

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 2027-2046 integrated resource plan, 2027-2029 Action Plan and 2027-2029 Energy Supply Plan.

Docket No. 26-05 ____

VOLUME 4 OF 41

TESTIMONY

DESCRIPTION	PAGE NUMBER
TESTIMONY	
Michael Brown	2
Kurtis Giubbini	40
Mathew Johns	51
John Lescenski	68
Fady Atala	77
Charles Pottey	91
Layne Maxfield	130
Sean Spitzer	153
Michael Holland	215

MICHAEL O. BROWN

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26-05___

Prepared Direct Testimony of

Michael O. Brown

SECTION I: INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Michael O. Brown. My job title is Integrated Energy Services Director for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6226 W. Sahara Ave. Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I have more than 25 years of experience in energy efficiency (“EE”), renewable energy, demand response (“DR”), distributed energy resources (“DERs”), dynamic pricing, and advanced meter and smart grid infrastructure in a variety of roles. I have been continuously employed by NV Energy since September 2005, working in the Demand Side Management (“DSM”), Renewable Energy and Origination, and Integrated Energy Services departments focused on building out integrated EE and DR programs and related infrastructure and services. I have supported major

1 projects such as the statewide advanced meter infrastructure deployment and the
2 Nevada Dynamic Pricing Trial. I have a Bachelor of Science degree in chemistry
3 and international relations as well as a Master of Business Administration. More
4 details regarding my professional background and experience are set forth in my
5 Statement of Qualifications, included as **Exhibit Brown-Direct-1**.

6
7 **3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**
8 **CURRENT POSITION?**

9 A. I provide leadership and strategic direction to cross-functional planning and
10 operations teams in the Integrated Energy Services department. I also provide
11 business oversight of the development of and implementation of DSM, DR and
12 DER operations and planning software and DSM and Distributed Resources Plan
13 (“DRP”)-related pilot projects, demonstrations, and trials.

14
15 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
16 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
17 **(“COMMISSION”)?**

18 A. Yes. I have provided written testimony and also appeared before the Commission
19 in various dockets including, more recently, the 2025 Energy Supply Plan Update
20 for the Extended Day Ahead Market request (Docket No. 25-10025), 2025 Joint
21 DRP Update (Docket No. 25-08029), 2024 Joint Integrated Resource Plan (“IRP”)
22 (Docket No. 24-05041), 2023 Joint DRP Update (Docket No. 23-09002), 2022
23 Joint DRP Update (Docket No. 22-09001) and the application by the Companies
24 seeking Commission approval of their 2021 Joint IRP (Docket No. 21-06001),
25 within which NV Energy’s second Distributed Resources Plan (“2021 Joint DRP”)

1 was filed. I have also participated in Commission workshops in various
2 investigatory dockets.

3
4 **5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY**
5 **IN THIS CASE AND HOW IS YOUR TESTIMONY ORGANIZED?**

6 A. Section II of my testimony is in support of the following sections of the 2026 Joint
7 DRP narrative:

- 8 • Section 7.A – Incremental Investment in Tools, Systems, or Technologies to
9 Integrate Distributed Energy Resources; Distributed Energy Resource
10 Management System;
- 11 • Section 7.B – Incremental Investment in Tools, Systems, or Technologies to
12 Integrate Distributed Energy Resources; Department of Energy Grid Services
13 Grant Project;
- 14 • Section 8.A.2 – Proposed Programs, Tariffs, Pilots or Demonstrations; Non-
15 Wires Alternative Analysis; NWA Tariffed-On-Bill Pilot Program;
- 16 • Section 8.B – Proposed Programs, Tariffs, Pilots or Demonstrations; Locational
17 Net Benefits Analysis; and
- 18 • Section 8.C – Proposed Programs, Tariffs, Pilots or Demonstrations; Load
19 Flexibility Program Tariff Riders.

20
21 In Section III of my testimony, I support Section 9.A – Grid Services Compensation
22 Overview of the DSM Plan narrative filed in this instant docket that explains the
23 Companies’ proposed implementation of new grid service tariff riders within a
24 proposed DR participation structure.

1 6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

2 A. I am sponsoring the following exhibits and technical appendices:

- 3 • Exhibit Brown-Direct-1 - Statement of Qualifications
- 4 • Technical Appendix DSM-2 - Demand Response Energy Savings Curves
- 5 • Technical Appendix DSM-5 – 2027-2029 DR Scenarios and DR Whitepaper

6
7 **SECTION II: 2026 JOINT DRP NARRATIVE SUPPORT**

8 7. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE 2026 JOINT
9 DRP NARRATIVE SECTIONS THAT YOU ARE SUPPORTING IN THIS
10 FILING.

11 A. Sections 7.A and 7.B – *Incremental Investment in Tools, Systems, or Technologies*
12 *to Integrate Distributed Energy Resources; Distributed Energy Resource*
13 *Management System; and Department of Energy Grid Services Grant Project*
14 provide updates on two projects that were approved by the Commission in the 2021
15 Joint DRP filing in Docket No. 21-06001. The first project update focuses on the
16 status of the capital project to build a Distributed Energy Resource Management
17 System (“DERMS”). The second update focuses on NV Energy’s participation in
18 a United States Department of Energy (“DOE”) funded cooperative agreement
19 referred to as the DOE Grid Services Set (“GSS”) Grant project.

20
21 The DOE GSS Grant was a collaborative project. The project team included the
22 University of Nevada, Reno (“UNR”), University of Nevada, Las Vegas
23 (“UNLV”), and a private software development company Evolution Networks
24 (collectively, including NV Energy, the “Project Team”). The DOE funded
25 research, software development, and field demonstration of novel services from
26 aggregated DERs. In addition to the cost share required under the cooperative

1 agreement, NV Energy installed a 1-megawatt (“MW”)/4-megawatt-hour
2 (“MWh”) battery energy storage system (“BESS”) at its Beltway Substation in Las
3 Vegas to support testing of the software and services developed under the
4 cooperative agreement.

5
6 **Section 8.A.2 – Proposed Programs, Tariffs, Pilots or Demonstrations; NWA**
7 *Tariffed-On-Bill Pilot Program* proposes that the Companies evaluate a new tariff-
8 based investment solution that enables customers to adopt bill-saving EE measures
9 and other DERs with little or no upfront cost. This pilot is structured to support the
10 recommended non-wires (*i.e.*, Non-Wires Alternative (“NWA”)) solutions to
11 identified, forecasted constraints on NV Energy’s distribution system in 2029 and
12 2031 involving the Lorenzi and Regena Substations.

13
14 **Section 8.B – Proposed Programs, Tariffs, Pilots or Demonstrations; Locational**
15 *Net Benefits Analysis* refers to NV Energy’s efforts in its DOE GSS Grant project
16 to implement a field demonstration to evaluate the capability of DER aggregations
17 to provide locational net benefits and support NWA solutions.

18
19 **Section 8.C – Proposed Programs, Tariffs, Pilots or Demonstrations; Load**
20 *Flexibility Tariff Riders* discusses a set of grid services tariff riders that NV Energy
21 filed with the Commission on October 14, 2025, in Docket Nos. 25-10012 and 25-
22 10013, that are designed to support load flexibility programs across the DSM Plan
23 and the DRP.

1 8. Q. PLEASE DESCRIBE NV ENERGY’S RECENT ACTIVITIES
2 REGARDING THE DEVELOPMENT AND DEPLOYMENT OF DERMS.

3 A. NV Energy contracted with Oracle Utilities (“Oracle”, and collectively with NV
4 Energy, the “Parties”) to build a “system of systems” DERMS. This means that
5 Oracle will integrate several software systems to deliver an overall solution that
6 meets the contracted functional requirements for a DERMS.

7
8 The Parties planned a multiple software release strategy in which prioritized
9 functionality is delivered and moved into production first and subsequent releases
10 continue to add incremental functionality. The first release was completed and
11 moved into production on May 22, 2023. This release improved the speed and
12 security of communications with DER devices in the field using the Oracle Live
13 Energy Connect software product.

14
15 The Parties have developed plans for future releases that extend over a longer time
16 frame than originally expected. The Phase 1b release will occur in November 2026
17 and will be called Phase 1b(i). This will allow replacement of NV Energy’s existing
18 Demand Response Management System and at-scale settlement for load flexibility
19 programs using the newly proposed Grid Services Tariff Riders for energy and
20 capacity discussed in my Q&A 28 below and in Section 8.C of the 2026 Joint DRP
21 narrative. Subsequently, a release called Phase 1b(ii) will occur in April 2027 and
22 add event optimization and post-event measurement and verification functionality.

23
24 Releases are planned for DERMS Phase 2 in 2027 and 2028, respectively. There
25 have been no further updates to the budget since the updates provided in the 2024
26 IRP in Docket No. 24-05041. The budget estimate continues to be an estimated
27

1 budget of \$24,829,777, above the originally approved \$15,482,578 filed and
2 approved by the Commission in Docket No. 21-06001.

3
4 **9. Q. PLEASE DESCRIBE NV ENERGY’S RECENT ACTIVITIES**
5 **REGARDING ITS PARTICIPATION IN THE DOE GSS GRANT**
6 **PROJECT.**

7 A. The DOE GSS Grant project has now concluded. It was divided into three major
8 phases referred to as Budget Periods. The first two Budget Periods had specific
9 deliverables that had to be completed and accepted by DOE before authorization to
10 proceed into the next phase. The Project Team completed the Budget Period 1
11 research phase of the project on January 31, 2022, and completed the Budget Period
12 2 development phase of the project at the end of 2023. Finally, the Project Team
13 concluded the Budget Period 3 field trial at the end of July 2025 and submitted final
14 project reports in November and December 2025. Budget Period 3 focused on
15 monitoring participants in a field demonstration, testing new customer recruitment
16 messaging, and measuring grid services performance of DER aggregations.

17
18 **10. Q. HOW IS NV ENERGY LEVERAGING ITS PARTICIPATION IN THE DOE**
19 **GSS GRANT PROJECT?**

20 A. Although laboratory and real-time simulation activities were fully successful, field
21 deployment revealed real-world challenges related to DER equipment
22 configuration and communications, inverter performance variability, cybersecurity
23 requirements, communication protocols and translations, multi-party access to
24 DER devices, coordination between cloud platforms and utility operational
25 technology (“OT”), a wide range of diversity in both customer and 3rd party vendor
26
27

1 willingness to participate in grid services programs, DER business model conflicts,
2 and limited customer understanding of grid services and dynamic rate options.

3
4 NV Energy has channeled these lessons learned into its DERMS architectural
5 approach and functional requirements, proposed Rules No. 15 revisions in Docket
6 Nos. 25-12031 and 25-12032, and proposals for a new series of grid services riders
7 in Docket Nos. 25-10012 and 25-10013. Lessons learned have also supported NV
8 Energy’s organizational capacity development to deploy DER aggregations that
9 include both front-of-the-meter and behind-the-meter DERs and, hence, are critical
10 for future deployment of non-wires solutions.

11
12 NV Energy will continue to transition software and approaches developed under
13 the grant project into production systems over time including migrating the control
14 approaches for the Beltway Substation BESS into the DERMS Phase 2 “Grid
15 DERMS” product designed to control fleets of distributed energy storage devices
16 and supplementing the proposed grid service rider series with additional stackable
17 services (*i.e.*, complementary services that could be bundled as appropriate for a
18 program use case and DER capability).

19
20 **11. Q. WHAT IS THE PURPOSE OF NV ENERGY’S PROPOSED NWA**
21 **TARIFFED-ON-BILL PILOT PROGRAM.**

22 A. The purpose of the NWA Tariffed-On-Bill (“TOB”) Pilot Program (“NWA TOB
23 Pilot”) is to address a key barrier to successful non-wires solution
24 implementation—limited customer participation due to upfront cost constraints—
25 by introducing a tariff-based investment solution that enables customers to adopt
26 bill-saving EE measures and other DERs with little or no upfront cost. By
27

1 facilitating participation at scale in targeted grid locations, the NWA TOB Pilot
2 seeks to improve the effectiveness of non-wires solutions in deferring or avoiding
3 wired transmission and distribution investments while delivering customer bill
4 savings and minimizing impacts to non-participating customers.

5
6 The structure of most traditional EE programs can create barriers to entry for many
7 customers. Participation is often restricted to customers who own their homes and
8 are either capable of making a sizable upfront investment or have qualifying credit,
9 income, and assets to personally secure a loan. These barriers frequently eliminate
10 the potential participation of the highest energy-intensive customers, those who use
11 the most energy per square foot of their home and tend to have an outsized impact
12 on peak loading during extreme weather, and further exacerbate the challenges
13 faced by non-wires solutions that require not only scale but are in a specific location
14 with fewer customers to deliver the critical load reductions. The NWA TOB Pilot
15 will help remove these barriers and better align utility system value for all
16 customers with economics that work for individuals that can provide the most
17 value.

18
19 The NWA TOB Pilot will address these barriers by offering an all-inclusive option
20 to help ensure that customers recognize energy bill savings and are able to
21 contribute critical load reductions to grid constrained locations, without restrictions
22 related to home ownership, income, credit, or upfront investments needed. The
23 NWA TOB Pilot will enable this through utility investment in EE and DER
24 improvements across multiple premise types including single-family homes,
25 mobile homes, multifamily, and commercial properties based on the savings
26 opportunities available. The NWA TOB Pilot will be open to all customers in a
27

1 select identified constrained area of the grid in which NV Energy has recommended
2 non-wires solutions to mitigate the constraints, beginning with customers served by
3 the Lorenzi and Regena Substations in Las Vegas. Assuming the Commission’s
4 approval to commence the NWA TOB Pilot and its success, NV Energy would seek
5 to expand the offering to other customers in other identified constrained areas of
6 the grid.

7
8 **12. Q. HOW WILL THE NWA TOB PILOT WILL WORK?**

9 A. NV Energy will offer an essential utility service that helps fund the upfront
10 equipment and installation costs of energy saving services, DR-enabling
11 technologies, and other DERs in customer homes and businesses located within
12 specific grid-constrained areas. Participating customers will benefit from money-
13 saving, resource-efficient upgrades installed with no up-front payment and no debt
14 obligation and will repay the initial investment over time through a fixed monthly
15 tariff assigned to the premise itself. Since the cost recovery mechanism is a tariff
16 tied to the customer’s meter, it works well for rental properties to encourage
17 investment in upgrades that may not otherwise be undertaken due to the “split-
18 incentive” issue that can discourage landlords from making EE investments when
19 tenants are the beneficiaries of the monthly bill savings. The NWA TOB Pilot tariff
20 and bill and energy savings automatically transfer with notice to the next occupant.
21 This benefits customers as they only pay the tariffed charge on their utility bill for
22 as long as they occupy the location where the upgrades are installed. These features
23 of the NWA TOB Pilot make for an inclusive program available to utility customers
24 in grid-constrained areas, including renters, because program eligibility does not
25 depend on income, credit score, home-ownership status, or the ability to pay for
26
27

1 upfront install costs, thereby removing key barriers that have historically limited
2 participation in EE and DER programs.

3
4 Implementation of the NWA TOB Pilot will consist of: (i) an advanced energy
5 assessment to evaluate the savings opportunity of the location considering the usage
6 history and current efficiency level of the premise, (ii) development of a custom
7 bid outlining eligible improvement measures and their estimated savings which
8 becomes the basis for establishing the monthly charge and terms of the tariff, and
9 (iii) direct installation of energy saving measures with upfront installation costs
10 paid for by NV Energy and recovered through a tariff tied to the premise itself.

11
12 Through the NWA TOB Pilot, NV Energy will fund inclusive utility investments
13 in individual homes and businesses that will be recovered through monthly tariff
14 charges paid by their occupants, which would be set at a level designed to produce
15 a lower total bill through efficiency savings. The term of the cost recovery will be
16 established by NV Energy for each premise and will not exceed the estimated
17 average lifetime of the improvements or the duration of the full parts and labor
18 warranty. Capitalizing the NWA TOB Pilot's investment costs will help put it on a
19 level playing field with NV Energy's grid-side investments, furthering NV
20 Energy's ability to invest in EE, DERs, and more resilient homes and businesses.

21
22 **13. Q. IS THE INVESTMENT UNDER THE NWA TOB PILOT CONSIDERED A**
23 **LOAN? WILL PARTICIPANTS BE REQUIRED TO MEET CREDIT**
24 **SCORE REQUIREMENTS?**

25 A. No. The NWA TOB Pilot will not involve any loans or property assessments, nor
26 will it require a customer credit check, promissory note, collateral assets, personal
27

1 guarantee, or a home lien. The program may require bill screening to ensure
2 customers are in “good standing” to prevent those at higher risk of disconnection
3 from participating, reducing risk to the program and ratepayers.

4
5 The proposed NWA TOB Pilot is intended to complement existing customer
6 financing options as opposed to competing with them by addressing a distinct gap
7 in the market. Traditional financing mechanisms such as loans, leases, or third-
8 party financing are generally dependent on customer creditworthiness, require
9 customer action to secure financing, and may not align with the specific timing or
10 geographic needs of grid-constrained areas. Customers who have access to and
11 prefer third-party financing remain free to pursue those options.

12
13 By offering this additional pathway to participation, the NWA TOB Pilot structure
14 enables participation from customers who may not otherwise pursue or qualify for
15 these options, while aligning project deployment with targeted grid needs. As a
16 result, the offering expands access to energy improvements and supports grid
17 reliability in a way that augments existing financing solutions.

18
19 **14. Q. WHAT CUSTOMER PROTECTIONS WILL THE NWA TOB PILOT**
20 **OFFER TO ENSURE THAT PARTICIPATING CUSTOMERS RECEIVE**
21 **NET BILL SAVINGS FROM THE DEPLOYED MEASURES?**

22 A. The NWA TOB Pilot includes several customer protections to ensure that
23 participating customers experience net bill savings:

- 24 • First, only measures that are projected to generate energy savings sufficient to
25 exceed the tariff repayment charge by a defined percentage are eligible for
26 inclusion in the offering. This ensures that expected bill savings not only cover
27

1 the repayment obligation but also provide a net financial benefit to the
2 customer. This screening is conducted upfront using reliable engineering
3 estimates of forecasted energy and demand savings;

- 4 • Second, the tariff repayment is structured to be less than the estimated monthly
5 bill savings over the repayment period such that customers are expected to see
6 immediate savings on their monthly energy costs;
- 7 • Third, NV Energy will leverage proven, cost-effective EE services and
8 technologies with well-documented performance and will implement quality
9 assurance and verification processes to ensure installations are completed
10 properly to deliver the expected savings; and
- 11 • Finally, participating customers are not required to make any upfront payment,
12 and repayment is tied to the meter rather than the individual customer, reducing
13 financial risk and improving accessibility.

14
15 Collectively, these protections are designed to ensure that customers benefit from
16 participation in the NWA TOB Pilot.

17
18 **15. Q. HOW WILL THE NWA TOB PILOT ADDRESS SITUATIONS WHERE**
19 **ACTUAL ENERGY SAVINGS ARE INSUFFICIENT TO COVER THE**
20 **TARIFF REPAYMENT COSTS?**

21 A. Whenever a customer is found to have insufficient energy savings to cover their
22 annual repayment charges, a post-installation investigation process conducted by
23 the program implementer will take place with tariff charges paused until
24 remediation of the cause occurs. If poor workmanship is found to be the cause, then
25 the contractor will fix it at their cost, and the term will be extended as necessary. If
26 the upgrade has failed during its warranty period due to a design defect, then the
27

1 manufacturer must fix or replace it. If the owner, participant, or occupants remove,
2 damage, or fail to maintain the upgrade, then they will be held responsible. If no
3 responsible party is determined, then NV Energy will pay for the repair and will
4 extend the cost recovery term to recover its cost but not increase the monthly
5 payment amount. If the upgrades cannot be repaired or replaced cost effectively,
6 then NV Energy will waive the remaining charges, and those unrecovered initial
7 costs will then be recovered as program cost.

8
9 Using vetted and qualified contractors to install NWA TOB Pilot measures is
10 critical to ensuring equipment performs as intended, project savings are realized,
11 and costs can be recovered. Expectations of qualified contractors typically include
12 requiring warranties on workmanship and participation in on-site quality assurance
13 inspections to ensure installations are conducted in a confident and professional
14 manner. These consumer protections will increase the NWA TOB Pilot's
15 attractiveness to customers, resulting in more completed projects, and increasing
16 the NWA TOB Pilot's effectiveness to achieve critical load reductions in grid-
17 constrained areas.

18
19 Since the NWA TOB Pilot measures are considered an essential utility service, just
20 like any other such service, non-payment ultimately can result in disconnection.
21 However, with the aforementioned safeguards in place, the approach protects
22 customers from disconnection by helping to ensure that all participants pay lower
23 bills. The NWA TOB Pilot will make clear to all participants upfront that paying
24 the NWA TOB Pilot tariff is not optional.

1 16. Q. **HOW WILL THE NWA TOB PILOT ADDRESS SITUATIONS WHERE A**
2 **CUSTOMER CHANGES THEIR BEHAVIOR AND CONSEQUENTLY**
3 **DOES NOT REALIZE THE PROJECTED ENERGY SAVINGS?**

4 A. The approach requires that at the time of project approval, bill savings are expected
5 based on engineering savings estimates or calibrated modeling approaches to
6 account for uncertainty, variability in usage patterns, and other external factors such
7 as weather.

8
9 Importantly, the NWA TOB Pilot does not guarantee realized savings at the
10 individual customer level, as actual energy usage may vary over time due to
11 changes in customer behavior, occupancy, or the addition of new loads. As a result,
12 the tariff repayment charge is fixed and does not adjust based on realized savings.
13 This approach is consistent with standard industry practice and helps maintain
14 administrative simplicity while avoiding the need for complex, customer-level
15 measurement and verification.

16
17 To mitigate the risk that a customer may not realize the full projected savings, the
18 offering applies a bill reduction screening test prior to project approval. This test
19 ensures that the expected savings exceed the tariff repayment obligation, thereby
20 providing a buffer to accommodate potential variations in actual energy use. In
21 addition, customers are provided with clear disclosures indicating that projected
22 savings are estimates and may vary based on individual circumstances. This ensures
23 that participants can make informed decisions prior to enrollment.

1 17. Q. WHO IS RESPONSIBLE FOR THE NWA TOB PILOT'S COSTS
2 ASSOCIATED WITH OPERATIONS AND MAINTENANCE,
3 WARRANTIES, INSURANCE, HEALTH, AND SAFETY?

4 A. Multiple parties are responsible for these costs associated with any equipment
5 installed through the program.

6
7 The property owner is required to maintain homeowner's or renter's insurance and
8 is responsible for routine operations and maintenance and notifying the program
9 implementation contractor of any failures or performance issues. The program
10 implementer will then conduct an investigation to determine the cause of the issue
11 or failure and identify a remediation plan. NV Energy may elect to purchase
12 extended warranties and include those costs within the overall project cost to be
13 recovered through the repayment charge.

14
15 All NV Energy insurance requirements will flow down to program implementers
16 and program contractors. Health and safety requirements associated with project
17 installations are the responsibility of the installation contractor.

18
19 18. Q. HOW WILL THE NWA TOB PILOT ADDRESS OCCUPANT TURNOVER
20 UPON THE SALE OF A HOME OR WHEN A NEW RENTER OCCUPIES
21 A DWELLING WITH A TOB TARIFF?

22 A. The NWA TOB Pilot is designed such that the tariffed repayment obligation is tied
23 to the premises' electric meter, not the individual customer. This structure ensures
24 continuity of cost recovery and aligns repayment responsibility with the customer
25 receiving the ongoing benefits of the installed energy improvements.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

In the event of a home sale, the TOB tariff remains in place and is disclosed as part of the property transaction, similar to other utility-related obligations. To support transparency and ensure proper disclosure, participant agreements will require the current owner to notify prospective buyers of the repayment obligation. In addition, NV Energy will file a notice in the real estate records of the applicable county indicating that the premises has received program-funded energy improvements and is subject to a tariffed repayment obligation. This recorded notice will inform prospective buyers during the transaction process that a tariff is in place. The new homeowner assumes responsibility for the tariff charge upon establishing electric service, while also benefiting from reduced energy usage and improved comfort associated with the installed measures.

For rental properties, the tariff charge transfers automatically with the utility account when a new tenant establishes service. As an additional consumer protection measure, the property owner will be required to notify prospective tenants of the repayment obligation prior to lease execution and obtain written acknowledgment as part of the leasing process. This ensures that incoming tenants are fully informed of both the repayment obligation and the associated benefits before occupancy. As with homeowners, the incoming tenant receives the benefits of the efficiency upgrades, which are expected to exceed the monthly tariff charge.

Importantly, if a premise becomes vacant and the electric meter is de-energized, then the monthly tariff charge will be paused during the period of vacancy. Charges will resume only once a new occupant establishes service at the premises, ensuring that repayment obligations are incurred only when the property is actively receiving electric service and associated benefits.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

The program will also include clear disclosure requirements and coordination with property owners and property managers, as applicable, to ensure that all incoming occupants are aware of the tariff and associated benefits prior to occupancy.

Overall, this approach maintains program integrity, avoids stranded costs, and ensures that repayment obligations remain aligned with realized benefits over time.

19. Q. WILL CUSTOMERS HAVE THE OPTION TO PREPAY THE REMAINING TOB TARIFF BALANCE?

A. Yes. Property owners will have the option to prepay the remaining balance of the tariffed repayment obligation at any time. This provides flexibility in situations such as a home sale or refinancing, where an owner may prefer to satisfy the obligation upfront rather than transfer it to a subsequent occupant.

The prepayment amount will be calculated based on the remaining unpaid balance of the tariff, including any accrued but unpaid charges, and will not include future allowed returns on the investment that would have otherwise been incurred over the remaining repayment term. As a result, customers who elect to prepay will avoid future financing costs associated with the tariff.

Prepayment will fully satisfy the tariff obligation for the premises, after which the monthly tariff charge will be removed from the customer’s electric bill. This option enhances customer choice while maintaining the overall integrity of the repayment structure.

1 20. Q. **WHAT IS THE CUSTOMER RECRUITMENT APPROACH AND WHAT**
2 **ARE THE PLANNING ASSUMPTIONS FOR THE NWA TOB PILOT?**

3 A. NV Energy will begin by recruiting customers served by the Lorenzi and Regena
4 Substations, where the Companies have identified forecasted grid constraints in
5 2029 and 2031 and have recommended cost-effective non-wires solutions. The
6 NWA TOB Pilot is designed to recruit approximately 600 residential premises
7 (representing roughly 5.5 percent of residential customers in the targeted area) and
8 any interested commercial premises served by these substations. The NWA TOB
9 Pilot will feature a standardized package of EE and DR measures, including air
10 sealing, attic insulation, duct repair, and DR-enabled smart thermostats. These
11 improvements are expected to generate approximately 3,100 kilowatt-hours
12 (“kWh”) in annual energy savings per participating premise, totaling approximately
13 1,900 MWh annually across all participants. In addition, the NWA TOB Pilot is
14 projected to deliver 1 MW of coincident peak capacity (*i.e.*, at the time of peak
15 loading on the substations) with approximately 0.5 MW from EE improvements
16 and 0.5 MW of DR capacity.

17
18 Customers residing in participating premises are estimated to pay an average
19 monthly charge of approximately \$23 over a 10-year period. The tariff is designed
20 to recover the full cost of the improvements, including a return on capital set at NV
21 Energy’s weighted average cost of capital, currently estimated at approximately
22 8.81 percent. On average, the installed improvements are projected to reduce annual
23 electricity expenses by approximately \$367 per household, equivalent to about \$31
24 per month. After accounting for the \$23 monthly tariff repayment, customers are
25 expected to realize a net bill savings of approximately \$7 per month. As participants
26
27

1 pay back the investment through the tariff, these funds can be reinvested in
2 additional projects.

3
4 While the NWA TOB Pilot analysis is based on this standardized residential
5 offering, the program is not intended to preclude participation from commercial
6 customers or the inclusion of additional measures that meet the program’s payback
7 criteria. NV Energy may pursue additional opportunities where projects can be
8 demonstrated to be both cost-effective and operationally feasible within the TOB
9 framework.

10
11 **21. Q. WHAT IS REQUIRED TO LAUNCH THE NWA TOB PILOT PROGRAM?**

12 A. NV Energy is proposing a total 36-month program budget of approximately \$2.84
13 million spanning the Companies’ 2026 Joint IRP action plan period from January
14 1, 2027, through December 31, 2029. NV Energy estimates annual budgets to be
15 \$852,000 in 2027 for start-up costs and initial program implementation, \$1,412,000
16 in 2028 to implement the majority of program’s projects, and \$576,000 in 2029 to
17 implement remaining projects and evaluate the NWA TOB Pilot.

18
19 The above budget estimate includes approximately \$1.12 million in direct funding
20 using utility capital for project costs which would support 600 projects at an average
21 cost of \$1,870 per premise. This amount would be used to implement the projects
22 after applying approximately \$387,000 in federal, state, and NV Energy incentives,
23 or \$645 per premise, that customers are eligible for. As participants pay back the
24 investment through the tariff, these funds can be reinvested in additional projects.

1 The remaining budget estimate includes \$1.12 million for start-up and
2 implementation costs, \$300,000 for marketing the program to customers served by
3 the Lorenzi and Regena Substations, and \$300,000 for evaluation, measurement,
4 and verifications services provided by a third-party.

5
6 **22. Q. WHAT OTHER STATES AND UTILITIES HAVE SUCCESSFULLY**
7 **DEPLOYED TOB PROGRAMS?**

8 A. The following states currently have active TOB programs or pilot activities:
9 Arkansas, California, Georgia, Illinois, Kansas, Kentucky, Massachusetts,
10 Minnesota, Missouri, North Carolina, Tennessee, Vermont, and Virginia.¹ Utilities
11 operating TOB-like programs include Duke Energy in North Carolina, Spire,
12 Evergy, Eversource, Ameren Missouri, BayREN, Midwest Energy Inc, Roanoke
13 Electric Cooperative, La Grange Georgia, and Appalachian Electric Cooperative.

14
15 According to the recent study *Utility Value of a Pay As You Save® Energy*
16 *Efficiency Program*² over the last 20 years and across 18 utilities in eight states,
17 “energy upgrade programs using EEQUIP-like programs have reported take rates
18 of 50%-90% with higher average capital investment per site compared to on-bill
19 loans, while keeping utility uncollectible debts below 0.1%.” This study contains
20 the most robust program results based on data from the Roanoke Electric
21 Cooperative’s Upgrade to Save (“U2\$”) program which is operated by EEtility.
22 Using a sample of 147 U2\$ Program participant homes, the study found a mean
23 annualized reduction in electricity consumption of 4,228 kWh (18 percent) and a
24

25
26 ¹ Energy Star, Inclusive Utility Investment Program Activity.
https://www.energystar.gov/products/inclusive_utility_investment

27 ² *Utility Value of a Pay As You Save® Energy Efficiency Program*, Stephen Bickel and Jill Ferguson of
LibertyHomes, and Daniel Kauffman, Enpira.

