, provided the program is designed and implemented effectively. However, the Commission finds that budgetary approval is not reasonable at this time without the additional detail outlined above.

I. NWA Projects: Solar for All ("S4A") and Utility Owned Community Solar ("UOCS")

NV Energy's Position

96. NV Energy states that it has worked with the NCEF on two potential funding pathways to market for Environmental Protection Agency ("EPA") funding, identified in the 2024 IRP Supply-Side Plan as UOCS and S4A. (Ex. 153 at 10-11; Ex. 117 at 219.) NV Energy requests that the Commission approve the resource type and size of the UOCS and S4A resources such that NV Energy may return for further approval with resource costs and customer program requirements and/or design in the appropriate filings. (Ex. 153 at 12-13.)

97. NV Energy asserts that UOCS is a placeholder to utilize EPA funds that could buy down the cost of facilities related to NV Energy's efforts regarding the Expanded Solar Access Program ("ESAP") by developing incremental cost-effective community-based solar resources. (Ex. 117 at 219.) NV Energy states that it would seek to pair these systems with

BESS facilities if the location is within an identified distribution-constrained area to support NWA opportunities. (Ex. 117 at 219.)

98. NV Energy further asserts that S4A placeholders are related to a funding pathway to create a new customer program with funding from NCEF to reduce the cost of purchasing power from smaller-scale solar PV plants that could also be strategically developed and located to support grid operations. (Ex. 117 at 219.)

99. NV Energy states that the goal for both UOCS and S4A solar resources is to lower the levelized cost of energy from such facilities to the same as or below the market rate of utility-scale power purchase agreements ("PPAs"). (Ex. 117 at 219.)

SEIA's Position

100. SEIA recommends that the Commission grant, in part, NV Energy's request for approval of placeholder community solar resources but withhold consideration of ownership structure because competitive resource procurement that does not predetermine ownership structure will ensure maximum ratepayer benefit and that the benefits of the federal funding reach as many Nevadans as possible. (Ex. 1800 at 3, 14-15.) SEIA explains that it recommends the Commission approve the total additional 59 MW of community solar capacity and 58 MW of associated battery storage, without distinguishing between UOCS, S4A, or approving any ownership structure. (Ex. 1800 at 14.)

101. SEIA states that NV Energy has not identified community solar resources, projects, or bids as a part of its DRP filing, but instead has included the incremental UOCS and new S4A program as placeholder resources that are not tied to specific requests for a specific project or contract. (Ex. 1800 at 13.) SEIA provides that it is not reasonable for the Commission to approve ownership structure of the proposed additional, cost-effective community solar resources for UOCS or S4A placeholders because NV Energy plans to use federal funding

specifically intended to increase solar access for low-income communities and there is no demonstrable benefit to ratepayers in preemptively setting aside some projects as utility-owned at this stage in the process with just the assumption that 50 percent of the project costs will be brought down. (Ex. 1800 at 13.)

BCP's Position

102. BCP recommends that the Commission reject NV Energy's concept of the community-based, federally funded solar program, and instead recommends that the Commission direct NV Energy to submit each resource once it obtains EPA funds for Commission review because currently there is not sufficient information to support this concept. (Ex. 400 at 12, 13.)

Staff's Position

103. Staff states that federal and state funding through EPA or NCEF will reduce the cost for the UOCS facilities and the power purchase price for the proposed S4A projects, and without these funds, the levelized cost of energy ("LCOE") for both UOCS and S4A will be higher than utility-scale projects. (Ex. 302 at 8-9.) Staff further states that further detail regarding funding and project-specific execution is needed to support the UOCS and S4A approvals because Staff cannot conclude how much solar PV or BESS capacity can be installed in a specific timeline without additional detail. (Ex. 302 at 9.)

104. Staff therefore recommends that the Commission deny NV Energy's request for a concept approval of the size and type of the UOCS and S4A programs until detailed scope of work, budget, roles and responsibilities and project execution plans are developed and reviewed by all parties in a future IRP or IRP amendment. (Ex. 302 at 7-10). Staff further recommends that any request on the subject in a future IRP or IRP amendment include additional federal and state funding details and LCOE comparisons of different contractual structures and project

execution or program implementation details developed and made available for review by all parties. (Ex. 302 at 10.)

NV Energy's Rebuttal

105. NV Energy responds that it is encouraged by Staff, BCP, and SEIA's shared interest in seeking solutions to use federal funding to support low-income customers with new options while supporting grid constraints with distributed solar and storage. (Ex. 165 at 21.) NV Energy further states that development of the S4A program design did not align with timing of the IRP, but also desires more information on this subject. (Ex. 165 at 21.)

Commission Discussion and Findings

106. The Commission agrees that federal and state funding through EPA or NCEF will reduce the cost for the UOCS facilities and the power purchase price for the proposed S4A projects. However, the Commission finds that further detail regarding funding and project-specific execution is needed to support the UOCS and S4A approvals because the Commission cannot conclude how much solar PV or BESS capacity can be installed in a specific timeline without additional detail. Therefore, the Commission denies NV Energy's request for a concept approval of the size and type of the UOCS and S4A programs at this time until detailed scope of work, budget, roles and responsibilities, and project execution plans are developed and reviewed by all parties in a future IRP or IRP amendment. Furthermore, the Commission finds that any request on the subject in a future IRP or IRP amendment must include additional federal and state funding details and LCOE comparisons of different contractual structures and project execution or program implementation details developed and made available for review by all parties.

///

J. NWA Analysis, NWA Constraint Analysis, Department of Energy ("DOE") Grant Funding/Further Requests for Proposals ("RFP"), and Directive 15

NV Energy's Position

107. NV Energy states that it has developed NWA Suitability/Screening Criteria to identify situations where an NWA solution would be a viable alternative to an existing or forecasted constraint. (Ex. 152 at 6; Ex. 117 at 65.)

108. Regarding meeting with stakeholders to discuss NWA, NV Energy asserts that it has complied with the Commission's Directive 15 in Docket No. 21-06001 and states that Technical Appendix DRP-1 provides the issues list that was established in response to the Commission's Directive 15 in Docket No. 21-06001 and the discussion on each issue from NV Energy's perspective. (Ex. 152 at 15-16; Ex. 117 at 20.) NV Energy further states that Technical Appendix DRP-2 contains the running meeting notes taken by NV Energy for each meeting. (Ex. 117 at 20.)

109. NV Energy states that it has completed deliverables for Budget Period 1 (Research) and Budget Period 2 (Development) of the DOE Grid Services Grant Project and is now working on Budget Period 3 (Deployment). (Ex. 145 at 6.) NV Energy further states that Budget Period 3 is focused on deploying a field demonstration to test new approaches to recruit customers into bundled DER aggregation to provide grid services and will include operational research by the University of Nevada-Reno ("UNR") and the University of Nevada-Las Vegas. (Ex. 145 at 6-7.) NV Energy states that UNR will simulate the capability of larger DER aggregations to support distribution feeder voltages. (Ex. 145 at 7.) NV Energy states that it expects the final total budget to climb by 5 percent from $3,981,689 to $4,179,661. (Ex. 145 at 7.)

///

SWEEP's Position

110. SWEEP recommends that the Commission direct NV Energy to remove the two-percent cap on EE in NWA-screening and replace it with a ten-percent screening value cap because NV Energy's two-percent reduction in overall energy usage or peak load is not reasonable when considering NWAs. (Ex. 1602 at 4, 6.) SWEEP explains that NV Energy's proposed program is overall energy savings across all fuels used in a home and may not be directly applicable to electricity usage at peak times, which is required for an NWA solution. (Ex. 1602 at 7.) SWEEP states that its recommended ten-percent level of savings is achievable with a targeted deep energy retrofit approach. (Ex. 1602 at 8.)

111. SWEEP recommends that the Commission direct NV Energy to remove the 15-percent cap on demand response in NWA-screening and replace it with a 25-percent screening value cap because it is not clear to SWEEP where the proposed 15-percent cap assumption comes from in NV Energy's analysis. (Ex. 1602 at 4, 9.) SWEEP explains that this value seems like it needs to be feeder-specific, and NV Energy should not provide a definitive limit but instead it would be appropriate for the model to select all available demand response up to 27 percent of peak load. (Ex. 1602 at 9.) SWEEP states that 27 percent is NV Energy's estimate of capacity that could be utilized for additionally reducing forecasted load at no additional incremental costs. (Ex. 1602 at 9-10.)

Vote Solar's Position

112. Vole Solar states that NV Energy appears to delay aggregating DERs until it can use its own software being developed via a DOE grant to dispatch and measure DERs. (Ex. 1300 at 24.) Vote Solar asserts that this is unnecessary because commercial aggregators, which are capable of providing aggregated-DER solutions, currently exist. (Ex. 1300 at 24.) Vote Solar

recommends that the Commission order NV Energy to develop RFPs for third-party DER aggregators for release within 90 days of the final order in this Docket. (Ex. 1300 at 24, 57-58.)

113. Vote Solar states that NV Energy omitted customer-sited energy storage systems from its NWA analyses. (Ex. 1301 at 13-15, 29-33.)

114. Vote Solar recommends that NV Energy design incentive programs that benefit low-income and historically underserved communities when evaluating community benefits for NWA. (Ex. 1301 at 36.) Vote Solar states that NV Energy should maximize the number of its DERs located in and benefiting low-income and historically underserved communities and that NV Energy should include a survey of the low-income and historically underserved areas surrounding NV Energy's list of grid constrains in the next DRP filing. (Ex. 1301 at 36.)

115. Vote Solar states that NV Energy capped the available DERs in the NWA portfolio alternatives at two percent for EE and 15 percent for demand response. (Ex. 1301 at 6.) Vote Solar asserts that both caps are unreasonable because the E3 Forecasting Anywhere results for 2034 are projections of customer adoption of DERs under current conditions, not measures of technological limitations, and these projections should therefore be incorporated into the analysis. (Ex. 1301 at 12-13.)

116. Vote Solar requests that the Commission order NV Energy to revise or expand its modeling to incorporate the following scenarios: 1) Include avoided GHG emission at the social cost of carbon; 2) Include avoided marginal transmission capacity value; 3) Remove the two-percent EE and fifteen-percent demand response caps and only limit the analyses to technical potential, and; 4) Include customer-sited behind-the-meter battery storage as a DER option. (Ex. 1300 at 4; Ex. 1301 at 22-23.)

117. Vote Solar recommends the Commission order NV Energy to perform its NWA analysis under the corrected modeling paradigms recommended by Vote Solar and discussed in the Directive 15 meetings on a monthly basis beginning January 1, 2025. (Ex. 1300 at 59.) Vote Solar asserts that NV Energy did not abide by representations made during the stakeholder process arising from Directive 15 of Docket No. 21-06001 regarding moving to a monthly NWA process in early 2024. (Ex. 1300 at 25-26.)

WRA's Position

118. WRA recommends that the Commission require NV Energy to eliminate the two-percent cap on EE in the NWA analysis and instead use a more accurate local EE supply curve. (Ex. 1201 at 22.)

119. WRA states that NV Energy's justification for the two-percent EE peak load reduction cap is based on the utility's energy savings goal, which is approximately double the statewide energy savings goal of about 1.1 percent of retail sales, leading NV Energy to deem this cap level appropriate. (Ex. 1201 at 10.) WRA argues that comparing retail sales goals to a peak load cap is flawed, arguing that NV Energy misinterprets the relationship between local peak load reduction and statewide energy savings. (Ex. 1201 at 10.) WRA states that NV Energy's annual energy savings targets are based on electric sales measured in kilowatt-hours rather than on peak load reductions in kilowatts. (Ex. 1201 at 10-11.)

120. WRA states that NV Energy assessed 37 NWA projects, and out of the projects assessed, the modeling reached the two-percent EE cap in 30. (Ex. 1201 at 11.) WRA argues that the two-percent EE cap is overly restrictive because 30 out of the 37 projects hit the maximum EE the model allows, suggesting that the model underestimates the actual EE available as a resource in that area. (Ex. 1201 at 11.) WRA suggests that NV Energy close the

EE gap by gathering data on customer savings and types through their DSM programs, as well as actual customer type information from the proposed NWA project area, to calculate a more accurate EE cap for each project. (Ex. 1201 at 11.) WRA states that NV Energy believes this may be achievable using a new analysis tool called LoadSEER. (Ex. 1201 at 11.) WRA elaborates that the revised analysis should include local, measure-specific EE supply curves. (Ex. 1201 at 11.) WRA states that NV Energy can set a higher EE cap for the NWA initial screening but perform a more detailed analysis using specific EE supply curves if the NWA project passes the first screening stage. (Ex. 1201 at 12.)

NV Energy's Rebuttal

121. NV Energy responds that it should first utilize the programs and resources the Commission approves within this IRP to advance NWAs before proceeding to a mandated RFP as recommended by Vote Solar. (Ex. 165 at 6.) NV Energy further states that the terms of the requested RFP are unclear and would require consideration of the method for providing different customer offerings for different NV Energy customers based on location and the cost-recovery for these solutions. (Ex. 165 at 6.)

122. NV Energy states that Vote Solar's assertion that NV Energy does not utilize third-party aggregators is incorrect, and that a mandated RFP would eliminate the benefits of the fully integrated DER-management system ("DERMS") NV Energy currently enjoys via Oracle. (Ex. 165 at 6, Exhibit Steele-Rebuttal-1.)

123. NV Energy states that in the NWA analysis, NV Energy includes customer-cited energy storage systems. (Ex. 160 at 3.) NV Energy states that the behind-the-meter customer-sited energy storage measure began in 2023 and is growing after having been approved in Docket No. 22-07004. (Ex. 160 at 3-4). NV Energy states that it is willing to investigate behind-the-meter energy storage capacity in a future DSM plan. (Ex. 160 at 4.)

124. NV Energy states that its proposed DSM plan meets the statutory requirements of NRS 704.751(5) for low-income and historically underserved communities' DSM spending. (Ex. 160 at 5-6). NV Energy states that its Grid Value Portfolio in its DSM plan has a standalone low-income program that installs EE in qualified households. (Ex. 160 at 6.) NV Energy states that qualified income participants are eligible to receive higher incentive rates in all other DSM programs that are capable of increasing their incentives. (Ex. 160 at 6.)

125. NV Energy states that the additional benefits identified by Vote Solar and WRA should not be immediately added to the LNBA by NV Energy or ordered added to the LNBA by the Commission, but states that these additional benefits as well as those identified by E3 in DRP-Table 82 on page 147 of the DRP Narrative should be discussed and considered for inclusion in the LNBA. (Ex. 163 at 50.) NV Energy recognizes that the issue of including additional benefits in the LNBA analysis was identified in intervener testimony in Docket No. 21-06001 and states that the issue was planned for discussion in the stakeholder process required by Directive 15 of Docket No. 21-06001. (Ex. 163 at 50.)

126. NV Energy asserts that the proper way to address which of the proposed benefits should be included in the LNBA, and how (i.e. whether quantitatively monetized or by percentage proxy), is via a discussion with the DSM and DRP stakeholders. (Ex. 163 at 50-51.) NV Energy states that any agreed-upon additional benefits should be included in the September 1, 2025 DRP update. (Ex. 163 at 50-51.) NV Energy confirms that it stated to DRP stakeholders its intention to move to a monthly process of performing NWA analysis in meetings held with them related to Directive 15 of Docket No. 21-06001. (Ex. 163 at 44.) NV Energy states that upon considering the issue further, it determined that a more prudent staged improvement would be to move from once per year to performing NWA analyses several times per year, but not

immediately moving to a monthly basis from once per year. (Ex. 163 at 44.) NV Energy further states that the inconsistency between the issues list in Technical Appendix DRP-1 and the issues list in its February 5, 2024, issues list is the result of an unintentional oversight which occurred due to NV Energy's expectation that a further meeting would occur between February 5, 2024, and the DRP filing, which meeting did not ultimately occur. (Ex. 163 at 65.)

Commission Discussion and Findings

127. The Commission finds that NV Energy should first utilize the programs and resources that the Commission approves within this IRP to advance NWAs before proceeding to a mandated RFP as recommended by Vote Solar because the terms of the requested RFP are unclear and would require consideration of the method for providing different customer offerings for different NV Energy customers based on location and the cost-recovery for these solutions. Furthermore, the Commission agrees with NV Energy that Vote Solar's assertion that NV Energy does not utilize third-party aggregators is incorrect. Finally, the Commission finds that a mandated RFP would eliminate the benefits of the fully integrated DERMS that NV Energy currently enjoys via Oracle.

128. The Commission directs NV Energy to include information regarding more robust behind-the-meter energy storage capacity incentives in a future DSM plan as the Commission finds that this is a potential area for program growth.

129. The Commission finds that NV Energy's proposed DSM plan meets the statutory requirements of NRS 704.751(5) for low-income and historically underserved communities. NV Energy's Grid Value Portfolio in its DSM plan has a standalone low-income program that installs EE in qualified households, and the DSM plan's Energy Smart Schools programs offer more incentive dollars to public schools located in historically underserved communities. Furthermore, qualified income participants are eligible to receive higher incentive rates in all

other DSM programs that are capable of increasing their incentives. For these reasons, the Commission finds that the combination of the incentives and offerings for low-income and historically underserved communities will meet the 10 percent minimum level of spending required by NRS 704.751(5).

130. The Commission finds that the additional benefits identified by Vote Solar and WRA, as well as those identified by E3 in DRP-Table 82 on page 147 of the DRP Narrative, should be discussed and considered for inclusion in the LNBA. The Commission notes that the issue of including additional benefits in the LNBA analysis was identified in intervener testimony in Docket No. 21-06001 and was planned for discussion in the stakeholder process required by Directive 15 in the Order issued by the Commission in Docket No. 21-06001.

131. The Commission finds that while NV Energy attempted to meet the requirements of Directive 15 of the Order in Docket No. 21-06001, NV Energy did not do so, and the Commission now orders NV Energy to meet with stakeholders to include, amongst other things, the above-listed additional benefits in the September 1, 2025 DRP update.

132. The Commission finds that the Directive 15 meetings were lacking in sufficient substance and frequency to comply with Directive 15 of Docket No. 21-06001. The Commission empathizes with interveners in this Docket that expressed frustration at the Directive 15 meeting process. The Commission orders NV Energy to ensure that the Directive 15 meeting process going forward occurs on a more frequent basis and contains meaningful opportunities for stakeholder discussion and feedback throughout the process and leading into the update.

///

///

///

K. LNBA

NV Energy's Position

133. NV Energy states that the LNBA is necessary for evaluating the economics of DERs deployed at different locations on the system and their potential to defer traditional wired solutions. (Ex. 117 at 141.)

Vote Solar's Position

134. Vote Solar states that the LNBA calculates costs and benefits over a ten-year period while the service life of the DER portfolio and benefits will extend longer than ten years. (Ex. 1301 at 6.) Vote Solar asserts that this methodology effectively makes the present value of net costs of the non-wired portfolio appear higher than it would be if all benefits that will accrue over the life of the DERs are included. (Ex. 1301 at 7.)

135. Vote Solar states that the LNBA only accounts for the benefit of system losses through 2033. (Ex. 1301 at 6.) Vote Solar asserts that an NWA portfolio of DERs will avoid losses for the entire life of the DER portfolio. (Ex. 1301 at 7-8.) Vote Solar concludes that the calculation of net costs, therefore, does not include the benefit of avoided system losses after 2033 even though the NWA DER portfolio will avoid system losses for the full equipment life. (Ex. 1301 at 8.)

136. Vote Solar states the LNBAs include an investment tax credit ("ITC") value set to zero, while the Inflation Reduction Act of 2022 ("IRA") extended and expanded available tax credits for DERs. (Ex. 1301 at 6.) Vote Solar asserts that under the IRA, the tax credit for solar and battery storage is at least 30 percent and could be higher based on bonus credits and accelerated depreciation. (Ex. 1301 at 8.)

137. Vote Solar states the LNBAs apply a property tax and operations and maintenance, even though NV Energy will not own and maintain property for each of the DERs

in its portfolio. (Ex. 1301 at 6, 9.) Vote Solar asserts that O&M costs, which do not exist, falsely increases the apparent cost of the NWA portfolio. (Ex. 1301 at 9.)

NV Energy's Rebuttal

138. NV Energy agrees to certain changes in the LNBA analysis suggested by Vote Solar but submits that these changes should be made on a going-forward basis only, beginning with the September 1, 2025 DRP update. (Ex. 163 at 45, 48.) Specifically, NV Energy agrees that NWA analyses should be run for 20 years instead of 10 years, agrees to revise the NWA analysis spreadsheet to account for the effect of reduced system losses beyond 10 years, agrees to include the effect of the ITC at 30 percent, and agrees to not apply property tax and O&M to DER technologies that should not have these adders. (Ex. 163 at 45-46.)

Commission Discussion and Findings

139. The Commission finds reasonable Vote Solar's proposed changes to the LNBA analysis and finds that the following changes shall be made on a going-forward basis beginning with the September 1, 2025 DRP update: 1) the NWA analyses shall be run for 20 years instead of 10 years; 2) NV Energy shall revise the NWA analysis spreadsheet to account for the effect of reduced system losses beyond 10 years; 3) NV Energy shall include the effect of the ITC at 30 DER energy resource technologies that should not have these adders.

L. NWA Compliance with NAC 704.9237(3)(c)

NV Energy's Position

140. NV Energy requests that the Commission determine the NWAs and utility infrastructure upgrade solutions recommendations of the DRP are prudent and in compliance with NAC 704.9237(c). (Ex. 152 at 9; Ex. 148 at 7; Ex. 117 at 146-148, 179, 301.)

///

Vote Solar's Position

141. Vote Solar requests that the Commission clarify in its decision in this Docket that under the NRS and NAC: (1) A determination of positive net benefits is the exclusive and determinative factor to determine that a NWA is the "preferred solution" and that NV Energy is required to propose the NWA pursuant to NAC 704.9237(3)(c), and (2) NVE cannot own any of the DERs utilized to relieve the grid constraints or otherwise satisfy any other requirement of a DRP. (Ex. 1300 at 5.)

142. Vote Solar asserts that, pursuant to NAC 704.9237(3)(c), both wired utility infrastructure and NWAs are subject to the same requirement that the utility recommend them only if they are the preferred solution, which Vote Solar asserts is a determination made exclusively on the LNBA. (Ex. 1300 at 17.) Vote Solar further asserts that, based on the regulation, a net positive LNBA is determinative that a NWA is the preferred solution and NV Energy is required to recommend it. (Ex. 1300 at 17-18.)

NV Energy's Rebuttal

143. NV Energy states that it disagrees with Vote Solar's assertion that NV Energy's NWA process outlined in DRP-Figure 11 constitutes an extra-legal process and is in violation of NAC 704.9237(3)(c). (Ex. 163 at 6, 40-41.) NV Energy asserts that under its interpretation, the regulation refers to circumstances in which NV Energy has determined that an NWA solution is the preferred solution, and reiterates its position stated in the DRP narrative that "[a] positive preliminary financial result from the NWA Screening Analysis Tool should not be interpreted as a final determination…that an NWA solution is the preferred solution to an identified constraint." (Ex. 163 at 40.)

144. NV Energy further asserts that Vote Solar adds the word "exclusively" to support Vote Solar's interpretation of NAC 704.9237 in its testimony, while this language is not present

in the regulation. (Ex. 163 at 41.) NV Energy further states that it believes that the language of the regulation stating "[s]uch recommendations must be based on the locational net benefit analysis" does not preclude the process in DRP-Figure 11, which it asserts is a proper internal due diligence process, and then updating the analysis towards a final determination. (Ex. 163 at 40-41.) NV Energy further states that under its interpretation of NAC 704.9237(3)(c), the recommended preferred solution to an identified constraint should be based upon an analysis that contains local costs and benefits, not just system level ones, i.e. an LNBA, and that the language stating "on the basis of the analysis in the grid needs assessment" is meant to convey that NV Energy should not recommend a solution that does not show itself to be a cost-effective one. (Ex. 163 at 40-41.)

Commission Discussion and Findings

145. The Commission finds that NV Energy has complied with NAC 704.9237(3)(c). The Commission finds that this regulation refers to circumstances in which NV Energy has determined that an NWA solution is the preferred solution, and highlights NV Energy's position that "[a] positive preliminary financial result from the NWA Screening Analysis Tool should not be interpreted as a final determination… that an NWA solution is the preferred solution to an identified constraint."

146. The Commission finds that Vote Solar adds the word "exclusively" to support Vote Solar's interpretation of NAC 704.9237 in its testimony, while this language is not present in the regulation. The Commission's interpretation of NAC 704.9237(3)(c) is that the recommended preferred solution to an identified constraint should be based upon an analysis that contains local costs and benefits, not just system-level, i.e. an LNBA, and that the language stating "on the basis of the analysis in the grid needs assessment" is meant to convey that NV Energy should not recommend a solution that is not cost-effective.

M. NWA Waiver Requests

NV Energy's Position

147. NV Energy requests that the Commission waive the requirements of NAC 704.9237(2)(f) and NAC 704.9237(3)(b). (Ex. 152 at 9; Ex. 117 at 302-303.)

148. NV Energy states that, as to NAC 704.9237(2)(f), it used the latest available forecasts to determine constraints on the transmission and distribution systems, but all DER types as defined in NAC 704.90583 are not yet represented in the forecasts. (Ex. 117 at 302.) NV Energy further states that it has disaggregated system-level private solar PV and EV forecasts down to substation and feeder levels. (Ex. 117 at 302.) NV Energy asserts that E3 produced geolocational forecasts for DERS at the census block level, and NV Energy incorporated some of this data into the NWA analyses. (Ex. 117 at 302.) NV Energy asserts that it will include the Forecasting Anywhere results for all DER types into its planning, forecasting, and analyses associated with the DRP as appropriate over the next year to close the compliance gap ahead of the September 1, 2025 DRP update. (Ex. 117 at 302.)

149. NV Energy states, as to NAC 704.9237(3)(b), it concluded that any contingencies analyzed would need to be limited in scope to ensure that the analysis could be completed, particularly due to the timelines of NV Energy's monthly update and annual full-system updates. (Ex. 117 at 303.) NV Energy further states that it will continue to investigate how other utilities may be approaching this issue and assess whether other techniques may be applied to ensure than the analytical process would not be made impracticable by adding contingency conditions. (Ex. 117 at 303.)

Vote Solar's Position

150. Vote Solar asserts that NV Energy has not demonstrated that it is unable to produce a forecast of net distribution system loads and has hired E3 to project geospatial DER

growth which was able to disaggregate the forecast to individual circuits and substations. (Ex. 1300 at 48.) Vote Solar asserts that NV Energy has, nonetheless, only allocated the DER adoption forecast to distribution circuits for one year (2034) outside of the required forecast period. (Ex. 1300 at 48.)

151. Vote Solar disagrees with NV Energy's assertion that delaying net forecasts does not impact its DRP analysis and asserts that the failure to provide a net forecast overstates loads and distribution system needs. (Ex. 1300 at 49.) Vote Solar further asserts that NV Energy has identified more distribution system capital investments and on a shorter timeline than would be needed, based on loads net of DERs. (Ex. 1300 at 49.)

Staff's Position

152. Staff does not object to the requested waivers of NAC 704.9237(2)(f) and NAC 704.9236(3)(b), and notes that the Commission reviewed and approved similar waivers in consolidated Docket Nos. 21-06001 and 21-06002. (Ex. 302 at 3-4.) Staff states that NV Energy has provided adequate justification to waive the requirements of NAC 704.9237(2)(f) and NAC 704.9236(3)(b) for this IRP. (Ex. 302 at 4.)

153. Staff further states, however, that it recommends the Commission issue a directive to ensure continued compliance with NRS 704.741(5)(a), requiring all future DRP related filings by NV Energy to include an examination of potential quantification or monetization of safety benefits within its LNBA to be compliant with NRS 704.741(5)(a). (Ex. 302 at 4.)

NV Energy's Rebuttal

154. NV Energy responds that the DRP as filed was not based upon the distributed resource forecasts at the required levels of the distribution system, and therefore any load

forecasts of distributed feeders and substation transformers could not be based upon net load forecasts.

155. NV Energy notes that Staff recommends the Commission find the DRP meets the requirements of NRS 704.741 and approve NV Energy's requested waivers of NAC 704.9237(2)(f) and NAC 704.9237(3)(b) as adequately justified. (Ex. 163 at 10.)

156. NV Energy reiterates that it plans to close this compliance gap as to NAC 704.9237(2)(f) ahead of the September 1, 2025 DRP update. (Ex. 163 at 15 citing Ex. 117 at 303.)

Commission Discussion and Findings

157. The Commission finds it reasonable and not contrary to the public interest to waive the requirements of NAC 704.9237(2)(f) and NAC 704.9237(3)(b). The Commission notes that it reviewed and approved similar waivers in consolidated Docket Nos. 21-06001 and 21-06002. The Commission finds that NV Energy has provided adequate justification to waive the requirements of NAC 704.9237(2)(f) and NAC 704.9236(3)(b) for this IRP. As to NAC 704.9237(2)(f), the Commission finds that NV Energy used the latest available forecasts to determine constraints on the transmission and distribution systems, but all DER types as defined in NAC 704.90583 are not yet represented in the forecasts. NV Energy has disaggregated system-level private solar PV and EV forecasts down to substation and feeder levels. E3 produced geolocational forecasts for DERS at the census block level, and NV Energy incorporated some of this data into the NWA analyses. The Commission notes that NV Energy asserts that it will include the Forecasting Anywhere results for all DER types into its planning, forecasting, and analyses associated with the DRP as appropriate over the next year to close the compliance gap ahead of the September 1, 2025 DRP update. (Ex. 117 at 302.)

158. As to NAC 704.9237(3)(b), the Commission finds that any contingencies analyzed would need to be limited in scope to ensure that the analysis could be completed, particularly due to the timelines of NV Energy's monthly update and annual full-system updates. The Commission notes that NV Energy will continue to investigate how other utilities may be approaching this issue and assess whether other techniques may be applied to ensure that the analytical process would not be made impracticable by adding contingency conditions.

159. The Commission directs NV Energy to ensure continued compliance with NRS 704.741(5)(a), requiring all future DRP-related filings by NV Energy to include an examination of potential quantification or monetization of safety benefits within its LNBA to be compliant with NRS 704.741(5)(a).

N. Transportation Electrification Plan ("TEP") Programs/Requests

NV Energy's Position

160. NV Energy includes the TEP as Section 10 of the DRP. (Ex. 117 at Section 10; Ex. 149 at 3, 23-33; Ex. 151 at 2-7.) NV Energy states that the TEP is included as required by SB 448 (2021), which created and outlined certain requirements for the TEP and provided for the TEP's inclusion in the DRP. (Ex. 149 at 23.)

161. NV Energy states that the TEP proposes a portfolio of Managed Charging programs for both Residential and Non-Residential customers focused on educating customers about the importance of moving EV charging to times of high renewable energy production and lower overall energy demand, managing customer charging and its impact to the electrical grid, advancing existing transportation programs and tariffs, and improving the program design for future plans. (Ex. 149 at 25.) NV Energy states that it anticipates issuing 40 Managed Charging events based on projected grid conditions and as needed during emergencies. (Ex. 149 at 27.) NV Energy asserts that the 2025-2027 Managed Charging program of the TEP includes the

Single Family Residential Managed Charging Build ("Residential"), the Qualified Income Multifamily Managed Charging Build ("Multifamily"), the Fleet Managed Charging Build ("Fleet") the Workplace Managed Charging Build ("Workplace"), and Managed Charging Manage. (Ex. 149 at 29-31; Ex. 101 at 269-286.)

162. NV Energy states that the Education Services proposed in the TEP are intended to better inform customers regarding the value of shifting vehicle charging to maximize the grid (i.e. "when charging matters") and increase awareness of transportation electrification benefits, programs, and services, while increasing program participation. (Ex. 149 at 27; Ex. 101 at 249-257.)

163. NV Energy states that it proposes a program development program to test products and services for potential inclusion in future offerings which will be focused on residential, small, medium and large commercial customers for both NPC and SPPC. (Ex. 149 at 28; Ex. 101 at 259-268.) NV Energy further states that it proposes three pilots within the program development program, the Residential EV time-of-use ("TOU") Sub-Metering pilot, the Vehicle to X pilot, and the Vehicle Telematics Managed Charging pilot. (Ex. 149 at 28; Ex. 101 at 261-264.)

164. NV Energy states that the TEP proposes, and funds, continued efforts to expand programs, as well as proposes various new pilot programs. (Ex. 117 at 241; Ex. 149 at 3.) NV Energy further states that a budget of $150,000 has been set aside to support planning, analysis, and consulting support to continue pursuit of federal grant applications with $50,000 earmarked for this purpose for each plan year. (Ex. 117 at 260.)

SWEEP's Position

165. SWEEP recommends that the Commission approve NV Energy's TEP with modifications because the proposal aligns with statutory criteria and it will accomplish the goals

of ratepayers saving money and reducing pollution in Nevada, in addition to benefiting the state's economy. (Ex. 1600 at 7, 12-13.) SWEEP states it does have some concerns about the proposed TEP, such as: 1) can NV Energy keep up with infrastructure needs and make sure that owning and operating an EV is at least as convenient and practical as a conventional vehicle; 2) how will NV Energy maximize the benefits of the transition to electric transportation for all customers; and 3) will low-to-moderate-income customers be left behind; therefore, SWEEP proposes twelve modifications to improve NV Energy's TEP to be approved by the Commission. (Ex. 1600 7-9.)

166. SWEEP requests that the Commission direct NV Energy to carry over the unspent 2024 budget, approximately $40 million, from the current Economic Recovery Transportation Electrification Plan ("ERTEP") and TEP, to support the proposed TEP's highway corridor and hub public charging projects, and school bus and public fleet electrification beyond 2024, otherwise these programs will expire at the end of the year and leave customers hanging. (Ex. 1600 at 7, 46-47.) SWEEP notes that the proposed TEP is not extending the current ERTEP and TEP; however, it would extend the Transit Electrification Grant program, which allocates limited funds to help customers seek out federal grants and extends the electric school bus V2G tariff through 2027. (Ex. 1600 at 43.) SWEEP states that despite NV Energy's current ERTEP and TEP expiring at the end of 2024, it does not appear these programs are currently on track to meet NV Energy's objectives before the end of the year. (Ex. 1600 at 43-44.)

167. SWEEP recommends that the Commission direct NV Energy, per NRS 704.7867 2(e), to include education about EV-charging and associated TOU rates in its TEP, which would increase customer awareness that driving EVs can save them money. (Ex. 1600 at 7.) SWEEP states that the Education Services and Grants portion of NV Energy's proposed plan does align

with the statute; however, SWEEP notes that the proposal could still do a better job about educating customers on the benefits of transportation electrification and opportunities to save money. (Ex. 1600 at 26.)

168. SWEEP recommends that the Commission direct NV Energy to implement a system-wide EV-charging management system that can make active managed charging a full-time activity, such as the "WeaveGrid" platform that can automatically optimize charging schedules at both the grid and distribution levels. (Ex. 1600 at 8.)

169. SWEEP recommends the Commission direct NV Energy to improve the Residential Managed Charging program by changing the current requirement language that a "customer must possess one qualifying charger per EV" to "customer must possess *at least* one qualifying charger per EV" because the current language implies multiple chargers for multiple EVs, and one family with two or more EVs could easily share a single residential charger. (Ex. 1600 at 8.)

170. SWEEP states that another way to improve the Residential Managed Charging program is to allow customers to participate with a qualifying charger and/or a vehicle that is capable of directly communicating with the charging management platform because this would have the capability to automatically assign ratepayers' vehicles to an opt-out charging window based on anticipated grid-wide conditions and anticipate conditions within a particular ratepayer's corner of the distribution grid. (Ex. 1600 at 8, 49.)

171. SWEEP recommends that the Commission direct NV Energy to clarify the eligibility for customers who take home a rented work EV as a transportation-network-company ("TNC") driver, such as Lyft's ExpressDrive program, because this would better improve the

Residential Managed Charging program as a result of many TNCs having aggressive electrification targets. (Ex. 1600 at 51.)

172. SWEEP recommends that the Commission direct NV Energy to improve the Income-Qualified Multifamily Managed Charging program because SWEEP states it is essential to help make EVs more accessible for income-qualified customers, so they are not left behind on energy savings. (Ex. 1600 at 8-9.) SWEEP explains that NV Energy should increase the size of the make-ready infrastructure installation incentive to the lesser of $20,000 or the actual cost per Level 2 charging port, and the incentive for income-qualified customers should be inclusive of both wiring and charger costs, because SWEEP further explains that even though these incentives might not cover 100 percent of building-owner costs, a more generous offering will be more effective at driving participation up; and thereby, increasing underserved community access to the use of electricity as a transportation fuel. (Ex. 1600 at 53.)

173. SWEEP requests that the Commission direct NV Energy to investigate and pilot options increasing underserved community and low-income customer access to low-cost public charging, perhaps through discounted rates or preloaded cards. (Ex. 1600 at 53.)

174. SWEEP recommends that the Commission direct NV Energy to adjust the minimum project size requirements in the Income-Qualified Multifamily Managed Charging program to help ensure that all residences have an option to participate. (Ex. 1600 at 45, 54.) SWEEP explains that the terms listed in the filing require "a minimum of six [...] dual port Level 2" chargers, which implies at least 12 ports per project. (Ex. 1600 at 54.) SWEEP states that 12 ports per project would limit participation and states that the minimum project size should be reduced to one dual-port charger. (Ex. 1600 at 54.)

175. SWEEP also recommends that the Commission direct NV Energy to allow multi-family buildings with two to four units to participate if they do not otherwise qualify for the Single-Family Residential Managed Charging proposal to improve the Income-Qualified Multifamily Managed Charging program and further ensure that all residences have an option to participate. (Ex. 1600 at 54.)

176. SWEEP recommends that the Commission direct NV Energy to modify its budget for the Income-Qualified Multifamily Managed Charging program to $14 Million, which would accommodate SWEEP's modifications to the program, including the infrastructure incentive of up to $20,000 per port and NV Energy's original forecast for participation in terms of number of new ports installed. (Ex. 1600 at 9, 55.) SWEEP explains that $14 million will make the more robust program viable and effective. (Ex. 1600 at 55.)

177. SWEEP recommends that the Commission direct NV Energy to improve the Fleet and Workplace Managed Charging program by eliminating the minimum and maximum number of ports a fleet depot or workplace must have to participate because the participation of smaller and larger fleets and workplaces in managed charging efforts will add to the overall ratepayer and public value of the programs. (Ex. 1600 at 8.)

United's Position

178. United recommends that the Commission approve NV Energy's TEP in its entirety, with some modifications. (Ex. 1500 at 3-4.) United explains one of the modifications is that the Commission should reject NV Energy's scaled-back TEP proposal because it is currently insufficient in comparison to NV Energy's prior TEP filings. (Ex. 1500 at 5, 7.) United notes that NV Energy is proposing a total budget of $19,233,000 for transportation electrification programs and investments during the 2025-2027 program years, yet NV Energy's previous two TEP filings' proposed budgets were $348,450,914 and $329,217,914. (Ex. 1500 at 5-6.) United

also disagrees with NV Energy spending $7,385,000 of its total proposed budget on educational services because United states it is important that significant portions of the TEP budget directly go towards building out NV Energy's programs and smaller portions should be delegated to educational services. (Ex. 1500 at 7.) United states that for the Commission to address these concerns, it should direct NV Energy to expand both its Managed Charging and Vehicle-to-X pilot programs. (Ex. 1500 at 7.)

179. United recommends that the Commission direct NV Energy to expand its Vehicle-to-X budget and make the following modifications to its TEP regarding the Vehicle-to-X pilot: 1) increase NV Energy's budget for the Vehicle-to-X pilot by $280,000; 2) broaden the eligibility criteria for the Vehicle-to-X pilot to include multifamily customers; and 3) produce a subsequent filing for stakeholder and Commission review by April 1, 2025. (Ex. 1500 at 4.) United explains that the current proposed budget for the pilot is insufficient because $70,000 allocated over three years will not result in a successful pilot program. (Ex. 1500 at 17.) United states that NV Energy's subsequent filing that United proposes should include additional information to inform the design of the Vehicle-to-X pilot, such as the number of customers NV Energy plans to enroll, the start and end date of the pilot, the proposed incentive structure for participating customers, and NV Energy's plan for submitting a study evaluating the pilot, which should include recommendations for the design of the pilot moving forward. (Ex. 1500 at 4.)

BCP's Position

180. BCP requests that the Commission direct NV Energy to implement periodic status updates for the School Bus Tariff program, which NV Energy has asked for an extension until 2027, because while BCP does not oppose extending the program until 2027 it has concerns on

whether NV Energy will receive adequate interest in this program to support continuing it beyond 2027. (Ex. 400 at 11.)

181. BCP recommends that the Commission deny the $3.511 million for federal grants because of a lack of specifics for this program. (Ex. 400 at 10.) BCP does not oppose NV Energy obtaining federal grants, BCP opposes the Commission approving costs that should be expensed in obtaining these federal grants. (Ex. 400 at 10.) BCP states that if NV Energy wants to request approval of the costs of this program, then it should do so in a future rate case once a grant is obtained and the NV Energy's costs for obtaining these grants are determined. (Ex. 400 at 10-11.)

Staff's Position

182. Staff recommends that the Commission approve the following programs: Technical Advisory Services, Technology Driven Enhancements, Federal Funding Opportunities, program development pilots, Transit Electrification Grants, and Rate Impact Cost Recovery Expenses. (Ex. 301 at 1.)

183. Staff states that the Technical Advisory Services provides NV Energy's customers with direct access to its TEP resources and will provide personalized assistance to unique customer needs which cannot be addressed by the transportation electrification call center. (Ex. 301 at 4.) Staff further states that the Technical Advisory Services will assist customers understand the technical requirements for program participation and access online tools which will be relevant to novel pilots and programs proposed in the TEP. (Ex. 301 at 4.)

184. Staff states that the Technology Driven Enhancements consists of both EV Identification and EV TOU Education and Outreach. (Ex. 301 at 4.) Staff further states that EV Identification will identify EV charging loads, residential charging locations, and hourly charging patterns, which will enable a full territory view of charging. (Ex. 301 at 4.) Staff states

that EV TOU Education and Outreach is designed specifically to move EV owners to TOU rates and provide coaching on the rate. (Ex. 301 at 4-5.) Staff asserts that these technologies will help close the gap between general EV drivers and those EV drivers who understand the effects EV charging behavior may have on the grid. (Ex. 301 at 5.)

185. Staff states that it supports NV Energy's request to pursue Federal Funding Opportunities because, while there is a nominal cost for assistance with grant applications, any outside funding that NV Energy secures will reduce the Plan's cost to ratepayers. (Ex. 301 at 5.)

186. Staff states that it supports the three Program Development Pilots proposed by NV Energy. (Ex. 301 at 5-6.) Specifically, Staff identifies (1) residential EV TOU sub-metering, (2) Residential Vehicle to X, and (3) vehicle telematics managed charging. (Ex. 301 at 5-6.) Staff asserts that pilot programs are a fiscally measured approach to gauge customer interest and gather data which may be used to develop large-scale programs that provide tangible benefits. (Ex. 301 at 6.) Staff states that it agrees with NV Energy that accurate use of EV-specific rates requires utility smart meters to disaggregate EV charging loads from whole-home loads, and developments in this area will be important for EV grid integration, load forecasting and load management. (Ex. 301 at 6.)

187. Staff states that it agrees with NV Energy that the Transit Electrification Grants program will allow eligible organizations to optimize both NV Energy programs and other funding sources while maximizing the benefits of transportation electrification, particularly within historically underserved communities. (Ex. 301 at 7.) Staff notes that electrifying public transportation provides a means for all NV Energy customers to participate in the TEP. (Ex. 301 at 7.)

188. Staff asserts that the Joint Application does not include information explaining what is entailed in the Rate Impact, Cost Recovery Expenses request. (Ex. 301 at 7.) Staff states, however, that NV Energy clarified in discovery that this item is for the cost of studies to be utilized for future TEPs. (Ex. 301 at 7-8.) Staff further states that while no specific study is presently contemplated, reserving a nominal budget will enable NV Energy to perform studies relating to the assessment and implementation of future transportation electrification pilots, programs, and/or tariffs. (Ex. 301 at 8.)

189. Staff recommends that the Commission modify the Community Based Partnerships/Educational Events ("CBP/EE") and Marketing and Customer Outreach ("MCO") to narrow the scope of its education, and as a compliance, order NV Energy to file the results of the EV Load Identification – Technology ("EV Identification") analysis and customer surveys upon completion, if the EV Identification analysis is approved. (Ex. 301 at 1.)

190. Staff states that the education budget for the CBP/EE and MCO should be tailored to educate customers about the importance of shifting EV charging times to times of high renewable energy production and lower overall energy demand consistent with the message "when charging matters." (Ex. 301 at 10.) Staff asserts that education focused on this message will help EV-driving ratepayers use additional per kilowatt-hour ("kWh") caused by their EV adoption in a manner that is less taxing on NV Energy's resources or the grid. (Ex. 301 at 10.) Staff further states that if the Commission is inclined to accept Staff's recommendation that the CBP/EE and MCO programs be refocused, then NV Energy should modify its marketing tools accordingly and Staff will review the digital, print, and direct messaging and TEP costs in the appropriate GRC for compliance. (Ex. 301 at 11.)

191. Staff notes that NV Energy plans to identify prospective participants via the EV Identification program and customer surveys to determine which low-income customers and customers residing in historically underserved communities may be eligible. (Ex. 301 at 12-13.)

192. Staff states that to ensure NV Energy has followed through with its stated plan to identify ratepayers who currently drive EVs, or intend to purchase or lease an EV in the next 36 months, the Commission should order, as a compliance item, that NV Energy file with the Commission the results of its EV Identification program, if approved, and the results of the completed lower-income and high usage charge ("HUC") customer surveys. (Ex. 301 at 14.)

193. Staff recommends that the Commission modify the Dealer Partnership Program to narrow the scope of its education and remove the webinar-related components. (Ex. 301 at 2.) Staff states that the Dealer Partnership program is overly broad and is not focused on the message of "when charging matters" or educating prospective car owners/leasers of NV Energy's EV programs and tariffs. (Ex. 301 at 15.) Staff further states that the program will provide duplicative information to dealerships using ratepayer funds, and that it is unclear why ratepayers should shoulder the burden to ease the EV-buying experience, especially for those who do not reside in NV Energy's service territories. (Ex. 301 at 15.) Staff recommends that the Dealer Partnership program's educational materials contain only information regarding NV Energy's EV programs and tariffs and how to enroll, education on "when charging matters", and the availability of NV Energy's online EV tools. (Ex. 301 at 16.) Staff states that the informational webinars NV Energy proposes a dealer must attend before enrolling in the Dealer Partnership program are unnecessary given Staff's recommendation that the scope of information be narrowed. (Ex. 301 at 16.) Staff asserts that any dealer with a question about NV Energy's available EV programs and tariffs will have a direct contact to NV Energy via the dedicated

phone and email hotline for dealers which NV Energy has requested, and Staff recommends approving. (Ex. 301 at 16-17.) Staff further asserts that eliminating the webinar requirement will cause there to be no specific dealerships for NV Energy to promote. (Ex. 301 at 17.) Staff therefore recommends that the Commission approve only the budget line items related to developing educational materials and the creation and maintenance of a dedicated email and telephone hotline for dealerships. (Ex. 301 at 17.)

194. Staff recommends that the Commission approve the Outside Services Ramp Up, if one or both of the Residential and Multifamily programs are approved. (Ex. 301 at 2.) Staff states that while no information was included in the Joint Application regarding the Outside Services Ramp Up budget line item, NV Energy responded to a data request that this item is a placeholder for engineering and IT services it will need to integrate the managed charging elements into the current demand response management system, prepare systems for data collection and implementation, and prepare reporting structures for the program. (Ex. 301 at 31.) Staff further states that NV Energy has represented that these costs will primarily be focused on the Residential and Multifamily programs and will be managed internally. (Ex. 301 at 31; Attachment KRO-21.) Staff further states that this budget will be reduced if either the Residential or Multifamily programs are not approved. (Ex. 301 at 32; Attachment KRO-22.)

195. Staff recommends that the Commission approve the proposed revisions to Schedule No. ESB-V2G, Electric School Bus Vehicle-to-Grid Trial, and tariffs. (Ex. 302 at 2.) Staff notes that the previous versions of the ESB-V2G tariffs are set to expire on December 1, 2024, but due to ongoing work with Nevada school districts, an extension of the V2G trial is necessary. (Ex. 302 at 10.) Staff recognizes that NV Energy proposes a new completion date of

December 31, 2027, and states that it does not identify any concerns with NV Energy's request to extend the date of the SPPC and NPC Schedule No. ESB-V2G tariffs. (Ex. 302 at 10.)

NV Energy's Rebuttal

196. NV Energy responds that the TEP is a foundation to support the transition to increased transportation electrification through managed customer charging which was proposed to meet the statutory requirements and goals of SB 448. (Ex. 158 at 3-4.) NV Energy states that while some parties have proposed modifications to the TEP, the TEP is not intended to meet every need or use case. (Ex. 158 at 4.) NV Energy further states that it is unable to address each suggestion or comment raised by the parties in the rebuttal time and does not agree to any items it may have failed to specifically address. (Ex. 158 at 4.) NV Energy reiterates that it requests the Commission approve the TEP as filed. (Ex. 158 at 4.)

197. NV Energy further states that it has not proposed extending the ERTEP or current TEP program as part of its current proposal, which programs are still active for reservations through 2024 with expected infrastructure in place in 2024 and 2025 and disagrees with SWEEP that these programs should be extended. (Ex. 158 at 14.) NV Energy states that it has made progress in the ERTEP with a projected spend across all programs of $14,765,713 through 2025. (Ex. 158 at 14.) NV Energy further states that under the previously approved TEP two sites have been reserved for the Interstate Corridor program and three additional school districts have signed agreements for 11 DCFC bi-directional ports with projected spend for the previous TEP of $12,209,716 through 2025. (Ex. 158 at 15.) NV Energy asserts that it will provide updates on all TEP portfolio elements, and additional updates are therefore unnecessary. (Ex. 158 at 15.)

198. NV Energy states that the educational focus of the Dealer Partnership Program will be consistent with the objectives of educating customers of the benefits of "when charging matters" and enrollment in programs, and that it has suggested webinars to educate dealers

because webinars have a farther reach at a lower cost than many in-person sessions, offer greater flexibility, and can be recorded for later use. (Ex. 158 at 19-20.)

199. NV Energy states that the full Outside Services Ramp Up budget of $150,000 should be approved. (Ex. 158 at 30.) NV Energy asserts that the budget will not be reduced significantly if any of the TEP programs, with the exception of the Residential program, are not approved because it is a placeholder for engineering and IT services which NV Energy will need to integrate into current operations and systems. (Ex. 158 at 30.)

200. NV Energy states that the budgets for Program Development pilot programs were created as a foundation for future TEP plan designs and that it does not see a need to modify the budget at this time. (Ex. 158 at 30.)

201. NV Energy denies that the $3.5 million dollars requested for transportation electrification grant costs would be expensed in obtaining federal grants, as it understands BCP to allege. (Ex. 158 at 20-21.) NV Energy states that it is not seeking federal dollars to fund this program but would instead fund the $3.5 million in grants over the Action Plan period itself to provide financial support to Nevada transit agencies for deployment of EV infrastructure and electrification. (Ex. 158 at 20-21.)

202. NV Energy clarifies that it has included $50,000 per year in the proposed TEP budget for outside services that may be required for grant concept papers and full grant applications, which may also be used to support program research and various administrative costs. (Ex. 158 at 21.)

Commission Discussion and Findings

203. First, the Commission declines to adopt SWEEP's request to carry over the unspent 2024 budget, approximately $40 million, from the current ERTEP and TEP. These

programs are set to expire at the end of the year. Furthermore, NV Energy's current TEP proposal does not extend the current ERTEP and TEP.

204. Second, the Commission approves the TEP based on Staff's analysis and recommendations. The Commission approves the following programs: Technical Advisory Services, Technology Driven Enhancements, Federal Funding Opportunities, program development pilots, Transit Electrification Grants, and Rate Impact Cost Recovery Expenses.

205. The Commission finds that the Technical Advisory Services provide NV Energy's customers with direct access to its transportation electrification program resources and will provide personalized assistance to unique customer needs which cannot be addressed by the transportation electrification call center. The Commission finds that the Technical Advisory Services will assist customers in understanding the technical requirements for program participation and accessing online tools which will be relevant to novel pilots and programs proposed in the TEP.

206. The Commission notes that the Technology Driven Enhancements consists of both EV Identification and EV TOU Education and Outreach. The Commission finds that the EV Identification will identify EV charging loads, residential charging locations, and hourly charging patterns, which will enable a full territory view of charging. The Commission finds that EV TOU Education and Outreach is designed specifically to move EV owners to TOU rates and provide coaching on the rate. The Commission agrees with Staff that these technologies will help close the gap between general EV drivers and those EV drivers who understand the effects that EV charging behavior may have on the grid.

207. The Commission approves NV Energy's request to pursue Federal Funding Opportunities because, while there is a nominal cost for assistance with grant applications, any outside funding that NV Energy secures will reduce the plan's cost to ratepayers.

208. The Commission approves the three program development pilots proposed by NV Energy. Specifically, the Commission approves the (1) residential EV TOU sub-metering, (2) Residential Vehicle to X, and (3) vehicle telematics managed charging. The Commission finds that these pilot programs are a fiscally measured approach to gauge customer interest and gather data that may be used to develop large-scale programs that provide tangible benefits. Accurate use of EV-specific rates requires utility smart meters to disaggregate EV charging loads from whole-home loads, and developments in this area will be important for EV grid integration, load forecasting, and load management.

209. The Commission finds that the Transit Electrification Grants program will allow eligible organizations to optimize both NV Energy programs and other funding sources while maximizing the benefits of transportation electrification, particularly within historically underserved communities. The Commission agrees with Staff that electrifying public transportation provides a means for all NV Energy customers to participate in the TEP programs.

210. The Commission agrees with Staff that the Joint Application does not include information explaining what is entailed in the Rate Impact, Cost Recovery Expenses request. However, NV Energy clarified in discovery that this item is for the cost of studies to be utilized for future TEPs. The Commission agrees with Staff that, while no specific study is presently contemplated, reserving a nominal budget will enable NV Energy to perform studies relating to the assessment and implementation of future transportation electrification pilots, programs, and/or tariffs.

211. The Commission modifies the Community Based Partnerships/Educational Events ("CBP/EE") and Marketing and Customer Outreach ("MCO") to narrow the scope of its education, and as a compliance, orders NV Energy to file the results of the EV Identification analysis and customer surveys upon completion. The Commission finds that the education budget for the CBP/EE and MCO should be tailored to educate customers about the importance of shifting EV charging times to times of high renewable energy production and lower overall energy demand consistent with the message "when charging matters." NV Energy shall modify its marketing tools accordingly, and Staff will review the digital, print, and direct messaging and TEP costs in the appropriate GRC for compliance.

212. To ensure that NV Energy has followed through with its stated plan to identify ratepayers who currently drive EVs or intend to purchase or lease an EV in the next 36 months, the Commission orders as a compliance item that NV Energy file the results of its EV Identification program, and the results of the lower-income and HUC customer surveys, with the Commission upon completion.

213. The Commission modifies the Dealer Partnership Program to narrow the scope of its education and remove the webinar-related components. The Commission agrees with Staff that the Dealer Partnership Program is overly broad and is not focused on the message of "when charging matters" or educating prospective car owners/lessors of NV Energy's EV programs and tariffs. The Commission further finds that the program will provide duplicative information to dealerships using ratepayer funds, and that it is unclear why ratepayers should shoulder the burden to ease the EV buying experience, especially for those who do not reside in NV Energy's service territories. The Commission finds that the Dealer Partnership Program educational materials shall contain only information regarding NV Energy's EV programs and tariffs and

how to enroll, education on "when charging matters," and the availability of NV Energy's online EV tools.

214. The Commission approves the Outside Services Ramp Up. The Commission agrees with Staff that while no information was included in the Joint Application regarding the Outside Services Ramp Up budget line item, NV Energy responded to a data request that this item is a placeholder for engineering and IT services that it will need to integrate the managed charging elements into the current demand response management system, prepare systems for data collection and implementation, and prepare reporting structures for the program. NV Energy has represented that these costs will primarily be focused on the Residential and Multifamily programs and will be managed internally. The Commission finds that the budget for the Outside Services Ramp Up shall be reduced because the Commission approves only the Residential and not the Multifamily programs (discussed in the section below).

215. The Commission approves the proposed revisions to Schedule No. ESB-V2G, Electric School Bus Vehicle-to-Grid Trial, and tariffs. The previous versions of the ESB-V2G tariffs are set to expire on December 1, 2024, but due to ongoing work with Nevada school districts, the Commission finds that an extension of the V2G trial is necessary. The Commission approves NV Energy's proposed new completion date of December 31, 2027.

216. Finally, per SWEEP's recommendation, the Commission directs NV Energy to improve the Residential Managed Charging program by changing the current requirement language to "customer must possess at least one qualifying charger per EV" because the current language implies multiple chargers for multiple EVs, and one family with two or more EVs could easily share a single residential charger. Also per SWEEP's recommendation, the Commission directs NV Energy to update the Residential Managed Charging program to allow

customers to participate with a qualifying charger and/or a vehicle that is capable of directly communicating with the charging management platform because this would have the capability to automatically assign ratepayers' vehicles to an opt-out charging window based on anticipated grid-wide conditions and anticipate conditions within a particular ratepayer's corner of the distribution grid. The Commission also directs NV Energy to make readily available on its website information regarding what chargers and models of chargers qualify to meet the charging management platform and to make a clear distinction of any chargers and models of chargers that do not qualify to meet the charging management platform.

O. Managed Charging Program Regulatory Asset

NV Energy's Position

217. NV Energy states that it seeks approval to create a regulatory asset, with carrying charges, to capture the TEP costs incurred before and between future rate cases which it proposes will be recorded in the service territory in which the work is performed or allocated. (Ex. 149 at 32; Ex. 117 at 287-291.)

BCP's Position

218. BCP recommends the cost for the TEP programs be accounted for in the normal ratemaking process rather than have a regulatory asset because this would constitute single-issue ratemaking. (Ex. 400 at 5, 6.)

Staff's Position

219. Staff states that NV Energy generally requests regulatory asset treatment with carry charges for the costs of the 2025-2027 TEP and identifies total budgeted TEP costs of approximately $19.2 million. (Ex. 300 at 2.) Staff states that it identified inconsistencies in NV Energy's rate impact figures due to value differences in TEP Tables 31 and 32 which expressed

values in cents per kWh rather than dollars per kWh, and that these errors were corrected in the September 19, 2024, errata. (Ex. 300 at 2.)

220. Staff asserts that there is nothing about the TEP which differentiates it from any other utility project that is completed and placed into service during the normal course of business. (Ex. 300 at 2.) Staff states that, based on discovery responses, it believes depreciation expense and routine O&M expenses related to the personnel required to operate the program and expenses for public awareness and education would be included in the proposed regulatory asset. (Ex. 300 at 3.)

221. Staff states that NV Energy should maintain its plant property and equipment ("PP&E") in a manner that it can tolerate variations in load, therefore a mere upgrade or addition is no different from installing any other piece of revenue-generating equipment even if the PP&E is dedicated to EV charging. (Ex. 300 at 3.) Staff further states that the utility gains the benefits of increased load from the TEP between rate cases, which is not used to offset any of its request for the regulatory asset and results in asymmetrical treatment. (Ex. 300 at 3-4.)

222. Staff asserts that there is nothing abnormal about depreciation or O&M costs being recorded by a utility during or before a test year that will not be recovered as part of the base rates in an upcoming GRC, and these expenses do not earn a ROR when included in the revenue requirement during a GRC. (Ex. 300 at 6.) Staff further states that if the Commission were to allow the requests costs to be recovered from ratepayers via a regulatory asset, this process would provide a benefit to the utility through the avoidance of regulatory lag and adding carrying charges in addition to this benefit would be unreasonable. (Ex. 300 at 6.) Staff estimates that the total requested carrying charges could amount to $2,099,555 (NPC $1,516,175 and SPPC $583,380). (Ex. 300 at 7-9, Brownrigg Attachment JAB-3.)

223. Staff also states that NV Energy was denied its request for regulatory asset carry charges for TEP costs in Docket 22-09006 and notes its concern that negative publicity of the slow spending in the program execution may spur NV Energy to ramp up its TEP spending, in which case denying regulatory asset treatment and imposing regulatory lag on NV Energy may encourage cost-effective spending. (Ex. 300 at 8-9.)

224. Staff recommends that the Commission reject NV Energy's request to establish a regulatory asset to record the costs of the 2025-2027 TEP with carrying charges, but states that if the Commission decides to grant the request for regulatory asset treatment then Staff recommends that carry charges not be approved, and any incremental revenues should be treated as a regulatory liability (offset) to any approved regulatory asset (granted with or without carrying charges). (Ex. 300 at 1, 9.)

NV Energy's Rebuttal

225. NV Energy responds that it disagrees with Staff and BCP's position that TEP costs are no different than normal utility costs incurred through the normal course of business. (Ex. 165 at 22-26.)

226. NV Energy states that the TEP costs at issue would not be incurred but for the need to implement SB 448 (2021), and asserts that SB 448 (2021) would not have been necessary if NV Energy's normal course of business was to accelerate transportation electrification. (Ex. 165 at 22.) Rather, NV Energy states that it will incur investments above the normal course of business to comply with the statute. (Ex. 165 at 22-23.)

227. NV Energy asserts that Staff's statement that NV Energy's analysis of the benefits, costs, and rate impacts was inadequate is not supported by evidence. (Ex. 165 at 23.) NV Energy states that it has supported the regulatory asset treatment request and made the

request in this filing rather than setting cost recovery for SB 448 costs in regulations in compliance with the Commission's order in Docket No. 21-06036. (Ex. 165 at 23.)

228. NV Energy states that it has not requested approval for any capital costs associated with the TEP, as no fixed asset investments are requested. (Ex. 165 at 24.) NV Energy states that it does, however, request regulatory asset recovery of the incremental costs that will be incurred for the TEP that would otherwise be recorded as operation, maintenance, administrative, and general ("OMAG"). (Ex. 165 at 24.) NV Energy explains that regulatory asset treatment for incremental OMAG costs is appropriate because costs associated with customer education, participation incentives and advisory services related to SB 448 are not currently included in the revenue requirement for NPC or SPPC, are incremental to the normal course of business, and such treatment will allow the Commission to review the costs for prudency before recovery is allowed. (Ex. 165 at 25.)

229. NV Energy states that Staff's suggestion that NV Energy will benefit from regulatory lag by collecting additional revenue due to load growth and that this additional revenue should offset any regulatory asset is unclear. (Ex. 165 at 25.) NV Energy questions how, under Staff's proposal, incremental revenue would be determined and what part of the current rates would be used to calculate the incremental revenues since the costs at issue were not included in the revenue requirements for NPC or SPPC. (Ex. 165 at 25.)

230. NV Energy states that the Commission should allow carry charges to be calculated on the deferred TEP OMAG costs to allow NV Energy to recover the time value of money paid for these costs before recovery in an eventual GRC. (Ex. 165 at 26.) NV Energy asserts that Staff ignores that a level of OMAG that allows NV Energy to earn the allowed ROR

is established in a GRC and compliance with SB 448 will require NV Energy to incur additional OMAG costs above the anticipated level during the rate effective period. (Ex. 165 at 26.)

231. NV Energy asserts that Staff's recommendation that carry charges do not apply if NV Energy's earned ROR exceed the authorized ROR is not necessary because NV Energy's Earnings Sharing Mechanisms will share excess earnings with customers. (Ex. 165 at 26.) However, NV Energy acknowledges that it can implement this recommendation if the Commission so orders. (Ex. 165 at 26.)

232. NV Energy asserts that it has presented evidence supporting its TEP requests which demonstrates that regulatory asset treatment would mitigate credit impacts and that such regulatory asset treatment, which was denied in Docket No. 22-09006, is now justified because SPPC's credit rating was downgraded in May 2024. (Ex. 165 at 27.)

233. NV Energy denies that its request for regulatory asset treatment constitutes single issue ratemaking as asserted by BCP based on that portion of the Commission's Order in Docket No. 13-12040 which states that any interested party can petition the Commission to establish a regulatory asset/liability as opposed to waiting for a GRC. (Ex. 165 at 27.)

Commission Discussion and Findings

234. The Commission finds that there is nothing about the TEP which differentiates it from any other utility project that is completed and placed into service during the normal course of business. The Commission finds that NV Energy should maintain its PP&E in a manner that it can tolerate variations in load; therefore, a mere upgrade or addition is no different from installing any other piece of revenue-generating equipment even if the PP&E is dedicated to EV charging. Furthermore, the utility gains the benefits of increased load from the TEP between rate

cases, which is not used to offset any of its request for the regulatory asset and results in asymmetrical treatment.

235. The Commission finds that there is nothing abnormal about depreciation or OMAG costs being recorded by a utility during or before a test year that will not be recovered as part of the base rates in an upcoming GRC, and these expenses do not earn a ROR when included in the revenue requirement during a GRC. The Commission finds that if the Commission were to allow the costs to be recovered from ratepayers via a regulatory asset, this process would provide a benefit to the utility through the avoidance of regulatory lag, and adding carrying charges in addition to this benefit would be unreasonable. For all of these reasons, the Commission denies NV Energy's request for a regulatory asset account to record the costs of the 2025-2027 TEP with carrying charges.

236. The Commission notes that it denied NV Energy's request for regulatory asset carry charges for TEP costs in Docket No. 22-09006, and in that docket the Commission noted its concern that negative publicity of the slow spending in the program execution may spur NV Energy to ramp up its TEP spending, in which case denying regulatory asset treatment and imposing regulatory lag on NV Energy may encourage cost-effective spending.

P. Managed Charging Programs

NV Energy's Position

237. NV Energy asserts that the 2025-2027 Managed Charging program of the TEP includes the Single Family Residential Managed Charging Build ("Residential"), the Qualified Income Multifamily Managed Charging Build ("Multifamily"), the Fleet Managed Charging Build ("Fleet") the Workplace Managed Charging Build ("Workplace"), and Managed Charging. (Ex. 149 at 29-31; Ex. 101 at 269-286.)

///

United's Position

238. United recommends that the Commission direct NV Energy to significantly expand its managed charging programs, as a cost-effective pathway to achieve greater demand reduction and to accelerate transportation electrification in Nevada, by making the following modifications to its TEP managed charging programs: 1) increasing NV Energy's demand reduction target for its Managed Charging Program to 53-MW; 2) increasing NV Energy's budget for its Managed Charging Program by approximately $16 million overall; and 3) expanding the managed charging program to include a Multifamily Charging Infrastructure Build Program in addition to the proposed Qualified Income Multifamily Charging Infrastructure Build Program. (Ex. 1500 at 4.) United explains that the Commission should approve an increase to NV Energy's budget for the managed charging programs, including a $4 million budget for the Multifamily Charging Infrastructure Build program and a $4 million budget for the Qualified Income Multifamily Charging Infrastructure Build program because the current proposed budgets are insufficient to achieve greater demand reduction and to accelerate transportation electrification in Nevada. (Ex. 1500 at 4.)

WRA and Sierra Club's Position

239. WRA and Sierra Club recommend that the Commission require NV Energy to make several modifications to its managed charging programs. (Ex. 1200 at 4.) To elaborate, WRA and Sierra Club recommend that the Commission direct NV Energy to 1) Share all available metrics on TOU load shifting in a future proceeding concerning TOU hours; 2) Consider how an active managed charging pilot program and updated EV recharge rider ("EVRR") TOU hours can shift charging into low-cost, high-renewable hours in a future TOU docket; 3) Modify managed charging programs so that notifications of events are delivered to any driver who is plugged in and allows drivers participating in all programs to override events;

and 4) Establish a minimum managed charging participation period of 12 months rather than the 36 months proposed by NV Energy. (Ex. 1200 at 6.)

240. WRA and Sierra Club recommend that the Commission require NV Energy to provide all available metrics on the TOU load shifting in a future proceeding involving TOU hours. (Ex. 1200 at 6.)

241. WRA and Sierra Club recommend that the Commission require NV Energy to explore an active managed charging pilot program and updated EVRR TOU hours, to encourage shifting charging into low-cost, high-renewable hours in a future TOU docket. (Ex. 1200 at 6.) WRA and Sierra Club state that the EVRR TOU rate should offer foundational price signals by providing variable rates during the most affordable hours for EV charging. (Ex. 1200 at 33.)

242. WRA and Sierra Club argue that NV Energy's proposed throttling of charging does not maximize reductions in charging demand. (Ex. 1200 at 34.) WRA and Sierra Club state that NV Energy's approach could potentially result in a 10 percent decrease in charging demand, with the most ambitious scenario suggesting a reduction of up to 50 percent. (Ex. 1200 at 37.)

243. WRA and Sierra Club recommend that the Commission require NV Energy to revise its managed charging programs to ensure that all drivers who are plugged in receive notifications about events and that all participants can override these events. (Ex. 1200 at 36.) WRA and Sierra Club argue that NV Energy's proposed Qualified Income Multifamily Charging Infrastructure Build Program and Workplace Managed Charging Build Program do not effectively reduce demand or enhance customer experience. (Ex. 1200 at 36.) WRA and Sierra Club state that the Qualified Income Multifamily Charging Infrastructure Build Program fails to provide any incentives for drivers to participate in managed charging events, as it allows drivers to override events without any penalty, while the electric account holder benefits from bill

credits for participation. (Ex. 1200 at 37.) WRA and Sierra Club state that the Workplace Managed Charging Build Program does not offer an opt out option for managed charging events, which means that an EV driver charging at their workplace might not achieve the required charge due to such an event. (Ex. 1200 at 37.)

244. WRA and Sierra Club recommend that the Commission require NV Energy to change its minimum participation period for managed charging from 36 months to 12 months. (Ex. 1200 at 38.) WRA and Sierra Club state that a 36-month minimum commitment may discourage customers who are new to managed charging programs. (Ex. 1200 at 38.)

Staff's Position

245. Staff states that it agrees with NV Energy that improving the system load factor by moving EV charging to off-peak and to times when renewable generation is significant will be critical as EV adoption grows. (Ex. 301 at 22.) Staff asserts that the Fleet program provides an opportunity to test the effectiveness of the managed charging program design due to a limited number of decision makers involved in the process and effective targeting of the "when charging matters" message to fleet drivers as well as effective notification of managed charging event times to fleet drivers. (Ex. 301 at 22.) Staff therefore recommends that the Commission approve the Fleet program as filed. (Ex. 301 at 22.)

246. Staff states that proposed $250 enrollment incentive amount for new equipment customers in the Residential program be reduced to $100 to match the enrollment incentive to bring your own charger ("BYOC") participants. (Ex. 301 at 23.) Staff further states that because not every available charger may be compatible with a managed charging program, the higher enrollment incentive may be seen as enticement for EV drivers to purchase capable chargers to these EV drivers may participate in the Residential program or future managed charging

programs but would be wasted on those who would willingly procure the required chargers without the higher enrollment incentive. (Ex. 301 at 23-24.) Staff also notes the lack of data showing that the $150 proposed by NV Energy is the amount needed to entice new customers to purchase the necessary charging technology. (Ex. 301 at 24.) Staff therefore recommends that the Commission approve the $100 enrollment incentives for both the BYOC participants and new equipment participants and a $500 enrollment inventive for eligible, income qualified participants and participants residing in historically underserved communities. (Ex. 301 at 24.) Staff states that its recommendation reduces the three-year Residential program budget to $2,154,000. (Ex. 301 at 24.)

247. Staff states that it is unclear whether or how the performance payments identified within the proposed Multifamily program paid to the property owner could be passed through to residents or participating EV drivers. (Ex. 301 at 25 citing attachment KRO-15.) Staff states that even if the property owner were inclined to pass through the performance payment, it is unclear how the property owner could identify which EV was connected during a managed charging event, and for how long, to properly compensate the EV driver. (Ex. 301 at 25-26.) Staff further states that since the proposed performance payment is a bill credit it is also unclear how the property owner would pass through the payment to the EV driver. (Ex. 301 at 26.)

248. Staff asserts that the Multifamily program is unlikely to build awareness of managed charging and educate customers of the importance of shifting EV charging times because any forewarning of a managed charging program, educational information, and performance payments would be directed to the property owner as opposed to the EV driver. (Ex. 301 at 26.) Staff states that without meeting the managed charging objective of educating EV drivers and encouraging behavior modification, this program is more akin to a make-ready

and charging infrastructure rebate program, which Staff states would be ineffective to encourage EV drivers to modify behavior based on "when charging matters." (Ex. 301 at 26-27.) Staff therefore recommends that the Commission deny the Multifamily program. (Ex. 301 at 28.)

249. Staff states that, similar to the Multifamily program, notifications, announcements, education, and participation payments under the Workplace program are directed to the building owner/entity who pays the electric bill as opposed to the EV driver being asked to change their charging behavior. (Ex. 301 at 29.) Staff further notes that the Workplace program does not provide an option to override managed charging events, which removes the disincentive of a program participant losing their annual participation payment by overriding such events. (Ex. 301 at 30.) Staff therefore recommends that the Commission deny the Workplace program, but notes that if the Commission approves the Workplace program, then the Commission should not include annual participation payments. (Ex. 301 at 30.)

250. Staff states that the Managed Charging Manage program's budget is dependent on which of the proposed managed charging-build programs are approved, and therefore if the Commission approves one or more managed charging-build programs Staff recommends that the corresponding costs be approved based on the need to maintain the program over time. (Ex. 301 at 31.) Staff further states that if the Commission denies the Multifamily and Workplace programs, then Staff recommends approving the Managed Charging Manage program with a three-year budget of $1,100,000 which is the Managed Charging Manage cost for only the Residential and Fleet programs. (Ex. 301 at 31.)

NV Energy's Rebuttal

251. NV Energy notes that it selected throttling over curtailing and delaying because throttling allows for a better customer service experience and flexibility for both the customer

and the utility without eliminating the option for total curtailment via a throttling to zero percent in cases of extreme need or emergency. (Ex. 158 at 24.)

252. As to the Residential program, NV Energy responds that a resident must have an EV registered to the premises to be eligible, and that it does not propose to incentivize chargers that do not have an equivalent EV to charge. (Ex. 158 at 25.) That is, if a residence has one EV, but applies for two chargers, the second charger will not be eligible. (Ex. 158 at 25.)

253. NV Energy asserts that the Multifamily program should be approved because this portion of the population requires support to move into the EV space and small targets allow for a program that may develop and expand moving forward. (Ex. 158 at 25.) NV Energy states that it is able to adjust the incentive structure for the Multifamily program based on the challenge to the owner of a multifamily owner to be held to a performance metric over which the owner has no control. (Ex. 158 at 26.) NV Energy states that it is possible to eliminate the performance incentive to the owner while still allowing the driver to opt out of the program, which would allow the owner to still receive the enrollment incentive an provide charging options to drivers. (Ex. 158 at 26.) NV Energy provides revised budgets in the event these participation payments are removed. (Ex. 158 at 26, Ex. Grant-Rebuttal-1.) NV Energy states that it is not agreeable to increase the size of the make-ready infrastructure incentive, which it states it believes is adequate to accomplish the program goals. (Ex. 158 at 27.) NV Energy states that buildings with two-to-four units do not fit the multifamily definition but is open to case-by-case review if this requirement hinders participation. (Ex. 158 at 27.)

254. As to the Workplace program, NV Energy states that it disagrees with Staff's recommendation that the Workplace program be denied because this program is a valuable opportunity to engage customers who can charge at work, thus shifting the potential peak load to

the morning hours when excess renewable energy is available. (Ex. 158 at 28.) NV Energy states that it has provided a revised budget for this program designed to eliminate the performance incentive to the owner while allowing drivers to opt out such that the owner will receive the enrollment incentive while drivers will have access to vehicle charging equipment at their workplaces. (Ex. 158 at 29, Exhibit Grant-Rebuttal-1.)

255. NV Energy states that the Managed Charging ("MC") program is designed to coincide with the approved programs for Residential, Qualified Income Multifamily, Fleet, and Workplace, and the MC program budget should therefore be established to provide maintenance and customer service to all approved program participants. (Ex. 158 at 29.)

Commission Discussion and Findings

256. The Commission approves the Fleet program as filed. The Commission finds that the Fleet program provides an opportunity to test the effectiveness of the MC program design due to a limited number of decision-makers involved in the process and effective targeting of the "when charging matters" message to fleet drivers as well as effective notification of managed charging event times to fleet drivers.

257. The Commission approves the Residential program as modified by Staff. The Commission modifies the proposed $250 enrollment incentive amount for new equipment customers in the Residential program to $100 to match the enrollment incentive to BYOC participants. The Commission modifies the enrollment incentive due to a lack of data showing that the amount proposed by NV Energy is the amount needed to entice new customers to purchase the necessary charging technology.

258. The Commission approves the $100 enrollment incentives for both the BYOC participants and new equipment participants and the $500 enrollment inventive for eligible, income-qualified participants and participants residing in historically underserved communities.

259. The Commission denies the Multifamily program at this time. It is unclear to the Commission whether or how the performance payments identified within the proposed Multifamily program paid to the property owner could be passed through to residents or participating EV drivers. The Commission agrees with Staff that even if the property owner were inclined to pass through the performance payment, it is unclear how the property owner could identify which EV was connected during a managed charging event, and for how long, to properly compensate the EV driver. Because the proposed performance payment is a bill credit, it is also unclear how the property owner would pass through the payment to the EV driver.

260. The Commission agrees with Staff that the Multifamily program is unlikely to build awareness of managed charging and educate customers of the importance of shifting EV charging times because any forewarning of a managed charging program, educational information, and performance payments would be directed to the property owner as opposed to the EV driver.

261. The Commission denies the Workplace program at this time. The Commission finds that, similar to the Multifamily program, notifications, announcements, education, and participation payments under the Workplace program are directed to the building owner/entity who pays the electric bill as opposed to the EV driver being asked to change charging behavior. The Commission agrees with Staff that the Workplace program does not provide an option to override managed charging events, which removes the disincentive of a program participant losing an annual participation payment by overriding such events.

262. The Commission notes that the Managed Charging Manage program's budget is dependent on which of the proposed managed charging-build programs are approved. Because the Commission denies the Multifamily and Workplace programs, the Commission approves the

Managed Charging Manage program with a three-year budget of $1,100,000 which is the Managed Charging Manage cost for only the Residential and Fleet programs.

Q. Estimated Demand Based Allowance ("EDBA") Adjustment

NV Energy's Position

263. NV Energy proposes to modify the upfront allowances for EV projects or projects that include EV charging. (Ex. 151 at 3.) Specifically, NV Energy proposes to apply EDBA percentages to 100 percent for EV projects to allow full up-front allowances to remove the cost barrier to EV charging infrastructure and promote development. (Ex. 151 at 5-7.)

WRA and Sierra Club's Position

264. WRA and Sierra Club state that the EDBA Adjustment modification proposed by NV Energy disallows charging stations which charge customers for charging from receiving 100 percent of the EBDA Adjustment upfront through the Rule 9 Allowance Adjustment. (Ex. 1200 at 30.) WRA and Sierra Club assert that will cause public direct current fast charging ("DCFC") and Level 2 chargers to be ineligible unless they dispense free electricity. (Ex. 1200 at 30.) WRA and Sierra Club assert that the EDBA Adjustment is ineffective to discourage the deployment of charging infrastructure and additional incentive programs are necessary. (Ex. 1200 at 30.)

BCP's Position

265. BCP opposes NV Energy's proposed charging subsidy and allowance mechanism for commercial class customers because BCP states that the subsidies are a marketing program to promote the use of EVs and that it is not the Commission's domain to promote the usage of commercial EVs, unless it involves a demand-side program. (Ex. 400 at 3-4.) BCP notes that the Commission has historically not allowed recovery for marketing of gas or electric appliances, which in BCP's opinion EVs fall under. (Ex. 400 at 4.) BCP states it does not support subsidies

or costs for marketing of EVs that low-income ratepayers are forced to pay to subsidize the upper income class, since EVs are mostly owned by upper middle class and not low-income ratepayers. (Ex. 400 at 4.) BCP provides that the commercial EV industry is currently adequately supporting the Nevada economy demand. (Ex. 400 at 4.)

Staff's Position

266. Staff states that NV Energy proposes to update the EDBA to a 100 percent up-front allowance for all commercial customers who install EV charging infrastructure. (Ex. 302 at 11.) Staff states that under the proposed EDBA change, customers will be eligible for the allowance if the EV charging equipment is separately metered, customers must enroll in the EVRR TOU rate (General Service EV Recharge Rider ("OGS-EVRR-TOU") or the EV Commercial Charging Rider ("EVCCR-TOU"), and customers must participate in a Managed Charging Program. (Ex. 302 at 11.) Staff notes that customers cannot charge drivers additional fees for vehicle charging and the EV charging equipment cannot be served by on-site generation. (Ex. 302 at 11.) Staff states that the EDBA update is reasonable because it will likely eliminate the capital cost barriers to installing EV chargers and recommends the Commission approve the proposed EDBA update. (Ex. 302 at 11.) Staff recommends that the Commission approve the proposed revisions to proposed EDBA change. (Ex. 302 at 2.)

NV Energy's Rebuttal

267. NV Energy notes that Staff recommends approval of the proposed EDBA Adjustment and states that WRA does not appear to directly reject the proposed EDBA Adjustment, but instead seeks to supplement the EDBA Adjustment with incentive programs for charging infrastructure. (Ex. 162 at 3.) NV Energy states that it disagrees with WRA's use of the word "supplement" because Rule 9 does not accommodate programs or incentives and NV Energy is, therefore, opposed to modify Rule 9 to promote such initiatives. (Ex. 162 at 4.) NV

Energy further states, however, that it does not disagree that additional incentives or broader incentive eligibility would accelerate charging infrastructure deployment but asserts that its own proposal best balances incentivizing deployment and managing costs to customers. (Ex. 162 at 4.)

268. NV Energy denies that the proposed EDBA Adjustment is a subsidy, as asserted by BCP, because a subsidy implies a financial aid that distorts the market by favoring one group of customers over another, while the proposed adjustment is an upfront payment that NV Energy would have invested over time. (Ex. 162 at 5.) NV Energy further asserts that the adjustment is in line with SB 448 because it is designed to balance the need for infrastructure development with overall costs to all customers. (Ex. 162 at 5-6.)

Commission Discussion and Findings

269. The Commission approves NV Energy's update to the EDBA Adjustment to a 100 percent up-front allowance for all commercial customers who install EV charging infrastructure. The Commission finds the EDBA Adjustment update reasonable because the Adjustment will likely eliminate the capital cost barriers to installing EV chargers.

R. TEP Budget

NV Energy's Position

270. NV Energy states that the TEP budget is segmented into five categories with the following corresponding budgets: Education Services, $7,385,000; Program Development and Grants, $3,511,000; Managed Charging Programs, $7,887,000; Rate Impact and Cost Recovery, $300,000; and Outside Services, $150,000. (Ex. 149 at 24; Ex. 117 at 241-247.) NV Energy states that the budget allocation assumes maximum enrollment and participation in each of the proposed programs and, for purposes of developing the budget, NV Energy projected a budget

split between the operating utilities at a ratio of approximately 70 percent allocated to NPC and 30 percent allocated to SPPC. (Ex. 149 at 24.)

WRA and Sierra Club's Position

271. WRA and Sierra Club argue that the overall impression of the programs proposed in NV Energy's TEP is that they are poorly executed and lack consideration for the programmatic details and the needs of the customers they aim to serve. (Ex. 1200 at 28.) WRA and Sierra Club state that NV Energy should have integrated the various insights gathered from customer surveys along with its prior experience from the ERTEP, EVID, and the 2022-2024 TEP in this TEP's contents. (Ex. 1200 at 28.) WRA and Sierra Club argue that NV Energy's TEP does not align with the legislature's statutory intent for TEPs and could have been improved if NV Energy effectively integrated lessons learned from past and ongoing programs, actively engaged stakeholders early in the process, and considered customer feedback in the development of the TEP. (Ex. 1200 at 28.)

272. WRA and Sierra Club state that SB 448 mandates investor-owned utilities to submit transportation electrification plans to speed up the transition to transportation electrification. (Ex. 1200 at 11.)

273. WRA and Sierra Club recommend adopting two alternative approaches (Plan A and Plan B) for NV Energy to meet SB 448's objectives. (Ex. 1200 at 4.)

274. WRA and Sierra Club's first alternative approach, Plan A, recommends that the Commission find that NV Energy has failed to meet SB 448 and instruct NV Energy to refile a TEP with a minimum of $26.2 million to support infrastructure and incentive programs. (Ex. 1200 at 4.)

275. WRA and Sierra Club's second alternative approach, Plan B, recommends that the Commission modify NV Energy's plan by increasing its budget by $26.2 million for programs based on incentives approved in the EVID program. (Ex. 1200 at 4-6.)

BCP's Position

276. BCP recommends that the Commission deny NV Energy's requested $7,385,000 for education services, as it appears most of the money is oriented toward marketing EVs. (Ex. 400 at 6-7, 8.) BCP further recommends Commission approval of educational outreach that would educate existing EV users of the benefits of managed charging to minimize the grid costs for charging those vehicles. (Ex. 400 at 7.) BCP states that in NV Energy's program objectives, the marketing appears to be orientated to encourage the use of EVs or charging programs to the general public and not to the individuals who already own and operate EVs. (Ex. 400 at 7.) BCP opposes NV Energy's marketing because: 1) it is not in the Commission's domain to promote EV usage unless it involves a DSM program; 2) EV marketing subsidies or costs that are recouped from low-income ratepayers; and 3) the EV-industry marketing efforts are already well represented by the EV community; and therefore, Nevada ratepayers should not have to bear the burden of paying costs for the electric utility marketing of these vehicles. (Ex. 400 at 8.) BCP states that the Commission should therefore direct NV Energy to design and implement an educational outreach program for managed charging that is specific to the existing users of EVs because this would eliminate the need for any EV marketing costs. (Ex. 400 at 9.)

Staff's Position

277. Staff recommends various TEP program modifications (discussed in detail above), which have corresponding budget ramifications. (Ex. 301 at 1-2.) Staff lists its proposed budget as follows:

Programs/Requests	NVE Proposed 3-Yr Budget	Staff Modified 3-Yr Budget
Education Services and Grants	**$ 7,385,000**	**$ 7,190,000**
Community Based Partnerships/Educational Events	$ 1,100,000	$ 1,100,000
Marketing and Customer Outreach	$ 1,850,000	$ 1,850,000
Technical Advisory Services	$ 3,000,000	$ 3,000,000
Dealer Partnership Program	$ 300,000	$ 105,000
Technology Driven Enhancements	$ 1,135,000	$ 1,135,000
Program Development & Grants	**$ 3,511,000**	**$ 3,511,000**
Federal Funding Opportunities	$ 150,000	$ 150,000
Program Development (Pilot Programs)	$ 361,000	$ 361,000
Residential EV time of use ("TOU") Submetering Pilot	$ 76,000	$ 76,000
Residential Vehicle to X ("V2X") Pilot	$ 70,000	$ 70,000
EV Telematics Managed Charging	$ 215,000	$ 215,000
Transit Electrification Grants	$ 3,000,000	$ 3,000,000
Residential Managed Charging Build	**$ 5,599,000**	**$ 2,154,000**
Single Family Residential Managed Charging Build	$ 2,655,000	$ 2,154,000
Qualified Income Multifamily Charging Infrastructure	$ 2,944,000	$ 0
Non-Residential Managed Charging Build	**$ 755,000**	**$ 473,000**
Fleet Managed Charging Build	$ 473,000	$ 473,000
Workplace Managed Charging Build	$ 282,000	$ 0
Managed Charging – Manage	**$ 1,533,000**	**$ 1,100,000**
Rate Impact, Cost Recovery Expenses	**$ 300,000**	**$ 300,000**
Outside Services Ramp Up	**$ 150,000**	**$ 150,000**
TOTAL	**$19,233,000**	**$14,878,000**

278. Staff states that its investigation revealed several federal and state funding sources that may reduce the overall TEP budget approval request, including but not limited to, EPA's Clean School Bus program for eligible charging infrastructure in Clark County, the NCEF, and National EV Infrastructure program's award to the State of Nevada. (Ex. 302 at 14.)

279. Staff states that the proposed 70/30 percent split between NPC and SPPC is based on general customer base split and targeted customer program adoption rates for the different programs and is also based on NV Energy's DSM cost split for DSM programs for 2021, 2022, and 2023, which are in the 63 percent to 80 percent range. (Ex. 302 at 14-15.) Accordingly, Staff recommends the Commission approve the proposed 70/30 percent NPC/SPPC split. (Ex. 302 at 2, 15.)

280. Staff states that NV Energy proposes different budget contingencies for different Action Plan years and explained in response to Staff's Discovery Request ("DR") 149 that the contingency amounts are based on the total spend in a given year or based on the total project budget and are not based on a year-by-year comparison. (Ex. 302 at 15 citing Attachment GS-8.) Accordingly, Staff recommends that the Commission cap contingency amounts for each year at 10 percent of the budget for that fiscal year. (Ex. 302 at 2, 15.)

281. Staff states that NV Energy consolidated the different TEP programs' budgets based on the best data available at the time and clarified in response to Staff DR 108 that the TEP budgets are not-to-exceed amounts. (Ex. 302 at 15 citing Attachment GS-9.) Accordingly, Staff recommends that the Commission cap TEP program budgets for each program and year in the Action Plan period as not-to-exceed amounts. (Ex. 302 at 2, 15.)

282. Staff recommends that the Commission order NV Energy to include both external funding and program execution details in their future TEP approval requests and as a compliance, file the federal and state funding details as they impact the TEP budget for this Action Plan no later than 180 days after the final order in this Docket is issued. (Ex. 302 at 3, 16.) Staff's recommendation in this regard is based on the drop in forecasted EV demand, Staff's concerns regarding the difference in full approved budgetary spend and program execution in the Action Plan years, and uncertainty as to whether NV Energy will receive federal or state funding awards in the Action Plan years which might reduce the overall TEP budget. (Ex. 302 at 16.) Staff asserts that based on the magnitude of the potential awards to NV Energy, the TEP budget could be impacted significantly and therefore justifies Staff's recommended compliance item. (Ex. 302 at 17.)

283. Staff further recommends that, consistent with its recommendations regarding specific TEP programs, Staff recommends that the Commission modify each Action Plan year's TEP budget as $4.26 million, $4.60 million, $6.02 million in 2025, 2026, and 2027, respectively, with a total of $14.88 million and a 10 percent contingency cap. (Ex. 302 at 3, 17.)

NV Energy's Rebuttal

284. NV Energy responds that it does not take a position on the budgets proposed by SWEEP, United, WRA, and Staff. (Ex. 158 at 5.) NV Energy asserts that it supports the TEP as filed with a $19.2 million budget because it will serve as a foundation for comprehensive vehicle grid integration to allow for future growth while entering the managed charging space. (Ex. 158 at 5.) NV Energy notes that certain aspects of the TEP may be altered and budgets adjusted to reflect small changes but asserts that the overall portfolio was presented at an appropriate budget level. (Ex. 158 at 4-5.)

285. NV Energy states that the TEP as filed meets the guidelines of SB 448 via the proposed investments in charging infrastructure and incentives for enrollment in managed charging programs, continued funding for investments and incentives for public transit and publicly owned fleet vehicles, investments and incentives to increase use of electricity as a transportation fuel, new customer programs to encourage EV charging in a manner that supports the operation and optimal integration of transportation electrification into the electricity grid, and funding for continued customer education and outreach programs. (Ex. 158 at 6-7.)

286. NV Energy denies that the TEP does not meet the statutory standards of NRS 704.7867 and 704.746(10) as asserted by WRA. (Ex. 158 at 8.) NV Energy responds that WRA conflates the two statutory standards, stating that NRS 704.7867 lists what features a TEP "may include" while NRS 704.746(1) provides the Commission with plan evaluation criteria. (Ex. 158 at 8.) NV Energy denies that NRS 704.746(10) requires that all eight goals listed in the statute

must be met for the Commission to approve a TEP, requiring only that the TEP meet "one or more." (Ex. 158 at 9-10.) NV Energy notes that SWEEP reached the opposite conclusion of WRA. (Ex. 158 at 11.)

287. NV Energy asserts that it has not included contingency plans in the budgets for each program because the TEP is not an infrastructure and building program and a contingency budget for overruns therefore does not apply. (Ex. 158 at 13.) NV Energy asserts that the program incentives are proposed to be set per unit or per participant, will not fluctuate or vary, and are proposed not-to-exceed at the approved portfolio level. (Ex. 158 at 13.)

288. NV Energy reiterates that the top two objectives of the customer marketing, outreach and education are to build awareness and understanding of "when charging matters" and to increase enrollment in available EV programs and services. (Ex. 158 at 15-16.) NV Energy states that it has included the third objective regarding the benefits of transportation electrification to comply with NRS 704.7867(2), which requires that the TEP include "Customer education and culturally competent and linguistically appropriate outreach programs that increase awareness of investments, incentives, rate designs and programs of the type listed in paragraphs (a) to (d), inclusive, and of the benefits of transportation electrification." (Ex. 158 at 16.)

289. NV Energy states that it disagrees with BCP's contention that "most of the [marketing] money is orientated toward marketing EVs" and states that the marketing, customer engagement, education and outreach will be to inform customers of "when charging matters" and promote enrollment in the managed charging pilots and programs. (Ex. 158 at 17.)

Commission Discussion and Findings

290. First, the Commission finds that the TEP as filed meets the guidelines of SB 448 via the proposed investments in charging infrastructure and incentives for enrollment in managed

charging programs, continued funding for investments and incentives for public transit and publicly-owned fleet vehicles, investments and incentives to increase use of electricity as a transportation fuel, new customer programs to encourage EV charging in a manner that supports the operation and optimal integration of transportation electrification into the electricity grid, and funding for continued customer education and outreach programs. The Commission agrees with NV Energy that WRA conflates the two statutory standards when it states that the TEP does not meet SB 448's requirements. NRS 704.7867 lists what features a TEP "may include" while NRS 704.746(10) provides the Commission with evaluation criteria. NRS 704.746(10) does not require that all eight goals listed in the statute must be met for the Commission to approve a TEP, requiring only that the TEP meet "one or more."

291. Second, the Commission approves the TEP budgets with Staff's recommended modifications because Staff's recommendations provide the most reasonable and prudent budget amounts based on the Commission's above findings regarding the proposed components of the TEP. The Commission approves the TEP budget as outlined in Staff Witness Olesky Table 1:

Table 1. Plan Components, the Plan's Requested Budget[2] and Staff's Proposed Budget

Programs/Requests	NVE Proposed 3-Yr Budget	Staff Modified 3-Yr Budget
Education Services and Grants	**$ 7,385,000**	**$ 7,190,000**
Community Based Partnerships/Educational Events	$ 1,100,000	$ 1,100,000
Marketing and Customer Outreach	$ 1,850,000	$ 1,850,000
Technical Advisory Services	$ 3,000,000	$ 3,000,000
Dealer Partnership Program	$ 300,000	$ 105,000
Technology Driven Enhancements	$ 1,135,000	$ 1,135,000
Program Development & Grants	**$ 3,511,000**	**$ 3,511,000**
Federal Funding Opportunities	$ 150,000	$ 150,000
Program Development (Pilot Programs)	$ 361,000	$ 361,000
Residential EV time of use ("TOU") Submetering Pilot	$ 76,000	$ 76,000
Residential Vehicle to X ("V2X") Pilot	$ 70,000	$ 70,000
EV Telematics Managed Charging	$ 215,000	$ 215,000
Transit Electrification Grants	$ 3,000,000	$ 3,000,000
Residential Managed Charging Build	**$ 5,599,000**	**$ 2,154,000**
Single Family Residential Managed Charging Build	$ 2,655,000	$ 2,154,000
Qualified Income Multifamily Charging Infrastructure	$ 2,944,000	$ 0
Non-Residential Managed Charging Build	**$ 755,000**	**$ 473,000**
Fleet Managed Charging Build	$ 473,000	$ 473,000
Workplace Managed Charging Build	$ 282,000	$ 0
Managed Charging – Manage	**$ 1,533,000**	**$ 1,100,000**
Rate Impact, Cost Recovery Expenses	**$ 300,000**	**$ 300,000**
Outside Services Ramp Up	**$ 150,000**	**$ 150,000**
TOTAL	**$19,233,000**	**$14,878,000**

292. NV Energy consolidated the different TEP programs' budgets based on the best data available at the time and clarified in response to Staff DR 108 that the TEP budgets are not-to-exceed amounts. Accordingly, the Commission caps the TEP program budgets for each program and year in the Action Plan period as not-to-exceed amounts.

293. The Commission orders NV Energy to include both external funding and program execution details in its future TEP approval requests and, as a compliance, file any federal and state funding details as they impact the TEP budget for this Action Plan no later than 180 days after the date of this Order. The Commission remains concerned regarding the difference in full approved budgetary spend and program execution in the Action Plan years, and uncertainty as to whether NV Energy will receive federal or state funding awards in the Action Plan years which

might reduce the overall TEP budget. The Commission notes that NV Energy has only spent approximately five percent of the approved TEP budget in two years since the last TEP approval. The Commission further notes that grant funding may significantly affect the TEP program budgets and therefore orders NV Energy to file with the Commission external grant and funding details.

294. The Commission approves the proposed 70/30 percent split between NPC and SPPC because it is reasonable based on general customer base split and targeted customer program adoption rates for the different programs and is also based on NV Energy's DSM cost-split for DSM programs for 2021, 2022, and 2023.

S. Demand-Side Management ("DSM") Budgets

NV Energy's Position

295. NV Energy states that it has filed for NPC and SPPC a combined DSM three-year Action Plan for the program period 2025 through 2027 pursuant to NAC 704.9006, 704.9057, 704.9156, 704.934, and 704.9489. (Ex. 106 at 1; Ex. 139 at 4.) NV Energy requests the Commission approve the proposed Grid Value Portfolio as the DSM Plan. (Ex. 101 at 30.)

296. NV Energy provides the budgetary and savings targets for the proposed Grid Value Portfolio in Table DSM-1. (Ex. 106 at 4-5; Ex. 146 at 2-3, 11.) NV Energy requests that the Commission approve the proposed Grid Value Portfolio as the DSM Plan with the following budgets:

> NPC with budgets of $55.9 million, $60.7 million, and $65.3 million in 2025, 2026, and 2027, respectively; SPPC $20.2 million, $22 million, and $23.9 million in 2025, 2026, and 2027 respectively; and NV Energy combined $76.1 million, $82.7 million, and $89.2 million in 2025, 2026, and 2027, respectively.

(Ex. 101 at 30.)

///

SWEEP's Position

297. SWEEP recommends that the Commission approve combined DSM budgets of $87 million in 2025, $96 million in 2026, and $107 million in 2027 across NV Energy's two service territories, because this budget is approximately halfway between NV Energy's two portfolios. (Ex. 1601 at 4, 25.) SWEEP explains that this is a reasonable budget that will allow NV Energy to both maximize cost-effective EE while also ramping up its demand response programs, which could lead to almost $468 in net benefits for ratepayers over the three-year term. (Ex. 1601 at 25.)

298. SWEEP recommends that the Commission direct NV Energy to modify the Non-Energy Benefits Total Resource Cost Test ("nTRC") discount rate to be the federal 30-year treasury rate, currently at 4.5 percent, because the U.S. government has identified the real rate on long-term government debt as a fair approximation of a discount rate for private consumption and it is appropriate to use a discount rate that has a customer perspective. (Ex. 1601 at 4, 26.) SWEEP explains that the use of the utility Weighted Average Cost of Capital ("WACC") is the incorrect discount rate for use because this discount rate provides a time value for utility shareholders, whereas the nTRC is designed to look at benefits and costs from the perspective of the whole utility system, as well as all Nevadans through the adder. (Ex. 1601 at 34.)

WRA's Position

299. WRA recommends that the Commission approve a budget level consistent with the cost per kWh savings in 2023 and 2024. (Ex. 1202 at 4.) WRA states that NV Energy considered three different objectives when constructing its 2025-2027 DSM portfolios: Grid Value, Traditional Value, and Strategic Decarbonization. (Ex. 1202 at 7.) WRA explains that Grid Value focuses on reducing peak demand, integrating renewable energy, and minimizing demand during high marginal costs and emissions. (Ex. 1202 at 7.) WRA states that Traditional

Value focused on energy savings to fulfill NV Energy's earlier target of 1.1 percent energy savings based on retail sales. (Ex. 1202 at 7.) WRA argues that NV Energy suggests a higher annual budget than it spent in 2023 and 2024. (Ex. 1202 at 6.) WRA states that NV Energy anticipates the cost of the preferred Grid Value portfolio to be $76 million in 2025, while it was $58.5 million in 2023 and is projected to be $61 million in 2024. (Ex. 1202 at 7.)

BCP's Position

300. BCP recommends that the Commission reject NV Energy's proposed DSM plan because there are deficiencies in the plan, and as a result of these deficiencies, BCP recommends that the Commission direct NV Energy to continue DSM in 2025 at the 2024 budget levels until an amended plan can be filed for 2026 and 2027 to correct the deficiencies identified by BCP. (Ex. 401 at 2, 12.) BCP recommends that the Commission direct NV Energy to continue DSM in 2025 at the 2024 budget levels until an amended plan can be filed for 2026 and 2027 to correct the deficiencies identified by BCP. (Ex. 401 at 2, 12.)

Staff's Position

301. Staff recommends rejecting NV Energy's proposed budget increase[3] for its DSM portfolios and instead retain the approved 2024 budgets of $49,841,501 for NPC and $15,879,503 for SPPC throughout the 2025-2027 Action Plan period because of a reduction in energy savings, the inclusion of non-cost-effective programs, rate impact analyses showing rate increases, and the lack of support for the proposed budget increases. (Ex. 303 at 14, 17.)

302. Staff states that NV Energy's proposed budgets under its preferred Grid Value Portfolio represent a 12 percent increase from NPC's approved 2024 budget and a 27 percent

[3] Staff also opposes a budget increase under NV Energy's proposed alternate Traditional Portfolio, which offers the same programs as the Grid Value portfolio with additional emphasis on promoting grid-connected devices to increase DR capacity. (*See* Exhibit 303 at 10.)

increase from SPPC's approved 2024 budget. (Ex. 303 at 10.) Staff states that the proposed budget for the Grid Value portfolio represents a large increase from 2024 despite many of the programs failing to be cost-effective, with a proposed portfolio that increases average rates in most cases. (Ex. 303 at 6.) Moreover, Staff provides that the rate-impact analyses conducted by NV Energy do not support the proposed DSM portfolios as proposed because they would increase average rates in most cases. (Ex. 303 at 14.)

303. Staff states that while cost-effectiveness of each individual program is not required provided that the portfolios are cost-effective overall, a variety of programs in NPC's and SPPC's portfolios are not cost-effective. (Ex. 303 at 11.) Staff also states that given cost-effectiveness concerns, increasing the budget is not prudent and the utility should instead re-evaluate the programs that it currently offers. (Ex. 303 at 12.) Staff notes that NV Energy is not projected to spend its entire 2024 budget, has not done so in a decade, and argues that NV Energy can reach Staff's recommended savings goals, which are based on the projected 2024 savings, without increasing its Action Plan's budgets. (Ex. 303 at 12.)

NV Energy's Rebuttal

304. NV Energy notes that Staff recommends the Commission retain the approved budgets for 2024 program year through the triannual 2025 through 2027 Action Plan, and NV Energy states that the savings target should remain at NV Energy's projected 2024 end of year savings. (Ex. 161 at 3.) NV Energy further notes that BCP proposes keeping the 2024 budgets for the program year 2025 to maintain DSM program continuity with a series of working groups to determine future budget levels and savings targets for program years 2026 and 2027 to be proposed in a future IRP amendment. (Ex. 161 at 3.) NV Energy also notes that SWEEP proposes an increased portfolio budget and increased energy and demand savings targets, United recommends increasing budgets for demand response programs and certain EE programs which

will increase the overall portfolio budget, and WRA recommends EE increases which will increase the portfolio budget. (Ex. 161 at 4.)

305. NV Energy asserts that it supports the proposed Grid Value Portfolio, as filed, as the DSM plan. (Ex. 161 at 4.)

Commission Discussion and Findings

306. The Commission rejects NV Energy's proposed budget increase for its DSM portfolios and instead modifies the plan to retain the approved 2024 budgets of $49,841,501 for NPC and $15,879,503 for SPPC throughout the 2025-2027 Action Plan period (except as otherwise noted in this Order) because of a reduction in energy savings, the inclusion of non-cost-effective programs, rate-impact analyses showing rate increases, and a lack of support for the proposed budget increases.

307. The Commission finds that NV Energy's proposed budgets under its preferred Grid Value Portfolio represent a 12 percent increase from NPC's approved 2024 budget and a 27 percent increase from SPPC's approved 2024 budget. The Commission agrees with Staff that the proposed budget for the Grid Value portfolio represents a large increase from 2024 despite many of the programs failing to be cost-effective, with a proposed portfolio that increases average rates in most cases. Moreover, the Commission finds that the rate-impact analyses conducted by NV Energy do not support the proposed DSM portfolios as proposed because they would increase average rates in most cases.

308. The Commission finds that while cost-effectiveness of each individual program is not required provided that the portfolios are cost-effective overall, a variety of programs in NPC's and SPPC's portfolios are not cost-effective. Given cost-effectiveness concerns, increasing the budget is not prudent and NV Energy should instead re-evaluate the programs that it currently offers. Finally, the Commission notes that NV Energy is not projected to spend its

entire approved budget in 2024, has not done so in a decade, and can reach Staff's recommended savings goals, which are based on the projected 2024 savings, without increasing its Action Plan's budgets.

T. Energy Savings Goals/Demand Response and EE Targets

NV Energy's Position

309. NV Energy states that the current DSM plan's savings goal is to achieve an amount of energy savings equal to an average reduction of 1.1 percent of the forecasted weather normalized sales during the plan period. (Ex. 146 at 4.) NV Energy recognizes that, pursuant to NAC 704.9212(1)(b), beginning on or after January 1, 2025, the goal for energy savings is to be "established by the Commission in an order denying, approving, or modifying the most recent demand side plan." (Ex. 146 at 5.) NV Energy states that it has, therefore, presented a new approach. (Ex. 146 at 5.)

310. NV Energy states that the Grid Value Portfolio proposes an energy savings goal of 0.7 percent of forecasted retail energy sales statewide and establishes a parallel goal of approximately 175-MW of demand reduction capacity over the three-year Action Plan period via flexibly scheduled DERs. (Ex. 146 at 5.) NV Energy asserts that the energy and demand savings and opportunities presented in the Grid Value portfolio are more cost-effective and provide more net benefits to customers with a lower rate-impact than retaining the prior approach. (Ex. 146 at 5.)

311. NV Energy states that the maximum achievable potential forecast resulted in an estimated 251.1-gigawatt hours ("GWhs") (NPC) and 108.9 GWhs (SPPC) of maximum achievable EE savings potential in 2025, rising to an estimated 662.1 GWhs (NPC) and 290.0 GWhs (SPPC) in 2040. (Ex. 142 at 8.)

312. NV Energy further states that the realistically achievable forecast resulted in an estimated 231.3 GWhs and 115.8 MWs of maximum achievable EE savings and peak demand savings potential in 2025 for NPC, rising to an estimated 600.1 GWhs and 390.9 MWs in 2040. (Ex. 142 at 8.) NV Energy also states that for SPPC, the forecast resulted in an estimated 84.4 GWhs and 20.3 MWs of maximum achievable EE savings and peak demand savings potential in 2025, rising to an estimated 242.9 GWhs and 81.0 MWs in 2040. (Ex. 142 at 8.)

SWEEP's Position

313. SWEEP recommends that the Commission approve the energy savings goals of 330 GWh for the year 2025, 346 GWh for 2026, and 367 GWh for 2027 across NV Energy's two service territories because it will provide greater grid value and net benefits to ratepayers and provide energy savings goals continuity. (Ex. 1601 at 4, 22, 23.) SWEEP states that its proposed goals equate to approximately one percent of NV Energy's projected retail sales and is based on the cost to achieve savings in 2024, plus an increase to account for inflation. (Ex. 1601 at 22-23.) SWEEP explains that it used NV Energy's two portfolios and identified budgets and savings goals from each portfolio, excluding the Business Energy Services and Energy Smart Schools programs, because for these programs NV Energy is assuming 25 percent cost increases per kwh from 2024 to 2025 and beyond. (Ex. 1601 at 23.) SWEEP states typically these types of cost increases in the business sector are unreasonable and inconsistent with achievement in other jurisdictions. (Ex. 1601 at 23.)

314. Sweep states that nTRC test has been decreasing the EE values of its portfolio and states that reduced cost-effectiveness is driven by declining avoided costs because a greater percentage of load is being served by capital intensive renewable generation. (Ex. 1601 at 26-27.) Because of this SWEEP believes that these types of changes in how the system is operated result in an underestimating the value of EE. (Ex. 1601 at 27.) SWEEP also states that

assumptions and methodologies such as net-to-gross ratios, expected amount of energy and capacity savings, and incremental costs are important inputs into the cost-effectiveness analysis; and that these inputs are developed during the Evaluation, Measurement, and Verification ("EM&V") process. (Ex. 1601 at 27.) Because of the importance of the EM&V process SWEEP states that this puts a greater focus on avoided costs in developing the DSM Plan. (Ex. 1601 at 27.) SWEEP recommends that Commission direct NV Energy to work with interested members of the DSM Collaborative to take a closer look at cost-effectiveness assumptions and methodologies with the end goal being to propose consensus updates to cost-effectiveness as part of the 2025 DSM Plan. (Ex. 1601 at 28.)

United's Position

315. United recommends that the Commission direct NV Energy to significantly increase its demand-reduction targets of 319 MW by 2027 to 693 MW by 2027, instead, which reflects a combined increase of 374 MW in demand savings relative to NV Energy's proposal, to ensure NV Energy's is appropriately leveraging demand-side solutions. (Ex. 1502 at 38-39.) United provides that it recommends a demand savings target of 588 MW for demand response programs, 52 MW for EE programs, and 53 MW for EV MC programs. (Ex. 1502 at 42.) United states that by using NV Energy's Market Potential Study ("MPS") and other public data sources, it developed a four-step method to calculate a reasonable demand savings target: 1) identify initial demand response starting potential; 2) adjust demand response potential for Nevada state policy scenario; 3) adjust demand response potential for recent storage attachment rates; and 4) adjust for EV-managed charging. (Ex. 1502 at 39-41.)

WRA's Position

316. WRA recommends that the Commission approve NV Energy's overall energy savings targets consistent with a one percent incremental annual saving rate for NV Energy. (Ex.

1202 at 4.) WRA states that the Commission should instruct NV Energy to target a one percent energy savings goal from 2025 to 2027. (Ex. 1202 at 19.) WRA states that the 1.1 percent target aligns with recent historical program achievement and expresses confusion as to why NV Energy cannot reach this level of savings in the future. (Ex. 1202 at 19.) WRA states that maintaining a 1 percent savings target is essential for preserving NV Energy's current GHG emission reductions resulting from its EE programs, addressing a crucial objective identified by the stakeholders. (Ex. 1202 at 19.)

317. WRA states that NV Energy could realize one percent energy savings by reducing the acquisition cost of the Business Energy Services ("BES") and Energy Smart Schools programs to match the levels seen in 2023 and 2024. (Ex. 1202 at 19.) WRA states that if NV Energy keeps these historical costs steady for both programs through 2027, it could achieve up to 0.95 percent combined savings in 2025 and 0.93 percent combined savings in 2027, all without altering the budget of the Grid Value portfolio. (Ex. 1202 at 20.) WRA states that to achieve the remaining 0.05 percent incremental savings, the BES budget would need to increase for SPPC only, applying an escalation factor of 1.5 in 2025, 1.55 in 2026, and 1.75 in 2027. (Ex. 1202 at 20.)

318. WRA states that NV Energy employs a Grid Value portfolio, resulting in lower energy savings and higher demand savings because it is more cost-effective than the Traditional portfolio while offering greater grid advantages. (Ex. 1202 at 12.) WRA states that NV Energy's MPS indicates that achieving a 1.1 percent annual efficiency target based on retail sales will become progressively more challenging due to the increasing center load, which provides minimal EE opportunities for the utility and rising baselines because of updated codes and standards. (Ex. 1202 at 12.)

BCP's Position

319. BCP recommends that the Commission should reject NV Energy's proposed demand response and EE targets because BCP is concerned by the lack of cost-effective EE programs and demand response comprises too large of a portion of the plan. (Ex. 401 at 2, 3-4, 6.) BCP states that the overall residential EE programs are "strikingly" not cost effective, which costs approximately twice the benefits, and only the Multifamily program in NPC and the Multifamily, and Residential Codes and New Construction programs for SPPC are marginally cost effective. (Ex. 401 at 3.) BCP further states that the Energy Smart Schools program is not cost effective in SPPC and only marginally cost effective in NPC. (Ex. 401 at 3.)

320. BCP states that it has three main concerns with demand response comprising such a large portion of the DSM plan: 1) demand response savings are not as predictable or reliable as EE because demand response depends on customer behavior; 2) demand response expenditures are on-going and for EE an up-front investment is made in the more efficient device, and there are no recurring payments needed beyond that; and 3) BCP has concerns with NV Energy's NTRC calculations for the demand response programs because neither incremental measure costs or rate incentives costs are included, which means it is likely that the demand response measure costs are understated and not as cost effective as the plan assumes. (Ex. 401 at 6-7.) BCP explains that if the demand response costs are understated and not as cost effective, then this would have an immediate negative impact of needlessly burdening customers with higher rates through ineffective spending and may further harm ratepayers if future capacity needs are not avoided. (Ex. 401 at 7-8.)

321. BCP states that it was disappointed that the DSM goals working group never got around to discussing actual quantitative kW and kWh savings targets for this plan. (Ex. 401 at 8.)

BCP notes that NV Energy independently developed the numeric targets proposed in its plan. (Ex. 401 at 8.) BCP states that if residential EE is not cost effective and demand response is not as cost effective as NV Energy's current analysis shows, then it would be imprudent to set targets which increase ratepayers' costs. (Ex. 401 at 8.)

Staff's Position

322. Staff recommends that the Commission reject NV Energy's proposed energy savings goals and instead set a goal of an average of 240,700,000 kWh annual savings per Action Plan period for NPC and an average of 64,000,000 kWh annual savings per Action Plan period for SPPC. (Ex. 303 at 17.) Staff states that its proposed annual savings goals correspond with 2024 projected savings and its recommended budget levels. (Ex. 303 at 7.) Staff further states that its recommendations establish the required budgets while acknowledging that savings are harder to obtain in SPPC's service territory. (Ex. 303 at 7.) Moreover, Staff provides that a set kWh goal, instead of a goal based on a percentage of retail sales, recognizes that new load will likely be more energy efficient and provide less opportunity for savings from DSM EE programs. (Ex. 303 7-8.) Staff notes that its recommendations apply to the 2025-2027 Action Plan period and all plans thereafter until modified by the Commission (Ex. 303 at 8.)

323. Staff generally agrees with NV Energy's recommendation to reduce its energy savings goals on the basis that they are becoming less cost-effective, particularly given that the value of EE declines during times when solar energy is abundant and marginal costs are lower. (Ex. 303 at 6.) Given this, Staff supports lowering the kWh savings goals and transitioning to a portfolio that maximizes other grid benefits. (Ex. 303 at 8.) However, Staff states its concern that NV Energy did not adequately justify its proposal to reduce its kWh savings goal from the utility-specific goal of 1.1 percent of sales to 0.7 percent of statewide sales. (Ex. 303 at 2 and 6.) Staff explains that in 2023, NPC exceeded its savings goal by achieving savings of 273,408877

kWh and projects to exceed its 2024 goal with 240,691,601 kWh in savings. Staff states that NPC's proposed DSM portfolio only projects savings of 188,144,000 kWh at a greater cost. (Ex. 303 at 6.) For SPPC, Staff states that it did not meet its 2023 goals, is not projected to meet its 2024 goals, and now proposes significantly lower savings at a greater cost. (Ex. 303 at 6-7.) Given the above, Staff provides that NV Energy did not adequately explain how cost savings between NPC and SPPC's plans, which contain similar programs and measures, can decrease within such a short period of time. (Ex. 303 at 6.)

NV Energy's Rebuttal

324. NV Energy responds that while it recognizes the need for ambitious energy savings targets, the proposed Grid Value Portfolio's balanced approach addresses the changing dynamics of Nevada's power grid and growing demand for electricity. (Ex. 161 at 5.) NV Energy asserts that a strategic shift to demand-side management is merited by increasing population, more energy intensive industries, and 24-hour operations from new sectors. (Ex. 161 at 5-6.)

325. NV Energy states that maintaining the historical 1.1 percent EE target as a percentage of retail sales will become increasingly difficult due to increases to building codes and appliance standards, increased EV load, increased data center load, and the reduced avoided cost value of EE savings during non-peak times which reduces the available economic potential. (Ex. 156 at 3-4.) NV Energy explains that the addition of new efficient loads (i.e. EVs and data centers) create difficulty in achieving savings goals based on a percentage of retail sales. (Ex. 156 at 4-5.) NV Energy asserts that the Grid Value Portfolio is more cost-effective and provides higher net benefits and peak demand savings than the Traditional portfolio because it is focused on targeted energy savings and demand reductions when avoided cost savings are highest. (Ex. 156 at 6.) NV Energy further asserts that, when compared to the Traditional portfolio, the Grid

Value Portfolio generates over twice as many net benefits over the 2025-2027 plan period at 70 percent of the cost. (Ex. 156 at 6, citing Table DSM-1 and Table DSM-2.)

326. NV Energy asserts that the proposed 0.7 percent energy savings goal aligns with cost effectiveness and grid needs as Nevada transitions to higher penetration of renewable resources, which NV Energy states will enable it to not simply meet targets but also maximize benefits to customers and the grid while minimizing rate impacts. (Ex. 161 at 6.) NV Energy further asserts that it values EE and the bill savings which energy efficient technologies bring to customers as well as the importance of continuing a target for achieving EE savings in the Grid Value Portfolio. (Ex. 161 at 6.) NV Energy states, however, that it also recognizes that scheduled and dispatchable demand response reductions are also a beneficial tool in operating the grid. (Ex. 161 at 6.)

327. NV Energy responds that while it may be feasible for NV Energy to achieve the same gigawatt-hour savings generated by NV Energy's programs in 2023 and those planned for 2024 in 2025-2027, this will be increasingly difficult and costly to achieve and will produce less value for customers than the proposed Grid Value plan. (Ex. 156 at 7.) NV Energy states that this is due to the effects of increases in building codes and appliance standards, increased saturation of key EE measures, higher incremental costs for EE measures, and lower avoided cost value of non-targeted EE savings at times when clean energy is available. (Ex. 156 at 7.) NV Energy asserts that these factors limit cost-effective market potential for EE savings while, at the same time, new opportunities with connected technologies increase the potential benefits available from dispatchable DSM resources. (Ex. 156 at 7-8.)

328. NV Energy states that the EE energy savings goals for the Grid Value portfolio are lower than the realistically achievable potentials in the MPS because the Grid Value portfolio

emphasizes greater capacity and net benefits by focusing on EE programs and DSM technologies. (Ex. 156 at 8.)

Commission Discussion and Findings

329. The Commission rejects NV Energy's proposed energy savings goals and instead sets a goal of an average of 240,700,000 kWh annual savings per Action Plan period for NPC and an average of 64,000,000 kWh annual savings per Action Plan period for SPPC, as proposed by Staff. The Commission finds that the annual savings goals correspond with 2024 projected savings and its recommended budget levels. The Commission finds that a set kWh goal, instead of a goal based on a percentage of retail sales, recognizes that new load will likely be more energy-efficient and provide less opportunity for savings from DSM energy-efficiency programs. The Commission finds that the energy savings goals apply to the 2025-2027 Action Plan period and all plans thereafter until modified by the Commission.

330. The Commission supports lowering the kWh savings goals and transitioning to a portfolio that maximizes other grid benefits. However, the Commission agrees with Staff's concern that NV Energy did not adequately justify its proposal to reduce its kWh savings goal from the utility-specific goal of 1.1 percent of sales to 0.7 percent of statewide sales. As Staff notes, in 2023, NPC exceeded its savings goal by achieving savings of 273,408,877 kWh and projects to exceed its 2024 goal with 240,691,601 kWh in savings. NPC's proposed DSM portfolio only projects savings of 188,144,000 kWh at a greater cost, and SPPC did not meet its 2023 goals, is not projected to meet its 2024 goals, and now proposes significantly lower savings at a greater cost. Given the above, the Commission finds that NV Energy did not adequately explain how cost-savings between NPC's and SPPC's plans, which contain similar programs and measures, can decrease within such a short period of time.

331. The Commission agrees with the overall DSM budget and energy savings goals recommended by Staff, above, in this Order. The Commission finds that NV Energy has proposed a target demand reduction goal of 175 MW, which is not realistic or achievable based on prior experience with the demand response programs. The Commission, however, recognizes the value of demand response and setting an aspirational goal for energy demand reduction. Accordingly, the Commission directs NVE to informationally file a MW goal for demand reduction, after working in conjunction with the DSM Collaborative, on April 1, 2026, for the 2026 and 2027 summer seasons. This goal should be a consensus of what is objectively achievable with the overall budgets for NPC increased by $2,000,000 annually and SPPC increased by $1,000,000 annually specifically to meet demand response objectives in addition to Staff's recommended budget levels.

U. DSM Collaborative

NV Energy's Position

332. NV Energy states that the DSM process benefits from collaboration with participants through the DSM Collaborative, which requires NV Energy, interveners, and other interested persons to:

> Work collaboratively to develop a list of feasible projects, to determine the appropriate cost/benefit test(s), to determine the projects that should be proposed as either trial or full, to determine the appropriate amount that should be spent on demand-side projects, Staff, rebates, etc., and to discuss and resolve any such matters that the parties deem appropriate.

(Ex. 106 at 41.)

333. NV Energy states that the DSM Collaborative process seeks a reasonable consensus between intervening parties which assists NV Energy with preparing an Action Plan that is well-rounded and vetted by multiple interveners with unique perspectives. (Ex. 106 at 41.)

334. NV Energy states that it presented the proposed DSM Plan programs and incentives to the DSM Collaborative on May 22, 2024. (Ex. 144 at 13.)

SWEEP's Position

335. SWEEP recommends that the Commission direct NV Energy to work with interested members of the DSM Collaborative to take a closer look at cost-effectiveness assumptions and methodologies and propose consensus updates to cost-effectiveness as part of the 2025 DSM Update because this can help with the issue of undervaluing EE, avoided costs, and EM&V. (Ex. 1601 at 4, 28.) SWEEP states that this analysis should include a methodology to quantify the hedge benefit efficiency programs within the nTRC because the use of EE as a fixed price resource can avoid fuel and power price volatility. (Ex. 1601 at 4, 31.)

United's Position

336. United recommends that the Commission direct NV Energy to adopt new goals for its DSM Collaborative because United states that parties would benefit from more frequent and detailed updates leading up to the 2025 DSM Update. (Ex. 1501 at 17.) United explains that the Commission has rejected previous programs when NV Energy did not provide adequate information, transparency, or proper analysis to support the proposed plans, such as its 2021 IRP and inaugural TEP filed in 2022. (Ex. 1501 at 16.) United provides that NV Energy states it will implement the Ace Guru cost-effectiveness software to the DSMore software migration before the 2025 DSM Update; and therefore, parties and stakeholders will have insufficient information to thoroughly review NV Energy's forthcoming updated DSM without additional education in the interim. (Ex. 1501 at 17.)

337. United notes that it is a member of the NV Energy DSM Collaborative; however, United explains that there are weaknesses in the current process and improvements are needed, most critically stakeholders appear not to have regular access to complete draft plans and reports

or the underlying analysis; often NV Energy produces materials but does not share them with adequate time for review; and written stakeholder comments and suggestions are not regularly accepted or incorporated into drafts. (Ex. 1501 at 18.)

338. United recommends that the Commission direct NV Energy to adopt an enhanced engagement process for its DSM Collaborative because United states it is important to ensure there is broad support and compelling evidence for the DSM programs NV Energy ends up pursuing. (Ex. 1501 at 20.) United suggest that this enhanced engagement process should incorporate: 1) ensuring there is a broad understanding of cost-effectiveness and benefit-cost frameworks, inputs, and results to support shared recognition of portfolio and program value; 2) establishing informal long-term and high-level five- to six- year DSM program goals; and 3) reviewing programs and budgets for 2026 and 2027 to determine if program revisions or budget increases are warranted and would increase total ratepayer benefits. (Ex. 1501 at 18-19.)

WRA's Position

339. WRA recommends that the Commission require NV Energy to assemble a stakeholder working group to evaluate and revise the cost-effectiveness inputs and assumptions for all programs, mainly focusing on residential equipment incentives. (Ex. 1202 at 32.)

BCP's Position

340. BCP states that the Commission should require NV Energy to establish a working group to conduct a collaborative, transparent analysis with stakeholders because it could help resolve some of the current deficiencies in NV Energy's DSM plan. (Ex. 401 at 2, 12.) BCP states that NV Energy could file the new plan and targets, based on the working group analysis, according to a Commission-issued schedule. (Ex. 401 at 2.) BCP explains that for the working group to succeed there needs to be consensus around the modeling, data, and assumptions used to formulate the DSM plan. (Ex. 401 at 12.) BCP states that the working group could resolve

certain issues before new budgets and targets are proposed for 2026 and 2027, such as: 1) assess whether the current methods for evaluating DSM measures and programs accurately value EE and demand response; 2) assess whether the current methods for evaluating rate impact accurately reflect the rate impacts associated with DSM programs; and 3) propose appropriate modifications to NV Energy's current analysis to properly value DSM and assess rate impacts. (Ex. 401 at 12.) BCP provides that NV Energy would then file the working group's analysis and newly proposed 2026 and 2027 budgets to clarify and add additional context to its proposal for the Commission to make a more informed decision. (Ex. 401 at 12.)

NV Energy's Rebuttal

341. NV Energy states that it values the shared cooperation and expertise exchanged between the parties and NV Energy, but it asserts that scheduling an unreasonable number of working groups and deliverables reduces the usefulness of working groups in the planning process, especially given the number of other dockets before the Commission and NV Energy's and the intervening parties' finite resources. (Ex. 161 at 7.)