1 median of 4,603 kWh (21 percent). The study also found the program generates
2 approximately 1.3 kW of peak demand reduction per home during winter mornings
3 and 1.18 kW in summer afternoons. According to the study, the U2\$ program
4 produced a positive return on investment over the life of the upgrades, estimating a
5 net present value of \$3,047 per home or \$996,240 for the program to date.
6

7 **23. Q. WHICH SPECIFIC REQUESTS OF THE COMMISSION ARE YOU**
8 **SUPPORTING IN THIS TESTIMONY?**

9 A. Section 11 of the 2026 Joint DRP narrative describes the Companies' requests for
10 the Commission. I support NV Energy's request for Commission approval of
11 Sections 7.A and 7.B of the 2026 Joint DRP narrative as in compliance with Nevada
12 Administrative Code ("NAC") 704.9237(2)(d). I also support NV Energy's request
13 for Commission approval of \$2,840,000 to support its proposed NWA TOB Pilot
14 Program as described in Section 8.A.2.
15

16 **24. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD FIND NV**
17 **ENERGY'S IDENTIFICATION OF ANY INCREMENTAL UTILITY**
18 **INVESTMENT OR EXPENDITURE NECESSARY TO INTEGRATE**
19 **COST-EFFECTIVE DERs AS DISCUSSED IN SECTIONS 7.A AND 7.B OF**
20 **THE 2026 JOINT DRP AS IN COMPLIANCE WITH NAC 704.9237(2)(d).**

21 A. Sections 7.A and 7.B of the 2026 Joint DRP fully describe the status of NV
22 Energy's efforts to cost-effectively integrate, control, and develop grid services for
23 DERs through the DERMS and DOE GSS Grant projects, which require
24 incremental investment on the part of the Companies. My testimony, and
25 specifically Q&As 7, 8, 9, and 10, describe these efforts and related cost updates.
26 The referenced narrative sections provide more detailed schedule and cost updates
27

1 and ongoing efforts to ensure costs continue to yield a net benefit to NV Energy
2 and its customers.

3
4 **25. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD APPROVE NV**
5 **ENERGY’S PROPOSED NWA TOB PILOT AS DISCUSSED IN SECTION**
6 **8.A.2 OF THE 2026 JOINT DRP.**

7 A. The NWA TOB Pilot as proposed offers Nevada stakeholders and the Companies
8 the opportunity to develop and evaluate the performance of a new method of utility
9 investment to support customer adoption of DERs in constrained areas of the grid.
10 The TOB utility investment mechanism does not involve any third-party loans or
11 property assessments. Rather, the utility invests the money to cover the remaining
12 upfront project costs of DER projects after all other government, utility, and third-
13 party rebates and incentives have been applied. Cost recovery of the utility
14 investment would consist solely of a monthly tariff charge assigned to the meter at
15 the location where upgrades are installed that is to be paid by the occupant or
16 successor occupant of that premise until all of NV Energy’s investment costs,
17 including authorized returns, have been recovered. The projects are purposely
18 designed to allow the bill savings associated with the project to cover the monthly
19 payments while still providing additional bill savings.

20
21 Since the original filing of only the first phase of a TOB pilot in Docket No. 24-
22 05041, NV Energy has addressed the concerns expressed by the Regulatory
23 Operations Staff of the Commission at the time, performed additional
24 benchmarking, provided updates on the investigation in Docket No. 25-08029, and

1 proposed a concrete budget and approach that supports specific identified non-
2 wires solutions that are also being recommended in this filing.³

3
4 The NWA TOB Pilot is designed to help NV Energy’s non-wires solutions be more
5 successful. This type of service offering adds to the overall toolkit used to help
6 ensure resource adequacy, increase electric grid reliability, and provides expanded
7 options for low-income customers and historically underserved communities.
8

9 **SECTION III: DSM PLAN NARRATIVE SUPPORT**

10 **26. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE 2026 JOINT**
11 **DSM PLAN NARRATIVE SECTION THAT YOU ARE SUPPORTING IN**
12 **THIS FILING.**

13 A. I support the Section 9.A, entitled *Grid Services Compensation Overview*. This
14 section describes the proposed DR program participation structure and how NV
15 Energy proposes to support the DR programs with a specific implementation of the
16 newly-proposed grid service tariff riders in Docket Nos. 25-10012 and 25-10013,
17 more specifically, the Energy Grid Service Tariff Rider (“GSR-E”) and the
18 Capacity Grid Service Tariff Rider (“GSR-C”).

19
20 This section of my testimony utilizes terms that have specific definitions within
21 Special Condition 1 of each of the proposed grid service tariff riders, and these
22 definitions should be referenced for better understanding of the discussion in my
23 testimony that follows.
24
25

26

27 ³ Refer to NV Energy witness Mr. Sinobio’s prepared direct testimony in this filing, Q&A 19.

1 27. Q. **WHAT IS NV ENERGY’S PROPOSED DR PROGRAM PARTICIPATION**
2 **STRUCTURE AND HOW ARE THE PROGRAMS SUPPORTED BY GRID**
3 **SERVICES COMPENSATION?**

4 A. NV Energy is proposing a three-tier participation framework that its DR programs
5 leverage as appropriate for different customer types and customer preferences. This
6 framework aligns with the grid services that are provided by each tier and are
7 supported by the newly proposed GSR-E and GSR-C grid service tariff riders.

8
9 Schedule GSR-E provides an energy credit for verified energy reductions during
10 load flexibility events that is calculated from the difference between the customer-
11 specific baseline and measured energy during the event and then multiplied by an
12 adjusted market rate.

13
14 Schedule GSR-C provides a capacity credit based on the customer's demonstrated
15 ability to reduce or provide capacity during specific events called Qualified Events.
16 The credit is calculated from the avoided cost of capacity, the customer's Annually
17 Qualified Capacity, and a Capacity Resource Rate. Credits may be provided
18 annually or upfront as a Multiple Year Capacity Credit, which are reconciled to
19 actual performance.

20
21 The three-tier participation structure is as follows:

- 22 • **Level I - Base Reliability.** Customers sign up to participate in events that
23 address forecasted energy shortages, transmission constraints, or other
24 conditions threatening system stability. Level I establishes eligibility for
25 capacity credits under GSR-C.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

- **Level II - Economic DR.** Customers sign up to respond to economic events dispatched during times of elevated wholesale prices or forecasted resource adequacy concerns, earning energy credits under GSR-E and contributing to capacity qualification under GSR-C.
- **Level III – Flexible DR.** Customers sign up to provide Operating Reserve (“OR”)—referring to a type of contingency reserve in which the load reduction can show up in less than 10 minutes from activation. Additionally, there is a charge event option available to customers with flexible energy storage resources that can be dispatched to charge or discharge. Compensation is provided through both GSR-C and GSR-E with an additional market-based payment for energy storage customers that have available capacity and can charge when system-level renewable energy production is higher than system-level load.

Residential programs are offered on a fully-bundled basis (*i.e.*, all three levels are included by default). Small and Medium Commercial smart thermostat programs are offered with bundled Levels I and II, with the option to participate at Level III. Commercial, Industrial, and Agricultural, programs are offered at the base Level I offering, with the other Levels II and III offered as optional. As proposed, the Schools DR program is not leveraging the GSR-E and GSR-C at this time and is a bundled Level 1 and Level 2 option. However, performance-based compensation under Schedules GSR-E and GSR-C and other relevant changes will be evaluated for applicability during the plan period.

Each offering is further characterized in the DSM Plan with program participation parameters related to event types, event constraints, and notifications.

1 This proposed structure can be expanded in the future as NV Energy develops and
2 brings forth more specific and additional grid service tariff riders.

3
4 **28. Q. PLEASE BRIEFLY DESCRIBE HOW NV ENERGY PROPOSES TO**
5 **IMPLEMENT THE FLEXIBLE FRAMEWORKS PROVIDED BY THE**
6 **GSR-E AND GSR-C GRID SERVICES TARIFF RIDERS THROUGH**
7 **ACTIVITIES IN THIS 2026 JOINT IRP.**

8 A. The grid service tariff riders have a number of flexible key parameters that can be
9 specified in the context of an IRP-related filing to support the proposed programs.
10 These parameters can then be translated into program participation agreements for
11 approved programs. NV Energy has included in Section 9 of the DSM Plan its
12 proposed key parameters and the planning assumptions that were used to develop
13 goals and budgets. NV Energy also provides a rationale for the selection of key
14 parameters.

15
16 **29. Q. PLEASE BRIEFLY DESCRIBE KEY PARAMETERS FROM NV**
17 **ENERGY’S PROPOSED SCHEDULE GSR-E TARIFF THAT ARE**
18 **PROPOSED FOR THE DR PROGRAMS.**

19 A. Key parameters specified for GSR-E included the following:
20 • **Energy Resource Rate** – NV Energy proposes 90 percent as the portion of
21 avoided energy costs during load flexibility events shared with customers. This
22 provides an incentive for customers to show up with demand reductions during
23 high-cost hours, while recognizing NV Energy transaction costs and need to
24 cover other program costs via avoided cost benefits;
25 • **Market Price** planning assumption – a conservative approach to budgeting and
26 cost-effectiveness analysis was used to estimate future energy credits to be paid
27

1 under GSR-E. A model was created to determine the dates and times for the
2 future dispatch of Economic Events using the long-term hourly marginal energy
3 cost forecast. This model was used to create energy savings curves for the
4 DSMore software cost-benefit analysis tools, and to calculate the average
5 hourly energy price expected during future load flexibility events for budgeting
6 purposes. These were calculated at a program level assuming 30 events per year
7 during the net system peak at the highest cost hours. Using this method, it was
8 determined that an average hourly value of \$95/MWh would be the best proxy
9 for the Market Price parameter in Schedule GSR-E for estimating energy grid
10 service compensation for program budgeting;

- 11 • **Distribution Node Energy Rate** – the proposed value of 8 percent is
12 representative of line losses during system peak loading times;
- 13 • **Events** per year planning assumption – a typical program year assumption of
14 30 economic events per year was used; and
- 15 • **Customer Specific Baseline Methodologies** – NV Energy proposed
16 commonly used baseline techniques for the residential and commercial
17 customer program segments. Industrial and Agricultural load baseline methods
18 cannot be set in advance and depend upon the specifics of the customer load
19 types.

20
21 **30. Q. PLEASE BRIEFLY DESCRIBE KEY PARAMETERS FROM NV**
22 **ENERGY’S PROPOSED SCHEDULE GSR-C TARIFF THAT ARE**
23 **PROPOSED FOR THE DR PROGRAMS.**

24 A. Key parameters specified for GSR-C included the following:

- 25 • **Qualified Events** – NV Energy proposes a minimum requirement of two load
26 flexibility events where the customer participates for a duration of two hours at

1 the time of net system peak in the temperature bins greater than 104 degrees F
2 at Nevada Power and greater than 98 degrees F at Sierra, where net system peak
3 is defined as the naturally-occurring peak minus must-take supply-side
4 renewable energy;

- 5 • **Event Capacity** – NV Energy proposes using Average kW, meaning the hourly
6 resource performance averaged over the two-hour dispatch window of a
7 Qualified Event;
- 8 • **Annually Qualified Capacity** – NV Energy proposes Average Event Capacity,
9 meaning the average Event Capacity across Qualified Events;
- 10 • **Capacity Resource Rate (“CRR”)** – NV Energy proposes a CRR of 60 percent
11 to be applied equally across programs, with the exception of Industrial
12 customers and Sierra Agricultural DR for which a base CRR of 30 percent is
13 proposed for installed capacity with a max of 60 percent for performance as
14 more is learned about the specifics of these load types. This represents the
15 portion of avoided capacity costs shared with customers considering the
16 construct of equivalent load carrying capability of the overall aggregated NV
17 Energy DR resource, phased dispatch of resources, load diversity, and
18 requirement to cover additional program costs via the avoided capacity benefit;
- 19 • **Avoided Cost of Generation & Transmission Capacity** - For Nevada Power,
20 the planning and budgeting assumptions for Avoided Cost of Generation and
21 Transmission Capacity rate of \$120/kW-yr is composed of an Avoided Cost of
22 Generation of \$100/kW-yr and an Avoided Cost of Transmission of \$20/kW-
23 yr. For Sierra, the planning assumption for the Avoided Cost of Generation and
24 Transmission Capacity rate of \$133/kW-yr is composed of an Avoided Cost of
25 Generation of \$100/kW-yr and an Avoided Cost of Transmission of \$33/kW-
26 yr.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

The Avoided Cost of Generation was approximated from values taken from Docket No. 25-10028 (NV Energy’s first amendment to its 2024 Joint IRP), more specifically, from Section 4 - Fuel and Purchase Power Price Forecasts the narrative and Technical Appendix FPP-1 of that filing. The narrative explains the methodology and that the data was sourced from a Wood Mackenzie report.

The assumed Avoided Cost of Transmission of \$20/kW-yr for Nevada Power and \$33/kW-yr for Sierra was derived from the Marginal Cost Study conducted for the Nevada Power General Rate Case in Docket No. 23-06007 and the Sierra General Rate Case in Docket No. 24-02026 and associated workpapers.

The proposed going-forward numbers reflect updated numbers after the original goal setting and budgeting process. The proposed Avoided Cost of Generation is updated to reflect the values in the Fuel and Purchase Power Price Forecasts section of the 2026 Joint Energy Supply Plan narrative filed within the Companies’ 2026 Joint IRP and leverages an updated Wood Mackenzie report. The updated proposed value of \$104/kW-yr averages the projected Avoided Cost of Generation capacity across the 2027-2029 action plan period across three regions: WECC SWRG; CAISO; and NWPP US.

The proposed going forward Avoided Cost of Transmission for Nevada Power has been updated to \$36/kW-yr for secondary distribution customers and \$33/kW-yr for primary distribution customers. These were derived from the latest Marginal Cost Study conducted for the Nevada Power General Rate Case

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

in Docket No. 25-02016. The proposed numbers for Sierra remain based on the Sierra General Rate Case in Docket No. 24-02026.

- **Distribution Node Capacity Rate** – planning and budgeting assumptions for the Distribution Node Capacity rate of \$25/kW-yr for Nevada Power and \$32/kW-yr for Sierra were derived from the Marginal Cost Study conducted for the Nevada Power General Rate Case in Docket No. 23-06007 and the Sierra General Rate Case in Docket No. 24-02026 and associated workpapers.

The proposed going forward Distribution Node Capacity rate for Nevada Power has been updated to \$46/kW-yr for secondary distribution customers and \$43/kW-yr for primary distribution customers. These were derived from the latest Marginal Cost Study conducted for the Nevada Power General Rate Case in Docket No. 25-02016. The proposed numbers for Sierra remain those based upon the Sierra General Rate Case in Docket No. 24-02026.

- **Multiple Year Capacity Credit** planning and budgeting exercises assumed an average customer for the Residential Energy Storage would choose a four-year commitment timeframe for this credit. However, the customers may choose their own timeframe or simply choose to receive annual capacity credits under GSR-C.
- **Customer Specific Baseline Methodologies** – these are consistent with GSR-E.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

31. Q. HOW DID NV ENERGY PERFORM SCENARIO ANALYSIS RELATED TO THE PROPOSED CRR PARAMETER WITHIN GSR-C FOR THE PROPOSED DR PROGRAMS?

A. Stakeholders in NV Energy’s Advice Letter Nos. 557 and 684-E filings (Docket Nos. 25-10012 and 25-10013, respectively), that proposed flexible grid service tariff riders, requested to see scenario analysis related to the CRR in the context of this 2026 Joint IRP filing and the specifically proposed key parameters. This has been provided by also evaluating a Low CRR scenario at 30 percent CRR and High CRR scenario at 85 percent CRR, in addition to the base case proposal. These results are presented in Technical Appendix DSM-5. This technical appendix also describes the planning estimates by DR program for the Annually Qualified Capacity value expected from an average participating customer.

32. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT BROWN-DIRECT-1

**Statement of Qualifications
for
MICHAEL O. BROWN
INTEGRATED ENERGY SERVICES DIRECTOR
NV ENERGY
6226 West Sahara Avenue
Las Vegas, Nevada 89146
(702) 402-5421
Michael.Brown@NVEnergy.com**

Summary of Qualifications

Michael has more than 25 years of direct experience in the energy sector with a focus on demand response, energy efficiency, and renewable energy in both deregulated and regulated electricity markets. He has held a variety of positions at consulting and energy service firms, including leadership roles in energy systems analysis; energy efficiency and renewable energy project development and project management; key account management for energy and commodity (gas and electricity) services; product development; and strategy development. Since 2005, Michael has worked at NV Energy. Michael's efforts at NV Energy have included the design and implementation of: one of the largest two-way communicating programmable thermostat programs in the country; an award-winning Home Energy Management program that integrates energy efficiency and demand response; a portfolio of commercial demand response programs utilizing open standard automated communications; and an advanced Demand Response Management System that allows demand side resources to actively participate in utility energy resource portfolio optimization and risk management processes.

Relevant Employment History

Integrated Energy Service Director (October 2022 – Present)

- Provides leadership and strategic direction for portfolio and program design, technology and services pilots, improvements to operational and planning systems, and product development for integrated energy services and programs.
- Serves as business lead for implementation of a Distributed Energy Resource Management system and Department of Energy Grid Services Grant.

NV Energy, Manager (December 2010 – October 2022)

- Managed a team responsible for providing core services in support of the delivery of integrated demand side management programs. Managed services include customer recruitment, customer operations, field services, analytics, engineering, and operations.
- Managed a team responsible for delivering a portfolio of residential, commercial, and agricultural demand response programs, and distributed energy resource integration and optimization.
- Responsibilities included program design and implementation, contract structuring and execution, business process improvement, stakeholder management, analysis of new products and services, business case development, and integration of demand side

resources with smart grid infrastructure.

NV Energy, Sr. Program Manager (May 2006 – December 2010)

- Key program management responsibilities included residential and small commercial direct load control and a federal grant program for consumer information gateway development and integration to enable price-responsive and direct load control.
- Experience also included taking lead role in bidding out and awarding online energy information, billing information, and energy audit software tool for customers.
- Managed Nevada Power Company's portfolio of residential and commercial energy efficiency programs with primary role for air conditioning programs and supporting role for lighting, education, and commercial programs.

Nevada Power Company, Strategist (September 2005 – May 2006)

- Worked in the demand side management planning department to design and develop energy efficiency programs.
- Developed zero energy homes and energy information pilot programs.

Energis Pax, Consultant (January 2004 – September 2005)

- Continued distributed generation strategy development work from business school project for BOC (British Oxygen).
- Evaluated and pursued Clean Development Mechanism opportunities in India.

Luthin Consulting, Contractor (June 2002 – September 2002)

- Short-term contract for energy and commodity management services for health care facilities in New York.

Enron Energy Services (EES), Account Manager (June 2000 to December 2001)

- Managed the operations of energy outsource and large commodity contracts valued in excess of \$300 million.
- Identified additional energy efficiency and demand response opportunities for clients.
- Worked with product structuring group to develop demand response products. Launched a demand response product for customers in New York and Massachusetts and provided leadership and training to fellow account managers in evolving demand response markets in the NYISO and New England ISO.

Enron Energy Services (EES), Project Developer (March 1999 to June 2000)

- Identified and developed energy efficiency projects in industrial and commercial buildings.
- Evaluated energy efficiency technologies and the impact of deregulation on project economics.

ICRC Energy Inc., Project Manager, Energy Services (January 1998 to March 1999)

- Managed a contract with the National Renewable Energy Laboratory (NREL) and the Federal Energy Management Program (FEMP) to provide technical assistance to Federal facilities.

- Performed energy efficiency and renewable energy feasibility studies and energy systems design aid.

McNeil Technologies, Inc. and Good Consulting Co., Energy Analyst

(June 1995 to January 1998)

- Supported two U.S. Department of Energy clients: FEMP and The Office of Photovoltaic Technologies.
- Work included supporting the ESPC program, FEMP analytical tools, and the Million Solar Roofs Initiative.
- For Good Consulting, performed energy consumption analysis for EPA laboratories with recommendations for energy efficiency measures.

Education

- **The College of William and Mary**
Bachelor of Science, Double Major, Chemistry and International Relations, May 1994
- **The Cranfield School of Management**
Master of Business Administration, September 2003

Memberships

Peak Load Management Alliance (PLMA) – currently serving as a Co-Chair of the Global Load Management Interest Group. Michael is the immediate past Chair of the Board of Directors, previously served as Vice Chair, an elected member of the Executive Committee and past Chair of the Education Committee. Developed and implemented a three course Demand Response Training Series.

Utility Load Management Exchange (ULME)

Association of Energy Engineers (AEE) - Certified Measurement & Verification Professional; passed Certified Energy Manager exam.

Industry Recognition

Provided leadership and management to the NV Energy teams that were recognized with the following awards:

2014 PLMA Award for Outstanding Commercial Demand Response Program Design

2015 Powergrid International Energy Efficiency/Demand Response Project of the Year Award for the mPowered Home Energy Management Program

2015 AESP Award for Outstanding Achievement in Pricing and Demand Response for the mPowered Home Energy Management Program

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MICHAEL O. BROWN, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026


Michael O. Brown

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

KURTIS GIUBBINI

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26-05 ____

Prepared Direct Testimony of

Kurtis Giubbini

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Kurtis Giubbini. I am a Transmission Planning Engineer I in the Transmission System Planning department for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Nevada, Reno. I began my employment with the Companies on May 20, 2024. I have experience in transmission planning, including various compliance tasks and large generator interconnection studies. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Giubbini-Direct-1**.

1 3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR
2 CURRENT POSITION?

3 A. I am responsible for developing electric transmission system models and
4 conducting analyses to assist planning efforts for the Companies' transmission
5 system. I conduct analyses to determine potential risks to system reliability and
6 identify the requirements for mitigation. In addition, I perform studies to determine
7 the system upgrades required for the interconnection of new load additions and
8 generator interconnections to the transmission system. I am also responsible for all
9 Non-Wires Alternative ("NWA") analyses for transmission projects associated
10 with the Distributed Resources Plan ("DRP").

11
12 4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY
13 WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA
14 ("COMMISSION")?

15 A No, I have not.

16
17 5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

18 A. My testimony is in support of Section 3.B of the 2026 Joint DRP narrative, entitled
19 "Distributed Resources Plan Analyses; Transmission Planning."

20
21 6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

22 A. I am sponsoring **Exhibit Giubbini-Direct-1**.

23

24

25

26

27

28 Giubbini-DIRECT

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

**7. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE 2026 JOINT
DRP NARRATIVE SECTION THAT YOU ARE SUPPORTING IN THIS
FILING.**

A. **Section 3.B – *Distributed Resources Plan Analyses; Transmission Planning***
describes the Companies’ activities, processes, and analyses on the transmission
system in support of the 2026 Joint DRP in the following areas:

1. *Load Forecasting* indicates what forecasts were used in performing the
transmission planning analyses in the 2026 Joint DRP;
2. *Technical Analysis Methodology* describes the general methodologies used by
NV Energy’s Transmission Planning department when conducting NWA
analyses;
3. *Grid Needs Assessment – 2026 Capital Plan* (“GNA”) describes how the
Companies identified existing and forecasted constraints on their transmission
systems for the years 2027 through 2032, the identifying information and
parameters of those constraints in terms of the deficiencies involved, the
planned wired capital project solutions for addressing those constraints, the
Companies’ NWA Suitability/Screening Criteria to determine which of the
identified constraints could be suitable for a potential non-wires solution, the
method and the NWA Screening Analysis Tool that the Companies used to
perform the NWA analyses, the results of the NWA analyses, including the
capacities of the Distributed Energy Resource (“DER”) technologies (demand
response, energy efficiency, conservation voltage reduction, solar photovoltaic,
and battery energy storage systems) used in the potential non-wires solution
portfolio, the Present Worth of Revenue Requirements analyses that were
performed by the Companies comparing the costs of the planned wired capital
project solutions against the costs and potential system-level and locational
benefits of non-wires solutions, and the planned wired capital project solutions

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

and the non-wires solutions that the Companies recommend to address the identified constraints on the transmission system.

8. Q. IS NV ENERGY MAKING ANY SPECIFIC REQUESTS OF THE COMMISSION IN THIS 2026 JOINT DRP?

A. Yes.

9. Q. WHICH SPECIFIC REQUESTS OF THE COMMISSION ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11.A of the 2026 Joint DRP narrative describes the Companies’ requests for the Commission. Specifically, I support NV Energy’s request for the Commission to approve certain elements contained in Section 3.B of the 2026 Joint DRP as compliant with NAC 704.9237 and determine, pursuant to NAC 704.9494(5), that they are prudent based on the following:

1. The load and DER forecasting methods as discussed in Section 3.B.1 are in compliance with NAC 704.9237(2)(f), subject to the request to waive certain aspects of that regulation as noted in Section 11.B and supported in NV Energy witness, Mr. Joseph Sinobio’s prepared direct testimony;
2. The GNA for the transmission system as discussed in Section 3.B.3 has been prudently performed in compliance with NAC 704.9237(3)(a), including the identification of transmission constraints and planned wired capital project solutions as discussed in Section 3.B.3.a, the NWA analyses as discussed in Section 3.B.3.b, the Locational Net Benefits Analysis (“LNBA”) as discussed in Section 3.B.3.c, and the planned wired transmission project solutions and non-wires solutions recommendations as discussed in Section 3.B.3.d;
3. The LNBA for the transmission system as discussed in Section 3.B.3.c has been prudently performed in compliance with NAC 704.9237(2)(a); and

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

4. The non-wires (NWA) solutions and planned wired distribution capital project (utility infrastructure upgrade) solutions recommendations discussed in Section 3.B.3.d are prudent and in compliance with NAC 704.9237(3)(c).

10. Q. PLEASE DESCRIBE HOW NV ENERGY UTILIZED THE LOAD AND DER FORECASTS EMPLOYED IN THIS 2026 JOINT DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT.

A. NAC 704.9237(2)(f) states that the DRP must:

Be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast must be for a period of not less than 6 years, beginning with the year after the distributed resources 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.

As stated in Section 3.B.1 of the 2026 Joint DRP narrative, NV Energy utilized the Western Electricity Coordinating Council’s most recently-approved (May 9, 2025) extreme weather case, or 1-in-10 year, integrated resource plan (“IRP”) native load forecast, control area load forecast, and as needed, applicable short-term distribution facility load forecasts at the time analyses were performed, which supported the determination of constraints on the transmission system and the consequent planned wired capital project solutions. The load forecasts covered the minimum six-year timeframe following the year of the filing of this 2026 Joint DRP.

The above activities meet the load forecast requirements of NAC 704.9237(2)(f). NV Energy’s activities related to, and use of DER forecasts is discussed and supported in NV Energy witness, Joseph Sinobio’s prepared direct testimony, including NV Energy’s request for a waiver of a portion of NAC 704.9237(2)(f).

1 **11. Q. PLEASE BRIEFLY DISCUSS NV ENERGY’S TECHNICAL ANALYSIS**
2 **METHODOLOGY FOR NON-WIRES SOLUTIONS FOR ITS**
3 **TRANSMISSION SYSTEM.**

4 A. Section 3.B.2 of the 2026 Joint DRP narrative generally describes the different
5 types of planned wired transmission capital project solutions and the drivers of
6 these projects from NV Energy’s 2026 Capital Plan that underwent NWA analysis.
7 Additionally, this section defines the general methodologies for NWA analysis
8 applied to each type of project and describes how the driver for each project may
9 impact the effectiveness of a non-wires solution.

10
11 The referenced section also provides a detailed explanation of how NV Energy
12 performs its NWA analysis for each project that passes its NWA
13 suitability/screening criteria, identifies many of the factors that are not considered
14 in the Companies’ NWA Screening Analysis Tool, and provides an in-depth
15 understanding of how NV Energy’s Transmission Planning department makes its
16 recommendations for non-wires solutions.

17
18 **12. Q. PLEASE DESCRIBE NV ENERGY’S ACTIVITIES REGARDING THE**
19 **GNA FOR THE COMPANIES’ TRANSMISSION SYSTEMS IN THIS 2026**
20 **JOINT DRP AND WHY THE COMMISSION SHOULD FIND SUCH**
21 **ACTIVITIES COMPLIANT.**

22 A. Section 3.B.3 of the 2026 Joint DRP narrative describes how NV Energy developed
23 and conducted its GNA for its transmission system including NWA analyses, an
24 LNBA (within the NWA analyses), and recommendations for implementation of
25 planned wired (utility infrastructure) capital (upgrade) project solutions and non-
26 wires (DER) solutions to forecasted transmission constraints.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Section 3.B.3.a of the 2026 Joint DRP narrative specifically describes NV Energy’s identification and description of the two identified forecasted constraints on its transmission system for 2027 through 2032, which covers the minimum six-year timeframe described in NAC 704.9237(2)(f).

Section 3.B.3.b of the 2026 Joint DRP narrative specifically describes NV Energy’s NWA suitability/screening criteria (referring to Section 3.A.3.b.(1)), the NWA analysis methods, and the results of the NWA analyses performed on the two forecasted constraints on its transmission system for 2027 through 2032.

Section 3.B.3.c of the 2026 Joint DRP narrative refers to Section 3.A.3.c, within which NV Energy’s LNBA methods are described.

Section 3.B.3.d of the 2026 Joint DRP narrative specifically describes NV Energy’s recommendations for implementation of the planned wired capital project solutions and non-wires solutions to the two forecasted constraints on its transmission system for 2027 through 2032.

These activities, as described in the referenced narrative, meet the requirements of NAC 704.9237(3)(a), 704.9237(2)(a), and 704.9237(3)(c).

13. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT GIUBBINI-DIRECT-1

**Statement of Qualifications
for
Kurtis W. Giubbini**

Summary of Qualifications

Two years of electric utility experience all for NV Energy (Nevada Power Company and Sierra Pacific Power Company) based in Reno, Nevada. Experience in transmission planning, substation design, interconnection system impact studies, transmission service request system impact studies, and various compliance elements.

Professional Experience

Engineer II, Transmission System Planning August 2025 – Current
Nevada Power Company and Sierra Pacific Power Company (d/b/a NV Energy)

Lead in generator interconnection system impact studies. Assists with policy development, compliance work, coordinating advanced studies, and non-wires alternative analysis.

Engineer I, Substation Design May 2024 – Aug 2025
Nevada Power Company and Sierra Pacific Power Company (d/b/a NV Energy)

Coordinated and designed the future and existing layouts of substations within NVE subsystem. Designed and reviewed drawing packages for the protection schemes and layout of all components within a substation to meet with NVE and NERC standards.

Training, Education, & Memberships

Bachelor of Science Degree in Electrical Engineering; University of Nevada, Reno; 2024

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, KURTIS GIUBBINI, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026


Kurtis Giubbini

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

MATHEW JOHNS

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26-05 ____

Prepared Direct Testimony of

Mathew Johns

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Mathew Johns. My current position is Vice President, Environmental Services and Land Management, for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I hold a Bachelor of Science Degree in Civil Engineering and Master of Science Degree in Agricultural Engineering. From 1996 to 2015, I worked on site cleanup and remediation projects nationwide as an environmental engineer, project manager, and program manager for global engineering consulting firms.

In 2015, I joined the Companies as Director, Environmental Remediation and Resource Development, with primary responsibility for managing NV Energy’s

1 Regulatory Assets and Asset Retirement Obligations (“AROs”) for Energy Supply,
2 including decommissioning, demolition, and environmental remediation of the
3 Companies’ retired generating facilities. I was also the Companies’ representative
4 for generating facility joint partnerships. In 2022, I assumed the role of Vice
5 President, Environmental Services and Land Management.

6
7 My statement of qualifications is attached as **Exhibit Johns-Direct-1**.