342. NV Energy states that since it and the intervening parties have participated in working groups for 18 months without consensus on a target, a single-year approval risks that the proposed DSM working group will not timely finish their discussions and NV Energy will not have approved budgets and targets for 2026 and 2027. (Ex. 161 at 8.) NV Energy further states that because it takes a minimum of six months to design, prepare, and launch a program, if working groups cannot agree and a timely amendment cannot be filed prior to July 1, 2025, new programs will be affected. (Ex. 161 at 8.)

343. NV Energy asserts that great time would be required to reconcile the parties' varied proposed alternative budgets and targets, and therefore recommends that the Commission

establish EE budgets and targets for the entire triennial Action Plan period and not deviate from this standard practice. (Ex. 161 at 8.)

Commission Discussion and Findings

344. The Commission finds that it will be beneficial for the next DSM Update for NV Energy to continue the DSM Collaborative working group to conduct a collaborative, transparent analysis with stakeholders regarding NV Energy's DSM plan going forward. The Commission orders NV Energy to work with interested stakeholders to continue to convene the DSM Collaborative and address participants' questions and concerns before the next DSM Update filed with the Commission. However, the Commission notes that intervening parties have participated in working groups for 18 months without consensus on a target, and a single-year approval risks that NV Energy will not have approved budgets and targets for 2026 and 2027. The Commission agrees with NV Energy that great time would be required to reconcile the parties' varied proposed alternative budgets and targets, and therefore the Commission approves the EE budgets and targets for the entire triennial Action Plan period and does not deviate from this standard practice except as noted for demand reduction goals as discussed in this Order.

V. Demand Response Program Structure and Incentive Model

NV Energy's Position

345. NV Energy identifies a proposed incentive structure for the Residential Demand Response Program, which includes upfront enrollment incentives, performance capacity payments, and performance energy market payments. (Ex. 106 at 221-223.) NV Energy further states that it will test and assess the proposed new incentive structure for implementation processes, payment structure, and customer satisfaction. (Ex. 106 at 222-223.) NV Energy states that it also plans to transition the Optional Load Management and Automation Services ("OLM-

AS") Tariff Rider into a grid service tariff rider, and such changes would be submitted in a separate advice letter filing at a later date. (Ex. 106 at 222.)

United's Position

346. United recommends that the Commission direct NV Energy to: 1) maintain its existing Demand Response program structure and incentive model during the 2025-2027 period, until a supplemental filling is approved by the Commission; 2) expand participation in the existing demand response program structure and incentive model to allow new types of devices, such as batteries, controllable loads, etc., as eligible participants; 3) adjust incentive levels for Build and Manage components as needed to maximize participation while maintaining cost-effectiveness because NV Energy's current proposed new demand response program structure lacks sufficient detail. (Ex. 1502 at 5.) United recommends that the Commission direct NV Energy to submit a supplemental filing, within six months, that includes additional information on its proposed changes to the Demand Response Program structure and incentive model to fully flesh out the details of NV Energy's proposed structure. (Ex. 1502 at 50.) United states the subsequent filing should include details on the target number of participants by technology types, eligibility requirements and terms of participation, methods and frequency of communication for demand response events, and incentive levels for enrollment and performance. (Ex. 1502 at 51.)

Staff's Position

347. Staff recommends that the Commission direct NV Energy to defer implementation of its proposed demand response incentive structures until the appropriate tariffs are approved by the Commission. (Ex. 303 at 17.) Staff states that new incentive structures may be necessary to increase demand response capacity; however, more analysis is needed before the new structure is implemented. (Ex. 303 at 15.) Staff provides that NV provided no details regarding how it will test and assess the new incentive residential demand response structure and

bears the burden to prove that the programs will be well-organized and successful. (Ex. 303 at 15-16.) Moreover, Staff argues that revised tariff language should be approved prior to the implementation of new incentive structures to outline how customers will be compensated for participation prior to the new incentive structures. (Ex. 303 at 16.)

NV Energy's Rebuttal

348. NV Energy notes that United recommends increasing the budgets for demand response programs by approximately 140 percent above the proposed budgets in the Grid Value Portfolio. (Ex. 159 at 4-5.) NV Energy, however, states that it stands by the demand response program submitted in the Joint Application. (Ex. 159 at 5.)

349. NV Energy does not appear to object to Staff's recommendation that the Commission direct NV Energy to defer implementation of its proposed demand response incentive structures until the appropriate tariffs are approved by the Commission.

Commission Discussion and Findings

350. The Commission directs NV Energy to defer implementation of its proposed demand response incentive structures until the appropriate tariffs are approved by the Commission. The Commission finds that new incentive structures may be necessary to increase demand response capacity; however, more analysis is needed before the new structure is implemented. NV Energy provided no details regarding how it will test and assess the new incentive residential demand response structure and bears the burden to prove that the programs will be well-organized and successful. Moreover, the Commission agrees with Staff that revised tariff language should be approved prior to the implementation of new incentive structures to outline how customers will be compensated for participation.

///

W. DSM Program Marketing

NV Energy's Position

351. NV Energy states that it will use marketing and engagement to inform and educate customers and various stakeholders about NV Energy's DSM program offerings, policies, procedures, and updates. (Ex. 106 at 63.)

BCP's Position

352. BCP recommends that the Commission require NV Energy to explicitly identify marketing strategies and costs that it intends to utilize for each program as part of the DSM plan because DSM marketing needs transparency. (Ex. 401 at 2, 11.) BCP notes that NV Energy seems amenable to greater transparency on DSM marketing, based on its responses to BCP's discovery requests in this Docket. (Ex. 401 at 11.) BCP recommends that the Commission direct NV Energy, based on its own agreement, to the following: 1) its DSM-programs' marketing will be explicitly tied to the DSM programs, designed to convey specific messages about the benefits and functionalities of the DSM programs, and not merely corporate image building or goodwill advertising; 2) it will create new DSM program specific contracts, invoicing and deliverables separate from other departments; and 3) it will provide periodic status updates to the DSM Collaborative of DSM marketing activities, including but not limited to all contracts for DSM marketing activities, tracking of all DSM marketing activities, tracking of money expended on those DSM marketing activities, and assessments of the effectiveness of the DSM marketing activities. (Ex. 401 at 11.) BCP states that it would like for all DSM advertising to include a disclaimer stating that the DSM programs are funded by ratepayers. (Ex. 401 at 11.)

NV Energy's Rebuttal

353. NV Energy responds that to meet energy savings targets set by the Commission, NV Energy must engage in marketing to create awareness of its Powershift programs, which is

best served via a multi-pronged marketing approach. (Ex. 159 at 15.) NV Energy notes that NAC 704.9523(2)(a) allows utility recovery for advertising and marketing costs of DSM programs. (Ex. 159 at 15.)

354. NV Energy states that it ensures that DSM program marketing is focused on creating explicit ties to the DSM programs and to convey specific messaging about the benefits of these programs. (Ex. 159 at 15-16.) NV Energy states that the multiple prongs of its marketing strategy, including Powershift branding, direct customer outreach, in-person education events, specific program messaging, and portfolio recognition of its programs work together to drive messaging regarding the DSM programs to the target audiences. (Ex. 159 at 16-17.) NV Energy denies that Powershift marketing will be focused on its other endeavors and identifies efforts it has taken to separate DSM marking from other branding campaigns. (Ex. 159 at 17-18.)

355. NV Energy states that the marketing/advertising spend is included within each program budget for the program with a percentage of the costs spread throughout the portfolio for Powershift brand and name recognition. (Ex. 159 at 18.) NV Energy further states that the costs for marketing/advertising are allocated to each program based on the percentage of the budget that the program represents for the overall portfolio, and such allocated costs are for the promotion of the portfolio of programs, community partnerships, and other direct promotional costs that are for more than one program. (Ex. 159 at 18.)

356. NV Energy asserts that it is not feasible to include a disclaimer on every type of DSM advertising as suggested by BCP. (Ex. 159 at 18-19.) NV Energy further states that while this disclaimer could be included on print, social media, and digital advertising, such an effort would be challenging. (Ex. 159 at 18-19). NV Energy states, however, that such a disclaimer

creates challenges for broadcast, radio, event live reads, and partnerships because the disclaimer would take away from the message and devalue the communication. (Ex. 159 at 19.)

Commission Discussion and Findings

357. The Commission approves NV Energy's proposed marketing/advertising spending included within each program budget for the program with a percentage of the costs spread throughout the portfolio for Powershift brand and name recognition at the 2024 levels. The costs for marketing/advertising are allocated to each program based on the percentage of the budget that the program represents for the overall portfolio, and such allocated costs are for the promotion of the portfolio of programs, community partnerships, and other direct promotional costs that are for more than one program. The Commission notes that NAC 704.9523(2)(a) allows a utility to recover advertising and marketing costs of DSM programs. The Commission finds that NV Energy's DSM program marketing is focused on creating explicit ties to the DSM programs and convey specific messaging about the benefits of these programs. The multiple prongs of NV Energy's marketing strategy, including Powershift branding, direct customer outreach, in-person education events, and specific program messaging, work together to drive messaging regarding the DSM programs to the target audiences.

358. The Commission directs NV Energy to include the specific detail of the market strategies in the DSM Plan Update narrative for the period covered by the update. The Commission finds that expanding this narrative in the annual filing will provide additional transparency and inform the effectiveness of market strategies in promoting the DSM programs.

359. The Commission declines to adopt BCP's proposed disclaimer because the Commission finds that it is not feasible to include a disclaimer on every type of DSM advertising as suggested by BCP.

///

X. Heat Pump Incentives/HVAC Program

NV Energy's Position

360. NV Energy states that it reevaluated heat pump water heater measures and incentives as part of the DSM Plan, which is included as part of the Residential AC and Heat Pump Program Invectives/Rebate subsection of Section 5 of the DSM Narrative (Ex. 144 at 12; Ex. 106 at 157-158.) NV Energy states that the current 2024 incentives range from $200 to $4,000, and the proposed incentives for the 2025-2027 DSM Plan period range from $365 to $4,000 depending on the high efficiency air conditioning equipment installed and expected energy savings. (Ex. 144 at 12.)

361. NV Energy proposes to separate the Residential Air Conditioning ("AC") component of the Residential AC and Heat Pumps Program into a standalone program from the Home Energy Saver program, and states that the new standalone Residential AC and Heat Pump Program will perform the same activities conducted by the Residential AC program component in 2024 with additional encouragement for the adoption of heat pumps. (Ex. 106 at 157; Ex. 149 at 2-3.) NV Energy further states that this program will maintain a mid-stream incentive model for high efficiency AC measures by providing instant rebates listed on the invoice. (Ex. 106 at 157; Ex. 149 at 2-3.)

SWEEP's Position

362. SWEEP recommends that the Commission direct NV Energy to add both a $2,500 incentive for ratepayers and a $100 incentive for contractors to the Residential Heating, Ventilation, and Air Conditioning ("HVAC") program because these incentives will better promote EE. (Ex. 1601 at 4, 35-36.) SWEEP explains that it is important for EE if NV Energy can drive cold climate heat pump sales to its SPPC ratepayers, which would provide efficient cooling as well as heating in this service territory. (Ex. 1601 at 35-36.) SWEEP states the

addition of a $100 contractor incentive for every qualifying heat pump or heat pump water heater it sells can help motivate contractors to accelerate energy efficient-unit sales and ultimately save ratepayers money on their utility bills by electrifying appliances that currently run on natural gas. (Ex. 1601 at 35.)

363. SWEEP states that, among the anomalous values it has identified in the Potential Study, the Potential Study assumes that heat pump water heaters have a market penetration of 1 percent in Nevada, yet the net-to-gross analysis applies one value of 0.74 program-wide to all retail appliances, which SWEEP asserts is inconsistent with other assumption around adoption of this technology. (Ex. 1601 at 27-28.)

WRA's Position

364. WRA recommends that the Commission require NV Energy to increase incentives for heat pumps relative to ACs, in line with Table MF-5. (Ex. 1202 at 4.) WRA states that NPC intends to offer an incentive of $1,382 per unit for heat pump and AC replacements, while SPPC plans to provide an incentive of $82 per unit for ACs and $393 per unit for heat pumps. (Ex. 1202 at 26.)

365. WRA also recommends that the Commission require NV Energy to offer a separate, larger incentive for cold-climate heat pumps of at least $2,700. (Ex. 1202 at 4.)

366. WRA recommends that the Commission approve the overall budgets for the residential AC and heat pump program in line with WRA's Table MF-7 to accommodate higher heat pump incentives and growth in the heat pump market. (Ex. 1202 at 4, 32.)

367. WRA states that NV Energy estimates a nTRC benefit-cost ratio for the AC and Heat Pump program of 0.41 to 0.43 for NPC and 0.55 to 0.56 for SPPC during the plan period. WRA states that NV Energy's methodology does not capture the environmental benefits of

efficient HVAC equipment and that the nTRC cost test does not appear to quantify emissions or pollution benefits. (Ex. 1202 at 25-26.)

368. WRA states that there is a reason to be concerned that the level of adoption for Home Energy Saver and Residential AC/Heat Pumps because on August 13, NV Energy filed a notice in Docket No. 23-06044 that NV Energy planned to suspend air conditioning and heat pump replacement measures effective of August 31, 2024, due to "exceptional participation." (Ex. 1202 at 27.) WRA states that the August 13 notice illustrates the risks of underestimating program adoption when developing targets and budgets. (Ex. 1202 at 27.) WRA also states that it is concerned that the Grid Value portfolio appears to assume that AC and heat pump participation will stagnate between 2025 and 2027. (Ex. 1202 at 27.) WRA states that given the rebates and tax credits that are available through the IRA, that it is unlikely that demand for HVAC replacement measures will decrease and that failure to plan for a higher budget could lead to a repeat of the budget issue that prompted the August 13 Notice. (Ex. 1202 at 27.)

NV Energy's Rebuttal

369. NV Energy states that it disagrees with SWEEP's statement that it is inappropriate to use the program-wide net-to-gross ("NTG") value of 0.74 for heat pump water heaters, and states that the 0.74 NTG is appropriate for heat pump water heaters or other measures with low market penetration. (Ex. 157 at 2-3.) However, NV Energy understands that this is a matter of professional judgment, and the Commission has authority to determine whether it is in the public interest to allow special NTG treatment for potentially valuable measures such as heat pump water heaters. (Ex. 157 at 2-3.)

370. NV Energy asserts that the proposed DSM Plan includes programs and measures at a level consistent with the DSM Plan's overall strategy to drive grid value optimization and allow for a more diverse set of targets at budget levels that NV Energy feels is appropriate. (Ex.

159 at 14.) NV Energy states that the details of final measures and incentive levels within each program are in progress through RFP processes, which are traditionally incorporated into programs during implementation. (Ex. 159 at 14.) NV Energy further states that it intends to continue this practice and engage stakeholders on the programs' measures and incentive levels through the DSM Collaborative as the Action Plan period progresses. (Ex. 159 at 14.)

Commission Discussion and Findings

371. The Commission adopts in part the recommendation presented by SWEEP for the HVAC program and specifically the cold climate heat pumps. The Commission acknowledges that an increased incentive for cold-climate heat pumps on a limited basis would serve to provide NV Energy and the Commission with a benchmark on whether a larger incentive would be useful in the future. Therefore, the Commission approves an incentive of $2,500 for cold-climate heat pumps in SPPC's service territory. This incentive shall be limited to an amount of 100 per year for each of the three years in the Action Plan period.

372. The Commission declines to make any other changes to the Residential HVAC program and notes that the overall DSM budget is being approved; NV Energy is responsible for implementing the programs within that overall budget in a cost-effective manner to achieve the savings goal.

Y. Large Customer Offsite DSM Program

NV Energy's Position

373. NV Energy did not request a large customer offsite DSM program in its Joint Application.

Google's Position

374. Google recommends that the Commission approve NV Energy's creation of a Large Customer Offsite DSM program upon request that the Commission require NV Energy to

collaborate with stakeholders on the contents of NV Energy's next DSM Plan amendment or update. (Ex. 500 at 3, 7.)

375. Google states that the Large Customer Offsite DSM Program allows large, fully bundled customers with a minimum peak demand of five megawatts or higher to make voluntary contributions in return for credits toward their bill. (Ex. 500 at 4.) Google states that customers who contribute will receive credit on their bill equal to the capacity savings from supported measures multiplied by the generation capacity cost portion of the base tariff generation rate over the life of the supported EE or demand response measure. (Ex. 500 at 4.) Google provides that capacity savings will be measured using NV Energy's routine EM&V process. (Ex. 500 at 5.) Google asserts that initial credits should be based on projected capacity savings from supported EE or demand response measures and are subject to the EM&V results. (Ex. 500 at 5.) Google states that following the above calculation will prevent overcompensating the contributing customers. (Ex. 500 at 5.) Google states it would like to further consult with NV Energy and stakeholders on how participating customers will convey contributions to NV Energy but suggests using a rider whose amount is specific to each participating customer, whereby the rider will collect the annual voluntary contribution based on a customer's expected usage. (Ex. 500 at 5.)

376. Google argues that the Large Customer Offsite DSM Program will benefit both customers who contribute and NV Energy itself. (Ex. 500 at 4.) Google states that customers who make voluntary contributions will receive credit on their bills. (Ex. 500 at 4.) Google states that NV Energy will benefit from customers' voluntary contributions because it will provide additional funding for its EE and demand response portfolio budgets for its DSM Plan. (Ex. 500

at 4.) Google further states that this will allow NV Energy to strengthen DSM initiatives beyond their scope to financially support existing programs. (Ex. 500 at 4.)

377. Google states that the funding from the customers' voluntary contributions should support existing program budgets instead of offsetting existing customer contributions. (Ex. 500 at 4.) Google states that it would work with NV Energy and stakeholders to identify the most impactful programs to contribute to. (Ex. 500 at 5.) Google states that this will allow NV Energy and stakeholders to invest in innovative solutions and targeted initiatives that might not align with traditional cost-benefit analyses, yet still offer substantial value and support to underserved communities. (Ex. 500 at 5-6.) Google states that this funding will also provide flexibility in funding allocation because it does not require the demonstration of standard cost-effectiveness requirements. (Ex. 500 at 5.)

NV Energy's Rebuttal

378. NV Energy responds that it supports the portfolio of programs proposed, which it asserts is informed by studies and past experience. (Ex. 159 at 13.) NV Energy further states that any modifications or proposals need to be backed by equivalent studies or data and would extend timelines for implementation. (Ex. 159 at 13.)

379. NV Energy acknowledges that Google recommends a stakeholder working group to develop details around the proposed Large Customer Offsite DSM Program, and broadly states that additional working groups are not necessary to facilitate collaboration among the interveners, Staff, BCP, and NV Energy. (Ex. 161 at 9.) NV Energy asserts that even with good-faith participation, it is not always possible to reach a consensus on all issues, and scheduling more workshops will not change this fact. (Ex. 161 at 9.) NV Energy states additional concerns with increased workshops and workshop frequency with respect to participation, workload, and the parties' resources. (Ex. 161 at 9-11).

Commission Discussion and Findings

380. The Commission declines to adopt Google's proposed Large Customer Offsite DSM Program at this time because the Commission finds that there is a lack of detail and evidentiary support in the record in this Docket. However, the Commission encourages Google, NV Energy, and any interested stakeholder to continue discussions around the proposed Large Customer Offsite DSM Program and refile any proposal for such a program, with the Commission for consideration, with additional detail and evidentiary support, in a future IRP or IRP amendment proceeding.

Z. Residential Codes and New Construction Program

NV Energy's Position

381. NV Energy states that the proposed 2023-2027 Residential Codes and New Construction Program supports the residential new construction market to increase EE of Nevada homes, benefitting residential customers through lower energy bills, increased comfort, reduced maintenance, and higher resale value. (Ex. 106 at 163; Ex. 149 at 17.) NV Energy states that the New Construction portion of this program will provide builders with education, technical assistance, and incentives to exceed building energy codes, while the Residential Codes portion of the program will provide tools to support local jurisdictions in adopting the state code and for improving energy code compliance. (Ex. 149 at 17.)

SWEEP's Position

382. SWEEP recommends that the Commission direct NV Energy to complete a refresh of the Residential Codes and New Construction program, in consultation with the DSM Collaborative, to include in the 2025 DSM Update filing because it is important for energy savings and has a lot of potential. (Ex. 1601 at 4, 37.) SWEEP explains that NV Energy is projected to only achieve 5.8 GWh in savings from this program; and yet in the MPS the annual

Realistically Achievable potential for residential new construction is over 13 GWh per year in the Nevada Power service territory alone. (Ex. 1601 at 36-37.)

NV Energy's Rebuttal

383. NV Energy states that as the efficiency level of codes and standards increases, incremental cost-effective energy savings potential available for utility DSM programs are limited because the baseline efficiency level is higher. (Ex. 156 at 3.) NV Energy further states that as population growth in Nevada increases, new residences must be built, accordingly NV Energy proposed a New Construction and Codes Program to incentivize builders to build above code so new residences are more energy efficient than minimum standards. (Ex. 159 at 11.)

Commission Discussion and Findings

384. The Commission declines to make any changes to the proposed 2025 – 2027 Residential Codes and New Construction Program. The Commission is accepting Staff's recommendation to maintain the DSM program overall budget at the 2024 levels for each year in the 2025-2027 period and is not approving specific program budgets. NV Energy's New Construction and Codes Program may fit within the approved budget level, and it is NV Energy's responsibility to implement the programs in an efficient and cost-effective manner.

AA. Measurement and Verification ("M&V") Reports

NV Energy's Position

385. NV Energy describes the M&V process in technical appendix DSM-11 and provides its M&V Reports in technical appendices DSM-12 through DSM-23. (Ex. 144 at 2, 4.)

Staff's Position

386. Staff recommends that the Commission accept the M&V reports for DSM program year 2023. (Ex. 303 at 17.)

///

Commission Discussion and Findings

387. The Commission accepts as sufficiently filed NV Energy's proposed M&V reports for DSM program year 2023 as proposed by NV Energy and recommended by Staff.

BB. MPS

NV Energy's Position

388. NV Energy states that the MPS performed by Integral Analytics, E3, and Tierra Resource Consultants ("Tierra") provided savings potential levels that informed the portfolio design of both the proposed Grid Value and the alternative Traditional portfolios. (Ex. 106 at 45.) NV Energy states that to determine forecasted potential, Tierra conducted a four-step process calculating Technical Potential, Economic Potential, Max Achievable and Realistic Potential. (Ex. 106 at 45.)

SWEEP's Position

389. SWEEP states that in its experience, DSM potential studies are too conservative in estimating the available amount of EE because potential studies 1) are a snapshot in time that assumes costs and technology will remain static during the study period, 2) regularly exclude important DSM measures, 3) screen out all measures that are not cost-effective, 4) make unreasonable assumptions about the efficiency of appliances, 5) do not adequately consider changes in customer perceptions through outreach, and 6) use payback to determine technology adoption without considering other factors that influence customer decision making. (Ex. 1601 at 14-15.) SWEEP asserts that each of the foregoing issues with potential studies, generally, effect NV Energy's Potential Study, specifically. (Ex. 1601 at 15-18.)

390. SWEEP states that, while it does not claim that NV Energy did not use a valid methodology, the flaws it has identified in the Potential Study lead SWEEP to believe that the Potential Study underestimates the amount of achievable potential because it is difficult to model

future customer behavior and technologies. (Ex. 1601 at 18.) SWEEP states that, based on the foregoing, it recommends that the Commission use the Potential Study as part of its process in approving a savings goal, but recognize that statements about "Achievable Potential" likely understate what SWEEP believes are available in the real-world. (Ex. 1601 at 18-19.)

United's Position

391. United recommends that the Commission direct NV Energy to improve its MPS because NV Energy's MPS-originated plan to dramatically limit its investment in distributed resources is based on faulty assumptions and premises. (Ex. 1502 at 23.) United notes that all MPS are a series of sequential steps to narrow down the amount of demand savings that the utility chooses to pursue, and in each step of this narrowing process, the analysts choose many assumptions, each of which can lead to more or less demand savings being identified in the final results. (Ex. 1502 at 24-25.) United states that these assumptions can significantly impact the savings pursued in the final DSM Plan, and in NV Energy's case, United explains that there are several questionable assumptions and other limitations in the MPS that result in an unreasonable and lower 2025-2027 final achievable level of demand savings. (Ex. 1502 at 25.) United explains that there are six limitations and faulty assumptions to NV Energy's MPS: 1) NV Energy's assumed technical potential for demand-side resources is based on a scenario not aligned with Nevada state policy; 2) NV Energy's assumed attachment rates for battery storage to distributed solar are too low; 3) NV Energy's assumed reduction factors used to convert economic potential to achievable potential are not reflective of real-world limitations; 4) NV Energy's MPS unnecessarily excludes significant types of demand response resources; 5) NV Energy's MPS unnecessarily limits future participation rates based on past program incentive levels; and 6) NV Energy's MPS underestimates the economic potential by undervaluing avoided capacity costs. (Ex. 1502 at 23-32.)

NV Energy's Rebuttal

392. NV Energy recognizes that there are potential shortcomings to market potential studies, but denies that such studies are systemically conservatively biased. (Ex. 155 at 4.) NV Energy asserts that such studies endeavor to predict customer behavior and decision making, and the results of such studies are guideposts guided by the set of assumptions. (Ex. 155 at 4.) NV Energy broadly defends the MPS and its assumptions as reasonable in response to the criticisms leveled by SWEEP and United. (Ex. 155 at 4-10.)

Commission Discussion and Findings

393. The Commission accepts NV Energy's MPS and declines to order the changes to the MPS proposed by SWEEP and United at this time. The Commission agrees with NV Energy that while there are potential shortcomings to market-potential studies, such studies endeavor to predict customer behavior and decision making, and they provide guideposts based on a set of assumptions. The Commission finds NV Energy's MPS and its assumptions reasonable because the MPS provided savings potential levels that informed the portfolio design of both the proposed Grid Value and the alternative Traditional portfolios.

CC. Data Center Demand Response Potential Study

NV Energy's Position

394. NV Energy did not produce a potential study specific to data center demand response.

WRA's Position

395. WRA recommends the Commission require NV Energy to produce an additional data center demand response potential study within 90 days of the Commission's decision. (Ex. 1202 at 4.) WRA states that this proposed study will allow NV Energy to amend its DSM Plan, detailing the programs it intends to create and implement through 2027. (Ex. 1202 at 4.)

396. WRA states that the MPS did not analyze data center measures, though it suggests that additional analysis could reveal significant opportunities for demand flexibility. (Ex. 1202 at 22.) WRA states that data centers present untapped potential for demand response and can invest in battery storage to adjust their demand or use it as a system resource. (Ex. 1202 at 14.) WRA states that NV Energy's expectation regarding data centers' contributions to load growth, further studies and development are needed. (Ex. 1202 at 14.)

NV Energy's Rebuttal

397. NV Energy states that a demand response potential study focused on data centers is unnecessary because the limitations of potential studies are more acute for data centers because general assumptions in such studies would not accurately characterize the potential for a program targeting a small number of very large loads. (Ex. 155 at 3.) NV Energy further states that such a study would need to work alongside data center developers as their plans emerge, which is not possible within 90 days. (Ex. 155 at 3.) NV Energy also states that it is better to provide appropriate price signals and let data centers respond than it is to rely on an updated MPS because it is impossible to know the operational flexibility of the customers. (Ex. 155 at 4.)

398. NV Energy further states that a supplemental data center demand response potential study need not be conducted because, while NV Energy should continue exploring emerging demand response opportunities for data centers, these would best be explored through implementation of pilots or demonstration projects within NV Energy's Program Development and/or Commercial Demand Response programs. (Ex. 156 at 16.) NV Energy asserts that if such initial pilot efforts are successful, the data from these projects could be applied to other sites and used in future studies without the need for a supplemental study. (Ex. 156 at 16.)

///

///

Commission Discussion and Findings

399. The Commission declines to order a demand response potential study focused on data centers at this time because the Commission finds such a study unnecessary; the limitations of potential studies are more acute for data centers because general assumptions in such studies would not accurately characterize the potential for a program targeting a small number of very large loads. Further, such a study would need to work alongside data center developers as their plans emerge, which is not possible within 90 days. The Commission agrees with NV Energy that it is better to provide appropriate price signals and let data centers respond than it is to rely on an updated MPS because it is not plausible to know the operational flexibility of the customers.

DD. New Gas Combustion Turbines and EE

NV Energy's Position

400. NV Energy requests approval of its Preferred Plan, which includes a Supply Plan addition of two 200 MW (nominal) gas-fired simple-cycle turbines at the North Valmy generation station with an estimated cost of approximately $573.3 million. (Ex. 174 at 6-7; Ex. 101 at 25; Ex. 105 at 17-18.)

401. NV Energy states that although it is requesting approval of fossil generation as part of the Preferred Plan, it is not deviating from clean energy goals because it is eliminating coal from the existing resource portfolio by the end of 2025. (Ex. 175 at 14.) NV Energy asserts that the Preferred Plan meets or exceeds the RPS in all years and targets NV Energy's proportionate share of Nevada's 2050 clean energy goal. (Ex. 175 at 14.) NV Energy states that the proposed Valmy Simple Cycle Plant will eliminate the Valmy "must-run" requirement which otherwise continues in perpetuity and provides needed capacity contribution. (Ex. 175 at 14-15.)

NV Energy further states that the Valmy Simple-Cycle Plant is not included in the Alternate Plan, which would continue the "must run" requirement in perpetuity. (Ex. 175 at 16.)

United's Position

402. United states that NV Energy's failure to invest in cost-effective demand-side resources in the 2025-2027 timeframe will be one reason why NV Energy will have to resort to more costly supply-side additions in 2028. (Ex. 1502 at 21.) United explains there are other solutions that might minimize the need to add supply-side resources on this timeframe, such as demand-side resources, which can often be implemented on a faster timeline than supply-side resources. (Ex. 1502 at 22.) United states that one of the primary purposes of pursuing demand-side resources is to defer or eliminate the need for supply-side resource additions such as NV Energy's proposed gas plant addition. (Ex. 1502 at 22.) United recommends that the Commission direct NV Energy to defer consideration of proposed new gas combustion turbines ("CTs") at this time in light of increased investments in demand-side resources that will address a significant portion of NV Energy's near-term system capacity needs. (Ex. 1502 at 22-23.) United explains that the extent to which demand-side resources could successfully reduce or eliminate these needs depends on NV Energy's level of investment in flexible load resources and its level of urgency in pursuing them. (Ex. 1502 at 22-23.) United provides that even if the gas plant addition cannot be fully avoided, the addition of flexible load resources is still valuable for reducing other future supply-side needs and aiding reliability. (Ex. 1502 at 23.)

Commission Discussion and Findings

403. While the Commission appreciates the flexibility that EE and demand response bring to managing grid resiliency, as discussed more fully in Phase III of this Order, the Commission finds that there is inadequate evidence in the record of this case to conclude that EE

and demand response are sufficient to replace the gas-fired turbines proposed by NV Energy. Currently, EE, demand response, and managed EV charging all rely on the voluntary participation of ratepayers, even under aggressive incentive structures and the programmatic recommendations made by United and others. Thus, the Commission is unable to find that such measures provide adequate reliability to meet energy demand and grid needs on their own.

V. AMENDED JOINT APPLICATION: PHASE III

A. NV Energy's Remaining Requests and Prayers for Relief and Rate Impact Analysis: Preferred Plan (the Balanced Plan) Overall.

404. In the remaining portions of the Joint Application not otherwise resolved by stipulation in Phase I or addressed in Phase II, NV Energy requests the following:

1. Approval of the 2024 IRP long-term base load forecast presented in the Load Forecast and Market Fundamentals volume of the IRP Filing as being the most accurate information upon which to base long-term planning decisions through the Action Plan period;
2. Approval of the three-year base load forecast presented in the 2024 ESP as being the most accurate information upon which to base near-term planning decisions through the Action Plan period;
3. Approval of NV Energy's recommended annual limits on the total amount of energy and capacity that eligible NRS Chapter 704B customers may be authorized to purchase from providers of new electric resources during the Action Plan period, and the Net Differential Energy Rate of $0.04165 per kWh, and the Variable O&M Credit (Charge) of $-0.00015 per kWh for the Action Plan period;
4. Issuance of a list of any current or ongoing legislatively mandated public policy programs for which eligible customers are required to pay costs, fees,

charges or rates pursuant to subsection 8 of NRS 704B.310;

5. Approval of the Balanced Plan as NV Energy's Preferred Plan including various projects including those identified in the Supply Plan, network upgrades identified in the Joint Application, and continued approval of the Greenlink project with a combined budget for Greenlink West, Greenlink North and Common Ties of $4,128 million[4];

6. Approval of the Corsac Generating Station 2 Power Purchase Agreement PPA for 115 MW of geothermal energy. NV Energy notes that the PPA is not effective until the Energy Supply Agreement ("ESA") has been fully executed and all conditions to its effectiveness have been satisfied;

7. Approval of $2 million for network upgrades to add a 345-kilovolt ("kV") line terminal at Lantern bus for the generator interconnection of the Corsac Geothermal project;

8. Approval of NV Energy's request to designate Greenlink West and common ties as critical facilities;

9. Approval of Construction Work in Progress ("CWIP") accounting treatment for the Greenlink project;

10. Approval of a regulatory asset, with no carrying charges, to record and include the Greenlink depreciation expense;

10. Approval of NV Energy's proposed long-term avoided costs; and

11. A finding that NV Energy has satisfied the directives and compliance items from Docket Nos. 21-06001, 22-03024, 22-07003, 22-07004, 22-09006, 23-

[4] Not including the $110 million estimated costs of the Ft. Churchill-Comstock Meadows #2 345-kV line separately identified in the Supply Plan.

02001, 23-02010, 23-02011, 23-06044, and 23-08015.

(Ex. 101 at 24-33.)

405. NV Energy filed the Joint Application pursuant to NRS 704.741 *et seq*., and NAC 704.0995 *et seq*. seeking approval of NV Energy's 2025-2024 joint triennial IRP, and the plan of action for the three-year period 2025-2027, including its ESP for the three-year period 2025-2027. (Ex. 101 at 1.)

406. NV Energy requests that the Commission approve the Base Long-Term Fuel and Purchased Power 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 period. (Ex. 101 at 24; Ex. 168 at 2; Ex. 169 at 2-3.)

407. NV Energy represents that after analyzing several energy supply portfolios based on capacity needs, cost to customers, decarbonizing goals, societal cost, economic impact on the state and other factors, it selected the Balanced Plan as its Preferred Plan. (Ex. 101 at 3; Ex. 175 at 8-16; Ex. 187 at 25-26.)

408. NV Energy states that the Balanced Plan contains the addition of three PPAs for solar generating resources totaling more than 1,000 MW, each with co-located BESS; two NV Energy-owned hydrogen-capable natural gas simple cycle CTs; and transmission infrastructure necessitated by the new resources and to support growing customer demand. (Ex. 101 at 3; Ex. 175 at 9; Ex. 187 at 25-26; Ex. 177 at 2-3.)

409. NV Energy further states that it has conducted and presents with the Joint Application numerous rate-impact analyses covering the alternative supply plans to demonstrate the effect on customer rates from the proposed investments. (Ex. 101 at 3; Ex. 189 at 2-4.) NV Energy asserts that it selected the Balanced Plan as its preferred plan because it closely aligns

with Nevada's energy policies, delivers the resources its customers value, and represents a balance of cost to customers, reliability, and environmental benefits, and requests that the Commission accept the Balanced Plan and authorize NV Energy to take all necessary steps in the Action Plan period to implement the plan. (Ex. 101 at 4; Ex. 101 at Ex. A; Ex. 187 at 6-12.)

410. NV Energy requests that the Commission approve NV Energy's proposed long-term avoided costs ("LTAC") based on the Preferred Plan. (Ex. 101 at 29; Ex. 187 at 38-39.)

Interwest's Position

411. Interwest recommends that the Commission approve various recommendations regarding the resource supply RFP process and regarding integrating these results into the 2024 IRP. (Ex. 2400 at 7-8.) Interwest argues that NV Energy's current RFP process is prolonged and is disconnected from IRP filings. (Ex. 2400 at 9.) Interwest states that NV Energy uses RFPs as merely one tool among several methods that include self-build plans and unsolicited offers, but primarily exercises discretion over these options. (Ex. 2400 at 10.) Interwest states that RFPs have only been effective in securing resources for approval in one out of the last four instances, suggesting that NV Energy regards them as its least preferred option. (Ex. 2400 at 10.) Interwest states that RFPs should be NV Energy's primary mechanism for resource acquisition, as well as the Commission's preferred approach to promote competition and transparency. (Ex. 2400 at 10.)

412. Interwest critiques NV Energy for not adhering to recognized competitive procurement practices during its RFP processes, stating that fairness requires providing all bidders with equal information, predictable outcomes, and prevent bypassing the procurement process by leveraging contracts outside of it. (Ex. 2400 at 10.) Interwest also states that it is concerned that the timing and content of the RFP, as well as the evaluation and selection of bids,

are too dependent on NV Energy's fluctuating discretion. (Ex. 2400 at 10.)

413. Interwest argues that NV Energy's bid evaluation process lacks clarity. (Ex. 2400 at 16.) Interwest states that NV Energy evaluates RFP bids through a confidential tabletop exercise, where it chooses projects that it aligns with its established criteria at its discretion, while eliminating others based on transmission assessments or other identified flaws. (Ex. 2400 at 16.) Interwest states that NV Energy does not utilize PLEXOS LT for testing RFP bids in capacity expansion scenarios. (Ex. 2400 at 16.)

414. Interwest supports the initiation of NV Energy's 2024 RFP and proposes that the Commission should: 1) direct NV Energy to carry out the RFP and include it in the approved Action Plan; 2) direct NV Energy to present the RFP results and analysis in its First Amendment, as an addition to the Supply Plan; and 3) explore additional findings and guidance for NV Energy regarding the RFP's scope. (Ex. 2400 at 19.)

SEA's Position

415. SEA argues that supporting NV Energy's proposed investments in new energy supply sources and upgrades to the transmission system network is crucial for maintaining the reliability of the current load system and accommodating future load growth, particularly in Northern Nevada. (Ex. 700 at 6.) SEA states that postponing or rejecting these energy supply and infrastructure initiatives would substantially undermine Nevada's capacity to support future load demands and economic development. (Ex. 700 at 7.)

SEIA's Position

416. SEIA states that it agrees with NV Energy's Preferred Plan request to add 1,028 MW of solar and battery storage resources because the proposed clean energy resources and associated PPAs offer needed capacity and energy to the system. (Ex. 1801 at 2.) SEIA further

states, however, that it does not believe the difference in portfolio costs or attributes between the Preferred Plan and the Alternative Plan adequately justify NV Energy's proposal for new gas resources at Valmy. (Ex. 1801 at 2.) SEIA asserts that its support for the PPAs should not be taken as an endorsement of NV Energy's overall portfolio, specifically NV Energy's procurement practices. (Ex. 1801 at 2-3.)

417. SEIA states that NV Energy's load growth forecast and resource projections reflect significant load additions from high load factor customers, including data centers. (Ex. 1801 at 3.) SEIA asserts that significant load growth could result in increased costs to customers through higher cost market purchases or higher requirements on fossil fuels. (Ex. 1801 at 3.) SEIA states that the Commission should carefully consider the context of unprecedented load growth in the IRP and in future resource procurement. (Ex. 1801 at 3.)

418. SEIA recommends that NV Energy be required to file RFPs for review and approval by the Commission before the RFP is issued and opened to bidders because additional review would ensure procured resources result from robust, competitive, and fair procurement processes. (Ex. 1801 at 5.) SEIA states that Commission review and approval of the RFP process would be consistent with other states' commissions' practices and recommendations in the 2020 "Making the Most of the Power Plant Market: Best Practices for All-Source Generation Procurement" report from Energy Innovation. (Ex. 1801 at 6.)

419. SEIA further recommends that NV Energy also be required to use an independent evaluator for future resource procurements because, while such practice will increase administrative costs, the proposed third-party evaluator would ensure that successful bids and resulting projects are in ratepayers' best interests by reviewing all bids for compliance with the Commission-approved RFP and fairly evaluating self-bid proposals against third-party developer

proposals. (Ex. 1801 at 6.) SEIA states that independent evaluation in the RFP process is supported by a 2021 report by Lawrence Berkely National Lab. (Ex. 1801 at 6.)

420. SEIA asserts that the significant load growth and anticipated resource needs identified by NV Energy merit the recommended advance RFP review and third-party evaluator process because these increased protections will help ensure that NV Energy's procurement processes are in the public interest, increase transparency, ensure fair procurement practices, and encourage market participation. (Ex. 1801 at 7.)

Sierra Club's Position

421. Sierra Club states before the increase in the major project load forecast in this IRP, the 2023 Valmy Must Run Study indicated that NV Energy's system would be reliable without must-run at Valmy Units 1 and 2 after installation of Greenlink West with additional reliability after installation of Greenlink North, and found that retiring Valmy Units 1 and 2 would be possible after installation of Greenlink West. (Ex. 1400 at 28.) Sierra Club's recommendations appear in more detail in specific sections of this Order.

WRA's Position

422. WRA recommends that the Commission direct NV Energy to execute and develop several resource plan revisions and more stakeholder engagement, such as: 1) NV Energy should revise its resource plans and economic analysis to incorporate industry-standard resource cost projections; 2) NV Energy, in collaboration with the other Parties, should resolve the technical concerns in NV Energy's data and modeling ecosystem and submit as an amendment to this filing; and 3) NV Energy should continue the development of more robust stakeholder engagement and feedback incorporation earlier in the planning process to identify and address concerns prior to completion of its modeling exercise. (Ex. 1206 at 5.) WRA states

that it identified errors and limitations in NV Energy's planning initiative, including: Candidate Resource Costs, Enhanced Geothermal Resource Profiles, Valmy Steamer Must-Run Mitigation Alternatives, Fuel Price Exposure, Direct Reliability Analysis of Portfolios, WRAP Compliance Planning, Risk Concentration on Technology Pathways, and Firm Dispatchable Resources; and therefore, the Commission should direct NV Energy to address these identified issues. (Ex. 1206 at 20-22.)

423. WRA recommends that the Commission approve NV Energy's renewables and storage Action Plan requests from the balanced portfolio because renewable resources are consistently selected in both NV Energy's modeling and WRA's independent modeling and prove to be in the ratepayers' best interest and align with state decarbonization goals. (Ex. 1208 at 5.)

424. WRA recommends that the Commission direct NV Energy to provide substantiating information necessary to achieve Nevada's 2050 net zero goal because a long-term decarbonization trajectory exposes customers to less risk via reduced fuel reliance and puts NV Energy back on track towards meeting state emissions reductions goals. (Ex. 1208 at 5-7.)

425. WRA explains that while NV Energy's proposed Balanced Plan reflects lower cost than more ambitious alternatives, it retains higher exposure to fuel and market purchase prices than alternatives, extenuating the potential circumstances that exposed many Nevadans to rate shock in the last IRP cycle. (Ex. 1208 at 15.) WRA states that when accounting for the errant capital expenditure assumptions for clean energy used in NV Energy's cost differential between cases shrinks significantly; and therefore, utilizing the higher fuel cost assumption brings the Balanced Plan cost in line with the cost of the Emissions Glide Path scenario provided

by WRA, which achieves significantly higher cumulative emissions reductions through 2050. (Ex. 1208 at 15.)

426. WRA supports NV Energy's proposed renewable energy and capacity needs; however, WRA states that while NV Energy's analysis identifies wind, pumped hydro, and "firm dispatchable resources", WRA's analysis identifies greater benefits from geothermal resources. (Ex. 1206 at 11-12.) WRA states air-cooled geothermal resources in Nevada face a significant ambient derate driven by high summer temperatures, resulting in a diurnal reduction during daytime hours for peak summer days. (Ex. 1206 at 37.) WRA explains that while this negatively impacts reliability contributions from geothermal in the near-term, increasing penetrations of solar and storage will shift hours of risk outside of these windows, resulting in a corresponding increase to the geothermal resource Effective Load Carrying Capability ("ELCC"). (Ex. 1206 at 37.)

427. WRA states that it is important for NV Energy's IRP to utilize accurate, well-vetted cost inputs for its plan development and analysis because this helps ensure that optimal resource investments are not missed. (Ex. 1206 at 34.) WRA notes that IRP proceedings are Nevada's primary analysis and planning process for the electric sector, which informs the Commission, legislators and the Administration to make thoughtful decisions about the state's energy policy. (Ex. 1206 at 34.) WRA explains that a technical concern with NV Energy's geothermal energy modeling profiles and reliability contributions is NV Energy uses historical production profiles to represent Enhanced Geothermal Systems ("EGS"), which significantly undercounts the resource's energy and capacity contributions, rendering it highly unlikely the capacity expansion model will select EGS. (Ex. 1206 at 34-35.) WRA states that NV Energy utilizes historical geothermal resource profiles from existing, conventional hydrothermal wells

and these historical profiles reflect significant performance degradation, likely driven by the finite hydrothermal reservoir, as well as nameplate capacities which may not reflect viable output from the underlying resource. (Ex. 1206 at 35.)

United's Position

428. United recommends that the Commission reject NV Energy's Balanced Plan as the Preferred Plan. (Ex. 1517 at 4.) United argues that NV Energy's Balanced Plan incurs higher costs, emissions, and risks in the near term compared to its Renewable Plan. (Ex. 1517 at 11.) United states that NV Energy's Balanced and Renewable Plans reflect updated Combination Cases developed by NV Energy, whereby alternative portfolios are developed using different combinations of the potential projects following the Base Case and Screening Evaluation steps. (Ex. 1517 at 9-10.) United notes that aside from a few differences, the Balanced Plan and Renewable Plan are largely identical; the Renewable Plan does not include the proposed new gas CTs at Valmy and incorporates substantial battery storage starting after 2040. (Ex. 1517 at 11-12.) United states that NV Energy's analysis shows the Renewable Plan has a 20-year Present Worth Revenue Requirement ("PWRR") that is $321 million greater than the Balanced Plan and a 26-year PWRR that exceeds the Balanced Plan by $1,047 million. (Ex. 1517 at 12.) United interprets these results to imply that the exclusion of Valmy CTs leads to a slightly more expensive portfolio. (Ex. 1517 at 13.) United states that other factors primarily drive the PWRR cost differential. (Ex. 1517 at 30.) United states that the significant addition of 4,700 MW of BESS by NV Energy during 2044-2050 is a key factor contributing to the Renewable Portfolio's higher PWRR compared to the Balanced Portfolio. (Ex. 1517 at 13.)

429. United states that there is insufficient justification for such substantial additions of short-duration BESS resources in the later years since 1) the Renewable Plan contains no

additional renewable resources that might require battery storage for integration; 2) implied ELCC value of incremental BESS resources in these later years is very low and does not provide significant capacity value relative to other possible resource options, and 3) these BESS additions were included through hand-picked adjustments made by NV Energy and were not part of any economic optimization. (Ex. 1517 at 13.)

430. United states that based on NV Energy's analysis, the Renewable Plan has the lowest-cost portfolio at least until 2035. (Ex. 1517 at 17.) United states that after 2035, the Renewable Plan may become more costly but only if one accepts NV Energy's questionable assumptions of the necessity for significant BESS additions from 2035-2050, as well as the absence of most cost-effective alternatives during that period. (Ex. 1517 at 17.) United states that NV Energy's conclusion that the Balanced Plan is least cost relies on extending the IRP analysis to 20 years or longer, rather than concentrating on a shorter timeframe, and assumes that the chosen BESS additions are economically optimal even though NV Energy has not re-optimized the portfolio in PLEXOS LT to confirm this. (Ex. 1517 at 18.)

431. United recommends that the Commission order NV Energy to issue all source RFP to meet the specific needs of the Renewable Plan. (Ex. 1517 at 4-5.) United elaborates on the specific needs should include capacity resources that reduce NV Energy's open position in the 2028 timeline; local capacity at Valmy, where the RFP should specify the resource capabilities needed to partially or completely alleviate the must-run constraint by 2031 when NV Energy's modeling shows that removing the constraint would result in reduced operations of the Valmy steam units; flexible load resources by 2027; and incremental renewable resources when practicable. (Ex. 1517 at 4-5.)

///

BCP's Position

432. BCP states that it does not object to the approval of the base long-term fuel and purchased power price forecasts as the best information to base long-term planning decisions through the Action Plan period. (Ex. 406 at 2.)

433. BCP recommends that the Commission direct NV Energy to develop LTACs based on which load long-term forecast it finds to be the most accurate information to base planning decisions through the Action Plan period pursuant to the recommended options provided to the Commission per BCP. (Ex. 406 at 10.)

Staff's Position

434. Staff recommends that the Commission find NV Energy's development and consideration of the four resource plans to be sufficient for the purpose of the economic analysis and consistent with relevant resource planning regulations NAC 704.9516, 704.937, and 704.9465. (Ex. 312 at 35-36.) Moreover, Staff notes that NV Energy complied with a directive contained in Ordering Paragraph 6 of the Commission's April 9, 2024, Modified Final Order in Docket No. 23-08015. (Ex. 312 at 6.)

435. Staff recommends that the Commission find NV Energy's economic analysis, including the PWRR, and Present Worth Societal Cost ("PWSC") analysis, is consistent with relevant resource planning regulations NAC 704.9395 and 704.9401. (Ex. 312 at 11, 36.)

436. Staff recommends that the Commission approve NV Energy's proposed LTAC rates and provides that the rates appear reasonable. (Ex. 313 at 68.)

437. Staff recommends that the Commission find NV Energy's Financial Plan is consistent with relevant resource planning regulations. (Ex. 312 I at 36.)

438. Staff recommends that the Commission find that NV Energy has satisfied certain

directives and compliances from Docket Nos. 21-06001, 22-03024, 22-07003, 22-07004, 22-09006, 23-02001, 23-02010, 23-02011, 23-06044, and 23-08015, which are all specified in NV Energy's third Prayer for Relief in its joint application. (Ex. 108 24, 28.)

439. Staff recommends that the Commission find NV Energy provided a customer rate impact analysis pursuant to NRS 704.741; however, NV Energy's analysis cannot be reasonably relied upon to estimate the impact of the proposed plans on customer rates because it does not quantify the impact of the proposed plans on customer rates but instead demonstrates the cost differences between the Base Case and alternative plans. (Ex. 312 at 21, 36.)

440. Staff disagrees with NV Energy's rate impact analysis methodology and contends that calling NV Energy's analysis a "rate impact analysis" is a misnomer because the method NV Energy used does not show the actual bill impact to customers of adding certain projects to already existing rates; rather, the analysis compares the differences in cost of the base case and alternative plans, as estimated by the clean electricity regulations ("CER"), and converts those differences to a per kWh cost for groups of customer classes. (Ex. 312 at 19.) Staff explains that NV Energy's method picks up differences in the cost of the base case and alternative plans, but such differences include differences in costs of placeholder generation and transmission resources, none of which are being requested for approval; rather, it is the least-cost case to meet demand, Renewable Portfolio Standard ("RPS") compliance, reserve margin, and NV Energy's proportionate contribution to the State's net zero goal and comprised entirely of placeholder generation and transmission resources for which NV Energy is not requesting approval. (Ex. 312 at 19-20.)

441. Staff states that, to the extent that an actual resource added in an alternative plan in a given year displaces generation and/or transmission placeholder resources in future years

that are assumed in the base case, NV Energy's rate impact analysis would show a Base Tariff General Rate ("BTGR") credit. (Ex. 312 at 20.) Staff notes that NV Energy's rate impact analysis of its Preferred Plan shows a BTGR credit from 2027-2030 for NPC, and 2027-2028 for SPPC. (Ex. 312 at 20.) Staff provides that the BTGR credits are attributable to NPC and SPPC's respective placeholder transmission resources and associated capital costs. (Ex. 312 at 21.) Staff further provides that the supposed impact to ratepayers is a "credit" for transmission placeholder resources that NV Energy has not asked for approval, and which are not going to be built anyway. (Ex. 312 at 21.) Staff states that from a high level, it does not make sense that rates would decrease as new resources are being added. (Ex. 312 at 21.)

442. Staff states that NV Energy did not provide its rate impact analysis in satisfaction of the stipulation approved in Docket No. 21-06001, which required that, if NV Energy sought incentives in a future proceeding for certain projects, it would agree to include all financial impacts associated with the request, including a rate impact analysis that specifies the rate impact of any such proposal on each rate class. (Ex. 312 at 21; Staff's Brief at 6.) Staff states that the rate impact analysis does not comport with the above stipulation because it does not provide the rate impact for each customer class nor each incentive requested. (Ex. 312 at 21; Staff's Brief at 6.)

NV Energy's Rebuttal

443. NV Energy states that SEIA's and others' recommendations for advanced RFP review and independent evaluation are administratively burdensome, costly, and unnecessary. (Ex. 201 at 8.) NV Energy asserts that it has demonstrated in this filing that the projects selected were the result of a robust, competitive, and fair procurement process. (Ex. 201 at 8.) NV Energy asserts that the procurement process is already transparent because: 1) RFP instructions,

resource types solicited, scoring criteria, key dates, and detailed commercial and legal terms are made clear to all bidders at the beginning of the event, 2) bidders are allowed to ask questions throughout the RFP process, 3) proposal scoring, due diligence, proposal ranking, and negotiated final contracts are all made available to Staff and select intervenors for review when the projects are filed, and 4) procurement event questions can be asked via the data request process throughout the IRP process. (Ex. 201 at 9.)

444. NV Energy further states that placeholder resource adjustments are implemented such that the open positions and systemwide RPS and Nevada Green Energy Rider attainment of each case is as similar as possible. (Ex. 202 at 19.) NV Energy further states that evaluating the differences between plans without maintaining consistent reliability standards could result in significant downstream impacts that skew the PWRR, and these adjustments are therefore appropriate. (Ex. 202 at 19.)

445. As to United's position that the ELCC analysis used by NV Energy should not be used as the basis for planning, NV Energy asserts that United's statement that incremental storage in the Renewable Plan reduces the total BESS firm capacity is inaccurate because United has conflated incremental BESS firm capacity with total BESS firm capacity. (Ex. 193 at 29-30.) NV Energy further states that United fails to understand declining marginal ELCCs with increasing penetration, which is an effect NV Energy has captured in its IRP filings since the 2020 Fourth Amendment to the 2018 IRP and which NV Energy states that it has discussed at length in this Docket. (Ex. 193 at 30-31 citing Ex. 125 Volume 28, Technical Appendix ECON-12 at 169.)

446. NV Energy further responds to United and denies that its candidate resource costs were erroneous. (Ex. 202 at 8-9.) NV Energy agrees with United that NV Energy's resource

needs are immediate in light of the updated load forecast and renewable/storage resource cancellations, and that this was a key driver of the PLEXOS LT expansion plan but disagrees with the implication that the analysis is flawed due to differences between costs of available projects and costs of candidate resources. (Ex. 202 at 8.) NV Energy states that while PLEXOS LT builds a long-term expansion plan, it is populated with placeholder resources which do not represent real projects and therefore subsequent analysis in the production cost model is required to assess the options for addressing the immediate near-term need. (Ex. 202 at 8-9.)

447. As to WRA's position regarding resource diversity, NV Energy does not dispute the valuable diversity of geothermal resources. (Ex. 202 at 9.) NV Energy states that placeholder resources do not indicate intended resources, but are simply the result of the least cost PLEXOS buildout, and a lack of near term geothermal resources does not indicate an intention not to pursue geothermal resources. (Ex. 202 at 9.)

448. In response to WRA's criticisms regarding the Planning Reserve Margin ("PRM") PRM-ELCC approach, NV Energy states that the concerns raised do not relate to the theory underlying the PRM-ELCC, but rather how NV Energy has put these concepts into practice. (Ex. 193 at 5.) NV Energy states that, while it may be theoretically possible to calculate unique PRM requirements for each year of the analysis, such an effort is so computationally intensive as to be prohibitive. (Ex. 193 at 5.) NV Energy asserts that WRAs criticisms reflect NV Energy's deliberate decisions regarding the scope of the PRM-ELLC study to provide the most useful results to inform near-term procurement choices and long-term planning. (Ex. 193 at 5.)

449. NV Energy further states that the PRM and ELCC studies intentionally focused on the 2025-2028 period based on the urgency of near-term reliability needs and the iterative nature of planning and procurement cycles. (Ex. 193 at 6.) NV Energy asserts that near-term

PRM-ELCC Studies are appropriate for use across the full planning horizon due to the cyclical and iterative nature of the IRP planning process, which NV Energy states will continue in an iterative manner which will allow NV Energy to continue to refine planning assumptions as new information becomes available. (Ex. 193 at 7-8.)

450. NV Energy states the PRM and ELCC study focused on the interaction between solar and storage because such resources are expected to represent the bulk of new capacity additions and because solar and storage are a strong complimentary pair with significant diversity benefits. (Ex. 193 at 9-10.) NV Energy replies to WRA's comments regarding the geothermal ELCC, stating that the incremental BESS added throughout the study period in the Renewable Plan are a direct result of the choice regarding near-term CTs in this plan, and WRA does not provide technical analysis to support a higher ELCC value for geothermal. (Ex. 193 at 10-12; Ex. 202 at 25-26.)

451. NV Energy denies WRA's assertion that conducting resource adequacy modeling in a separate model from capacity expansion and production cost could lead to inconsistencies because WRA has not, in fact, identified any such inconsistencies in the modeling provided by E3 in support of the IRP and asserts that such modeling is common practice in the industry. (Ex. 193 at 12.)

452. NV Energy disagrees with United's and WRA's characterization of Nevada's 2050 clean energy goal, stating that this is a "near zero" goal rather than an "absolute zero" goal. (Ex. 202 at 11.) NV Energy denies that its planning reflects any failure to engage with the significant challenge of meeting the State's 2050 clean energy goal as suggested by WRA and asserts that all alternative plans target the state's goal as illustrated in Figure EA-28 in the Supply Plan Narrative. (Ex. 202 at 12-13 citing Ex. 105 at 254-255 of 393.)

453. NV Energy denies that PWRR comparisons are not driven by near-term project selection, as asserted by WRA and United, because while the Low Carbon Plan and No Open Position Plan PWRRs are largely impacted by years after the Action Plan period due to the statutory requirements for these plans, the plans created by NV Energy from the PLEXOS LT least cost buildout vary only in the near-term projects selected and any resulting ramifications of these projects on the portfolios in subsequent years. (Ex. 202 at 20.) NV Energy further states that the differences between the Balanced Plan and the Renewable Plan are created by the decision to include only renewable and storage resources in the near term in the Renewable Plan irrespective of the selection of near-term CTs in the PLEXOS LT least cost buildout. (Ex. 202 at 20-21.) NV Energy states that it is not reasonably feasible to re-optimize each plan in PLEXOS LT as WRA and United suggest. (Ex. 202 at 21.)

454. NV Energy notes that WRA presents four alternative long-term portfolios, and distinguishes the 2024 IRP, stating that it does not focus on alternate hypothetical futures, but instead acknowledges that resources choices will change as years pass. (Ex. 202 at 22-23.) NV Energy asserts that WRA's focus on long term portfolios and later years of the study period are not required and are inappropriate in Nevada. (Ex. 202 at 23.)

455. NV Energy denies WRA's contention that the Preferred Plan is riskier to customers because it is more dependent on fossil fuel as opposed to WRA's alternative plans because the Preferred Plan is based on normalized assumptions including a normal weather load forecast, and fuel and purchased power price forecasts. (Ex. 202 at 24.)

456. NV Energy agrees with Staff's conclusion that the tables provided in FP-1 through FP-4 were not provided in satisfaction of the stipulation in Docket No. 21-06001 but were instead provided in satisfaction of the requirement of NRS 704.741(4)(b)(7). (Ex. 205 at

14-15.)

457. NV Energy states that its analysis qualifies as a "Rate Impact Analysis" despite Staff's argument to the contrary because the term "rate" specifically refers to a measurement against another quantity, here: dollars per kWh consumed. (Ex. 205 at 11.) NV Energy asserts that the statutory requirement of NRS 704.741(4)(b)(7) requires an evaluation of "rates charged to the customers of the utility" and does not require a nominal dollar cost impact on an average customer's bill. (Ex. 205 at 11.) NV Energy states that it completed the customer rate impact analysis using the capital expense recovery model, which it also used to analyze projects against cases, and provides consistent analysis. (Ex. 205 at 11.)

458. NV Energy asserts that its use of the Base Case scenario as a comparison point is the appropriate approach despite Staff's argument that this method does not account for rate credits in certain years because: 1) the comparison was designed to evaluate multi-year plans that would meet RPS compliance, the planning reserve margin, and the state's net zero goals; 2) an alternative approach, such as comparing to a plan relying predominantly on existing resources and market purchases, would not reflect the regulatory requirements and goals NV Energy must meet; and 3) while the base case does include hypothetical resources not requested for approval, this methodology allows for better comparability because, by analyzing the preferred scenario against the base, the impact of two plans designed to meet multiple constraints facing NV Energy are examined. (Ex. 205 at 11-12.) NV Energy further asserts that the preferred scenario precludes potential market purchase assumptions that would be needed to evaluate rate effect while accounting for regulatory requirements. (Ex. 205 at 12.)

Commission Discussion and Findings

459. The Commission finds NV Energy's development and consideration of the four

resource plans are sufficient for the purpose of the economic analysis and consistent with relevant resource planning regulations NAC 704.9516, 704.937, and 704.9465. In developing and presenting the four resource plans, the Commission finds that NV Energy complied with the directive contained in Ordering Paragraph 6 of the Commission's April 9, 2024, Modified Final Order in Docket No. 23-08015.

460. The Commission finds that NV Energy's economic analysis, including the PWRR and PWSC analysis, is consistent with relevant resource-planning regulations NAC 704.9395 and 704.9401. The Commission finds that NV Energy's Financial Plan is consistent with relevant resource planning regulations.

461. Except as otherwise provided in this Order, the Commission accepts NV Energy's Balanced Plan, which is NV Energy's Preferred Plan. The Commission finds that the Balanced Plan prudently and reasonably analyzes several energy supply portfolios based on capacity needs, cost to customers, decarbonizing goals, societal cost, economic impact on the state and other factors. In general, the Balanced Plan recommends the addition of three PPAs for solar generating resources totaling more than 1,000 MW, each with co-located BESS; two NV Energy-owned hydrogen-capable natural gas simple cycle CTs; and transmission infrastructure necessitated by the new resources and to support growing customer demand. The Commission finds that the Balanced Plan is reasonable and prudent because it is aligned with Nevada's energy policies and represents a balance of cost to customers, reliability, and environmental benefits. While it is generally accepting the Balanced Plan, the Commission will discuss specific projects in this Order as the Commission is not fully accepting or approving every project as proposed by NV Energy in the Balanced Plan.

462. The Commission approves NV Energy's proposed LTAC rates because the

Commission finds that NV Energy calculated the LTAC rates using timely and reasonable inputs.

463. Except as otherwise provided in this Order, the Commission finds that NV Energy has satisfied the directives and compliance items from the following dockets: Docket Nos. 21-06001, 22-03024, 22-07003, 22-07004, 22-09006, 23-02001, 23-02010, 23-02011, 23-06044, and 23-08015.

464. The Commission finds that NV Energy provided a customer rate impact analysis pursuant to NRS 704.741; however, NV Energy's analysis cannot be reasonably relied upon to estimate the impact of the proposed plans on customer rates because it does not quantify the impact of the proposed plans on customer rates but instead demonstrates the cost differences between the base case and alternative plans. The Commission agrees with Staff that calling NV Energy's analysis a "rate impact analysis" is a misnomer because the method that NV Energy used does not show the actual bill impact to customers of adding certain projects to existing rates; rather, the analysis compares the differences in cost of the base case and alternative plans, as estimated by the CER, and converts those differences to a per-kWh cost for groups of customer classes. NV Energy's method picks up differences in the cost of the base case and alternative plans, but such differences include differences in costs of placeholder generation and transmission resources, none of which are being requested for approval; rather, it is the least-cost case to meet demand, RPS compliance, reserve margin, and NV Energy's proportionate contribution to the State's net-zero goal and comprised entirely of placeholder generation and transmission resources for which NV Energy is not requesting approval. Furthermore, as Staff explains, NV Energy's analysis provides that the supposed impact to ratepayers is a "credit" for transmission placeholder resources for which NV Energy has not sought approval, and which are

not going to be built anyway. The Commission agrees with Staff that, at a high level, it does not make sense that rates would decrease as new resources are being added.

465. Regarding the interveners' requests for changes to the RFP process, the Commission agrees that there need to be changes to the IRP RFP process. The Commission agrees with interveners that the current RFP process can be improved with increased transparency and stakeholder input. The Commission finds that the appropriate place to make recommendations for changes to the RFP process, and the IRP process in general, is in Docket Nos. 23-05013 (IRP Investigatory docket) and/or 23-07026 (Rulemaking to implement AB 524.) The Commission takes seriously its obligations under AB 524, as well as its commitment to all stakeholders to improve the RFP and IRP processes. The Commission encourages interveners in this Docket to file their recommendations in those dockets for consideration.

B. Joint IRP Long-Term Base Load Forecast; ESP Three-Year Load Base Forecast

NV Energy's Position

466. NV Energy requests that the Commission approve the Long-Term Base Load Forecast and Market Fundamentals as being the most accurate information upon which to base long-term planning decisions through the Action Plan period. (Ex. 101 at 24.) Specifically, NV Energy requests that the Commission find that: 1) the 2024 Joint IRP Forecast is based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified pursuant to NAC 704.9321; 2) the 2024 Joint IRP Forecast contains all of the items required by NAC 704.925 and other applicable regulations, and; 3) the 2024 Joint IRP Forecast is suitable for making long-term planning decisions over the 2025 to 2044 period. (Ex. 171 at 5.)

467. NV Energy further requests that the Commission approve the three-year base load forecast presented in the 2024 ESP as being the most accurate information upon which to base

near-term planning decisions through the Action Plan period. (Ex 101 at 24.) NV Energy states that the information provided for the 2024 ESP is identical to the 2024 Joint IRP load forecast. (Ex. 171 at 3.)

468. NV Energy states that the 2024 Joint IRP Forecast provides the foundation for all other load forecasts included in the Joint IRP filing, and further states that the Load Forecast Narrative and Load Forecast Technical Appendices are identical for both the ESP and the 2024 Joint IRP Forecast. (Ex. 171 at 3, 5.) NV Energy asserts that the 2024 Joint IRP Forecast considers the effects of applicable new technologies, new governmental programs or regulations, and customers who acquire energy pursuant to NRS 704.787 or NRS Chapter 704B. (Ex. 171 at 8-9.)

469. NV Energy states that, for the three-year Action Plan period 2025-2027, the Compound Annual Growth Rate ("CAGR") of the annual retail energy for NV Energy is 1.9 percent (1.1 percent NPC and 3.3 percent SPPC). (Ex. 171 at 6-7.) NV Energy further states that annual energy consumption during this period increases 2,059 GWh for the combined NV Energy system, with 778 GWh at NPC and 1,280 GWh at SPPC. (Ex. 171 at 7.) NV Energy states that the CAGR of NPC and SPPC's coincident peak is 0.9 percent (0.4 percent NPC and 1.9 percent SPPC), and System Peak Demand is expected to increase 226 MW for the combined system during the three-year Action Plan period, with 87 MW at NPC and 134 MW at SPPC. (Ex. 171 at 7.)

470. NV Energy further states that, for the twenty-year forecast period 2025 through 2044, the CAGR of its annual retail energy is 2.9 percent (1.9 percent NPC and 4.4 percent SPPC). (Ex. 171 at 8.) NV Energy further states that annual energy consumption increases 27,164 GWh for the combined NV Energy system, with 10,209 GWh at NPC and 16,955 GWh

at SPPC. (Ex. 171 at 8.) NV Energy asserts that the CAGR of NPC and SPPC's coincident peak is 2.2 percent (1.4 percent NPC and 4.9 percent SPPC) and System Peak Demand is expected to increase 4,811 MW for the combined system during this period, with 2,480 MW at NPC and 2,381 MW at SPPC. (Ex. 171 at 8.)

471. NV Energy explains that it has made changes to its forecast methodology, specifically regarding the use of hourly class load data, since its Third Amendment to the 2021 Joint IRP. (Ex. 171 at 9-11.) NV Energy asserts that it has updated the 2024 Joint IRP Forecast economic outlook, included growth in NEM customers who install rooftop solar generation, updated changes in forecasted EV growth, updated the forecast from DSM programs, and updated large customer activity. (Ex. 171 at 11-20.) NV Energy states that if updated Major Project information were included in the 2024 Joint IRP Forecast, overall load levels would be higher than those included in the base load forecast. (Ex. 171 at 20.) NV Energy further states, however, that its incorporation of the expected loads for upcoming Major Projects that are included in the load forecast represent a reasonable result that the Commission may find suitable for making long-term planning decisions in this Docket. (Ex. 171 at 20.)

CMN and SNGG's Position

472. CMN and SNGG recommend that the Commission direct NV Energy to reduce its large customer load forecast growth, related to major projects, by 949 MW in 2033 to reflect customers that have not executed Rule 9 agreements because NV Energy's large customer load growth is currently overstated given the makeup of the customer types requesting electric service and more accurately align with recent historical data. (Ex. 800 at 3.) CMN and SNGG explain that NV Energy assumes that a larger percentage of the 39 major projects, including 12 data centers, requesting service will eventually receive electric service from than

historical data suggests. (Ex. 800 at 3-4.) CMN and SNGG further explain that the customer type is relevant when reviewing large customer load growth because new technologies and industries, such as data centers, often have limited historical data, which makes it more difficult to accurately predict future energy needs. (Ex. 800 at 5.)

473. CMN and SNGG state that electricity consumption can fluctuate significantly with new technologies and industries due to factors like internet traffic and cloud computing demands; and therefore, this volatility and a higher likelihood of a customer withdrawing their service request both impact forecast accuracy. (Ex. 800 at 5-6.) CMN and SNGG provide that data centers tend to investigate development at multiple locations simultaneously, with the intent to develop at a singular location, and this difference in commitment levels adds another layer of complexity to the forecasting process. (Ex. 800 at 6.)

474. CMN and SNGG explain that NV Energy predicts only about 40 percent of projects in the initial planning stages could move forward; and therefore, NV Energy reduces the projected load for these early-stage projects compared to those with firmer commitments. (Ex. 800 at 6-7.)

SEA's Position

475. SEA recommends that the Commission approve NV Energy's proposed load forecast, energy supply resources, and the transmission system network upgrades outlined in NV Energy's Preferred Plan. (Ex. 700 at 1.)

476. SEA states that it believes that NV Energy's load forecast is conservative, suggesting that actual loads could be higher. (Ex. 700 at 5.) SEA states that NV Energy lowers anticipated load from projects with Rule 9 agreements by 48 percent before incorporating it into the load forecast. (Ex. 700 at 5-6.) SEA highlights that Nevada is among the fastest-growing

states in the country. (Ex. 700 at 5.) SEA states that since the load forecast was finalized, advancements from both new and existing customers could lead to an approximate net increase of 800 MW in load beyond the base forecast by 2033. (Ex. 700 at 6.) SEA states that without proactive planning, these new loads might have no choice but to seek operational expansion in other states. (Ex. 700 at 6.)

SEIA's Position

477. SEIA states that NV Energy's load growth forecast and resource projections reflect significant load additions from high load factor customers, including data centers. (Ex. 1801 at 3.) SEIA asserts that significant load growth could result in increased costs to customers through higher cost market purchases or higher requirements on fossil fuels. (Ex. 1801 at 3.) SEIA states that the Commission should carefully consider the context of unprecedented load growth in the IRP and in future resource procurement. (Ex. 1801 at 3.)

Sierra Club's Position

478. Sierra Club states that NV Energy's near-term industrial load forecast is uncertain, and there is substantial risk that NV Energy's projected industrial load growth will be lower than anticipated. (Ex. 1400 at 4.) Sierra Club further states that if NV Energy's load forecast does not materialize, then there may be an option to end the must-run requirement at the Valmy Steam Units without installing the proposed Valmy CTs. (Ex. 1400 at 28.)

479. Sierra Club asserts that NV Energy's major projects load forecast, particularly with respect to data centers, is highly uncertain. (Ex. 1400 at 29-31.) Sierra Club asserts that the major projects load forecast is founded on existing large customer requests, discounted based on whether the request is in the study phase or a signed agreement exists. (Ex. 1400 at 30-31.) Sierra Club asserts that NV Energy's methodology relies on subjective judgment and puts

customers at risk of overbuilding if NV Energy's projections do not materialize, or if growth is less than projected. (Ex. 1400 at 31.)

480. Sierra Club asserts that under either overbuild scenario, existing customers might be forced to pay for the unnecessarily overbuilt projects. (Ex. 1400 at 32.) Sierra Club asserts that NV Energy's low load forecast in the IRP removes all loads from major projects currently in the study phase but includes as the largest portion of the large industrial load forecast those large projects with signed agreements, which Sierra Club asserts are also uncertain. (Ex. 1400 at 33-34.) Sierra Club further asserts that NV Energy should have included at least one portfolio based on a low load forecast without substantial new industrial load growth, which would inform what NV Energy should do if the projected large customer load growth does not materialize to the extent NV Energy projects. (Ex. 1400 at 34-35.)

481. Sierra Club recommends that the Commission require NV Energy to notify the Commission immediately if any near-term large customer new load requests in Northern Nevada are cancelled or reduced, which Sierra Club asserts may justify further study of NV Energy's plans at Valmy including the proposed Valmy CTs and investment in the Valmy Steam Units. (Ex. 1400 at 5.)

Tract's Position

482. Tract recommends that the Commission approve NV Energy's load forecast, but the Commission should explore methods for discounting large loads and incorporating early-stage large projects into load forecast in future IRPs or IRP amendments because NV Energy's current load forecast may be too conservative in relation to large customer loads, including data centers. (Ex. 2200 at 21.) Tract states that NV Energy's load assumptions heavily discount major projects and exclude large customer requests that have not yet entered the study

phase. (Ex. 2200 at 19.) Tract explains that even though NV Energy reported total requested capacity additions from large commercial customers of approximately 7,600 MW, which includes 6,500 MW requested within NV Energy's service territory, the forecast derates studies load by 85 percent and derates contracted load by 48 percent. (Ex. 2200 D at 19.) Tract provides that given the high demand for large commercial and industrial development, like data centers, contracted customers can quickly replace study-phase customers who did not enter Rule 9 agreements, resulting in an upward shift of the base load forecast. (Ex. 2200 at 19.) Tract states that the 48 percent discount seems high given that data centers are typically developed and constructed by some of the largest, most well-capitalized businesses in the world; and therefore, once a commitment is made on a data center project, the investment is rarely speculative with customers deploying resources to fulfill their planned growth. (Ex. 2200 at 19.)

483. Tract explains that by NV Energy failing to consider any load in queue for projects that have not yet entered the formal study phase, consideration was not given to project applicants who submit line extension applications with information related to the load or capacity necessary to serve their intended projects, which are relevant for long-term system planning. (Ex. 2200 at 19.)

484. Tract requests that the Commission consider and recognize the significant risk mitigations included in Rule 9 executed agreements, particularly those classified as abnormal risk because Tract states its perspective on risk mitigation measures aids in the efficient expansion of the transmission system and benefits all customers by balancing risk. (Ex. 2200 at 21.) Tract recommends that the Commission direct NV Energy to have additional requirements for abnormal risk projects to: 1) provide security for all up-front utility investment; 2) have the

applicant comply with stringent performance obligations under milestone schedules; and 3) phase their developments where feasible. (Ex. 2200 at 12.) Tract states that it is its understanding that under abnormal risk mitigations, NV Energy conservatively requires that Tract's financial security cover 100 percent of the utility investment in its projects, including the Federal Energy Regulation Commission ("FERC") transmission facilities, at least until another beneficiary is identified, which places Tract's project's financial responsibility entirely with large customers. (Ex. 2200 at 12-13.) Tract explains that in this way, large project customers offer protection to new FERC transmission to mitigate ratepayer risk while expanding the integrated transmission system. (Ex. 2200 at 13.) Tract states that because it will be the party primarily benefitting from these facilities, Tract is fully committed to providing the financial backstop necessary to support its projects in a way that ensures risk to other customers is mitigated and represents a responsible and mutually beneficial solution that allows for both the prudent expansion of the transmission system and the continued economic development enabled by projects like Peru Shelf and South Valley. (Ex. 2200 at 13.) Tract explains that the financial security under its Rule 9 agreements provides a backstop for those unanticipated shortfalls, avoiding the need for either the Company or its customers to provide additional cost recovery. (Ex. 2200 at 12.)

485. Tract further provides that in its experience, when NV Energy performs a load study based on a customer request, it includes an analysis to identify whether specific portions of the customer line-extension facilities are considered transmission or distribution. (Ex. 2200 at 8.) Tract explains that the way it is now, a customer can have facilities classified as distribution even though the lines are operated at only 345 kV because it performs a distribution function; however, in the FERC context, "transmission" equates to network that is shared with the bulk

electric system and "distribution" equates to radial or customer-dedicated facilities. (Ex. 2200 at 8-9.) Tract states that as it understands it, if a facility is deemed high-voltage distribution agreements ("HVD"), pursuant to NV Energy's Rule 9, that facility is deemed to be distribution or customer dedicated regardless of its voltage and would not satisfy FERC's well-established guidelines and the seven-factor test from Order 888 (1996). (Ex. 2200 at 9.) Tract provides that Rule 9 deals with HVD or substation facilities in two sections, one for individual customers or projects, and another for master planned communities, and both sections utilize prescribed tests to determine a customer's direct cost responsibility. (Ex. 2200 at 9.) Tract explains that once customer cost responsibility is determined, those costs are then divided among a combination of contribution in aid of construction ("CIAC"), advance subject to refund (pre-funded allowance), or up-front allowance. Under the Master Planned Communities section, customers are not eligible for up-front allowances. (Ex. 2200 at 10.) Tract states that large development customers will be assessed additional charges for Income Tax Gross Up, covering NV Energy's income tax liability on the customer's financial contribution to the benefit of the utility; and additionally, large customers are required to true up total costs of the project to the utility to avoid allocation of unexpected costs to ratepayers. (Ex. 2200 at 10.) Tract notes that customers will also have additional obligations under Rule 9, such as being responsible for many financial and resourcing commitments. (Ex. 2200 at 10-11.)

WRA's Position

486. WRA requests that the Commission open an investigatory docket regarding best practices for EE and demand response for large loads, forecasting load itself, rate design for 'Major Projects,' and other issues related to data centers. (Ex. 1206 at 20-22.) WRA recommends that the Commission direct NV Energy to consider adopting a stakeholder-

engagement practice and sharing of its models in future proceedings to foster a more collaborative and transparent approach to resource planning and allow a better evaluation of NV Energy's decision-making process behind resource selection. (Ex. 1205 at 5, 11-12.)

BCP's Position

487. BCP recommends the Commission reject the load forecast and keep the previously approved forecast in Docket No. 22-09006 in place; or choose the low load forecast provided in NV Energy's filing; or accept BCP's modifications the base load forecast; or accept NV Energy's base forecast with the caveats that should the load not materialize, the unutilized capacity from plant will be held for future use or in the alternative a regulatory liability may be created in the future to capture the offsetting revenues and billing determinates between rate cases. (Ex. 402 at 24.)

488. BCP states its concern that the unprecedented, speculated load growth could result in the overbuilding of capacity and plant, such as generation and transmission at SPPC and NPC, should the load not materialize. (Ex. 402 at 3.) BCP explains that speculative load from major projects could result in higher rates for captive customers should the respective revenue and billing determinants not materialize or help pay or offset costs. (Ex. 402 at 3.) BCP states that higher electric rates could also disincentivize future economic development because companies considering doing business in the state factor and are sensitive to the price of electricity when determining location. (Ex. 402 at 3.)

489. BCP states that NV Energy has experienced load failing to materialize and explain that most recently, SPPC experienced under-utilized capacity due to load not materializing in the Tahoe Reno Industrial Center ("TRIC") for the Tracy area master plan. (Ex. 402 at 3.) BCP states that the problem of load not materializing would likely be compounded in

the future with the 3,820 MW of additional capacity being modeled for the Tracy Area load forecast by NV Energy. (Ex. 402 at 3.)

490. BCP states that it lacks confidence in NV Energy's load forecast based upon three areas of concern - signed contracts for major projects, study major projects, and the EV adoption as proposed by NV Energy. (Ex. 402 at 4-5.) BCP states that NV Energy's load forecast deviates from previous forecasts because in the past it only incorporated projects with signed Rule 9 agreements into the retail sales forecasts. (Ex. 402 at 5.) BCP provides that NV Energy deviated from its past practice of only including Rule 9 agreements, which increases and magnifies the unreasonable, speculative nature of the current load forecast. (Ex. 402 at 5.) BCP notes that this Docket contains an unusually large number of project requests with no signed Rule 9 agreements in place, and if those agreements do not materialize, their magnitude will have a substantial impact on the forecasted demand to the detriment of captive ratepayers with plant that is not used, useful, or necessary. (Ex. 402 at 5.) BCP contends that the IRP process needs to focus on building internal generation or contracting PPAs and the respective infrastructure to meet non-speculative need. (Ex. 402 at 6.)

491. BCP states that unlike signed Rule 9 agreements, commitments based upon an engineering study request on its own should not inspire enough confidence to trigger the capital expenditure that would be required to have resources in place and such studies can be easily placed on hold without further guarantees. (Ex. 402 at 6.) BCP argues that if prospective clients want to be included in the IRP process, they need to sign firm agreements to meet their requested load, especially given that some with signed agreements have not met the loads and resources they requested in the past. (Ex. 402 at 6.)

492. BCP states that NV Energy's reduction of the study loads, at an average of 85 percent, does not alleviate its concerns about their speculative nature. (Ex. 402 at 6-7.) BCP provides that NV Energy represented that 40 percent of study phase projects move forward and states its criticism that the representation was based on anecdotal discussions from the Major Projects department. (Ex. 402 at 7.) BCP states that it is important that new resources are developed based on secured demand rather than speculative and anecdotal statistical wagering given the consequences could be detrimental to ratepayers. (Ex. 402 at 7.)

493. BCP states that customers with signed Rule 9 agreements do not alleviate all concerns, nor does it inspire confidence in NV Energy's load forecast, even though they adjusted requested, applicant-signed loads by an average of 48 percent. (Ex. 402 at 8.) BCP states that the fact that NV Energy reduced its requested loads by that amount signals a problem with the current approach. (Ex. 402 at 8.). BCP states that in comparing the performance of signed contracts meeting their load based on 2023's forecast, SPPC signed contracts forecasted for 231.7 MW and only met 22.7 percent of that expected load while NPC signed contracts forecasted at 82.8 MW and met 76 percent of the expected load, which in aggregated amounted to 36.7 percent of the overall expected load. (Ex. 402 at 8.)

494. BCP provides that an evaluation of four contracted applicants' loads at the end of 2023 compared to their cumulative requested capacity demonstrates dismal numbers. (Ex. 402 at 10.) BCP states that its analysis showed that all four agreements in its analysis were amended downward and pushed the loads out further in time, with some agreements being modified, with NV Energy's approval, multiple times. (Ex. 402 at 11-12.) BCP states that all four applicants are nowhere near fulfilling their obligations of requested loads in the timely manner that they requested, all with no consequences despite NV Energy having safeguards in place. (Ex. 402 at

12.) BCP states that modifying these safeguards should be a priority to protect customers from the utility from earning its ROR on currently overbuilt infrastructure. (Ex. 402 at 12.)

495. BCP explains that the first safeguard NV Energy utilizes implements a phased approach to construct the connection facilities as load materializes; however, facilities are being built without load triggers being met. (Ex. 402 at 12.) BCP states a second safeguard establishes agreement load milestones for a phase approach however legacy contracts do not mimic this approach. (Ex. 402 at 12.) A third safeguard required a security for up to 100 percent of the utility investment, but this protection was unhelpful because NV Energy has never cashed an applicant's security. (Ex. 402 at 12.) BCP states that NV Energy's fourth safeguard implements a reduction of service or termination charges, however the low reduction in service or termination charge ("RSTC") thresholds and ability to amend agreements creates a deficient framework. (Ex. 402 at 12.) The fifth safeguard is a 100 percent monetary advance subject to a potential refund for 100 percent of the utility's investment, which NV Energy has done on some legacy contracts; however, this safeguard did not prevent under-utilized capacity. (Ex. 402 at 12.) BCP states that the sixth safeguard, which requires applicants currently taking service to provide annual updated load forecasts, does not sufficiently protect ratepayers because the updated forecasts are hollow if the applicant has not agreed to amend its contracts to be contractually obligated to the updated forecast. (Ex. 402 at 12.) BCP provides that NV Energy implements a seventh safeguard which reviews monthly or annual reviews of progress to full buildout; however, BCP contends that a prudent company would do so already upon receipt of the annual forecast. (Ex. 402 at 13.)

496. BCP states that NV Energy's methodology that downward adjusts load requests based on a decision matrix factoring startup delay is not reasonable because it relies on a request

for which the applicant will not be held accountable if the load is not met. (Ex. 402 at 15.) BCP states that NV Energy's load forecast also includes speculative loads from un-signed phases under the guise of a signed contract and argues that if an applicant desires for unsigned phases to be included in the IRP process, it must sign firm agreements to meet the requested load in the future. (Ex. 402 at 15.) BCP states that NV Energy needs to enact a provision in its agreements that allows NV Energy, at its own discretion, to permanently reallocate unused capacity to other customers and subsequently amend its contract so the requested load is binding on the applicant. (Ex. 402 Morton P3 at 16.)

497. Regarding EV load forecast adoption rates, BCP states that despite optimistic studies, EV adoption has slowed, and national policy may change based on the outcome of the November election. (Ex. 402 at 19.)

498. BCP states it made three changes to the base load forecast regarding EV rates, major projects in the study phase, and major projects with signed contracts. (Ex. 402 at 20.) For EV growth rates, BCP states it utilized the Mid Scenario levelized growth rate contained in DMV's study regarding EV adoption, which BCP contends is more responsible given the slowed adoption and risks involved with policy changes. (Ex. 402 at 20.). BCP's second change to the forecast removes the loads related to major projects currently in the study phase that have been included in the base forecast but lack a signed contract to date. (Ex. 402 at 20.) Finally, BCP states that it modified the load of seven specific major projects with signed contracts to remove speculative load from future phases that lack signed agreements and reduced the load to those contracts' RSTC triggers since NV Energy anticipates a reduction in service. (Ex. 402 at 21.)

Staff's Position

499. Staff recommends the Commission accept its recommendation to remove all

major projects without signed Rule 9 agreements from the long-term base load forecast and the three-year base load forecast and that, with that modification, Staff supports approval of NV Energy's long-term and three-year base load forecasts. (Ex. 304 at 1-2.) Staff's recommended exclusion of certain projects relates to its concern that the costs of new facilities built to meet unprecedented projected load may go into rates before the billing determinates materialize for the load, increasing rates paid by current ratepayers. (Ex. 304 at 7.) In making its recommendation, Staff notes that it is critical of its inability to compare NV Energy's new forecast methodology, which changed various inputs and assumptions, to previously approved methodologies; however, it does not ultimately object to the methodology. (Ex. 304 at 3-5.)

500. Staff's primary concern with NV Energy's base load forecast regards its forecasted load growth resulting from four major projects, some of which do not have signed Rule 9 Interconnection Agreements. (Ex. 304 at 5.) Staff explains that NV Energy's load forecast includes unprecedented load growth, with 39 new bundled-service projects, only 14 of which have signed customer agreements, with the remaining 25 pending engineering studies. (Ex. 304 at 6.) Staff notes that NV Energy included 7,600 MW of capacity additions, with 6,500 MW for SPPC and 1,180 MW for NPC. (Ex. 304 at 6.) Staff further notes that 12 of those projects are bundled-service high load factor data centers requesting 5,900 MW of capacity by 2033 and contends that the magnitude of potential load from these projects, which have been incorporated into the load forecast, present a risk to current ratepayers. (Ex. 304 at 6.) Staff explains that if new facilities are built to serve potential new load, and that load slowly or fails to materialize, existing customers will be burdened with costs to pay for facilities that are not being fully utilized and were not designed for their use. (Ex. 304 at 6.)

501. Staff states that Rule 9 and Rule 1 contain provisions to protect ratepayers or offset costs if significant new loads do not materialize due to project failures by requiring that interconnected customers achieve 25 percent of their obligated load or risk NV Energy reducing its provision of service to that customer. (Ex. 304 at 7-8.) However, Staff states that such protections are inadequate to protect ratepayers because without signed agreements, ratepayers are not afforded the protections linked to Rule 9 and Rule 1. (Ex. 304 at 8.) Accordingly, Staff recommends the projects with unsigned agreements be removed from the base forecast. (Ex. 304 at 8.)

502. Staff states that over the last several years it has raised concerns regarding the amount of actual load growth relative to the amount of new transmission capacity NV Energy has been installing over the last several years. (Ex. 311 at 3.) As an example, Staff provides that in the last two GRCs, Staff cautioned that the Tracy Area Master Plan was overbuilt for the load it is serving and the billing determinants promised did not materialize, with NV Energy changing the area's estimated load from 360 MWs to 200 MW between the two filings from June of 2022 and February of 2024. (Ex. 311 at 3.) Staff asserts that this demonstrates that the area is being overbuilt and burdening existing customers with facilities that are not being fully utilized. (Ex. 311 at 3.) Staff states that in the 2024 GRC (Docket No. 24-02026), the Commission ordered SPPC to place the revenue associated with all new load in the Tracy Master Plan area into a regulatory liability account to help offset the costs for current ratepayers. (Ex. 311 at 4.) Staff states that in this proceeding, it shares the same concerns but at a magnitude up to ten times larger. (Ex. 311 at 3-4.)

503. Staff cites its concern regarding the large data centers outlined in the Joint Application and provides that similar to any new load on the system, there is no guarantee that

the anticipated load from the data centers will come to fruition at the expected time and amount once NV Energy has finished constructing the project and is ready to serve load. (Ex. 311 at 5.)

NV Energy's Rebuttal

504. NV Energy notes that multiple parties characterize the large load growth driven by large major projects as uncertain, speculative, and potentially overstated, while other parties argue that the demand included in the forecast is potentially understated and too conservative, which may limit the economic benefits this load growth could bring to Nevada. (Ex. 194 at 2.) NV Energy asserts that considering all parties' testimony, NV Energy's base load forecast is a reasonable mid-range approach. (Ex. 194 at 3.) NV Energy also recognizes BCP's recommendation for a lower adoption rate for EV sales, and Vote Solar's criticism of NEM customer growth in Phase II. (Ex. 194 at 3.)

505. NV Energy states that it is impossible to use the most up-to-date information when developing the load forecast because it is one of the first inputs into an IRP and, in this case, the inputs for the load forecast update were finalized in June/July 2023 so the forecast could be finalized by October 2023. (Ex. 194 at 5.) NV Energy further states that the Commission may still rely on the load forecast even if the data used to develop it was dated because NV Energy's base load forecast represents substantially accurate data that was gathered from the most current and best sources available at the time the forecast was developed, particularly with respect to individual major projects, EV sales, and NEM trends. (Ex. 194 at 5.)

506. NV Energy asserts that CMN and SNGG incorrectly use data from NV Energy's response to SNGG DR 3-06 to state that the Rule 9 capacity amounts are overstated. (Ex. 194 at 11, Pollard-Rebuttal-1.) NV Energy states that it appears CMN and SNGG incorrectly assume that the existing customer loads include the major project loads, and that the percentages in CMN

and SNGG's testimony based on SNGG DR 3-06 are representative of large transmission major projects. (Ex. 194 at 11.) NV Energy states that CMN and SNGG's method is flawed because: 1) they did not consider that customers requesting service in one year may not be starting service in that same year; 2) SNGG DR 3-06 includes all customer projects, including those served at the secondary and primary distribution levels, which do not consider load ramp schedules or exclude customer projects less than 5 MW; and 3) CMN and SNGG's approach does not consider that large major transmission voltage projects are built using a phased-in approach. (Ex. 194 at 11-12.)

507. NV Energy states that, contrary to Sierra Club's position, it is appropriate to account for all major projects in the load forecast to acknowledge the effect these projects have on the total load serving capabilities of NV Energy's system. (Ex. 194 at 12-13.) NV Energy asserts that it has considered and included in the base load forecast adjustments reflecting potential changes in status and effective loads for Commission consideration, which it argues is not speculative, but instead recognizes project evolution which NV Energy asserts should be considered as part of future load growth on the system. (Ex. 194 at 13-14.)

508. NV Energy denies Vote Solar's contention that it has not historically projected NEM customer growth and its impact on sales and demand, stating that it has projected such growth in past IRP filings but has not always reflected this information in sales forecasts. (Ex. 194 at 20.) NV Energy states that for this filing the forecasted NEM customer growth and resulting sales impacts have been incorporated into the load forecast. (Ex. 194 at 20.) NV Energy notes that Vote Solar relies on more current information than was available to NV Energy at the time it developed the forecast and concedes that Vote Solar is correct that the

higher growth in NEM installations is greater than what was included in the load forecast but denies that this constitutes a flaw in the forecast as it arises from a timing issue. (Ex. 194 at 21.)

509. NV Energy states that WRA's request that the Commission open an investigatory docket regarding "best practices for EE and demand response for large loads, forecasting load itself, rate design for 'Major Projects,' and other issues related to data centers" is unnecessary because interested parties have the opportunity to intervene in NV Energy's filings, are not precluded from participating regarding these matters in the future, and a general investigatory docket would be of limited utility. (Ex. 206 at 13.) NV Energy also states that it views WRA's request for a more robust stakeholder engagement and feedback incorporation process as unnecessary given the already existing structure of NAC 704.952(1) and asserts that this recommendation is more suited to the existing Commission investigatory docket regarding the IRP process in Docket No. 23-05013. (Ex. 206 at 14-15.)

510. In response to Staff's comments regarding methodology changes in the load forecast development, NV Energy states that one of the primary reasons for the methodology change was to provide all parties with files enabling tracing of calculations through development and provided additional input workpapers during the discovery process. (Ex. 194 at 6.) NV Energy asserts that while Staff has concerns regarding the load forecast development, Staff supports the overall load forecast methodology. (Ex. 194 at 6.)

511. NV Energy asserts that anticipated load growth related to development of new AI technologies, referenced by BCP, merits addressing the increase in requests for service and inclusion of all major projects currently in the queue should be considered for the base load forecast. (Ex. 194 at 7-8.) However, NV Energy states, contrary to BCP's position, all major projects should be included in the load forecast whether or not a signed agreement exists to

account for the negative effect on system demand should the projects materialize. (Ex. 194 at 8.) NV Energy asserts that, to address the uncertain nature of those projects without signed Rule 9 agreements, it incorporated an average 85 percent reduction to the customer requested facilities peak megawatt levels. (Ex. 194 at 8.)

512. NV Energy states that BCP's calculations incorrectly tie the current load levels of major projects to the total final build out rather than the load ramp schedules. (Ex. 194 at 10.) NV Energy asserts that when actual loads to the expected phased loads are compared, as of August 2024 current major projects are at 54 percent of requested peak facility requirements, which is slightly higher than NV Energy's approach. (Ex. 194 at 10.) NV Energy further denies that the load ramp up schedule and facilities requirements are speculative prior to a signed Rule 9 agreement, and entirely disregarding these potential loads introduces further risk into the IRP process by limiting response to expected system growth. (Ex. 194 at 14.)

513. NV Energy disagrees with BCP's recommendation that the EV forecast be modified with a lower levelized growth rate to reflect a reduced market demand for EVs and cites data from the Department of Motor Vehicles reflecting an 11.5 percent increase in EVs in less than a year, which exceeds the growth rate recommended by BCP and is more up to date than the information on which BCP relies. (Ex. 194 at 19-20.) NV Energy offers a correction to BCP's load forecast adjustment for EV load based on more recent EV totals – 73 MW reduction over the 3-year Action Plan and 258 MW by 2044. (Ex. 194 at 20.)

514. In response to BCP's other concerns regarding the load forecast, NV Energy states that while it understands BCP's concerns, BCP's position largely focuses only on a handful of large projects in only a certain area of the service territory in a certain instance of time. (Ex. 199 at 9-10.) NV Energy asserts that BCP's narrow view, resulting from selecting

only a handful of projects, does not accurately provide the Commission with the full and accurate picture of the provisions in the Rules which have been successful and provide flexibility depending on the project and associated risk. (Ex. 199 at 10.) NV Energy states that the Rules are time-tested to protect customers and allow for proper development and growth in Nevada. (Ex. 199 at 10.)

515. NV Energy disagrees with BCP's three recommendations in this regard. (Ex. 199 at 10-11.) NV Energy asserts that BCP's recommendation that any amendment to any agreement be subject to a confidential compliance filing is administratively burdensome. (Ex. 199 at 10.) NV Energy further asserts that BCP's recommendation that NV Energy be required to investigate a different structure to the RSTC is unnecessary and restrictive because NV Energy has already demonstrated that the RSTC can be adjusted in specific agreements. (Ex. 199 at 10.) NV Energy further asserts that BCP's recommendation that NV Energy propose a new tariff for take and pay contracts is also unnecessary because NV Energy has demonstrated taking similar action in agreements, such as that with Google. (Ex. 199 at 10-11.)

516. NV Energy further states that it is concerned that BCP is structuring its information, specifically in BCP's attachments PAM-6 and PAM-10, in a manner that supports its goals rather than accurately demonstrating the situation. (Ex. 199 at 11.) NV Energy identifies issues with BCP's characterization of RSTC triggers and omission of various items relating to NV Energy contracts discussed by BCP, including language allowing NV Energy to work with customers to identify solutions and provisions relating to advance subject to potential refund amounts. (Ex. 199 at 11-12.) NV Energy further asserts that BCP also omits various contracts from its analysis which include provisions for triggering a change if thresholds were

not met, and which include increased requirements for an advance subject to potential refund. (Ex. 199 at 12.)

517. NV Energy denies BCP's contention that the load ramp schedule and facilities requirements are speculative until such time as a customer signs a Rule 9 qgreement because, while the values may be variable before the Rule 9 agreement is signed, it does not mean that the loads are entirely speculative. (Ex. 194 at 14.) NV Energy states that incorporating these projects improves the overall information included in the load forecast, which is especially important in this filing given the potential impact of large loads on the system, and ignoring these potential loads would introduce additional risk into the IRP process. (Ex. 194 at 14.) However, NV Energy states that while all projects in the pipeline should be accounted for in the load forecast, it is reasonable to consider larger expected reductions in those projects without a signed agreement. (Ex. 194 at 15.) NV Energy asserts that it is possible that the base load forecast is, in fact, too conservative following recommendations from Staff and BCP to reflect recent information regarding projects that have signed Rule 9 agreements because six of the 19 projects which were in the study phase at the time the forecast was developed now have signed agreements representing 1,430 MW of peak loads, or 32 percent of the total 4,430 MW originally requested for the load forecast under the study phase umbrella. (Ex. 194 at 15-16.)

518. NV Energy further states that additional projects have entered the study phase since the forecast was completed representing a total net increase in requested capacity of 4,810 MW. (Ex. 194 at 16.) NV Energy asserts that removing projects without a signed agreement as of July 2, 2024, as suggested by Staff, would have an upward impact on NV Energy's base load forecast, which is why NV Energy mitigated this risk by using a discounted approach to projects without a signed agreement. (Ex. 194 at 16-17.) NV Energy asserts that the Commission should

consider retaining the approach of including study phase projects in future load forecasts, adjusted appropriately to reflect their changing nature as NV Energy has proposed, because this will allow better demand anticipation while minimizing risks associated with unverified loads. (Ex. 194 at 17.)

519. NV Energy states that it understands the risk and opportunity associated with these very large projects. (Ex. 194 at 13.) NV Energy states that, because of this risk, it has been increasing the provisions and shifting additional risk to the customer developing the project. (Ex. 194 at 13.) Regarding the Public Utilities Commission of Ohio's docket and proposed tariff, NV Energy states that the proposed tariff does not speak to the costs associated with the local transmission and distribution facilities required to connect the project. (Ex. 194 at 13.) NV Energy states that a cursory review of the proposed Ohio tariff for line extensions appears to require the utility invest a minimum of 60 percent for all local transmission and distribution facilities with no options or requirements for security or advances subject to potential refund for that investment, which is significantly riskier than the provisions in Nevada's Rule 9. (Ex. 194 at 13.)

Commission Discussion and Findings

520. The Commission approves the Long-Term Base Load Forecast and Market Fundamentals as being the most accurate information upon which to base long-term planning decisions through the Action Plan period. Specifically, the Commission finds that the 2024 Joint IRP Forecast 1) is based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified pursuant to NAC 704.9321; 2) contains all of the items required by NAC 704.925 and other applicable regulations; and 3) is suitable for making long-term planning decisions over the 2025 to 2044 period.

521. Furthermore, the Commission approves the three-year base load forecast presented in the 2024 ESP as being the most accurate information upon which to base near-term planning decisions through the Action Plan period.

522. The Commission notes that multiple parties characterize the large load growth driven by major projects as uncertain, speculative, and potentially overstated, while other parties argue that the demand included in the forecast is potentially understated and too conservative. The Commission agrees with NV Energy that, considering all parties' testimony, NV Energy's base load forecast is a reasonable mid-range approach.

523. The Commission also agrees with NV Energy that it is impossible to use the most up-to-date information when developing the load forecast because it is one of the first inputs into an IRP and, in this case, the inputs for the load forecast update were finalized in June/July 2023 so that the forecast could be finalized by October 2023. The Commission finds that it may still rely on the load forecast even though the data used to develop it was dated because NV Energy's base load forecast represents substantially accurate data that was gathered from the most current and best sources available at the time when the forecast was developed, particularly with respect to individual major projects.

524. The Commission finds that for this filing, the forecasted NEM customer growth and resulting sales impacts as well as EV forecast have been incorporated into the load forecast. The Commission finds that, while Vote Solar relies on more current NEM information than was available to NV Energy at the time when it developed the forecast, the Commission does not find this to be a fatal flaw in the forecast but rather an issue of timing. For the EV forecast, the Commission accepts NV Energy's correction to BCP's load forecast adjustment for EV load

based on more recent EV totals – 73 MW reduction over the 3-year Action Plan and 258 MW by 2044.

525. The Commission finds that removing projects without a signed agreement as of July 2, 2024, as suggested by Staff, would have an upward impact on NV Energy's base load forecast, which is why NV Energy mitigated this risk by using a discounted approach to projects without a signed agreement. The Commission finds reasonable NV Energy's approach of including study-phase projects in future load forecasts, adjusted appropriately to reflect their changing nature as NV Energy has proposed, because this will allow better demand anticipation while minimizing risks associated with unverified loads.

526. The Commission finds that all major projects should be included in the load forecast regardless of whether a signed agreement exists to account for the potential negative effect on system demand should the projects materialize. To address the uncertain nature of those projects without signed Rule 9 agreements, NV Energy incorporates an average 85 percent reduction to the customer-requested facilities peak megawatt levels for the expected energy requirements and incorporates the remaining 15 percent into the load forecast in phases in accordance with respective load's development timelines, which the Commission finds reasonable and conservative for planning purposes. The Commission finds that this approach is reasonable and prudent because it mitigates the potential negative impact of these loads changing over time and having a material impact on the Preferred Plan as only 15 percent of the requested loads are incorporated into the load forecast over the next ten years.

527. The Commission notes that when actual loads are compared to the expected phased loads, as of August 2024, current major projects are at 54 percent of requested peak facility requirements, which is slightly higher than the loads included in NV Energy's forecast

using its discounted phased-in approach. The Commission finds that the load ramp-up schedule and facilities requirements are not purely speculative prior to a signed Rule 9 agreement; entirely disregarding these potential loads introduces further risk into the IRP process by limiting response to expected system growth. The Commission finds that NV Energy's approach reasonably balances NV Energy's requirement to plan and respond to load growth with NV Energy's requirements to manage risks to existing customers.

528. The Commission appreciates and shares Staff's and BCP's concerns regarding the costs of new facilities built to meet unprecedented projected load and how these costs may go into rates before the billing determinates materialize for the load, increasing rates paid by current ratepayers. The Commission finds that there is no guarantee that the anticipated load from the data centers will come to fruition at the expected time and amount once NV Energy has finished constructing the facilities to serve the requested load. The Commission highlights a recent docket at the Public Utilities Commission of Ohio, and the consideration there that data centers with anticipated load greater than 25 MW make a 10-year commitment to pay for a minimum of 90 percent of the energy usage that was planned for each month regardless of how much energy the customers actually use. The Commission directs NV Energy, Staff, BCP, and any other interested stakeholders to address the Ohio proposal in the Rule 9 workshops, ordered in Phase II, as a potential option to reduce the current ratepayer risk involving these extremely large loads. The Commission directs NV Energy to file a status update within six months of the effective date of this Order addressing the Commission's concerns in this area and the potential for an Ohio-like Rule 9, and Rule 1 as necessary, amendment(s) in Nevada.

529. Additionally, the Commission directs NV Energy to address Tract's suggested changes in the Rule 9 workshops as well, and include proposed Rule 9 changes regarding the

following suggestions in the six-month status report: Tract recommends that the Commission direct NV Energy to have additional requirements for abnormal risk projects to 1) provide security for all up-front utility investment; 2) have the applicant comply with stringent performance obligations under milestone schedules; and 3) phase their developments where feasible.

530. Finally, the Commission directs NV Energy to address BCP's suggestion to enact a provision in its agreements that allows NV Energy, at its own discretion, to permanently reallocate unused capacity to other customers and subsequently amend its contract so that the requested load is binding on the applicant in the Rule 9 workshops as well, and include proposed Rule 9 changes in the six-month status report.

C. NRS Chapter 704B

NV Energy's Position

531. NV Energy requests that the Commission approve its recommended annual limits on the total amount of energy and capacity that eligible NRS Chapter 704B customers may be authorized to purchase from providers of new electric resources during the Action Plan period. (Ex. 101 at 24.) NV Energy states that it has followed the methodology approved in the 2021 Joint IRP, such that the difference between the load at the end of 2027 yields the Action Plan period load growth under normal economic conditions. (Ex. 171 at 23.) NV Energy states that in addition to the base year load calculation for NPC, loads for individual customers on tariff schedules with non-standard, fully bundled price options were excluded from the load growth calculations for both utilities, and the adjusted difference in load was then reduced by 50 percent to offset eligible loads by future expected growth in large commercial and industrial customer sales. (Ex. 171 at 23.)

532. NV Energy states that the proposed eligible loads, which represent annual limits for the Action Plan period, are 260,662 MWh for NPC and, due to a lack of import capacity, 0 MWh for SPPC. (Ex. 171 at 24-25 and Table Pollard-Direct-6.) NV Energy further states that customers under special tariffs are not included in the calculations of the maximum annual limits because these customers do not contribute the same revenue per kWh as other bundled customers and do not contribute towards the system generation costs. (Ex. 171 at 25.) NV Energy asserts that it is therefore appropriate to exclude these customers from the calculations to ensure that revenue associated with exiting loads is offset only by the revenue from load growth paying traditional bundled rates. (Ex. 171 at 25-26.) NV Energy further asserts that it also considered the determinants required by NRS 704.741(6) and the pending regulation, including import capacity, system constraints, and the effect of eligible customers purchasing less energy and capacity than authorized by the proposed annual limit. (Ex. 171 at 26-27; Ex. 103 at 83.)

533. To determine the large commercial and industrial year-end sales growth over the three-year action period, January 1, 2025, through December 31, 2027, NV Energy calculated the difference between the projected large commercial and industrial load in 2027, from the three-year average of actual annual large commercial and industrial loads during the 2021-2023 period. (Ex. 171 at 23-25.) NV Energy then removed the loads for individual customers on tariff schedules with non-standard, fully bundled pricing options, such as the GS-4 New Generation tariff, Large Customer Market Price Energy ("LCMPE") tariff, Market Price Energy ("MPE") tariff, Economic Development Rate Rider ("EDRR") tariff, or the Clean Transition Tariff ("CTT"). (Ex. 171 at 23-25.) Finally, NV Energy applied a 50 percent reduction to reflect the requirement that the annual limits are not to exceed 50 percent pf the large commercial and industrial load growth during the three-year Action Plan period. (Ex. 171 at 23-25.)

534. NV Energy further requests that the Commission approve the Net Differential Energy Rate of $0.04165 per kWh, and the Variable O&M Credit (Charge) of $-0.00015 per kWh for the Action Plan period. (Ex. 101 at 24.) NV Energy states that, to meet the NRS 704B.310 public interest requirement, NRS Chapter 704B customers will continue to pay the equivalent of the fully bundled BTGR and a Net Differential Energy Rate for a three-year period. (Ex. 171 at 27.) NV Energy further states that the incremental Renewable Base Tariff Energy Rate ("R-BTER") and other public policy program rates shall be included for these customers' bills on an ongoing basis, and any additional costs related to Decommissioning and Remediation and Regulatory Asset charges must be imposed by the Commission on customers choosing to exit bundled service. (Ex. 171 at 27.) NV Energy asserts that its calculations demonstrate that NPC customers choosing to exit the system will pay the Net Differential Energy Rate of $0.04165 per kWh during the applicable three-year transition period, which will be partially offset by the $-0.00015 per kWh variable O&M costs credit, and such customers must also pay other costs including the Base Tariff Energy Rate ("BTER") for the transmission period and the then-current R-BTER (currently $0.00404.) (Ex. 171 at 28.)

535. NV Energy further requests that, pursuant to NRS 704B.310(8), the Commission issue a list of any current or ongoing legislatively mandated public policy programs for which eligible customers are required to pay costs, fees, charges or rates. (Ex. 101 at 25.) NV Energy proposes the following legislatively mandated public policy programs that eligible customers are required to pay: Renewable Energy Program Rate, Temporary Renewable Energy Development Program Rate, Universal Energy Charge, NEM, EE and Conservation Programs, ESAP, Natural Disaster Protection Plan, TEP, ERTEP, EDRR, and R-BTER. (Ex. 103 at 19.)

536. NV Energy filed exemplar LCMPE models for NPC's and SPPC's LCMPE tariffs in compliance with Directives 5 and 6 of the Commission's November 1, 2023, Order in consolidated Docket Nos. 23-02010 and 23-02011 for approval by the Commission. (Ex. 192 at 2-3.) NV Energy states that the models use an hourly load profile of a representative large customer and the general characteristics of the most recently approved solar and battery resource as the underlying ESA renewable energy resource to determine the long-term every rate component of a representative ESA. (Ex. 192 at 3.)

537. NV Energy states that, in general, the models begin with an hourly load profile and resource information. (Ex. 192 at 3.) NV Energy states that it used a representative large customer rate class for the hourly load profile and the general characteristics of the most recently approved solar and battery resource as exemplars. (Ex. 192 at 3.) NV Energy states that the models continue to provide the calculation of the ESA rate, including rate components that apply in all hours but are collected through the ESA rate such as a planning reserve margin. (Ex. 192 at 3.) NV Energy states that the models also include other rate components applicable outside of resource hours such as the BTER and Deferred Energy Accounting Adjustment ("DEAA"). (Ex. 192 at 3.) NV Energy states that the models provide both the ESA rate and the resulting overall fully bundled effective rate and compares that to the customers' otherwise applicable rate class. (Ex. 192 at 3.) NV Energy states that while the models show the comparison to the otherwise applicable rate class for transparency, at the time of filing an ESA, NV Energy will provide the applicable comparison of the ESA rate to the distribution-only rate, the most appropriate otherwise applicable rate class for an eligible LCMPE customer. (Ex. 192 at 3.)

538. NV Energy states that the updates to the models include replacing the one-year representative capacity portion of LTAC with a 25-year average of the forecasted LTAC to

represent the forecasted rates over the term of the ESA. (Ex. 192 at 3.) NV Energy states that this average capacity price is added to any hour that the load is not served by the resource. (Ex. 192 at 3.)

539. NV Energy states that it has filed advice letters requesting approval of an additional tariff that employs an ESA. (Ex. 192 at 4.) NV Energy states that an ESA under the CTT begins with the same models as are presented here for the LCMPE. (Ex. 192 at 4.) NV Energy states that the CTT is applicable for existing fully bundled customers and therefore requires a different rate comparison because the otherwise applicable class is the fully bundled rate. (Ex. 192 at 4.)

BCP's Position

540. BCP recommends that the Commission: 1) deny approval of the LCMPE model as proposed by NV Energy; 2) require NV Energy to amend the pricing model to include payment of R-BTER for all energy supplied by the designated resource; and 3) require NV Energy to amend the pricing model to utilize the fully bundled rate, not the Distribution-Only Service ("DOS") rate, as the appropriate comparison to the ESA rate. (Ex. 405 at 8-9.)

541. BCP states that the proposed LCMPE model does not require payment of the R-BTER on energy supplied from the dedicated resource and cites its concern that approval of the model as filed could be interpreted as granting the right to exclude payment of the R-BTER in future ESAs under the tariff, resulting in harm or the loss of a benefit to non-participating customers. (Ex. 405 at 4.) BCP states that historically, the Commission has required customers to pay the R-BTER, and reforms to Chapter 704B pursuant to SB 547 (2019) mandate that all customers, including those seeking an alternate supply under 704B and exempt from exit fees, to pay all public policy costs. (Ex. 405 at 3.) BCP provides that the Commission has deemed the R-

BTER a public policy cost, and since 2019, not a single 704B or LCMPE has been granted an exemption from paying the R-BTER. (Ex. 405 at 3-4.)

542. BCP states that the fact that a designated resource is renewable and contributes to Nevada's decarbonization goals should not exempt LCMPE customers from paying the R-BTER because generally an LCMPE customer is taking a low-cost renewable resource away from non-participants and is receiving a financial benefit in the form of reduced energy costs. (Ex. 405 at 5.) Moreover, BCP contends that customers who seek to be fully renewable should not object to state policies designed to increase the supply of renewables. (Ex. 405 at 5.)

543. BCP states that the proposed LCMPE model compares the ESA rate to an otherwise applicable rate ("OAR"), but not the applicable OAR, instead using the DOS rate. (Ex. 405 at 5.) BCP explains that using the DOS rate is not an "apples to apples" comparison and could result in the approval of an ESA rate below the appropriate fully bundled rate. (Ex. 405 at 6.) BCP states that it is problematic for an ESA rate to be less than the fully bundled rate because it essentially creates a cheaper utility within the utility for a special customer, which might not harm participating customers, but causes them to forgo the benefit of a cheaper resource. (Ex. 405 at 6-7.). BCP contends that ESA customers should pay a premium above the OAR because a customer who wishes to source renewables in excess of the mandated RPS choses to do so on its own volition and captive ratepayers should not subsidize that choice. (Ex. 405 at 7.) BCP states that setting a floor to the effective ESA rate to the fully bundled rate is the simplest and most cost-effective way to ensure that non-participants are not harmed by the ESA. (Ex. 405 at 7.)

544. BCP states that even if its recommendations are accepted, it is still critical of the proposed LCMPE model because it only examines ESAs on an individual basis and does not

consider the cumulative effects of multiple agreements over time. (Ex. 405 at 7.) BCP states that NV Energy has yet to adequately demonstrate that non-participants will not forgo the benefit of a rate reduction of the lowest cost resources are designated for ESA customers, nor has there been an evaluation of whether the cumulative effect of multiple ESAs will shift fuel volatility risk to non-participants. (Ex. 405 at 8.) BCP explains that ESA customers' energy supplies are disproportionately from supplies not subject to price volatility, thus reducing the share of non-volatile priced supply for non-participating customers and shifting the associated risk. (Ex. 405 at 8.)

Staff's Position

545. Staff recommends that the Commission approve NV Energy's exemplar LCMPE base pricing model framework for use as a baseline in future ESAs filed under the LCMPE tariff, but only if all of Staff's recommendations are adopted, which include: 1) incorporating the full BTGR of the ESA customer's OAR class for grid delivered energy in lieu of the grid hour capacity cost price proposed by NV Energy into the model; 2) utilizing the most recently approved inputs at the time the ESA is approved; and 3) the inclusion of a rate comparison using an ESA customer's OARs. (Ex. 312 at 22, 36.) Staff emphasizes that the model and/or any resulting ESA rate should not mean that an ESA is in the public interest. (Ex. 312 at 35.)

546. Staff explains that the LCMPE model is intended to be a model framework to be used as a starting point for determining ESA pricing and a starting point for a rate comparison that applies to all ESAs filed under the LCMPE so that all ESA customers would have the same starting point. (Ex. 312 at 30-31.) Staff states that it is important to set an accurate ESA rate because it will be fixed for a very long period of time and non-participating ratepayers bear the risk of an understated price as they would be responsible for any cost differential between the

long-term ESA rate and the actual cost to serve an ESA customer even though non-participating ratepayers did not have input during the ESA negotiations. (Ex. 312 at 28.) Staff states that non-participants will also likely have little recourse to amend or terminate the ESA to mitigate or eliminate such risk. (Ex. 312 at 28.) Staff states that while NV Energy may claim certain benefits associated with an individual ESA, it has not quantified or guaranteed such benefits, either for the LCMPE model or in another ESA case, such that those benefits can be compared against the risk of increased costs. (Ex. 312 at 28.)

547. Staff notes that while ESA customers bear the risk of an over-stated long-term energy rate, it is a voluntary tariff and such a risk is overstated because ESA customers are likely large, sophisticated, and capable of analyzing the terms, negotiated the deal from the beginning, and likely has options to eliminate or mitigate such risk, including the option to amend or terminate the ESA early. (Ex. 312 at 28-29.) Meanwhile, Staff states that the LCMPE model does not address all requirements of the LCMPE tariffs and lacks provisions such as a determination of no harm or foregone cost reductions to non-participating ratepayers or potential benefits of an ESA. (Ex. 312 at 29.) Staff argues that given the low risk to ESA customers and the risk being assumed by non-participating customers, Staff is critical of the lack of a premium or additional cost for locking in and fixing an ESA rate over the term of the ESA. (Ex. 312 at 29.) Staff explains that an ESA passes risk to customers if the price is set too low, and non-participating customers receive no compensation for assuming that risk. (Ex. 312 at 29-30.)

548. Staff explains that as currently proposed, the BTGR charged to an ESA customer does not contain any generation capacity costs because the ESA customer receives the BTGR generation credit; therefore, NV Energy adds the grid hour capacity component to the ESA rate with the intent to compensate non-participating customers for the ESA customers use of NV

Energy's internal generation during grid hours. (Ex. 312 at 32.). Staff states that it recommends billing an ESA customer for the full BTGR rate of its otherwise applicable class for grid delivered energy rather than the grid hour capacity price component because the grid hour capacity cost does not appropriately capture the costs associated with the ESA customer's use of NV Energy's internal generation during grid hours. (Ex. 312 at 32.)

549. Staff recommends that in lieu of the grid hour capacity cost component of the ESA Long-term energy rate in NV Energy's exemplar LCMPE models, the eligible customer should be billed the full BTGR rate of its otherwise applicable rate class for grid-delivered energy. (Ex. 313 at 86.)

550. Staff states that NV Energy made changes to the exemplar LCMPE model from the model used in the pending Madison Square Gardens ("MSG") ESA in Docket No. 23-08019. (Ex. 313 at 75.) Specifically, Staff states that NV Energy modified its "non-solar capacity charge" component used in that proceeding, which NV Energy now refers to as the grid hour capacity cost component of the ESA long-term energy rate. (Ex. 313 at 75-76.) Staff states that NV Energy changed the calculation of the grid hour capacity cost from the one-year representative capacity portion of the LTAC rate it previously used to a fixed 25-year average of the forecasted capacity component of the LTAC rate to represent the forecasted LTAC rates over the term of the ESA. (Danse P3 at 76.) Staff states that the 25-year average of the forecasted LTAC capacity price is added to any hour that the load is not being served by the renewable energy resource. (Ex. 313 at 76.)

551. Staff explains that it also has concerns regarding NV Energy's exemplar LCMPE model being used as a framework to determine the ESA long-term energy rate. (Ex. 313 at 76.) Staff states that it also has concerns regarding NV Energy's use of the grid hour capacity cost as

a component of the ESA long-term energy rate, NV Energy's use of the LTAC capacity pricing forecast in the grid hour capacity cost calculation, and the mismatch between NV Energy's calculation of the BTGR generation credit and the calculation of the grid hour capacity cost component. (Ex. 313 at 76-77.)

552. Staff states that the fixed 25-year average of the forecasted LTAC capacity price is not representative of the actual generation capacity cost to serve the eligible customer using NV Energy's internal generation during grid delivered hours. (Ex. 313 at 78.) Staff explains that because the LTAC only includes a capacity component during the hours of 7:00 a.m. through 10:00 p.m. on peak-period for the months of June through September, the exemplar model only assesses a capacity cost for any energy delivered to the customer during that period, yet the customer receives a generation capacity credit for not using the same generation for all 8,760 hours a year. (Ex. 313 at 78.)

553. Staff additionally provides that although NV Energy uses a 25-year average of the forecasted LTAC capacity price in the exemplar models, that 25-year average LTAC capacity price is fixed for the 25-year term, instead of updating the grid hour capacity cost component of the ESA long-term energy rate to reflect the new forecasted LTAC capacity price in NV Energy's subsequent triennial IRP filings, which is contrary to the Commission's November 1, 2023, Order in Docket Nos. 23-02010 & 23-02011 - the Application of NPC for approval of an ESA with Resorts World Las Vegas, LLC. (Ex. 313 at 79.)

554. Staff disagrees with NV Energy's claim that there are no generation capacity costs to serve an eligible customer's load during the hours of 11:00 p.m. to 6:00 a.m. and explain that similar to a NEM customer, the eligible customer is back-stopping its load by relying on NV Energy's system and NV Energy has to have sufficient generating capacity to serve that

customer at any time which comes at a cost. (Ex. 313 at 79.) Staff states that NV Energy's cost of service study determines each customer classes' generation capacity costs at the time of peak system demand and recovers this cost over all the hours of the year through the BTGR rates rated to each customer, as evidenced by the generation credits NV Energy lists in NPC's exemplar LCMPE model. (Ex. 313 at 79-80.) Staff states that although the LCMPE tariff provides large customers with alternative pricing options, the LCMPE customer should not be able to circumvent traditional cost of service ratemaking principles and eschew its obligation to pay its fair share of the costs to serve its load. (Ex. 313 at 80.) Staff states that the LCMPE tariff requires that an ESA be in the public interest and in determining the public interest, the Commission must consider whether non-participating customers of the utility experience increased costs for electric service or forgo the benefit of a reduction of costs for electric service as a result of the ESA. (Ex. 313 at 80.)

555. Staff argues that NV Energy's use of the 25-year average of the forecasted LTAC capacity price is contrary to the Commission's orders in Docket Nos. 23-02010 & 23-02011 and the Modified Final Order in Docket No. 21-06001. (Ex. 313 at 80.) Staff explains that in Docket Nos. 23-02010 & 23-02011, the Commission had concerns utilizing a fixed LTAC as a proxy when the renewable resource is not producing energy because the LTAC itself is updated in every triennial IRP. (Ex. 313 at 80.) Staff states that the Commission's concerns are exacerbated when fixing the 25-year average of the forecasted LTAC capacity price over 25 years because over that ESA term, the forecasted LTAC capacity price will be updated 8 times using a 3-year IRP filing cycle. (Ex. 313 at 80-81.)

556. With respect to the Resorts World ESA in Docket No. 21-06011, Staff provides that the Commission found that NPC did not meet its burden of showing how the application, as

filed, met the public interest because of the issues the Commission had with reliance on a pricing forecast, without adjustment, over the period during which the long-term energy rate would be in effect and stated that reliance on a static commodity forecast for the long-term is not appropriate. (Ex. 313 81.) Staff further provides that the Commission rationalized that there should be an ability to update at periodic intervals any long-term energy price that uses a natural gas forward pricing as a component of the calculation, and that the modified Resorts World ESA should address why using a single natural gas pricing forecast for a long-term energy price is appropriate. (Ex. 313 at 81.) Staff explains that NV Energy's exemplar ESA models are still relying on a pricing forecast, but here it is the LTAC capacity pricing forecast instead. (Ex. 313 at 81.) Staff is also critical of NV Energy's decision not to adjust or allow for a true-up to the LTAC capacity pricing forecast over the 25-year period during which the grid hour capacity cost component of the ESA long-term energy rate would be in effect. (Ex. 313 at 81.)

557. Staff explains that it is concerned with NV Energy's calculation of the grid hour capacity cost. (Ex. 313 at 82.) First, Staff provides that there is a mismatch between how NV Energy evaluates the cost of its internal generation capacity. (Ex. 313 at 82.) Staff states that the eligible 704B customer is either being served or not being served by the same generation capacity; however, NV Energy's exemplar LCMPE model uses two different methodologies to calculate the savings accrued from the customer not using NV Energy's internal generation during the time the underlying ESA renewable resource is producing energy using the BTGR generation capacity credits, and the costs incurred from the customer using NV Energy's internal generation during grid delivered hours using the 25-year average of the forecasted LTAC capacity price. (Ex. 313 at 82.) Staff asserts that the generation capacity credit should be calculated the same way as the generation capacity. (Ex. 313 at 82.) Moreover, Staff states that

NV Energy's use of a fixed 25-year average of the forecasted LTAC capacity price as a proxy for the capacity cost of its internal generation resources during grid delivered hours is not representative of NV Energy's actual cost to serve an eligible customer. (Ex. 313 at 82.) Additionally, Staff provides that NV Energy's claim that there are no generation capacity costs to serve an eligible customer's load during grid delivered hours is baseless. (Ex. 313 at 82.)

558. Staff states that NV Energy's mismatch between calculating the BTGR generation capacity credit and grid hour capacity cost under NV Energy's exemplar LCMPE models results in harm to non-participating customers. (Ex. 313 at 83.) Staff explains that the revenue generated by NV Energy through charging the eligible customer the grid hour capacity cost for using NV Energy's internal generation capacity based upon the 25-year average of the forecasted LTAC capacity price does not equal the BTGR costs associated with the customer's use of NV Energy's internal generation during grid delivered hours, and therefore there is a shortfall in BTGR generation revenues that is not addressed. (Ex. 313 at 83.)

559. Staff states, as an example, that in the exemplar NPC LCMPE model, NV Energy calculated a $913,693.33 cost associated with the eligible customer's use of NV Energy's generation capacity during grid-delivered hours. (Ex. 313 at 83.) However, Staff states that NV Energy provided an approximate $4.3 million generation capacity credit to the ESA customer during grid-delivered hours, leaving a shortfall of approximately $3.39 million. (Ex. 313 at 83.) Staff states that it is unclear whether this cost shift will be borne by all customers, other eligible customers, or become the responsibility of the shareholders. (Ex. 313 at 83.) Staff states that NV Energy should be required to address how it intends to incorporate eligible customers in its cost-of-service study and rate design and remove any BTGR revenue shortfalls before the Commission approves any potential ESA that is based on the corresponding LCMPE model

supporting that ESA under the LCMPE tariff. (Ex. 313 at 83-84.)