8
9 **3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**
10 **CURRENT POSITION?**

11 A. I lead a group of directors, managers, engineers, environmental scientists, and land
12 resource professionals who perform or direct environmental analyses, specialty
13 studies, and other tasks necessary for obtaining regulatory approvals and land rights
14 for utility projects. My departments are responsible for all aspects of compliance
15 and permitting pertaining to environmental and land resource matters for the
16 Companies’ facilities.

17
18 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
19 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
20 **(“COMMISSION”)?**

21 A. Yes. I have submitted pre-filed testimony with the Commission in past Companies’
22 filings for general rate cases and integrated resource plan filings, including most
23 recently Nevada Power’s 2025 General Rate Case (“GRC”), Docket No. 25-02016,
24 the Companies’ 2024 Joint Integrated Resource Plan, Docket No. 24-05041, and
25 the Companies’ Fifth Amendment to the 2021 Joint Integrated Resource Plan,
26 Docket 23-08015.

1 **5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 A. The purpose of my testimony is to support the discussion and updates to certain
3 environmental regulatory matters in the Generation Section of the Supply Plan as
4 they relate to previously approved projects at the North Valmy Generating Station
5 (“Valmy”), Tracy Generating Station (“Tracy”), new generation proposed as part
6 of this integrated resource plan at the Fort Churchill Generating Station (“Fort
7 Churchill”), and existing generation.

8
9 Previously approved projects include the Valmy Natural Gas Conversion Project,
10 Valmy Simple-Cycle Plant, and Tracy Units 4 and 5 (“Tracy 4/5”, also referred to
11 as Tracy Piñon Pine Unit 4) Emission Controls Upgrade Project.^{1,2,3} Currently
12 proposed projects include the Fort Churchill Additions 1 Project, Fort Churchill
13 Additions 2 Project, and Fort Churchill Additions 3 Project.

14
15 **6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

16 A. I am sponsoring **Exhibit Johns-Direct-1 - Statement of Qualifications.**

17
18 **7. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING**
19 **CONFIDENTIAL?**

20 A. No.

21
22
23 ¹ Docket No. 23-08015, March 1, 2024, Order, approving Sierra’s requests to proceed with the Valmy Units 1 and 2
Natural Gas Conversion Project and Tracy 4/5 Emission Controls Upgrade Project.

24 ² Docket No. 24-05041, December 27, 2024, Order, approving Sierra’s request to proceed with the Valmy Simple
Cycle Plant.

25 ³ These previously approved projects have been referred to by different names in prior filings. In the 2024 Joint
26 Integrated Resource Plan Action Plan Progress Report (Docket No. 26-02031), the projects are identified as the North
Valmy Coal-to-Gas Conversion, North Valmy Simple-Cycle Capacity Project, and Tracy Units 4 and 5 Emissions
Controls Upgrade Project.

1 8. Q. PLEASE PROVIDE ANY UPDATES RELATED TO THE
2 ENVIRONMENTAL REGULATIONS SINCE THE 2024 JOINT
3 INTEGRATED RESOURCE PLAN, DOCKET NO. 24-05041.

4 A. Certain existing, promulgated and proposed environmental regulations were
5 discussed in the Fifth Amendment to the 2021 Joint Integrated Resource Plan,
6 Docket 23-08015, and 2024 Joint Integrated Resource Plan, Docket No. 24-05041.
7 The discussion below provides updates to these regulations, which are discussed in
8 greater detail in the Generation Supply Plan Narrative.

9
10 **Regional Haze Rule⁴**

11
12 Since March 2024⁵, Sierra has worked with the Nevada Division of Environmental
13 Protection (“NDEP”) to evaluate the Regional Haze Rule for the Second Decadal
14 (Second Implementation) Planning Period (2018-2028) requirements applicable to
15 Valmy Units 1 and 2 (following natural gas conversion) and Tracy 4/5. For Valmy
16 Units 1 and 2, additional NOx reductions while firing natural gas were determined
17 to be cost-effective through 2049, to a control level equivalent to Selective Non-
18 Catalytic Reduction (“SNCR”) performance. Sierra and NDEP also preserved
19 flexibility to meet SNCR limits using either Flue Gas Recirculation (“FGR”) or
20 Selective Catalytic Reduction (“SCR”). This flexibility in emission control
21 technology supported compliance with other federal requirements that may take
22 effect, including the Good Neighbor Plan. For Tracy 4/5, SCR was determined to
23 be cost-effective through 2049.

24
25
26 ⁴ EPA Regional Haze Rule, Clean Air Act § 169A; 40 C.F.R. §§ 51.300–51.309.
27 ⁵ Docket No. 23-08015, March 1, 2024, Order, approved Sierra’s requests to proceed with the Valmy Units 1 and 2
28 coal-to-gas conversion and Tracy 4/5 projects.

1 The NDEP then prepared state regulations to make the Regional Haze Rule
2 requirements for Valmy Units 1 and 2 and Tracy 4/5 legally enforceable pursuant
3 to state law.⁶ The state regulation sets NOx emission levels, identifies control
4 technologies, and establishes a compliance deadline. Under the state regulation,
5 NOx controls must be installed within 36 months of the U.S. Environmental
6 Protection Agency’s (“EPA”) approval of Nevada’s Regional Haze State
7 Implementation Plan (“SIP”). The NDEP submitted the SIP revision for Valmy
8 Units 1 and 2 and Tracy 4/5 to EPA in May 2025 (the “2025 Nevada Regional Haze
9 SIP Revision”).

10 On February 6, 2026, the EPA approved portions of the 2022 Nevada Regional
11 Haze SIP, including the July 2023 withdrawal of proposed retirement
12 determinations for Tracy 4/5 and Valmy Units 1 and 2, and portions of the 2025
13 Nevada Regional Haze SIP Revision.⁷ The EPA did not act on the revised
14 reasonable progress determinations or the proposed NOx emission controls for
15 Tracy 4/5 and Valmy Units 1 and 2 included in the 2025 Nevada Regional Haze
16 SIP Revision. The timing of the EPA’s action complied with a July 2024 consent
17 decree (with additional time consideration resulting from the government shutdown
18 in 2025) between the EPA and the Sierra Club, National Parks Conservation
19 Association, and Environmental Integrity Project, regarding timelines for the EPA
20 to approve or deny previously submitted SIPs from several states, including
21 Nevada.⁸

22
23
24 ⁶ Nev. Admin. Code chapter 445B, as amended by regulation adopted by the Nevada State Environmental Commission
in 2024, establishing source-specific Regional Haze Rule requirements for NV Energy’s North Valmy Generating
Station Units 1 and 2 and Tracy Generating Station Piñon Pine Unit 4 (Tracy 4/5).

25 ⁷ 90 Fed. Reg. 48,481 (Oct. 23, 2025) (proposed rule) and 91 Fed. Reg. 5321 (Feb. 6, 2026), the EPA refers to the
Nevada SIP filings as the “2022 Nevada Regional Haze Plan” and the “2025 SIP Supplement”.

26 ⁸ *Sierra Club, et al. v. U.S. Environmental Protection Agency*, No. 1:23-cv-01744-JDB (D.D.C.), Consent Decree
27 entered July 12, 2024, establishing deadlines for EPA action on Regional Haze State Implementation Plans, including
plans submitted by Nevada.

1 The EPA is expected to evaluate the proposed NOx controls for Tracy 4/5 and
2 Valmy Units 1 and 2 and Tracy 4/5 included in the 2025 Nevada Regional Haze
3 SIP Revision through a separate action. The EPA has not provided a schedule for
4 that evaluation; however, for planning purposes, Sierra anticipates the EPA may
5 act later in 2026. Under the state regulation, NOx controls for these units must be
6 installed within 36 months following EPA approval of the proposed NOx controls
7 for Tracy 4/5 and Valmy Units 1 and 2.

8
9 **Good Neighbor Plan**

10
11 The federal “Good Neighbor Plan” for the 2015 Ozone National Ambient Air
12 Quality Standards (“NAAQS”) became effective on August 4, 2023, and was
13 intended to take effect for 22 states, including Nevada.⁹ The federal Good Neighbor
14 Plan has been subject to litigation since its issuance, and its implementation is
15 currently stayed in the various states where it would be effective, including Nevada.
16 On January 30, 2026, the EPA proposed Phase 1 of its reconsideration of the federal
17 Good Neighbor Plan¹⁰. Under this reconsideration, the EPA intends to withdraw
18 its disapproval of Nevada’s September 28, 2018 Good Neighbor SIP submission
19 published on February 13, 2023¹¹, and, reversing its prior position, approve
20 Nevada’s Good Neighbor SIP. The EPA acknowledges that Nevada applied the
21 four-step interstate transport framework (the “Framework”) and determined that
22 Nevada sources do not contribute more than 1% percent of the 2015 Ozone NAAQS
23 to any nonattainment or maintenance receptor. If the EPA’s reconsideration is
24

25
26 ⁹ 88 Fed. Reg. 36,654 (June 5, 2023)

27 ¹⁰ 91 Fed. Reg. 4,026 (Jan. 30, 2026)

28 ¹¹ 88 Fed. Reg. 9,336 (Feb. 13, 2023) (final rule), Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards

1 finalized as proposed, Nevada would not be required to adopt any new permanent,
2 enforceable emission control measures under Nevada’s Good Neighbor SIP.

3
4 **Greenhouse Gas Emissions Standards**

5
6 On May 9, 2024, the EPA published a final rule for federal greenhouse gas
7 emissions standards for fossil fuel-fired electric generating units (“*GHG Emissions*
8 *Standards*”).¹² The rule became effective on July 8, 2024. Litigation commenced
9 following publication. However, the GHG Emissions Standards remain in effect as
10 published.

11
12 On June 17, 2025, the EPA proposed repealing the GHG Emissions Standards in
13 its entirety.¹³ The EPA is also proposing, as an alternative, to repeal a narrower set
14 of requirements that includes the emission guidelines for existing fossil fuel-fired
15 steam generating units, the carbon capture and sequestration/storage (“CCS”)-
16 based standards for coal-fired steam generating units undertaking a large
17 modification, and the CCS-based standards for new baseload stationary combustion
18 turbines. On February 27, 2026, the EPA submitted a status report to the U.S. Court
19 of Appeals for the District of Columbia Circuit indicating that the proposed
20 rulemaking process is ongoing and that the agency continues to analyze and gather
21 information from a variety of sources.¹⁴ In that report, the EPA stated it intended
22 to send a draft final rule to the Office of Management and Budget in early spring
23 2026. The next EPA status report to the court is due on May 29, 2026.

24
25 ¹² *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil*
26 *Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-*
Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024).

27 ¹³ 90 Fed. Reg. 25,752 (June 17, 2025).

28 ¹⁴ U.S. Environmental Protection Agency, *Status Report to the U.S. Court of Appeals for the District of Columbia*
Circuit (Feb. 27, 2026), Case No. 24-1120.

Mercury and Air Toxics Standards

On May 7, 2024, the EPA finalized amendments to the Mercury and Air Toxics Standards (“MATS”) to strengthen the National Emission Standards for Hazardous Air Pollutants for coal- and oil-fired electric utility steam generating units.¹⁵ The amendments would have applied to Valmy Units 1 and 2 only if they continued operating on coal. Historical emissions test data indicate the units would have met the revised limit; however, compliance would have required adding particulate matter (“PM”) continuous emissions monitoring system (“CEMS”) capability and integrating it into existing facility systems. On February 24, 2026, the EPA finalized the repeal of the 2024 amendments.¹⁶

With Valmy Units 1 and 2 converted to natural gas, the 2012 MATS rule no longer applies to Sierra generation operations.

9. Q. DO THESE ENVIRONMENTAL REGULATIONS IMPACT THE APPROVED VALMY SIMPLE-CYCLE PLANT?

A. The current and proposed regulations do not impact the decision to pursue the Valmy Simple Cycle Plant comprised of two simple-cycle generating units. Under the current GHG Emissions Standards, these units are expected to operate as low-utilization units (capacity factor of 20 percent or less), only requiring the use of clean fuel (i.e., natural gas). If the GHG Emissions Standards are rescinded, these capacity factor limits no longer apply.

¹⁵ 89 Fed. Reg. 38,508 (May 7, 2024).

¹⁶ 91 Fed. Reg. 9,088 (Feb. 24, 2026).

1 If the federal Good Neighbor Plan remains in effect in Nevada, the units would be
2 integrated into the statewide ozone-season NOx budgets and emissions allowance
3 program from May-September through a market-based trading program. If the EPA
4 finalizes its Phase 1 reconsideration as proposed, Nevada will be excluded from the
5 federal Good Neighbor Plan requirements.

6
7 The Valmy Simple Cycle Plant may be considered under Regional Haze Rule
8 during future decadal planning periods; however, no additional requirements would
9 be expected as they will be constructed with SCR equipment for NOx control.
10 MATS standards are not applicable to these units.

11
12 **10. Q. HOW DO UPDATES TO THESE ENVIRONMENTAL REGULATIONS**
13 **SINCE DOCKET NO. 23-08015 IMPACT THE VALMY NATURAL GAS**
14 **CONVERSION PROJECT AND TRACY 4/5 EMISSIONS UPGRADE**
15 **PROJECT?**

16 A. The Valmy Natural Gas Conversion Project is being completed in two phases with
17 the natural gas conversion portion being completed prior to installation of NOx
18 controls due to Regional Haze Rule timing. Valmy Unit 1 was converted to natural
19 gas operation in December 2025. Valmy Unit 2 was taken offline on January 4,
20 2026, once the remaining coal was depleted and will be converted to natural gas
21 operation in 2026 in preparation for summer operations.

22
23 As discussed in Q&A 8, the EPA has not made a final determination for the
24 proposed NOx controls for Valmy Units 1 and 2 and Tracy 4/5 included in the 2025
25 Nevada Regional Haze SIP Revision. For planning purposes, the Companies
26
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

anticipate the EPA may act later in 2026. Under the state regulation, NOx controls for these units must be installed within 36 months of EPA’s approval.

Valmy Units 1 and 2 operating on natural gas will meet the standards for the existing gas-fired steam units under the current GHG Emissions Standards. If the EPA rescinds the GHG Emissions Standards, these standards will no longer apply to Valmy Units 1 and 2. The MATS rule does not affect Valmy Units 1 and 2 with the units converted to natural gas operation.

11. Q. DO THE UPDATES TO THESE ENVIRONMENTAL REGULATIONS SINCE DOCKET NO. 23-08015 IMPACT THE TRACY 4/5 EMISSION CONTROLS UPGRADE PROJECT?

A. As discussed in Q&A 8, the EPA has not made a final determination for the proposed Tracy 4/5 NOx controls included in the 2025 Nevada Regional Haze SIP Revision. For planning purposes, Sierra anticipates the EPA may act later in 2026. Under the state regulation, NOx controls for these units must be installed within 36 months of EPA’s approval.

Outcomes of the Good Neighbor Plan or GHG Emissions Standards do not affect the Tracy 4/5 Emission Controls Upgrade Project.

1 12. Q. DO THE UPDATES TO THESE ENVIRONMENTAL REGULATIONS
2 IMPACT THE PROPOSED FORT CHURCHILL ADDITIONS?

3 A. The environmental regulations mentioned above impact the proposed new
4 generation at Fort Churchill Additions 1, 2, and 3, in the same way as they affect
5 the two approved units of the Valmy Simple Cycle Plant, as described in Q&A 9.

6
7 13. Q. HOW DO THESE REGULATIONS IMPACT THE REMAINDER OF NV
8 ENERGY’S FLEET?

9 A. Prior assessment under the Regional Haze Rule for the Second Decadal (Second
10 Implementation) Planning Period (2018-2028) did not identify additional NV
11 Energy units, besides Valmy Units 1 and 2 and Tracy 4/5, for which emission
12 controls may be considered to support visibility protection for Federal Class 1 areas,
13 such as Jarbidge Wilderness Area.

14
15 If the Good Neighbor Plan remains in effect in Nevada, NV Energy’s fleet, except
16 for Brunswick, would be integrated into the statewide ozone-season NOx budgets
17 and emissions allowance program from May-September through a market-based
18 trading program. If the EPA finalizes its Phase 1 reconsideration as proposed,
19 Nevada will be excluded from the good neighbor plan.

20
21 Under the current GHG Emissions Standards, Fort Churchill Units 1 and 2, Tracy
22 Unit 3, and Valmy Units 1 and 2 will also be regulated as existing gas-fired steam
23 units requiring routine methods of operation and maintaining carbon dioxide
24 (“CO₂”) emission rates of between 1,400 to 1,600 lb CO₂/MWh based on unit
25 capacity factors. Fort Churchill Units 1 and 2 and Tracy 3 currently operate within
26 or below these CO₂ emission rates. Valmy Units 1 and 2 operating on natural gas
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

will also meet these CO₂ emission rates. The Silverhawk Peaker Project units are considered “new units” under the current Federal GHG Rule, as construction started after May 23, 2023, and will operate under the low-utilization category (20 percent capacity factor or less) which only requires the use of clean fuels (i.e., natural gas). The remaining existing NV Energy units are not impacted by the current GHG Emissions Standards. If the GHG Emissions Standards are rescinded by the EPA, these requirements will no longer apply.

The proposed updates to MATS are specific to coal- and oil-fired units and do not impact the remainder of NV Energy’s fleet.

14. **Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes.

EXHIBIT JOHNS-DIRECT-1

MATHEW J. JOHNS
VICE PRESIDENT, ENVIRONMENTAL SERVICES AND LAND MANAGEMENT
NV Energy, Inc.
6226 West Sahara Avenue
Las Vegas, NV 89146
(702) 402-5477

Mr. Johns joined NV Energy in August 2015. He has over 25 years of experience in environmental remediation, project, and program management. Prior to joining NV Energy, Mr. Johns worked as an environmental consultant for industrial companies primarily in the power, manufacturing, mining, oil and gas sectors.

EMPLOYMENT HISTORY

NV Energy, Inc.
8/2015 to 2/2022

Director, Environmental Remediation and Resource Development

Primary responsibility for managing Regulatory Assets and Asset Retirement Obligations (“AROs”) for Energy Supply. These obligations include decommissioning, demolition, and environmental remediation of the company’s generating facilities.

3/2022 to Present

Vice President, Environmental Services and Land Management

Primary responsibility for leading the teams responsible for all aspects of compliance and permitting pertaining to environmental and land resource matters for Nevada Power and Sierra facilities.

CH2M HILL
6/2000 to 7/2015

Project and Program Management Assignments:

- Owner's Engineer and Construction Management (OECM), power client (2008 to 2014). Responsible for the planning, permitting, engineering and construction oversight services for wastewater and solid waste improvement and related closure projects at a coal-fired power plant.
- Program Design Manager, manufacturing client program, U.S. Nationwide (2011 to 2014). Responsibilities included establishing design teams, identifying delivery approaches, and ensuring best practices to deliver design-construction projects in an efficient manner for environmental remediation projects across the United States.
- Program Management for Greenfield Refined Products Pipeline (2007-2008). Assistant manager for preliminary engineering, cost estimating and permitting phase services for a grass-roots 400-mile refined products pipeline in the southwestern US.

Facilities Operations and Management Assignments:

- Interim Measures and Groundwater Response Action, Power Client, CA (2004-2005). Managed an immediate groundwater response action to establish hydraulic control of chromium-contaminated groundwater near a critical drinking water body in the southwestern United States. Activities included construction of onsite batch treatment and temporary storage facilities, transportation, and offsite disposal.
- Facility Operations and Compliance Groundwater Extraction and Treatment System, Power Client, CA (2005-2006). Managed for the start-up and operation of a groundwater extraction and treatment system for chromium-contaminated water. The water was treated to rigorous permit limits allowing for onsite disposal into injection wells. Onsite staff included a site operations manager, up to eight full-time operators providing 24-hour/7-day per week operations, engineering staff focused on facility optimization, and environmental compliance specialists.

Other Project Management and Technical Experience

- Mine site closure and post-closure monitoring, Colorado (2006 to 2015)
- Groundwater permeable reactive barrier design, Michigan (2005).
- Municipal landfill closure, Federal facility, Wyoming (2000 to 2004).
- Groundwater investigations, Federal facility, Wyoming (2000 to 2004).
- Groundwater permeable reactive barrier pilot study, Texas (2002 to 2003).
- Groundwater treatment systems design, Federal facilities, Florida (2000 to 2005).

ERM-SOUTHWEST

6/1996 – 6/2000

Project Engineering Assignments

- Coal ash landfill closure design, Texas
- Calcium carbide waste disposal site closure design, Michigan.
- Groundwater slurry wall design, Texas
- Groundwater recovery trench design, Texas
- Hazardous and non-hazardous landfill closure design, Texas
- Corrective action management unit application and design Basis, Texas

EDUCATION

Master of Science in Agricultural Engineering, Texas A&M University, 1996

Bachelor of Science in Civil Engineering, University of Colorado, 1994

PROFESSIONAL REGISTRATIONS

Registered Professional Engineer – Civil Engineering - Arizona

Registered Professional Engineer – Civil Engineering - Nevada

Registered Professional Engineer – Civil Engineering - Texas

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MATHEW JOHNS, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026



Mathew Johns

JOHN LESCENSKI

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26- 05 ____

Prepared Direct Testimony of

John Lescenski

SECTION 1: INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is John Lescenski. My current position is Manager, Generation Engineering and Technical Services, for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have worked in the Companies’ Energy Supply (Generation) department for over 35 years in various engineering and management roles. My statement of qualifications is attached as **Exhibit Lescenski-Direct-1**.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Manager, Generation Engineering and Technical Services, I am responsible for generation fleet-wide asset strategy development, regulatory planning and analysis, technical support for new solar resource contracts and technical support to the Companies’ generation fleet.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?

A. Yes. I provided written testimony in the Companies’ past filings for annual deferred energy accounting adjustments (“Annual DEAAs”), integrated resource plans (“IRPs”) and general rate cases (“GRCs”), including most recently in Docket Nos. 24-02026, 24-05041, 25-02016, 26-02035, and 26-02036.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Supply Plan for the Companies’ thermal generation included in the Obsidian Plan, which the Companies propose as their preferred plan (the “Preferred Plan”).

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring the following Exhibit and Technical Appendices:

Exhibit Lescenski-Direct-1 – Statement of Qualifications

Technical Appendix GEN-1 – Generating Unit Characteristics Table
(CONFIDENTIAL)

Technical Appendix GEN-2 – Emissions Rates - Generation

**7. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING
CONFIDENTIAL?**

A. Yes. Technical Appendix GEN-1 includes the Generating Unit Characteristics Table that provides characteristics used in the dispatch of the Companies’ generating units. This confidential technical appendix contains commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information discloses the Companies’ views and expectations of the relevant markets and its future procurement opportunities. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies and their customers by limiting their ability to foster competition among prospective suppliers, compromising the Companies’ negotiating position and reducing bargaining leverage. Publication of this information would unfairly advantage competing suppliers and impair the Companies’ ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

8. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL TREATMENT OF THIS INFORMATION?

A. The requested period for confidential treatment is five years.

9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION’S REGULATORY OPERATIONS STAFF (“STAFF”) OR THE NEVADA ATTORNEY GENERAL’S BUREAU OF CONSUMER PROTECTION (“BCP”) TO FULLY INVESTIGATE THE INFORMATION SET FORTH IN THIS FILING?

A. No, in accordance with the accepted practice in Commission proceedings, the confidential material will be provided to Staff and the BCP under standardized protective agreements.

10. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section II, I describe the status of the previously approved Lenzie Chilled Water Storage Project. Companies’ witness Fady Atala identifies in his Prepared Direct Testimony all other recently approved fossil fuel generation projects that are still under development or construction, including the North Valmy Simple-Cycle Capacity Project approved in Docket No. 24-05041. Mr. Atala also describes new fossil fuel Fort Churchill addition projects included in the Supply Plan pursuant to the Companies’ Preferred Plan.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

SECTION II: PREVIOUSLY APPROVED PROJECT STATUS

11. Q. PLEASE DESCRIBE THE PREVIOUSLY APPROVED PROJECTS YOU ARE SUPPORTING.

A. I am supporting the Lenzie Chilled Water Storage Project that was approved by the Commission in Docket No. 22-03024, First Amendment to the 2021 IRP, and is described in this docket’s Supply Plan narrative within the Generation subsection.

12. Q. WHAT IS THE STATUS OF THIS PROJECT?

A. The project continues in design and construction. The project completion was delayed due to coordination with unit outages required to relocate the natural gas supply lines. The project is expected to be completed before the summer 2027 peak season.

13. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT LESENSKI-DIRECT-1

JOHN W. LESCENSKI
MANAGER, PLANT ENGINEERING AND TECHNICAL SERVICES

Currently Manager, Plant Engineering and Technical Services at NV Energy, responsibilities include generation fleet-wide asset strategy development, technical support for new solar resource contracts, working to ensure the existing and future generation fleet of power plants meets the energy supply requirements of our customers while meeting the stringent emissions requirements for fossil-fired power plants.

Professional Experience

Joining Nevada Power (now NV Energy) in 1989 as an Engineer in Generation Engineering and Construction at the Reid Gardner Power Plant, progressing to Manager for strategy planning for integrating business planning with power plant operations, in conjunction as primary witness for Generation issues in regulatory filings of the Integrated Resource Planning, Depreciation Cases, and General Rate Cases. Leading development of generation inputs to Resource Planning for alternative analysis. Responsible for strategic assessments of NV Energy's generation fleet through plant condition assessments and long term life span analysis.

- Technical Support for Renewable PPA contract RFPs and renewable project development
- Technical Support for Solar PPA contract compliance with Energy Contract Management
- Successfully completed the \$54 million Nellis Solar PV2 project, installing a 15MW photovoltaic station on a closed landfill on the Nellis Air Force Base. Responsible as project manager from contracting and construction management through startup
- Successfully completed the \$16 million King's Beach Power Plant replacement, responsible for the project from inception through start-up
- Lead early efforts in the development of the Ely Energy Center project
- Lead the study of the Valmy expansion alternatives and repowering
- Spearheaded the resource planning efforts for the retirement and decommissioning of the Clark Units 1-3 and their replacement with the new 600 MW Clark Peaking Plant.
- Coordinated with Environmental Services on the air permit application and permitting for the contemporaneous change for the Clark Peaker Project
- Coordinated the Reid Gardner emissions alternative analysis and resource planning approval and supported the regulatory filings for emissions upgrades and the eventual retirement
- Developed Life-Span Analysis Process (LSAP) to guide the decision making for determining the remaining economic useful life of a generating unit and reinvestment decisions to continue operations. This Process is now relied upon by the Public Service Commission of Nevada.
- Project Engineer for the Harry Allen Unit 4 simple cycle 7EA combustion turbine expansion project, supporting resource plan application/approval through turbine purchase and EPC bidding and contracting
- Lead technical analyst for the generation business services department, providing services as lead Owner/user inspector and subject matter expert supporting the Clark and Reid Gardner Plant Engineering Staff.

Education

Masters of Arts in Economics – University of Nevada, Las Vegas • Spring 2019

Professional Paper: Econometric Analysis of the Effect of Deregulation on Retail Energy Prices

Graduate Certification in Renewable Energy – University of Nevada, Reno • 2013

Master of Business Administration – University of Nevada, Las Vegas • 1996

Bachelor of Science in Mechanical Engineering – University of Southern California • 1989

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JOHN LESCENSKI, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026



John Lescenski

FADY ATALA

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26-05 ____

Prepared Direct Testimony of

Fady Atala

SECTION I: INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Fady Atala. My current position is Senior Director of Major Projects for Nevada Power d/b/a NV Energy (“Nevada Power” or the “Company”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra,” and together with Nevada Power, the “Companies”). My business address is 6226 W Sahara Ave., in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have more than 11 years of experience in power generation. My background spans roles in engineering, operations management, and project oversight. I have been responsible for establishing contracting frameworks, monitoring budgets and schedules, mitigating risks, and overseeing large engineering, construction and procurement efforts. Prior to my current role, I served as Operations Manager for the Clark and Sun Peak generating stations, where I was responsible for ensuring

1 plant and operational performance. My statement of qualifications is attached as
2 **Exhibit Atala-Direct-1.**

3
4 **3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**
5 **CURRENT POSITION?**

6 A. As Senior Director of Major Projects, my responsibilities include leading the Major
7 Projects Management team overseeing the planning, development, and
8 construction of new renewable and thermal power plants and large capital projects.
9 My role involves directing the multidisciplinary team of project directors,
10 managers, and project control professionals, who manage and oversee every phase
11 of the projects. This includes planning, development, negotiating contracts,
12 ensuring regulatory compliance, and providing oversight of equipment
13 manufacturers and construction contractors. My team focuses on delivering
14 projects efficiently and on schedule, while maintaining high standards of safety,
15 quality, and budget control.

16
17 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
18 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
19 **(“COMMISSION”)?**

20 A. Yes. I provided written testimony in the Companies’ past filing for general rate case
21 (“GRC”), Docket No. 25-02016.

22
23 **5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

24 A. The purpose of my testimony is to support the Supply Plan for the Companies’
25 thermal generation related to previously approved projects and the proposed Fort
26 Churchill Projects requested for approval as part of the Preferred Plan, including
27

1 updates in project costs for the latter. I also support the resource costs and
2 characteristics for candidates for placeholder resources in the Economic Analysis,
3 Technical Appendix ECON-10. Finally, I explain the need and prudence of early
4 investment in preliminary engineering and development of future thermal projects.
5

6 **6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

7 A. I am sponsoring or co-sponsoring the following Exhibits and Technical
8 Appendices:

9 **Exhibit Atala-Direct-1** – Statement of Qualifications

10 **Technical Appendix GEN-3** – Generation Brownfield Study
11 (CONFIDENTIAL)

12 **Technical Appendix ECON-10** – Candidate Resources - Redacted (co-
13 sponsor) (CONFIDENTIAL)

14
15 **7. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING**
16 **CONFIDENTIAL?**

17 A. Yes. Technical Appendices GEN-3 and ECON-10 include cost projection details
18 for potential future generating units. These confidential technical appendices
19 contains commercially sensitive and/or trade secret information that derives
20 independent economic value from not being generally known. This information
21 discloses the Companies' views and expectations of the relevant markets and its
22 future procurement opportunities. This information is not known outside the
23 Companies and its distribution is limited within the Companies. Releasing this
24 highly sensitive information would disadvantage the Companies and their
25 customers by limiting their ability to foster competition among prospective
26 suppliers, compromising the Companies' negotiating position and reducing
27

1 bargaining leverage. Publication of this information would unfairly advantage
2 competing suppliers and impair the Companies' ability to achieve the most
3 favorable pricing and terms and conditions from suppliers on behalf of their
4 customers.

5
6 Additionally, the confidential information in the Supply Plan includes Tables GEN-
7 3, -6, -9, and -12 in the Generation Section and certain items in the Additional
8 Studies and Information subsection of the Economic Analysis which provide
9 specific cost expectations for the Fort Churchill projects and future projects
10 components. Disclosing this information publicly would negatively affect the
11 Companies' negotiating position and result in higher customer costs.

12
13 **8. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL**
14 **TREATMENT OF THIS INFORMATION?**

15 A. The requested period for confidential treatment is five years.

16
17 **9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE**
18 **COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR**
19 **THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER**
20 **PROTECTION ("BCP") TO FULLY INVESTIGATE THE INFORMATION**
21 **SET FORTH IN THIS FILING?**

22 A. No, in accordance with the accepted practice in Commission proceedings, the
23 confidential material will be provided to Staff and the BCP under standardized
24 protective agreements.