560. Staff recommends that the Commission order NV Energy to modify its exemplar LCMPE models by removing the BTGR generation credits that the ESA customer receives during grid hours, thereby charging the eligible customer the full BTGR rates during grid-delivered hours. (Ex. 313 at 84.) Staff explains that under this method, the grid hour capacity cost component is removed from the exemplar LCMPE model. (Ex. 313 at 84.) Staff reasons that because the customer receives the BTGR generation credits to estimate the savings of not using NV Energy's internal generation, the same credits should be used to calculate the costs to the customer for using NV Energy's internal generation during grid hours. (Ex. 313 at 84.) Staff states that under this method, no averaging or forecasting would be required because the BTGR rates are updated every GRC. (Ex. 313 at 84.)

561. Staff provides that alternatively, the Commission could remove the BTGR generation credits from the LCMPE model and calculate the generation credits for all hours using the same LTAC capacity price. (Ex. 313 at 84.) Staff explains that under this method, the eligible customer will receive generation credits based on the LTAC capacity price during the hours that the underlying generation resource is producing and will pay the full BTGR rates during the grid-delivered hours since the generation credits and the capacity costs are calculated by the same LTAC capacity price and offset against each other. (Ex. 313 at 84.) Staff states that because the LTAC capacity price is updated every IRP, this method would not require any averaging over a long period. (Ex. 313 at 84.)

562. Staff states that NV Energy agrees that rates should be based upon providing service to a utility's customers and that properly designed rates should produce revenues from each class of customers which match as closely as possible the cost to serve each class or

individual customer. (Ex. 313 at 85.) However, Staff states that when it asked NV Energy why it was not charging eligible customers its otherwise applicable fully bundled BTGR during grid-delivered hours because NV Energy's billing system lacks the ability to do so, requiring manual billing, and due to the complexity of individualized tariffs and rates for eligible customers. (Ex. 313 at 85.) Staff states that requiring that NV Energy manually bill an eligible customer is no excuse to deviate from traditional ratemaking principles. (Ex. 313 at 85.)

563. Staff disagrees with NV Energy that requiring a customer to pay its otherwise applicable fully bundled rate during grid hours requires a separate tariff for each eligible customer. (Ex. 313 at 85.) Moreover, Staff states that allowing an eligible customer to eschew paying the full cost to serve its load because of the need to provide individual billing is unfair, deviates from traditional ratemaking principles, and is discriminatory. (Ex. 313 at 85-86.) Staff states that there is no requirement that an ESA long-term energy rate be fixed over the ESA term. (Ex. 313 at 86.) Staff notes NV Energy's contention that a variable rate would make the ESA rate unattractive to customers; however, the Commission has previously not been persuaded that an ESA is required to be set at a fixed price. (Ex. 313 at 86.)

564. Staff states that requiring an eligible customer to be billed the fully bundled BTGR rate associated with its otherwise applicable rate class does not eliminate all harm of the potential ESA to non-participating ratepayers. (Ex. 313 at 86.) Staff states that evaluating the harm, if any, of an ESA can only be assessed at the time that it is filed with the Commission. (Ex. 313 at 86.) Staff states that its modifications are intended to minimize harm to non-participants, although additional modifications to the model and/or the ESA may still be required. (Ex. 313 at 86.)

565. Staff recommends that the Commission deny NV Energy's requests for approval

of the recommended annual limits on the total amount of energy and capacity that eligible NRS 704B customers may be authorized to purchase from providers of new electric resources during the Action Plan period, the Net Differential Energy Rate of $.0.04165 per kWh, and the variable O&M credit rate of -$0.00015 per kWh for the Action Plan period, and order NV Energy, as a compliance item, to calculate and file the NRS Chapter 704B annual limits, Net Differential Energy Rate and variable O&M credit rate without removing the loads of customers who do not have a Commission-approved ESA. (Ex. 313 at 71.)

566. Staff states that it is concerned that NV Energy removed loads of customers who have not yet been approved by the Commission to take service under the LCMPE or CTT tariffs from its calculation of NPC's annual limits. (Ex. 313 at 70.) Staff provides that NV Energy removed Las Vegas Convention & Visitor Authority's ("LVCVA") loads even though LVCVA's application in Docket No. 24-06012 has not been approved by the Commission. (Ex. 313 at 70.) Staff states that NV Energy's October 9 and October 10, 2024, errata and subsequent supplement did not address those concerns. (Ex. 313 at 70.) Staff states that the errata and corresponding supplement only appear to have addressed NV Energy's original filing overstating the amount of customer load interested in receiving service under the LCMPE or CTT tariffs. (Ex. 313 at 70.) Accordingly, Staff recommends that NV Energy, as a compliance item, recalculate the NRS Chapter 704B annual limits, Differential Energy Rate and Variable O&M credit rate without removing the loads of customers that do not have a Commission-approved ESA. (Ex. 313 at 71.)

567. Staff recommends requiring the use of the most recently approved inputs, including but not limited to the LTAC, generation revenue requirement, an ESA customer's fully bundled OARS forecasted BTER/DEAA rates, and WACC at the time the ESA is approved. (Ex. 312 at 32.) Staff explains that since the ESA rate will be fixed for a long period of time, it is

important to ensure that an ESA does not harm non-participating ratepayers, and a major component of setting the price correctly requires incorporating the most recently available approved information at the time the fixed price is approved. (Ex. 312 at 32-33.) Staff notes that NV Energy stated that its current intent is to use the most recent Commission-approved inputs at the time of the ESA pricing exercise. (Ex. 312 at 33.)

568. Staff explains that using the most recently approved information at the time of ESA approval ensures that such information is used in the LCMPE model if a GRC, IRP, DEAA, or other case that could affect the LCMPE model inputs is concurrently pending with an ESA. (Ex. 312 at 33.) Staff provides that there may be instances where inputs to the models such as rates, WACC, LTAC, public policy charges, etc. may not change between the filing and approval date, but there may be instances where inputs change between filing and approval since there is no deemed approved date for ESAs. (Ex. 312 at 33.) Staff notes that such an occurrence happened in Docket No. 23-08019 regarding MSG's ESA. (Ex. 312 at 33-34.) In making its recommendation, Staff provides that it is not recommending incorporating new inputs/information after the Commission approved an ESA. (Ex. 312 at 34.) Rather, Staff explains that it wants to ensure that NV Energy and an ESA customer are not able to cherry-pick a more favorable long-term ESA by arbitraging the schedule of other cases to its advantage. (Ex. 312 at 34.)

569. Regarding its recommendation to include a rate comparison using an ESA customer's OARs, Staff explains that while a rate comparison between the ESA customer's OARs to the ESA is provided in the exemplar LCMPE model, at the time of filing an ESA, NV Energy will provide the applicable comparison of the ESA rate to the DOS rate, the most appropriate otherwise applicable rate class for an eligible LCMPE customer. (Ex. 312 at 34.)

Staff provides that NV Energy should be able to provide a rate comparison to the DOS rate; however, Staff also contends that NV Energy's claimed transparency provided in the exemplar model should be continued. (Ex. 312 at 34.) Therefore, Staff asserts that the LCMPE model should include an ESA customer's OARs under which it would be if it were a bundled customer. (Ex. 312 at 34.)

570. Staff states its concern regarding how the BTGR Generation Credit given to LCMPE customers will be recovered. (Ex. 311 at 3.) Staff states that as currently proposed, the ESA customer will receive a form of credit for not using NV Energy's internal generation resource (BTGR), signifying that the values will be used in Short Form Statement O to estimate the impact on remaining ratepayers of NV Energy, which NV Energy confirmed. (Ex. 311 at 7.). Staff states that NV Energy's joint application itself is silent on the matter of recovery and explain that because the BTGR generation credit is not collected from an ESA customer compared to the OARs, that portion of the revenue requirement will have to be collected elsewhere. (Ex. 311 at 3-4.) Staff states that this BTGR generation credit shortfall could be recovered three different ways: 1) NV Energy does not seek recovery of the funds and shareholders instead shoulder the cost; 2) NV Energy creates a regulatory asset account and explicitly requests recovery of those costs/unrecovered revenues from non-participating ratepayers thereby creating a subsidy for ESA customers; or 3) NV Energy includes the revenues lost in Statement O and recovers those costs from remaining ratepayers. (Ex. 311 at 5.)

571. Staff states that it would not oppose the first option, as it would hold non-ESA customers harmless; however, Staff is skeptical that NV Energy intends for its shareholders to bear the costs since the company has indicated it will seek recovery of those costs. (Ex. 311 at 5-6.) Under the second and third options, Staff states that non-participating customers would be

required to cover the shortfall of revenue requirement of those ESA customers that voluntarily choose to take service under the LCMPE tariff. (Ex. 311 at 6.)

572. Staff states that NV Energy's filing is hypothetical and specifics regarding an ESA will be included and determined in each ESA filing under the tariff; however, while models appear to show that the LCMPE customer is covering the cost for service it will receive, it also shows that the customer will receive a BTGR generation credit paid under the OARS, meaning that the revenue requirement difference will ultimately be paid by remaining customers. (Ex. 311 at 6.) Staff notes that this matter is to be addressed in a GRC, not an IRP, but needs to be considered before any ESA can be approved. (Ex. 311 at 6.). Staff posits that if NV Energy is requesting that an ESA customer receive a discount on the amounts paid through the exemplar model in its joint application, it is reasonable to assume the same issue will arise in an actual ESA filing, making it important to address this instance of different treatment for similar types of customer classes. (Ex. 311 at 7-8.).

573. Staff explains that NEM customers and ESA customers are very similar in that they both receive electric service from a solar generating facility and receive energy from the utility when the solar facility is unavailable. (Ex. 311 at 8.) Staff states that in the Class Cost of Service Study, NEM customers are treated as if they are full requirement customers and as such, all consumption by NEM customers is used to allocate costs that NV Energy would have incurred to serve that load. (Ex. 311 at 8.) In contrast. Staff provides that the ESA customers receive a credit for not using NV Energy's internal generation resources despite receiving electricity from generation from NV Energy's internal generating resources (the BTGR) when the customer's solar generating facility is unavailable. (Ex. 311 at 8-9.)

574. Staff recommends that the Commission approve NV Energy's request to issue a

list of any current and ongoing legislatively mandated public policy programs for which eligible customers are required to pay costs, fees, charges or rates pursuant to NRS 704B.310(8), and as a compliance item, order NV Energy to clarify how the Commission's Orders to cease recording amounts to the NEM regulatory asset accounts in Docket Nos. 23-06014 and 24-02026 affects the NEM public policy costs NV Energy proposes to charge eligible customers pursuant to NRS 704B.310(8). (Ex. 313 at 73.)

575. Staff states that it has concerns regarding NV Energy's inclusion of the NEM public policy program in this request. (Ex. 313 at 72.) Specifically, Staff provides that it is unclear why NV Energy included the NEM public policy program as a legislatively mandated public policy program for which NV Energy proposes that eligible customers are required to pay costs, fees, charges, or rates pursuant to NRS 704.310(8). (Ex. 313 at 72.) Staff explains that NV Energy has not clarified whether the AB 405 NEM regulatory asset is included in the "NEM public policy costs," and if so, notes that in NPC's GRC in Docket No. 23-06007 and SPPC's GRC in Docket No. 24-02026, NV Energy was directed to cease recording amounts to the AB 405 regulatory asset. (Ex. 313 at 72-73.) Staff states that NV Energy should be ordered to address, as a compliance, how the Commission's direction to cease recording amounts into the AB 405 NEM regulatory asset accounts affect the total cost of the NEM legislatively mandated public policy programs for which NV Energy proposes eligible customers be required to pay. (Ex. 313 at 73.)

NV Energy's Rebuttal

576. NV Energy states that it disagrees with Staff's recommendation that customers currently pursuing ESA service option should be incorporated into the NRS 704B eligible limits calculation because the optional LCMPE/CTT tariff is designed to align potential exiting loads

with the expected loads that will provide the same revenue under fully bundled service to prevent harm to remaining ratepayers. (Ex. 194 at 26.) NV Energy further states that such customers are excluded in the calculation of load growth to ensure that exiting load is replaced by loads for a net zero impact to other customers when rates are set in a GRC. (Ex. 194 at 26-27.)

577. NV Energy also states that three currently pending dockets regarding customers requesting service under an ESA which, if approved, will overstate the load eligible for exiting fully bundled service and may result in harm to remaining ratepayers if replacement load growth does not materialize. (Ex. 194 at 27.) NV Energy states that by not preemptively elevating the limit prior to the Commission's decisions in Docket Nos. 23-02010 and 23-02011, NV Energy has proposed a conservative approach to protect existing customers. (Ex. 194 at 27.) NV Energy further states that if a pending ESA is denied, these loads could be included at the time NV Energy files its next full IRP. (Ex. 194 at 27.) NV Energy asserts that Staff's recommendation should not be accepted and NV Energy's request should be approved because Staff's recommendation would result in a negligible effect on the NRS Chapter 704B eligible limits, resulting in a decrease of 0.1 MW at NPC and 0 MW at SPPC based on the zero transmission import capacity, and rates of $0.04166 per kWh for the BTER neutrality charge and -$0.00018 per kWh for the Variable O&M credit. (Ex. 194 at 28.)

578. NV Energy states that Staff's recommendation for a compliance item requiring clarification on the recovery of the NEM regulatory asset defined in the list of public policy costs charged to eligible NRS Chapter 704B customers is unnecessary because NV Energy's petition for reconsideration regarding removal of the regulatory asset is still pending. (Ex. 194 at 28.) NV Energy states that even if such costs are not recovered in a regulatory asset, NRS Chapter 704B customers should contribute to any costs assessed to other customers due to the NEM

public policy program. (Ex. 194 at 28.) NV Energy further states that because exiting customers will recover these costs via payment of bundled rates over the three-year exit period and through DOS rates afterward, a compliance item requiring further clarification is unnecessary. (Ex. 194 at 28.)

579. NV Energy further states that it disagrees with BCP's recommendation that the R-BTER be mandatorily applied to the designated renewable resource in the LCMPE pricing model. (Ex. 206 at 2.) NV Energy notes that the Commission addressed this issue in Docket Nos. 23-02010 and 23-02011, stating:

> The Commission has the ability to require the R-BTER to be paid currently on a case-by-case basis, and has, in the only approved ESAs, uniformly required the R-BTER to be paid. As such, the Commission does not at this time find it necessary to mandate that all future ESAs will include R-BTER payment and leaves such determination to individual future ESA approval dockets.

(Ex. 206 at 2-3, citing November 1, 2023, Order at 38.)

580. NV Energy further states that it recognizes the Commission's discretion in applying the R-BTER in each ESA application employing the LCMPE pricing model and clarifies that it requests approval of the model with the specific inputs to be provided with each ESA application. (Ex. 206 at 3.) NV Energy further explains that the LCMPE pricing model contains a placeholder set to zero for the R-BTER for hours where the designated resource is available, but notes that the R-BTER is paid in all hours and for all usage when the resource is not available, defined as the grid hours in the pricing model. (Ex. 206 at 3.)

581. NV Energy asserts that the most appropriate comparison for an eligible LCMPE customer is DOS rather than otherwise applicable class, contrary to Staff and BCP's positions, but has provided the comparison to the fully bundled effective rate for complete transparency and ease of reference. (Ex. 206 at 3-4.)

582. NV Energy asserts that, if the Commission agrees with Staff's recommendations against using the capacity portion of the long-term avoided costs to price grid hour capacity costs, then NV Energy recommends the ESA pricing model be changed as follows:

a. Zero the BTGR generation credits during grid hours;

b. Apply the planning reserve margin to the customer's annual consumption served by the underlying renewable resource in the ESA price calculation;

c. Separate out the administrative fee from the planning reserve margin cost to apply that fee to the customer's annual consumption in the ESA price calculation;

d. Remove the grid hour capacity costs from the ESA price calculation.

(Ex. 206 at 6-7.)

583. NV Energy states that it generally agrees with Staff's recommendation that the pricing model should use the most recently approved inputs at the time the ESA is approved, but states that the recommendation and review of updated inputs are more appropriately addressed with each ESA application and are not necessary for approval of the pricing model in this Docket. (Ex. 206 at 7-8.)

584. NV Energy states that it disagrees with Staff's concerns regarding the LCMPE. (Ex. 206 at 8.) NV Energy denies that there is uncertainty regarding how MPE or LCMPE customers would be treated in a GRC because NV Energy has calculated LCMPE and MPE generation credits in Statement O in each GRC for NPC and SPPC since NPC's 2020 GRC and how BTGR revenue is recovered from different customer groups is handled in the rate design process of NPC and SPPC's GRCs. (Ex. 206 at 8-10.) NV Energy asserts that any concerns regarding this revenue recovery should be addressed in GRC dockets, but acknowledges that MPE/LCMPE customers should be treated the same as NEM customers with the exception of certain differences in the calculation of cost of service for NEM customers. (Ex. 206 at 9-11.)

Commission Discussion and Findings

585. The Commission approves NV Energy's exemplar LCMPE base pricing model framework for use as a baseline in ESAs filed under the LCMPE tariff, subject to the inclusion of all of Staff's recommendations, which include 1) incorporating the full BTGR of the ESA customer's otherwise applicable rate class for grid-delivered energy in lieu of the grid-hour capacity cost price proposed by NV Energy into the model; 2) utilizing the most recently approved inputs at the time when the ESA is approved; and 3) a rate comparison using an ESA customer's OARs. The Commission emphasizes that the model is appropriate for use as a *starting point* for determining the ESA price and for a rate comparison in assessing whether ESAs filed under the LCMPE tariff are in the public interest.

586. The Commission approves Staff's recommendation against using the capacity portion of the long-term avoided costs to price grid-hour capacity costs, with NV Energy's clarifications:

a. Zero the BTGR generation credits during grid hours;

b. Apply the planning reserve margin to the customer's annual consumption served by the underlying renewable resource in the ESA price calculation;

c. Separate out the administrative fee from the planning reserve margin cost to apply that fee to the customer's annual consumption in the ESA price calculation;

d. Remove the grid-hour capacity costs from the ESA price calculation.

The Commission agrees with Staff that the generation capacity cost for grid energy should be calculated the same way as the ESA generation capacity credit and that NV Energy's use of fixed 25-year forecasted LTAC capacity price for grid-delivered energy does not reflect NV Energy's actual cost to serve the ESA customer. Again, the Commission notes that the LCMPE model is intended to be a model framework to be used as a starting point for determining ESA price and a starting point for a rate comparison that applies to all ESAs filed under the LCMPE to provide consistency. It is important to set an accurate ESA rate because it will be fixed for an extended period of time, and non-participating ratepayers bear the risk of an understated price as they would be responsible for any cost differential between the long-term ESA rate and the actual cost to serve an ESA customer even though non-participating ratepayers did not have a chance to provide input during the ESA negotiations. Furthermore, non-participants will also likely have little recourse to amend or terminate the ESA to mitigate or eliminate such risk. The Commission finds that while NV Energy may claim certain benefits associated with an individual ESA, it has not quantified or guaranteed such benefits, either for the LCMPE model or in a specific ESA case, such that those benefits can be compared against the risk of increased costs.

587. The Commission agrees with Staff that while ESA customers bear the risk of an over-stated long-term energy rate, it is a voluntary tariff, and such a risk is overstated because ESA customers are large customers by definition, sophisticated, capable of analyzing the terms, negotiated the deal from the beginning, and likely have options to eliminate or mitigate risk, including the option to amend or terminate the ESA early. Meanwhile, the LCMPE model does not address all requirements of the LCMPE tariffs and lacks provisions such as a determination of no harm or foregone cost reductions to non-participating ratepayers, or potential benefits of an ESA. The Commission also agrees with Staff that, given the low risk to ESA customers in comparison to the risk being assumed by non-participating customers, it is concerning that there is a lack of a premium or additional cost for locking in and fixing an ESA rate over the term of the ESA.

588. In summary, the Commission finds that because the grid-hour capacity cost does not appropriately capture the costs associated with the ESA customer's use of NV Energy's

internal generation during grid hours, in lieu of the grid-hour capacity cost component of the ESA long-term energy rate in NV Energy's exemplar LCMPE models, the eligible customer shall be billed the full BTGR rate of its otherwise applicable rate class for grid-delivered energy. The Commission orders NV Energy to modify its exemplar LCMPE models by removing the BTGR generation credits that the ESA customer receives during grid hours, thereby charging the eligible customer the full BTGR rates during grid-delivered hours. Under this method, the grid-hour capacity cost component is removed from the exemplar LCMPE model. Because the customer receives the BTGR generation credits to estimate the savings of not using NV Energy's internal generation, the same credits should be used to calculate the costs to the customer for using NV Energy's internal generation during grid hours. Under this method, averaging or forecasting is not required because the BTGR rates are updated in every GRC.

589. The Commission orders the use of the most recently approved inputs, including but not limited to the LTAC, generation revenue requirement, an ESA customer's fully bundled OARs forecasted BTER/DEAA rates, and WACC at the time the ESA is approved. The Commission finds that because the ESA rate will be fixed for an extended period of time, it is important to ensure that an ESA does not harm non-participating ratepayers, and a major component of setting the price correctly requires incorporating the most recently available approved information at the time when the fixed price is approved.

590. The Commission finds that the most appropriate comparisons for an eligible LCMPE customer are to DOS *and* OARs, rather than one or the other. NV Energy suggests a DOS comparison is the most appropriate, but also includes an OARs comparison in the exemplar LCMPE model. Staff and BCP suggest an OARs comparison. The Commission finds that both comparisons are appropriate for complete transparency and ease of reference and thus orders NV

Energy to include comparisons to both the DOS and OARs that an applicant would be subject to if it were a bundled customer in ESA filings.

591. The Commission approves NV Energy's request to issue a list of any current and ongoing legislatively mandated public policy programs for which eligible customers are required to pay costs, fees, charges, or rates pursuant to NRS 704B.310(8). As a compliance item, the Commission orders NV Energy to clarify how the Commission's Orders to cease recording amounts to the NEM regulatory asset accounts in Docket Nos. 23-06014 and 24-02026 affect the NEM public policy costs that NV Energy proposes to charge eligible customers pursuant to NRS 704B.310(8). The Commission approves NV Energy's issues list with the caveat of the NEM regulatory asset accounts, which the Commission will be able to vet more thoroughly with the filing of the compliance item. The Commission orders the compliance to be filed within one month of issuance of this Order. In ordering this compliance item, the Commission notes the Commission's overall opinion that NRS Chapter 704B customers should contribute to any costs assessed to other customers due to the NEM public policy program.

592. The Commission approves NV Energy's requests for approval of the recommended annual limits on the total amount of energy and capacity that eligible NRS 704B customers may be authorized to purchase from providers of new electric resources during the Action Plan period, the Net Differential Energy Rate of $.0.04165 per kWh, and the variable O&M credit rate of -$0.00015 per kWh for the Action Plan period.

593. The Commission disagrees with Staff's recommendation to include customers currently pursuing ESA service option in the NRS 704B eligible limits calculation. The Commission finds that the exclusion of those customers currently pursuing an ESA under the optional LCMPE/CTT tariff options is designed to align any potential existing loads with the

expected loads that will provide the same revenue under fully bundled service so that there is no harm to remaining ratepayers. The restriction of the maximum limit set at 50 percent of the expected load growth of large commercial and industrial customers over the three-year period is to hold other ratepayers harmless if another customer decides to leave, as its load will be replaced by load growth. Customers on an LCMPE or future CTT tariff may not rely on NV Energy's generation fleet in the same way as a fully bundled customer. Therefore, an LCMPE or CTT customer cannot be considered in the calculation because its use of the system generation resources would not directly offset the existing fully bundled customer.

594. Furthermore, the Commission notes that there are three currently pending dockets regarding customers requesting service under an ESA which, if approved, will overstate the load eligible for existing fully bundled service and may result in harm to remaining ratepayers if replacement load growth does not materialize. By preemptively elevating the limit prior to the Commission's decisions in Docket Nos. 23-02010 and 23-02011, the Commission finds that NV Energy has proposed a conservative approach to protect existing customers.

595. Finally, the Commission notes that Staff's recommendation regarding pending ESA customers would only result in a negligible effect on the NRS Chapter 704B eligible limits, resulting in a decrease of 0.1 MW at NPC and 0 MW at SPPC based on the zero-transmission import capacity, and rates of $0.04166 per kWh for the BTER neutrality charge and -$0.00018 per kWh for the Variable O&M credit.

596. The Commission disagrees with BCP's recommendation that the R-BTER be mandatorily applied to the designated renewable resource in the LCMPE pricing model. The Commission notes that it addressed this issue in Docket Nos. 23-02010 and 23-02011, stating:

> The Commission has the ability to require the R-BTER to be paid currently on a case-by-case basis, and has, in the only approved ESAs, uniformly required the R-BTER to be

> paid. As such, the Commission does not at this time find it necessary to mandate that all future ESAs will include R-BTER payment and leaves such determination to individual future ESA approval dockets.

(November 1, 2023, Order at 38.)

597. The Commission clarifies here that its approval of the LCMPE pricing model is with the specific inputs to be provided with each ESA application. The LCMPE pricing model contains a placeholder set to zero for the R-BTER for hours where the designated resource is available, but notes that the R-BTER is paid in all hours and for all usage when the resource is not available, defined as the grid hours in the pricing model.

D. North Valmy

NV Energy's Position

598. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of two 200 MW (nominal) gas-fired simple-cycle turbines at the North Valmy generation station to serve SPPC's customers with commercial operation projected by June 30, 2028, and with an estimated cost of $575.3 million without allowance for funds used during construction ("AFUDC"). (Ex. 101 at 25; Ex. 174 at 6-7; Ex. 105 at 17, 239.)

599. NV Energy states that although it is requesting approval of fossil generation as part of the Preferred Plan, it is not deviating from clean energy goals because it is eliminating coal from the existing resource portfolio by the end of 2025. (Ex. 175 at 14.) NV Energy asserts that the Preferred Plan meets or exceeds the RPS in all years and targets NV Energy's proportionate share of Nevada's 2050 clean energy goal. (Ex. 175 at 14.) NV Energy states that the proposed Valmy Plant will eliminate the Valmy "must-run" requirement which otherwise would continue in perpetuity and provides needed capacity contribution. (Ex. 175 at 14-15.) NV

Energy further states that the Valmy Plant is not included in the Alternate Plan, which would require the "must run" requirement continue in perpetuity. (Ex. 175 at 16.)

600. NV Energy further requests that the Commission approve $5.22 million for network upgrades to add a 345-kV lead line terminal at the North Valmy Substation bus for the generator interconnection of the Valmy Plant. (Ex. 101 at 28.)

Interwest's Position

601. Interwest recommends that the Commission conduct a more detailed examination of the Valmy Plant and the market options available considering responses to the 2024 RFP. (Ex. 2400 at 7.)

602. Interwest argues that throughout the 2021 IRP, NV Energy made several proposals for the Valmy Plant to solve a voltage problem in the area, along with two separate proposals focusing on solving the transmission issue with solar/ BESS generation. (Ex. 2400 at 34.) Interwest states that despite the Commission's request in the Fourth Amendment to the 2021 IRP in Docket No. 22-11032, NV Energy has not presented a comprehensive analysis of the transmission and economic impacts of options for solutions to the retirement of the Valmy Plant and, instead, proposed a partial solution to transition the Valmy Plant to be repowered with natural gas combustion, resulting in a 522 MW gas addition to the Valmy Plant for voltage regulation and contingency related voltage issues on the SPPC system. (Ex. 2400 at 34-35.) Interwest states that NV Energy proposes North Valmy to prevent a must-run condition at the Valmy Plant. (Ex. 2400 at 35.)

603. Interwest argues that NV Energy failed to provide any substantive evidence regarding the claimed must-run condition of the Valmy Plant, relying solely on assertions that such conditions exist. (Ex. 2400 at 34.) Interwest points out that there is no clarity on how the

construction of the North Valmy Units would resolve the must-run condition, particularly in terms of how the North Valmy Units and the Valmy Repower would function together to address the issue. (Ex. 2400 at 34-35.) Interwest states that NV Energy has argued that the Valmy Plant would need to operate continuously without the North Valmy Units. (Ex. 2400 at 36.) Interwest states that postponing the North Valmy Units would not lead to a perpetual must-run condition for the Valmy Plant. (Ex. 2400 at 36.) Interwest states that resource planning does not operate under a long-term commitment but aims to optimize the system based on future needs. (Ex. 2400 at 36.)

604. Interwest states that the PLEXOS LT model's optimization runs could only choose CT candidate resources in increments of 440 MW, starting in 2027. (Ex. 2400 at 37.) Interwest states that the base case limited the total build to 880 MW, restricting the selection to a maximum of four CTs within the planning period. (Ex. 2400 at 37.) Interwest states that, as a result, NV Energy restricted the model from selecting a single CT or any configuration with less than 400 MW of CTs. (Ex. 2400 at 37-38.) Interwest states that the capacity expansion model did not adequately assess the benefits of various configurations and locations for two CTs. (Ex. 2400 at 38.) (Ex. 2400 at 38.) Interwest points out that after 2027, the model selected no additional gas units for almost two decades, indicating a potential over evaluation of CT capacity. (Ex. 2400 at 39.) Interwest states that the model did not identify the next firm dispatchable units until 2045, despite the new firm generation capacity becoming available after 2040 due to planned CT retirements. (Ex. 2400 at 39.)

Sierra Club's Position

605. Sierra Club asserts that before the increase in the major project load forecast in this IRP, the 2023 Valmy Must Run Study indicated that NV Energy's system would be reliable

without must-run at Valmy Units 1 and 2 after installation of Greenlink West with additional reliability after installation of Greenlink North and found that retiring Valmy Units 1 and 2 would be possible after installation of Greenlink West. (Ex. 1400 at 28.)

606. Sierra Club notes that the Title V air quality permit for the Valmy Plant imposed a retirement date of December 31, 2028, for the coal-fired units. (Ex. 1400 at 6.) Sierra Club further notes that Valmy Units 1 and 2 are two of only three generators located in the Carlin Trend Load Pocket, and NV Energy has previously determined that at least two of the three local generators must run at all times to avoid the risk of load shed in the Carlin Trend Load Pocket. (Ex. 1400 at 6.)

607. Sierra Club states that in NV Energy's Fifth Amendment to the 2021 IRP in Docket No. 23-08015, the Commission approved NV Energy's plan to install selective catalytic reduction ("SCR") technology at Unit 1 and Unit 2, convert the units to gas, and amend the Supply Plan to operate Units 1 and 2 through 2039. (Ex. 1400 at 6-7.) Sierra Club states that the Commission did not approve other proposed capital investments to support continued operation of the Valmy Plant through 2049 based on its finding that the details of these additional investments were uncertain. (Ex. 1400 at 6-7.) Sierra Club asserts that the U.S. EPA's Regional Haze Rule and Good Neighbor Plan, temporarily stayed, may require emission reduction at the Valmy Plant through emissions control technology or reduced generation which increases the risks associated with installation of SCR at the Valmy Plant if a less expensive technology is ultimately required. (Ex. 1400 at 9-10, 21-24.)

608. Sierra Club asserts that NV Energy has not adequately studied whether it will be able to end the ongoing must-run requirement at Valmy Units 1 and 2, despite NV Energy's Preferred Portfolio including the benefits of ending the must-run requirement at the Valmy Plant

after 2028. (Ex. 1400 at 3-4.) Sierra Club asserts that this presents several risks to customers. (Ex. 1400 at 13-26.)

609. Sierra Club recommends that NV Energy provide a detailed technical explanation confirming that the proposed Valmy CT units will enable NV Energy to end the must-run requirement at both Valmy Units and reduce cost and pollution at the units at a similar rate to that shown in the 2024 Preferred Portfolio. (Ex. 1400 at 4.)

610. Sierra Club further recommends that, before the Commission grants approval of cost-recovery for the proposed Valmy CTs in a rate case, NV Energy should be required to provide an explanation and analysis confirming that it will realize the expected cost and pollution reduction benefits at the Valmy Steam Units by removing the must-run requirement during normal system conditions. (Ex. 1400 at 4-5, 27.)

611. Sierra Club states that NV Energy has not taken any steps to plan for implementing seasonal operations at Valmy Units 1 and 2 despite the IRP analysis showing that seasonal operation of the Valmy Plant would be economic once must-run operation is no longer needed, and NV Energy has not communicated with Idaho Power about potential seasonal operations. (Ex. 1400 at 4, 27.) Sierra Club recommends that NV Energy should provide an explanation and analysis of the benefits, obstacles, and next steps toward implementing seasonal operations at the Valmy Plant with the sooner of its next IRP amendment or before both units are converted to gas in 2026. (Ex. 1400 at 5, 27.)

United's Position

612. United states one of the primary purposes of pursuing demand-side resources is to defer or eliminate the need for supply-side resource additions such as NV Energy's proposed gas plant addition. (Ex. 1502 at 22.) United recommends that the Commission direct NV Energy to

defer consideration of proposed new gas CTat this time in light of increased investments in demand-side resources that will address a significant portion of NV Energy's near-term system capacity needs. (Ex. 1502 at 22-23.) United explains that the extent to which these demand-side resources could successfully reduce or eliminate these needs depends on NV Energy's level of investment in flexible load resources and its level of urgency in pursuing them. (Ex. 1502 at 22-23.) United provides even if the gas plant addition cannot be fully avoided, the addition of flexible load resources is still valuable for reducing other future supply-side needs, and aiding reliability. (Ex. 1502 at 23.)

613. United recommends that the Commission should order NV Energy to defer the 2028 Valmy CT additions and instead pursue the incremental near-term BESS additions in the Renewable Plan. (Ex. 1517 at 31.)

614. United argues that NV Energy's choice of the Balanced Plan fails to adequately consider the risks associated with adding new gas resources. (Ex. 1517 at 25.) United is skeptical that NV Energy's Balanced Plan analysis truly reflects all the risks associated with investing in new gas capacity. (Ex. 1517 at 25.) United highlights three risk factors that they believe were insufficiently addressed in NV Energy's analysis: hydrogen gas feasibility and cost risk, stranded cost risk, and opportunity cost risk. (Ex. 1517 at 25.) United states that while NV Energy acknowledges that the new units are capable of operating on hydrogen, they have not provided any evidence or thorough analysis regarding the technical feasibility, the cost implications, or the availability of hydrogen fuel for the units. (Ex. 1517 at 26.)

615. United argues that implementing a must-run requirement, such as the Valmy Plant, may increase costs and emissions since it compels an older, less efficient gas-fired steam generator to operate more frequently than it otherwise would without this constraint. (Ex. 1517 at

28.) United states that investing in Valmy CTs in the near-term presents an opportunity cost, especially considering that a similarly sized BESS could offer greater overall benefits to the system. (Ex. 1517 at 29.)

616. United states that there is no pressing need or significant advantage to eliminating the must-run constraint by 2028 to warrant the investment in Valmy CTs by that deadline. (Ex. 1517 at 30.) United states that when comparing NV Energy's Balanced Plan with the Renewable Plan, it finds no substantial decrease in gas-fired generation levels. (Ex. 1517 at 30.) United states that delaying the proposed CT investments for at least three years may have minimal negative impacts on costs or emissions and would provide an opportunity to evaluate other potential solutions more thoroughly. (Ex. 1517 at 30.)

WRA's Position

617. WRA recommends that the Commission require NV Energy to conduct additional analysis prior to approving Valmy CTs because WRA has concerns with the proposal, including NV Energy's lack of deeper engagement with clean firm resources. (Ex. 1206 at 13.) WRA provides that the Valmy CTs parallel a similar request for additional CTs at Silverhawk approved in the IRP Fourth Amendment to the 2021 IRP in Docket No. 22-11032 and the request to convert, rather than retire, the Valmy coal units, approved in the Fifth Amendment to the 2021 IRP in Docket No. 23-08015. (Ex. 1206 at 16.) WRA states that it recommended exploring additional analysis prior to the Commission approving these other projects; however, NV Energy only pursued the transition from installed capacity conventions to unforced outage capacity conventions recommendation after the Amendment proceedings. (Ex. 1206 at 16.) WRA recommends and supports direct probabilistic modeling of resource portfolios; yet NV Energy does not appear to have implemented, or have future plans to implement, direct probabilistic

reliability risk modeling for its portfolios, which WRA states concern about in light of the reliability risk identified probabilistically in 2030 for the NV Energy Preferred Plan. (Ex. 1206 at 16-17.)

618. WRA states that NV Energy has not made any real efforts to consider clean resource alternatives to the Valmy CTs either, despite National Renewable Energy Laboratory identifying the Valmy Plant as one of the best candidates nationally for replacement of a fossil thermal asset with geothermal. (Ex. 1206 at 17.) WRA provides that the Commission directed NV Energy in the Final Order in the Fifth Amendment to the 2021 IRP in Docket No. 23-08015 to provide updates "regarding the potential for geothermal resources in the Valmy region", aligning with state policy interests. (Ex. 1206 at 17-18.) WRA notes that although NV Energy does provide an update on Valmy region geothermal resources, this update does not resolve the lack of any clear signal or solicitation to the market for geothermal resources in Northern Nevada to address Valmy region needs. (Ex. 1206 at 18.)

619. WRA states that one of the key benefits of the Valmy CT resources is its ability to eliminate the must-run requirement for the Valmy steam units; however, it is important to recognize that the addition of CTs at Valmy is not the sole pathway to alleviating the must-run requirement for the units. (Ex. 1206 at 38.)

BCP's Position

620. BCP states that it does not object to the approval of the two 200 MW gas-fired CTs at the North Valmy generation station. (Ex. 406 at 2.) BCP provides that the two 200 MW CTs are required to close open positions either under to the base or low load forecasts in addition to complying with Western Resource Adequacy Program ("WRAP") requirements to close open positions. (Ex. 406 at 2.)

621. BCP states that it does not object to the approval of the necessary network upgrades to add a 345-kV lead line terminal at the Valmy Plant bus estimated at $5.22 million for the generator interconnection of the simple-cycle turbines. (Ex. 406 at 3.)

Staff's Position

622. Staff recommends that the Commission approve NV Energy's request to construct two 200-MW CTs at the North Valmy generation station. (Ex. 307 at 1.) Staff states that NV Energy has not proposed a new conventional generation resource in nearly 20 years despite facing substantial load growth during that time, and despite it retiring 300 MW of older, less efficient conventional generation. (Ex. 307 at 2.) Staff states that conventional resources are needed to ramp and follow the output of intermittent resources such as solar and wind, and NV Energy's proposal to add three MW of new renewable energy resources for every one MW of conventional resources creates a reasonable ratio to meet clean energy goals and resource adequacy. (Ex. 307 at 2.) Staff states that, even after accounting for inflation, the project compares reasonably to recently constructed combined cycle plants built at the Silverhawk site in Southern Nevada. (Ex. 307 at 3.) However, Staff provides that the Valmy units will not be capped to 700 max hours run per year, creating substantially more value at a comparable cost. (Ex. 307 at 3.)

623. Staff states that the cost of the Valmy project cannot be meaningfully compared to a renewable energy resource such as solar plus BESS because the Valmy Units will be able to run at any given time, which is crucial given SPPC's significant winter peak. (Ex. 307 at 4.) Staff states there are no viable long-term storage options that could enable renewable energy to be stored and supplied 24 hours a day. (Ex. 307 at 4.) Resources like solar PV plus storage are not capable of completely meeting high winter loads or loads that have year-round load factors

such as mining and data centers. (Ex. 307 at 4.) Moreover, Staff notes that the resource additions proposed in the instant IRP are approximately 28 percent conventional and 72 percent renewable, which comports with the Governor's Climate Innovation Plan in addition to Nevada's 2050 net zero carbon goal. (Ex. 307 at 6.)

624. Staff states that the proposed CTs are needed to provide additional generation capacity to meet resource adequacy and energy scarcity issues, which are expected to continue for the foreseeable future as detailed in the North American Electric Reliability Corporation ("NERC")'s Long Term Reliability Assessment published in December of 2023. (Ex. 307 at 4.) Staff notes that the report categorized most of the western United States of being "at risk" of energy shortfalls during extreme weather conditions over the upcoming ten-year period. (Ex. 307 at 4-5.) Moreover, Staff states that NV Energy's base load forecast in the instant IRP shows 1,638 MW of load growth over the upcoming six years, with over 1,000 MW of that growth forecasted to be in SPPC's territory. (Ex. 307 at 5.) Staff states that only utilizing NV Energy's low load forecast, there would be 956 MW of growth with 616 MW occurring in SPPC's territory, which would still be enough load growth to justify the need for the proposed CTs. (Ex. 307 at 5.) Staff notes that much of that forecasted growth comes from large high-load factor customers that cannot be served through the night without additional dispatchable resources. (Ex. 307 at 5.) Staff contends that the proposed generation addition at the Valmy Plant is crucial to serve the expected new load while maintaining reliable service. (Ex. 307 at 5.)

625. Staff states that the addition of the CTs will allow NV Energy to continue working toward Nevada's 50 percent by 2030 RPS goal. (Ex. 307 at 5.) Staff provides that resources like the Valmy CTs will be needed to follow the additional renewable resources necessary to meeting the RPS. (Ex. 307 at 5.) Staff states that while the amount of electricity

generated by all of NV Energy's conventional resources will decline over the coming years, the most reliable way to the net zero carbon by 2050 goal is to maintain all of the conventional capacity NV Energy has, and add capacity if needed, as an insurance policy against the inevitable hiccups that will occur as the state transitions to high penetrations of renewables. (Ex. 307 at 5.) Staff notes that Nevada has narrowly avoided loss of load because of its retained conventional capacity and that had the Commission ordered the retirement of any of the capacity others have argued for in the past, loss of load would have likely been unavoidable, especially given fires and regional transmission outages that have occurred, in addition to rising temperatures. (Ex. 307 at 5-6.)

626. Staff states that the Valmy CTs will create additional benefits such as addressing the increased load from shoulder months (such as October and April) becoming hotter. (Ex. 307 at 7.) Staff explains that as more hot days occur in shoulder months, there is a mismatch between load and generation that can only be addressed by a dispatchable resource like the proposed CTs. (Ex. 307 at 8.) Additionally, Staff states that the CTs are forecasted to run as a perfect complement to solar PV plus BESS resources such that when the three resources' outputs are combined, they could look somewhat like the load shape for a typical summer day or an unusually hot shoulder month day. (Ex. 307 at 8.) Staff states that a dispatchable resource is precisely what the grid needs until BESS or some other technology can provide energy deeper into the evening hours to replace the energy from conventional resources. (Ex. 307 at 8.)

627. Staff states that the Valmy CTs also provide a benefit by helping meet the forward showing requirements of the WRAP. (Ex. 307 at 10.) Staff explains that NV Energy elected for their first binding season with WRAP to be the winter of 2027-2028; however, NV Energy does not have enough resources to participate, which could result in significant penalties to the

utilities. (Ex. 307 at 10.) Staff states that NV Energy projects to be 2,100 MW short without any new resource additions and NV Energy's preferred plan, including the instant CT, would reduce that deficiency to 540 MW, which can be covered through firm contracts meeting WRAP standards. (Ex. 307 at 10.)

628. Staff states that the proposed CTs would also remove the necessity for "must run" requirements for the Valmy steam units; however, Staff notes that even without the addition of the Valmy CTs, additional, renewable resources that have or will come online, which will render the must-run requirement moot. (Ex. 307 at 12-13.) Moreover, Staff states that the Greenlink North project going online by 2028 would eliminate the "must run" requirement, meaning that the "must run" issue has been addressed regardless of the whether the CTs are approved. (Ex. 307 at 13.)

NV Energy's Rebuttal

629. NV Energy denies that elimination of the Valmy must-run requirement is the primary driver behind the selection of the Valmy CTs, stating that while several interveners focus intently on the possibility of addressing the must-run constraint with other means than Valmy CTs, the primary driver behind the selection of the Valmy CTs is capacity. (Ex. 202 at 35.) NV Energy explains that the Valmy CTS provide 379 MW or firm dispatchable capacity, available at any time and not subject to a declining ELCC. (Ex. 202 at 35.)

630. In response to Sierra Club, NV Energy states that the high forecasted load growth and amount of load additions under contract cause NV Energy to anticipate that the Valmy must-run requirement would still exist without the Valmy CTs even after the Greenlink Nevada Project is completed. (Ex. 198 at 5.) NV Energy acknowledges that if the forecasted load growth does not occur, the must-run requirement may initially not be required, but additional growth

will require ramped up system generation, including a contingency under which 800 MW of generation ramp may be required, which is more severe than the current ramp requirement. (Ex. 198 at 5-6.)

631. In response to Sierra Club's recommendation that NV Energy provide a narrative explanation regarding implementing seasonal operation at the Valmy Plant, NV Energy responds that shutting down units when they are not necessary to support customer and system needs is a normal practice and detailed explanations on the subject are not necessary because NV Energy has a number of generating units that are not needed for extended periods when customer load is low, but are required during peak periods. (Ex. 195 at 2-3.) NV Energy states that Idaho Power Company's 50 percent ownership of the Valmy Plant permits Idaho Power Company and NV Energy the same rights to operate the units in support of either utility's system when needed. (Ex. 195 at 4.) NV Energy states that if both utilities do not run the units for a period of time, the utilities will agree to place the units in reserve shutdown, but where NV Energy does not intend to run its share of the units while Idaho Power Company requires unit operation the units are kept operating. (Ex. 195 at 4.) NV Energy states that it will continue to use the LSAP approved by the Commission in 2008 to review the Valmy Units' retirement dates on a going forward basis and will include the analysis in future IRP filings as appropriate. (Ex. 195 at 4-5.) Therefore, NV Energy recommends that the Commission continue to rely on the LSAP to determine lifespans and retirement dates for NV Energy's generating units, and states that a further order on this matter is not necessary. (Ex. 195 at 5.)

632. NV Energy denies that acquiring 500 MW of standalone BESS in lieu of the Valmy CTs, as suggested by WRA would eliminate the Valmy must-run requirement. (Ex. 198 at 4; Ex. 202 at 37-38.) NV Energy explains that the must-run requirement is based on outage

experience with the Humboldt-Rogerson and Falcon-Robinson lines. (Ex. 198 at 4.) NV Energy continues that on September 25, 2022, its Balancing Authority was found to be in an Insecure Operating State following a forced outage of the Humbolt-Rogerson line, Newmont's TS Power Plant, and with both Valmy units offline. (Ex. 198 at 4.) NV Energy states that an Insecure Operating State constitutes a Transmission System Emergency which must be returned to a secure state no longer than 30 minutes after the Insecure Operating State is declared. (Ex. 198 at 4-5.) NV Energy concludes that the 500 MW BESS recommended by United would not solve this issue because it could take over four hours to correct the transmission outage, or such outage may occur when the BESS charge state is low. (Ex. 198 at 5.)

633. NV Energy states that it disagrees with United's contention that adding the Valmy CTs will not reduce gas generation system wide because the Valmy CTs will have quick start capability enabling them to contribute to the Operational Reserve-Supplemental, which will allow a reduction in the amount of Operating Reserve-Spinning. (Ex. 198 at 6-7.) NV Energy asserts that this will allow it to reduce the amount of gas generation that must be kept online and unloaded, which will reduce gas generation system wide. (Ex. 198 at 7.)

634. Regarding United's contention that NV Energy's candidate resource costs were erroneous, NV Energy asserts that the cost of the candidate CTs were based on the best information available at the time and are generic because they were developed early in the plan development process. (Ex. 195 at 5-6.) NV Energy states that the Valmy CTs' costs and costs shown in the Brownfield Study of Technical Appendix GEN-3 of the Joint Application include site-specific costs for site conditions and required infrastructure not included in the generic candidate resource costs. (Ex. 195 at 6.)

635. NV Energy disagrees with United's position that the Commission should require NV Energy to modify its PLEXOS modeling going forward to include higher amounts of flexible load resources because such items should be treated as load modifiers rather than evaluated in PLEXOS. (Ex. 202 at 44.)

636. NV Energy states that it is not necessary to share its PLEXOS models in future IRP proceedings as recommended by WRA because NV Energy currently shares its modeling inputs and outputs via technical appendices and workpapers. (Ex. 202 at 45.) NV Energy asserts that these inputs and outputs constitute a substantial amount of data presented in a common format not specific to any particular vendor's modeling tool. (Ex. 202 at 45.) NV Energy further states that it also provides specific information such as PLEXOS model setting when requested in discovery. (Ex. 202 at 45.) Therefore, NV Energy asserts, sufficient information is available for the interveners to conduct their own modeling if they so choose. (Ex. 202 at 45.)

637. NV Energy states that it does not entirely agree with Staff's position that the Valmy must-run requirement has already been addressed without regard to whether the Valmy CTs are approved. (Ex. 198 at 2.) NV Energy asserts that two issues cause the must-run requirement, the need to provide adequate voltage support in the Carlin Trend area and the need for real power generation at Valmy, and NV Energy is uncertain whether the agreement with Nevada Gold Mines will provide the necessary voltage support for the Carlin Trend area. (Ex. 198 at 2-3, Pottey-Rebuttal 1, Pottey-Rebuttal 2.) NV Energy further states that real power generation is required at Valmy because during periods of high system imports, the system is not strong enough to survive the loss of certain 345-kV lines without shedding load in the Carlin Trend and Reno load pockets, which is exacerbated upon loss of either the #3419 Humboldt-Rogerson line or the #3428 Falcon-Robinson Summit line. (Ex. 198 at 3-4.)

Commission Discussion and Findings

638. The Commission approves, as part of NV Energy's Preferred Plan, a Supply Plan addition of two 200-MW (nominal) gas-fired simple-cycle turbines at the North Valmy generation station to serve SPPC's customers with commercial operation projected by June 30, 2028, and with an estimated cost of $575.3 million without AFUDC.

639. The Commission finds that although it is approving limited fossil-fuel generation as part of the Preferred Plan, NV Energy is not deviating from clean energy goals because it is eliminating coal from the existing resource portfolio by the end of 2025. The Commission highlights that NV Energy's Preferred Plan meets or exceeds the RPS in all years and targets NV Energy's proportionate share of Nevada's 2050 clean energy goal. Furthermore, the Valmy CTs will eliminate the Valmy "must-run" requirement which otherwise would continue in perpetuity and provides needed capacity contribution.

640. The Commission also approves $5.22 million for network upgrades to add a 345-kV lead line terminal at the North Valmy Substation for the generator interconnection of the Valmy Plant.

641. The Commission notes that NV Energy has retired 300 MW of older, less efficient conventional generation. The Commission finds that NV Energy's proposal to add three MW of new renewable energy resources for every one MW of conventional resources creates a reasonable balance between meeting clean energy goals and resource adequacy requirements.

642. The Commission finds that, even after accounting for inflation, the Valmy CT project compares reasonably to recently constructed generation built at the Silverhawk site in Southern Nevada. The Commission finds that the Valmy project cannot be meaningfully

compared to a renewable energy resource such as solar plus BESS because the Valmy units will be able to run at any given time, which is crucial given SPPC's significant winter peak. Moreover, the resource additions proposed in this Docket are approximately 28 percent conventional and 72 percent renewable, which comports with the Governor's Climate Innovation Plan in addition to Nevada's 2050 net zero carbon goal.

643. The Commission finds that the Valmy CTs are needed to provide additional generation capacity to meet resource adequacy and energy scarcity issues, which are expected to continue for the foreseeable future as detailed in the North American Electric Reliability Corporation's Long Term Reliability Assessment published in December of 2023. That report categorized most of the western United States as being "at risk" of energy shortfalls during extreme weather conditions over the upcoming ten-year period. Moreover, NV Energy's base load forecast in this Docket shows 1,638 MW of load growth over the upcoming six years, with over 1,000 MW of that growth forecasted to be in SPPC's territory. Only utilizing NV Energy's low load forecast, there would be 956 MW of growth with 616 MW occurring in SPPC's territory, which would still be enough load growth to justify the need for the Valmy CTs. The Commission echoes Staff's statement that the generation addition at Valmy is crucial to serve the expected new load while maintaining reliable service. Nevada has narrowly avoided loss of load because of its retained conventional capacity, and had the Commission ordered the retirement of any of the capacity that others have argued for in the past, loss of load would have likely been unavoidable, especially given fires and regional transmission outages that have occurred, in addition to rising temperatures and other effects of climate change.

644. The Commission finds that the Valmy CTs will create additional benefits such as addressing the increased load due to shoulder months (such as October and April) becoming

hotter. As more hot days occur in shoulder months, there is a mismatch between load and generation that can only be addressed by a dispatchable resource like the proposed CTs. The Valmy CTs are forecasted to run as a complement to solar PV plus BESS resources such that when the three resources' outputs are combined, they could look somewhat like the load shape for a typical summer day or an unusually hot shoulder-month day. As Staff states, the Commission finds that a dispatchable resource is precisely what the grid needs until BESS or some other technology can economically provide energy deeper into the evening hours to replace the energy from conventional resources.

645. Finally, the Commission finds that the Valmy CTs provide a benefit by helping meet the forward-showing requirements of the WRAP. NV Energy elected for its first binding season with WRAP to be the winter of 2027-2028; however, NV Energy does not have enough resources to participate, which could result in significant penalties to NV Energy. NV Energy projects to be 2,100 MW short without any new resource additions, and NV Energy's Preferred Plan, including the Valmy CTs, would reduce that deficiency to 540 MW, which can be covered through firm contracts meeting WRAP standards.

E. Dry Lake East PPA, Boulder City Solar III PPA, Libra PPA, Corsac PPA

NV Energy's Position

646. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of the Dry Lake East PV and BESS PPA for 200 MW of renewable energy and 200 MW of storage with commercial operation projected in December of 2026. (Ex. 101 at 25; Ex. 175 at 9.) NV Energy represents that the PPA is with NPC for a 25-year term at a flat energy price of $36.78 per MWh and 20-year term for the battery component at a rate of $13,440 per MW-month. (Ex. 101 at 25.)

647. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of the Boulder Solar III PV and BESS PPA for 127.9 MW of renewable energy and 127.9 MW of storage with commercial operation projected in June of 2027. (Ex. 101 at 25; Ex. 175 at 9.) NV Energy represents that the PPA is with NPC for a 25-year term at a flat energy price of $34.60 per MWh and 20-year term for the battery component at a rate of $15,460 per MW-month, but for years 21-25 the remaining battery capacity will be available exclusively to NPC at a price of $0.00 per MW month. (Ex. 101 at 25.)

648. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of the Libra Solar PV and BESS PPA for 700 MW of renewable energy and 700 ME of storage with commercial operation projected for December of 2027. (Ex. 101 at 25; Ex. 175 at 9.) NV Energy represents that the PPA is with NPC for a 25-year term at a flat energy price of $34.97 per MWh and 20-year term for the battery component at a rate of $13,350 per MW-month, but for years 21-25 the remaining battery capacity will be available exclusively to NPC at a price of $0.00 per MW month. (Ex. 101 at 25-26.)

649. NV Energy requests that the Commission approve the Corsac Generating Station 2 PPA for 115 MW of geothermal energy with commercial operation projected for January of 2030. (Ex. 101 at 29; Ex. 185 at 6; Ex. 183 at 10-11.) NV Energy represents that the PPA is with SPPC for a 15-year term at a flat energy price of $107.00 per MWh, will provide 24/7 renewable energy and portfolio credits ("PCs") to Callisto Energy via an ESA, and will not be effective until the ESA has been fully executed and all conditions to its effectiveness have been satisfied. (Ex. 101 at 29.)

///

///

Interwest's Position

650. Interwest recommends that the Commission approve the three solar plus storage PPAs, and the Corsac geothermal PPA. (Ex. 2400 at 7.)

651. Interwest argues that the PPAs serve the public interest, noting that NV Energy selected those projects during the 2023 RFP and represent viable projects. (Ex. 2400 at 40.) Interwest highlights that these PPAs will produce significant amounts of clean energy, and their substantial storage capacity will enhance reliability and provide capacity benefits. (Ex. 2400 at 40.)

652. Interwest supports the Corsac geothermal PPA, asserting that it will supply baseload geothermal power, with costs primarily attributed to its CTT customers. (Ex. 2400 at 41.)

SEA's Position

653. SEA argues that supporting NV Energy's proposed investments in new energy supply sources and upgrades to the transmission system network is crucial for maintaining the reliability of the current load system and accommodating future load growth, particularly in Northern Nevada. (Ex. 700 at 6.) SEA states that postponing or rejecting these energy supply and infrastructure initiatives would substantially undermine Nevada's capacity to support future load demands and economic development. (Ex. 700 at 7.)

SEIA's Position

654. SEIA states that it agrees with NV Energy's request to add 1,028 MW of solar and battery storage resources because the proposed clean energy resources and associated PPAs offer needed capacity and energy to the system. (Ex. 1801 at 2.) SEIA further states, however, that it does not believe the difference in portfolio costs or attributes between the Preferred Plan

and the Alternative Plan adequately justify NV Energy's proposal for new gas resources at Valmy. (Ex. 1801 at 2.) SEIA asserts that its support for the PPAs should not be taken as an endorsement of NV Energy's overall portfolio, specifically NV Energy's procurement practices. (Ex. 1801 at 2-3.)

WRA's Position

655. WRA recommends that the Commission approve the PV/BESS and Geothermal PPAs: Dry Lake East, Boulder III, Libra, and Corsac because these resources are critical to return NV Energy to a positive compliance outlook for Nevada's statutory RPS obligations and to move NV Energy forward toward meeting a growing portion of its capacity need with clean energy and storage (Ex. 1206 Pappas at 5, 13.) WRA states that each of these PPAs will provide significant renewable energy and capacity for the NV Energy system, but even with these resources, NV Energy faces a relatively tight RPS compliance situation on the path to 2030 and 2050; and therefore, NV Energy will benefit significantly from the PPAs capacity contributions for both reliability and compliance with the WRAP. (Ex. 1206 at 13.) WRA explains that the proposed resources will form an important hedge against the rising concentration of NV Energy's portfolio exposed to natural gas fuel prices, including market purchases. (Ex. 1206 at 13.) WRA states that NV Energy has lost considerable time and momentum toward its statutory climate and clean energy goals since the 2021 IRP filing, including its Fifth Amendment, because of a lack of successful renewable project execution following the cancellations of Hot Pot, Iron Point, Chuckawalla, Southern Bighorn, Boulder Solar III, and the Eavor geothermal project. (Ex. 1206 at 14.) WRA notes that while NV Energy is bringing forth the Corsac geothermal PPA, which a single customer sourced and will fund and is not part of NV Energy's broader resource plan, WRA states that NV Energy does not appear to have considered the

potential for its expansion to serve customer renewable and capacity needs. (Ex. 1206 at 18-19.) WRA further states that NV Energy indicates it is not actively pursuing any bilateral geothermal opportunities at this time. (Ex. 1206 at 18-19.) WRA states that to the extent the capacity expansion model does consider geothermal generally, without considering its unique benefits for addressing Northern Nevada local reliability constraints, it does so with a significant handicap because NV Energy's generic geothermal candidate resource has a presumed operating profile, which fails to reflect the potential contributions of new geothermal resources. (Ex. 1206 Position at 19.) WRA explains that this erroneous resource profile, which could have easily been identified and corrected through a stakeholder engagement process, results in a geothermal resource with very low likelihood of selection, raising its levelized cost of energy by approximately half. (Ex. 1206 at 19.)

BCP's Position

656. BCP states that it does not object to the approval of the Dry Lake East PV and BESS PPA for 200 MW of renewable energy and 200 MW of storage with an expected commercial operation in December of 2026. (Ex. 406 at 3.) BCP provides that the Dry Lake project is required to comply with the fifty percent RPS mandate by 2030. (Ex. 406 at 3.)

657. BCP states that it does not object to the approval of the Boulder Solar III PV and BESS PPA. (Ex. 406 at 3.) BCP provides that the project is required to comply with the fifty percent RPS mandate by 2030. (Ex. 406 at 3.)

658. BCP does not object to the approval of the Libra Solar PV and BESS PPA. (Ex. 406 at 3-4.) BCP states that the project is required to comply with the fifty percent RPS mandate by 2030. (Ex. 406 at 4.) BCP also does not object to the approval of the necessary network upgrades to construct a new line position at the Ft. Churchill Substation for the generator

interconnection of the Libra PV/BESS project. (Ex. 406 at 4.)

659. BCP does not object to the conditional approval of the Corsac Generation Station 2 PPA. (Ex. 406 at 4.) BCP notes that the PPA is not effective until the ESA with Callisto Energy is executed and all conditions for its effectiveness have been satisfied. (Ex. 406 at 4.) BCP also does not object to the approval of the necessary network upgrades to add a 345-kV line terminal at Lantern bus for the generator interconnection of the Corsac Geothermal project. (Ex. 406 at 4.)

Staff's Position

660. Staff recommends that the Commission approve the Dry Lake East and Boulder City III PPA as filed. (Ex. 306 at 24.) In recommending approval of these PPAs, Staff notes that it should not be construed as recommending approval of underlying ESAs related to these facilities. (Ex. 306 at 3.) Similarly, Staff states that its recommendations should not be interpreted as recommending approval of the CTT. (Ex. 306 at 3.) Staff states that it will address its recommendations for those ESAs and the CTT in the appropriate pending applications outside of this Docket. (Ex. 306 at 3.) Staff also emphasizes that its recommendations should not be construed as recommending approval to use those facilities' weighted average cost as the generating facility price per MWh model input for the LVCVA and Couer ESA. (Ex. 306 at 4.)

661. Staff states that it recommends approval of the Dry Lake East ("DLE") and Boulder City III ("BS3") PPAs because NV Energy has a need for resources to help close its open capacity positions and to provide PCs to meet its increasing RPS compliances. (Ex. 306 at 15.) Staff states that it agrees with NV Energy that DLE and BS3 will help support native load customer needs and RPS compliance at competitive pricing for a solar plus BESS system. (Ex. 306 at 15-16.)

662. Staff recommends that the Commission approve the Libra PPA without allocating its energy, capacity, and PCs to either NPC or SPPC at this time. (Ex. 306 at 24.) In recommending approval of the PPA, Staff notes that it should not be construed as recommending approval of an underlying ESA related to those facilities. (Ex. 306 at 3.) Similarly, Staff states that its recommendations should not be interpreted as recommending to approve the CTT. (Ex. 306 at 3.) Staff states that it will address its recommendations for those ESAs and the CTT in the appropriate pending applications outside of this Docket. (Ex. 306 at 3.) Staff also emphasizes that its recommendations should not be construed as recommending approval to use those facilities' weighted average cost as the generating facility price per MWh model input for the LVCVA and Couer ESA. (Ex. 306 at 4.)

663. Staff states that it recommends approval of the Libra PPA, without allocation, because NV Energy needs resources to close its open capacity positions, obtain portfolio credits ("PCs") for RPS compliance, and to potentially serve as the generating facility for a pending ESA with a customer located in SPPC's service territory. (Ex. 306 at 6.) Staff notes that NV Energy's RPS compliance outlook is uncertain due to projected load growth, previously approved projects being cancelled by developers, and transmission constraints; however, approval of the proposed PPAs in the instant application should position the utility to meet its future credit commitments. (Ex. 306 at 7.) Staff states that without the addition of the three solar PV plus BESS projects proposed in the instant IRP, SPPC is forecasted to be noncompliant with the RPS in 2027, and NPC would be noncompliant in 2028. (Ex. 306 at 7.) Staff explains that NV Energy intends to allocate all three solar PV plus BESS projects to NPC, moving its projected RPS noncompliance date to 2030, while SPPC's would remain 2027. (Ex. 306 at 8.)

Staff further explains that even if NV Energy allocated 100 percent to SPPC to meet its RPS, it would still be forecasted to be noncompliant in 2027. (Ex. 306 at 8.)

664. Staff states that NV Energy acknowledges that SPPC will fall short of its RPS goals in 2027 but has adequate credits to cover SPPC's deficit, such that NV Energy might achieve RPS compliance in all years of the Action Plan. (Ex. 306 at 8.) Staff states that NV Energy intends to pursue all viable plans including inter-company PC transfers and/or procurement of additional generating resources as needed to avoid non-compliance. (Ex. 306 at 8.) Staff explains that there is an established Commission process for transferring PCs for compliance, provided that the borrowing utility repays the PCs before the lending utility needs them for their own RPS compliance. (Ex. 306 at 9.) Staff states that NV Energy is not seeking approval for an inter-company PC transfer in the instant docket, however, Staff provides that NV Energy should seek Commission approval for such a transaction, and a PC Agreement should be used. (Ex. 306 at 9.)

665. Staff disagrees with NV Energy's proposed 100 percent allocation of the Libra PPA to NPC. (Ex. 306 at 10.) Staff argues that the cost of the resource should be borne by the same ratepayers who receive the localized economic benefits from the construction of the resource, which is in SPPC's territory. (Ex. 306 at 10.) Moreover, due to its location and ability to provide a reliability benefit into the Carson load pocket, which directly benefits SPPC customers, at least a portion of Libra should be allocated to SPPC. (Ex. 306 at 10.) Staff additionally states that the cost of service, cost of energy, and joint dispatch agreement related questions may arise in Docket No. 24-06011, the Coeur ESA, regarding whether an ESA customer located in SPPC's territory should be allowed to utilize a generating resource that is allocated 100 percent to NPC. (Ex. 306 at 10.)

666. Staff states that it normally recommends resource allocation at the time of PPA approval, but in this instance, recommends the Commission wait on this decision because NV Energy is forecasting an unprecedented amount of expected load growth over the next ten years, several large, the uncertainty of several very large potential company-owned resources, and the impact that this project will have on NV Energy's RPS forecasts. (Ex. 306 at 10.) Regarding load growth, Staff explains that the PCs needed to meet RPS compliance is based on a company's annual retail sales, and Libra's allocation is based on NV Energy's open capacity position at the time of filing. (Ex. 306 at 10.) However, Staff states its concern with the forecasted load growth resulting from new major projects, and there is no guarantee that the load will come online at the expected size or in-service date. (Ex. 306 at 10.)

667. Additionally, Staff provides that NV Energy anticipates submitting company-owned renewable projects in the future for a more balanced portfolio and has also entered into Option Agreements for land to develop projects and meet anticipated load growth, RPS, and open positions. (Ex. 306 at 11-12.) Staff states that it does not currently know what potential resource types, size, or development schedule of projects that could be built on this land. (Ex. 306 at 12.) Staff provides that it does not know if or when these projects will be included in an IRP for Commission approval; however, their inclusion or exclusion in the RPS forecast and load and resources table impact the PC supply and capacity needs which in turn influence how Libra should be allocated. (Ex. 306 at 12.) Staff states that the known company-owned resources included in the filing as "named placeholders" include 800 MW of solar and 600 MW of BESS with the first phase estimated Commercial Operation Date ("COD") of April 1, 2031, and a 600 MW solar project with 100 MW of BESS, with an estimated COD of April 1, 2030, and an additional phase for a 500 MW BESS. (Ex. 306 at 12.) Staff states that while it is helpful to

know about these projects in advance, until a project is in front of the Commission for approval, its size, COD, and ability to come to fruition is speculative. (Ex. 306 at 12-13.)

668. Staff recommends that the Commission approve the Corsac PPA with the requirement that if the Callisto ESA is terminated early, then NV Energy will not be allowed to recover the costs of purchasing Corsac's generation for the remainder of the PPA term. (Ex. 306 at 24.) Alternatively, Staff recommends that the Commission approve the PPA with the requirement that if the Callisto ESA is terminated early, then NV Energy must seek Commission approval to set the price it will charge to ratepayers for Corsac's generation for the remainder of the PPA term. (Ex. 306 at 24.) In recommending approval of the PPA, Staff notes that it should not be construed as recommending approval of an underlying ESA related to those facilities. (Ex. 306 at 3.) Similarly, Staff states that its recommendations should not be interpreted as recommending approving the CTT. (Ex. 306 at 3.) Staff states that it will address its recommendations for those ESAs and the CTT in the appropriate pending applications outside of this Docket. (Ex. 306 at 3.)

669. Staff states that the Corsac PPA will not be effective until the Callisto ESA has been fully executed and all conditions to its effectiveness have been satisfied. (Ex. 306 at 4.) Staff further states that those conditions include Commission approval of the ESA, tariff, and underlying resource in addition to both parties to the agreement finding the terms of the Commission's order satisfactory. (Ex. 306 at 17-18.) Staff notes that the Callisto ESA allows for early termination for a fee; however, termination of the ESA would not alter NV Energy's obligations as a party to the PPA. (Ex. 306 at 18-19.) Given that, Staff explains that its recommendation includes contingencies to consider a scenario where Callisto elects to terminate its ESA early to prevent ratepayers being used as a safety net in the event a single large customer

decides to no longer pay for an out-of-the-money resource that was procured solely on its behalf. (Ex. 306 at 19-20.) Therefore, Staff contends that the Commission must consider the PPA terms that the ratepayers would be bound by, and what costs ratepayers would be obligated to pay, should the Callisto ESA terminate early. (Ex. 306 at 20.)

670. Staff states that NV Energy represents that the ESA includes a provision requiring an early termination payment to hold non-participating ratepayers harmless for the period encompassing the effective date of the termination until the expiration of the ESA term. (Ex. 306 at 20.) However, Staff provides that it is not certain whether ratepayers would be held harmless by the terms of the ESA and note that the Callisto ESA and CTT do not include the term "hold harmless." (Ex. 306 at 20-21.) Staff states that by addressing the termination clause of the ESA, Staff does not intend for its recommendations to be construed as approval of the early termination provision, nor is it asking the Commission to modify the language contained in the ESA. (Ex. 306 at 21.) Staff explains that this is a unique Commission decision where there is the existence of a PPA in this Docket that is predicated on the approval of an ESA in another docket that is enabled by a proposed tariff filing pending in another docket. (Ex. 306 at 21.) Staff notes that its recommendations in this Docket should not be construed as supporting the pending related ESA agreement or CTT. (Ex. 306 at 21.)

671. Staff states that it recommends denying cost recovery of the money paid for Corsac's generation by NV Energy if the Callisto ESA terminates early to address the risk that, even factoring an early termination payment, the PPA price could be more expensive than renewable generation available to be built to serve NV Energy at the time of the ESA's early termination. (Ex. 306 at 21-22.) Staff states that, because NV Energy decided, without approval from the Commission, to take on the obligation of paying for the generation of Corsac through

the end of its PPA term if the ESA was terminated early, and given NV Energy's representation that it would not have brought this resource for approval given its price, Staff reasons that NV Energy, not ratepayers, should assume the entire risk of paying for generation priced higher than available renewable resources. (Ex. 306 at 22.)

672. Staff explains that in its alternate recommendation, if the ESA terminates early, then NV Energy should request approval in an IRP or an amendment to set a per MWh price that ratepayers would pay to Corsac through the end of the PPA term, either being equal to the per MWh price set in the PPA if the early termination payment is shown to hold non-participants harmless, or at some lower per MWh price that will hold ratepayers harmless, with the out of the money portion of the PPA's per MWh cost borne by shareholders. (Ex. 306 at 22.) Staff states that a potential methodology to determine harm to ratepayers in the event of an early expiration would be to compare the cost of Corsac's generation for the remaining years of the term, minus the amount of the early termination payment, to the price of renewable generation available to be built to serve NV Energy at the time of the ESA's early termination, pricing which can be obtained through NV Energy's most recently issued all resource RFP. (Ex. 306 at 22-23.) Staff asserts that given NV Energy's representation to hold ratepayers harmless for the ESA, it is incumbent upon them to demonstrate that is ultimately the case. (Ex. 306 at 23.)

673. Staff recommends that the Commission approve the network upgrades associated with the the Dry Lake East PV/BESS, Libra PV/BESS, and Corsac Geothermal Generating Station 2 projects, assuming that the corresponding PPAs are approved. (Ex. 305 at 2, 6-7.) Staff states that all three requested network upgrades are essential to connect each underlying project to its respective substation and eventually the grid. (Ex. 305 at 5.) Staff states that the Dry Lake East and Libra solar projects will add 900 total MW of renewable resources to NV Energy's

capacity, helping it comply with Nevada's RPS and to help reach the net-zero plan. (Ex. 305 at 5.) Staff further states that approving the network upgrades for the Corsac Geothermal Project will help reduce load obligations and increase system reliability. (Ex. 305 at 5-6.). Staff states that the estimated costs of these network upgrades appear reasonable compared to other recently performed upgrades. (Ex. 305 at 6.)

NV Energy's Rebuttal

674. NV Energy notes that Staff recommends approval of the Dry Lake East PPA and the Boulder City III PPA as filed. (Ex. 201 at 11.)

675. NV Energy asserts that Staff and BCP have recommended that the Commission approve the Dry Lake network upgrades at Harry Allen. (Ex. 197 at 2.) NV Energy asserts the Dry Lake network upgrades at Harry Allen are required per the executed Large Generator Interconnection Agreement ("LGIA") and the IRP's Preferred Plan. (Ex. 197 at 2.)

676. NV Energy notes that Staff recommends approval of the Libra PPA without allocating its energy, capacity, and PCs to either NPC or SPPC at this time. (Ex. 201 at 11.) NV Energy states that it agrees with adjusting Libra's energy, capacity, and PCs at a later date based on future needs but disagrees that approval should not specify allocation at this time and restates its position that Libra's energy, capacity, and PCs should be allocated to NPC for planning purposes based on the economic analysis and RPS forecast. (Ex. 201 at 12.)

677. NV Energy disagrees with Staff, stating that Staff's proposed condition related to the Callisto Enterprises ESA is not necessary because the early termination terms of the ESA adequately protect customers. (Ex. 201 at 12; Ex. 206 at 12-13.) NV Energy asserts that the early termination provision utilizes a Commission-approved rate to determine the amount that

existing customers will pay while the ESA customer will pay any excess between the Commission-approved rate and the PPA price. (Ex. 206 at 12.)

Commission Discussion and Findings

678. The Commission approves the Dry Lake East and Boulder City III PPAs as filed. The Commission notes that in approving these PPAs, the Commission is not approving the underlying ESAs related to these facilities in this Order. Similarly, the Commission is not approving the CTT in this Order. The Commission will address the ESAs and the CTT in the appropriate pending applications outside of this Docket. Finally, the Commission is not approving the use of those facilities' weighted average cost as the generating facility price per MWh model input for the LVCVA and Couer ESA.

679. The Commission approves the Dry Lake East and Boulder City III PPAs because NV Energy has a need for resources to help close its open capacity positions and to provide PCs to meet its increasing RPS compliances. The Commission agrees with NV Energy and Staff that these PPAs will help support native-load customer needs and RPS compliance at competitive pricing for solar plus BESS systems.

680. The Commission approves the Libra PPA without allocating its energy, capacity, and PCs to either NPC or SPPC at this time. The Commission notes that it should not be construed as approving an underlying ESA related to those facilities. Similarly, the Commission's Order in this Docket should not be interpreted as approving the CTT. The Commission will address ESAs and the CTT in the appropriate pending applications outside of this Docket. The Commission emphasizes that its approval should not be construed as recommending approval to use those facilities' weighted average cost as the generating facility price per MWh model input for the LVCVA and Couer ESA.

681. The Commission approves the Libra PPA, without allocation, because NV Energy needs resources to close its open capacity positions, obtain PCs for RPS compliance, and because the Libra PPA may potentially serve as the generating facility for a pending ESA with a customer located in SPPC's service territory. NV Energy's RPS compliance outlook is uncertain due to projected load growth, previously approved projects being cancelled by developers, and transmission constraints; however, approval of the Libra PPA, along with Dry Lake and Boulder City III PPAs, should position NV Energy to meet its future RPS commitments.

682. NV Energy acknowledges that SPPC will fall short of its RPS goals in 2027 but has adequate credits to cover SPPC's deficit, such that NV Energy might achieve RPS compliance in all years of the Action Plan. The Commission notes that NV Energy intends to pursue all viable plans, including inter-company PC transfers and/or procurement of additional generating resources as needed to avoid non-compliance. There is an established Commission process for transferring PCs for compliance, provided that the borrowing utility repays the PCs before the lending utility needs them for their own RPS compliance. NV Energy is not seeking approval for an inter-company PC transfer in the instant docket; however, the Commission finds that NV Energy should seek Commission approval for such a transaction, and a PC Agreement should be used.

683. The Commission disagrees with NV Energy's proposed 100 percent allocation of the Libra PPA to NPC at this time because the cost of service, cost of energy, and joint dispatch agreement related questions may arise in Docket No. 24-06011, the Coeur ESA, regarding whether an ESA customer located in SPPC's territory should be allowed to utilize a generating resource that is allocated 100 percent to NPC.

684. The Commission notes that, normally, the Commission approves resource allocation at the time of PPA approval, but in this instance, the Commission waits on this decision because NV Energy is forecasting an unprecedented amount of expected load growth over the next ten years, and the related uncertainty of these projects will affect NV Energy's RPS forecasts.

685. Finally, the Commission approves the Corsac PPA with the requirement that if the Callisto ESA is terminated early, then NV Energy must seek Commission approval to set the price that it will charge to ratepayers for Corsac's generation for the remainder of the PPA term. As noted above for Dry Lake East and Boulder City III, the Commission will address its recommendations for the ESA related to Corsac and the CTT in the appropriate pending applications outside of this Docket.

686. The Corsac PPA will not become effective until the Callisto ESA has been fully executed and all conditions to its effectiveness have been satisfied. Those conditions include Commission approval of the ESA, tariff, and underlying resource in addition to both parties to the agreement finding the terms of the Commission's order satisfactory. The Callisto ESA allows for early termination for a fee; however, termination of the ESA would not alter NV Energy's obligations as a party to the PPA. Given that, the Commission approves the Corsac PPA with the contingency to consider a scenario where Callisto elects to terminate its ESA early to prevent ratepayers being used as a safety net in the event a single large customer decides to no longer pay for an out-of-the-money resource that was procured solely on its behalf.

687. The Commission notes that the ESA includes a provision requiring an early termination payment to hold non-participating ratepayers harmless for the period encompassing the effective date of the termination until the expiration of the ESA term. However, the

Commission agrees with Staff that even with this provision, it is not certain whether ratepayers would be held harmless by the terms of the ESA; neither the Callisto ESA nor the CTT include the term "hold harmless."

688. The Commission finds that if the ESA terminates early, then NV Energy needs to request approval in an IRP or an amendment to set a per-MWh price that ratepayers would pay to Corsac through the end of the PPA term, either being equal to the per-MWh price set in the PPA if the early termination payment is shown to hold non-participants harmless, or at some lower per-MWh price that will hold ratepayers harmless, with the out-of-the-money portion of the PPA's per-MWh cost borne by shareholders. The Commission notes that Staff provides a potential methodology to determine harm to ratepayers in the event of an early termination, which would be to compare the cost of Corsac's generation for the remaining years of the term, minus the amount of the early termination payment, to the price of renewable generation available to be built to serve NV Energy at the time of the ESA's early termination, pricing which can be obtained through NV Energy's most recently issued all-resource RFP. Given NV Energy's representation to hold ratepayers harmless for the ESA, it is incumbent upon it to demonstrate that is ultimately the case.

689. Finally, the Commission approves the associated network upgrades for the Dry Lake East PV/BESS, Libra PV/BESS, and Corsac Geothermal Generating Station 2 projects. The Commission finds that the requested network upgrades are essential to connect each underlying project to its respective substation and eventually the grid. The Dry Lake East and Libra solar projects will add 900 total MW of renewable resources to NV Energy's capacity, helping it comply with Nevada's RPS and to help reach the net-zero goal. Furthermore, the network upgrades for the Corsac Geothermal Project will help reduce load obligations and

increase system reliability. The Commission finds the estimated costs of these network upgrades reasonable compared to other recently performed upgrades.

F. Tolson Substation

NV Energy's Position

690. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Tolson substation transformer #2, 230/138 kV, with a projected March 2028 in-service date and a cost of $9.60 million. (Ex. 101 at 26; Ex. 177 at 2, 14-15.)

BCP's Position

691. BCP does not object to the approval of the Tolson Substation 230/138-kV transformer #2. (Ex. 406 at 9.)

Staff's Position

692. Staff recommends that the Commission approve the proposed addition of the Tolson Substation Transformer #2. (Ex. 308 at 2,5.)

693. Staff states that it reviewed NV Energy's transmission planning assessment of the project and note that it included a corrective Action Plan that, in part, discussed the eventual need for a Tolson - Ford 138-kV line addition and a Pebble - Tolson 138-kV line uprate due to either a combination of P6 contingencies or because the proposed addition of the Tolson 230/128-kV Bank #2 will create overloads. (Ex. 308 at 3-4.) Staff provides that these additional projects were not proposed in the instant joint application or previous IRP filing and explain that NV Energy asserts in the filing that these projects need to be completed regardless of the installation of the Tolson 230/138-kV 336 MVA Transformer #1. (Ex. 308 at 4.)

694. Staff provides that adding the second Tolson bank would make the overloads in the 138-kV system worse, which further justifies the two 138-kV lines; however, neither of those

costs, which total an additional $14.36 million through 2028, are being sought for approval. (Ex. 308 at 4.) Staff states that it is concerned that neither of the necessary and eventual projects were included in the instant joint application despite being necessary to achieving an in-service date of March 2028; however, Staff does not consider the additional future network upgrades to be a barrier to moving forward with the Tolson Substation Transformer #2 project. (Ex. 308 at 5.)

NV Energy's Rebuttal

695. NV Energy states that the Tolson Substation Transformer is required per NERC standard TPL 001-5. (Ex. 197 at 2.)

Commission Discussion and Findings

696. The Commission approves, as part of NV Energy's Preferred Plan, a Supply Plan addition of Tolson substation transformer #2, 230/138 kV, with a projected March 2028 in-service date and a cost of $9.60 million because the Tolson Substation Transformer is required per NERC standard TPL 001-5. The Commission notes that no party objects to this project.

G. Reid Gardner-Harry Allen

NV Energy's Position

697. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Reid Gardner-Harry Allen 230-kV line #3 and separation of lines #1 and #2 with a projected May 2026 in-service date and a cost of $24.20 million. (Ex. 101 at 26; Ex. 177 at 2, 15-16.)

BCP's Position

698. BCP does not object to the approval of the Reid Gardner to Harry Allen 230-kV transmission line. (Ex. 406 at 3.)

///

Staff's Position

699. Staff recommends that the Commission reject the addition of the Reid Gardner - Harry Allen 230 kV line #3 and Separation of Lines #1 and #2 project. (Ex. 308 at 9, 14.) Staff states it has two primary concerns with the project – 1) the viability of the interconnection customer's procurement of the required lands to which the only LGIA is based upon; and 2) the forecasted costs of $24.20 million appears low and either incorrectly estimated or not fully explained and transparent. (Ex. 308 at 11.)

700. Regarding the land, Staff states that its review of the 2023 RFP deduced that this confidential interconnection customer ranked poorly as compared to evaluations of other companies and their permutations for Solar plus storage PPAs. (Ex. 308 at 11.) Staff provides that the confidential company's low score was due to its non-price scores, which received the lowest possible score for the lands and environmental category, giving Staff little to no confidence that this interconnection customer will be able to secure the land required for them to interconnect a 200 MW Solar plus BESS facility, demonstrating a high likelihood that this interconnection will not come to fruition despite a signed LGIA. (Ex. 308 at 11-12.) Staff states that this project is high risk because the only interconnection customer has no risk other than a small security invested to secure NV Energy as the off-taker, and if the interconnection customer is unable to secure the land or permits and NV Energy has built the project, those costs would be borne by ratepayers in transmission rates. (Ex. 308 at 12.)

701. Regarding project costs, Staff states that its concern is predicated upon a simple cost estimation for the construction of the single 230-kV circuit. (Ex. 308 at 12.) Staff explains that using the 2.3-mile Reid Gardner to Tortoise #2 transmission line previously approved in Docket No. 19-05003, which had a projected cost of $5,745,400, as a proxy to estimate the

average linear cost to construct a transmission line, NV Energy's estimate is too comparatively low. (Ex. 308 at 12.) Staff estimates that a project of this size should be forecasted to cost approximately $64 million for a single 230-kV transmission circuit, based on the historical costs of a similar caliber project noted above. (Ex. 308 at 12-13.). Given this, Staff contends that given the requests in the joint application, there would be additional costs that have not been presented. (Ex. 308 at 13.). Moreover, Staff states that NV Energy has a history of exceeding their original cost estimates approved by the Commission, including the Greenlink Nevada Project. (Ex. 308 at 13.)

NV Energy's Rebuttal

702. NV Energy notes that Staff has recommended that the Reid Gardner-Harry Allen 230 kV line #3 be denied. (Ex. 197 at 4.) NV Energy recommends on rebuttal that the Reid Gardner-Harry Allen 230 kV line #3 be granted conditional approval with security provided by the customer and asserts that the in-service date for the Reid Gardner-Harry Allen 230 kV line #3 has been moved to January 1, 2028. (Ex. 197 at 4.)

703. NV Energy further states that the customer wishing to connect the generation project at Reid Gardner has a valid fully executed LGIA, and the line is required pursuant to FERC's Open Access Transmission Tariff ("OATT"), pursuant to which NV Energy has executed the LGIA. (Ex. 198 at 8.) NV Energy states that it is currently working through the Bureau of Land Management ("BLM")'s permitting process for Reid Gardner-Harry Allen 230 kV line #3, which it notes was previously approved in Docket No. 22-11032, and the projected in-service date has been moved to January 1, 2028, upon the customer's request. (Ex. 198 at 8.)

704. In response to Staff's concern that the forecast cost for this project should be approximately $64 million, NV Energy states that the estimated cost for the project submitted in

the filing is $24.2 million, and the latest estimate available places the estimated cost at $26 million, and pursuant to the LGIA the interconnection customer is required to securitize the network upgrade costs. (Ex. 198 at 9.) NV Energy states that if the Commission denies approval of this project at this time, NV Energy will be obligated under the LGIA to resubmit the project in a future IRP or IRP amendment, which may be accomplished without delaying the new in-service date. (Ex. 198 at 9.) NV Energy requests that, to avoid the need for resubmission, the Commission approve the project in this proceeding subject to the interconnection customer fully securitizing all network upgrade interconnect costs as required by the LGIA. (Ex. 198 at 9.)

Commission Discussion and Findings

705. The Commission grants conditional approval of the Reid Gardner-Harry Allen 230 kV line #3 with the conditional approval of security provided by the customer and an in-service date moved to January 1, 2028. The Commission grants the conditional approval to recognize the importance of the line and balance Staff's legitimate concerns.

706. The Commission notes that the customer wishing to connect the generation project at Reid Gardner has a valid fully executed LGIA, and the line is required pursuant to FERC's OATT, pursuant to which NV Energy has executed the LGIA. NV Energy is currently working through the BLM's permitting process for Reid Gardner-Harry Allen 230 kV line #3, which was previously approved in Docket No. 22-11032, and the projected in-service date has been moved to January 1, 2028, upon the customer's request.

707. The Commission is still concerned by the projected cost estimates; even with NV Energy's updated estimated cost for the project at $26 million, this estimated cost is still well below Staff's $64 million cost estimate. To help alleviate the Commission's cost concerns, the

Commission conditionally approves the project subject to the interconnection customer fully securitizing all network upgrade interconnect costs as required by the LGIA.

H. Lantern-Comstock Meadows

NV Energy's Position

708. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Lantern-Comstock Meadows 345-kV line with a projected December 2029 in-service date and a cost of $105 million. (Ex. 101 at 26; Ex. 177 at 2, 16.)[5]

BCP's Position

709. BCP recommends that, at this juncture, the Commission reject approval of the Lantern to Comstock Meadows 345-kV transmission line (Ex. 406 at 6, 40.) BCP states that the permitting for the project was approved in Docket No. 22-11032 as part of the Fernley Area Master Plan but such permitting activities have not been initiated. (Ex. 406 at 6.) BCP explains that there are no executed line extension or HVD agreements to establish the need for service from the proposed interconnected Vaquero and Viking Substations and the Veterans substation has been postponed indefinitely. (Ex. 406 at 6.) BCP provides that the need and an estimated in-service date for the line should be fully supported and justified in a future IRP filing, and such a filing would not require a reintroduced Triennial IRP application. (Ex. 406 at 6.)

Staff's Position

710. Staff recommends that the Commission reject NV Energy's request for the Lantern-Comstock Meadows 345-kV transmission line, or if approved, place all costs associated with the project into the appropriate Plant Held for Future Use or a regulatory liability account until an appropriate amount of load is being supplied from the project. (Ex. 309 at 1-2.)

[5] The Commission notes that NV Energy's Lantern-Comstock Meadows request is duplicated at sections VIII.G.vii and VIII.G.x of the Joint Application.

711. Staff recommends rejecting this project because the substation and switching station that this line will fold into, Vaquero and Viking, do not have signed agreements. (Ex. 309 at 7.). Moreover, NV Energy claims that the two stations to be served by this transmission line will be placed into service in May 2029, but the transmission line itself will not be placed in-service until December of 2029. (Ex. 309 at 7.) Staff explains that it is impossible for the two facilities to operate and serve load without the transmission line. (Ex. 309 at 7.). Moreover, any argument to serve the loads at Vaquero and Viking facilities with an investment exceeding $100 million are speculative until NV Energy has firm commitments and signed agreements. (Ex. 309 at 7.)

712. Additionally, Staff provides that NV Energy now asserts that the need for this 345-kV transmission line project is not only tied to the Sierra Solar facility, but also as contingent facilities for multiple customers. (Ex. 309 at 7.) However, Staff states that only one other LGIA is included in the list, and it is only for a 115 MW facility. (Ex. 309 at 7-8.) Staff questions how a 115 MW LGIA would trigger the need for this transmission line without Sierra Solar Phase II (600 MW) also coming online. (Ex. 309 at 8.) Staff notes that in Docket No. 23-08015, the Commission approved a request to construct transmission infrastructure capable of serving 700 MW of load, which could accommodate both Sierra Solar Phase 1 and the 115 MW LGIA. (Ex. 309 at 8.) Staff argues that this transmission line should only be brought forward for approval when Sierra Solar Phase II is being considered or when additional firm, signed agreements have been submitted to the Commission. (Ex. 309 at 8.)

713. Staff states that the timing of the Lantern-Comstock line is clearly intertwined with the Sierra Solar 2 project expansion, which has not been approved by the Commission and has been shown to be uneconomic. (Ex. 309 at 8.) Staff contends that this line should be

considered a network upgrade for the Sierra Solar facility and not approved in this Docket, but instead in the same filing request for the Sierra Solar 2 expansion. (Ex. 309 at 8.) Staff also cites its concern that approval of the transmission project prior to approval of a potential Sierra Solar 2 project would bias the RFP process by giving preferential treatment to the NV Energy-owned project. (Ex. 309 at 9.) Staff notes that two other large solar projects are under development in the same Fernley/Yerington area that could both compete against a proposed Sierra Solar 2 project, yet NV Energy is not proposing to pre-build network upgrades associated with those facilities. (Ex. 309 at 9.)

714. Staff states that the Lantern-Comstock project would also trigger the need for a security update, mainly a block wall, at the substation. (Ex. 309 at 9.) Staff states it is not clear whether the Fort Churchill-Comstock Line #2 or the Lantern-Comstock line will trigger this need, but the costs need to be considered and included in one of those projects. (Ex. 309 at 9-10.) Staff estimates that, should this line necessitate a block wall security perimeter, it would increase the project cost by $5-10 million. (Ex. 309 at 10.)

NV Energy's Rebuttal

715. NV Energy notes that Staff and BCP have recommended that the Lantern-Comstock Meadows 345-kV line project be denied. (Ex. 197 at 5.) NV Energy recommends on rebuttal that the Lantern-Comstock Meadows 345-kV line project be approved and asserts that the Lantern-Comstock Meadows 345-kV line project is required by OATT, LGIAs, Designated Network Resources, Network Integrated Transmission Service Agreement ("NITSA"), and Rule 9 agreements. (Ex. 197 at 5.)

716. NV Energy responds to Staff and BCP's position that approval of this project is unnecessary due to the lack of signed Rule 9Agreements for the Vaquero and Viking facilities,

stating that the Lantern-Comstock Meadows 345-kV line is required pursuant to the FERC's OATT, pursuant to which NV Energy has entered into two LGIAs. (Ex. 198 at 10.) NV Energy further states that the Comstock-Meadows 345-kV line is also required due to the two Designated Network Resources ("DNRs") (Corsac Geothermal and Sierra Solar) added to the NITSA pursuant to the OATT. (Ex. 198 at 10.) NV Energy further states that the Lantern-Comstock Meadows 345 kV line has been identified as a contingent facility for several transmission load service requests from Rule 9 customers, including those served at the Gosling, Goose, Mackay, Naniwa, Nighthawk, Vaquero, Veterans, and Viking facilities, which will be required even if Sierra Solar Phase II project does not proceed. (Ex. 198 at 10-11.) NV Energy asserts that the Lantern-Comstock Meadows 345-kV line will be required for the 120 kV native load growth planned to be served from the Chukar Substation. (Ex. 198 at 11.)

717. NV Energy states that the additional 345-kV line entering the Comstock Meadows substation will not necessarily require the security update recommended by Staff in the form of a block wall around the substation because, based on the most recent CIP-014-3 analysis performed in 2023, Comstock Meadows is not a critical impact substation with its current three lines. (Ex. 198 at 11.) NV Energy further states, however, that it will include the fourth line from Lantern in the next CIP-014-3 analysis scheduled for 2025. (Ex. 198 at 10.)

718. NV Energy responds to Staff's recommendation that the Lantern-Comstock Meadows 345-kV line (and other projects), if approved, be placed into Plant Held for Future Use stating that such treatment would constitute an unprecedented deviation from NV Energy's ability to recover costs for facilities that are used and useful for their intended purpose. (Ex. 199 at 7.) NV Energy further asserts that Staff's recommendations that various projects, including the Lantern-Comstock Meadows 345 kV-line, be placed into Plant Held for Future Use are

impractical in designing a comprehensive transmission and distribution system to meet load growth. (Ex. 199 at 7.)

719. NV Energy references its testimony on the subject of Plant Held for Future Use in Docket No. 24-02026, and states that placement of used and useful assets into a Plant Held for Future Use account defined by the Code of Federal Regulations is in violation of the definition and intent of that account. (Ex. 199 at 8.) NV Energy further states that Staff's recommendations regarding a regulatory liability account remain unclear and undefined as to what conditions are applicable as well as how the regulatory liability account will provide suggested benefits to customers. (Ex. 199 at 8.) NV Energy asserts that moving away from a long-standing standard that reasonably incurred costs for used and useful projects which serve and benefit customers are recoverable is concerning and will challenge NV Energy to efficiently support growth and economic development. (Ex. 199 at 8-9.)

720. NV Energy contends that from an accounting perspective, Plant Held for Future Use is not included in rate base and recovery of the depreciation expense for this account is not included in a GRC, which is an effective disallowance to NV Energy because there is no "return on or of" these investments. (Ex. 205 at 6.) NV Energy asserts that such treatment does not allow NV Energy to recover the cost of the facilities even though they are put in-service to meet customer-requested demand. (Ex. 205 at 6-7.)

721. NV Energy asserts that if the Commission does not approve the Lantern-Comstock Meadows 345 kV line, NV Energy would continue work on the project and would be required to resubmit the project for Commission approval, possibly in a full IRP filing in 2027, which date would not allow NV Energy to meet the required in-service date. (Ex. 198 at 12.) NV Energy therefore recommends the Commission approve the project in this Docket subject to

the interconnection customers or load addition customers having fully securitized all network upgrade costs in accordance with the LGIA or Rule 9 agreements. (Ex. 198 at 12.)

Commission Discussion and Findings

722. The Commission approves the Lantern-Comstock Meadows 345-kV line project at a cost of $105 million because the Commission finds that the Lantern-Comstock Meadows 345-kV line project is required by OATT, LGIAs, DNRs, NITSA, and Rule 9 agreements.

723. The Commission finds that the Lantern-Comstock Meadows 345-kV line is required pursuant to the FERC's OATT, pursuant to which NV Energy has entered into two LGIAs. Furthermore, the Lantern-Comstock-Meadows 345-kV line is also required due to the two DNRs (Corsac Geothermal and Sierra Solar) added to the NITSA pursuant to the OATT. Additionally, the Lantern-Comstock Meadows 345-kV line has been identified as a contingent facility for several transmission load service requests from Rule 9 customers, including those served at the Gosling, Goose, Mackay, Naniwa, and Nighthawk facilities, which will be required even if the Sierra Solar Phase II project does not proceed. The Commission finds that the Lantern-Comstock Meadows 345-kV line will be required for the 120-kV native load growth planned to be served from the Chukar Substation. (Ex. 198 at 11.)

I. Comstock Meadows Transformer #2, West Tracy Transformer #1, Naniwa Switching Station, Nighthawk Switching Station

NV Energy's Position

724. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Comstock Meadows 345/120-kV transformer #2 with a projected May 2027 in-service date and a cost of $13 million. (Ex. 101 at 26; Ex. 176 at 2, 4.)

725. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of West Tracy transformer #1 345/120-kV with a projected May 2028 estimated in-service date and a cost of $13 million. (Ex. 101 at 26; Ex. 176 at 2, 5.)

726. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Naniwa Switching Station 345-kV with a projected May 2027 in-service date and a cost of $26 million. (Ex. 101 at 28; Ex. 176 at 3, 10.)

727. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Nighthawk 345/120 kV Substation with a projected December 2028 in-service date and a cost of $67 million. (Ex. 101 at 28; Ex. 176 at 3, 11.)

BCP's Position

728. BCP recommends conditional approval of the Comstock Meadows 345/120-kV transformer #2 only upon loads reaching a 500 MW threshold on the Comstock Meadows 120-kV reach. (Ex. 406 at 7, 31.) BCP explains that it is upon NV Energy to effectively manage the timing for the transformer and if NV Energy installs the transformer before the 600-MW load threshold, then the transformer should be considered plant held for future use. (Ex. 406 at 7, 31.)

729. BCP recommends conditional approval of the West Tracy 345/120-kV transformer #1 only upon loads reaching a 600 MW threshold in the TRIC on the 120-kV transmission system. (Ex. 406 at 7, 30.) BCP explains that it is upon NV Energy to effectively manage the timing for the transformer and if NV Energy installs the transformer before the 500 MW load threshold, then the transformer should be considered plant held for future use. (Ex. 406 at 7, 30.)

730. BCP recommends the Commission reject approval of the Naniwa 345-kV Switching Station. (Ex. 406 at 8.) BCP provides that NV Energy can file for approval in a

subsequent IRP filing and that such a filing would not require a reintroduced Triennial IRP application. (Ex. 406 at 8.)

731. BCP does not object to the approval of the Nighthawk 345-kV Switching Station. (Ex. 406 at 9.) BCP explains that the need was established with an executed HVD agreement for service up to 461 MW from the Nighthawk Switching Station. (Ex. 406 at 9.)

Staff's Position

732. Staff recommends approving NV Energy's request for the Comstock Meadows 345/120 kV Transformer #2, West Tracy Transformer #1 345/120 kV, the Naniwa 345-kV Switching Station, and the Nighthawk 345/120-kV Substation. (Ex. 311 at 2.) However, in approving these projects, Staff states that the Commission should order that NV Energy place some or all costs associated with these projects into the appropriate Plant Held for Future Use or create a regulatory liability account associated with the increased billing determinants to help offset the cost of the new facilities from impacting existing customers until an appropriate amount of load is being supplied from these projects. (Ex. 311 at 2.) Staff recommends approval of the projects because NV Energy has signed agreements, including security, in place with known customers that each of the projects will be serving and the new load should be paying for the infrastructure expansion needed to serve the increased growth, assuming the loads show up in time and in the magnitudes to which they have committed. (Ex. 311 at 13.)

733. Staff recommends the projects be placed into the appropriate Plant Held for Future Service or an appropriate regulatory liability account because all other ratepayers and rate classes will be paying for the facilities requested in the instant joint application until the load shows up that the facilities were built for and the current protections in place do not adequately protect ratepayers. (Ex. 311 at 14.) Staff states that its recommendation will allow the

opportunity for Staff and the Commission to review the project costs and timing in a GRC until the appropriate amount of load is using the facilities and to ensure that the costs will not be unjustly shifted onto existing customers and ensure that the growth pays for itself. (Ex. 311 at 14.)

734. As with other similar recommendations in this proceeding, Staff cites its concern that if NV Energy is allowed to place the project into rates simply for being energized while being temporally overbuilt, it would result in an unjust cost shift, particularly for a project of this magnitude. (Ex. 311 at 14.) Staff states that its recommendation will put NV Energy on notice that it must properly manage these projects or bear some of the timing risk. (Ex. 311 at 14-15.) Staff provides that this approach will balance NV Energy's need to obtain approval for projects with ratepayers' ability to pay a fair rate while not guaranteeing the timing of recovery unless NV Energy prudently manages the project and timing. (Ex. 311 at 15.)

NV Energy's Rebuttal

735. NV Energy disagrees with Staff's recommendation that Comstock Meadows 345/120-kV Transformer #2 and West Tracy Transformer #1 345/120 kV should be approved upon reaching a predetermined MW loading threshold, and if not, the transformers should be considered Plant Held For Future Use because theses transformers are necessary pursuant to existing customers' load forecasts, and utility best practice is to construct network upgrades prior to reaching the area load limit. (Ex. 197 at 5-6.) NV Energy denies that it is possible to predict the exact year when the MW threshold will be reached, and states that it instead intends to annually review the need for these transformers based on area load forecasts and may adjust the in-service date for the transformers accordingly. (Ex. 197 at 6.) NV Energy further states that additional generation on the 345-kV system (i.e. Libra, Valmy CTs, and Sierra Solar) help delay

the need for 525/345-kV transformers for load service but asserts the transformers will be used and useful as soon as they are placed in service because they will provide capacity for load growth, voltage support, and transformer redundancy. (Ex. 197 at 6.)

736. NV Energy further states that placing a Plant Held For Future Use threshold on a project would be unprecedented and in violation of FERC accounting guidelines[6] which require that a transmission or distribution asset is considered used and useful and providing a direct benefit to the system when it is tested and energized and/or placed into its intended used and useful state. (Ex. 197 at 6.)

737. For the reasons stated above, NV Energy disagrees with Staff's recommendation and asserts that placing a Plant Held for Future Use threshold on a project would be unprecedented and in violation of FERC accounting guidelines. (Ex. 197 at 6.)

738. NV Energy notes that Staff has recommended that the Commission approve the Naniwa Substation project with Plant Held For Future Use, and BCP has recommended that the Naniwa Substation project be denied. (Ex. 197 at 3.) NV Energy recommends on rebuttal that the Naniwa project be granted conditional approval with an amended and restated Rule 9 agreement. (Ex. 197 at 3; Ex. 199 at 6.)

739. NV Energy further states that negotiating an amendment to the Rule 9 agreement does not obviate the fact that there is an executed Rule 9 agreement already in place which will be effective if NV Energy and the customer are unable to agree on the amendment. (Ex. 199 at 6-7.) NV Energy further provides that under the proposed amendment, the utility investment will decrease and the security for the investment will shift to be an advance subject to a potential refund. (Ex. 199 at 6-7.) NV Energy therefore recommends that the Naniwa Substation project

[6]Code of Federal Regulations ("CFR") Part 101 Uniform System of Accounting Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act Electrical Plant Instructions

be approved subject to a compliance filing including the amended and restated agreement. (Ex. 199 at 7.)

740. NV Energy notes that BCP has recommended that the Commission approve the Nighthawk project, and Staff has recommended that the Nighthawk project be approved with Plant Held for Future Use. (Ex. 197 at 3.) NV Energy recommends on rebuttal that the Nighthawk project be approved as submitted and asserts the Nighthawk project is required per executed Rule 9 agreement. (Ex. 197 at 3.)

Commission Discussion and Findings

741. The Commission approves NV Energy's request for the Comstock Meadows 345/120-kV Transformer #2 at a cost of $13 million, West Tracy Transformer #1 345/120-kV at a cost of $13 million, and the Nighthawk 345/120-kV Substation at a cost of $67 million, and conditionally approves the Naniwa 345-kV Switching Station at a cost of $26 million pursuant to an amended and restated Rule 9 agreement.

742. First, the Commission shares Staff's concerns regarding overbuilding projects and leaving existing ratepayers to pay. However, the Commission also agrees with NV Energy that it is impossible to predict the exact year when the MW threshold will be reached, and moreover finds that the transformers will be used and useful as soon as they are placed into service because they will provide capacity for load growth, voltage support, and transformer redundancy. The Commission also finds that placing a Plant Held For Future Use threshold on a project would be unprecedented and in potential violation of FERC accounting guidelines which require that a transmission or distribution asset is considered used and useful and providing a direct benefit to the system when it is tested and energized and/or placed into its intended used and useful state. To help protect from overbuilding and protect existing customers, the Commission orders NV

Energy to annually review the need for these transformers based on area load forecasts and adjust the in-service date for the transformers accordingly.

743. Regarding Nighthawk, the Commission approves the Nighthawk project as it is required per an executed Rule 9 agreement. As stated above, the Commission finds that placing a Plant Held For Future Use threshold on a project would be unprecedented and potentially in violation of FERC accounting guidelines which require that a transmission or distribution asset is considered used and useful and providing a direct benefit to the system when it is tested and energized and/or placed into its intended used and useful state.

744. Regarding Naniwa, the Commission conditionally approves the project subject to a compliance filing, including the amended and restated Rule 9 Agreement. Under the proposed amendment, the utility investment will decrease and the security for the investment will shift to be an advance subject to a potential refund. Once the Rule 9 Amendment is executed, NV Energy will file the proposed amendment with the Commission to trigger the approval of the Naniwa project.

J. Machacek Substation

NV Energy's Position

745. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of 230 kV line breakers at the Machacek Substation with a projected June 2027 in-service date and a cost of $14.8 million. (Ex. 101 at 26; Ex. 177 at 3, 17.)

MWP's Position

746. MWP recommends that the Commission approve NV Energy's requested improvements to the Machacek Substation, which include the addition of breakers as provided in the IRP. (Ex. 2600 at 5.) MWP requests that the Commission allow NV Energy to upgrade the

Machacek Substation, a jointly used facility by MWP and NV Energy, to meet the current design and engineering standards that NV Energy applies to similar facilities within its balancing authority. (Ex. 2600 at 2.) MWP highlights that the Machacek Substation currently does not have the necessary 230-kV circuit breakers, which continues to affect MWP members, and that the proposed improvements by NV Energy would adequately address their customers' critical needs served by this substation. (Ex. 2600 at 2.)

747. MWP states that since the transfer of the Machacek Substation to NV Energy in 2012, the load at the substation has increased by over 27 percent reaching a peak load of 26,750 kWh. (Ex. 2600 at 3.) MWP states that it has urged NE Energy to upgrade the Motor Operated Disconnect ("MOD") since December of 2015, primarily due to the rising mining load in the area. (Ex. 2600 at 3.)

748. MWP argues that the equipment's current condition is a safety concern for NV Energy and MWP employees. (Ex. 2600 at 3.) MWP states that transmission and substation crews are often required to manually open and close the MODs, a task that should be automated, which increases the risk of injury to personnel and damage to equipment. (Ex. 2600 at 3.) MWP states that the current MOD cannot operate while under load, which means that the entire station must be de-energized whenever maintenance is required or at fault occurs from either side of the facility. (Ex. 2600 at 3.) MWP states that each time the station is de-energized, it leads to power outages impacting the businesses' reliance on the Machacek Substation. (Ex. 2600 at 3.) MWP states that from October 2021 to November 2023, there have been at least ten outages attributed to equipment issues at the substation. (Ex. 2600 at 4.) MWP states that it has garnered support from both MWP's Generation and Transmission Cooperative and Desert Power Electric Cooperative ("Desert") in this matter. (Ex. 2600 at 4.) MWP states that Desert has assessed the

condition of the facilities at the Machacek Substation and found that they do not comply with the minimum safety and reliability standards because the re-energization cycles are causing unnecessary damage on transformers and MWP's equipment. (Ex. 2600 at 4.)

749. MWP argues that it has been mistreated compared to similar 230-kV substations serving other NV Energy and other transmission customers. (Ex. 2600 MWP at 5.) MWP states that as a network integration transmission service ("NITS") customer, MWP expects equal treatment. (Ex. 2600 MWP at 5.) MWP states that it is also classified as a network transmission customer of NV Energy, and that its expectations align with those of any other NITS customer; however, due to the status of the MODs, the services provided are noticeably lacking. (Ex. 2600 at 5.) MWP states that if the prior IRP filings had been approved, then MWP customers would not have been impacted so drastically. (Ex. 2600 at 5.)

BCP's Position

750. BCP states that it does not object to the approval of the 230-kV line breakers at the Machacek Substation. (Ex. 406 at 9.)

Staff's Position

751. Staff recommends approving NV Energy's request for the 230-kV line breakers at the Machacek Substation. (Ex. 311 at 2.) Staff explains that the Machacek Substation was acquired in 2012, included in rates in 2013, and had only reached its payback period of the acquisition in Docket No. 19-06039. (Ex. 311 at 17.) Staff was previously concerned with NV Energy's request to invest $6.2 million into the substation, which originally only cost $884,000, and was also critical of a lack of any due diligence report concerns regarding the status of the facility prior. (Ex. 311 at 17-18.) Staff contends that NV Energy should have known whether there were any maintenance or reliability concerns given that SPPC was responsible for its

maintenance years before purchasing it, and but-for the purchase, Mount Wheeler, the prior owner, would have been responsible for the upgrade costs. (Ex. 311 at 18.)

752. Staff states that NV Energy should have conducted better due diligence to identify issues with the substation prior to purchase, but the issues regarding the age of the equipment and reliability need to be addressed now that NV Energy owns this substation. (Ex. 311 at 18.) However, Staff provides that because it has been over ten years since the acquisition, the upgrades are needed and more reasonable for the age of the facilities. (Ex. 311 at 18.) Moreover, Staff states that bringing the substation up to today's standards will improve safety and reliability. (Ex. 311 at 18.)

NV Energy's Rebuttal

753. NV Energy asserts the Machacek 230-kV Breakers are required to improve reliability. (Ex. 197 at 2.)

Commission Discussion and Findings

754. The Commission approves, as part of its Preferred Plan, a Supply Plan addition of 230-kV line breakers at the Machacek Substation with a projected June 2027 in-service date and a cost of $14.8 million. The Commission finds the history of Machacek useful: the Machacek Substation was acquired in 2012, included in rates in 2013, and had only reached its payback period of the acquisition in Docket No. 19-06039. Staff was previously concerned with NV Energy's request to invest $6.2 million into the substation, which originally only cost $884,000, and was also critical of a lack of any due diligence report concerns regarding the status of the facility prior. The Commission agrees with Staff that NV Energy should have known whether there were any maintenance or reliability concerns given that SPPC was responsible for its maintenance years before purchasing it, and but-for the purchase, MWP, the prior owner, would

have been responsible for the upgrade costs. The Commission finds that NV Energy should have conducted better due diligence to identify issues with the substation prior to purchase, but the issues regarding the age of the equipment and reliability need to be addressed now that NV Energy owns this substation. Because it has been over ten years since the acquisition, the upgrades are needed and are reasonable for the age of the facilities. Most importantly, the Commission approves the Machacek project to bring the substation up to today's standards to improve safety and reliability.

K. Darling Substation

NV Energy's Position

755. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Darling Substation with two 230/12-kV transformers with a projected June 2028 in-service date and a cost of $43.5 million. (Ex. 101 at 27; Ex. 176 at 2, 6.)

BCP's Position

756. BCP does not object to the approval the of Darling 230/12-kV Substation with one 230/12 37 MVA transformer to support load growth in the area. (Ex. 406 at 9-10.) BCP states that the estimated cost of $43.5 million should be reduced to reflect the installation of this first transformer. (Ex. 406 at 10.) BCP states that at this juncture, the Commission should reject the second transformer. (Ex. 406 at 10, 29.) BCP states that NV Energy can file for reconsideration in a future IRP filing for the second transformer to establish the need such as an executed line extension agreement. (Ex. 406 at 9-10.) BCP states that such a filing would not require a reintroduced triennial IRP application. (Ex. 406 at 10.)

Staff's Position

757. Staff recommends denying in part the elements of the addition of the Darling

Substation project associated with the second 230/12 kV 37 MVA transformer required for Project ID 3011004285, as NV Energy has not entered into a fully executed agreement between NV Energy and the applicant entity. (Ex. 308 at 14, 17.) If the Commission approves the entirety of the project, Staff recommends that the costs associated with the additional 230/12 kV 37 MVA transformer be placed into Plant Held for Future Use or a regulatory liability account. (Ex. 308 at 17.)

758. Staff states that its recommendation relates to NV Energy's position in SPPC's 2024 rate case in Docket No. 24-02026, in which they asserted that if a facility is built and energized, it is irrelevant how much load the facility was designed for and is serving provided that the facility is serving a single watt of power, NV Energy must be authorized to place the facility in rates for 100 percent recovery. (Ex. 308 at 16.). Staff additionally states that in its petition in the aforementioned GRC, it should also be the sole beneficiary of the load growth that accrues on these substation additions regardless of whether the facilities have been included in rates and existing ratepayers are already compensating NV Energy for 100 percent of its investment, creating a "game of heads they win, tails the existing customers lose," which is an inappropriate allocation of risk for projects driven by large and sometimes speculative load additions. (Ex. 308 at 16.)

NV Energy's Rebuttal

759. NV Energy notes that Staff and BCP have recommended that the Commission approve the Darling Substation project with one transformer and agrees to the same in rebuttal. (Ex. 197 at 3.) NV Energy asserts the Darling Substation is required for load relief, but states that the Rule 9 customer, which required the second Darling 230/12-kV transformer, has not signed a Rule 9 agreement. (Ex. 197 at 3; 6-7.)

Commission Discussion and Findings

760. The Commission approves, as part of NV Energy's Preferred Plan, a Supply Plan addition of Darling Substation with one 230/12 kV transformer. Staff and BCP recommended the approval of one transformer, instead of two, and NV Energy agreed in rebuttal. The Commission finds that the Darling Substation is required for load relief in the area but finds that the Rule 9 customer, which required the second Darling 230/12-kV transformer, has not signed a Rule 9 agreement. The Commission finds that NV Energy's Preferred Plan contains a budget request for two transformers but not one, and since the Commission is approving one transformer, the Commission directs NV Energy to file an update with the Commission on the budget for one transformer within 14 days of the effective date of this Order.

L. Log Cabin Substation

NV Energy's Position

761. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Log Cabin Substation with a 230 kV transformer with a projected in-service date of June 2028 and a cost of $33.75 million. (Ex. 101 at 27; Ex. 176 at 2, 6.)

BCP's Position

762. BCP recommends that the Commission reject approval of the Log Cabin Substation with a 230/12-kV transformer. (Ex. 406 at 10, 29.) BCP provides that as proposed, the need for this substation lacks an executed line extension agreement(s). (Ex. 406 at 10.). BCP states that NV Energy can file for approval in a subsequent IRP filing to establish the need such as executed line extension agreement(s) and note that such a filing would not require a reintroduced Triennial IRP application. (Ex. 406 at 10.)

///

Staff's Position

763. Staff recommends the Commission deny NV Energy's request for the Log Cabin Substation project, because NV Energy has not entered into a fully executed agreement between NV Energy and the applicant entity. (Ex. 309 at 17, 19.) Staff states that without a signed agreement, purchasing the transformer exposes risk to existing ratepayers because no controls to protect them would be in place, such as the controls outlined in Rule 9 that require an applicant to provide security, construction deposits, reduction in service charges and appropriate milestones. (Ex. 309 at 18.) Staff states that such a high risk should not be permitted as it would cause undue harm to ratepayers that would have to subsidize those facilities until the load of the applicant materializes. (Ex. 309 at 18.)

764. While Staff contends that the lack of an executed agreement is reason enough to reject this project, Staff also cites its concern that NV Energy's forecast shows the Northwest Substation to exceed capacity by 10.4 MVA before June 1, 2028, requiring multiple new feeder breakers fed from the new Log Cabin Substation transformer as well as from a new breaker position at an existing substation. (Ex. 309 at 18.). Staff states that given the timing of the forecasted exceedance at Northwest Substation, NV Energy should continue its negotiations for a line extension agreement, and if necessary and feasible in the interim, utilize the feeder breaker position identified within the Planning Memo to satisfy the relief at the Northwest Substation that is not expected for a few years. (Ex. 309 at 18-19.) Staff states that in the event the Commission approves this project, it should require that a portion, or potentially all of the project costs, be placed into Plant Held for Future Use or create a regulatory liability account for the increase in billing determinants that may accrue if the projected loads are late coming online and the facilities are included in general rates before that load develops. (Ex. 309 at 19.)

NV Energy's Rebuttal

765. NV Energy notes that Staff and BCP have recommended that the Log Cabin Substation project be denied. (Ex. 197 at 4.) NV Energy also recommends on rebuttal that the Log Cabin Substation project be denied as Rule 9 agreements have not been executed. (Ex. 197 at 4, 7.)

Commission Discussion and Findings

766. The Commission denies approval of the Log Cabin Substation as recommended by Staff, BCP, and NV Energy. The Commission denies the Log Cabin Substation project because Rule 9 agreements have not been executed.

M. Spring Canyon Substation

NV Energy's Position

767. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Spring Canyon Substation with three 230-kV transformers with a projected in-service date of December 2026 and a cost of $49.6 million. (Ex. 101 at 27; Ex. 176 at 2, 7.)

BCP's Position

768. BCP recommends that at this juncture, the Commission reject the approval of the Spring Canyon Substation with three 230/12-kV transformers. (Ex. 406 at 10.) BCP provides that as proposed, the need for this substation lacks an executed line extension agreement(s). (Ex. 406 at 10, 29.) BCP states that NV Energy can file for approval in a subsequent IRP filing to establish the need such as an executed line extension agreement(s), and that such a filing would not require a reintroduced Triennial IRP application. (Ex. 406 at 10.)

///

Staff's Position

769. Staff recommends that the Commission reject the Spring Canyon Substation project because it has not entered into a fully executed agreement between NV Energy and the applicant entity. (Ex. 309 at 19, 21.) Staff states that without an executed agreement in place, purchasing the transformer exposes risk to existing ratepayers because without a Rule 9 agreement, there is no security, construction deposits, reduction in service charges, and appropriate milestones to protect ratepayers. (Ex. 309 at 19, 21.) Staff states that such a high risk should not be permitted because it would require ratepayers to pay for those facilities until the loads of the applicant customers materialize. (Ex. 309 at 20.) In this instance, because the Spring Canyon Substation is not at least partly driven by the need to provide relief to existing facilities, and because the four pending Rule 9 agreements related to this project are still being negotiated, purchasing the transformer exposes risk to existing ratepayers. (Ex. 309 at 20.)

770. Staff states that if the Commission does approve this project, it should include a provision in its order that some, or all of the project costs be placed in Plant Held for Future Use or a new regulatory liability account as part of a future rate case proceeding to account for the increase in billing determinants that may accrue if project loads are late to come online and the facilities are included in rates before that load develops. (Ex. 309 at 21.)

NV Energy's Rebuttal

771. NV Energy states that Staff and BCP have recommended that the Spring Canyon Substation project be denied. (Ex. 197 at 4.) NV Energy recommends on rebuttal that the Spring Canyon Substation project be granted conditional approval with an executed Rule 9 agreement and asserts the Spring Canyon Substation project is required per the pending execution of the relevant Rule 9 agreement. (Ex. 197 at 4.)

772. NV Energy further states that it submitted requests for approval of transmission projects that do not currently have an executed Rule 9 agreement because these customers have actively engaged NV Energy in moving forward with their projects and NV Energy is required to seek Commission approval of any transmission project that is greater than 200 kV in a resource plan filing. (Ex. 199 at 3.) NV Energy further states that it must navigate when to request approval for long-lead transmission projects, which may significantly affect the customer's project and business objectives where such customers do not yet have executed Rule 9 agreements and must wait until the next IRP or IRP amendment. (Ex. 199 at 3-4.) NV Energy states that, therefore, it included several transmission project requests in this IRP because the relevant customers are engaged in the process and are likely to execute the Rule 9 agreements in the coming months. (Ex. 199 at 3-4.)

773. NV Energy clarifies that in the Joint Application it requested conditional approval, pending executed Rule 9 agreements, for the Mackay 345-kV Substation, Gosling 345-kV Substation, Ft. Churchill to Veterans 525-kV line, Spring Canyon 230/12-kV Substation, Vaquero 345/120 kV Substation, and Viking 345/120 kV Substation. (Ex. 199 at 4.)

774. NV Energy states that, since filing the Joint Application, Rule 9 agreements have been executed for Mackay 345-kV Substation, Gosling 345-kV Substation, and Ft. Churchill to Veterans 525-kV line, and therefore recommends these projects for approval. (Ex. 199 at 4.) NV Energy further states that it anticipates Rule 9 agreements will be executed in the near future for Spring Canyon 230/12-kV Substation, Vaquero 345/120-kV Substation, and Viking 345/120-kV Substation. (Ex. 199 at 4.) NV Energy requests that rather than reject projects for which no Rule 9 agreement has been executed, the Commission grant conditional approval subject to a compliance filing when and if these projects have executed agreements to support timely

progress with these large projects and developments upon execution of the relevant Rule 9 agreement. (Ex. 199 at 4-5.)

775. NV Energy states that, with respect to the Spring Canyon 230/12-kV Substation project, NV Energy will request the appropriate number of transformers based on the capacity required under the executed Rule 9 agreements, similar to its suggestion regarding the Darling 230/12-kV Substation. (Ex. 199 at 4; Ex. 197 at 3; 6-7.)

Commission Discussion and Findings

776. The Commission rejects the Spring Canyon Substation project at this time because NV Energy has not entered into a fully executed agreement between NV Energy and the applicant entity. Without an executed agreement in place, purchasing the transformer exposes existing ratepayers to risk because there is no security, construction deposits, reduction in service charges, and appropriate milestones to protect ratepayers. The Commission finds this too high a risk because if the Commission allowed this project to proceed it would require ratepayers to pay for those facilities until the loads of the applicant customers materialize. Furthermore, because the Spring Canyon Substation is not at least partly driven by the need to provide relief to existing facilities, and because the four pending Rule 9 agreements related to this project are still being negotiated, purchasing the transformer exposes existing ratepayers to too high of a risk. NV Energy may refile the Spring Canyon Substation project in a future IRP or IRP amendment if/when there is an executed Rule 9 agreement.

N. Ft. Churchill-Comstock Meadows

NV Energy's Position

777. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Ft. Churchill-Comstock Meadows 345 kV line #2 with a projected in-

service date of December 2027 and an incremental cost of $97.4 million. (Ex. 101 at 27; Ex. 177 at 3, 19.)

Tract's Position

778. Tract recommends that the Commission approve the Ft. Churchill-Comstock Meadows 345 kV Line #2 because this facility is directly contracted for or contingent on Tract's Peru Shelf and South Valley projects and benefits other customers besides Tract. (Ex. 2200 at 21.)

BCP's Position

779. BCP does not object to the approval of the Ft. Churchill to Comstock Meadows 345 kV #2 transmission line. (Ex. 406 at 7-8.) BCP states that there is an executed HDV agreement for up to 461 MW for service at the Nighthawk 345/120-kV Substation which is to be interconnected into the Ft. Churchill to Comstock Meadows 345 kV #2 transmission line. (Ex. 406 at 8.) However, BCP notes that the current estimate for this line is $100 million. (Ex. 406 at 16.)

Staff's Position

780. Staff recommends that the Commission approve NV Energy's request for the addition of the Fort Churchill to Comstock Meadows #2 345-kV transmission line based on an estimated incremental cost of $97.4 million, but the in-service date should be contingent on the specific customer's load referenced by Q&A 15 of the Direct Testimony of Layne Maxfield, materializing. (Ex. 313 at 65.) Staff states that there is a risk associated with serving the extremely large and speculative loads associated with data centers, which based on current agreements current study phases, could quintuple SPPC's current peak load. (Ex. 313 at 62.) Staff states its concern that NV Energy will incur $110 million in costs to construct the Fort

Churchill to Comstock Meadows #2 345-kV transmission line for customers whose loads may not materialize leaving ratepayers on the hook – a scenario that recently occurred when SPPC constructed extensive transmission infrastructure in the TRIC to serve large load requested by data centers that have not materialized to the extent that those customers forecasted. (Ex. 313 at 62-63.)

781. Staff states that NV Energy has an obligation to manage risks with these loads and although it is obligated to construct infrastructure to serve a data center customer's forecasted load pursuant to a Rule 9 agreement, NV Energy must also manage any risk of that load not materializing to offset incremental costs to remaining ratepayers. (Ex. 313 at 63.) Staff states that NV Energy can manage this risk by applying abnormal risk provisions to the applicable agreements, requiring 100 percent security of the utility investment, requiring an advance subject to potential refund, implementing a phased approach to construct transmission infrastructure over time as load materializes, and establishing agreement milestones to ensure the customer and NV Energy are progressing together. (Ex. 313 at 63.) Staff states that because data center loads in Nevada have not materialized as forecasted, NV Energy must fully enforce its Rule 9 agreements. (Ex. 313 at 63.)

782. Staff states the Commission can also reduce risk by granting prudency of the Fort Churchill to Comstock Meadows #2 345 kV transmission line based on the need to serve the specific customer, but the Commission should not grant prudency approval to meet a specific in-service date; rather, that date should be contingent on the specific customer's load materializing with the resulting costs associated with the project being evaluated in the context of a GRC when NV Energy seeks to recover those costs. (Ex. 313 at 63-64.). Staff states that the Fort Churchill to Comstock Meadows #2 345-kV transmission line is not a part of the Greenlink Nevada Project

and therefore is not required to be in service by December 31, 2028. (Ex. 313 at 64.) Staff states that although NV Energy has included both Fort Churchill to Comstock Meadows lines with its Greenlink West project in previous filings, and the permitting has been done in tandem, the instant request is not part of the Greenlink Nevada Project as it is not required to complete the project and is solely required to serve a specific customer. (Ex. 313 at 64.) Accordingly, Staff contends that the in-service date should be based upon that customer's load materializing. (Ex. 313 at 64.)

783. Staff states that the cost of the Fort Churchill to Comstock Meadows #2 345 kV transmission line's projected cost does not include costs associated with building a block wall security perimeter, which may be required under NERC Critical Infrastructure Protection ("CIP") standards. (Ex. 313 at 64-65.) Staff cautions that should the perimeter be required the projected cost will be higher. (Ex. 313 at 65.)

NV Energy's Rebuttal

784. NV Energy states that the Ft. Churchill-Comstock #2 345-kV line is required per an executed Rule 9 agreement. (Ex. 197 at 2.)