1 **10. Q. HOW IS YOUR TESTIMONY ORGANIZED?**

2 A. In section II, I identify recently approved thermal and renewables projects that are
3 still under development or construction. In Section III, I describe the Fort Churchill
4 Projects. In Section IV, I describe the need for early investment for future thermal
5 units.

6
7 **SECTION II: PREVIOUSLY APPROVED PROJECT STATUS**

8
9 **11. Q. PLEASE DESCRIBE THE PREVIOUSLY APPROVED PROJECTS YOU
10 ARE SUPPORTING.**

11 A. I am supporting the following projects that were approved by the Commission in
12 previous Integrated Resource Plans (“IRP”) or IRP Amendments and are described
13 in the Supply Plan, Generation, section of the narrative:

- 14 • Valmy Natural Gas Conversion
- 15 • Valmy Simple-Cycle Project
- 16 • Sierra Solar Phase I Project
- 17 • Tracy 4 and 5 Selective Catalytic Reduction Project.

18
19 **SECTION III: FORT CHRUCHILL PLANT PROJECTS**

20
21 **12. Q. PLEASE DESCRIBE THE FORT CHURCHILL AERODERIVATIVE
22 PLANT WHICH IS PLANNED FOR COMMERCIAL OPERATION IN
23 2030.**

24 A. The Fort Churchill Aeroderivative Plant which is planned to be commercially
25 operational in 2030 is made up of eight ~50 MW aeroderivative simple-cycle
26 generating units, designed for peaking service in Sierra’s service territory. The
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

estimated cost of the project is approximately \$2.007 billion (2030\$) (without AFUDC).

The aeroderivative generating units for the Fort Churchill Aeroderivative Plant are highly efficient, state-of-the-art, combustion turbines. To reduce emissions, a combination of dry low-nitrogen oxide (“NOx”) combustion systems, selective catalytic reduction and carbon monoxide catalyst will be incorporated into the design.

Each of the aeroderivative gas turbines can reliably produce approximately 50 MW within 5 minutes. The unit can also balance renewable resources by load-following at 50 MW/minute ramp rates while maintaining emissions compliance.

13. Q. PLEASE DESCRIBE THE FORT CHURCHILL AERODERIVATIVE PLANT WHICH IS PLANNED FOR COMMERCIAL OPERATION IN 2031.

A. The Fort Churchill Aeroderivative Plant which is planned to be commercially operational in 2031 is made up of eight ~50 MW aeroderivative simple-cycle generating units, designed for peaking service in Sierra’s service territory. The estimated cost of the project is approximately \$2.048 billion (2031\$) (without AFUDC).

The aeroderivative generating units for the Fort Churchill Aeroderivative Plant are highly efficient, state-of-the-art, combustion turbines. To reduce emissions, a combination of dry low-NOx combustion systems, selective catalytic reduction and carbon monoxide catalyst will be incorporated into the design.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

The aeroderivative gas turbine can reliably produce approximately 50 MW within 10 minutes. The unit can also balance renewable resources by load-following at 50 MW/minute ramp rates while maintaining emissions compliance.

14. Q. PLEASE DESCRIBE THE FORT CHURCHILL FRAME SIMPLE-CYCLE PLANT WHICH IS PLANNED FOR COMMERCIAL OPERATION IN 2032.

A. The Fort Churchill Frame Simple-Cycle Additions Project is planned to be commercially operational in 2032 and is made up of two ~200 MW simple-cycle generating units, designed for peaking service in Sierra’s service territory. The estimated cost of the project is approximately \$0.978 billion (2032\$) (without AFUDC).

The simple-cycle generating units for the Fort Churchill Frame Additions Project are highly efficient, state-of-the-art, combustion turbines. To reduce emissions, a combination of dry low-NOx combustion systems, selective catalytic reduction and carbon monoxide catalyst will be incorporated into the design.

The simple-cycle frame gas turbine can reliably produce approximately 200 MW within 10 minutes. The unit can also balance renewable resources by load-following at 40 MW/minute ramp rates while maintaining emissions compliance.

1 15. Q. HOW WILL THE NATURAL GAS BE SUPPLIED FOR THE PROPOSED
2 FORT CHURCHILL PROJECTS?

3 A. The Fort Churchill Projects are expected to rely on natural gas transportation
4 service from the interstate pipeline system serving northern Nevada. If approved,
5 the projects will require expansion of the existing pipeline system. This is described
6 by the Companies' witness Vinnie Vitiello.

7
8 16. Q. PLEASE DESCRIBE HOW THE THERMAL PROJECT COSTS AS
9 REQUESTED FOR APPROVAL DIFFER FROM THE COSTS AS
10 STUDIED IN THE ECONOMIC ANALYSIS IN THIS 2026 JOINT IRP.

11 A. In the Additional Studies and Information subsection of the Economic Analysis
12 Section of the Narrative (under the heading Differences Between Projects As
13 Studied And Projects As Requested for Approval), cost updates for the
14 Aeroderivative and Frame CTs are described.

15
16 The Aeroderivative CT project costs increased in two steps during IRP
17 development, first from the economic analysis to the Financial Plan and again from
18 the Financial Plan to the Prayer for Relief, with the latter reflecting the most current
19 and supportable cost basis for the projects requested for approval. The cost of each
20 of the Aeroderivative CT projects described in the Generation Section of the Supply
21 Plan Narrative and requested in the Prayer for Relief are aligned, but these costs
22 exceed the project costs included in the Financial Plan, which in turn exceed the
23 project costs included in the economic analysis across all plans.

24
25 Frame CT project costs in the Generation Section of the Supply Plan Narrative and
26 in the Financial Plan reflect a lower cost basis than in the economic analysis across
27

1 all plans due to refinement of site-specific construction assumptions after the
2 economic analysis was complete. For the Frame CT projects requested for approval,
3 the costs described in the Generation Section the Supply Plan Narrative, Financial
4 Plan, and Prayer for Relief are aligned.

5
6 **SECTION IV: NEED FOR EARLY INVESTMENT FOR FUTURE THERMAL UNITS**
7

8 **17. Q. PLEASE DESCRIBE THE NEED FOR EARLY INVESTMENT IN**
9 **PRELIMINARY ENGINEERING AND DEVELOPMENT FOR THE**
10 **FUTURE COMBUSTION TURBINE RESOURCE.**

11 A. The Companies are requesting early development funding to support preliminary
12 design engineering and project development activities for a future combustion
13 turbine resource.¹ This work would occur after the Companies identify the
14 preferred site/location and combustion turbine technology configuration.

15
16 The purpose of the requested funding is to begin preliminary development work
17 necessary to mature the project definition, improve estimate accuracy, reduce
18 execution risk, and provide the Commission and stakeholders with a more reliable
19 basis for evaluating the future project. The estimated preliminary development cost
20 is \$13.041 million for a simple-cycle resource.

21
22 This preliminary work may include engaging an Engineer of Record firm to
23 advance the project to approximately 30 percent engineering design, including
24 preliminary equipment arrangements, site layout, major balance-of-plant scope,
25 and key design interfaces. Following the preliminary engineering work, the
26 Companies may engage an EPC contractor to perform a constructability review

27 ¹ Under the Base Load Forecast, the next thermal resource is modeled to be in service in 2034.

1 based on the 30 percent design package. This effort would help validate execution
2 assumptions, identify potential construction constraints, assess labor and site
3 logistics, and support development of a preliminary schedule of values and updated
4 cost estimate.

5
6 The requested funding also includes related early-stage activities such as NV
7 Energy labor and overheads, owner's engineering and consulting support,
8 environmental and permitting support, geotechnical survey work, and contingency.
9 These activities will help move the project beyond planning-level assumptions and
10 establish a more reliable basis for future cost, schedule, permitting, and execution-
11 risk evaluations.

12
13 Importantly, these early development costs are expected to contribute directly to
14 the future project when it is approved. They are not expected to be sunk costs
15 because the engineering design, constructability review, surveys, permitting
16 support, and estimate development would become part of the project development
17 record and support future execution.

18
19 This request is intended to support better project definition, improve cost
20 confidence, and preserve the Companies' ability to meet future in-service dates
21 when thermal resources are required to maintain system reliability and serve future
22 customer demand

23
24 **18. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

25 A. Yes.

EXHIBIT ATALA-DIRECT-1

STATEMENT OF QUALIFICATIONS**Fady Atala****Senior Director of Major Projects, Major Projects****NV Energy**

6226 West Sahara Avenue, Las Vegas, Nevada 89146

Mr. Fady Atala has been an employee of NV Energy since 2014, with over 11 years of experience in the power generation industry. Mr. Atala's background spans roles in projects oversight, operations management and engineering. Mr. Atala's responsibilities include leading the Major Projects team overseeing the construction of new thermal and renewable power plants and large capital projects. His role involves directing this multidisciplinary team of project directors, managers, and project control professionals, who manage and oversee every phase of development and construction. This includes negotiating contracts, ensuring regulatory compliance, and providing oversight of equipment manufacturers and contractors. Prior to his current role, Mr. Atala served as Operations Manager for the Clark and Sun Peak generating stations, where he was responsible for ensuring plant and operational performance. He also was the plant engineer for the Clark and Sun Peak generating stations and an engineer for the whole generation fleet.

Professional Experience**NV Energy, Las Vegas, NV*****Senior Director of Major Projects***

August 2025 to Present

NV Energy, Las Vegas, NV***Director of Engineering and Project Management***

June 2023 to July 2025

NV Energy, Las Vegas, NV***Operations Manager for the Clark and Sun Peak generating stations***

July 2021 to June 2023

NV Energy, Las Vegas, NV***Engineering***

November 2014 to July 2021

Education**University of Nevada, Las Vegas**

Master of Science in Mechanical Engineering

Notre Dame University – Louaize (NDU), Keserwan District, Lebanon

Bachelor of Science in Mechanical Engineering

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, FADY ATALA, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026

Fady Atala
Fady Atala

CHARLES A POTTEY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Triennial Integrated Resource Plan (2027-2046)
Docket No. 26-05 ____

Prepared Direct Testimony of

Charles A. Pottey

1. **Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS
AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

A. My name is Charles Pottey. I am the Director of Transmission Planning for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra,” and together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

2. **Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE
UTILITY INDUSTRY.**

A. I have a Bachelor of Science degree in Electric Power Engineering and a Master of Engineering degree in Electric Power Engineering, both from Rensselaer Polytechnic Institute. I am a registered Professional Engineer. I have more than 45 years of experience in the electric utility industry mostly with the Companies. I have experience in transmission planning, resource planning, distribution planning, rates and regulatory affairs, transmission business services and electric grid operations. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Pottey-Direct-1**.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am the Director of Transmission Planning for NV Energy. I am responsible for all transmission planning associated with integrated resource plans (“IRP”), compliance, generator interconnections and transmission service requests, including load addition functions for the Companies.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?

A. Yes, I have testified in many IRP, IRP amendments and rate case proceedings, including most recently in Docket No. 25-10025.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I sponsor the Transmission Section of the Supply Plan discussing the Companies’ transmission systems and associated projects, except for the transmission additions required for large customer load additions. The transmission additions required for large customer load additions are sponsored by Mr. Maxfield. Additionally, I support the Companies’ requests to construct the required transmission system network upgrades required for the Preferred Plan or the Alternate Plan including:

1. Ft. Sage 345 kV line terminal and 345/69 kV transformer
2. Northwest 230 kV line terminal
3. NSO-Magnolia 230 kV line addition
4. Onyx substation 230/69 kV 336 MVA substation
5. Harry Allen 230 kV bus and line reactors
6. Coyote Creek 345 kV breaker addition
7. Equestrian 230 kV breaker
8. Northwest 525/230 kV 1,500 MVA transformer #7
9. East Tracy – West Tracy 345 kV line #2
10. Reconductor East Tracy – West Tracy 345 kV line #3425
11. Replacement of the East Tracy 345/120 kV transformer
12. Frontier-Lander 230 kV line
13. Brooks 230/138 kV substation
14. Coyote Creek – Falcon 345 kV line
15. Olinghouse-Chucker 345 kV line
16. Third Robinson Summit 345 kV 600 MVA phase shifting transformer
17. Esmeralda-Millers 230 kV line
18. Walker River 120 kV terminal for Lux Solar/BESS
19. Walker River third 345/230 kV 300 MVA transformer and 230 kV terminal
for Winston Solar/BESS
20. Walker River 345 kV terminal for Sleepy Orange solar/BESS.
21. Miller Substation 138 kV terminal for Commerce Station BESS project
22. Crystal Substation 525 kV terminal for Coyote Springs solar/BESS
23. Gonder Substation 345 kV terminal for White Pine solar/BESS.
24. Mira Loma 120 kV terminal and reconductoring #129 Glendale – Valley
Road 120 kV line for five miles for Trego Grid BESS.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

- 25. Iron Mountain - Lorenzi 138 kV line uprate
- 26. Dry Lake East II PV/BESS transmission additions.
- 27. North Valmy 345 kV terminal for Hot Pot and Iron Point PV/BESS
- 28. Walker River 345 kV terminal, Walker River - Grayskull 525 kV line, Grayskull two (2) 525/345 kV 1,500 MVA transformer bank, Grayskull – Nighthawk #1 345 kV line, Grayskull – Nighthawk 345 kV line #2 for Ft Churchill natural gas generator DNR
- 29. Two Valmy 120 kV terminals, 120 kV 150 MVA phase shift transformer (PST) at Oreanna, rebuild of #118 120 kV line from Eagle to NGPP, and #3422 Lantern – East Tracy 345 kV line reconductor to bundled 2x1026 ACCC for the Valmy area geothermal portfolios.

I will also explain the status of the SWIP-North project and associated capacity entitlements, requirements for potential future transmission projects, and the status of the Greenlink Transmission Project.

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

- A. I am sponsoring the following Exhibit and Technical Appendices:
- **Exhibit Pottey-Direct-1** – Statement of Qualifications;
 - **TRAN-11** - Ft Sage - PSREC TIA for Ft. Sage Interconnection 11-3-24 EXECUTED;
 - **TRAN-12** - Northwest - GridLiance West TIA at Northwest RS 169 EXECUTED;
 - **TRAN-13** - NITSA 17-00004 btw NPC and Switch South - 14th AR;
 - **TRAN-14** - TPL-001 2025 Appendix A - Corrective Action Plans.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

7. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I discuss the Companies’ requests to construct the required transmission system network upgrades required to interconnect requested resource additions and to meet system reliability requirements. Next, I will discuss the status of the SWIP-North project and the capacity entitlements associated with the project. I then discuss potential future transmission projects that may be needed. The last portion of my testimony updates the status of the Greenlink Transmission project.

8. Q. WHY IS THE FT SAGE 345 KV LINE TERMINAL AND 345/69 KV TRANSFORMER REQUIRED?

A. The terms of the executed FERC jurisdictional Transmission Interconnection Agreement (“TIA”) require the construction of a new 345/69 50 MVA transformer at the existing Ft Sage substation. The transformer will be installed on a new 345 kV terminal and bus inside the existing substation perimeter. Plumas-Sierra Rural Electric Cooperative (“PSREC”) will operate their system with a normally open between the Companies transmission system and Pacific Gas and Electric (“PG&E”) transmission system. The normal open significantly reduced the costs because it eliminates the need for a phase shifting transformer that is typical for similar Transmission to Transmission TIA. The estimated cost for the new transmission additions is \$6.9 million.

9. Q. WHY IS THE NORTHWEST 230 KV LINE TERMINAL REQUIRED?

A. The terms of the executed FERC jurisdictional TIA require the construction of an additional 230 kV line terminal at the existing Northwest substation and re-terminating several existing lines to accommodate the paths of incoming lines at Northwest substation. Once complete, the existing Desert View #1 line and the new

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Desert View #2 Line will share a bay and center breaker. This project also requires the re-termination of two existing Iron Mountain lines due to location of available bay and the incoming line routes.

10. Q. WHY IS THE NSO - MAGNOLIA 230 KV LINE ADDITION REQUIRED?

A. The construction of NSO-Magnolia 230 kV line is required to comply with North American Electrical Reliability Corporations (“NERC”) standard TPL-001-5.1 Transmission System Planning Performance Requirements. The Tolson-McCullough 230 kV line overloads for loss of Eldorado-Magnolia 230 kV line and for multiple breaker failure events at Faulkner and Magnolia. Also, various N-1-1 events, which result in the loss of 230 kV lines between Eldorado and the Las Vegas valley, will cause the overload of the Tolson-McCullough 230 kV line. The N-1 loss of Tolson-Faulkner line overloads the Tolson-McCullough 230 kV line. Re-terminating the Arden-Magnolia line at Magnolia and adding an additional line breaker mitigates the breaker failure violation which could still overload Tolson-McCullough, even after the NSO-Magnolia 230 kV line. The Companies requested DNR for Southern Bighorn I and II for a total of 400 MW and Dry Lake East II for 150 MW, also require the addition of Northwest 525/230 kV transformer #7 and the NSO-Magnolia 230 kV line. The addition of Northwest 525/230 kV 1,500 MVA transformer #7 will provide some relief for these overloads and allows for the required 7 to 10 years to complete the project. The estimated cost for the new transmission additions is \$67.99 million.

1 **11. Q. WHY IS THE ONYX SUBSTATION 230/69 KV 336 MVA SUBSTATION**
2 **REQUIRED?**

3 A. The construction of Onyx (originally named Goat) substation, which is in the Apex
4 area to the west of HGIII substation and east of Sheep Mountain, is required to
5 comply with NERC standard TPL-001-5.1 Transmission System Planning
6 Performance Requirements. In the event of loss of Nellis-Carey 69 kV line, the
7 Pecos-Gypsum 138 kV line, Gypsum 138/69 kV bank, and breakers failures will
8 overload the Nellis-Carrey 69 kV line, Nellis-Speedway 69 kV line, and Gypsum-
9 Speedway 69 kV. The estimated cost for the new transmission additions is \$50.0
10 million.

11
12 **12. Q. WHY ARE THE HARRY ALLEN 230 KV BUS AND LINE REACTORS**
13 **REQUIRED?**

14 A. The addition of Harry Allen 230 kV bus and Pecos 230 kV line reactors are required
15 to comply with NERC standard TPL-001-5.1 Transmission System Planning
16 Performance Requirements. With the addition of multiple generators in the area at
17 Harry Allen, Reid Gardner, Crystal, Silver Hawk and addition of the Pecos #5
18 transformer, and the Greenlink project, twenty-four 230 kV breakers and seventeen
19 138 kV breakers at Pecos exceed their interrupting rating. The estimated cost for
20 the new transmission additions is \$10.87 million.

21
22 **13. Q. WHY IS THE COYOTE CREEK 345 KV BREAKER ADDITION**
23 **REQUIRED?**

24 A. The addition of breakers at Coyote Creek substation are now required to comply
25 with NERC standard TPL-001-5.1 Transmission System Planning Performance
26 Requirements. Coyote Creek #3401 breaker failure trips off both 345/120 kV
27

1 transformer #2 and 345 kV line to Valmy interrupting Western Electricity
2 Coordinating Council (“WECC”) Path 16. Coyote Creek #3420 breaker failure trips
3 off both 345/120 kV transformer #1 and 345 kV line to Valmy also interrupting
4 WECC Path 16. When Path 16 has heavy imports, loss of both the #3420 line and
5 345/120 kV transformer will overload the remaining transformer to 130% of the
6 emergency rating. The estimated cost for the new transmission additions is \$3.4
7 million.

8
9 **14. Q. WHY IS THE EQUESTRIAN 230 KV BREAKER REQUIRED?**

10 A. The addition of a new 230 kV breaker at Equestrian substation is required to comply
11 with NERC standard TPL-001-5.1 Transmission System Planning Performance
12 Requirements. A breaker failure of Equestrian breaker #2302 trips both Equestrian-
13 Mead 230 kV lines. Loss of these lines overloads the Greenway-Mead 230 kV line.
14 The estimated cost for the new transmission additions is \$6.94 million.

15
16 **15. Q. WHY IS THE NORTHWEST 525/230 KV 1,500 MVA TRANSFORMER #7
17 REQUIRED?**

18 A. The Northwest 525/230 kV 1,500 MVA transformer bank #7 is required to facilitate
19 a Network Integration Transmission Service (“NITS”) customer 360 MW DNR.
20 Northwest transformer #7 is also required to serve the Companies 1,200 MW DNR
21 request for Amargosa, at Sagebrush substation. The new transformer in
22 combination with new resources and 525 kV transmission lines will necessitate
23 replacing fifteen (15) 230 kV breakers at Northwest substation with 80 kA breakers,
24 because they now exceed the short circuit duty rating of the circuit breaker. The
25 230 kV bus may also need to be rebuilt to withstand the additional fault duty, it is
26 currently being studied. The Companies’ requested DNR for Coyote Springs 600
27

1 MW requires the addition of Northwest transformer #7. Also, the Companies’
2 requested DNR for Southern Bighorn I and II for a total 400 MW and Dry Lake
3 East II for 150 MW requires the addition of Northwest #7 transformer. The
4 Companies identified the Northwest transformer #7 in the NERC TPL-001-5.1
5 study in a 2030 case for multiple N-1 events in the Southern system, which
6 overloaded various 230 kV lines in the South-West area of Las Vegas. The
7 Companies are requesting approval to construct Northwest 525/230 kV 1,500 MVA
8 transformer bank #7 with associated fifteen (15) breaker replacements. The
9 estimated cost for the new transmission additions is \$63.5 million.

10
11 **16. Q. WHY IS THE EAST TRACY – WEST TRACY 345 KV LINE #2**
12 **REQUIRED?**

13 A. The East Tracy – West Tracy 345 kV line #2 with 2x1026 ACCC is required for
14 the Companies Hot Pot and Iron Point DNR request for 600 MW at North Valmy
15 and the Valmy Geothermal Portfolio DNR request of 190 MW. There is also a NITS
16 customer’s DNR request for Naniwa 600 MW at East Tracy 345 kV that requires
17 the construction of East Tracy – West Tracy 345 kV line #2. The new line requires
18 rerouting East Tracy – West Tracy 345 kV Line #3425 and partially double circuit
19 with the 120 kV #1103 line. Without the addition of the new East Tracy – West
20 Tracy 345 kV line #2, the N-1 contingency loss of East Tracy – West Tracy 345
21 kV line #3425 causes overloads on East Tracy 345/120 transformer #1, North
22 Valley Road 345/120 kV transformer #1 and #2, North Valley Road 120 kV line
23 #174, and North Valley Road – Valley Road 120 kV line #103. The new 345 kV
24 line requires re-termination of 345 kV lines at West Tracy. The estimated cost for
25 the new transmission additions is \$15.98 million.

1 17. Q. **WHY IS IT NECESSARY TO RECONDUCTOR EAST TRACY – WEST**
2 **TRACY 345 KV LINE #3425?**

3 A. It is necessary to reconductor the existing East Tracy – West Tracy 345 kV line
4 #3425 with 2x1026 ACCC, for the Companies Hot Pot and Iron Point DNR request
5 for 600 MW at North Valmy and geothermal DNR request for 190 MW portfolios
6 in Valmy area. There is also a NITS customer’s DNR request for Naniwa 600 MW
7 at East Tracy 345 kV that requires reconductoring East Tracy – West Tracy 345 kV
8 line #3425. After the addition of the new resources there is an, N-0, overload of
9 East Tracy – West Tracy 345 kV Line #3425. The estimated cost for the new
10 transmission additions is \$2.0 million.

11
12 18. Q. **WHY IS THE REPLACEMENT OF THE EAST TRACY 345/120 KV**
13 **TRANSFORMER REQUIRED?**

14 A. The existing East Tracy 345/120 kV 280 MVA transformers must be replaced with
15 a 400 MVA transformer. There is a NITS customer’s DNR request for Naniwa 600
16 MW at East Tracy 345 kV that requires the transformer to be replaced for loss of
17 West Tracy – Gosling 345 kV line overload the existing 280 MVA transformer to
18 104%. The Naniwa DNR also requires replacement of two 120 kV line switches
19 #1101, #1113, and the reconductor of #103 120 kV line between Pah Rah and
20 Spanish Springs. The Companies are requesting approval to replace the East Tracy
21 345/120 kV transformer #1 with a 400 MVA unit, reconductor #103 120 kV line
22 and replace two 120 kV switches. The estimated cost for the new transmission
23 additions is \$25.2 million.

1 19. Q. **WHY IS THE FRONTIER-LANDER 230 KV LINE REQUIRED?**

2 A. The construction of the Frontier-Lander 230 kV line is required for the Companies
3 White Pine Solar DNR request for 350 MW at Gonder. The addition of White Pine
4 Solar causes N-1 contingency overloads on the Alpine-Walker River 230 kV line,
5 Austin-Frontier 230 kV line, Walker River-Wassuk 120 kV line, and Table
6 Mountain-Thorne 120 kV line. An ancillary benefit of Lander-Frontier 230 kV line
7 would be to relieve transmission congestion on the 230 kV transmission system and
8 will reduce or eliminate the need for the existing generation tripping RAS, more
9 analysis of this benefit will be required. The estimated cost for the new transmission
10 additions is \$30.0 million.

11
12 20. Q. **WHY IS THE BROOKS 230/138 KV SUBSTATION REQUIRED?**

13 A. The Brooks 230/138 kV substation is required for the Companies' DNR requests
14 for Southern Bighorn I and II totaling 400 MW and Dry Lake East II 150 MW.
15 Pecos 230/138 kV transformer outages caused by breaker failures overload Pecos
16 230/138 kV transformer #2, #3, #4, and #5. This is a known issue but being
17 accelerated due to the new DNR requests aggravating these overloads. Brooks
18 facilitates the loads to continue to grow in the north side of Las Vegas on the 138
19 kV system. Brooks will fold three existing 138 kV lines into its 138 kV bus
20 significantly relieving Pecos 230/138 kV transformers. The Pecos-Brooks 230 kV
21 line was already constructed at 230 kV standards and energized at 138 kV; it will
22 now be reterminated into 230 kV line positions at both Brooks and Pecos. The
23 Companies also require relief of Miller 138/12 kV from Brooks 138/12 kV
24 transformer addition and distribution upgrades. The Companies are requesting
25 approval to construct Brooks substation with a 230/138 kV 400 MVA transformer,
26
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

138 kV line folds, a 138/12 kV 33 MVA transformer and distribution upgrades. The estimated cost for the new transmission additions is \$86.0 million.

21. Q. WHY IS THE COYOTE CREEK – FALCON 345 KV LINE REQUIRED?

A. The Coyote Creek – Falcon 345 kV line is required for the Companies Hot Pot and Iron Point DNR request for 600 MW at North Valmy. The loss of Valmy – Falcon 345 kV line or a breaker failure of Valmy #3500 causes overloads on #155 Coyote Creek – Bell Creek 120 kV, and both Coyote Creek 345/120 kV transformer #1 and #2. If the Coyote Creek transformers are taken out of service for an overload subsequently the Falcon 345/120 kV transformers overload and ultimately load shedding would occur. Coyote Creek – Falcon 345 kV line, approximately 23 miles, greatly improves the reliability of the region’s transmission, benefiting the many large loads that are very sensitive to load interruptions. The Falcon substation's 345 kV and 120 kV buses will be reconfigured to a breaker and a half bus with addition of the Coyote Creek – Falcon 345 kV line. The addition of four (4) 120 kV line breakers greatly improves the system reliability to the region’s large 120 kV customers. It is anticipated that an ancillary benefit of the new Coyote Creek – Falcon 345 kV line is that the Falcon RAS could be retired or reduced, further illustrating the increased transmission system reliability. The Companies are requesting approval to construct the Coyote Creek – Falcon 345 kV line. The estimated cost for the new transmission additions is \$66.0 million.

22. Q. WHY IS THE OLINGHOUSE – CHUKAR 345 KV LINE REQUIRED?

A. The Olinghouse-Chukar 345 kV line is required for the Companies’ Hot Pot and Iron Point DNR request for 600 MW at North Valmy. With the addition of Hot Pot and Iron Point loss of Olinghouse-East Tracy 345 kV line causes overloads Falcon-

1 Robinson Summit 345 kV line and Valmy-Lantern 345 kV line. Olinghouse-
2 Chukar 345 kV line is approximately 11 miles long. The estimated cost for the new
3 transmission line is \$26.6 million.

4
5 **23. Q. WHY IS THE ADDITION OF A THIRD ROBINSON SUMMIT 345 KV 600**
6 **MVA PHASE SHIFTING TRANSFORMER (“PST”) REQUIRED?**

7 A. A third 600 MVA PST at Robinson Summit 345 kV bus is required to operate in
8 parallel with the two PST that are part of the SWIP-N scope. In the event of loss of
9 the Robinson Summit PST, the Falcon and Robinson Summit series capacitors
10 (“SC”) overload. When the SC are taken out of service it reduces the transfer
11 capability of the 345 kV line, which will limit the dispatch of the Companies’ DNR
12 request for Hot Pot and Iron Point 600 MW at North Valmy and the import/export
13 capabilities between north and south systems. The estimated cost for the new
14 transmission additions is \$25.0 million.

15
16 **24. Q. WHY IS IT NECESSARY TO CONSTRUCT THE ESMERALDA –**
17 **MILLERS 230 KV LINE?**

18 A. The Esmeralda – Millers 230 kV line with associated 525/230 kV transformers at
19 Esmeralda, rebuilding Millers with 230/120 kV transformer, and 230 kV line
20 terminal at both Esmeralda and Millers is required to grant the
21 Companies three DNR request totaling 70 MW for three projects. The three
22 projects are included in the Zanskar Geothermal Portfolio and Ormat Geothermal
23 Portfolios. A new 120 kV line terminal for the generator lead line for the
24 Companies’ requested DNR for Big Smokey 20 MW geothermal project is also
25 required at Millers. A new 120 kV line terminal for the generator lead line for the
26 Companies’ requested DNR for Mason 25 MW geothermal project at Wassuk is
27

1 also required. A new 120 kV line terminal is required at Candelaria switching
2 station for the generator lead line for the Companies' requested DNR for Excelsior
3 25 MW geothermal project. The estimated cost for the new transmission line and
4 terminal additions is \$172.0 million.

5
6 **25. Q. WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE LUX**
7 **SOLAR/BESS PROJECT?**

8 A. The Companies' DNR request for the 125 MW Lux Solar/BESS will require the
9 construction of a lead line terminal for the interconnection at Walker River 120 kV
10 bus. It is also necessary to resolve clearance issues on the Walker River – Buckeye
11 120 kV line. The estimated cost for the new transmission additions is \$2.5 million.

12
13 **26. Q. WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
14 **WINSTON SOLAR/BESS PROJECT?**

15 A. The Winston Solar/BESS project will require installing a third 345/230 kV 300
16 MVA transformer at Walker River and a 230 kV lead line terminal for
17 interconnection of Winston Solar at Walker River. The estimated cost for the new
18 transmission additions is \$28.0 million.

19
20 **27. Q. WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
21 **SLEEPY ORANGE SOLAR/BESS PROJECT?**

22 A. The Sleepy Orange Solar/BESS project will require a 345 kV lead line terminal at
23 Walker River. The estimated cost for the new transmission addition is \$3.0 million.

1 28. Q. **WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
2 **COMMERCE STATION BESS PROJECT?**

3 A. The Commerce Station BESS project will require a 138 kV lead line terminal at
4 Miller substation. The estimated cost for the new transmission additions is \$0.6
5 million.

6
7 29. Q. **WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
8 **COYOTE SPRINGS SOLAR/BESS PROJECT?**

9 A. A new 525 kV line terminal for the Companies' requested DNR for Coyote Springs
10 Solar/BESS for 600 MW at Crystal substation 525 kV bus is required. The Coyote
11 Springs 600 MW DNR also requires the Northwest 525/230 kV 1,500 MVA
12 transformer #7 that I discussed in Q&A 16 above. The estimated cost for the new
13 transmission addition is \$4.0 million.

14
15 30. Q. **WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
16 **WHITE PINE SOLAR/BESS PROJECT?**

17 A. The White Pine Solar/BESS project will require installation of a new 345 kV lead
18 line terminal for the Companies' requested DNR for White Pine Solar/BESS for
19 350 MW at Gonder substation 345 kV bus. The White Pine 350 MW DNR also
20 requires the construction of the new Frontier – Lander 230 kV line which is
21 described in Q&A 20 above. The DNR also requires a new generation runback RAS
22 of White Pine for loss the Gonder 345/230 kV transformer or loss Gonder-Robinson
23 Summit 345 kV line, Robinson Summit PST failures or 345 kV breaker failures at
24 Gonder. The White Pine DNR also requires the 345 kV breaker additions at Coyote
25 Creek substation described in Q&A 14 above. The estimated cost for the new
26 transmission additions is \$2.9 million.

1 31. Q. **WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
2 **TREGO GRID BESS PROJECT?**

3 A. The 200 MW Trego Grid BESS project will require a new 120 kV lead line MW at
4 Mira Loma 120 kV substation. The Trego Grid BESS 200 MW DNR also requires
5 the construction of several network upgrades:

- 6 • Reconductoring #129 Glendale – Valley Road 120 kV line five miles
- 7 • Replace Vally Road bus and jumpers
- 8 • Upgrade relays at Mt. Rose substation
- 9 • Upgrade Sugar Loaf substation breaker 1001
- 10 • Contingent facility – New Lemmon Valley – Lazy 5 120 kV line
 - 11 ○ Required for NERC TPL-001-5.1, new in 2026 Corrective Action
 - 12 Plan (CAP)
- 13 • Contingent facility - Reconductor Valley Road – North Valley 120 kV line
 - 14 ○ Required for Sierra Solar Phase 1, DNR required Network Upgrade
 - 15 (NU)

16 The estimated cost for the new transmission addition is \$7.0 million.

17
18 32. Q. **WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
19 **SOUTHERN BIGHORN I AND II PV/BESS?**

20 A. Southern Bighorn I and II shares an existing lead line and there is no network
21 upgrades required for interconnection. The Southern Bighorn I and II PV/BESS
22 400 MW DNR requires the construction of several network upgrades, in addition
23 to those described and requested above:

- 24 • Iron Mountain – Lorenzi 138 kV line uprate
- 25 • Contingent facility – Craig – Pecos line uprate
 - 26 ○ Required for NERC TPL-001-5.1 CAP #2067

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

- Contingent facility – Second Tolson 230/138 kV transformer and Ford-Tolson 138 kV line
 - Required for NERC TPL-001-5.1 CAP #2065
- Contingent facility – Northwest 525/230 kV 1,500 MVA transformer #7
 - Required for NERC TPL-001-5.1 CAP #2104
- Contingent facility – Magnolia – NSO 230 kV line
 - Required for NERC TPL-001-5.1 CAP #2077
- Contingent facility – Gilmore – Leavitt 138 kV line uprate
 - Required for NERC TPL-001-5.1 CAP #2076

The estimated cost for the new transmission addition is \$0.3 million.

33. Q. WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE DRY LAKE EAST II PV/BESS?

A. Dry Lake East II shares an existing lead line and there is no network upgrades required for interconnection. The Dry Lake East II PV/BESS 150 MW DNR requires the construction of several network upgrades in addition to those described and requested above:

- Contingent facility – Iron Mountain – Lorenzi 138 kV line uprate
 - Required for the Southern Bighorn DNR
- Contingent facility – Craig – Pecos 138 kV line uprate
 - Required for NERC TPL-001-5.1 CAP #2067
- Contingent facility – Second Tolson 230/138 kV transformer and Ford-Tolson 138 kV line
 - Required for NERC TPL-001-5.1 CAP #2065
- Contingent facility – Northwest 525/230 kV 1500 MVA transformer #7
 - Required for NERC TPL-001-5.1 CAP #2104

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

- Contingent facility – Magnolia – NSO 230 kV line
 - Required for NERC TPL-001-5.1 CAP #2077
- Contingent facility – Gilmore – Leavitt 138 kV line uprate
 - Required for NERC TPL-001-5.1 CAP #2076

34. Q. WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE HOT POT AND IRON POINT PV/BESS PROJECTS?

A. The Hot Pot and Iron Point PV/BESS 600 MW DNR will require a terminal at North Valmy 345 kV bus. The 600 MW DNR also requires the construction of several additional network upgrades listed below:

- Contingent facility – Lantern – Comstock Meadow 345 kV line
 - Required for various agreements including Rule 9 agreements, NITS agreements for DNRs, Point to Point Transmission Service Agreements
- Contingent facility – Reconductor East Tracy – West Tracy 345 kV line #1
 - Required for NITS customer agreement for Naniwa 600 MW DNR
- Contingent facility – Construct new East Tracy – West Tracy 345 kV line #2
 - Required for NITS customer agreement for Naniwa 600 MW DNR
- Contingent facility – Chukar 345/120 kV 400 MVA transformers #1 and #2
 - Required for several Rule 9 agreements for 120 kV delivery
- Contingent facility – reconductor #103 North Valley Road – Valley Road
 - Required for Sierra Solar Phase I
- Construct Coyote Creek – Falcon 345 kV line, \$66 million

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

- Contingent Facility - Rebuild #118 from Eagle to NGPP with 1026 ACCC, \$14.80 million
 - Required by the Valmy area geothermal portfolios DNR request for 190 MW
- Contingent Facility - Reconductor #3422 East Tracy – Lantern to 1026 ACCC, \$15 million
 - Required by the Valmy area geothermal portfolios DNR request for 190 MW
- Install third PST at Robinson Summit 345 kV, \$25 million
- Resolve clearance issues on #3420 line, \$0.50 million
- Change conductor size of Lantern – Comstock Meadows to 2x1590 ACSR
 - Incremental cost increase of \$5.27 million
- Install phase shifter at Oreanna 120 kV line, \$60 million
- Construction of a generation runback/tripping RAS, in combination with prescriptive load shedding with the sleeved energy customer, will be required until permanent mitigations are completed.

The estimated cost for the new transmission additions is \$8.4 million.

35. Q. WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE FORT CHURCHILL NATURAL GAS GENERATION?

A. A lead line terminal at Walker River 345 kV bus is required for the Companies’ DNR request for multiple natural gas generation units including aeroderivative eight (8) 50 MW, eight (8) 50 MW and simple cycle turbine two (2) 220 MW generators totaling 1,240 MW over the three phases. The Companies requested Ft Churchill natural gas generator DNR require the construction of the Walker River - Grayskull 525 kV line. Which requires the Companies to construct the Grayskull

1 two (2) 525/345 kV 1,500 MVA transformer bank, Grayskull – Nighthawk #1 345
2 kV line, Grayskull – Nighthawk 345 kV line #2, resolve clearance violation on
3 #124 line by replacing five (5) structures, reconductor #109 120 kV line six miles,
4 reconductor Gosling to Comstock or Goose depending on if Goose is built. The Ft
5 Churchill natural gas generation DNR is contingent on the Chukar 345/120 kV
6 transformers described and requested above. The network upgrades described also
7 allow the Companies to deliver imports to the TRIC area. Without the addition of
8 these network upgrades, the TRIC customers will be limited to approximately 2,400
9 MW of combined flows from Walker River 345 kV via the 345 kV Common Ties.
10 The 2,400 MW limit would include the increased import capacity to 2,800 MW
11 gained by the construction of Greenlink. The Companies request approval to
12 construct the Walker River – Grayskull 525 kV line and Grayskull substation with
13 two (2) 525/345 kV 1,500 MVA transformer bank. The Companies request
14 approval to construct two (2) Grayskull – Nighthawk 345 kV lines and fold Lantern
15 – Comstock into Grayskull 345 kV bus. The estimated cost for the new transmission
16 additions is \$484.5 million.

17
18 **36. Q. WHAT TRANSMISSION ADDITIONS ARE REQUIRED FOR THE**
19 **VALMY AREA GEOTHERMAL PORTFOLIOS?**

20 A. The Valmy area geothermal portfolios require the construction of two 120 kV lead
21 line terminals and two POI substations to interconnect the Companies’ DNR
22 requested geothermal generation for 190 MW, at multiple locations near Valmy on
23 the 120 kV transmission system. A 120 kV 150 MVA PST is required at Oreanna,
24 rebuild of #118 120 kV line from Eagle to NGPP, and #3422 Lantern – East Tracy
25 345 kV line reconductor to bundled 2x1026 ACCC for the Companies’ requested
26 Valmy geothermal portfolios DNRs. The geothermal portfolios DNR request also
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

require the construction of East Tracy – West Tracy #2. All four of the previous network upgrades are also contingent facilities for the Hot Pot and Iron Point DNR request for 600 MW. The balance of the geothermal resources in the portfolios share lead lines with these or existing generators. The estimated cost for the new transmission additions is \$150.4 million.

37. Q. WHAT IS THE STATUS OF THE SWIP-NORTH PROJECT?

A. The SWIP-North project is currently under development by Great Basin Transmission, LLC. Great Basin Transmission, LLC (“Great Basin”) is an indirect, wholly owned subsidiary of LS Power Associates, L.P. The Project consists of: (1) a new 285-mile, 500 kV transmission line (SWIP-North Line) that will run from the existing Midpoint substation located near Twin Falls, Idaho to the existing Robinson Summit substation located near Ely, Nevada; (2) expansion of the Midpoint and Robinson substation facilities to accommodate the interconnection and operation of the SWIP-North Line; and (3) new 70-percent series compensation for the SWIP-North Line and for the existing ON Line, the existing 231-mile, 500 kV transmission line that runs from the Robinson Summit substation to the Harry Allen substation located near Las Vegas, Nevada. Great Basin plans to complete the Project by mid-2028. The WECC has approved a path rating for the SWIP-North Line of 2,070 MW in the north-to-south direction and 1,920 MW in the south-to-north direction.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

FIGURE POTTEY-1
SWIP PROJECT SEGMENTS



38. Q. PLEASE DESCRIBE THE ADDITIONAL CAPACITY AND ENTITLEMENTS RELATED TO SWIP-NORTH.

A. The ownership, maintenance, and operation of the SWIP-North Line—including the treatment of its transmission capacity—will be governed by the Second Amended and Restated Transmission Use and Capacity Exchange Agreement (“TUA”) by and among Nevada Power and Sierra [For a history of the

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

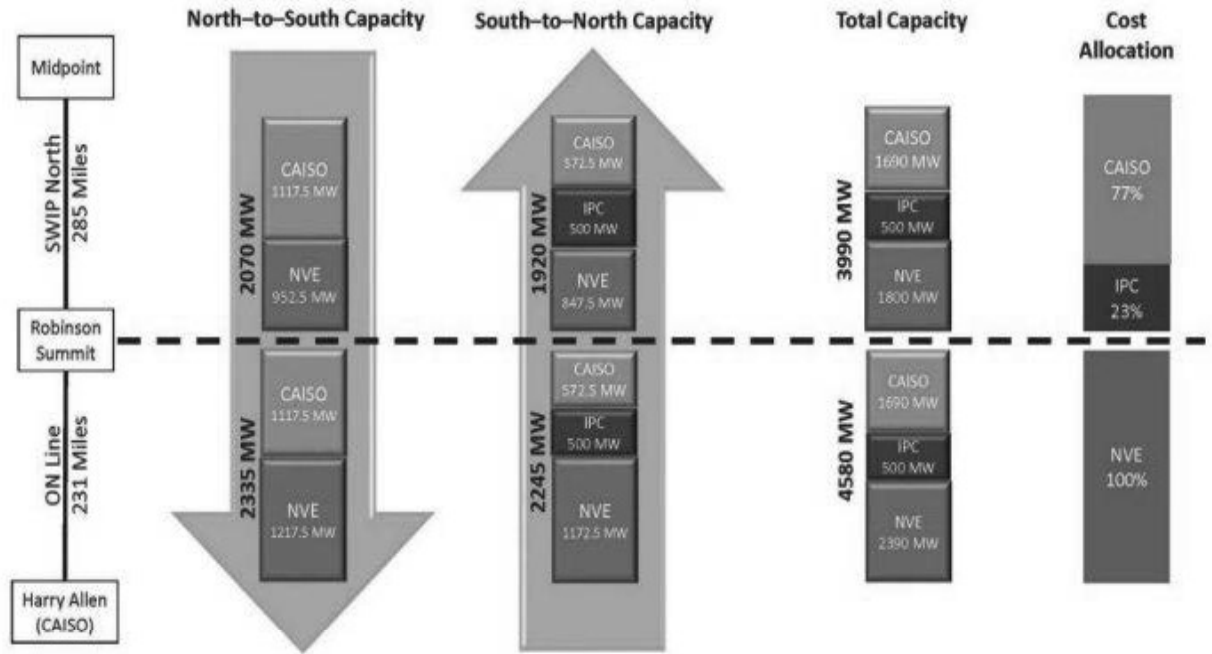
amendments to the TUA, see the transmittal letter for NV Energy’s July 1, 2020, filing in Docket No. ER20-2295-000.]

Under the currently effective TUA, completion of the SWIP-North Project will trigger a capacity swap that will result in Great Basin receiving over half of the above-listed transmission capacity on the SWIP-North Line—specifically, 1,117.5 MW north to south and 1,072.5 MW south to north—with NV Energy holding the balance of the SWIP-North Line transmission capacity. As part of this swap, Great Basin will also receive 1,117.5 MW north to south and 1,072.5 MW south to north capacity on the existing ON Line.

NV Energy understands that Great Basin will assign their capacity on the SWIP-North line and ON Line to the California Independent System Operator (“CAISO”) and Idaho Power Company (“IPC”). IPC will receive 500 MW of south to north capacity on both SWIP-North and ON Line. All of Great Basin’s remaining capacity on both SWIP-North and ON Line will be assigned to CAISO. Great Basin has also submitted a Participating Transmission Owner application to CAISO for the capacity on both SWIP-North and ON Line that will be turned over to CAISO.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

FIGURE POTTEY-2
SWIP-NORTH AND ON LINE CAPACITY ALLOCATION



39. Q. WHAT POTENTIAL FUTURE TRANSMISSION PROJECTS ARE THE COMPANIES EVALUATING?

A. NV energy is evaluating a number of potential future transmission projects that may be needed to interconnect additional load, generation or to provide additional inter-regional transfer capability. These projects include the Bonanza-NOB-Walker River 500 kV line, Sagebrush (Amargosa) - Bighorn - Eldorado/Mead 525 kV line, Cross-Tie 500 kV line, and ON Line 2 – Robinson Summit – Harry Allen 525 kV line #2

1 40. Q. PLEASE DESCRIBE THE BONANZA – NOB - WALKER RIVER 500 KV
2 LINE.

3 A. NV Energy and Bonneville Power Administration (“BPA”) are jointly working on
4 transmission planning studies for a potential new interconnection between our
5 systems. The new interconnection would be a 500 kV transmission line from
6 BPA’s proposed Bonanza Substation to NV Energy’s Walker River substation that
7 is currently under development as part of the Greenlink project. The project would
8 also include an intermediate substation at the Nevada Oregon Border (“NOB”). An
9 additional intermediate substation could be developed at Granite to interconnect
10 renewable resources in the Gerlach area. The Walker River - Grayskull 525 kV line
11 described above that is required for the Ft Churchill natural gas generator DNR
12 could be the first segment of the line from Walker River. BPA would permit and
13 construct the line from Bonanza to NOB and NV Energy would permit and
14 construct the line from NOB to Walker River. In combination with the Greenlink
15 project this interconnection would provide a new transmission path between the
16 Pacific Northwest and the Desert Southwest and allow for the interconnection of
17 potential renewable resources in the Gerlach area.

18
19 41. Q. PLEASE DESCRIBE THE SAGEBRUSH (AMARGOSA) - BIGHORN -
20 ELDORADO/ MEAD 525 KV LINE.

21 A. NV Energy has a BLM grant offer to build the Bighorn-Eldorado 525 kV
22 transmission line. The Sagebrush (Amargosa)-Bighorn –Eldorado/ Mead 525 kV
23 transmission line could be developed to enhance the capability to deliver additional
24 renewable resources from the Amargosa area to southern Nevada, CAISO, and the
25 Desert Southwest.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

42. Q. PLEASE DESCRIBE THE CROSS-TIE 500 KV LINE.

A. The Cross-Tie Transmission Line being developed by TransCanyon is a proposed 500 kV line connecting Utah and Nevada. The approximately 214-mile line would go from PacifiCorp’s Clover substation to NV Energy’s Robinson Summit substation. The project would strengthen the transmission system between Utah and Nevada, relieve congestion on other key transmission lines in the region, and increase the ability for California, Nevada, Utah and Wyoming to import and export additional energy.

43. Q. PLEASE DESCRIBE THE ON LINE 2 – ROBINSON SUMMIT – HARRY ALLEN 525 KV LINE #2.

A. The Companies were granted an offer for the right-of-way N-82076 to construct and operate a 235-mile 525 kV transmission line and fiber optic line called ON Line 2 in 2011 by the Bureau of Land Management (“BLM”). The line would roughly parallel the existing ON Line and run from Robinson Summit to Harry Allen. The BLM later extended the grant offer in abeyance until 2024. The Companies have requested and been granted an additional extension of the abeyance until 2028. The need for ON Line 2 is being evaluated and is dependent on the transmission requests that could be received. A 2028 in-service date would align with the planned in-service date of the Greenlink North and potentially the Crosstie transmission project. If SWIP North and Crosstie are both constructed as planned, then it may become necessary to construct ON Line 2. Additionally, if large resources are added on Greenlink or at Robinson Summit, ON Line 2 could become a required network upgrade. There is the potential to construct a collector substation, which is not currently permitted, to interconnect large renewable resources in the designated

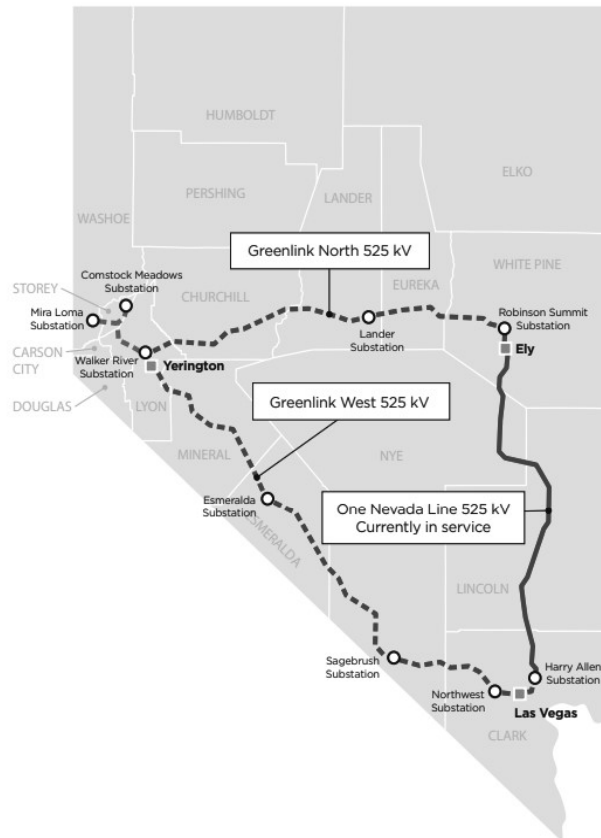
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

renewable energy zone that is located along the ON Line 2 route and deliver these resources to the Las Vegas load center and the CAISO system.

44. Q. PLEASE DESCRIBE THE GREENLINK PROJECT.

A. The Greenlink Project consists of a comprehensive, large-scale new transmission addition centered on construction of a pair of major 525 kV transmission lines (Greenlink West and Greenlink North) spanning approximately 593 miles, and three 345 kV transmission lines (“Common Tie Lines”). The Greenlink Project will be placed in commercial service in phases from 2027 to 2028.

**FIGURE POTTEY-3
GREENLINK PROJECT SEGMENTS**



1 Greenlink West, which NV Energy will construct as part of the first phase of
2 Greenlink Nevada, will be a 358-mile, 525 kV transmission line from Las Vegas to
3 Yerington, Nevada. The first sub-segment of Greenlink West is a 325-mile, 525 kV
4 transmission line from Northwest Substation in Las Vegas to Walker River
5 Substation in Yerington. This sub-segment will have two renewable energy
6 collector substations in Amargosa and Esmeralda counties. The second sub-
7 segment of Greenlink West is a 33- mile, 525 kV transmission line within Las
8 Vegas from Harry Allen Substation to Northwest Substation. With ON Line,
9 Greenlink West will increase resiliency by eliminating the single contingency
10 between the northern and southern systems resulting from the loss of ON Line.

11
12 Greenlink North, the second major segment of Greenlink Nevada, will be a 235-
13 mile, 525 kV transmission line from Walker River Substation in Yerington to
14 Robinson Summit Substation in Ely, Nevada.

15
16 The construction of Greenlink West and Greenlink North will require the
17 construction of three 345 kV transmission lines that are referred to as the Common
18 Ties from Walker River Substation. The Common Ties include the construction of
19 the new Walker River 525/345/230/120 kV substation adjacent to the existing Ft.
20 Churchill substation. The first common tie is a 44-mile, 345 kV transmission line
21 to Mira Loma Substation in Reno. The second and third common ties are a pair of
22 37-mile, 345 kV transmission lines to Comstock Meadows Substation in Reno.

23
24 **45. Q. WHAT IS THE STATUS OF GREENLINK NORTH?**

25 A. The Bureau of Land Management (“BLM”) published the final Environmental
26 Impact Statement (“EIS”) for Greenlink North (Walker River substation –
27

1 Robinson Summit substation) in May 2025. The final EIS for Greenlink North
2 limited construction activities to five and a half months (September – mid-
3 February) each year to mitigate environmental impacts in sage grouse habitat. The
4 companies requested reconsideration of the seasonal restrictions within legacy
5 transmission corridors. The BLM is performing studies to reconsider seasonal
6 restrictions in legacy corridors through a supplemental EIS, anticipated to be
7 completed early spring 2026, followed by a record of decision in early summer
8 2026.

9
10 The Companies are in the process of securing material yards along Common Ties
11 and Greenlink north to facilitate construction starting in July 2026 and January
12 2027, respectively. Construction on Greenlink North is planned to start in January
13 2027. The Companies expect completion of construction for Greenlink North and
14 a planned in-service date by December 31, 2028.

15
16 **46. Q. WHAT IS THE STATUS OF GREENLINK WEST?**

17 A. The Companies received BLM right-of-way grant for Greenlink West (Northwest
18 substation – Walker River substation) and Common Ties (Mira Loma substation –
19 Walker River substation and Comstock Meadows substation – Walker River
20 substation lines #1 and #2) in December 2024. The Commission bifurcated
21 Greenlink West into smaller segments and issued permission to construct under
22 UEPA for segment 1 (Northwest Substation-Sagebrush Substation) in January
23 2025, segment 2 (Esmeralda Substation-Sagebrush Substation) in March 2025 and
24 segment 3 (Esmeralda substation-Walker River substation) in April 2026. The
25 construction contractor (MasTec) started construction on segment 1 of Greenlink
26 West (Northwest substation – Sagebrush substation) in January 2025. MasTec has
27

1 completed installation of 100 percent of foundations in Segment 1 and has erected
2 89 transmission structures. Additionally, MasTec has also framed 126 transmission
3 structures on the ground. The new in-service date for Greenlink West is December
4 31, 2027, due to a review by the Federal Aviation Administration and the
5 Department of Defense. The Department of Defense raised concerns regarding the
6 location of certain towers, height of certain wire spans and lighting and marking
7 requirements. The federal government shutdown between October 1, 2025, and
8 November 12, 2025, further hindered the resolution of those concerns. Since then,
9 those concerns have essentially been resolved, resulting in, among other things,
10 lighting and marking requirements in certain areas. On January 22, 2026, NV
11 Energy instructed MasTec to remobilize to continue construction work on the
12 project lines; however, the review by the Federal Aviation Administration and the
13 Department of Defense slowed progress on the project. NV Energy is currently
14 working with federal and local governmental agencies and its contractors to regain
15 schedule and mitigate potential delays to the extent possible. The Companies
16 expect completion of segment 4 of Greenlink West (Harry Allen to Northwest
17 Substation 525 kV transmission line) by the planned in-service date of December
18 31, 2028.

19
20 **47. Q. WHAT IS THE STATUS OF THE GREENLINK COMMON TIES?**

21 A. The BLM issued a notice to proceed (“NTP”) for three Common Ties (Walker
22 River substation – Mira Loma substation, Walker River substation – Comstock
23 Meadows substation Lines #1 and #2) on November 6, 2025. The City of Reno,
24 Storey County and Lyon County require landowner affidavits for conditional or
25 special use permits within their jurisdictions. NV Energy has requested that the
26 entities waive this requirement to mitigate the risk of stranded investment. NV
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Energy may petition the Commission for review pursuant to NRS 278.26506 in the event the request for waiver is denied by the local entities and NV Energy is unable to obtain all landowner affidavits. Construction on Greenlink Common Ties is planned to start in the second quarter of 2026.

48. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT POTTEY-DIRECT-1

STATEMENT OF QUALIFICATIONS

CHARLES A. POTTEY

My name is Charles A. Pottey. My business address is 6100 Neil Road, Reno, Nevada. I am the Director of Transmission Planning for Nevada Power Company, dba NV Energy and Sierra Pacific Power Company, dba NV Energy.

I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science Degree in Electric Power Engineering in 1975, and a Master of Engineering Degree in Electric Power Engineering in 1977.

I am a registered Professional Engineer in Colorado.

Since September of 2021 I have been employed as the Director of Transmission Planning. I am responsible for all transmission associated with integrated resource plans (“IRP”), compliance, generator interconnections and transmission service requests, including load addition functions for the Companies. I am also responsible for regional and inter-regional transmission planning.

From April of 2015 until April of 2017, I was employed as the Director of Transmission Policy, Contracts and Business Services. I served as the primary contact for new transmission customer requests for interconnections to the transmission grid. I ensured compliance with applicable regulations and response deadlines associated with the Open

Access Transmission Tariff (OATT). My staff negotiated and finalized contracts with transmission customers for addition and withdrawal of generation interconnections, transmission service, ancillary services and agreements for co-owned facilities. I lead the billing and settlement function of the energy imbalance market entity and OATT.

From April 2010 until April of 2015, I was employed as the Manager of Network and IRP Transmission Planning. I was responsible for leading a staff of engineers who perform transmission system analyses to evaluate the operation of Sierra's and Nevada Power's system and analyze required system additions. I recommended optimal transmission additions considering economics, feasibility, performance, and reliability of alternatives to provide reliable and economical electric service to Sierra and Nevada Power customers. I oversaw the evaluation of the long-range needs of the electric transmission system including capacity, reliability, voltage regulation, stability and operation during contingency conditions to ensure compliance with all NERC and WECC transmission planning reliability requirements. I managed the preparation of the Transmission section of the Integrated Resource Plan and Energy Supply Plan filings.

From December 2004 until April 2010, I was employed as the Manager of the Long-Term Resource Planning. I was responsible for directing technical analysis to evaluate the capital cost, production cost, and reliability of various transmission, generation, purchase power, and demand side alternatives to ensure sufficient electric resources are available to provide reliable and economical electric service to Sierra Pacific Power and Nevada Power customers. I managed the preparation of the Integrated Resource Plan and

Energy Supply Plan filings. I directed the development of detailed system modeling to accurately represent system operating constraints including system transmission limitations for production costing studies of existing and future power supply options.

From February 2002 until December 2004, I was employed as principal consultant in Sierra's Long-Term Resource Planning Department. I was responsible for developing analysis of various resource options to ensure sufficient resources are available to reliability and economically serve Sierra and Nevada Power's electric customers.

From June 2000, until February 2002, I was employed as a Senior Rate Engineer in Sierra's Rates and Regulatory Affairs Department. I was responsible for preparing price analysis and developing rates for electric, gas and water services offered by Sierra Pacific and Nevada Power.

From January 1991 until June 2000, I was employed as a Senior Engineer in Sierra's Resource Planning department. I was responsible for performing technical analyses to evaluate the capital cost, production cost, and reliability of various generation, purchase power, and demand side alternatives to ensure sufficient electric resources are available to provide reliable and economical electric service to Sierra's customers. I developed detailed modeling of Sierra's system to accurately represent system operating constraints including system transmission limitations for production costing studies of existing and future power supply options. I have performed production costing, reliability, and economic analysis to evaluate the cost, benefits, and reliability of potential supply and

demand side alternatives to satisfy specific future resource requirements. I have also evaluated the economics and reliability of Qualifying Facilities, Independent Power Producers, and other non-Sierra owned generation options.

From August 1988 until January 1991, I was employed as a Senior Engineer in Sierra's Electric System Planning department. I was responsible for performing engineering studies to evaluate Sierra's long range and operational transmission and distribution system requirements. I performed powerflow and stability studies to evaluate the operation of Sierra's system and analyze required system additions and recommended optimal additions considering economics, feasibility performance, and reliability of the alternatives. I developed a loss evaluation procedure to calculate the present worth value of system losses. I evaluated system import and export constraints and prepared appropriate operating nomograms.

From November 1982 until August 1988, I was employed as a Senior Engineer in Sierra's Electric System Control Center. I was responsible for providing technical support to Sierra's Electric System Control Center to assure optimal system operation. I evaluated generation dispatch and scheduled power purchases to ensure Sierra system was operated in the most economic manner possible while maintaining required system reliability. I developed operating guidelines and procedures for transmission and distribution facilities.

From December 1979 until November 1982 McGraw Edison employed me as an Apparatus Engineer. I was Responsible for providing sales engineers, product departments, and electric utility customers throughout the Rocky Mountain region with technical assistance on the application, installation, testing, and maintenance of McGraw Edison's complete line of electrical equipment.

From August 1978 until December 1979 Tri-State Generation and Transmission Association, employed me as a Project Engineer. I was responsible for coordinating all project activities for major substation and transmission line additions.

From May 1977 until August 1978 McGraw Edison Company employed me as a Power System Engineer. I was responsible for performing analytical studies for electric utility clients. I performed insulation coordination studies, calculated system unbalances, evaluated negative sequence currents, and analyzed transient recovery voltages.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CHARLES A. POTTEY, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026

Charles A. Pottey
Charles A. Pottey

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

LAYNE M MAXFIELD

1 **BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

2 Nevada Power Company d/b/a NV Energy and
3 Sierra Pacific Power Company d/b/a NV Energy

4 2026 Joint Integrated Resource Plan (2027-2046)
5 Docket No. 26-05 _____

6 Prepared Direct Testimony of

7 **Layne Maxfield**

8
9 **SECTION I – INTRODUCTION**

10 **1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS**
11 **AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

12 A. My name is Layne Maxfield, I am the Manager of Transmission System Planning
13 at Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific
14 Power Company d/b/a NV Energy (“Sierra” and together with Nevada Power, the
15 “Companies” or “NV Energy”). My business address is 6100 Neil Road, Reno
16 Nevada 89511. I am filing testimony on behalf of the Companies.