785. NV Energy disagrees with Staff's position that the Fort Churchill – Comstock Meadows #2 transmission line should not be part of the Greenlink Nevada Project and states that it is unable to understand the rationale behind this argument because this transmission line was requested and partially approved in Docket No. 20-07023 with the expectation that this transmission line will be constructed once required by load growth. (Ex. 203 at 24.) NV Energy states that this transmission line is being permitted along with Greenlink West and now that the load forecast has reached a point where the line is required to serve load, it has requested approval to construct the line in this Docket. (Ex. 203 at 24.) NV Energy further states that all

three Common Ties, including this line, are planned to serve load in the northern Nevada service region and are required as part of the Greenlink Nevada Project. (Ex. 203 Lateef Phase II at 24.)

Commission Discussion and Findings

786. The Commission approves NV Energy's request for the addition of the Fort Churchill to Comstock Meadows #2 345-kV transmission line based on an estimated incremental cost of $97.4 million, but the Commission orders the in-service date to be contingent on the specific customer's load, referenced by Q&A 15 of the Direct Testimony of Layne Maxfield, materializing. The Commission finds that there is a risk associated with serving the extremely large and somewhat speculative loads associated with data centers, which based on current agreements and current study phases, could quintuple SPPC's current peak load. The Commission shares Staff's concern that NV Energy will incur around a hundred million dollars in costs to construct the Fort Churchill to Comstock Meadows #2 345-kV transmission line for customer(s) whose load(s) may not materialize, leaving ratepayers on the hook – a scenario that recently occurred when SPPC constructed extensive transmission infrastructure in the TRIC to serve large loads requested by data centers that have not materialized to the extent that those customers forecasted.

787. The Commission notes NV Energy's obligations to both manage risks with these loads and to construct infrastructure to serve a data center customer's forecasted load pursuant to a Rule 9 agreement. NV Energy must also manage any risk of that load not materializing to offset incremental costs to remaining ratepayers. NV Energy can manage this risk by applying abnormal risk provisions to the applicable agreements, requiring 100 percent security of the utility investment, requiring an advance subject to potential refund, implementing a phased approach to construct transmission infrastructure over time as load materializes, and establishing

agreement milestones to ensure the customer and NV Energy are progressing together. The Commission finds that because data center loads in Nevada have not always materialized as forecasted, NV Energy must fully enforce its Rule 9 agreements. For these reasons, the Commission finds that the in-service date shall be contingent on the specific customer's load materializing with the resulting costs associated with the project being evaluated in the context of a GRC when NV Energy seeks to recover those costs.

O. Ft. Churchill Substation

NV Energy's Position

788. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of the third and fourth 525/345-kV transformers located at the Ft. Churchill Substation at a cost of $12 million for each transformer. (Ex. 101 at 27; Ex. 177 at 3, 19-20; Ex. 176 at 7-8.) NV Energy represents that it seeks conditional approvals for these transformers because they will be constructed only upon loads connecting at the Ft. Churchill Substation materializing. (Ex. 101 at 27.)

Tract's Position

789. Tract recommends that the Commission approve the Ft. Churchill 525/345-kV transformers 3 and 4 because this facility is directly contracted for or contingent on Tract's Peru Shelf and South Valley projects and benefits other customers besides Tract. (Ex. 2200 at 21.)

BCP's Position

790. BCP recommends conditional approval of the third and fourth 525/345-kV transformers at the Fort Churchill only upon loads connecting at the Fort Churchill Substation materializing at 600 MVA and 1,200 MVA for the third and fourth transformers, respectively. (Ex. 406 at 8, 32.) BCP explains that it is upon NV Energy to effectively manage the timing for

the transformer and if NV Energy installs the transformers before the 600 MVA or the 1,200 MVA threshold, then the transformers should be considered plant held for future use. (Ex. 406 at 8, 32.)

Staff's Position

791. Staff recommends that the Commission approve NV Energy's request for conditional approval to construct the third and fourth 525/345 kV transformers located at the Fort Churchill substation at a cost of $12 million each only upon loads connecting at the Fort Churchill substation materializing. (Ex. 313 at 68.) Staff states that there is a risk associated with serving large and speculative loads associated with data centers given the 10,000 MW in additional executed agreements and projects still in the study phase, which could quintuple SPPC's current peak load. (Ex. 313 at 67.) Staff provides that NV Energy does not expect that all of the projected loads will materialize because historically actual loads are significantly less than the load growth forecast provided by customers. (Ex. 313 at 67.)

792. Staff states that NV Energy's Rule 9 tariff contains risk protocols to protect ratepayers such as abnormal risk provisions to applicable agreements, requiring 100 percent security of the utility investment, requiring an advance subject to potential refund, implementing a phased approach to construct transmission infrastructure over time as the load materializes, and establishing agreement milestones to ensure the customer and NV Energy are progressing together. (Ex. 313 at 67.) Staff states that because data center loads in Nevada have not materialized to the amount those data centers have forecasted, NV Energy must fully enforce its Rule 9 agreements. (Ex. 313 at 67.)

///

///

NV Energy's Rebuttal

793. NV Energy disagrees with Staff's recommendation that the Ft. Churchill 525/345 kV transformers #3 and #4 should be approved upon reaching a predetermined MW loading threshold, and if not, the transformers should be considered Plant Held For Future Use, and asserts that placing a Plant Held for Future Use threshold on a project would be unprecedented and in violation of FERC accounting guidelines. (Ex. 197 at 6.)

Commission Discussion and Findings

794. The Commission approves NV Energy's request for conditional approval to construct the third and fourth 525/345-kV transformers located at the Fort Churchill substation at a cost of $12 million each only upon loads connecting at the Fort Churchill substation materializing. As previously discussed above, the Commission finds that there is a risk associated with serving large and speculative loads of data centers given the 10,000 MW in additional executed agreements and projects still in the study phase, which could quintuple SPPC's current peak load. Because data center loads in Nevada have not always materialized to the amount that those data centers have forecasted, NV Energy must fully enforce its Rule 9 agreements.

P. Mackay Substation

NV Energy's Position

795. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Mackay Substation 345 kV with a projected December 2027 in-service date and a cost of $28 million. (Ex. 101 at 27; Ex. 176 at 8.)

///

///

Tract's Position

796. Tract recommends that the Commission approve the Mackay 345 kV Switchyard because this facility is directly contracted for or contingent on Tract's Peru Shelf and South Valley projects and benefits other customers besides Tract. (Ex. 2200 D at 21.) Tract states that the Mackay facility provides benefits beyond Tract's immediate use by strengthening the regional integrated transmission network, creating additional points of interconnection into NV Energy's high voltage network, providing a 25 percent reservation for future use, and Mackay substation's physical extents have been designed to contemplate future expansion at both 525 kV and 120 kV. (Ex. 2200 at 16.)

BCP's Position

797. BCP does not object to the approval of the Mackay 345 kV Substation. (Ex. 406 at 8.) BCP states that the need was established with an executed HVD agreement for service up to 450 MW from the Mackay Substation. (Ex. 406 at 8.)

Staff's Position

798. Staff recommends that the Commission approve the Mackay Substation 345 kV project and the Gosling 345 kV Switching Station project with a provision that some or all costs associated with the projects may be placed into Plant Held for Future Use, or be put into a new regulatory liability account associated with the increased billing determinants, to help offset the costs of the new facilities from affecting existing customers until an appropriate amount of load materializes. (Ex. 308 at 5.) Staff recommends approval of the projects because NV Energy currently has signed agreements in place, including security, with the customers that the project will be serving, meaning that the new load has made contractual commitments to take service and that load will be paying for the infrastructure expansion needed to serve that growth,

assuming it materializes. (Ex. 308 at 7.)

799. Staff states that it does have general concerns approving projects to serve loads with such high-power factors and notes the risk that should the loads not materialize, there is a risk that existing ratepayers face undue harm through the costs to install the infrastructure. (Ex. 308 at 7.) However, Staff explains that the high voltage distribution agreements contain project controls requiring customer security, construction deposits, reductions in service charges and construction milestones, but these controls do not eliminate the risk. (Ex. 308 at 8.) Staff states that the Commission can enhance protections for existing ratepayers through additional methods such as placing project costs into Plant Held for Future Use or establishing a regulatory liability account until an appropriate amount of load materializes. (Ex. 308 at 8.). Staff states that utilizing such methods in an IRP diminishes any future arguments that meeting a small fraction of the expected load down to the flow of a single electron to qualify a project as energized, used, and useful, and places the onus on NV Energy and its applicant customer. (Ex. 308 at 9.)

NV Energy's Rebuttal

800. NV Energy notes that Staff has recommended that the Mackay Substation project be approved with Plant Held for Future Use treatment. (Ex. 197 at 3.) NV Energy recommends on rebuttal that the Mackay Substation project be approved as submitted and asserts the Mackay Substation is required per executed Rule 9 agreement. (Ex. 197 at 3.) NV Energy further notes that, since filing the Joint Application, a Rule 9 agreement has been executed for the Mackay 345 kV Substation. (Ex. 199 at 4.)

Commission Discussion and Findings

801. The Commission approves, as part of NV Energy's Preferred Plan, a Supply Plan addition of Mackay 345-kV Substation with a projected December 2027 in-service date and a

cost of $28 million because a Rule 9 Agreement has been executed for the Mackay 345-kV Substation since NV Energy filed the Joint Application. Furthermore, as Tract points out, the Mackay facility provides benefits beyond Tract's immediate use by strengthening the regional integrated transmission network, creating additional points of interconnection into NV Energy's high voltage network, and providing a 25 percent reservation for future use.

Q. Gosling Switching Station

NV Energy's Position

802. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Gosling 345-kV switching station with a projected April 2027 in-service date and a cost of $5 million. (Ex. 101 at 27; Ex. 176 at 3, 8-9.) NV Energy further states that in addition, the relevant customer's second phase will require 525-kV transformers at Goose substation and will also require the Ft. Churchill-Mackay-Goose-Veterans 525-kV line. (Ex. 176 at 8-9.)

Tract's Position

803. Tract recommends that the Commission approve the Gosling 345 kV Switchyard because this facility is directly contracted for or contingent on Tract's Peru Shelf and South Valley projects and benefits other customers besides Tract. (Ex. 2200 at 21.) Tract states that the Gosling facility provides benefits beyond Tract's immediate use by strengthening the regional integrated transmission network, creating additional points of interconnection into NV Energy's high voltage network, and providing a 25 percent reservation for future use. (Ex. 2200 at 16.)

BCP's Position

804. BCP does not object to the approval of the Gosling 345 kV Switching Station BCP explains that the need was established with an executed HVD agreement for service up to

450 MW from the Gosling Switching Station. (Ex. 406 at 8.)

Staff's Position

805. As noted, above, Staff recommends that the Commission approve the Gosling 345 kV Switching Station project and specifically outline in its order that NV Energy may be required to place some, or all costs associated with this project into Plant Held for Future Use or to establish a regulatory liability account associated with the increased billing determinants to help offset the costs of the new facilities from impacting existing customers until an appropriate amount of load materializes. (Ex. 308 at 9.)

NV Energy's Rebuttal

806. NV Energy notes that Staff has recommended that the Gosling Substation project be approved with Plant Held for Future Use. (Ex. 197 at 3.) NV Energy recommends on rebuttal that the Gosling Substation project be approved as submitted and asserts the Gosling Substation is required per executed Rule 9 Agreement. (Ex. 197 at 3.) NV Energy further notes that, since filing the Joint Application, a Rule 9 Agreement has been executed for the Gosling 345-kV Substation. (Ex. 199 at 4.)

Commission Discussion and Findings

807. The Commission approves, as part of its Preferred Plan, a Supply Plan addition of Gosling 345-kV Substation with a projected April 2027 in-service date and a cost of $5 million because a Rule 9 Agreement has been executed for the Gosling 345-kV Substation since NV Energy filed the Joint Application. Furthermore, as Tract points out, the Gosling facility provides benefits beyond Tract's immediate use by strengthening the regional integrated transmission network, creating additional points of interconnection into NV Energy's high voltage network, and providing a 25 percent reservation for future use.

R. Ft. Churchill-Veterans

NV Energy's Position

808. NV Energy requests that the Commission approve siting and permitting costs for Ft. Churchill-Veterans 525 kV line with a projected May 2031 in-service date and in the amount of $14 million. (Ex. 101 at 28; Ex. 177 at 3, 20.)

Tract's Position

809. Tract recommends that the Commission approve siting and permitting costs for the Ft. Churchill-Mackay-Goose-Veterans 525kV Line because this facility is directly contracted for or contingent on Tract's Peru Shelf and South Valley projects and benefits other customers besides Tract. (Ex. 2200 at 21.) Tract states that the Ft. Churchill-Mackay-Goose-Veterans project is critical in supporting the long-term growth of the energy infrastructure in Nevada, and it is a necessary component of Tract's Phase two load expansion at each the Peru Shelf and South Valley sites. (Ex. 2200 at 17.)

BCP's Position

810. BCP does not object to the approval of the siting and permitting costs for a Fort Churchill to Veterans 525 kV transmission line estimated up to $14 million subject to determining the Veterans location. (Ex. 406 at 9, 35-36.) However, BCP recommends that the Commission reject the approval of the proposed May 2031 in-service date for the Fort Churchill to Veterans 525 kV line because NV Energy has not demonstrated the need for the line by May of 2031. (Ex. 406 at 9, 36.) BCP notes that the need and an estimated in-serve date for the line should be fully supported and justified in a future IRP filing. (Ex. 406 at 9, 37.)

Staff's Position

811. Staff recommends approving NV Energy's request for the siting and permitting

costs for the Fort Churchill - Veterans 525 kV transmission line, provided that NV Energy is directed that it is not permitted to perform any land acquisition as part of this approval given the utility's failure to provide a cost breakdown for the project. (Ex. 311 at 2.) Staff recommends approval of the siting and permitting plan because it will help NV Energy meet its obligation to support load growth for an additional 1,125 MW of Master Planned Community Rule 9 load, which will be required when the load exceeds 900 MW between Gosling switching station and Mackay substation. (Ex. 311 at 16.). Staff explains that approving the siting and permitting will help NV Energy meet customer load needs without expending the entire cost of the new line until the load is ready. (Ex. 311 at 16.) However, Staff recommends that no land, land rights, or private easements should be acquired as part of the siting and permitting process because NV Energy was unable to provide a breakdown of what is included in the costs being requested. (Ex. 311 at 16.)

NV Energy's Rebuttal

812. NV Energy notes that BCP and Staff have recommended that the Commission approve the Ft. Churchill-Veterans 525 kV line permitting. (Ex. 197 at 3.) NV Energy recommends that the Ft. Churchill-Veterans 525 kV line permitting be approved and asserts the Ft. Churchill-Veterans 525 kV line permitting is required for future load growth per customer forecasts. (Ex. 197 at 3; 7.) NV Energy further notes that, since filing the Joint Application, a Rule 9 Agreement has been executed for the Ft. Churchill-Veterans 525 kV line. (Ex. 199 at 4.)

Commission Discussion and Findings

813. The Commission approves NV Energy's request for the siting and permitting costs for the Fort Churchill - Veterans 525-kV transmission line, but the Commission directs NV Energy that it cannot perform any land acquisition as part of this approval given NV Energy's

failure to provide a cost breakdown for the project. The Commission approves the siting and permitting plan because it will help NV Energy meet its obligation to support load growth for an additional 1,125 MW of Master Planned Community Rule 9 load, which will be required when the load exceeds 900 MW between Gosling switching station and Mackay substation. The Commission finds that approving the siting and permitting will help NV Energy meet customer load needs without expending the entire cost of the new line until the load is ready. However, the Commission finds that no land, land rights, or private easements shall be acquired as part of the siting and permitting process because NV Energy was unable to provide a breakdown of what is included in the costs being requested.

S. Vaquero Substation

NV Energy's Position

814. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Vaquero 345/120 kV Substation with a projected May 2029 in-service date and a cost of $30 million. (Ex. 101 at 28; Ex. 176 at 3, 11-12.)

BCP's Position

815. BCP recommends that at this juncture, the Commission reject approval of the Vaquero 345/120 kV Substation. (Ex. 406 6, 29.) BCP states that as proposed, the need for this substation lacks an executed line extension or HVD agreement(s) and NV Energy can file for approval in a subsequent IRP filing to establish the need such as an executed HVD agreement(s) and the substation location is finalized. (Ex. 406 at 6-7, 27.) BCP provides that such a filing would not require a reintroduced Triennial IRP application. (Ex. 406 at 7.)

Staff's Position

816. Staff recommends denying NV Energy's request for the Vaquero 345/120 kV

Substation. (Ex. 311 at 3.) However, if the Commission approves this project, Staff recommends that the Commission require NV Energy to place this project in the appropriate Plant Held for Future Use account or create a regulatory liability associated with the increased billing determinants to help offset the costs of the facility from impacting existing customers until an appropriate amount of load is being supplied from the projects. (Ex. 311 at 3.) Staff states that its recommendations are based upon the lack of a signed agreement for the project. (Ex. 311 at 19.)

817. Staff states that without signed contracts, approving projects and authorizing NV Energy to expend capital to build this project would not be prudent, particularly given NV Energy's stance that if the facilities are energized and serving a watt of power, the projects must be allowed for full inclusion in rates. (Ex. 311 at 19.) Staff states that without an agreement, the risk of this project would fall entirely on ratepayers, assuming NV Energy can demonstrate the costs are just and reasonable in a GRC. (Ex. 311 at 19-20.) Moreover, Staff cites its concern that the project is not well developed, as it is projected to be in-service six months before the Lantern - Comstock 345 kV transmission line required to connect the Vaquero 345/120 kV Substation and Viking 345 kV Switching Station are built. (Ex. 311 at 20.) Staff provides that NV Energy can bring this project back for approval in an amendment if and when it signs agreements with the customers to be served from these substations. (Ex. 311 at 20.) Staff explains that the projects total almost $85 million and should not be a cost/risk solely born by ratepayers. (Ex. 311 at 20.)

NV Energy's Rebuttal

818. NV Energy notes that Staff and BCP have recommended that the Vaquero Substation project be denied. (Ex. 197 at 3.) NV Energy recommends on rebuttal that the

Vaquero Substation project be granted conditional approval with an executed Rule 9 agreement and asserts the Vaquero Substation project is required per the pending execution of the relevant Rule 9 agreement. (Ex. 197 at 3.) NV Energy further states that it anticipates the Rule 9 agreement for Vaquero Substation will be executed in the near future and requests conditional approval for the project subject to a compliance filing upon execution of the Rule 9 agreement. (Ex. 199 at 4-5.)

Commission Discussion and Findings

819. The Commission denies NV Energy's request for the Vaquero 345/120-kV Substation because there is no executed Rule 9 agreement for this project. The Commission finds that it is not prudent to approve this project without an executed Rule 9 agreement, and the risk of this project would fall entirely on ratepayers, without knowing that the presumed load would materialize, and assuming NV Energy could demonstrate the costs are just and reasonable in a GRC. NV Energy may bring this project back for approval in an IRP or IRP amendment if/when NV Energy signs Rule 9 agreement(s) with the customer(s) to be served from these substations.

T. Viking Switching Station

NV Energy's Position

820. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Viking 345 kV Switching Station with a projected May 2029 in-service date and a cost of $55 million. (Ex. 101 at 28; Ex. 176 at 3, 12.)

BCP's Position

821. BCP recommends that at this juncture, the Commission reject approval for the Viking 345 kV Switching Station. (Ex. 406 at 29.) BCP explains that as proposed, the need for

this substation lacks an executed line extension or HVD agreement(s) and NV Energy can file for approval in a subsequent IRP filing. (Ex. 406 at 7.) BCP notes that such a filing would not require a reintroduced Triennial IRP application. (Ex. 406 at 7.)

Staff's Position

822. As with the Vaquero 345/120 kV Substation, Staff recommends denying NV Energy's request for the Viking 345 kV switching station. (Ex. 311 at 3.) However, if the Commission approves this project, Staff recommends that the Commission require NV Energy to place the project in the appropriate Plant Held for Future Use account or create a regulatory liability associated with the increased billing determinants to help offset the costs of the facility from impacting existing customers until an appropriate amount of load is being supplied from the projects. (Ex. 311 at 3.) Staff states that its recommendations are based upon the lack of a signed agreement for the project. (Ex. 311 at 19.)

823. Staff states that without signed contracts, approving projects and authorizing NV Energy to expend capital to build this project would not be prudent, particularly given NV Energy's stance that if the facilities are energized and serving a watt of power, the projects must be allowed for full inclusion in rates. (Ex. 311 at 19.) Staff states that without an agreement, the risk of this project would fall entirely on ratepayers, assuming NV Energy can demonstrate the costs are just and reasonable in a GRC. (Ex. 311 at 19-20.) Staff provides that NV Energy can bring this project back for approval in an amendment if and when it signs agreements with the customers to be served from these substations. (Ex. 311 at 20.)

NV Energy's Rebuttal

824. NV Energy notes that Staff and BCP have recommended that the Viking Switching Station project be denied. (Ex. 197 at 4.) NV Energy recommends on rebuttal that the

Viking Switching Station project be granted conditional approval with an executed Rule 9 agreement and asserts the Viking Switching Station project is required per the pending execution of the relevant Rule 9 agreement. (Ex. 197 at 4.)

825. NV Energy further states that it anticipates a Rule 9 agreement for Viking Switching Station will be executed in the near future and requests conditional approval for the project subject to a compliance filing upon execution of the Rule 9 agreement. (Ex. 199 at 4-5.)

Commission Discussion and Findings

826. The Commission denies NV Energy's request for the Viking 345-kV Substation because there is no executed Rule 9 agreement for this project. The Commission finds that it is not prudent to approve this project without an executed Rule 9 agreement, and the risk of this project would fall entirely on ratepayers, without knowing that the presumed load would materialize, and assuming NV Energy could demonstrate the costs are just and reasonable in a GRC. NV Energy may bring this project back for approval in an IRP or IRP amendment if/when NV Energy signs Rule 9 agreement(s) with the customer(s) to be served from these substations.

U. Veterans Substation

NV Energy's Position

827. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Veterans 345/120 kV Substation with a projected May 2030 in-service date and a cost of $40 million. (Ex. 101 at 28; Ex. 176 at 3, 12-13.)

BCP's Position

828. BCP recommends that the Commission reject approval of the Veterans 345/120 kV Substation. (Ex. 406 at 7, 29.) BCP states that NV Energy provided an update explaining that the Veterans Substation has been postponed indefinitely. (Ex. 406 at 7.)

Staff's Position

829. Staff recommends rejecting NV Energy's request for the Veterans 345/120 kV Substation. (Ex. 309 at 3.) Staff explains that because it recommends rejecting the Lantern-Comstock Meadows 345 kV line, it also recommends rejecting approval of this substation. (Ex. 309 at 11.) Staff contends that if NV Energy can serve the load for the one project projected to come online soon, and before the projected in-service date of the Veterans Substation of May of 2030, then it can wait to construct the Lantern - Comstock Meadows line until it can provide better justification. (Ex. 309 at 11.) Moreover, the Vaquero substation will eventually be constructed, which will serve the load that would otherwise be served by the Veterans Substation. (Ex. 309 at 11-12.) Accordingly, Staff argues that the Veterans Substation should be denied. (Ex. 309 at 12.)

NV Energy's Rebuttal

830. NV Energy notes that Staff and BCP have recommended that the Veterans Substation project be denied. (Ex. 197 at 4.) NV Energy also recommends on rebuttal that the Veterans Substation project be denied, if the Vaquero Substation is conditionally approved, as this project has been consolidated with Vaquero. (Ex. 197 at 4.) NV Energy further states that, if the Vaquero Substation is not approved, then Veterans Substation is required for area load growth and executed Rule 9 agreements. (Ex. 197 at 7.)

Commission Discussion and Findings

831. The Commission denies NV Energy's request for the Veterans 345/120-kV Substation because there is no executed Rule 9 agreement for this project. The Commission finds that it is not prudent to approve this project without an executed Rule 9 agreement, as the risk of this project would fall entirely on ratepayers, without knowing that the presumed load

would materialize, and assuming NV Energy could demonstrate the costs are just and reasonable in a GRC. NV Energy may bring this project back for approval in an IRP or IRP amendment if/when NV Energy signs Rule 9 agreement(s) with the customer(s) to be served from these substations. If NV Energy brings back the Veterans Substation for approval, NV Energy will also need to explain how the Veterans Substation does or does not overlap with the Vaquero Substation.

V. Prospector Line Terminal

NV Energy's Position

832. NV Energy requests that the Commission approve, as part of its Preferred Plan, a Supply Plan addition of Prospector 230 kV line terminal with a projected December 2026 in-service date and a cost of $2.2 million. (Ex. 101 at 28; Ex. 176 at 3, 13.)

BCP's Position

833. BCP states that it does not object to the approval of the Prospector 230 kV line terminal. (Ex. 406 at 10.)

Staff's Position

834. Staff recommends the Commission deny the Prospector 230 kV Line Terminal project because while a Rule 9 agreement exists, there has been no demonstration that any security or advances subject to potential refunds have been secured from the applicant. (Ex. 308 at 21-22, 24.) Given the date of the agreement, which was four months prior to the filing of the joint application, and over eight months after NV Energy updated Staff with its summary table of securities and advance subject to potential refund ("ASTPR"), Staff cites its concern that there may be some unknown scope, schedule, or budget changes, or that the project has since been canceled. (Ex. 308 at 23.)

835. Staff states that notwithstanding the signed agreement, without the demonstration of a security or ASTPR collected more than eight months after signing, Staff cannot treat the Prospector project differently from others lacking a signed agreement because in this instance, there appears to be no backstop that would protect ratepayers from harm should the project not fully materialize. (Ex. 308 at 23-24.) However, if the Commission does approve the project, Staff recommends that the Commission include a provision that some, or all, of the project costs be placed into Plant Held for Future Use or that a new regulatory liability account be created as part of a future GRC to account for the increase in billing determinants that may accrue if the loads are late coming on-line and the facilities are included in rates prior to the load developing. (Ex. 308 at 23-24.)

NV Energy's Rebuttal

836. NV Energy notes that BCP has recommended that the Commission approve the Prospector network upgrades project, and Staff has recommended that the Prospector network upgrades project be denied. (Ex. 197 at 3.) NV Energy recommends on rebuttal that the Prospector network upgrades project be approved as submitted and asserts the Prospector network upgrades project is required per an executed Rule 9 agreement. (Ex. 197 at 3.)

837. NV Energy further states that no party other than Staff objects to this project. (Ex. 199 at 5.) NV Energy asserts that Staff objects to the Prospector network upgrades because there was no demonstration that NV Energy received security or an advance subject to potential refund. (Ex. 199 at 5-6.) NV Energy states that it served a supplemental response to Staff DR 385 after Staff filed its testimony showing that the security was received for this project. (Ex. 199 at 5-6.)

///

Commission Discussion and Findings

838. The Commission approves, as part of NV Energy's Preferred Plan, a Supply Plan addition of Prospector 230-kV line terminal with a projected December 2026 in-service date and a cost of $2.2 million. The Prospector network upgrades project is required per an executed Rule 9 agreement. The Commission finds that Staff objected to the Prospector network upgrades because there was no demonstration that NV Energy received security or an advance subject to potential refund, but during discovery NV Energy served a supplemental response to Staff DR 385 after Staff filed its testimony showing that the security was received for this project.

W. Harry Allen Substation

NV Energy's Position

839. NV Energy requests that the Commission approve $4 million for network upgrades to construct a new line position and lead line at the Harry Allen Substation for the generator interconnection of the Dry Lake East PV/BESS project. (Ex. 101 at 28; Ex. 177 at 21.)

BCP's Position

840. BCP states that it does not object to the approval of the necessary network upgrades to add a new line position and lead line at the Harry Allen Substation estimated at $4 million for the interconnection of the Dry Lake East PV/BESS project. (Ex. 406 at 3.)

Staff's Position

841. Staff recommends that the Commission approve the network upgrades to construct a new line position and lead line at the Harry Allen Substation for the generator interconnection of the Dry Lake East PPV/BESS project, if its corresponding PPA is approved by the Commission. (Ex. 305 at 1-2.)

///

Commission Discussion and Findings

842. The Commission approves the $4 million for network upgrades to construct a new line position and lead line at the Harry Allen Substation for the generator interconnection of the Dry Lake East PV/BESS project because the Commission is approving the corresponding PPA.

X. Ft. Churchill Substation Interconnection

NV Energy's Position

843. NV Energy requests that the Commission approve $3.9 million for network upgrades to construct a new line position at the Ft. Churchill Substation for the generator interconnection of the Libra PV/BESS project. (Ex. 101 at 29; Ex. 177 at 21.)

BCP's Position

844. BCP does not object to approval of necessary network upgrades to construct a new line position at the Ft. Churchill Substation estimated at $3.9 million for the generator interconnection of the Libra PV/BESS project. (Ex. 406 at 4.)

Staff's Position

845. Staff recommends that the Commission approve the network upgrades to construct a new line position at the Fort Churchill Substation for the generator interconnection of the Libra PV/BESS project if its corresponding PPA is approved by the Commission. (Ex. 305 at 2.)

NV Energy's Rebuttal

846. NV Energy asserts the Libra network upgrades at Ft. Churchill are required per executed LGIA and the IRP's preferred plan. (Ex. 197 at 3.)

///

///

Commission Discussion and Findings

847. The Commission approves $3.9 million for network upgrades to construct a new line position at the Ft. Churchill Substation for the generator interconnection of the Libra PV/BESS project because the Commission is approving the corresponding PPA.

Y. Lantern Bus 345 kV Line Terminal

NV Energy's Position

848. NV Energy requests that the Commission approve $2 million for network upgrades to add a 345 kV line terminal at Lantern bus for the generator interconnection of the Corsac Geothermal project. (Ex. 101 at 29; Ex. 177 at 21-22.)

BCP's Position

849. BCP states that it does not object to the approval of the necessary network upgrades to add a 345 kV line terminal at Lantern bus estimated at$2 million for the generator interconnection of the Corsac Geothermal project. (Ex. 406 at 4.)

Staff's Position

850. Staff recommends that the Commission approve the network upgrades to add a new line terminal at Lantern bus for the generator interconnection of the Corsac Geothermal Generating Station 2 project, if its corresponding PPA is approved by the Commission. (Ex. 305 at 2.)

NV Energy's Rebuttal

851. NV Energy asserts the Corsac network upgrades at Lantern are required per executed LGIA and the IRP's preferred plan. (Ex. 197 at 3.)

///

///

Commission Discussion and Findings

852. The Commission approves $2 million for network upgrades to add a 345-kV line terminal at Lantern bus for the generator interconnection of the Corsac Geothermal project because the Commission is approving the corresponding PPA.

Z. Greenlink

i. Budget and Continued Approval

NV Energy's Position

853. NV Energy requests continued approval of the Greenlink Nevada Project with a combined budget for Greenlink West, Greenlink North and Common Ties of $4,128 million. (Ex. 101 at 29; Ex. 175 at 19-20; Ex. 182 at 9-10.)

CMN and SNGG's Position

854. CMN and SNGG recommend that the Commission reject NV Energy's Greenlink critical facility designation and related incentives, including requests for CWIP in rate base, a depreciation expense regulatory asset, and continual Commission approval of the Greenlink Nevada Project because, per Docket No. 21-06001, CMN and SNGG explain that it may be more reasonable and prudent for the Commission to review Greenlink's costs and related incentives in future GRCs when NPC and SPPC are each seeking to adjust customer rates to recover Greenlink costs due to the current uncertain project costs; and further, incentives cannot be included in customers' rates until a GRC (Ex. 801 at 2, 6, 11; CMN and Wynn's Brief at 3-5; SNGG's Brief at 2-4.) CMN and SNGG explain that NV Energy's current forecast includes a significant amount of contingency and a forecast of cost escalation through the completion of the Greenlink Nevada Project in December 2028. (Ex. 801 at 11.) CMN and SNGG note that regardless of whether the Commission approves Greenlink incentives in this proceeding though,

the incentives cannot generate cash flows for NV Energy until new rates are approved in a future GRC. (Ex. 801 at 6.) CMN and SNGG state that they are unclear if the Commission needs to take action on NV Energy's request for continuing approval; however, regardless, giving the project continuing Commission approval eliminates the incentive for NV Energy to manage project costs and reduces protections for ratepayers. (Ex. 801 at 11.)

Interwest's Position

855. Interwest recommends that the Commission approve the continued development and capital investment in the complete Greenlink Nevada Project. (Ex. 2400 at 7.)

856. Interwest argues that continued investment in the Greenlink Nevada Project necessitates a robust regional transmission backbone. (Ex. 2400 at 42.) Interwest states renewable energy enhances system value by offering diverse resources and locations. (Ex. 2400 at 42.) Interwest states that improved transmission access boosts reliability and reduces long-term system costs by minimizing the need for extensive generation tie-lines and smaller interconnection upgrades for new generators. (Ex. 2400 at 42.)

857. Interwest emphasizes that interregional transmission is essential for fostering market growth in the West, as it supports resource diversity and applies downward pressure on energy delivery costs. (Ex. 2400 at 42.) Interwest argues that rising costs are attributed to market dynamics rather than mismanagement, asserting that the Greenlink Nevada Project delays could inflate its final costs without alleviating the need to strengthen connections between Nevada's load centers. (Ex. 2400 at 43.)

858. Interwest states that the Greenlink Nevada Project reinforces an important north-south reliability segment and will facilitate the integration of significant amounts of Nevada-based renewable generation into the grid, not only in this IRP but also for IRPs in the future. Ex.

2400 at 43.) Interwest states that investments in the bulk transmission grid can lower costs and expedite new generation interconnections. (Ex. 2400 at 43.)

859. Interwest warns that without the Greenlink Project, project development in Nevada would become riskier and more expensive, resulting in a reduced transfer capacity needed for effective market structures. (Ex. 2400 at 44.) Interwest acknowledges that while NV Energy could achieve resource adequacy without the Greenlink Nevada Project, it stresses that the Greenlink Nevada Project is critical for managing the substantial energy demands stemming from load growth and market development. (Ex. 2400 at 45.) Interwest states that the Greenlink Nevada Project is pivotal for unlocking Nevada's renewable energy potential, as transmission expansion has historically been key to developing new renewable resources. (Ex. 2400 at 45.)

NWCAE's Position

860. NWCAE supports NV Energy's application and proposed projects, specifically construction of the Greenlink Nevada Project because NV Energy's workers are members of Local 396, which is required to represent its members and ensure that its members' material, social and intellectual welfare is advanced per the International Brotherhood of Electrical Workers ("IBEW") International Constitution. (Ex. 2800 at 2.) NWCAE states that members of Local 396 and the fellow outside electrical local in northern Nevada, Local 1245, are who will be building the Greenlink Nevada Project; and additionally, Local 396 and 1245's members are also ratepayers who will benefit from the economies of scale and power transfer capabilities the Greenlink Nevada Project will create. (Ex. 2800 at 3.) NWCAE explains that the Greenlink Nevada Project will provide jobs to 900-1000 of its members throughout the course of construction, which includes over 600 line employees. (Ex. 2800 at 6.)

861. NWCAE explains the significant increased costs for the Greenlink Nevada Project are because of supply chain issues, increases in fuel costs, labor wages increases, BLM-related construction changes, and inflation; yet the Greenlink Nevada Project is still important despite the increased costs to build it because it presents an important and unique opportunity to build Nevada's energy infrastructure by ensuring that the current demand for electricity is met and the Greenlink Nevada Project looks to the future and allows infrastructure to be built now at a lower cost than waiting years to construct and incurring additional costs. (Ex. 2800 at 3, 6.) NWCAE explains that wage and benefit increases were included in a newly executed collective bargaining agreement between Local 396, Local 1245, and NV Energy for the 2023 to 2027 term and accounts for job market conditions for Local 396 and Local 1245 members, prevailing economic forces, and the unique skills and nature of work performed by the members. (Ex. 2800 at 4.) NWCAE states that there was a one-time 15 percent increase for certain employee classifications, including all line classifications in September 2023, and a one-time three-and-a-half percent increase for certain classifications, and then inflationary wage adjustments began in September 2023, which will include a two to two-and-a-half percent wage increase for all employees in all classifications, which are within the market range for public utility employees. (Ex. 2800 at 5.) NWCAE states that the wage increases are for employee retention, which benefits ratepayers to keep knowledgeable employees working for SPPC. (Ex. 2808 at 6-7.)

Tract's Position

862. Tract recommends that the Commission approve the Greenlink Nevada Project because this facility is directly contracted for or contingent on Tract's Peru Shelf and South Valley projects, but also benefits other customers besides Tract. (Ex. 2200 at 21.)

///

BCP's Position

863. BCP recommends the Commission not make a finding granting the "continued approval" of the entire Greenlink Nevada Project. (Ex. 406 at 4, 20; BCP's Brief at2-3.). BCP states that instead, the Commission should defer to its governing orders for approvals and acceptances pursuant to Docket Nos. 20-07023, 21-06001, and 23-08015. (Ex. 406 at 4-5, 20-21; BCP's Brief at 2-3.) BCP provides that based on these governing orders, and assuming the Commission approves the Ft. Churchill to Comstock Meadows #2 345 kV transmission, all components of the Greenlink Nevada Project have and will be Commission approved. (Ex. 406 at 5, 21.)

864. BCP recommends that the Commission reject the approval of the estimated $4,128 million for the entire Greenlink Nevada Project. (Ex. 406 at 5, 21.) BCP provides that instead, the Commission should defer to its approval and acceptance pursuant to the governing orders in Docket No. 20-07023, Docket No. 21-06001, and Docket No. 23-08015 at an estimated $2,633 million. (Ex. 406 at 5, 21; BCP's Brief at 2-3.) BCP notes that pursuant to NAC 704.9494(6) and the Commission's Order in 20-07028, all costs expended to construct the previously approved Greenlink Nevada Project are subject to a prudency review in a future GRC. (Ex. 406 at 5; (BCP's Brief at 2-3.)

865. BCP notes that pursuant to NAC 704.9494(6) and the Commission's Order in 20-07023, all costs expended to construct the previously approved Greenlink Nevada Project are subject to a prudency review in a future GRC. (Ex. 406 at 21.) BCP states that seeking continued "approval" implies a presumption of prudence and provides that no party to this proceeding has conducted a prudency review of the $4.128 billion estimate, which does not include the Fort Churchill to Comstock Meadows #2 345 kV line requested for approval in this

Docket. (Ex. 406 at 22.) BCP recommends that should the Commission make a finding on the budget estimate, it should limit that finding to acknowledging the increased budget versus "approval." (Ex. 406 at 22.)

866. BCP provides that the NAC does not contain provisions requiring continued approval of a project while it is in development; however, provisions like NAC 704.9503(1)(d) require NV Energy to inform the Commission of projects that it is unable to develop and must terminate. (Ex. 406 at 17.) BCP states that NV Energy seeks continued approval for the entire Greenlink Project based on escalated costs. (Ex. 406 at 20.)

867. BCP states that NV Energy is not proposing to terminate any components of the Greenlink Nevada Project and provide that cancellation of any component would likely be unfeasible and violate the intent of SB 448 (2021). (Ex. 406 at 17.) BCP states that because Greenlink West, Common Ties, and Greenlink North are directly and indirectly required to comply with the requirements of the TICEEP or SB 448 (2021), it is not feasible for the Commission to terminate the development of any components of the current Greenlink Nevada Project. (Ex. 406 at 19.)

868. BCP explains that NV Energy has taken the position that the TICEEP was not legislatively mandated pursuant to SB 448 (2021); rather, it only required a filing for the TICEEP at the Commission and did not mandate that NV Energy construct and place any of the components into service. (Ex. 406 at 19-20.) BCP disagrees with NV Energy's position given that NV Energy was party to an approved stipulation in Docket No. 21-06001, which agreed that NV Energy satisfied the requirements of SB 448 (2021), subsections 21 and 24, which sets forth the criteria for obtaining approval of TICEEP. (Ex. 406 at 18, 20.)

///

Staff's Position

869. Staff disagrees with NV Energy's characterization that the Commission approved a $2.484 billion budget for the Greenlink Nevada Project. (Ex. 313 at 15.) Staff explains that NV Energy received piecemeal Commission approval for the project itself, but a budget has never been presented. (Ex. 313 at 15.) Staff states that it is not aware where NV Energy arrived at its $2.484 billion budget. (Ex. 313 at 15.)

870. Staff states that it is also concerned with NV Energy's treatment of the Nevada Project as a fungible project. (Ex. 313 at 21.) Staff explains that in Docket No. 21-06001, NV Energy received Commission approval to construct Greenlink North as required by statute, including the build out of the Lander 230 kV substation and two 525/230 kV transformers, with an in-service date of December 31, 2028. (Ex. 313 at 21.) Staff states that NV Energy has not requested to modify any portion of Greenlink North and therefore any attempt to do otherwise should be construed as a failure to comply with a Commission Order and a statute, which Staff contends is worthy of potential administrative sanctions. (Ex. 313 at 21.)

871. Staff provides that in its filing, NV Energy did not specify which statutory authority under which it bases its request. (Ex. 313 at 23.) Staff explains that the Commission's approval of Greenlink West was authorized under the traditional IRP process outlined in NRS 704.741 whereas the Commission's approval of the Greenlink North project and the Harry Allen to Northwest 525 kV transmission line were authorized pursuant to the TICEEP requirements outlined in NRS 704.79871 through NRS 704.7879. (Ex. 313 at 23; Staff's Brief at 2-4.) Staff states that the Commission may no longer have the authority to cancel the Greenlink West project because it is an integral part of NV Energy's TICEEP and the governing statutes setting forth the Nevada Legislature's public policy decisions. (Ex. 313 at 23; Staff's Brief at 2-3.) Staff

explains that IRP process evaluates needs to meet system demand through a robust analysis containing a range of alternatives to provide reliable electric service; whereas, the TICEEP process contains specific, statutorily mandated projects to spur economic development by a certain date. (Ex. 313 at 23.)

872. Staff states that in discovery, NV Energy represented that it seeks continued Commission approval of Greenlink North through the TICEEP but would not provide a specific authority for Greenlink West, instead relying on the applicable Optional Pricing and Resource Planning provisions of Chapter 704 of the NRS and NAC. (Ex. 313 at 25.) Staff states that the Commission has the authority to grant NV Energy's requested approval of the Fort Churchill to Comstock Meadows #1 transmission line and the construction of the Fort Churchill to Comstock Meadows #2 345-kV transmission line; however, the Commission has already approved the construction of the former at a budget of $67.9 million in Docket No. 20-07023. (Ex. 313 at 25.) Accordingly, Staff provides that the Commission does not have to re-approve the Fort Churchill to Comstock Meadows #1 345-kV transmission line and can review the prudency of any cost increases in the context of a GRC. (Ex. 313 at 25-26.)

873. Staff states that from a practical standpoint, the Commission may not have the authority to grant NV Energy's request for continued approval of Greenlink West because the Commission's authority to determine prudency was circumvented by SB 448 (2021) and the enactment of the TICEEP. (Ex. 313 at 26.) Staff states that not constructing Greenlink West affects NV Energy's TICEEP, which is essentially a three-legged stool including Greenlink West, Greenlink North, and Harry Allen to Northwest 525 kV transmission lines. (Ex. 313 at 26.) Staff states that the 2021 Legislature crafted the TICEEP in SB 448 based upon the Commission's approval of Greenlink West in Docket No. 20-07023. (Ex. 313 at 27-28.) Staff

explains that without Greenlink West, NV Energy's TICEEP fails to achieve the purpose and objectives outlined in NRS 704.79877(1), NRS 704.79877(2)(a), and NRS 704.79877(4). (Ex. 313 at 26.). Staff states that the Commission cannot force NV Energy to take an action that would violate the law and therefore, the Commission has no additional decision to make in the instant docket. (Ex. 313 at 26.)

874. Staff states that failing to construct Greenlink West and just building Greenlink North and Harry Allen transmission lines would not satisfy each of the TICEEP criteria that must be met in NRS 704.79877(1)(a)-(f). (Ex. 313 at 29.) Staff states that NRS 704.79877(2)(a) mandates the construction of high-voltage transmission infrastructure interconnecting northwest and northeast Nevada that increases the transmission import capacity of northern Nevada by not less than 800 MW. (Ex. 313 at 30-31; Staff's Brief at 2-3.) Staff states that without Greenlink West, Greenlink North would only increase the transmission import capacity of northern Nevada by 175, falling well short of the statutory requirement. (Ex. 313 at 31; Staff's Brief at 2-3.) As such, Staff contends that the construction of Greenlink West was implicitly embedded in the 800 MW import capacity figure, meaning that in order to achieve the capacity mandates of the TICEEP, Greenlink West must be built. (Ex. 313 at 31; Staff's Brief at 2-3.) Staff states that NRS 704.79877(4) requires the TICEEP to include an evaluation of the impact that the implementation of the TICEEP will have on a variety of considerations including but not limited to transmission system reliability, resiliency, renewable development, economic activity, carbon emissions, reduce energy supply costs by selling and buying electricity to and from other states, its provision of open access transmission service, rates, and the financial condition of the utility. (Ex. 313 at 31.) Moreover, Staff states that NV Energy has asserted that it cannot satisfy the

requirements of NRS 704.79877(4)(a)-(m) without constructing Greenlink West. (Ex. 313 at 31-34.)

875. Staff disagrees with NV Energy's assertion that the TICEEP requires the construction of Greenlink North. (Ex. 313 at 34.) Staff explains that NV Energy provides that it was only required to file its TICEEP on or before September 21, 2021, but does not require it to construct and place in-service any component. (Ex. 313 at 34.) Staff states that during discovery, NV Energy provided that the Commission's Order in Docket No. 21-06001 approved construction of Greenlink North with a planned in-service date of December 31, 2028, and that an intentionally delayed in-service date of 2031 or later would be contrary to the Commission's Order. (Ex. 313 at 34.) Staff disagrees with NV Energy's contention and argues that it is the most important issue at stake in this IRP. (Ex. 313 at 35.)

876. Staff states that NRS 704.79877(1) clearly requires NV Energy to file the TICEEP, which sets forth a plan for the construction of Greenlink North and Harry Allen to Northwest 525 kV transmission line that will be placed into service not later than December 31, 2028. (Ex. 313 at 35.) Staff explains that the legislative history of SB 448(2021) demonstrates that the bill was intended to direct investment in transmission lines across western Nevada and central Nevada to connect three large energy hubs, with costs recovered in a manner that most benefits ratepayers while allowing the utility a ROR on its investments. (Ex. 313 at 35-36.) Moreover, Staff provides that in Docket No. 21-06001, NV Energy stipulated that construction of Greenlink North and the Harry Allen to Northwest 525 kV transmission line fulfilled a specific statutory mandate pursuant to NAC 704.9484(2)(d). (Ex. 313 at 36.)

877. Staff states that NV Energy has previously represented that such a mandate existed in SB 448 because it contemplated the construction of a facility that meets the

requirements of the TICEEP. (Ex. 313 at 36.) Staff argues that because NV Energy's TICEEP relies on the Greenlink Nevada Project to ensure a reliable and resilient transmission network that can serve existing and projected transmission obligations, it must construct the Greenlink Nevada project. (Ex. 313 at 36.) Staff states that if construction of the Greenlink Nevada Project was not mandated in SB 448, as stated by NV Energy, then both the Greenlink West and Harry Allen to Northwest 525 kV transmission line projects cannot be designated as critical facilities and are not eligible for incentives, as the stipulation in Docket No. 21-06001 only designated these components as critical facilities because all parties agreed the projects were legislatively mandated. (Ex. 313 at 36-37; Staff's Brief at 6.) Staff states that NV Energy has presented no evidence in the instant filing to support a critical facility designation for Greenlink North and Harry Allen to Northwest transmission line but is instead relying on the previous designation which was solely based on the construction of the TICEEP being mandated by the Legislature. (Ex. 313 at 37; Staff's Brief at 6.)

878. Staff states that NV Energy does not seek to modify its Greenlink Nevada Project in the instant filing and is only providing an updated cost estimate/budget for approval. (Ex. 313 at 37.) Staff states that NV Energy has not provided information regarding what the cost to cancel the Greenlink Nevada Project would be because the project is invoiced based on completion of milestones and would vary based upon the extent of the Commission's denial and timing of completing all work and receiving final invoices. (Ex. 313 at 37.) Staff states that NV Energy has not paused development of the project and will continue incurring costs after the final order in this proceeding. (Ex. 313 at 37.) Staff states that if the Greenlink Nevada Project was not mandated by statute, the Commission would still not be able to decide to authorize NV

Energy to continue with or cancel the project because it would require a complete cost-benefit analysis to understand the consequences of such an action. (Ex. 313 at 37.)

879. Staff states that the $1.775 billion increase represents a 71 percent increase from the $2.484 billion cost estimate that NV Energy claims the Commission approved and is an increase of $1.312 billion from the $2.927 billion cost estimate provided by NV Energy in 23-08015. (Ex. 313 at 38.) Staff states that NV Energy attributes the $1.775 billion cost increase to the following: 1) $416 million for contingency; 2) $340.8 million in escalation costs; 3) $97.4 million for adding the Fort Churchill to Comstock Meadows #2 345 kV transmission line construction costs; 4) $124 million to address to BLM requirements; 5) $30.7 million for increased environmental mitigation efforts required by BLM; and 6) $101 million for sales and use taxes that were not included in the original estimate. (Ex. 313 at 38.)

880. Staff states that even with the inclusion of contingency and escalation costs into the Greenlink Nevada Project, there are still cost risks that could result in NV Energy exceeding its updated cost estimate. (Ex. 313 at 39.) Staff explains that since Greenlink North is currently in the BLM permitting process, any delays or additional required environmental mitigation measures could have a significant effect on costs. (Ex. 313 at 39.) Staff states that if delays are extensive, it would require the utility to compress the construction schedule further to meet the aggressive statutorily required in-service dates, further resulting in increased costs. (Ex. 313 at 39-40.) Staff additionally states that any growth to a commodity index above 3.5 percent per year would also increase costs. (Ex. 313 at 40.) Staff states that NV Energy executed an agreement with an engineering, procurement, and construction contractor for the combined construction of the Greenlink Nevada Project, resulting in $300 million in savings; however, NV Energy treated these savings as a contingency reserve to offset additional anticipated significant

costs not accounted for in the $4.239 billion estimate. (Ex. 313 at 40.) Staff states that this demonstrates that NV Energy has no idea what the final cost to construct the project will be. (Ex. 313 at 40.)

881. Staff disagrees with NV Energy's assessment that costs having only risen 16 percent annually from 2021 to 2024. (Ex. 313 at 41.) Staff explains that NV Energy's estimate miscalculated the contingency costs, overstated costs associated with project expansion and included sales tax and escalation costs that were not included in the 2021 estimate. (Ex. 313 at 41-42.) Staff states that the omission of sales tax in its original estimate was particularly concerning because NV Energy touted the local economic benefits associated with paying sales tax on the project, which were included in the present worth of societal cost figures. (Ex. 313 at 42.) Staff provides that after adding back erroneously removed costs, NV Energy's 2021 Greenlink Nevada Project cost estimate increased by 23 percent annually between 2021-2024, which is higher than the approximately 17 percent per year growth rate that the Bureau of Labor Statistics' Producer Price Indices. (Ex. 313 at 42.) Staff further notes that NV Energy failed to mention its July 20, 2023, $2.927 billion cost estimate for the Greenlink Nevada Project in Docket No. 23-08015 and similarly failed to explain how costs for the project have increased well over the inflation rate in just ten months. (Ex. 313 at 42-43.)

882. Staff argues that NV Energy mismanaged the Greenlink Nevada Project. (Ex. 313 at 43.) Staff provides that, as discussed above, NV Energy's original budget was incomplete and flawed. (Ex. 313 at 43.) Staff further provides that the project is too aggressive and unrealistic. (Ex. 313 at 43.) Staff explains that Greenlink West and Greenlink North contemplated in service dates of December 31, 2026, and December 31, 2029, respectively. (Ex. 313 at 43.) Staff states that six months later, it revised the schedule for Greenlink North to have an in-service date of

December 31, 2028, which was later enshrined in statute. (Ex. 313 at 43.) Staff contends that NV Energy compressed the schedule by a year without explaining why or how it would achieve the new in-service date, and NV Energy did not update the original cost estimate to reflect the compressed schedule. (Ex. 313 at 43.) Staff states that the utility pushed for the aggressive schedule at a time where the world was experiencing supply-chain issues from COVID and the highest inflation in 40 years, making the decision to compress the schedule inexplicable and unreasonable. (Ex. 313 at 43.) Staff states that NV Energy is not prudently managing the Greenlink Nevada Project and provides that the management strategy appears to maximize its shareholder profitability. (Ex. 313 at 43-44.) Staff states that NV Energy's push to move the date of Greenlink North and maintain Greenlink West's in-service date unnecessarily increased the costs of the project. (Ex. 313 at 44.)

NV Energy's Rebuttal

883. NV Energy states that it continues to seek continued approval for the Greenlink Nevada Project investments after significant discovery and testimony regarding this request based on NV Energy's transparency regarding the costs causing the increase in the anticipated budget, continued critical need for the projects, and has provided comparative examples resulting in higher costs. (Ex. 206 at 15.) NV Energy asserts that continued approval is requested to affirm NV Energy's recommendation to approve these projects at the higher budget. (Ex. 206 at 15.)

884. NV Energy states that in Docket No. 23-08015, the Commission conditionally approved the 230 kV buildout of the Amargosa and Esmeralda Substations and directed NV Energy to record the costs of the 230 kV buildout in plant held for future use until the 230 kV facilities are serving additional customer load or related LGIAs are entered into that would make

use of this equipment. (Ex. 203 at 6.) NV Energy asserts that the original cost estimate for the Greenlink Nevada Transmission Project is $2.484 billion, consisting of the combined cost estimate provided by NV Energy in response to Staff DR 232 in Docket No. 21-06001 ($2.471 billion) and previously approved for conceptual design, permitting, and land acquisition for the Fort Churchill-Comstock Meadows #2 transmission line ($12.8 million). (Ex. 203 at 6-7.)

885. NV Energy responds to Staff's statement that NV Energy has executed an engineering, procurement, and construction contract for combined construction of the Greenlink Nevada Project, stating that it has executed a construction only contract for combined construction of the Greenlink Nevada Project transmission lines, substations, and telecommunications infrastructure and asserts that it remains responsible for procurement of all long-lead-time equipment and materials and has retained a separate engineer-of-record for the project. (Ex. 203 at 7.) NV Energy denies Staff's assertion that it is using a potential $300 million savings from the combined construction as a contingency for additional anticipated cost increases that are not included in the $2.239 billion cost estimate because NV Energy is continuing to work with the contractor to understand planned crew sizes and the make-up and construction schedule, and is currently unable to determine the exact level by which the Greenlink Nevada Project cost estimate will need to be adjusted. (Ex. 203 at 7-8.)

886. NV Energy denies Staff's assertion that the Commission may not have jurisdiction to provide continued approval for the Greenlink Nevada Project due to SB 448 because the project budgets are not locked by statute, and NV Energy has requested, and the Commission has granted, approval for Greenlink-associated projects in past Docket Nos. 20-07023 and 21-06001. (Ex. 203 Lateef at 8-9.) NV Energy asserts that it did not seek approval of the updated Greenlink costs in its Fifth Amendment to the 2021 IRP (Docket No. 23-08015)

because the escalation in that docket was informational and based on limited preliminary and final proposals for materials and services that were available at the time with the expectation that numerous contracts would be finalized prior to the IRP filing in this Docket. (Ex. 203 Lateef Phase III at 9.) NV Energy states that it has now executed contracts for long-lead-time materials and construction contracts which have enabled it to project cost escalation over the course of the project and believes that it is important to receive continuing Commission approval of the Greenlink Nevada Project due to the forecasted significant escalation in costs over the original estimates. (Ex. 203 at 10.) However, NV Energy states that its request for continued approval does not limit the Commission's authority for a prudency review in a future GRC. (Ex. 203 at 10-11.)

887. NV Energy denies Staff's characterization of its request regarding these facilities as ever-changing. (Ex. 203 at 19-21.) NV Energy asserts that it provided additional information in response to Staff's concerns regarding the Amargosa and Esmeralda substation buildout. (Ex. 203 at 16-17 citing Ex. Lateef-Rebuttal-2.) NV Energy asserts that the 230 kV buildout costs for the Amargosa and Esmeralda substations are not included in the increase the Greenlink Nevada Project cost forecast because the Amargosa an Esmeralda substations will only be built when and if NV Energy executes LGIAs that require 230-kV interconnections at these substations, as contemplated in the Commission's Order in Docket No. 23-08015. (Ex. 203 at 17.) NV Energy states that it received approval to construct the Amargosa and Esmeralda substations in Docket No. 20-07023, requested and received conditional approval for the 230 kV buildouts in Docket No. 23-08015, and now requests approval of the 230-kV buildouts as expansions of the previously approved Amargosa and Esmeralda substations with 525 kV facilities. (Ex. 203 at 17-18.)

888. NV Energy states that it disagrees with BCP's position that continued approval implies a presumption of prudence because while IRP approval may result in a project being deemed a "prudent investment," NV Energy remains obligated to justify the prudency of all expenditures associated with the investment in a future rate case. (Ex. 203 at 11.)

889. NV Energy agrees with BCP's recommendation for quarterly prudency reviews between NV Energy, Staff, and BCP while Greenlink is underway. (Ex. 203 at 11-12.)

Commission Discussion and Findings

890. The Commission does not make a finding granting the "continued approval" of the entire Greenlink Nevada Project. The Commission finds NV Energy's request for continued approval unnecessary, as the Commission has not revoked any approval of the Greenlink Nevada Project. Moreover, the Commission in this Docket approves the Ft. Churchill to Comstock Meadows #2 345-kV transmission line, which is another Greenlink project. Instead of granting "continued approval," the Commission refers to its orders in Docket Nos. 20-07023, 21-06001, and 23-08015. Based on those orders, and the Commission approval in this Docket of the Ft. Churchill to Comstock Meadows #2 345-kV transmission line, the Commission notes that all components of the Greenlink Nevada Project have received Commission approval.

891. The Commission similarly declines to provide the requested approval of the estimated $4.128 billion for the entire Greenlink Nevada Project. Instead, the Commission refers to its orders in Docket Nos. 20-07023, 21-06001, and 23-08015. Pursuant to NAC 704.9494(6), all costs expended to construct the previously-approved Greenlink Nevada Project are subject to a prudency review in a future GRC.

892. The Commission finds that "continued approval" implies a presumption of prudence and finds that no party to this proceeding has conducted a prudency review of the

$4.128 billion estimate, which does not include the Fort Churchill to Comstock Meadows #2 345-kV line approved in this Docket. The Commission does not find it reasonable or in the public interest to grant a request that equates to a prudency approval for unvetted costs.

893. Neither the NRS nor the NAC contains provisions requiring continued approval of a project while it is in development; however, provisions like NAC 704.9503(1)(d) require NV Energy to inform the Commission of projects that it is unable to develop and must terminate. NV Energy is not proposing to terminate any components of the Greenlink Nevada Project; the Commission notes here that cancellation of any component would likely be infeasible and may violate SB 448 (2021). Moreover, the record in this Docket lacks information regarding the costs of any such cancellation or whether there are better alternatives currently available.

894. While the Commission makes no finding regarding continued approval of the Greenlink Nevada Project because such a finding is unnecessary, the Commission questions whether it actually has authority to grant NV Energy's request for continued approval because of SB 448 (2021) and the enactment of the TICEEP. The Greenlink Nevada Project is essentially a three-legged stool including the Greenlink West, Greenlink North, and Harry Allen to Northwest 525-kV transmission lines. The 2021 Legislature crafted the TICEEP in SB 448 based upon the Commission's approval of Greenlink West in Docket No. 20-07023. Without Greenlink West, NV Energy's TICEEP fails to achieve the purpose and objectives outlined in NRS 704.79877(1), NRS 704.79877(2)(a), and NRS 704.79877(4). The Commission has no additional decision to make in the instant docket regarding the approval of the Greenlink Project due to the Commission's previous approvals of the Greenlink Nevada Project in aforementioned dockets, and thus, the Commission does not need to further address the question of whether the Commission could grant NV Energy's request for continued approval.

ii. Critical Facility Designation, CWIP, and Incentives

NV Energy's Position

895. NV Energy requests that the Commission designate as critical facilities Greenlink West and common ties. (Ex. 101 at 29; Ex. 177 at 13-14.) NV Energy notes that Greenlink West consists of a 525 kV transmission line connecting the Fort Churchill and Harry Allen substations, through the Esmeralda, Amargosa, and Northwest substations while the common ties projects are two 345 kV transmission lines that connect the Fort Churchill substation to the Comstock Meadows and Mira Loma substations. (Exhibit 180 at 3, fn 1.) NV Energy requests critical facilities designation for both Greenlink West and common ties. (Exhibit 177 at 14.) NV Energy asserts that the Commission has already designated Greenlink North and the Harry Allen to Northwest 525 kV project as critical facilities. (Ex. 177 at 13.) NV Energy states that the Greenlink project is required to protect system reliability, is included in all recent transmission planning studies, it may be impossible to comply with statutory reliability requirements without the Greenlink project, the system may not have the necessary flexibility to respond to system contingencies without the Greenlink Nevada Project, it promotes diversity of supply by allowing interconnection of a diverse range of resources, allows for the transfer of energy between northern and southern Nevada, is critical to development of additional renewable energy resources, provides access to renewable energy resources located at Amargosa, Esmeralda and Lander substations, is necessary to fulfill statutory mandates included the RPS standard and FERC OATT provisions, and is needed to promote retail price stability. (Ex. 177 at 13.)

896. NV Energy asserts that Greenlink West includes a separate 35-mile 525 kV transmission line connecting Northwest and Harry Allen substations in southern Nevada which completes the 525 kV transmission loop and provides substantial benefits in terms of electrical

system reliability and operational flexibility. (Ex. 182 at 5.) NV Energy asserts that the Commission has already granted critical facility designation to the Harry Allen to Northwest 525 kV project. (Ex. 177 at 13; Ex. 190 at 14.)

897. NV Energy requests the Commission approve CWIP in rate base accounting treatment for Greenlink West and Common Ties and Greenlink depreciation expense after the in-service date and until included in rates, in a regulatory asset with no carry charges. (Ex. 101 at 29.) (Ex. 189 at 4-5; Ex. 190 at 14-18.)

CMN and SNGG's Position

898. CMN and SNGG recommend that the Commission reject NV Energy's Greenlink critical facility designation and related incentives, including requests for CWIP in rate base, a depreciation expense regulatory asset, and continual Commission approval of the Greenlink Nevada Project because, per Docket No. 21-06001, CMN and SNGG explain that it may be more reasonable and prudent for the Commission to review Greenlink's costs and related incentives in future GRCs when NPC and SPPC are each seeking to adjust customer rates to recover Greenlink costs due to the current uncertain project costs; and further, incentives cannot be included in customers' rates until a GRC (Ex. 801 J.Leyko Position at 2, 6, 11.) CMN and SNGG explain that NV Energy's current forecast includes a significant amount of contingency and a forecast of cost escalation through the completion of the Greenlink Nevada Project in December 2028. (Ex. 801 at 11.) CMN and SNGG note that regardless of whether the Commission approves Greenlink incentives in this proceeding though, the incentives cannot generate cash flows for NV Energy until new rates are approved in a future GRC. (Ex. 801 at 6.) CMN and SNGG state that they are unclear if the Commission needs to take action on NV Energy's request for continuing approval; however, regardless, giving the project continuing

Commission approval eliminates the incentive for NV Energy to manage project costs and reduces protections for ratepayers. (Ex. 801 at 11.)