17
18 **2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE**
19 **UTILITY INDUSTRY.**

20 A. I have 22 years of experience in the electrical utility industry, which includes
21 engineering, project management, and department manager experience. I
22 previously worked as a technical advisor to Rocky Mountain Power’s Project
23 Management Office. In addition, I have worked cumulatively for two years as a
24 Senior and Senior II, Transmission Planning Engineer at Rocky Mountain Power
25 and the Companies, respectively. I currently have worked for approximately four
26 years as Manager, Transmission System Planning for the Companies, in which I

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

have prepared transmission narratives for Integrated Resource Plans (“IRP”) and amendments. My statement of qualifications is attached as **Exhibit Maxfield-Direct-1**.

3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I supervise transmission interconnection studies and transmission service studies as prescribed by the Federal Energy Regulatory Commission (“FERC”) approved Open Access Transmission Tarriff (“OATT”). I also contribute oversight for regulatory compliance. I review and approve all customer transmission system impact studies, facilities studies and coordinate area master planning, in which I ensure consistency of transmission study results and their proposed mitigations, with the transmission area master plans.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?

A. Yes, I provided testimony in the 2024 Joint IRP, Docket No. 24-05041.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support all of the Companies’ requests for projects that are required per executed Rule 9 agreements, including distribution-load-growth projects.

RULE 9 AGREEMENTS

- Sapphire 230/12 kilovolt (“kV”) substation
- Sapphire phase 1

- 1 - Sapphire phase 2
- 2 - Sapphire phase 3
- 3 - Sapphire phase 4
- 4 - Sapphire phase 5
- 5 Basin 525/230 kV substation, Basin phase 1
- 6 - Includes Sapphire-Basin 230 kV line
- 7 - Basin phase 2
- 8 Sand Dune 230 kV switching station,
- 9 - Sand Dune phase 1
- 10 - Sand Dune phase 2
- 11 - Sand Dune phase 3
- 12 Opal 230 kV switching station
- 13 - Includes HGIII-Opal-Sapphire 230 kV line
- 14 Navigator 230 kV switching station
- 15 - Includes HGIII-Navigator-Sand Dune 230 kV line
- 16 HGIII 525/230 kV 600 megavolt-ampere (“MVA”) Transformer
- 17 - HGIII phase 1
- 18 - HGIII phase 2
- 19 Chukar 345/120 kV 280 MVA transformer #1 and 345/120 kV 400 MVA
- 20 transformer #2
- 21 Viking 345 kV switching station
- 22 Vaquero 345/120 kV substation
- 23 East Tracy 345 kV line terminal
- 24 Petroglyph 345 kV switching station
- 25 Mallard 525/345 kV substation
- 26 Goose 525/345 kV substation

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Walker River – Goose – Mackay – Walker River 525 kV lines
Spring Canyon 230/12 kV substation
Scorpion 230 kV switching station

Additionally, I support the differences between the transmission projects as studied in the Economic Analysis and as requested for approval, as described in the Additional Studies and Information subsection of the Economic Analysis Section of the Narrative.

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

Exhibit Maxfield-Direct-1 – Statement of Qualifications.

I am sponsoring the following Technical Appendices:

TRAN-1 - Confidential Agreement Petroglyph – High-Voltage Distribution (“HVD”)

TRAN-2 - Confidential TRIC to Walker River Transmission Master Plan Map

TRAN-3 - Confidential Agreement -Basin ph1 & Sapphire ph3

TRAN-4 - Confidential Agreement - Sapphire ph2

TRAN-5 - Confidential Agreement Sand Dune – HVD

TRAN-6 - Confidential Agreement Sand Dune - HVD ph2

TRAN-7 - Confidential Agreement Chukar - 23-00052 HVD

TRAN-8 - Confidential Agreement Viking - HVD 24-00020-RNO

TRAN-9 - Confidential Agreement Spring Canyon - MPU 3010833586-MPU

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

TRAN-10 - Confidential Agreement Spring Canyon-LNV4-Apparatus
Procurement.

**7. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING
CONFIDENTIAL?**

A. Yes. The transmission map provided as Technical Appendix TRAN-2 Confidential, TRIC to Walker River Transmission Master Plan Map, is confidential at this time and was included for visualization purposes only. It is a preliminary map used for planning purposes. A preliminary map should be considered non-public information because its disclosure may harm the Companies and increase costs to customers. In the past, preliminary project maps have been used by bad actors to speculatively secure lands ahead of the project which then increases the Companies' right-of-way and land cost and thus unnecessarily inflates project costs. In addition, the Rule 9 customer agreements contain customer-specific information and are, therefore, confidential. The agreements include:

- TRAN-1 Confidential Agreement Petroglyph - HVD 25-00058
- TRAN-3 Confidential Agreement -Basin ph1 & Sapphire ph3
- TRAN-4 Confidential Agreement - Sapphire ph2
- TRAN-5 Confidential Agreement Sand Dune – HVD
- TRAN-6 Confidential Agreement Sand Dune - HVD ph2
- TRAN-7 Confidential Agreement Chukar - 23-00052 HVD
- TRAN-8 Confidential Agreement Viking - HVD 24-00020-RNO
- TRAN-9 Confidential Agreement Spring Canyon - MPU 3010833586-
MPU
- TRAN-10 Confidential Agreement Spring Canyon-LNV4-Apparatus
Procurement.

1 8. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL
2 TREATMENT OF THIS INFORMATION?

3 A. The requested period for confidential treatment is five years.
4

5 9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE
6 COMMISSION’S REGULATORY OPERATIONS STAFF (“STAFF”) OR
7 THE NEVADA ATTORNEY GENERAL’S BUREAU OF CONSUMER
8 PROTECTION (“BCP”) TO FULLY INVESTIGATE THE INFORMATION
9 SET FORTH IN THIS FILING?

10 A. No, in accordance with the accepted practice in Commission proceedings, the
11 confidential material will be provided to Staff and the BCP under standardized
12 protective agreements.
13

14 10. Q. HOW IS YOUR TESTIMONY ORGANIZED?

15 A. For each project for which the Companies are requesting construction approval, a
16 brief description and statement of need is provided, largely matching the
17 Transmission Section of the Supply Plan. My testimony is provided in five sections
18 as depicted below. Sections II, III and IV are broken out by the type of project they
19 describe.

20 - SECTION I - INTRODUCTION

21 - SECTION II - RULE 9 AGREEMENTS

22 - SECTION III – TRANSMISSION INTERCONNECTION AGREEMENTS

23 - SECTION IV - NERC COMPLIANCE

24 - SECTION V - DIFFERENCES BETWEEN PROJECTS AS STUDIED AND
25 PROJECTS AS REQUESTED FOR APPROVAL
26

1 **SECTION II – RULE 9 AGREEMENTS**

2 **11. Q. PLEASE DESCRIBE SAPPHIRE 230/12 KV SUBSTATION PHASE 1.**

3 A. Sapphire substation, with two (2) 230/12 kV 37 MVA transformers, is required in
4 2027. Sapphire substation is a distribution area upgrade project that will provide
5 relief to existing facilities at Gypsum substation to serve new loads in the north side
6 of the Apex area of Las Vegas. Additionally, a Rule 9 agreement for 84 MVA has
7 been executed with a Master Plan Developer agreement, requiring two (2) 230/12
8 kV 37 MVA transformers. The Sapphire substation will be connected to the existing
9 230 kV transmission system by folding the existing Harry Allen – Pecos 230 kV
10 line #2.

11
12 **12. Q. PLEASE DESCRIBE SAPPHIRE PHASE 2.**

13 A. A Rule 9 agreement for 500 MW has been executed requiring a High Voltage
14 Distribution (HVD) 230 kV line terminal at Sapphire and HVD line to the customer.
15 An optional requirement may be constructed, if funded by the customer, which is a
16 redundant 230 kV HVD line terminal and HVD line.

17
18 **13. Q. PLEASE DESCRIBE SAPPHIRE PHASE 3.**

19 A. A Rule 9 agreement, with the same customer described in phase 2 and for an
20 additional 500 MW, has been executed requiring the construction of Basin 525/230
21 kV substation with a 525/230 kV 1,500 MVA transformer at Basin. The Basin
22 substation is described and requested below. The agreement requires the Basin-
23 Sapphire 230 kV line, which is to be terminated in the 230 kV HVD line terminal
24 position which was built in phase 2.

1 **14. Q. PLEASE DESCRIBE SAPPHIRE PHASE 4.**

2 A. A Rule 9 agreement for 855 MW is expected to be executed before the Commission
3 issues a ruling on the 2026 IRP. The agreement requires two (2) HVD 230 kV line
4 terminals at Sapphire and a second 525/230 kV 1,500 MVA transformer at Basin.
5

6 **15. Q. PLEASE DESCRIBE SAPPHIRE PHASE 5.**

7 A. A Rule 9 agreement for 375 MW is expected to be executed before the Commission
8 issues a ruling on the 2026 IRP. The agreement requires the HGIII-Opal-Sapphire
9 230 kV line with a new 230 kV line terminal at Sapphire.
10

11 **16. Q. PLEASE DESCRIBE BASIN 525/230 KV SUBSTATION PHASE 1.**

12 A. Basin substation is required to serve a Rule 9 customer with a signed agreement for
13 an additional 500 MW HVD for a total of 1,000 MW, to be served from Basin
14 substation by two (2) 230 kV HVD lines. Basin substation is located near the
15 Sapphire substation in the Apex area. Basin will be connected to the existing
16 transmission system by folding the Silver Hawk – Harry Allen 525 kV line, addition
17 of 525/230 kV 1,500 MVA transformer and re-termination of the previously
18 discussed HVD line from Sapphire into Basin, creating the new Basin – Sapphire
19 230 kV line.
20

21 **16. Q. PLEASE DESCRIBE BASIN PHASE 2.**

22 A. A second Rule 9 agreement for 855 MW is expected to be executed before the
23 Commission issues a ruling on the 2026 IRP. The agreement requires a second
24 525/230 kV 1,500 MVA transformer at Basin.
25
26
27

1 17. Q. PLEASE DESCRIBE SAND DUNE 230 kV SWITCHING STATION PH. 1.

2 A. South of the Apex area, a fold of the Harry Allen – Pecos 230 kV line #2 into the
3 new Sand Dune switching station is required to serve a Rule 9 customer with a
4 signed 550 MW HVD agreement. The addition of this load causes overloads on the
5 Harry Allen – Pecos #1 230 kV line so that the existing line from Harry Allen to
6 Sand Dune must be reconductored to bundled 1026 ACCC.

7
8 18. Q. PLEASE DESCRIBE SAND DUNE PHASE 2.

9 A. A second Rule 9 agreement for 340 MW has been executed, requiring a 230 kV
10 terminal as well as the reconductor of a portion of the existing Harry Allen – Pecos
11 #1 230 kV line from Sand Dune to Pecos is required to be reconductored to bundled
12 1026 ACCC. The addition of two (2) stage voltage controlled 48 MVAR capacitors
13 are necessary to maintain transmission system voltage.

14
15 19. Q. PLEASE DESCRIBE SAND DUNE PHASE 3.

16 A. A third customer Rule 9 agreement for 432 MW, which is anticipated to be executed
17 before the Commission issues a ruling on the 2026 IRP. The customer requires a
18 230 kV line terminal at Sand Dune to connect the 230 kV line to Navigator
19 switching station, creating Sand Dune-Navigator-HGIII 230 kV line. Navigator is
20 described and requested below.

21
22 20. Q. PLEASE DESCRIBE OPAL 230 KV SWITCHING STATION.

23 A. It is now required to construct Opal (originally called Belcher) switching station
24 near Basin substation in Apex. This new switching station is required to serve a
25 Rule 9 customer 375 MW HVD agreement, which is anticipated to be executed
26 before the Commission issues a ruling on the 2026 IRP. The customer will take
27

1 redundant power delivery from two (2) 230 kV HVD lines from Opal. Opal will be
2 connected to the existing transmission system by constructing HGIII-Opal-
3 Sapphire 230 kV line.
4

5 **21. Q. PLEASE DESCRIBE NAVIGATOR 230 KV SWITCHING STATION.**

6 A. The Navigator switching station is required to provide service to a customer with a
7 Rule 9 agreement for 432 MW, which is expected to be executed before the
8 Commission issues a ruling on the 2026 IRP. The new Navigator 230 kV switching
9 station is located south of HGIII and north of Sand Dune in the Apex area.
10 Navigator will be connected to the 230 kV transmission by constructing HGIII-
11 Navigator-Sand Dune 230 kV line. The additional 230 kV load also requires
12 additional 230 kV transmission capacity to be added by constructing the 525/230
13 kV 600 MVA transformer at HGIII, which also requires the Harry Allen – Chuck
14 Lenzie 525 kV line to be folded into HGIII.
15

16 **22. Q. PLEASE DESCRIBE HGIII 525/230 KV SUBSTATION PHASE 1.**

17 A. A Rule 9 agreement for 375 MW (at Opal) which is expected to be executed before
18 the Commission issues a ruling on the 2026 IRP, requires the 230 kV line terminals
19 at HGIII for a line to Opal. The 230 kV line is a section of the Sapphire-Opal-HGII
20 described in Sapphire phase 5.
21

22 **23. Q. PLEASE DESCRIBE HGIII 525/230 KV SUBSTATION PHASE 2.**

23 A. A Rule 9 agreement for 432 MW (at Navigator) is expected to be executed before
24 the Commission issues a ruling on the 2026 IRP, requiring a 230 kV line terminal
25 at HGIII, line fold of Harry Allen – Chuck Lenzi 525 kV line into HGIII and a new
26
27

1 525/230 kV 600 MVA transformer at HGIII. The 230 kV line is a section of the
2 Sand Dune-Navigator-HGIII 230 kV line.

3
4 **24. Q. PLEASE DESCRIBE CHUKAR 345/120 KV 400 MVA TRANSFORMERS.**

5 A. It is now required to install the previously master planned Chukar 345/120 kV 400
6 MVA transformers #1 and #2, which are contingent facilities for a Network
7 Integrated Transmission Service (“NITS”) customer, for the 600 MW Naniwa
8 Designated Network Resource (“DNR”), who’s Point Of Interconnection (“POI”)
9 is East Tracy 345 kV. The Companies’ DNR request for Hot Pot and Iron Point 600
10 MW at North Valmy also requires the Chukar 345/120 kV transformer #1 and #2
11 additions which are contingent facilities. The Companies’ DNR request for the Ft
12 Churchill natural gas generation DNR for 1,223 MW, at its Walker River 345 kV
13 point of interconnection, requires the Chukar 345/120 kV 400 MVA transformer
14 #1 and #2 additions as contingent facilities. Chukar 345/120 kV transformers were
15 initially required to serve the current 120 kV Rule 9 HVD agreement load forecasts
16 in the next five years. Both of the Chukar 345/120 kV 400 MVA transformers are
17 contingent facilities for an executed Rule 9 agreement for 315 MW. It has been
18 identified that the previously planned 280 MVA transformers will ultimately not be
19 sufficient, to prevent the need to replace the transformers, 400 MVA transformers
20 will be used. The 345 kV transmission system will be connected to Chukar by
21 folding Lantern – Comstock Meadows 345 kV line.

22
23 **25. Q. PLEASE DESCRIBE VIKING 345 KV SWITCHING STATION.**

24 A. The new Viking switching station will be connected to the 345 kV system by
25 folding the Lantern – Comstock 345 kV line and is required to serve a Rule 9
26 customer with a signed HVD agreement for 461 MW.

1 **26. Q. PLEASE DESCRIBE THE VAQUERO 345/120 KV SUBSTATION.**

2 A. The new Vaquero 345/120 kV substation is incorporated into the area transmission
3 master plan with service to a customer with a Rule 9 agreement for 461 MW, which
4 is expected to be executed before the Commission issues a ruling on the 2026 IRP.
5 The customer will take service from 120 kV HVD lines which will require the
6 construction of two (2) 345/120 kV 280 MVA transformers, 345 kV ring bus and
7 120 kV breaker and a half bus. This large load will require the Lantern – Comstock
8 Meadows 345 kV line to be folded into the new Vaquero 345 substation. The
9 Vaquero location is located in Fernley, Nevada; Vaquero’s construction opens up
10 the ability to serve additional loads in the area on the 120 kV transmission system.

11
12 **27. Q. PLEASE DESCRIBE THE EAST TRACY 345 KV LINE TERMINALS.**

13 A. It is now required to install two (2) 345 kV HVD line terminals at East Tracy
14 substation. These are required to serve a customer with a Rule 9 agreement for 300
15 MW which is anticipated to be executed before the Commission issues a ruling on
16 the 2026 IRP. The lead time on breakers is now approximately three years.
17 Therefore, it is necessary to order the breakers now. The customer is responsible
18 for the redundant HVD line costs, including the new line terminal addition.

19
20 **28. Q. PLEASE DESCRIBE PETROGLYPH 345 KV SWITCHING STATION.**

21 A. It is now required to install the Petroglyph switching station to serve a new Rule 9
22 agreement for 450 MW. Petroglyph is connected to the 345 kV system by folding
23 the new West Tracy-Comstock Meadows 345 kV line. The customer will take
24 redundant power delivery from two (2) 345 kV HVD lines from Petroglyph.

1 29. Q. **PLEASE DESCRIBE MALLARD 525/345 kV SUBSTATION.**

2 A. It is now required to install the Mallard 525/345 kV substation. This new substation
3 is required to serve a Rule 9 customer’s 1,050 MW MPC Master Planned
4 Community agreement, and for whose HVD customers are expected to execute
5 their Rule 9 agreements, before the Commission issues a ruling on the 2026 IRP.
6 To serve this large load and maintain the system voltage limits described in the
7 North American Electrical Reliability (“NERC”) standard for transmission
8 reliability requirements TPL-001-5.1, a shunt capacitor bank with three stages of
9 200 MVAR, for a total of 600 MVAR (3x200 MVAR) and two (2) 525/345 kV
10 1,500 MVA transformers are required. Mallard will be connected to the system by
11 folding the Mackay-Goose 525 kV section of the Walker River-Goose-Mackay-
12 Walker River 525 kV line, which is described below. Alternatively, Mallard could
13 be connected from the Walker River – Grayskull-Mackay-Mallard 525 kV line if
14 necessary. The customer will take redundant power delivery from two (2) 345 kV
15 HVD lines from Mallard.

16
17 30. Q. **PLEASE DESCRIBE THE GOOSE 525/345 kV SUBSTATION.**

18 A. It is now required to install the Goose 525/345 kV substation. This new substation
19 is required to serve a Rule 9 applicant SHVD agreement for 360 MW which is
20 expected to be executed before the Commission issues a ruling on the 2026 IRP.
21 The Goose substation is connected to the 345 kV system by folding the Gosling-
22 Comstock Meadows 345 kV line and the construction of the Walker River-Goose-
23 Mackay-Walker River 525 kV line which is described and requested below. The
24 large load requires a set of two (2) 525/345 kV 1,500 MVA transformers banks,
25 and the applicant requires redundant power delivery for future HVD customers via
26 345 kV HVD lines from Goose.

- 1 **31. Q. PLEASE DESCRIBE MACKAY 525/345 kV SUBSTATION.**
- 2 A. The new Mackay 525/345 kV substation is incorporated into the area transmission
3 master plan. Mackay is required to provide service to a customer with a Rule 9
4 agreement Master Planned Community (MPC) signed for 1,215 MW, of whose
5 HVD customers are expected to execute their rule 9 agreements prior to the
6 Commission making a ruling on the 2026 IRP. The Mackay was previously
7 approved and now it is required to construct three (3) 525/345 kV 600 MVA
8 transformers to accommodate the load additions. The need for additional
9 transmission capacity will require the Walker River – Goose – Mackay – Walker
10 River 525 kV lines described below.
- 11
- 12 **32. Q. PLEASE DESCRIBE WALKER RIVER-GOOSE-MACKAY-WALKER**
13 **RIVER 525 kV LINES.**
- 14 A. The new Mackay and Goose 525/345 kV substation loads are so large that they
15 require redundant 525 kV transmission because the underlying 345 kV system is
16 not sufficient in N-1 scenarios. Mackay and Goose are required to provide service
17 to a customer with a signed Rule 9 agreement Master Planned Community (MPC)
18 for the combined total of 2,025 MW. This large load will require the Walker River
19 – Goose – Mackay – Walker River 525 kV lines to be constructed.
- 20
- 21 **33. Q. PLEASE DESCRIBE SPRING CANYON 230/12 kV SUBSTATION.**
- 22 A. Spring Canyon Substation with three 230/12 kV 37 MVA transformers is required
23 in summer 2028. Spring Canyon 230/12 kV Substation is an area upgrade project
24 to source several Master Planned Community agreements (MPC) in the Eldorado
25 Valley area. The Eldorado Valley is a growing commercial and industrial center in
26 southern Henderson, Nevada. The Companies have received requests totaling 74.1

1 MVA for service in Eldorado Valley from warehousing, manufacturing, data
2 centers, and mixed development customers. The Eldorado Valley area is currently
3 being served from the 69/12 kV 88 MVA Mission Substation, which is fully
4 contracted, with no available capacity. Greenway Substation can support
5 approximately 30 MVA of load growth but is eight miles from the proposed Spring
6 Canyon site, which creates an entry barrier for customers due to line extension cost
7 and feeder route permitting time. Active projects justifying construction of Spring
8 Canyon Substation include 3010885444 – Eldorado Industrial, requested in-service
9 date: November 29, 2024, 5.7 MVA; 3010833586 – Panattoni Eldorado Valley
10 Master Plan, requested in-service date: December 1, 2026, 31.1 MVA; 3010047083
11 – WDA Innovative Park at Eldorado Master Plan, requested in-service date:
12 December 1, 2026, 37.3 MVA. Two Master Planned Umbrella (“MPU”)
13 agreements have been executed. The manufacturers of transformers of this size are
14 quoting a lead time approaching three years.

15
16 **34. Q. PLEASE DESCRIBE SCORPION 230 kV SWITCHING STATION.**

17 A. It is now required to install the Scorpion 345 kV switching station which is required
18 to serve a Rule 9 customer 350 MW HVD agreement which is expected to be
19 executed before the Commission issues a ruling on the 2026 IRP. The customer
20 will take redundant power delivery from two (2) 230 kV HVD lines from the
21 Scorpion switching station. Scorpion is connected to the 230 kV system by folding
22 the Mead-Arden 230 kV line.

1 **SECTION III – DIFFERENCES BETWEEN PROJECTS AS STUDIED AND**
2 **PROJECTS AS REQUESTED FOR APPROVAL**

3 **35. Q. PLEASE DESCRIBE THE TRANSMISSION COSTS USED FOR**
4 **RESOURCE EVALUATION PURPOSES IN THE ECONOMIC ANALYSIS.**

5 A. The IRP selection process required initial estimates of transmission costs
6 associated with the specific generation projects, for evaluation purposes. The
7 Transmission System Planning department prepared the estimates as requested for
8 this purpose. The estimates were based on standalone preliminary transmission
9 steady state models, which means that the standalone transmission system models
10 added each potential generator and included none of the other potential generators.
11 This assumption was necessary because it is not possible to predict what
12 combination of generators would be selected and, importantly, in what order they
13 would be requesting transmission service, in any set of resource plans. Based on
14 the results of the initial transmission study network, upgrades were identified and
15 the initial cost estimates were calculated as a summation of the costs of the network
16 upgrades. It was known when the initial generator transmission cost estimates were
17 calculated that they were not complete because multiple generators were
18 anticipated to be selected in each case and plan. The exact combination of
19 generators selected and the order they were to be submitted as Designated Network
20 Resources (DNR) would change the network upgrades required.
21
22
23
24
25
26
27

1 36. Q. DESCRIBE THE TRANSMISSION COSTS USED IN THE REQUESTS
2 FOR APPROVALS (DESIGNATED NETWORK RESOURCES (DNR)
3 REQUESTS).

4 A. As part of the Federal Energy Regulatory Commission jurisdictional OATT defined
5 process, the Preferred Plan’s resources have now been requested as DNRs, and the
6 system impact studies (SIS) for each DNR have been conducted. The DNR SIS
7 results are reflected in the Transmission Section and Joint Application Prayer for
8 Relief of this 2026 Joint IRP. The capital expense recovery (CER) calculation for
9 each plan was developed using the initial transmission cost estimates, whereas the
10 Prayer for Relief in the Joint Application reflects the DNR SIS cost estimates.

11
12 Despite the differences between the DNR SIS cost estimates and the costs modeled
13 in the Economic Analysis, it was determined, based on the alternative plans
14 evaluated, that the differences between the DNR SIS results and the initial estimates
15 would not have a material impact on the selection of the Preferred Plan.

16
17 37. Q. DESCRIBE THE TRANSMISSION SERVICES REQUEST QUEUE’S
18 EFFECT ON TRANSMISSION COSTS ASSIGNED TO THE
19 RESOURCES?

20 A. Transmission service rights are granted in the order they are requested. As such,
21 network upgrades are assigned to the first project that identified them as required.
22 Although, importantly, subsequent requests may also require the same network
23 upgrades. This tends to make a particular project look less attractive than the
24 subsequent resource. This conclusion can be misleading. If the prior queued project
25 is not selected, the network upgrades would simply become required for the
26 subsequent resource in that region. When a particular network upgrade is required

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

for subsequent requests, it is called a contingent facility. If the prior request was to be withdrawn, cost responsibilities or security requirements would become the responsibility of the subsequent requests that require it. This principle applies to generator interconnection agreements, transmission interconnection, and transmission service agreements.

38. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT MAXFIELD-DIRECT-1

Statement of Qualification

Layne M. Maxfield

My name is Layne M. Maxfield, I have 22 years of experience in the power industry. I have been the Manager of Transmission System Planning (TP) for NV Energy for the past four years. My direct reports include the transmission planning engineers who perform the system impact studies for generator interconnections, transmission service and associated facilities studies. TP conducts the recurring compliance studies according to the North American Electric Reliability Corporation (NERC) standards including TPL-001. TP is also responsible for the transmission to transmission interconnection studies. TP maintains transmission area master plans that are based on the customer load forecast and future transmission needs. I have prepared the transmission narrative for the 2024 integrated resource plan (IRP) and three (IRP) amendments. Also, I have created business practices for interconnection customers and transmission reliability standards for the Companies. I am responsible for coordinating transmission system planning efforts with all the Companies departments and outside entities.

From 2020 to 2021, I was a Senior and Senior II, Transmission Planning Engineer for PacifiCorp and then the Companies. I was Responsible for system impact studies for transmission service requests. I created Western Electric Coordinating Council (WECC) system models. I was the lead planner for the Companies large generator interconnection cluster studies required under the Open Access Transmission Tariff (OATT), which is FERC jurisdictional. During which time the interconnection queue at NV Energy nearly doubled in size. I was a contributor to the annual NERC TPL-001 study.

From 2013 to 2020, I was the technical advisor to PacifiCorp's Project Management Office (PMO), titled as a Commissioning Engineer. Wherein I supported the project managers in Idaho, Utah, and Wyoming. I managed the construction contractors' outages, developed construction sequence plans for major projects, coordinated construction between internal construction crews, contract construction crews, operations, control centers, reviewed all commissioning documents for the electrical equipment and ultimately authorized energization of new equipment. I was the primary contributor to the update of the Rocky Mountain Power's Grounding Safety Procedure Manual. I received a Project Management Professional (PMP) certification from Project Management Institute (PMI).

From 2007 to 2013, I was the engineering department head at the City of Idaho Falls power division. Annually, I created the ten year capital plans for the municipal electrical utility. I was the technical witness to the city council regarding the utilities' capital projects. I was a presenter for transmission siting public outreach meetings and stake holder meetings. I participated in the recertification of the Gem State hydro project with FERC. I was the project manager for the following projects: a 161 kV transmission line in the siting phase, generator protection relay upgrades, substation protection relay upgrades, transformer maintenance, new substations, cable replacement and rejuvenation, distribution system master planning, and the 4 kV to 12 kV voltage conversion projects retiring four substations. I lead the team to develop the utilities first distribution system model. I was a lead contributor in a Department of Energy (DOE) funded smart grid demonstration projects, which included auto-restoration which leveraged the new smart meter communication infrastructure, among other pilot projects. I managed the field engineers and the inspectors, wherein I reviewed distribution designs and line extension estimates. I also developed construction standards and transitioned the utility to construction material assemblies to aid the efficiency of engineering, procurement, warehouse, and construction. I procured engineering service contracts for large projects. I wrote equipment specifications for equipment procurements. I

attained an Idaho Professional Engineer License and trained my direct reports who were field engineers and inspectors.

In 2007, I was promoted internally to the System Engineer for Overton Power District #5 wherein I created the distribution system master plans. I also Managed the creation of the first distribution system model from GIS data. I was the project manager of new substations which entailed managing and reviewing outside engineering contractor's work. Also, I Performed studies to verify distribution system performance and planned the corrective system mitigations as necessary. I completed substation engineering certification training at the University of Wisconsin - Milwaukee. I completed the Northwest Public Power Association staking engineering training, which entail distribution system design and standards.

In 2004 to 2007, I was a Field Engineer at Overton Power District #5, where I served our customers by engineering the line extension plans and line extension estimates. I would then coordinate the customer payments with procurement to secure long lead time materials and authorize construction after customer payments were received.

I received a bachelor's degree in electrical engineering from the University of Nevada Las Vegas in 2004.

I received a professional engineering license in electrical engineering in the State of Idaho in 2008.

I am currently enrolled in a Master of Business Administration program from Western Governors University, with expected graduation in January of 2027.

AFFIRMATION

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Pursuant to the requirements of NRS 53.045 and NAC 703.710, LAYNE M. MAXFIELD, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026



Layne M. Maxfield

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

SEAN SPITZER

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26-05 ____

Prepared Direct Testimony of

Sean Spitzer

**1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS
AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

A. My name is Sean Spitzer. I am the Director of Renewable Energy and Origination for Sierra Pacific Power Company d/b/a NV Energy (“Sierra”) and Nevada Power Company d/b/a NV Energy (“Nevada Power” and, together with Sierra, the “Companies”). My business address is 7155 S. Lindell Road in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

**2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE
UTILITY INDUSTRY.**

A. I graduated from California State University, Chico, with a Masters in Environmental Science in 2011 and a Bachelor of Science in Environmental Studies from University of California, Santa Barbara, in 2006. I have more than 15 years of experience in the energy industry. Before joining the Companies, I worked for General Electric (GE Hitachi Nuclear Energy), and Clean Harbors Environmental Services.

My statement of qualifications is attached as **Exhibit Spitzer-Direct-1**.

1 3. Q. **WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**
2 **CURRENT POSITION?**

3 A. In my current role, I serve as the Director of Renewable Energy and Origination.
4 My responsibilities include procurement and contract negotiations for renewable
5 and non-renewable energy resources, building a clean energy project portfolio and
6 ensuring new opportunities align with policy and financial goals. I lead and
7 collaborate with a team responsible for long term energy and capacity procurement
8 for the Companies. This includes planning and executing competitive solicitations
9 for new energy resources, evaluating proposals, negotiating power purchase
10 agreements (“PPAs”) or build-transfer agreements, and coordinating internally
11 with planners, engineers, and analysts to integrate new resources into the
12 Companies’ portfolio. I am also involved in ensuring that our resource procurement
13 strategy aligns with Nevada’s Renewable Portfolio Standard (“RPS”) compliance
14 and the Companies’ goal of achieving carbon reduction targets.

15
16 4. Q. **HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
17 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
18 **(“COMMISSION”)?**

19 A. Yes. Most recently, I provided written testimony in the First Amendment to the
20 Companies’ 2024 Joint Integrated Resource (“IRP”) Plan , Docket No. 25-10028.

21
22 5. Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

23 A. The purpose of my testimony is to sponsor the Companies’ Renewables Section of
24 the Supply Plan to the 2026 Joint Triennial Integrated Resource Plan (“2026 Joint
25 IRP”). Specifically, I present 23 long-term PPAs for approval. I describe the
26 differences between the renewable and storage projects as studied in the economic
27

1 analysis and as requested for approval, as described in the Additional Studies and
2 Information subsection of the Economic Analysis Section of the Narrative.
3 Additionally, I provide an update on the Valmy geothermal resources.
4

5 **6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

6 A. I am sponsoring the following Exhibits:

- 7 • **Exhibit Spitzer-Direct-1** - Statement of Qualifications
- 8 • **Exhibit Spitzer-Direct-2** - Sponsored Technical Appendices
- 9 • **Exhibit Spitzer-Direct-3** - Technical Appendices of Confidential Due
10 Diligence
- 11 • **Exhibit Spitzer-Direct-4** - Technical Appendices of PPAs with
12 Confidential Exhibits
- 13 • **Exhibit Spitzer-Direct-5** - Technical Appendices of NAC-NRS
14 Compliance
- 15 • **Exhibit Spitzer-Direct-6** - Technical Appendices of Key Provisions

16
17 I am sponsoring all of the Renewable (REN) Technical Appendices as listed in my
18 Exhibits Spitzer-Direct-2 through Spitzer-Direct-6 and co-sponsoring the following
19 Technical Appendix:

- 20 • **ECON-10** – Candidate Resources – Redacted

21
22 **7. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING**
23 **CONFIDENTIAL?**

24 A. Yes. The Technical Appendices listed in Exhibit Spitzer-Direct-3 - Technical
25 Appendices of Confidential Due Diligence are confidential as they contain
26 summaries of the Companies' due diligence review of the projects which, if
27

1 publicly disclosed, could provide an unfair market advantage to competitors by
2 showing the Companies' internal analysis of projects. Confidentiality of the
3 Companies' technical evaluation of projects is essential to future successful
4 negotiations and competitive solicitations to obtain the best value on behalf of the
5 Companies' customers.

6
7 Additionally, the Technical Appendices listed in Exhibit Spitzer-Direct-4 -
8 Technical Appendices of PPAs with Confidential Exhibits contain targeted
9 redactions. These PPAs contain an Approved Contractors List exhibit which has
10 been redacted from the publicly filed versions. The exhibit contains commercially
11 sensitive information disclosure of which may negatively affect the Companies and
12 their contractual counterparties.

13
14 Technical Appendices REN-24 and REN-26 are also confidential. Technical
15 Appendix REN-24 contains project proposal pricing submitted to the Companies,
16 and Technical Appendix REN-26 provides the results of the Companies' scoring of
17 the 2024 All-Source Requests for Proposals ("2024 RFP") bids received.
18 Disclosure of confidential cost and bid information contained in Technical
19 Appendices REN-24 and REN-26 could negatively impact the Companies' ability
20 to obtain competitive offers from bidders in the future and deliver the best value to
21 the Companies' customers.

22
23 Technical Appendix ECON-10 includes Renewable Candidate Resources and
24 Storage Candidate Resources. These confidential technical appendix contains
25 commercially sensitive and/or trade secret information that derives independent
26 economic value from not being generally known. This information discloses the
27

1 Companies' views and expectations of the relevant markets and its future
2 procurement opportunities. This information is not known outside the Companies
3 and its distribution is limited within the Companies. Releasing this highly sensitive
4 information would disadvantage the Companies and their customers by limiting
5 their ability to foster competition among prospective suppliers, compromising the
6 Companies' negotiating position and reducing bargaining leverage. Publication of
7 this information would unfairly advantage competing suppliers and impair the
8 Companies' ability to achieve the most favorable pricing and terms and conditions
9 from suppliers on behalf of their customers.

10
11 **8. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL**
12 **TREATMENT OF THIS INFORMATION?**

13 A. The requested period for confidential treatment is five years.

14
15 **9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE**
16 **COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR**
17 **THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER**
18 **PROTECTION ("BCP") TO FULLY INVESTIGATE THE INFORMATION**
19 **SET FORTH IN THIS FILING?**

20 A. No, in accordance with the accepted practice in Commission proceedings, the
21 confidential material will be provided to Staff and the BCP under standardized
22 protective agreements.

23
24 **10. Q. HOW IS YOUR TESTIMONY ORGANIZED?**

25 A. In section II, I describe the Companies' 2024 All-Source Request for Proposals
26 ("2024 RFP") process, evaluation and selection of bid proposals. In section III, I
27

1 describe the general characteristics of the PPAs sought for approval. In sections IV
2 through XXI, I discuss the Companies’ request for approval of each of the 23 PPAs
3 individually. Specifically, I address:

- 4 1. The description;
- 5 2. The project-specific benefits;
- 6 3. The price competitiveness; and
- 7 4. The reason for bringing the PPAs forward.

8 Finally, in section XXII, I briefly discuss the Companies’ update on the Valmy
9 geothermal resources.

10
11 **II. 2024 ALL-SOURCE RFP**

12 **11. Q. WHY WAS THE 2024 ALL-SOURCE RFP ISSUED?**

13 A. The Companies issued the 2024 RFP with the intent of securing proposals for the
14 acquisition of long-term dispatchable energy and energy storage resources to
15 support various objectives including system needs and RPS compliance.

16
17 **12. Q. PLEASE DESCRIBE THE 2024 ALL-SOURCE RFP.**

18 A. The 2024 RFP was launched in November, 2024, and concluded in February, 2026.
19 The protocol requested utility-scale projects of at least 20 megawatts (“MWs”) in
20 size that could reach commercial operation on or before December 31, 2030. The
21 Companies also requested proposals to purchase and develop its Amargosa Solar
22 project and its Sierra Solar Phase II project. The Companies received 198 total bids
23 in the 2024 RFP, including a total of 73 unique project sites proposed from 34
24 counterparties. The bids represented nearly 15 GW of generating resources and
25 over 21 GW of storage, from multiple technologies including geothermal,
26
27

1 photovoltaic solar, wind, conventional thermal generation, and energy storage
2 systems.

3
4 During the 2024 RFP evaluation period, and in anticipation of a change in law
5 regarding the tax credits available for wind, solar, and energy storage technologies
6 such as battery energy storage systems (“BESS”), the Companies collected updated
7 bid pricing that reflected the assumption that no tax credits are available to proposed
8 projects, dubbed “cap pricing”. Separately, and after the passage of the One Big
9 Beautiful Bill Act (“OBBBA”), the Companies also requested bidders to describe
10 their strategies implemented to “safe harbor” equipment and maximize tax credit
11 eligibility for each of the project bids.

12
13 **13. Q. PLEASE DESCRIBE THE INITIAL EVALUATION OF RFP BIDS.**

14 A. As described in the protocol, the bids were initially scored and ranked based on a
15 combination of price, non-price, and economic benefits to the State of Nevada. The
16 due diligence evaluation included: (1) Status and timing of interconnection and
17 feasibility of available transmission capacity on the timeline of the project’s
18 intended COD, (2) Evaluation of site control, (3) Status of material permits, (4)
19 Review of material equipment for bankability and performance, (5) Determination
20 of whether the project development milestone schedule supports contractual COD,
21 (6) Scope and extent of material exceptions to the pro forma agreement—
22 particularly for revisions to terms that shift risk from the developer to the
23 Companies’ customers such as by granting relief to project underperformance
24 and/or excused delays to critical project milestones, (7) Evaluation of development
25 and operating experience of the developer, (8) Evaluation of the developer’s
26 financial capability, (9) Evaluation of developer’s jobsite safety performance
27

1 history, (10) Evaluation of the available water supply, and (11) Levelized price
2 evaluation.

3
4 Bids that were determined to have a fatal flaw, such as lack of available
5 transmission capacity prior to the project’s intended COD, were removed from
6 consideration. For each generating or storage proposal, the Companies calculated a
7 Levelized Cost of Energy (“LCOE”) or a Levelized Cost of Storage (“LCOS”),
8 respectively. Based on the weighted scores, an initial shortlist was developed for
9 each technology type. A copy of the 2024 RFP Bid Score Summary is provided in
10 Confidential Technical Appendix REN-26.

11
12 **14. Q. PLEASE DESCRIBE THE FINAL SHORTLIST SELECTION PROCESS.**

13 A. As discussed in the Renewables Section of the Supply Plan, the Companies were
14 presented with unique challenges to the bid selection process at a junction very late
15 into the 2024 RFP timeline. Significant changes in law and federal policy arose
16 primarily in the third quarter of 2025, affecting most solar and energy storage
17 projects’ tax credit eligibility and certainty of project permitting schedules. Thus,
18 most of the Companies’ completed project evaluations were undermined by these
19 sweeping changes. To adapt to changing circumstance and secure viable projects
20 that best mitigate the newly introduced risks, the Companies focused on selecting
21 projects that were deemed viable based on due diligence reviews and 1) Were
22 located entirely on private land or otherwise were not subject to the Department of
23 Interior (“DOI”) memorandum setting the new DOI review policy (“DOI Review
24 Policy Memorandum”) (e.g. geothermal, and standalone BESS), 2) Were solar and
25 BESS projects sited on private land with minimal federal nexus (e.g. access road,
26 generation tie line, etc.), 3) Supported a near term need particularly in northern
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Nevada as discussed in the Economic Analysis Section of the Narrative, and 4) Conveyed a safe harbor strategy that positioned the projects to secure tax credit eligibility.

15. Q. PLEASE DESCRIBE ANY ADDITIONAL ANALYSES CONDUCTED ON THE SHORTLISTED BIDS.

A. The Economic Analysis Section describes the creation of cases and plans using a list of potential projects that includes the shortlisted bids. The Preferred Plan includes all shortlisted projects. The Preferred Plan (Obsidian) is described in the Economic Analysis.

III. GENERAL CHARACTERISTICS OF PPAs REQUESTED FOR APPROVAL

16. Q. PLEASE EXPLAIN HOW THE COMPANIES ORIGINATED EACH PPA.

A. Sixteen of the PPAs were originated from the Companies' 2024 RFP process:

- Amargosa Energy Center (Phase 1);
- Amargosa Energy Center (Phase 2);
- Castor Storage;
- Commerce Station Energy Storage;
- Coyote Energy 1;
- Dry Lake East Energy Storage II;
- Jersey Valley Solar and Storage;
- Lux Solar Center;
- NGP Blue Mountain Third Amendment;
- Sleepy Orange
- Southern Bighorn 1;
- Southern Bighorn 2;

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

- Trego Grid;
- White Pine Solar;
- Winston Solar - LG Facility; and
- Winston Solar - MK Facility

Three of the PPAs were the result of bilateral discussions between the Companies and the project developers:

- Boulder Solar III;
- Fish Springs Ranch Energy Storage; and
- Libra Solar and Storage Project Third Amendment

Four of the PPAs are sleeved PPAs associated with customer agreements:

- Hot Pot Energy Center;
- Iron Point Energy Center;
- Nevada Geothermal Portfolio (OKGP); and
- North Nevada Geothermal Portfolio

17. Q. WHAT ARE THE BENEFITS THAT THE PPAs WILL PROVIDE TO THE COMPANIES, THEIR CUSTOMERS, AND THE STATE OF NEVADA?

A. The projects that the PPAs represent will provide many benefits, such as helping to reduce the Companies' open capacity position, and reduce reliance on power market purchases. These projects are capable of providing grid-supporting ancillary services such as primary frequency response and voltage support, strengthening reliability. The generating resources for bundled-load customers will provide valuable renewable energy credits to support the state's RPS and help meet customer demands for sustainable energy. Nevada's economy will see a number of economic benefits from the approval of these projects. A complete listing of the

1 economic benefits from the projects in accordance with Nevada Administrative
2 Code (“NAC”) § 704.8887(2) and Nevada Revised Statutes (“NRS”) §
3 704.741(4)(b)(8) is presented in the respective Technical Appendices listed in
4 Exhibit Spitzer-Direct-5 - Technical Appendices of NAC-NRS Compliance, and a
5 summary of net economic benefits including jobs and payroll estimates provided
6 by the developers of each proposed project is provided in Technical Appendix
7 REN-25.

8
9 **18. Q. WHAT KEY PROVISIONS HAVE THE COMPANIES NEGOTIATED IN**
10 **THE PPAs?**

11 A. Each of the projects are nuanced, requiring thoughtful consideration and discourse
12 with the counterparties to arrive at agreeable terms. The Companies worked closely
13 with developers to craft numerous creative solutions in the agreements to mitigate
14 risk of project non-delivery. A list of the Technical Appendices summarizing the
15 key provisions for each of the PPAs is provided in Exhibit Spitzer-Direct-6 -
16 Technical Appendices of Key Provisions.

17
18 **19. Q. PLEASE COMMENT ON THE EVALUATION OF THE PPAs.**

19 A. The Companies completed technical and pricing due diligence for all the projects.
20 Scoring of all the bids is provided in Technical Appendix REN-26. The non-pricing
21 due diligence summaries for all contracted PPAs are included in the respective
22 Confidential Technical Appendices listed in Exhibit Spitzer-Direct-3 - Technical
23 Appendices of Confidential Due Diligence .

1 20. Q. PLEASE DESCRIBE ANY ADDITIONAL ANALYSIS CONDUCTED FOR
2 THE PPAs.

3 A. The Resource Planning group conducted an economic analysis that included the
4 PPAs. The analysis is described in the Economic Analysis Section.

5
6 21. Q. PLEASE DESCRIBE ANY DIFFERENCES BETWEEN PROJECTS AS
7 STUDIED AND PROJECTS AS REQUESTED FOR APPROVAL.

8 A. As described in the Additional Studies and Information subsection of the Economic
9 Analysis, PPA updates were made after the economic analysis was substantially
10 complete for this 2026 Joint IRP. The Resource Planning group conducted an
11 economic analysis in which the PPAs were studied with the following differences:

- 12 • The Lux Solar Center PPA contains a provision that allows the project size
13 of the facility to be reduced from 125 MW solar PV and 125 MW BESS to
14 121 MW solar PV and 121 MW BESS, with a corresponding price increase
15 of the solar PV energy from \$55.95 per MWh to \$57.97 per MWh. This
16 project was studied at 125 MW PV and 125 MW BESS.
- 17 • The Winston Solar MK Facility PPA contains a provision that allows the
18 project size of the solar PV facility to be reduced up to 100 MW, bringing
19 the total size of the Winston Solar facility down to no less than 300 MW
20 solar PV while maintaining the size of the 400 MW BESS, and causing no
21 changes to the solar PV price per MWh. This project was studied at 400
22 MW PV and 400 MW BESS.
- 23 • The Amargosa Energy Center (Phase 1) PPA and the Amargosa Energy
24 Center (Phase 2) PPA each contain a provision that allows the solar PV
25 energy to be reduced from \$68.47 per MWh to \$35.47 per MWh, if either
26 or both phases of the project reach their intended COD on or prior to
27

1 December 31, 2030. This provision was not captured in the economic
2 analysis.

- 3 • The Nevada Geothermal Portfolio (OKGP) PPA contains a provision that
4 allows the final size of the combined geothermal facility capacity to be up
5 to 150 MW, with no changes to the price per MWh. This provision was not
6 captured in the economic analysis, where it was studied as a 50 MW project.
- 7 • The Jersey Valley Solar and Storage PPA contains a provision requiring
8 COD to be achieved on January 10, 2028. It was studied with a COD of
9 November 29, 2027.
- 10 • The Boulder Solar III PPA requires that the price of the solar PV energy is
11 \$49.95 per MWh. It was studied at a price of \$51.30 per MWh.
- 12 • The Libra Solar and Storage Third Amendment PPA contains a provision
13 requiring that the term of the additional 200 MW BESS capacity will begin
14 on January 1, 2048. This contract change with impact starting in 2048 was
15 not evaluated.

16
17 **III. AMARGOSA ENERGY CENTER (PHASE 1) AND (PHASE 2) PPAs**

18 **22. Q. PLEASE DESCRIBE THE AMARGOSA ENERGY CENTER (PHASE 1)**
19 **AND (PHASE 2) PPAs.**

20 A. Nevada Power is requesting approval of the Amargosa Energy Center (Phase 1)
21 and (Phase 2) PPAs, together referred to as the Amargosa Energy Center PPAs,
22 being developed by Longroad Energy, through a subsidiary named AV Energy
23 Center, LLC. The PPAs represent two equal project phases that when combined are
24 for a 1,200 MW solar facility paired with a 1,200 MW, four-hour BESS, capable
25 of providing 4,800 MWh of dispatchable energy and capacity. The project is
26 located on approximately 7,226 acres near the town of Amargosa, in Nye County,
27

1 Nevada, on U.S. Bureau of Land Management (“BLM”) land previously studied
2 for large-scale energy development within the BLM-designated Amargosa Valley
3 Solar Energy Zone. The COD is planned for December 31, 2030, and the term of
4 the PPA is 25 years for the solar and 20 years for the BESS. A copy of the two
5 PPAs are provided as Technical Appendices REN-3-AEC(a)(1) and REN-3-
6 AEC(a)(2).

7
8 These PPAs resulted from the Companies’ solicitation in the 2024 RFP for
9 proposals to purchase and develop their Amargosa Solar project assets. The PPAs
10 include a provision that will allow for a downward price adjustment mechanism to
11 pass through the tax credit savings if either or both project phases is ultimately able
12 to qualify for and claim the solar tax credit. The two PPAs are nearly identical,
13 with a distinction that Amargosa Energy Center (Phase 2) PPA contains a provision
14 to address delays associated with the delivery of major equipment, given the
15 physical logistics associated with equipment deliveries at the scale and magnitude
16 of the 1,200 MW resource.

17
18 **23. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE AMARGOSA**
19 **ENERGY CENTER PROJECT THAT SUPPORTED ITS SELECTION?**

20 A. The Amargosa project is needed for several reasons: 1) It has been a named
21 placeholder resource for energy and renewable portfolio credits (“PCs”) in the
22 Companies’ 2024 Joint IRP filing and therefore its energy and credits have been
23 planned to stay within the Companies’ service territory to serve the Companies’
24 customers, 2) The Companies have reserved transmission capacity for Amargosa
25 and have established the facility as a Designated Network Resource (“DNR”), 3)
26 Its value has been vetted through a competitive solicitation open to all developers
27

1 to participate in bidding a proposal for the Amargosa project, and 4) The project
2 details and risks are known to the Companies, providing streamlined due diligence
3 review.

4
5 **24. Q. IS THE PRICE FOR THE AMARGOSA ENERGY CENTER PPA**
6 **COMPETITIVE?**

7 A. Yes. Amargosa Energy Center PPAs' energy price for the solar is fixed at \$68.47
8 per megawatt-hour ("MWh") for the 25-year term, and the BESS rate is fixed at
9 \$12,340 per megawatt-month ("MW-month") for a 20-year term. The Companies
10 calculated a hybrid LCOE of \$130.78 per MWh under the worst-case conservative
11 pricing assumptions. However, as discussed in the Renewables Section of the
12 Supply Plan, if either or both PPAs are ultimately able to achieve COD such that
13 they are eligible to claim the solar tax credits, the price of the solar energy will be
14 reduced, resulting in additional savings that will be passed on to the Nevada
15 Power's customers for the remaining contract term. As shown in Table REN-2 in
16 the Renewables Section, this proposal represents the lowest LCOE of all the viable
17 Amargosa Solar project bids.

18
19 **IV. BOULDER SOLAR III PPA**

20 **25. Q. PLEASE DESCRIBE THE BOULDER SOLAR III PPA.**

21 A. Nevada Power is requesting approval of the Boulder Solar III PPA, being developed
22 by Hanwha Renewables, through a subsidiary named Boulder Solar III, LLC. The
23 PPA is for a 127.9 MW solar facility paired with a 127.9 MW, four-hour BESS,
24 capable of providing 511 MWh of dispatchable energy and capacity. The project is
25 located on approximately 1,050 acres in Nevada Power's service territory in
26 Boulder City, Clark County, Nevada, on land specifically designated for large-scale
27

1 energy development within the Eldorado Valley Energy Zone. The COD is planned
2 for June 30, 2028, and the term of the PPA is 25 years for the solar and 25 years for
3 the BESS, however, the guaranteed capacity of the BESS will reduce from 128 MW
4 to 32 MW in contract years 21-25. A copy of the PPA is provided as Technical
5 Appendix REN4-BS3(a).

6
7 This PPA represents the third iteration of the Boulder Solar III project for the
8 Commission’s review; the previous Boulder Solar III PPA for a 127.9 MW solar
9 and 127.9 MW BESS resource approved in Docket No. 24-05041, was terminated.

10
11 **26. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE BOULDER SOLAR**
12 **III PROJECT THAT SUPPORTED ITS SELECTION?**

13 A. The Boulder Solar III project can deliver energy in Nevada Power’s system in the
14 summer of 2028, helping address systemwide open capacity needs and peak energy
15 demand. Boulder Solar III utilizes existing infrastructure, sharing a generation tie
16 line and interconnection facilities with the Boulder Solar II and Boulder Solar I
17 projects, which translates to minimal network upgrade costs and reduced schedule
18 risk stemming from interconnection delays. The project has received its Right-of-
19 Way from the BLM on January 23, 2026, authorizing the project to begin physical
20 construction. Thus, the risk of permitting delays associated with DOI Review
21 Policy Memorandum impacts is eliminated, and the project is well positioned to
22 reach commercial operation in time to secure the available solar tax credits and pass
23 the value on to Nevada Power’s customers for the contract term.

1 27. Q. **IS THE PRICE FOR THE BOULDER SOLAR III PPA COMPETITIVE?**

2 A. Yes. The Boulder Solar III PPA’s energy price for the solar is fixed at \$49.95 per
3 MWh for the 25-year term, and the BESS rate is fixed at \$15,460 per MW-month
4 for a 25-year term. The Companies calculated a hybrid LCOE of \$125.22 per MWh.
5 For perspective, the Companies calculated the average LCOE of other solar and
6 BESS project proposals from the 2024 RFP that were not selected using the
7 submitted cap pricing of the solar energy and found that this project’s LCOE is 20
8 percent lower in comparison. A copy of the project LCOE comparison to average
9 LCOE using solar cap pricing of non-selected solar and BESS project proposals is
10 presented in Confidential Technical Appendix REN-24.
11

12 V. **CASTOR STORAGE PPA**

13 28. Q. **PLEASE DESCRIBE THE CASTOR STORAGE PPA.**

14 A. Nevada Power is requesting approval of the Castor Storage PPA, being developed
15 by Primergy Solar through a subsidiary named Castor Storage, LLC. The PPA is
16 for a 310 MW eight-hour lithium-ion BESS, capable of providing 2,480 MWh of
17 dispatchable energy and capacity. The project is located in Clark County, Nevada,
18 within the footprint of the existing Gemini Solar facility. The COD is planned for
19 May 31, 2029, and the term of the PPA is 20 years. A copy of the PPA is provided
20 as Technical Appendix REN-5-CS(a).
21

22 29. Q. **WHAT ARE THE SPECIFIC ATTRIBUTES OF THE CASTOR STORAGE
23 PROJECT THAT SUPPORTED ITS SELECTION?**

24 A. At eight hours of capacity, the Castor Storage project will be the Companies’ first
25 long-duration BESS resource. Because it is located at the existing Gemini Solar
26 facility, it enables efficient use of previously developed site control,
27

1 interconnection capacity, and permitting approvals, thus lowering development risk
2 and cost. With an expected COD of May 31, 2029, the project is capable of adding
3 significant capacity a year earlier than any thermal units. The PPA also includes
4 minimal changes from the pro-forma agreement, ensuring elevated customer
5 protections from non-delivery and poor performance. The project will qualify for
6 tax credits, which is reflected in the pricing, passing the value on to Nevada Power’s
7 customers for the contract term.
8

9 **30. Q. IS THE PRICE FOR THE CASTOR STORAGE PPA COMPETITIVE?**

10 A. Yes. The Castor Storage PPA’s capacity price for the BESS is a fixed \$18,950 per
11 MW-month for a 20-year term. The Companies calculated an LCOS of \$103.21 per
12 MWh, the lowest amongst the 2024 RFP shortlisted bids for BESS resources. To
13 put that in perspective, as provided in Technical Appendix REN-23, this LCOS is
14 roughly 38% lower than the LCOS of the 150 MW Dodge Flat battery addition that
15 the Commission approved previously in Docket No. 25-10028.
16

17 **VI. COMMERCE STATION ENERGY STORAGE PPA**

18 **31. Q. PLEASE DESCRIBE THE COMMERCE STATION ENERGY STORAGE**
19 **PPA.**

20 A. Nevada Power is requesting approval of the Commerce Station Energy Storage
21 PPA, being developed by BayWa r.e., through a subsidiary named Commerce
22 Station Energy Storage LLC. The PPA is for 100 MW of lithium-ion BESS with 4-
23 hour storage duration, capable of providing 400 megawatt-hours (“MWh”) of
24 dispatchable energy and capacity. The BESS will be fully capable of grid charging.
25 The project is located on private land in the City of North Las Vegas, within Nevada
26 Power’s system. The COD of the resource is targeted for May 29, 2028, and the
27

1 term of the PPA is 20 years. A copy of the PPA is provided as Technical Appendix
2 REN6-CSB(a).

3
4 **32. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE COMMERCE**
5 **STATION ENERGY STORAGE PROJECT THAT SUPPORTED ITS**
6 **SELECTION?**

7 A. With an expected COD of May 29, 2028, the Commerce Station Energy Storage
8 project can achieve COD in the near term and ahead of the 2028 summer peak. The
9 PPA also includes minimal changes from the pro forma agreement, ensuring
10 elevated customer protections from non-delivery and poor performance. Commerce
11 Station Energy Storage does not require any BLM or federal approvals subject to
12 the DOI Review Policy Memorandum process, thereby mitigating schedule risk due
13 to permitting. The project will qualify for tax credits, which is reflected in the
14 pricing, passing the value on to Nevada Power’s customers for the contract term.
15 The project also requires minimal network upgrades, enhancing customer value.

16
17 **33. Q. IS THE PPA PRICE FOR THE COMMERCE STATION ENERGY**
18 **STORAGE PPA COMPETITIVE?**

19 A. Yes. The price of the Commerce Station Energy Storage BESS is a fixed rate of
20 \$13,950 per megawatt-month (“MW-month”). Additionally, the Companies
21 calculated the LCOS for the Commerce Station Energy Storage as \$139.81 per
22 MWh. As provided in Technical Appendix REN-23, this is nearly 16 percent less
23 than the most recent BESS resource presented for the Commission’s review, the
24 similarly sized 150 MW Dodge Flat BESS Addition approved in Docket No. 25-
25 10028.

1 **VII. COYOTE ENERGY 1 PPA**

2 **34. Q. PLEASE DESCRIBE THE COYOTE ENERGY 1 PPA.**

3 A. Nevada Power is requesting approval of the Coyote Energy 1 PPA, being developed
4 by Estuary Power LLC, through a subsidiary named Coyote Energy 1, LLC. The
5 PPA is for a 600 MW solar facility paired with a 600 MW, four-hour BESS, capable
6 of providing 2,400 MWh of dispatchable energy and capacity. The project is
7 located in Nevada Power’s service territory in Lincoln County, Nevada, on 8,300
8 acres of privately owned land. The COD is planned for December 31, 2030, and the
9 term of the PPA is 25 years for the solar and 20 years for the BESS. A copy of the
10 PPA is provided as Technical Appendix REN-7-CE1(a).

11
12 **35. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE COYOTE ENERGY**
13 **1 PROJECT THAT SUPPORTED ITS SELECTION?**

14 A. The Coyote Energy 1 project can deliver energy to Nevada Power’s system in 2030,
15 helping address systemwide open capacity needs. The project requires only a short
16 generation tie-line across BLM-managed land, thus the associated environmental
17 permitting risk is significantly lower than for generation resources sited
18 predominantly on BLM land. The project will qualify for tax credits, which is
19 reflected in the pricing, passing the value on to Nevada Power’s customers for the
20 contract term.

21
22 **36. Q. IS THE PRICE FOR THE COYOTE ENERGY 1 PPA COMPETITIVE?**

23 A. Yes. The Coyote Energy 1 PPA’s energy price for the solar is fixed at \$42.99 per
24 MWh for the 25-year term, and the BESS rate is fixed at \$14,930 per MW-month
25 for a 20-year term. The Companies calculated a hybrid LCOE of \$108.15 per MWh.
26 For perspective, the Companies calculated the average LCOE of other solar and
27

1 BESS project proposals from the 2024 RFP that were not selected using the
2 submitted cap pricing of the solar energy and found that this project’s LCOE is 31
3 percent lower in comparison. A copy of the project LCOE comparison to average
4 LCOE using solar cap pricing of non-selected solar and BESS project proposals is
5 presented in Confidential Technical Appendix REN-24.
6

7 **VIII. DRY LAKE EAST ENERGY STORAGE II PPA**

8 **37. Q. PLEASE DESCRIBE THE DRY LAKE EAST ENERGY STORAGE II**
9 **PPA.**

10 A. Nevada Power is requesting approval of the Dry Lake East Energy Storage II PPA,
11 being developed by NextEra Energy Resources, LLC, through a subsidiary named
12 Dry Lake East Energy Storage II, LLC. The PPA is for 150 MW of lithium-ion
13 BESS with 4-hour storage duration, capable of providing 600 MWh of dispatchable
14 energy and capacity. The BESS will be fully capable of grid charging. The project
15 is located on 48 acres of land managed by the BLM in Clark County, Nevada,
16 adjacent to the Dry Lake East facility and within Nevada Power’s system. The COD
17 of the resource is targeted for December 31, 2027, and the term of the PPA is 20
18 years. A copy of the PPA is provided as Technical Appendix REN-8-DLE2(a).
19

20 **38. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE DRY LAKE EAST**
21 **ENERGY STORAGE II PROJECT THAT SUPPORTED ITS SELECTION?**

22 A. With an expected COD of December 31, 2027, the Dry Lake East Energy Storage
23 II project can achieve COD in the near term and ahead of the 2028 summer peak.
24 Dry Lake East Energy Storage II does not require any BLM or federal approvals
25 subject to the DOI Review Policy Memorandum process, thereby mitigating
26 schedule risk due to permitting. The project will qualify for the Investment Tax
27

Credit (“ITC”), including the additional Energy Community Tax Credit Bonus of 10 percent, which is reflected in the pricing, passing the value on to Nevada Power’s customers for the contract term.