BCP's Position

899. BCP recommends that the Commission reject the approval to designate Greenlink West and Common Ties as critical facilities. (Ex. 406 at 5, 23; BCP's Brief at 4.) BCP states that instead, the Commission should defer to its governing orders in Docket No. 20-07023 and Docket No. 23-08015. (Ex. 406 at 5, 23.) BCP notes that in Docket 20-07023 the Commission denied critical designation for the approved Greenlink West and Common Ties. (Ex. 406 at 5.) BCP further notes that in Docket 23-08015, NV Energy did not request critical facility designation for the approved Amargosa and Esmeralda 525/230 transformers. (Ex. 406 at 5, 23.) Moreover, BCP states that NV Energy guaranteed it would go forward with Greenlink West without critical facility designation. (Ex. 406 at 23.) BCP notes that in Docket No. 23-08015, NV Energy did not request critical facility designation for the approved Amargosa and Esmeralda 525/230 transformers. (Ex. 406 at 23.)

900. BCP recommends that the Commission reject the requests for approval of CWIP accounting treatment and a regulatory asset to record and include the Greenlink depreciation for the Greenlink Nevada Project in this IRP case. (Ex. 406 at 5, 23.) BCP explains that pursuant to the Commission's acceptance of the Phase IV Corrected Stipulation in Docket No. 21-06001, NV Energy can request CWIP and regulatory asset incentives for the Harry Allen to Northwest 525 kV and Ft. Churchill to Robinson 525 kV transmission lines. (Ex. 406 at 5-6, 24.) BCP further explains that only in a GRC can the financial impact of these incentives be known and measurable for each rate class. (Ex. 406 at 5; BCP's Brief at 4.) BCP recommends the

Commission make a finding that the requests for CWIP and regulatory asset incentives be subject to a future GRC and not requested in IRP proceedings. (Ex. 406 at 6; BCP's Brief at 4.)

901. BCP explains that NV Energy agreed via stipulation in Docket No. 21-06001 that it could request CWIP in rates for the Harry Allen to Northwest 525 kV and the Fort Churchill to Robinson 525 kV transmission lines designated as critical facilities. (Ex. 406 at 24.) BCP explains that any such request is required to include all financial impacts associated with the request, including a rate impact analysis that specifies the rate impact of any such proposal on each rate class. (Ex. 406 at 24.) BCP states that NV Energy's filing is insufficient and bases its analysis on estimates of general classes of customers, which does not comply with the stipulation. (Ex. 406 at 4.). BCP states that only through a rate case can actual financial impacts be known and measurable and set for each rate class and also provides that the intent of NAC 704.9484(3), requests for financial incentives should "be in an application to change general rates filed pursuant to NAC 703.2201-703.2481, inclusive." (Ex. 406 at 25.)

902. BCP recommends that the Commission deny NV Energy's request to authorize critical facility financial incentives, including CWIP in rate base during construction, and regulatory asset treatment for depreciation expense after completion, for the Greenlink North, Greenlink West, and Common Ties projects because incentives should only be requested in a GRC where the financial factors impacting the credit metrics of SPPC and NPC can be accurately ascertained. (Ex. 408 at 21; BCP's Brief at 4.)

903. BCP provides that pursuant to NAC 704.9484(3), an IRP is not the proper proceeding to request critical facility incentives such as CWIP and regulatory asset treatment because the regulation specifically mandates that such a request occur in an application to change general rates. (Ex. 408 at 9; BCP's Brief at 4.) BCP explains that in an IRP, a utility may seek

critical facility designation and inform the Commission that it will seek incentives in its next GRC; however, requesting approval of incentives in the instant docket is premature. (Ex. 408 at 9; BCP's Brief at 4.) BCP states that in addition to clear regulatory language, it also makes sense to evaluate a request for financial incentives from a policy perspective because only in a GRC can the Commission fully assess the financial condition of the utility on a prospective basis to ascertain whether such incentives are necessary. (Ex. 408 at 9; BCP's Brief at 4.) BCP states that NV Energy supports its request for incentives by focusing on the financial metrics of the Funds From Operation to Debt ("FFO/Debt") ratio. (Ex. 408 at 9.) BCP is critical of this rationale because the only proceeding in which the Commission can ascertain the FFO/Debt ratio is in the context of a GRC proceeding in conjunction with the authorized return on equity, equity level in the capital structure, the actual cost of debt, the approved level of rate base, the level of revenues used to set rates, and the level of expenses authorized. (Ex. 408 at 9-10.) BCP states that NV Energy provided a list of financial assumptions that, should they occur, could indicate the need for incentives, however BCP contends that such rationale is insufficient to justify approval of incentives at this time. (Ex. 408 at 10.)

904. BCP states that NV Energy requested critical facility incentives for the projects to generate cash flow during the construction phase to support credit metrics and reduce regulatory lag. (Ex. 408 at 10.) BCP states that NV Energy also bases its request on the argument that CWIP in rate base will save customers money in the long run. (Ex. 408 at 10.) BCP disagrees that CWIP will provide customers with net savings and states that NV Energy failed to provide any evidence that there is a financial need for CWIP for SPPC and NPC to maintain their credit metrics. (Ex. 408 at 10-11.) BCP states that NV Energy's own analysis demonstrates that the critical facility financial incentives are not needed as the figures provided by NV Energy show

that the utility has an FFO/Debt ratio sufficient to avoid a credit downgrade without the inclusion of critical facility ratemaking treatment. (Ex. 408 at 13.)

905. BCP states that if a utility is materially and consistently above the 18 percent FFO/Debt threshold, it is an indication that rates are set too high, and if consistently below 18 percent, it indicates that rates are too low. (Ex. 408 at 14.) BCP states that the results displayed for NPC and SPPC in the Behren Direct-3 and Behren Direct-4 tables, which show FFO/Debt ratios from 2024-2033 for NPC and SPPC respectively, are reasonable and demonstrate that CWIP and regulatory asset incentives are not necessary. (Ex. 408 at 13-14.) BCP states that NV Energy must demonstrate the need for regulatory asset incentives because the regulations that contemplate financial incentives and special ratemaking treatment are merely permissive and given that the regulations also contemplate that such requests should be made in a GRC, it follows that NV Energy's requests are premature and unwarranted from a financial perspective. (Ex. 408 at 14-15.)

906. BCP states that NV Energy identified two occasions where the Commission allowed interim rate recovery of CWIP, including the purchase/construction of the Lenzie power plant in Docket No. 04-6030 and construction of the Tracy power plant in Docket No. 05-8004. (Ex. 408 at 15.) BCP explains that the plants were acquired at the direction of the Commission to address concerns regarding NV Energy's exposure to the wholesale purchased power market, and the plants were being acquired when NV Energy was in junk bond status, near bankruptcy, and having trouble attracting capital. (Ex. 408 at 15.) BCP explains that at the time of its need for additional generating resources, NV Energy was in severe financial distress due to a $448 million disallowance on a $928 million revenue shortfall related to fuel and purchased power expenditures. (Ex. 408 at 15-16.) In contrast, BCP states that NV Energy's situation is entirely

different today, with both companies having strong credit ratings and both companies over-earning for the past several years. (Ex. 408 at 16.)

907. BCP states that it is highly unusual for the Commission to authorize CWIP in rate base because it violates the used and useful standard and amounts to single-issue ratemaking. (Ex. 408 at 16.) BCP explains that the request asks ratepayers to pay for assets before they are in service providing benefits to customers, and also seeks to go beyond a test year to include one item that increases rates without considering other items over that same period of time that could decrease rates, such as depreciation, accumulated deferred income tax, load growth, lower capital costs, and other cost savings. (Ex. 408 at 16-17.)

908. BCP states that ratepayers will not save money from including CWIP in rate base. (Ex. 408 at 17.) BCP explains that when the time value of money is included in NV Energy's calculation, as it must be, it is better for ratepayers to avoid paying costs in the early years for a project while it is under construction and before it is placed in service. (Ex. 408 at 17.). BCP states that the present value of the cost stream with CWIP in rates is going to be higher for ratepayers than the present value of the cost stream without CWIP in rates. (Ex. 408 at 17.)

909. BCP states that NV Energy's filing demonstrate slight benefits to ratepayers by including CWIP in rate base - $16.2 million for NPC and $2.7 million for SPPC. (Ex. 408 at 17-18.) However, BCP provides that: 1) the calculated savings are miniscule compared to the total investment (less than one percent of the total investment); 2) NV Energy's calculations take into account the present value of the entire 80-year life of the projects, which, based on BCP's calculations, would require a ratepayer to stay on NV Energy's system for 52 years before receiving any net benefit from the CWIP model; and 3)NV Energy used the WACC as a discount

rate for ratepayers, which would be the appropriate rate for NV Energy, but a consumer discount rate would be much higher. (Ex. 408 at 18-19.)

910. Regarding the discount rate, BCP explains that the value of money to a ratepayer would reflect opportunity cost and, on the margin, it might be a credit card with an interest rate of 21 percent, or even more conservatively 10 percent. (Ex. 408 at 19.) BCP states that based on its calculations, at ten percent, there is no net benefit from including CWIP in rate base and instead represents a large detriment to customers. (Ex. 408 at 19.) BCP calculates that customers would break even at a discount rate of 7 percent. (Ex. 408 Garrett P3 at 19.) Given the above, BCP states that the claim that CWIP would save customers money is inaccurate, even when using NV Energy's own model. (Ex. 408 at 19.)

911. BCP states that from an earnings perspective, inclusion of CWIP in rates is not a benefit to the utility because regulated entities are allowed to accrue a return on the CWIP balance while the project is under construction through AFUDC, which keeps the utility whole from an earnings perspective during the construction period. (Ex. 408 at 19-20.) Meanwhile, BCP states that the inclusion of CWIP in rates shifts construction project risk to ratepayers because otherwise, the utility would bear the risk during construction that the project might never be finished or included in rates. (Ex. 408 20.) BCP states that by including CWIP in rates, a material portion of that risk shifts to ratepayers. (Ex. 408 at 20.) BCP states that because NV Energy does not benefit from an earnings perspective, including CWIP in rate base only shifts risks to customers while improving cash flow to the utility at an equal and offsetting cost to ratepayers. (Ex. 408 at 20.)

912. BCP states that if CWIP is allowed during the construction of the project, NV Energy will not have urgency from a financial perspective to complete the project. (Ex. 408 at

20-21.) BCP explains that without CWIP, a utility foregoes cash flow on the project during construction, the loss of which provides financial motivation to complete the project on time. (Ex. 408 at 21.) BCP states that without this motivation, construction projects can be strung-out over longer periods of time due to the lack of financial urgency. (Ex. 408 at 21.) BCP states that NV Energy's request for a regulatory asset for depreciation expense is inconsistent with NAC 704.9484(3), as it is not a listed incentive under the regulation. (Ex. 408 at 21-22.) BCP states that NAC 704.9484(3)(c) makes clear that a regulatory asset incentive may include costs incurred to construct the project but does not provide for costs and expense items associated with ongoing operations, such as depreciation, which is incurred only after the project has been placed into service. (Ex. 408 at 22.) Accordingly, BCP argues that NV Energy's requested relief is not available under the regulation. (Ex. 408 at 22.) BCP states that NV Energy can protect itself from the added cost of unrecovered depreciation expense without a regulatory asset in conjunction with a rate case filed after the projects are completed and placed into service. (Ex. 408 at 22.)

Staff's Position

913. Staff recommends that the Commission reject NV Energy's request to designate the Greenlink West project and Common Ties as critical facilities. (Ex. 310 at 22; Staff's Brief at 6-7.) Staff explains that NV Energy bases its request to designate Greenlink West and Common Ties with critical facilities status for consistency with the Greenlink North and Harry Allen to Northwest 525 kV project, which obtained critical facility status via stipulation in Docket No. 21-06001. (Ex. 310 at 6.) However, Staff notes that Greenlink West and Common ties were not at issue in that stipulation, and the Commission has previously denied its request to designate Greenlink West and Common Ties as critical facilities because it was determined to be part of normal utility planning. (Ex. 310 at 6-7; Staff's Brief at 6-7.) Staff contends that NV Energy is

requesting critical facilities treatment under the "guise" of consistency and argue that the joint application lacks adequate justification under the regulatory factors to consider such a designation under NAC 704.9484(2). (Ex. 310 at 7.)

914. Staff objects to the critical facility status for the Greenlink West and Common Ties projects from both an engineering and financial perspective. (Ex. 310 at 7.) Staff recommends the Commission reject NV Energy's request to designate the Greenlink West and Common Ties projects as critical facilities. (Ex. 313 at 48.) Staff states that in Docket No. 20-07023, the Commission declined to designate the Greenlink West project, which included Common Ties, as critical facilities because they were considered part of normal utility planning under Nevada law and given NV Energy's representation that it would pursue the project without the designation. (Ex. 313 at 46; Staff's Brief at 6-7.)

915. Staff reasons that because the TICEEP was predicated upon the Commission's approval of the Greenlink West project, one can assume the Nevada Legislature was satisfied with the Commission's Order in Docket No. 20-07023, including the finding that the Greenlink West Project was not a critical facility. (Ex. 313 at 47.) Staff states that had the legislature intended for the project to be a critical facility, then it could have mandated it in SB 448 (2021) but chose not to do so. (Ex. 313 at 47.) Moreover, Staff provides that NV Energy stated that it intends to continue to develop and construct the Greenlink West and project and Common Ties even if the Commission denies NV Energy's request for critical facilities. (Ex. 313 at 47.)

916. Staff states that, from a financial perspective, NV Energy is essentially arguing for critical facilities treatment to support the financial strength of NV Energy; however, Staff provides that Commission regulations do not list the financial position of the utility as criterion for critical facility designation and it is not relevant in making that determination. (Ex. 310 at 8.)

Staff asserts that the only relevance NV Energy's financial position has to critical facilities regards whether an incentive is appropriate. (Ex. 310 at 8.) To that end, Staff notes that in the past dockets that NV Energy cited as a basis for its recommendation, the Commission expressly held that while "improvement of a utility's financial situation and financial health are desirable goals, the critical facility regulation was not designed to reward the utility for those reasons." (Ex. 310 at 8.)

917. Staff argues that NV Energy's current financial circumstances do not warrant the need for incentives compared to the financial context of past decisions where it was awarded financial incentives because such reasons are not representative of NV Energy's current situation. (Ex. 310 at 8.) Staff provides that NV Energy utilizes critical facilities designations that received financial incentives in Docket Nos. 04-06030 and 05-08004 as justification for its instant request. (Ex. 310 at 7, 9.) Staff explains that those projects came on the heels of the 2000-2001 Western U.S. Energy Crisis at a time where NV Energy only owned 50 percent of its generating assets, and the utility was overly exposed to wholesale purchased power markets. (Ex. 310 at 9.) Staff further explains that designation and incentives were merited to encourage the completion of the projects to obtain reliability and price stability benefits. (Ex. 310 B at 9.) Additionally, Staff states that at the time of these dockets, NV Energy had a credit rating of B1, which is four levels below investment grade. (Ex. 310 at 9.) Staff states that NV Energy was nearing bankruptcy, not yet owned by Berkshire Hathaway, and had difficulty obtaining reasonably priced capital. (Ex. 310 at 9-10.)

918. Staff states that in 2001, NV Energy fell into severe financial distress following a failed attempt to deregulate the energy market and the events that led to the Western U.S. Energy Crisis. (Ex. 310 at 10.) Staff explains that during the deregulatory transition, NV Energy stopped

using deferred energy accounting mechanisms and had accrued approximately $1.127 billion in deferred energy balances between the two companies. (Ex. 310 at 10.) Staff states that to address rate shock, the payback period on those balances of those accounts required a three-year collection period, creating the need for NV Energy to receive additional financial regulatory support. (Ex. 310 at 10.) Staff notes that even during this period of financial duress, critical facility designation and associated incentives were opposed in a dissent by a commissioner. (Ex. 310 at 12.)

919. Staff states that NV Energy's current financial circumstances do not jeopardize the completion of these projects, nor do they warrant financial incentives. (Ex. 310 at 12.) Staff states that NV Energy's credit ratings are Baa1 and Baa2 for NPC and SPPC, respectively, which are substantially higher than in 2004-2005. (Ex. 310 at 12.) Staff further states that unlike 2004-2005, NV Energy is now financially backed by Berkshire Hathaway Energy and in 2021, NV Energy's Chief Executive Officer, Doug Cannon, testified to the State Legislature that NV Energy is prepared to fund $2.5 billion in private money into Nevada that would not be expected to be paid back for at least five or six years. (Ex. 310 at 12-13.) Given the abundance of private funding and representations regarding investment payback periods, Staff argues that ample funding is already available for NV Energy's projects without the need for financial incentives under critical facility designations. (Ex. 310 at 13.) Moreover, Staff provides that NV Energy committed to develop and construct Greenlink West and Common Ties regardless of critical facility designation. (Ex. 310 at 13.)

920. Staff states that because the Greenlink West and Common Ties projects do not meet the criteria for critical facilities designations, they should not be eligible for financial incentives. (Ex. 310 at 14.) However, Staff provides that should the Commission disagree, any

request for financial incentives should instead be considered in the context of a GRC, which would more accurately ascertain the true rate impact of any financial incentive. (Ex. 310 at 14.; Staff's Brief at 6.)

921. Staff recommends that the Commission reject any financial incentive requests for Greenlink North and Harry Allen to Northwest 525 kV because any request for incentives must be included in a GRC consistent with the stipulation approved in Docket No. 21-06001. (Ex. 310 at 22; Staff's Brief at 6.)

922. Staff explains that in Docket No. 21-06001, the parties agreed by stipulation to designate the Greenlink North line and Harry Allen to Northwest 525 kV project as critical facilities for the purpose of fulfilling a specific statutory mandate pursuant to NAC 704.9484(2)(d); however, the stipulation did "not grant or authorize any incentive pursuant to NAC 704.9484(3), reserving this Commission determination for future proceedings." (Ex. 310 at 3.) Staff further explains that the stipulation included a provision that "[i]f [NV Energy] seek[s] such incentives in a future proceeding for these projects, [NV Energy agrees that] such a request must include all financial impacts associated with such a request, including a rate impact analysis that specifies the rate impact of any such proposal on each rate class." (Ex. 310 at 3; Staff's Brief at 6.) Given that requirement, Staff provides that NV Energy can only request financial incentives in a GRC, not an IRP. (Ex. 310 at 4; Staff's Brief at 6.) Staff provides that the impact analysis in the instant joint application lacks granularity and grouped several rate classes into general rate class descriptions, as opposed to the more detailed rate classes that would result from a GRC, which amounts to mere estimates that are not representative of a future rate design. (Ex. 310 at 4; Staff's Brief at 6.)

923. Staff recommends that the Commission deny NV Energy's request for CWIP in

rate base accounting treatment for the Greenlink Nevada Project and include the project's depreciation expense with no carry charge in a regulatory asset. (Ex. 313 at 61.)

924. Staff states that NV Energy's claimed need for financial support to maintain a specific credit rating does not satisfy any of the required criteria under NAC 704.9482(2) for a critical facility designation. (Ex. 313 at 49.) Even if the Commission determined that the financial position of the utility somehow relates to the required criteria, Staff provides that NV Energy has not provided any information to ascertain how maintaining a specific credit rating promotes retail price stability any better than not maintaining a specific rating, nor has NV Energy provided any information regarding the cost to ratepayers of granting NV Energy financial incentives in order to maintain the credit rating versus allowing the consequential cost to flow through ratepayers resulting from NV Energy's credit being downgraded. (Ex. 313 at 49.) Staff provides that NV Energy itself noted in the instant proceeding that NV Energy has been able to successfully access debt markets at competitive rates relative to industry peers with similar credit ratings and to receive common equity infusions from its parent company, NV Energy, Inc. (Ex. 313 at 49.)

925. Staff states that in the midst of the COVID-19 pandemic, NV Energy stated it had the private capital to bring to Nevada to fund the Greenlink Nevada Project to spur economic develop and committed to the State Legislature that it would not recover any of that capital investment until the Greenlink Nevada Project goes into service and provides the benefits of that capital investment to the state. (Ex. 313 at 50.) Staff states that the cost of the private capital that NV Energy invests in Nevada to ratepayers includes the return of and return on capital investments to construct the asset; however, NV Energy now threatens not to fund the capital unless it receives additional financial incentives to start recovering the return on its capital

investment before ratepayers receive any benefits associated with the assets. (Ex. 313 at 50.) Staff argues that NV Energy should be held to its public commitments, which were made by its President and CEO Doug Cannon, to avoid the appearance of a bait-and-switch scheme. (Ex. 313 at 51.) Staff states that NV Energy should be held to its word. (Ex. 313 at 51.)

926. Staff states that NV Energy has taken the position that CWIP in rate base is not the return of NV Energy's capital investment; rather it is partially a return on its capital investment, and NV Energy would not recover the costs associated with CWIP in rate base until it is reflected in rates. (Ex. 313 at 52-53.) Staff argues that asking customers to begin paying for any costs associated with the project is asking for recovery of the costs of the project early and there is no other reasonable interpretation of NV Energy's incentive requests. (Ex. 313 at 53.)

927. Staff states that NV Energy has numerous options to address its financial concerns for SPPC besides CWIP in rate base and regulatory asset treatment of depreciation expense such as decoupling, alternative ratemaking, or pursing alternatives to large company-owned rate-based transmission projects like the Greenlink Nevada Project. (Ex. 313 at 53-54.) Staff explains that if SPPC lacks the balance sheet, credit capacity, or cannot obtain the necessary capital investment to construct the project from its parent company, Berkshire Hathaway Energy without significant increases in rates, NV Energy could explore joint ownership models similar to the agreement it has for joint ownership of the One Nevada Line transmission project with LS Power. (Ex. 313 at 54.)

928. Staff argues that the requested financial incentives may also allow NV Energy to receive a return on numerous expenditures that have not been determined to be prudent or just and reasonable, creates intergenerational inequities, and potential inequities between NPC and SPPC ratepayers. (Ex. 313 at 54.) Staff states that a proper review of the costs associated with

the project cannot occur until it has been completed and all costs are known. (Ex. 313 at 55.) Staff notes that NV Energy has already included $4.23 million of costs associated with the cancellation of the four 525/230 kV transformers that are not prudent or reasonable, and given that, Staff has no confidence that NV Energy is ensuring that the costs of the project are prudent, just, and reasonable. (Ex. 313 at 55.)

929. Staff states that if the 10,000 MW of anticipated and proposed loads that the project intends to serve materialize, NV Energy will have more billing determinants to spread the cost of the project over, which in time would lower the impact on customer bills. (Ex. 313 at 55.) Staff explains that NV Energy's requested financial incentives create generational inequities because it is asking current customers to pay for costs that would have been paid for, at least in part, by the new customers that the project is being built to help serve. (Ex. 313 at 55.) Staff states that the Commission should deny NV Energy's request for CWIP in rate base to provide additional time for the anticipated billing determinants to materialize and for NV Energy to access cheaper renewable energy to help offset the impact that the Greenlink Nevada Project will have on energy bills. (Ex. 313 at 55-56.)

930. Staff states that granting NV Energy's requested incentives could create inequities between NPC and SPPC customers. (Ex. 313 at 55.) Staff provides that the cost allocation for Greenlink West was set at a 70/30 allocation between NPC and SPPC, respectively, with the Commission reserving the right to modify the allocation in the future. (Ex. 313 at 56.) Staff states that Greenlink North and the Harry Allen to Northwest 525 kV transmission lines were set by statute at a 70/30 percent split between NPC and SPPC, respectively; however, the Commission is empowered to adjust that allocation, but the statute also empowers the Commission to reassess the allocation based upon actual benefits that accrue to each utility after

the lines are placed into service. (Ex. 313 at 56.) Staff explains that it is not currently known what generation projects or customer loads will be interconnected to the Greenlink Nevada Project. (Ex. 313 at 56.) Moreover, Staff states that given SPPC's projected increased load growth, the cost allocation is no longer applicable. (Ex. 313 at 55.) Accordingly, Staff argues that the cost allocation rations must be modified in a GRC. (Ex. 313 at 56.)

931. Staff states that NV Energy requested and received FERC approval for CWIP in rate base, recovery of 100 percent of prudently incurred costs in the event the project does not materialize for reasons outside of NV Energy's control, and deferral of the Greenlink Nevada Project depreciation expense into a regulatory asset. (Ex. 313 at 56-57.) In approving the above, Staff provides that FERC Commissioner Mark Christie stated his concern that FERC needs to revisit the array of financial incentives offered to transmission developers and questioned whether FERC's determination for those incentives has become nothing more than a "check-the-box exercise." (Ex. 313 at 57.) Staff states that given the Greenlink Nevada Project's significant cost, assessing whether to grant NV Energy's requested financial incentives should not be a mere "check-the-box exercise." (Ex. 313 at 58.) Staff states that NV Energy will need to file an application seeking approval of CWIP in rate base and has yet to make such a filing, nor determined when it might. (Ex. 313 at 59.) Staff provides that NV Energy intends to determine the timing of a potential FERC filing after the Commission makes a ruling on the requested CWIP accounting treatment for native load customers in the instant docket. (Ex. 313 at 59.) Staff is critical of this because on one hand, NV Energy states that it is imperative that SPPC generate more cash flow, but on the other hand, NV Energy does not know when, or if, it will file a FERC rate case to recover the financial incentives for which it has already received approval. (Ex. 313 at 59.)

932. Staff states that NV Energy is incented to allocate more of the Greenlink Nevada Project to NPC and explain that NV Energy's native load FERC transmission jurisdictional cost allocation is approximately 82 percent for NPC and 64 percent for SPPC. (Ex. 313 at 59.) Staff explains that because NPC recovers approximately 18 percent more of its transmission requirements from native load than SPPC, allocating more Greenlink costs to NPC allows NV Energy to collect more revenue for native load customers, thereby potentially delaying the need for NV Energy to file a FERC rate case. (Ex. 313 at 59.)

933. Staff states that NV Energy is required to mitigate costs by utilizing any federal tax incentives or federal funding pursuant to NRS 704.79878(1) and propose a rate method or mechanism to mitigate any increase in its total revenue requirement of more than ten percent due to recovery of the costs of the Greenlink Nevada Project pursuant to NRS 704.79878(2); however, the legislative mandates are silent on placing any caps on the costs that would be incurred, other than such costs must be deemed just and reasonable by the Commission in a GRC. (Ex. 313 at 60.) Staff states that NV Energy's incentive is getting to build the project and earn a return on a significant capital investment. (Ex. 313 at 60.) Staff states that NV Energy's final project cost has increased over 100 percent over its original cost estimate, and such an increase creates concerns that would make it inappropriate to award financial incentives. (Ex. 313 at 60.)

934. Staff recommends that the Commission reject NV Energy's request to approve CWIP in rate base accounting treatment for the Greenlink Nevada project. (Ex. 310 at 22.) Staff argues that any request for a financial incentive associated with Greenlink North and Harry Allen to Northwest 525 kV projects should be requested in a GRC in a manner consistent with the stipulation in Docket No. 21-06001. (Ex. 310 at 15.) Additionally, Staff states that consistent

with its other recommendations, NV Energy should not receive critical facility designations for the projects and therefore any associated incentives should also be rejected. (Ex. 310 at 15.) Staff also characterizes NV Energy's request for CWIP as an unnecessary risk shift to ratepayers where customers would be paying for facilities before they will be placed into service and will be responsible for those costs even if the project is never completed. (Ex. 310 at 15.)

935. Staff states that CWIP in rate base also violates the "used and useful" standard of the regulatory compact with ratepayers paying for projects that are not yet in service. (Ex. 310 at 15.) Staff provides that this can result in scenarios such as the Tracy Area Master Plan, where project load does not materialize as anticipated, and ratepayers are left paying for something that is not used and useful. (Ex. 310 at 15.) Staff opposes also opposes NV Energy's request for CWIP because most of the costs will not occur until the later stages of the project's timeline. (Ex. 310 at 15.) Moreover, Staff is concerned that awarding CWIP would not incent the utility to finish the project in a timely manner, whereas the AFUDC approach creates a greater sense of urgency to complete the project in time for an upcoming rate case to avoid regulatory lag. (Ex. 310 at 15-16.)

936. Staff states that there are no material savings in the PWRRs by using NV Energy's forecasted CWIP in rate base versus the traditional AFUDC approach, and those negligible savings are highly dependent on construction activity and rate case timing. (Ex. 310 at 16.) Staff calculates that as a percentage, utilizing CWIP instead of AFUDC would only realize total project savings of 0.067 percent for NPC and 0.14 percent for SPPC. (Ex. 310 at 16.) Accordingly, Staff recommends denying NV Energy's request. (Ex. 310 at 22.)

937. Staff states that the Commission should deny NV Energy's request to designate the Amargosa and Esmeralda 230 kV substations as critical facilities. (Ex. 313 at 22.) Staff

provides that NV Energy has not demonstrated the need for the build-out, has not executed large generator interconnection or Rule 9 customer agreements for the substations. (Ex. 313 at 22.) Moreover, Staff states that NV Energy determined that its Amargosa Solar project significantly reduces interconnection transmission capacity on the Amargosa 230 kV substation because it already reserved a majority of the Greenlink West transmission capacity at the Amargosa 525 kV substation for the Amargosa Solar project and therefore it is unclear whether these collector substations will ever need to be built. (Ex. 313 at 22.)

938. Staff states that it was confused by NV Energy's request for continued approval for the build-out of the Amargosa and Esmeralda 230 kV substations, including the procurement of four 525/230-kV 600-MVA transformers for each substation as part of its Greenlink Nevada budget and accompanying request for critical facility designation because the build-out of the Amargosa substations, including the procurement of four 525/230 kV transformers, were recently approved by the Commission in Docket No. 23-08015. (Ex. 313 at 17.)

939. Staff states that it is concerned about NV Energy's cancellation of the four 525/230 kV transformers at the Amargosa and Esmeralda substations, and its intention to move the two 525/230 kV transformers at the Lander substation to either the Amargosa or Esmeralda substations. (Ex. 313 at 20.)

940. Staff provides that NV Energy has changed its mind about the urgent need for the four transformers at the Amargosa and Esmeralda substations, which previously received Commission approval, only to demonstrate that the need was not urgent because NV Energy cancelled the acquisition of the transformers before the Commission could render its decision. (Ex. 313 at 20.) Staff further provides that NV Energy regularly argues about matters being urgent when it is not the case but nevertheless requests that the Amargosa and Esmeralda

substations are critical, as it is requesting that the Commission designate the substations as critical facilities to receive financial incentives. (Ex. 313 at 20-21.) Staff explains that NV Energy intends to re-order materials and start construction of the substations once LGIAs or agreements to serve a customer's load are executed. (Ex. 313 at 21.) Staff contends that NV Energy has failed to explain how a facility could be designated as a critical facility when the need for that facility is not currently known and may never be needed. (Ex. 313 at 21.)

941. Staff recommends that the Commission reject NV Energy's request to approve a regulatory asset, with no carry charges, to record and include the Greenlink Nevada Project depreciation expense. (Ex. 310 at 22.) However, should the Commission designate this project as a critical facility and entertain incentives, the Commission should reject NV Energy's request for a regulatory asset. (Ex. 310 at 19.).

942. Staff states that without incentive treatment under a regulatory asset, NV Energy would not recover the depreciation expenses that occur during the interim period – also known as regulatory lag. (Ex. 310 at 19.) However, Staff explains that regulatory lag can also accrue to a utility's benefit, such as instances where increased load growth and additional billing determinants occur in between GRC cycles, because rates are not proportionately adjusted based on updated customer counts. (Ex. 310 at 19-20.) Accordingly, Staff states that any regulatory mechanism that addresses lag related to the recovery of capital should also address lag related to overcollection of depreciation expense and increased load growth. (Ex. 310 at 20.)

943. Staff states that the Commission recently established a regulatory liability account with carry to capture BTGR and Basic Service Charge revenues associated with new incremental customers and load within a specific area. (Ex. 310 at 20.) Staff recommends that if the Commission decides to grant NV Energy's request, which Staff opposes, a similar regulatory

liability mechanism would be appropriate for a more symmetrical payback mechanism. (Ex. 310 at 21.) Alternatively, Staff states that NV Energy can file additional rate cases outside of its statutory three-year cycle, which can drastically reduce the regulatory lag the regulatory asset attempts to address. (Ex. 310 at 21.)

944. Finally, Staff notes that NV Energy has a compressed and more costly construction schedule given its 2028 deadline for certain projects. (Ex. 310 at 21.) Staff contends that denying regulatory asset treatment incents NV Energy to more prudently manage the overall construction costs until they can be recovered in rates. (Ex. 310 at 21.). For these reasons, Staff opposes NV Energy's request. (Ex. 310 at 22.)

NV Energy's Rebuttal

945. NV Energy states on rebuttal that Greenlink West and Common Ties projects meet the requirements to be designated as critical facilities because they meet four of the requirements provided in NAC 704.9484. (Ex. 198 13.) First, NV Energy states that it is required to maintain system reliability, which may not be possible without Greenlink West because all recent transmission planning studies have included Greenlink West. (Ex. 198 at 13.) Second, NV Energy states that Greenlink West promotes diversity of supply by allowing for the interconnection of a diverse range of resources including additional renewable energy resources and conventional thermal generation and provides access to renewable energy resources at the Amargosa and Esmeralda substations. (Ex. 198 at 14.) Third, NV Energy asserts that the Greenlink Nevada Project is necessary to meet statutory mandates including the renewable portfolio standard and for compliance with the FERC OATT provisions requiring transmission expansion to provide additional system import capacity for NITS customers. (Ex. 198 at 14.) Fourth, NV Energy asserts that the Greenlink Nevada Project is required to promote retail price

stability as it allows for the development of the most economic portfolio of generation resources. (Ex. 198 at 14.) NV Energy states that the Commission should, therefore, designate the remaining portions of Greenlink, including Greenlink West and Common Ties, as critical facilities similar to Greenlink North. (Ex. 198 at 14-15.)

946. NV Energy denies that any provision of NAC 704.9848 prevents the Commission from making a determination that a facility that is approved as part of the normal resource planning process from being designated as a critical facility, as Staff contends. (Ex. 198 at 15.) NV Energy asserts that NAC 704.9848 is part of the resource planning regulations and does not identify abnormal resource planning within its criteria for determination whether a facility qualifies for critical facility designation. (Ex. 198 at 15.)

947. NV Energy asserts that Nevada ratepayers will benefit from the requested critical facilities designation because the Commission may also allow CWIP for the designated facility in rates, which will reduce the total cost of the project by reducing the amount of AFUDC accumulated and reduce the costs that will be recovered in rates and reduce potential rate shock while reducing NV Energy's total earnings based on the reduced cost of the project. (Ex. 198 at 16.)

948. In response to comments from BCP, CMN and SNGG, NV Energy acknowledges that the Commission declined to grant, at that time, critical facility treatment to Greenlink West facilities in Docket No. 20-07023. (Ex. 203 at 14, citing March 21, 2021 Order.) NV Energy states that it agrees with BCP that Greenlink West and Common Ties are not more critical because their estimated costs have increased, but states that it is requesting the designation based on new information that was not available to NV Energy in Docket No. 20-07023. (Ex. 203 at 14-15.) NV Energy further acknowledges that it did not request critical facility designation for

the Amargosa and Esmeralda Substation buildout in Docket No. 20-07023, but states that this was because the equipment requested in that Docket did not represent all the facilities for these substations. (Ex. 203 at 15.) NV Energy asserts that it now has information regarding the magnitude of the interconnection requests at Esmeralda and Amargosa Substations which supports the criticality of these Greenlink West facilities to protect reliability and promote diversity of supply and access to renewable energy. (Ex. 203 Lateef Phase III at 15.) NV Energy further agrees with Staff that its "TICEEP is a three-legged stool with the Greenlink West, Greenlink North, and Harry Allen to Northwest 525 [kV] transmission lines representing individual legs of the stool…" (Ex. 203 Lateef Phase III at 15-16.) NV Energy further states that Greenlink West and Common Ties are required to fulfil statutory mandates, and notes that Greenlink North and Harry Allen to Northwest 525 kV transmission lines have already been designated as critical facilities. (Ex. 203 at 16.)

949. NV Energy states that BCP incorrectly concludes that Tables FP-1 through FP-4 do not comply with the stipulation in Docket No. 21-06001 to specify rate impacts for each rate class, because these tables were not provided for such purpose. (Ex. 205 at 14.) Rather, NV Energy asserts that these tables were provided to satisfy the requirement in NRS 704.741(4)(b)(7). (Ex. 205 at 14.)

950. NV Energy asserts that development of the Amargosa and Esmeralda substations with 525 kV facilities is proceeding as a part of Greenlink West, and its request for designation of the Amargosa and Esmeralda substations as critical facilities is based on the magnitude of renewable interconnections at these substations and associated electric system reliability needs. (Ex. 203 at 21-22.) NV Energy states that whether the interconnections are at 525 kV or 230 kV is not a factor its request for critical facilities designation for these substations. (Ex. 203 at 22.)

951. NV Energy denies Staff's assertion that there are already imprudent costs included in the estimate provided in this Docket based on "cancellation fees" because it fully intends to proceed with the 230 kV buildout once required by executed interconnection agreements, and the noted cancellation fees are calculated by the manufacturer based on development milestones which may be offset by reduced costs for work required when NV Energy proceeds with procurement of the transformers. (Ex. 203 at 22.) NV Energy ultimately disagrees with Staff's recommendation that the Amargosa and Esmeralda Substations not be granted critical facility designation. (Ex. 203 at 24.)

952. NV Energy asserts that it has satisfied the requirements of the Stipulation in Docket 21-06001 to specify rate impacts for each rate class in requesting incentives for Greenlink based on the CWIP analysis provided in its direct testimony which measures the yearly change in revenue requirement that is expected to occur if a return on CWIP were approved during the construction phase of the Greenlink projects. (Ex. 205 at 15.) NV Energy states that this analysis shows an increase in revenue during the construction phase and a decrease in revenue required for the life of the Greenlink projects after they are put in-service. (Ex. 205 at 15.) NV Energy further states that this analysis was provided as a workpaper which included a customer rate impact that spread total revenue into commonly used ratepayer classifications (residential, small commercial, industrial, streetlights, and public authority) to reflect how CWIP in rate base would affect major groups of NV Energy's customers and stakeholders. (Ex. 205 at 15.)

953. NV Energy responds that it has deployed significant capital to construct Commission-approved transmission infrastructure necessary to serve state and federal customers, and given the equity levels set in the most recent GRCs for NPC and SPPC, NV Energy needs to

issue additional debt to reduce the equity levels for NPC and SPPC to the levels prescribed by the Commission due to the equity investment necessary for the Greenlink Nevada Project and other capital projects. (Ex. 204 at 4.) NV Energy asserts that additional cash flows will better position NV Energy to take out additional debt by increasing NV Energy's borrowing capacity. (Ex. 204 at 4.) NV Energy states that including CWIP in rate base is a historically recognized method for increasing cash flows during large construction periods and asserts that this method is a balanced approach which increases cash flow to the utility while reducing rate base when the infrastructure goes in service. (Ex. 204 at 4.) NV Energy asserts that this method ultimately lowers the total cost that customers pay for the project. (Ex. 204 at 4-5.)

954. NV Energy states that it cannot rely on equity infusions to fund large capital projects because the Commission has ordered that NPC and SPPC both operate at an approximate 52 percent equity ratio, and shareholders will not make equity available to NV Energy if the investment cannot be expected to earn the Commission authorized return on equity, but will instead earn only the lower Commission-approved debt rate. (Ex. 204 at 5-6.) NV Energy asserts that credit metric pressure and credit downgrades could occur even if CWIP is granted due to the level of debt required to fund large capital projects, including Greenlink. (Ex. 204 at 4.) NV Energy further asserts, however, that CWIP would help secure debt at the best possible rate and mitigate further credit downgrades and is available as a tool to the Commission to send a signal to credit rating agencies that the Commission recognizes the scale of the capital investments and is taking a balanced approach to support financial outcomes while protecting customers. (Ex. 204 at 4-5.)

955. NV Energy states that customers will benefit from CWIP in rate base via saved money and rate stability because AFUDC application ceases when CWIP is recovered in rate

base and lowers total costs to be recovered from customers. (Ex. 204 at 6.) NV Energy further states that implementing CWIP in rate base would mitigate the rate effects associated with Greenlink North, in harmony with NRS 704.79878. (Ex. 204 at 6-7.) NV Energy asserts that CWIP in rate base may provide a greater long-term benefit to customers than AFUDC because under CWIP the overall cost of the project to customers over the life of the project is reduced rather than increasing the rate base and balance on which the utility would earn a return. (Ex. 204 at 7.) NV Energy denies that CWIP in rates shift risk to customer. (Ex. 204 at 9.)

956. NV Energy responds to Staff's contention that it cannot know if the CWIP will be any different than if NV Energy receives a credit downgrade, stating that the additional cash flows from CWIP would increase the funds available from operations which better positions NV Energy to fund construction and increases NV Energy's borrowing capacity. (Ex. 204 at 8.) NV Energy notes that it does agree with Staff's apparent argument that it is unknowable whether CWIP in rate base would prevent a credit metric downgrade, but states that cash flows available from CWIP would send a message to credit agencies regarding the Commission's awareness of the challenges facing NV Energy, even in the event of a credit downgrade. (Ex. 204 at 8-9.)

957. NV Energy states that Staff's suggestions regarding utilizing alternative ratemaking or decoupling to mitigate financial concerns may be viable alternatives in the future, but states that none of the options identified by Staff exist within the current regulatory structure, are untested, and NV Energy has reservations regarding SB 300 alternative rate making. (Ex. 204 at 9). NV Energy asserts that it has looked to proven tools in the regulatory structure because, to have a meaningful benefit to its large capital projects, a financial solution is urgently required. (Ex. 204 at 9-10.)

958. NV Energy denies that the requested incentives lead to the concerns about intergenerational inequities identified by Staff because, although a certain amount of intergenerational inequity exists throughout utility rate making, Greenlink is a 65–70-year project and many generations of customers will come and go throughout the lifetime of the project. (Ex. 204 at 10.) NV Energy reiterates that it is requesting CWIP in rate base for a period of three years, compared to the 70-plus years Greenlink is likely to be in service, and states that the Commission can shape recovery of the Greenlink costs in a GRC to ensure current customers receive the benefit of their pre-funding Greenlink via CWIP. (Ex. 204 at 10.)

959. NV Energy states that it acknowledges its past statements in 2020 regarding private funding of the project and not seeking recovery of any costs for Greenlink North prior to it being in-service. (Ex. 204 at 11.) NV Energy states, however, that it continues to bring billions of dollars of investment to facilitate the Greenlink Nevada Project and other capital projects, and that when it made its statements in 2020, it thought it would be able to utilize PPAs to meet RPS obligations. (Ex. 204 at 11.) NV Energy continues that because a PPA does not create financing obligations on the utility, it planned to utilize the capital to develop the Greenlink Nevada Project. (Ex. 204 at 11.) NV Energy states that several of these PPAs were terminated by the developer following the COVID-19 pandemic which left NV Energy with few options to achieve RPS compliance in 2027 and beyond. (Ex. 204 at 11.) NV Energy states that it, therefore, proposed the Sierra Solar project which could be developed timely and under control of NV Energy, requiring the deployment of $1.5 billion in capital at the same time Greenlink construction was ongoing. (Ex. 204 at 11.) NV Energy further states that its past statements occurred prior to one of the highest inflationary periods our country has ever witnessed and before the BLM permitting process required a number of project changes. (Ex. 204 at 12.) NV

Energy states that project has benefitted from nearly five years of refinement, but costs for the Greenlink projects have escalated not due to any mismanagement or fault on the part of any particular party. (Ex. 204 at 12.) NV Energy assert that the foregoing factors have led to its request for CWIP as a cash flow tool that will ultimately reduce costs for customers (Ex. 204 at 12.)

960. NV Energy states that FERC granted CWIP in rate base recovery for the Greenlink Nevada Project in Docket No. EL22-73-000, which is noted by Staff. (Ex. 204 at 13.) NV Energy asserts that it is in one of the largest capital deployment periods in history to meet state energy policies and suggests that while the Commission has independent jurisdiction in these matters, FERC may be looked to for guidance given its experience with capital deployments on a national scale. (Ex. 204 at 13.)

961. NV Energy denies Staff's position that CWIP in rate base would eliminate the incentive to complete the projects because this position drastically overstates the monies that would be recovered through CWIP. (Ex. 204 at 14.) NV Energy explains that it will recover only a very small portion of the total project costs through CWIP over the requested three-year period compared to the entire project budget. (Ex. 204 at 14.) NV Energy notes that, even with CWIP in place, it would face massive write-offs should it walk away from the Greenlink Nevada Project, and states that CWIP is simply a short-term cash flow option with benefits to NV Energy and its customers. (Ex. 204 at 14.)

962. NV Energy states that the first three years of the Greenlink Nevada Project is the most challenging, especially for SPPC in light of SPPC's size and cash flow challenges. (Ex. 204 at 14.) NV Energy further states, however, that it could agree to CWIP through 2027, and

recognizes that it will be incumbent on NV Energy to justify further CWIP recovery should circumstances change. (Ex. 204 at 15.)

963. NV Energy states that it is requesting regulatory asset treatment for the depreciation expense because it will experience material regulatory lag for major project recovery based on the timing of NPC and SPPC's respective GRCs and the constraints in NRS 704.110(6) limiting contemporaneous GRCs by affiliated utilities. (Ex. 205 at 5.) NV Energy asserts that deferral of depreciation expense of the projects will mitigate regulatory lag by allowing NV Energy to recover on the assets, without which NV Energy may not be given the opportunity to fully recover its investments for the facilities. (Ex. 205 at 5.) NV Energy asserts that Staff's contention that NPC and SPPC may file more frequent GRCs the constraint in NRS 704.110(6) will result in one or both of NPC and SPPC experiencing material regulatory lag. (Ex. 205 at 5-6).

964. NV Energy notes that Staff has proposed an alternate option under which Staff recommends that, if the Commission grants NV Energy's request to establish a regulatory asset for the depreciation expense related to the Greenlink project, then the Commission should create a regulatory liability for the supposed regulatory lag to the customers' detriment that would account for additional revenue incurred due to load growth. (Ex. 205 Behrens Rebuttal at 5-7). NV Energy states that Staff's proposed alternative ignores that the earning sharing mechanism ("ESM") already captures and mitigates excess earnings and is therefore unnecessary. (Ex. 205 at 7). NV Energy further states that the depreciation expense is a real cost that it will never collect from customers unless afforded regulatory asset treatment. Ex. 205 at 7.) NV Energy further states that when it proposed a symmetrical ESM to capture over- and under-earnings,

Staff rejected the proposal, but now proposes the same symmetrical approach for a regulatory liability account. (Ex. 205 at 7.)

965. Regarding Staff's discussion of the May 31, 2024, Moody's Credit Opinion, NV Energy asserts that Staff ignores the preceding May 6, 2024 Moody's Rating Action which stated:

> Sierra Pacific's downgrade reflects our expectation that the utility's CFO pre-WC to debt ratio will weaken to the 15% range over the next few years as its large capital spending
>
> associated with the Sierra Solar project was approved without any additional regulator support of its cash flow during the construction phase.

(Ex. 205 Behrens Phase III Rebuttal at 9.)

966. NV Energy further states that the May 31, 2024, Moody's Credit Opinion states that a further downgrade could occur if SPPC falls to 14 percent or below on a sustained basis, which may be caused by significant delays or cost increases, insufficient parent support, or unfavorable regulatory agency treatment. (Ex. 205 at 9.) NV Energy asserts that continued Commission action which may be viewed as unfavorable by the credit agencies may further erode NV Energy's rating, which could cause SPPC to be downgraded to Baa3 rating, only one step above non-investment grade. (Ex. 205 at 9.)

967. NV Energy further responds to Staff's note that NV Energy has Berkshire Hatheway Energy's ("BHE") financial support, stating that Staff also supports restrictions on returns for equity contributions from BHE as reflected in the 52.4 percent imputed equity ratios in the recent SPPC GRCs. (Ex. 205 at 9.) NV Energy asserts that it is unreasonable to expect a company to continue to invest where it is not permitted to earn a reasonable ROR on its equity investment. (Ex. 205 at 9.) NV Energy states that without additional liquidity support the credit metrics will be stressed during this large construction phase, but the credit metrics should improve when the large projects are in-service and in the intervening time NV Energy will

experience significant credit pressure. (Ex. 205 at 9-10.) NV Energy also states that a regulatory agency can be both "generally supportive" and take actions that directly or indirectly erode a company's credit rating. (Ex. 205 at 10 citing Docket No. 24-02026 Prepared Rebuttal Testimony of Ellen Lapson.)

Commission Discussion and Findings

968. First, the Commission grants NV Energy's request regarding critical facility designation and designates as critical facilities Greenlink West and common ties. The Commission has already designated Greenlink North and the Harry Allen to Northwest 525-kV project as critical facilities. The Commission finds that, per NAC 704.9484, the Greenlink Nevada Project is required to protect system reliability, is included in all recent transmission planning studies, promotes diversity of supply by allowing interconnection of a diverse range of resources, allows for the transfer of energy between northern and southern Nevada, is critical to development of additional renewable energy resources, and provides access to renewable energy resources located at Amargosa, Esmeralda and Lander substations. NAC 704.9484 contains an "or," not an "and," and provides that any one of a number of criteria or some combination of criteria may be met for the Commission to designate a facility as critical. The Commission finds that Greenlink West and the common ties meet the following criteria under NAC 704.9484: (a) Protecting reliability; (b) Promoting diversity of supply; (c) Developing renewable energy resources; (f) Any combination of paragraphs (a) to (e), inclusive. Importantly, however, the Commission finds that the critical facility designation does not guarantee any financial incentives associated with the Greenlink Nevada Project.

969. The Commission next finds that the request for CWIP approval is appropriately addressed in a GRC and not in this IRP proceeding. Only in a GRC can the financial impact of

these incentives be known and measurable for each rate class. NV Energy has recognized the appropriateness of requesting CWIP in GRCs, and several of the parties in this case recommend deferring any CWIP decision to a GRC. NV Energy has stated that it intends to file a GRC for NPC sometime in the first quarter of 2025. If NV Energy files a future CWIP request for the Greenlink Nevada Project, NV Energy must do so in a GRC.

970. The timing of NV Energy's request for CWIP in this case is concerning to the Commission for several reasons. First, NV Energy just completed an SPPC GRC. NV Energy did not request CWIP for the Greenlink Nevada Project in that docket, despite acknowledging in previous dockets before the Commission that a GRC is the most appropriate forum for NV Energy to ask for, and for the Commission to consider, CWIP. Had NV Energy sought CWIP for the Greenlink Nevada Project in the SPPC GRC, NV Energy would have had a Commission decision before 2025, the year for which NV Energy seeks CWIP for the Greenlink Nevada Project in this Docket. More concerning, however, is the general timeline in front of the Commission regarding CWIP and the Greenlink Nevada Project.

971. The Commission approved Greenlink West for construction, and Greenlink North for permitting, in Docket No. 20-07023, in which the Commission issued an Order on March 22, 2021. In that Order, the Commission denied critical facility designation (NV Energy did not seek CWIP in that docket, stating that a CWIP request was "premature" in that IRP docket) for any of the Greenlink Nevada Project. On May 17, 2021, Mr. Cannon testified on behalf of NV Energy to the Nevada Senate Committee on Growth and Infrastructure regarding the Greenlink Nevada Project. He stated, "NV Energy is coming forward with private money and saying we are prepared to fund $2.5 billion into the State. Shareholders do not recover on that money until that asset goes into service, through a contested proceeding with the PUCN…We will bring $2.5

billion to the table. We will put thousands of people to work today, and Nevadans will not be asked to pay for this investment until at least five to six years down the road." The Commission notes that the purpose of the CWIP incentive, according to FERC Commissioner Christie in FERC Docket No. EL22-73-00, is that it "allows recovery of costs *before* a project has been put into service—[Incentive policies—particularly the CWIP Incentive] run the risk of making consumers 'the bank' for the transmission developer…" (Christie Concurrence at 2.) The Commission acknowledges circumstances can change for a project, but the Commission questions how NV Energy could make such certain statements to the Legislature in May of 2021, and then in June of 2022, file a Petition for Declaratory Order with FERC seeking CWIP and other financial incentives for the Greenlink Nevada Project at the federal level.

972. To be fair, CWIP and other financial incentives from FERC do not automatically trigger; NV Energy would have to file a FERC rate case or make a FERC 205 filing for the CWIP incentives, which FERC granted to NV Energy, for CWIP and other financial incentives to go into effect. NV Energy has not filed a FERC rate case or triggered its CWIP ability with FERC. Again though, the Commission has concerns and questions. In Docket No. 20-07023, NV Energy's then-CFO Michael Cole filed with this Commission testimony regarding CWIP for the Greenlink Nevada Project and a FERC rate case, in which Mr. Cole stated the following:

> When I prepared my direct and supplemental testimonies, [NV Energy's] plans were to file a FERC rate case following the conclusion of this proceeding and CWIP recovery. The timing and specifics of that filing are still being evaluated, and, as such, no decisions have been made with respect to that filing…[NV Energy] [is] committed to mitigating the rate impacts from these capital projects and will continue to evaluate the best approach to achieve balanced objectives.

(Docket No. 20-07023, Cole Rebuttal at 5.) NV Energy filed that testimony on February 8, 2021. As of December 2024, NV Energy has not filed a FERC rate case, despite being granted CWIP and other financial incentives at FERC. The Commission notes and understands that for

NV Energy to file a FERC rate case, NV Energy must consider more than CWIP for the Greenlink Nevada Project. But the Commission looks at the timeline and NV Energy's CWIP request for the Greenlink Nevada Project— NV Energy first requested critical facility designation in 2020 in its IRP Amendment as a precursor to a CWIP GRC ask; the Commission denied that request in March 2021; NV Energy then seemingly guaranteed the Legislature in May 2021 that it would not ask for CWIP; NV Energy filed for CWIP and other financial incentives in June 2022 at FERC; FERC granted CWIP and other financial incentives in March 2023; NV Energy has not filed a FERC rate case to date to trigger the CWIP incentive; NV Energy did not request CWIP in NPC's GRC filed in June 2023, or in SPPC's GRC filed in February 2024, but then requested it again in this IRP filing in June 2024—and the Commission wonders why NV Energy's actions are so disjointed. The Commission is concerned that NV Energy's CWIP request for the Greenlink Nevada Project has not been consistent in three different forums—the Commission, FERC, and the Nevada Legislature.

973. Perhaps most concerning to the Commission in terms of timing and financial implications is NV Energy's failure to provide a full explanation of the financial risks of its decision to simultaneously pursue multiple self-build projects with price tags exceeding a billion dollars each (the Greenlink Nevada Project and the Sierra Solar Project). In its June 30, 2022, Petition for Declaratory Order with FERC for CWIP and other financial incentives for the Greenlink Nevada Project, NV Energy sought authorization to recover 100 percent CWIP in rate base. FERC summarized NV Energy's Petition in the following way:

> According to NV Energy, Greenlink Nevada will be the largest transmission investment in NV Energy's history, with a total estimated cost of more than $2.5 billion. NV Energy claims that the expenditure of such large sums will create significant financial challenges and pressure on NV Energy's cash flows, and that the CWIP Incentive will help alleviate financial risks and cash flow

> pressures that Greenlink Nevada will impose on NV Energy during the construction period.
>
> NV Energy explains that the CWIP Incentive would support NV Energy's ability to finance the construction of the Project and reduce the overall need to raise capital during the construction period. In addition, NV Energy argues that the CWIP Incentive would help keep the costs of the Project lower because it would stop AFUDC from accruing into the capital costs for the CWIP amounts. NV Energy also asserts that the cash flow from the CWIP Incentive will help NV Energy to raise equity and debt capital from investors who may otherwise be discouraged by the delay in recovery or the debt and equity carrying costs of the Greenlink Nevada investments, while also reducing the need for NV Energy to obtain debt and equity financing.

(FERC Docket No. EL22-73-000 at 22-26, issued March 23, 2023.)

974. On August 21, 2023, not a year after NV Energy's FERC filing, NV Energy filed its Fifth Amendment to the IRP, Docket No. 23-08015, and that filing contained a request for NV Energy to self-build the Sierra Solar Project, the most expensive generation project in NV Energy's history, with a proposed budget in 2023 of approximately $1.5 billion dollars. Despite having told FERC that the Greenlink Nevada Project, then a $2.5-billion project (now closer to approximately $4.2 billion), would create significant financial challenges and pressure on NV Energy's cash flow, NV Energy filed with this Commission a request for approval of the Sierra Solar Project without mentioning these Greenlink Nevada Project concerns in its filing. Again, to be fair, NV Energy did inform the Commission about credit metrics, and did request CWIP, for the Sierra Solar Project; however, NV Energy never mentioned the financial implications of attempting to develop these two enormously expensive projects at the same time, and how one project, Greenlink Nevada, was already such a financial concern for NV Energy. The Commission finds the link between NV Energy's large self-built and owned projects and its credit metrics to be particularly challenging. The Commission has not been provided comprehensive information illustrating whether large self-built and owned capital projects, like

the Greenlink Nevada Project and the Sierra Solar Project, which purportedly necessitate Commission approval of financial incentives to shield NV Energy and its ratepayers from adverse financial implications, are the best solution to serve the energy needs of Nevada. As a result, it remains unclear to the Commission to what extent those large investments are putting upward or downward pressure on NV Energy's credit metrics, and most importantly, whether such investments balance the interests of customers and shareholders and realize the best value.

975. The Commission does not wish to relitigate the Sierra Solar Project and stands by its decision. What the Commission is articulating here is a desire to see NV Energy's entire financial picture for planning purposes and not receive information piecemeal. NV Energy seeks a stable regulatory environment and cites the regulatory compact as the basis for that stability. The Commission agrees, but notes that the regulatory compact goes both ways; the Commission can only provide stable regulatory outcomes when it is given all of the information required to make decisions and has a full record upon which to base decisions. The need to see NV Energy's entire financial landscape and, most importantly, the effect on rates and ratepayers underpins the Commission's decision to consider the CWIP request for the Greenlink Nevada Project in a GRC.

976. The Commission rejects the requests for approval of CWIP accounting treatment and a regulatory asset to record and include the Greenlink depreciation for the Greenlink Project in this IRP case. Pursuant to the Commission's acceptance of the Phase IV Corrected Stipulation in Docket No. 21-06001, NV Energy can specifically request CWIP and regulatory asset incentives for the Harry Allen to Northwest 525-kV and Ft. Churchill to Robinson 525-kV transmission lines and may request other CWIP incentives in the GRC filing. Any such request is required to include all financial impacts associated with the request, including a rate impact

analysis that specifies the rate impact of any such proposal on each rate class. As previously discussed in this Order, NV Energy's filing is insufficient and bases its analysis on estimates of general classes of customers, which does not comply with the stipulation in Docket No. 21-06001. As contemplated by NAC 704.9484(3), only through a GRC can actual financial impacts be known and measurable and set for each rate class; thus, requests for financial incentives should "be in an application to change general rates filed pursuant to NAC 703.2201-703.2481, inclusive."

Therefore, it is ordered:

1. The Amended Joint Application filed by Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy in Docket No. 24-05041 is granted in part, as delineated in this order.

Compliances:

2. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file the results of the EV Load Identification analysis and the results of the lower-income and HUC customer surveys with the Commission when they are completed.

3. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file the federal and state funding details as they impact the TEP budget for the Action Plan no later than 180 days after issuance of this order.

4. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file an update with the Commission on the budget for one transformer at the Darling Substation within 14 days of the issuance of this Order.

5. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall alter its current 2.5 percent (3V) voltage variation criterion in the HCA to 3.0 percent (3.6V) as contained in IEEE 1547-2018.

6. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall, within 30 days of the issuance of this order, submit in this Docket information clarifying how the Commission's Orders to cease recording amounts to the NEM regulatory asset accounts in Docket Nos. 23-06014 and 24-02026 affect the NEM public policy costs that Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy propose to charge eligible customers pursuant to NRS 704B.310(8).

7. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file the Naniwa Rule 9 Agreement once the Agreement is executed.

Directives:

8. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall host a workshop on the issue of dependable PV output methodology within three months of the issuance of this order regarding PV output methodology, including an evaluation of SCE's methodology.

9. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall host at least four in-depth public workshops devoted to Rule 9 and the energization process. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall file in this Docket a status update within six months of the issuance of this order addressing the potential for an Ohio-like Rule 9, and Rule 1 as necessary, amendment(s) in Nevada; proposed Rule 9 changes regarding the following suggestions in the six-month status report: additional requirements for abnormal risk projects to: 1) provide security for all up-front utility investment; 2) have the applicant comply with stringent performance obligations under milestone schedules; and 3) phase their developments where feasible; and, finally, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall include in the six-month status report proposed Rule 9 changes to address BCP's

suggestion to enact a provision in its agreements that allows NV Energy, at its own discretion, to permanently reallocate unused capacity to other customers and subsequently amend its contract so the requested load is binding on the applicant.

10. Once the Rule 9 workshops are complete, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall use the information from stakeholders to prepare an Energization Report to be submitted with NV Energy's 2025 DRP update covering (i) timelines for processing Rule 9 applications, and (ii) additional processes, tools, Staffing requirements, or other refinements to internal processes, customer engagement, and/or the tariff necessary to achieve the customer's requested in-service date.

11. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall include in all future DRP related filings an examination of potential quantification or monetization of safety benefits within the LNBA to be compliant with NRS 704.741(5)(a).

12. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall change the current requirement language in the Residential Managed Charging program to "customer must possess at least one qualifying charger per EV." Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall update the Residential Managed Charging program to allow customers to participate with a qualifying charger and/or a vehicle that is capable of directly communicating with the charging management platform.

13. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall include both external funding and program execution details in their future TEP approval requests.

14. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall include in its DSM Plan Update narrative for the period covered by the update the specific details of its market strategies.

15. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall informationally file a MW goal for demand reduction, after working in conjunction with the DSM Collaborative, on April 1, 2026, for the 2026 and 2027 summer seasons. This goal should be a consensus of what is objectively achievable with the overall budgets for NPC increased by $2,000,000 annually and SPPC increased by $1,000,000 annually.

16. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall schedule public meetings to update Rule 15 with all interested stakeholders. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall start the Rule 15 update process with meetings with interested stakeholders, with a formal filing due by January 1, 2026. The formal filing shall include an update on the topics outlined by IREC including why or why not these items were addressed in the meetings and formal filing.

17. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall propose NEM reliability impact thresholds, related tracking, and Rule 15 or another tariff revision to ensure that there are no negative distribution system impacts with incremental NEM penetration in NV Energy's next IRP or IRP amendment filing after NV Energy obtains stakeholder input during the planned 2025 Rule 15 workshops.

18. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall include an evaluation of the contingency conditions in NV Energy's HCA

in the next DRP update on or before September 1, 2025, including the findings in the CPUC's Resolution E-5260.

19. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall include information regarding more robust behind-the-meter energy storage capacity incentives in a future DSM plan.

20. If the Callisto ESA is terminated early, then Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy shall seek Commission approval to set the price that it will charge to ratepayers for Corsac's generation for the remainder of the PPA term.

By the Commission,

HAYLEY WILLIAMSON
Chair and Presiding Officer

TAMMY CORDOVA, Commissioner

RANDY J. BROWN, Commissioner

Attest: Trisha Osborne
TRISHA OSBORNE
Assistant Commission Secretary

Dated: Carson City, Nevada
12-27-24

(SEAL)

PUBLIC UTILITIES COMMISSION OF NEVADA
PUC