39. Q. IS THE PRICE FOR THE DRY LAKE EAST ENERGY STORAGE II PPA COMPETITIVE?

A. Yes. The price of the Dry Lake East Energy Storage II PPA is a fixed rate of \$13,930 per MW-month. Additionally, as provided in Technical Appendix REN-23, the Companies calculated the LCOS for the Dry Lake East Energy Storage II as \$146.13 per MWh. This is over 12 percent less than the most recent BESS resource presented for the Commission’s review, the similarly sized 150 MW Dodge Flat BESS Addition approved in Docket No. 25-10028.

IX. FISH SPRINGS RANCH ENERGY STORAGE PPA

40. Q. PLEASE DESCRIBE THE FISH SPRINGS RANCH ENERGY STORAGE PPA.

A. Sierra is requesting approval of the Fish Springs Ranch Energy Storage PPA, being developed by NextEra Energy Resources, LLC, through a subsidiary named Fish Springs Ranch Energy Storage, LLC. The PPA is for 75 MW of lithium-ion BESS with 4-hour storage duration, capable of providing 300 MWh of dispatchable energy and capacity. The BESS will be fully capable of grid charging. The project is located on 8.5 acres of private land in Washoe County, Nevada, adjacent to the Fish Springs Ranch Solar Energy Center facility and within Sierra’s system. The COD of the resource is targeted for December 31, 2027, and the term of the PPA is 20 years. A copy of the PPA is provided as Technical Appendix REN9-FSR(a).

1 41. Q. **WHAT ARE THE SPECIFIC ATTRIBUTES OF THE FISH SPRINGS**
2 **RANCH ENERGY STORAGE PROJECT THAT SUPPORTED ITS**
3 **SELECTION?**

4 A. With an expected COD of December 31, 2027, the Fish Springs Ranch Energy
5 Storage project can achieve COD in Sierra's territory in the near term and ahead of
6 the 2028 summer peak. The BESS will utilize existing infrastructure from the Fish
7 Springs Ranch Solar Energy Center facility, resulting in minimal interconnection
8 costs and mitigation of schedule risk due to permitting delays. Additionally, as
9 discussed in the Economic Analysis Section of the Supply Plan Narrative of this
10 filing, the near-term in service date of this resource reduces reliability risk for
11 Sierra.

12
13 Fish Springs Ranch Energy Storage does not require any BLM or federal approvals
14 subject to the DOI Review Policy Memorandum process, thereby mitigating
15 schedule risk due to permitting. The project will qualify for the ITC, which is
16 reflected in the pricing, passing the value on to Sierra's customers for the contract
17 term.

18
19 42. Q. **IS THE PRICE FOR THE FISH SPRINGS RANCH ENERGY STORAGE**
20 **PPA COMPETITIVE?**

21 A. Yes. The price of the Fish Springs Ranch Energy Storage PPA is a fixed rate of
22 \$16,550 per MW-month. Additionally, the Companies calculated the LCOS for the
23 Fish Springs Ranch Energy Storage as \$162.79 per MWh. As provided in
24 Technical Appendix REN-23, this is over 2 percent less than the most recent BESS
25 resource presented for the Commission's review, the 150 MW Dodge Flat BESS
26 Addition approved in Docket No. 25-10028.

1 **X. HOT POT ENERGY CENTER AND IRON POINT ENERGY CENTER PPAs**

2 **43. Q. PLEASE DESCRIBE THE HOT POT ENERGY CENTER AND IRON**
3 **POINT ENERGY CENTER PPAs.**

4 A. Sierra is requesting approval of the Hot Pot Energy Center PPA and Iron Point
5 Energy Center PPA, together referred to as Hot Pot and Iron Point, as part of
6 sleeved PPAs associated with customer agreements. The projects are being
7 developed by Primergy Solar, through project subsidiaries named Hot Pot Solar,
8 LLC, and Iron Point Solar, LLC, respectively. The PPAs are sleeved with customer
9 agreements for Amazon Data Services, Inc. (“Amazon”), who will receive 100%
10 of the energy and renewable energy benefits from the project. The Companies
11 expect to file the customer agreements for the Commission’s consideration in a
12 separate docket at the same time as this 2026 Joint IRP filing. The PPAs represent
13 two paired solar and BESS facilities: Hot Pot, a 350 MW solar and 350 MW BESS
14 facility, and Iron Point, a 250 MW solar and 250 MW BESS facility. When
15 combined, the resources will provide 600 MW of solar energy and 600 MW of
16 BESS capacity with a four-hour duration. The projects are located on 2,200 and
17 1,400 acres of rural land in Humboldt County, Nevada, with limited BLM land
18 crossings for access roads and transmission line segments. The CODs are planned
19 for October 31, 2029, and December 31, 2029 for Hot Pot and Iron Point,
20 respectively, each for a 20-year term for the solar and the BESS. While the projects
21 were bid into the Companies’ 2024 RFP, they were not selected due to a fatal flaw
22 determination from a lack of firm available transmission capacity when the projects
23 intend to reach their CODs. Under the PPAs, the projects, and/or Amazon, will bear
24 all risk associated with non-compensable transmission curtailments. A copy of the
25 PPAs are provided as Technical Appendices REN-10-HPE(a) and REN-11-IPE(a).

1 These PPAs represent the second iteration of the Hot Pot and Iron Point projects
2 for the Commission’s review; the previous Hot Pot and Iron Point PPAs for 350
3 MW and 250 MW solar facilities with 350 MW and 250 MW BESS resources,
4 respectively, approved in Docket No. 21-06001, were terminated.

5
6 **44. Q. ARE THE HOT POT ENERGY CENTER AND IRON POINT ENERGY**
7 **CENTER PPAs CONTINGENT UPON APPROVAL OF THE CUSTOMER**
8 **AGREEMENTS?**

9 A. Yes. In addition to the requisite approval from the Commission, the PPAs are not
10 effective until all conditions to the effectiveness of the customer agreements
11 between Sierra and Amazon, have been satisfied.

12
13 **45. Q. GIVEN THE HOT POT ENERGY CENTER AND IRON POINT ENERGY**
14 **CENTER ARE SLEEVED PPAs ASSOCIATED WITH CUSTOMER**
15 **AGREEMENTS, WHAT CUSTOMER PROTECTIONS HAS SIERRA**
16 **NEGOTIATED IN THE PPAs?**

17 A. The Hot Pot and Iron Point PPAs include several customer protections consistent
18 with the Companies’ other PPAs through various provisions such as Sierra’s ability
19 to collect damages due to termination or production shortfalls.

20
21 **46. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE HOT POT ENERGY**
22 **CENTER AND IRON POINT ENERGY CENTER PROJECTS THAT**
23 **SUPPORTED ITS SELECTION?**

24 A. While the projects were brought forward by Amazon as dedicated resources to
25 serve their load, they will enable the Companies to satisfy the customer’s load and
26 demand for clean energy and renewable energy credits during solar hours and
27

beyond. The PPAs support the quickly evolving demands of Amazon, while providing benefits to all customers, such as displacing fossil-fueled generation, adding jobs and economic benefits to the state, and strengthening grid reliability.

47. **Q. IS THE PRICE FOR THE HOT POT ENERGY CENTER AND IRON POINT ENERGY CENTER PPAs COMPETITIVE?**

A. Yes. Both Hot Pot and Iron Point PPAs' energy price for the solar is fixed at \$36.00 per MWh and the BESS is a fixed rate of \$13,250 per MW-month, for the 20-year term. The Companies calculated a hybrid LCOE of \$105.31 per MWh for Hot Pot and \$107.92 per MWh for Iron Point. However, because the PPAs are part of sleeved customer agreements with Amazon, pricing was not a deciding factor in the bilateral negotiations.

XI. **JERSEY VALLEY SOLAR AND STORAGE PPA**

48. **Q. PLEASE DESCRIBE THE JERSEY VALLEY SOLAR AND STORAGE PPA.**

A. Sierra is requesting approval of the Jersey Valley Solar and Storage PPA, being developed by Ormat Technologies Inc. through a subsidiary named ORNI 45, LLC. The PPA is for a 67 MW solar facility paired with a 67 MW, four-hour BESS, capable of providing 268 MWh of dispatchable energy and capacity. The project is located in Sierra's service territory in Lander County, Nevada, on private land owned by the project. The COD is planned for January 10, 2028, and the term of the PPA is 25 years for the solar and 20 years for the BESS. A copy of the PPA is provided as Technical Appendix REN-12-JVS(a).

1 49. Q. **WHAT ARE THE SPECIFIC ATTRIBUTES OF THE JERSEY VALLEY**
2 **SOLAR AND STORAGE PROJECT THAT SUPPORTED ITS**
3 **SELECTION?**

4 A. The Jersey Valley Solar and Storage project is one of the very few bids received in
5 the 2024 RFP involving generating resources that are located entirely on private
6 land, including site access roads and generation tie-line routes. Thus, the risk of
7 permitting delays associated with DOI Review Policy Memorandum impacts is
8 eliminated, and the project is well positioned to reach COD in time to secure the
9 available solar tax credits and pass the value on to Sierra’s customers for the
10 contract term. The project also requires minimal network upgrades, enhancing
11 customer value. Additionally, as discussed in the Economic Analysis Section of the
12 Supply Plan Narrative of this filing, the near-term in service date of this resource
13 reduces reliability risk for Sierra.

15 50. Q. **IS THE PPA PRICE FOR THE JERSEY VALLEY SOLAR AND STORAGE**
16 **PPA COMPETITIVE?**

17 A. Yes. The Jersey Valley Solar and Storage PPA’s energy price for the solar is fixed
18 at \$34.65 per MWh for the 25-year term, and the BESS is a fixed \$18,950 per MW-
19 month for a 20-year term. The Companies calculated a hybrid LCOE of \$106.05
20 per MWh. For perspective, the Companies calculated the average LCOE of other
21 solar and BESS project proposals from the 2024 RFP that were not selected using
22 the submitted cap pricing of the solar energy and found that this project’s LCOE is
23 32 percent lower in comparison. A copy of the project LCOE comparison to
24 average LCOE using solar cap pricing of non-selected solar and BESS project
25 proposals is presented in Confidential Technical Appendix REN-24.

1 **XII. LIBRA SOLAR AND STORAGE PROJECT THIRD AMENDMENT PPA**

2 **51. Q. PLEASE DESCRIBE THE LIBRA SOLAR AND STORAGE PROJECT**
3 **THIRD AMENDMENT PPA.**

4 A. Nevada Power is requesting approval of the Libra Solar and Storage Project Third
5 Amendment PPA (“Libra Third Amendment”). This is an amendment to the current
6 Libra Solar and Storage Project (“Libra”) PPA with Nevada Power that was
7 approved in Docket No. 24-05041. The amendment will provide an additional 200
8 MW of BESS capacity in the latter 5 years of the contract term, starting in contract
9 year 21 and ending in contract year 25. This incremental BESS capacity was not
10 under contract for those contract years. The additional BESS contemplated in the
11 amendment is being developed by the project owner, SB Energy, through a
12 subsidiary named Libra Solar, LLC. The COD of the additional BESS is January 1,
13 2048, and the amendment would provide for a 5-year term, ending in 2052. A copy
14 of the PPA is provided as Technical Appendix REN-13-LSA(a).

15
16 **52. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE LIBRA SOLAR AND**
17 **STORAGE PROJECT THIRD AMENDMENT PROJECT THAT**
18 **SUPPORTED ITS SELECTION?**

19 A. The additional BESS capacity will add value to Sierra’s system. Integrating an
20 additional 200 MW of BESS in contract years 21 through 25 will add flexibility to
21 absorb additional solar energy in the latter years of the contract and mitigate
22 curtailments. As the incremental BESS will be an addition to the Libra facility at a
23 later date when it will be fully operational, it will utilize existing infrastructure,
24 resulting in no interconnection costs and mitigation of schedule risk due to
25 permitting delays. Lastly, due to discrete project cost increases experienced by the
26 developer over the past year, the contracting for the incremental BESS assures

1 delivery of the resource by providing targeted, time-limited additional BESS
2 payments that will partially offset project cost increases and allow the project to
3 continue development and reach its planned COD.
4

5 **53. Q. IS THE PRICE FOR THE LIBRA SOLAR AND STORAGE PROJECT**
6 **THIRD AMENDMENT PPA COMPETITIVE?**

7 A. Yes. The price of the Libra Solar and Storage Project Third Amendment PPA for
8 the additional BESS is at a fixed rate of \$24,260 per MW-month for the five-year
9 term. Because the payments will be made at a future time, the Companies calculated
10 the present value of the payments using Nevada Power’s Weighted Average Cost
11 of Capital (“WACC”), resulting in a net present value of \$5,088 per MW-month
12 for contract year 21 (the first year of the term). Incorporating the new BESS into
13 the project’s evaluation, the Companies calculated the hybrid LCOE for the
14 combined Libra and the Libra Third Amendment projects as \$101.46 per MWh.
15 For perspective, the Companies calculated the average LCOE of other solar and
16 BESS project proposals from the 2024 RFP that were not selected using the
17 submitted cap pricing of the solar energy and found that this project’s LCOE is 35
18 percent lower in comparison. A copy of the project LCOE comparison to average
19 LCOE using solar cap pricing of non-selected solar and BESS project proposals is
20 presented in Confidential Technical Appendix REN-24.
21

22 **XIII. LUX SOLAR CENTER PPA**

23 **54. Q. PLEASE DESCRIBE THE LUX SOLAR CENTER PPA.**

24 A. Sierra is requesting approval of the Lux Solar Center PPA, being developed by
25 Ørsted Americas, through a subsidiary named Lux Solar Center, LLC. The PPA is
26 for a 125 MW solar facility paired with a 125 MW, four-hour BESS, capable of
27

1 providing 500 MWh of dispatchable energy and capacity. The project is located in
2 Sierra's service territory in Lyon County, Nevada, on 1,100 acres of privately
3 owned land. The COD is planned for July 1, 2028, and the term of the PPA is 25
4 years for the solar and 20 years for the BESS. The PPA provides that if a
5 Conditional Use Permit from Lyon County is not obtained, the solar and BESS
6 capacity will each be reduced to 121 MWs in size, and the price of the solar resource
7 will increase slightly. This ensures that the resource can be delivered regardless of
8 the outcome of the Conditional Use Permit. A copy of the PPA is provided as
9 Technical Appendix REN-14-LSC(a).

10
11 **55. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE LUX SOLAR
12 CENTER PROJECT THAT SUPPORTED ITS SELECTION?**

13 A. The Lux Solar Center project is one of the very few bids received in the 2024 RFP
14 involving projects that are located entirely on private land, including site access
15 roads and generation tie-line routes. Thus, the risk of permitting delays associated
16 with DOI Review Policy Memorandum impacts is eliminated, and the project is
17 well positioned to reach COD in time to secure the available solar tax credits and
18 pass the value on to the Companies' customers for the contract term.

19
20 This solar and BESS resource will provide energy and capacity to Sierra's northern
21 Nevada grid before the 2028 summer peak, helping to cover the open capacity
22 needs identified for that year and beyond.

23
24 **56. Q. IS THE PRICE FOR THE LUX SOLAR CENTER PPA COMPETITIVE?**

25 A. Yes. The Lux Solar Center PPA's energy price for the solar is fixed at \$55.95 per
26 MWh for the 25-year term, and the BESS is a fixed \$18,090 per MW-month for a
27

1 20-year term. The Companies calculated a hybrid LCOE of \$135.70 per MWh. As
2 discussed above, if the Conditional Use Permit is not received, then the project size
3 is reduced to 121 MW and the price of the solar energy will be \$57.97 per MWh,
4 and the calculated hybrid LCOE in that scenario is \$143.92 per MWh. For
5 perspective, the Companies calculated the average LCOE of other solar and BESS
6 project proposals from the 2024 RFP that were not selected using the submitted cap
7 pricing of the solar energy and found that this project’s LCOE for the 125 MW
8 scenario is 13 percent lower in comparison, and 8 percent lower in the 121 MW
9 scenario. A copy of the project LCOE comparison to average LCOE using solar
10 cap pricing of non-selected solar and BESS project proposals is presented in
11 Confidential Technical Appendix REN-24.

12
13 **XIV. NEVADA GEOTHERMAL PORTFOLIO (OKGP) PPA**

14 **57. Q. PLEASE DESCRIBE THE NEVADA GEOTHERMAL PORTFOLIO**
15 **(OKGP) PPA.**

16 A. Sierra is requesting approval of the Nevada Geothermal Portfolio (OKGP) PPA,
17 being developed by Ormat Technologies (“Ormat”), through a subsidiary named
18 OKGP, LLC. The PPA is being sleeved through customer agreement for Callisto
19 Enterprises, LLC (“Callisto”), who will receive 100% of the energy and renewable
20 energy benefits from the project. The Companies expect to file the customer
21 agreement for the Commission’s consideration in a separate docket at the same time
22 as this 2026 Joint IRP filing. The PPA represents a portfolio of geothermal projects
23 that when combined will provide a minimum of 50 MW and up to a maximum of
24 150 MW of geothermal resources. The portfolio consists of up to six geothermal
25 projects located throughout northern Nevada, on land for which Ormat has secured
26 geothermal leases and associated site control. The Commercial Operation Date is
27

1 planned for December 31, 2030, and the term of the PPA is 15 years. A copy of the
2 PPA is provided as Technical Appendix REN-15-NGP(a).

3
4 **58. Q. IS THE NEVADA GEOTHERMAL PORTFOLIO (OKGP) PPA**
5 **CONTINGENT UPON APPROVAL OF THE CUSTOMER AGREEMENT**
6 **WITH CALLISTO?**

7 A. Yes. In addition to the requisite approval from the Commission, the PPA is not
8 effective until all conditions to the effectiveness of the customer agreement between
9 Sierra and Callisto, have been satisfied.

10
11 **59. Q. GIVEN THE NEVADA GEOTHERMAL PORTFOLIO (OKGP) IS A**
12 **SLEEVED PPA ASSOCIATED WITH A CUSTOMER AGREEMENT,**
13 **WHAT CUSTOMER PROTECTIONS HAS SIERRA NEGOTIATED IN**
14 **THE PPA?**

15 A. The Nevada Geothermal Portfolio (OKGP) PPA includes several customer
16 protections consistent with the Companies' other PPAs through various provisions
17 such as Sierra's ability to collect damages due to termination or production
18 shortfalls.

19
20 **60. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE NEVADA**
21 **GEOTHERMAL PORTFOLIO (OKGP) PROJECT THAT SUPPORTED**
22 **ITS SELECTION?**

23 A. While the project was brought forward by Callisto as a dedicated resource to serve
24 their load, it will enable the Companies to satisfy the customer's load and demand
25 for clean energy and renewable energy credits around-the-clock. The PPA supports
26 the quickly evolving demands of Callisto Enterprises, LLC, while providing
27

benefits to all customers, such as displacing fossil-fueled generation, adding jobs and economic benefits to the state, and strengthening grid reliability.

61. Q. IS THE PRICE FOR THE NEVADA GEOTHERMAL PORTFOLIO (OKGP) PPA COMPETITIVE?

A. Yes. Nevada Geothermal Portfolio (OKGP) PPA’s energy price for the geothermal is fixed at \$107.00 per MWh for the 15-year term. The Companies calculated a hybrid LCOE of \$107.00 per MWh that excludes network upgrade costs, as these costs are not currently known. However, because the PPA is part of a sleeved customer agreement with Callisto Enterprises, LLC, pricing was not a deciding factor in the bilateral negotiations.

XV. NGP BLUE MOUNTAIN THIRD AMENDMENT PPA

62. Q. PLEASE DESCRIBE THE NGP BLUE MOUNTAIN THIRD AMENDMENT PPA.

A. Sierra is requesting approval of the NGP Blue Mountain Third Amendment PPA, representing an existing geothermal facility located in Sierra’s territory near Winnemucca in Humboldt County, Nevada. This is an amendment to the current NGP Blue Mountain PPA with Nevada Power, approved in Docket No. 06-10021, that will facilitate capital improvements at the existing NGP Blue Mountain facility that, once completed, would increase the expected output of the facility, reaching up to 30 MW and degrading annually for the remainder of the term. The improvement project contemplated in the amendment is being developed by Ormat Technologies through a subsidiary named NGP Blue Mountain I, LLC. The COD of the improvement project is March 31, 2027, and the amendment would extend the term through 2046. The amendment also assigns the PPA from Nevada Power

1 to Sierra, aligning the resource with the load base it will serve. A copy of the PPA
2 is provided as Technical Appendix REN-16-NBM(a).

3
4 **63. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE NGP BLUE**
5 **MOUNTAIN THIRD AMENDMENT PROJECT THAT SUPPORTED ITS**
6 **SELECTION?**

7 A. Geothermal power is delivered as a baseload, around-the-clock renewable resource
8 that provides firm, dispatchable energy to the Companies' system. As the resource
9 is located in Sierra's system and can achieve additional increased generating
10 capacity in the near term, it will support helping address systemwide open capacity
11 needs. As the resource is an existing and operating facility, it will utilize existing
12 infrastructure, resulting in no interconnection costs and mitigation of schedule risk
13 due to permitting delays.

14
15 **64. Q. IS THE PRICE FOR THE NGP BLUE MOUNTAIN THIRD AMENDMENT**
16 **PPA COMPETITIVE?**

17 A. Yes. The price of the NGP Blue Mountain PPA Third Amendment is at a fixed rate
18 of \$105.00 per MWh for the geothermal energy. Additionally, the Companies
19 calculated the LCOE for the NGP Blue Mountain Third Amendment PPA as
20 \$105.00 per MWh, as there are no network upgrades or other costs to incorporate
21 the resource. This is nearly 2.5% percent less than the most recent geothermal
22 energy resource presented for the Commission's review, the Corsac Generating
23 Station 2 PPA approved in Docket No. 24-05041.

1 **XVI. NORTH NEVADA GEOTHERMAL PORTFOLIO PPA**

2 **65. Q. PLEASE DESCRIBE THE NORTH NEVADA GEOTHERMAL**
3 **PORTFOLIO PPA.**

4 A. Sierra is requesting approval of the North Nevada Geothermal Portfolio PPA, being
5 developed by Zanskar Geothermal & Minerals, Inc (“Zanskar”), through a
6 subsidiary named Overcall Energy LLC. The PPA is being sleeved through
7 customer agreement with Amazon, who will receive 100% of the energy and
8 renewable energy benefits from the project. The Companies expect to file the
9 customer agreement for the Commission’s consideration in a separate docket at the
10 same time as this 2026 Joint IRP filing. The PPA represents a portfolio of
11 geothermal projects that when combined will provide 100 MW of geothermal
12 resources. The portfolio consists of up to five geothermal projects located
13 throughout northern Nevada, on a mix of private and federal land for which Zanskar
14 has secured or is in the process of securing geothermal leases rights. The COD is
15 planned for December 31, 2030, but the PPA contains provisions to allow up to
16 three additional years of development to reach the full intended capacity. The term
17 of the PPA will begin when the first resource reaches its COD, and will continue
18 until December 31, 2050, approximately 20 years. A copy of the PPA is provided
19 as Technical Appendix REN-17-NNGP(a).

20
21 **66. Q. IS THE NORTH NEVADA GEOTHERMAL PORTFOLIO PPA**
22 **CONTINGENT UPON APPROVAL OF THE CUSTOMER AGREEMENT**
23 **WITH AMAZON?**

24 A. Yes. In addition to the requisite approval from the Commission, the PPA is not
25 effective until all conditions to the effectiveness of the customer agreement between
26 Sierra and Amazon, have been satisfied.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

67. Q. GIVEN THE NORTH NEVADA GEOTHERMAL PORTFOLIO IS A SLEEVED PPA ASSOCIATED WITH A CUSTOMER AGREEMENT, WHAT CUSTOMER PROTECTIONS HAS SIERRA NEGOTIATED IN THE PPA?

A. The North Nevada Geothermal Portfolio PPA includes several customer protections consistent with the Companies' other PPAs through various provisions such as Sierra's ability to collect damages due to termination or production shortfalls.

68. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE NORTH NEVADA GEOTHERMAL PORTFOLIO PROJECT THAT SUPPORTED ITS SELECTION?

A. While the project was brought forward by Amazon as a dedicated resource to serve their load, it will enable the Companies to satisfy the customer's load and demand for clean energy and renewable energy credits around-the-clock. The PPA supports the quickly evolving demands of Amazon, while providing benefits to all customers, such as displacing fossil-fueled generation, adding jobs and economic benefits to the state, and strengthening grid reliability.

69. Q. IS THE PRICE FOR THE NORTH NEVADA GEOTHERMAL PORTFOLIO PPA COMPETITIVE?

A. Yes. North Nevada Geothermal Portfolio PPA's energy price for the geothermal is fixed at \$105.00 per MWh for the 20-year term. The Companies calculated a hybrid LCOE of \$105.00 per MWh that excludes network upgrade costs, as these costs are not currently known. However, because the PPA is part of a sleeved customer

1 agreement with Amazon, pricing was not a deciding factor in the bilateral
2 negotiations.

3
4 **XVII. SLEEPY ORANGE PPA**

5 **70. Q. PLEASE DESCRIBE THE SLEEPY ORANGE PPA.**

6 A. Sierra is requesting approval of the Sleepy Orange PPA, being developed by
7 Primergy Solar through a subsidiary named Sleepy Orange, LLC. The PPA is for a
8 500 MW solar photovoltaic generation facility paired with a 500 MW, four-hour
9 lithium-ion BESS, capable of providing 2,000 MWh of dispatchable energy and
10 capacity. The project is located in Sierra’s service territory in Lyon County,
11 Nevada, sited on approximately 3,000 acres of Bureau of Land Management land.
12 The COD is planned for May 31, 2030, and the term of the PPA is 25 years for the
13 solar and 20 years for the BESS. A copy of the PPA is provided as Technical
14 Appendix REN-18-SOS(a).

15
16 **71. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE SLEEPY ORANGE
17 PROJECT THAT SUPPORTED ITS SELECTION?**

18 A. The Sleepy Orange project satisfied the “beginning of construction” requirements
19 prior to the passage of the One Big Beautiful Bill Act; therefore, it qualifies for safe
20 harbor status under specific tax rules and is allowed up to ten years to reach its
21 COD while maintaining eligibility to claim the solar tax credits. Due to the lowered
22 risk of compressed development period and tax credit cliff, coupled with firm fixed
23 pricing, Sleepy Orange is positioned well to navigate permitting and project
24 schedule challenges and ultimately deliver competitively priced energy for Sierra’s
25 customers over the contract term.

- 1 **72. Q. IS THE PPA PRICE FOR THE SLEEPY ORANGE PPA COMPETITIVE?**
2 A. Yes. The Sleepy Orange PPA’s energy price is a fixed rate of \$30.90 per MWh for
3 a 25-year term, and the capacity price for the BESS is a fixed \$12,750 per MW-
4 month for a 20-year term. The Companies calculated a hybrid LCOE of \$89.80 per
5 MWh, the lowest amongst the 2024 RFP shortlisted bids for paired solar and
6 storage resources. For perspective, the Companies calculated the average LCOE of
7 other solar and BESS project proposals from the 2024 RFP that were not selected
8 using the submitted cap pricing of the solar energy and found that this project’s
9 LCOE is 43 percent lower in comparison. A copy of the project LCOE comparison
10 to average LCOE using solar cap pricing of non-selected solar and BESS project
11 proposals is presented in Confidential Technical Appendix REN-24.
12

13 **XVIII. SOUTHERN BIGHORN 1 AND 2 PPAs**

- 14 **73. Q. PLEASE DESCRIBE THE SOUTHERN BIGHORN 1 AND 2 PPAs.**
15 A. Nevada Power is requesting approval of the Southern Bighorn 1 and 2 PPAs
16 (collectively referred to as “Southern Bighorn”), being developed by Avantus
17 Clean Energy, LLC, through project subsidiaries named 300MS 8me LLC and
18 425LM 8me LLC (Southern Bighorn 1 and 2, respectively). The PPAs represent
19 two projects that, in aggregate, are for a 400 MW solar facility paired with a 400
20 MW, four-hour BESS, capable of providing 1,600 MWh of dispatchable energy
21 and capacity. Southern Bighorn is located in Clark County, Nevada, on tribal land
22 owned by the Moapa Band of Paiutes. The COD is planned for July 15, 2028, and
23 the term of the PPA is 25 years for the solar and 20 years for the BESS. A copy of
24 the PPAs are provided as Technical Appendices REN-19-SBS(a)(1) and REN-19-
25 SBS(a)(2).
26
27

1 These PPAs represent the second iteration of the Southern Bighorn project for the
2 Commission’s review; the previous Southern Bighorn Solar PPA for a 300 MW
3 solar and 135 MW BESS resource approved in Docket No. 19-06039, was
4 terminated.

5
6 **74. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE SOUTHERN**
7 **BIGHORN 1 AND 2 PROJECTS THAT SUPPORTED ITS SELECTION?**

8 A. Southern Bighorn can deliver energy to Nevada Power’s system in the summer of
9 2028, helping address systemwide open capacity needs and peak energy demand.
10 The project has received its Right-of-Way grant from the BLM on January 23,
11 2026, authorizing the project to begin physical construction. Thus, the risk of
12 permitting delays associated with DOI Review Policy Memorandum impacts is
13 eliminated, and the project is well positioned to reach commercial operation in time
14 to secure the available solar tax credits and pass the value on to Nevada Power’s
15 customers for the contract term.

16
17 **75. Q. IS THE PRICE FOR THE SOUTHERN BIGHORN 1 AND 2 PPAs**
18 **COMPETITIVE?**

19 A. Yes. The Southern Bighorn PPAs’ energy price for the solar is fixed at \$47.23 per
20 MWh for the 25-year term, and the BESS rate is fixed at \$15,500 per MW-month
21 for a 20-year term. The Companies calculated a hybrid LCOE of \$117.93 per MWh.
22 For perspective, the Companies calculated the average LCOE of other solar and
23 BESS project proposals from the 2024 RFP that were not selected using the
24 submitted cap pricing of the solar energy and found that this project’s LCOE is 25
25 percent lower in comparison. A copy of the project LCOE comparison to average
26
27

1 LCOE using solar cap pricing of non-selected solar and BESS project proposals is
2 presented in Confidential Technical Appendix REN-24.
3

4 **XIX. TREGO GRID PPA**

5 **76. Q. PLEASE DESCRIBE THE TREGO GRID PPA.**

6 A. Sierra is requesting approval of the Trego Grid PPA, being developed by Coval
7 Infrastructure DevCo Holdings LP through a subsidiary named Trego Grid, LLC.
8 The PPA is for a 200 MW, four-hour lithium-ion BESS, capable of providing 800
9 MWh of dispatchable energy and capacity. The project is located in Sierra's service
10 territory in northern Nevada, sited on a seven-acre parcel owned by the project and
11 adjacent to Sierra's Mira Loma Substation in Washoe County. The COD is planned
12 for June 30, 2028, and the term of the PPA is 20 years. A copy of the PPA is
13 provided as Technical Appendix REN-20-TG(a).
14

15 **77. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE TREGO GRID**
16 **PROJECT THAT SUPPORTED ITS SELECTION?**

17 A. This 200 MW battery will deliver much-needed flexible, dispatchable capacity to
18 Sierra's northern Nevada grid before the 2028 summer peak, helping to cover the
19 open capacity needs identified for that year and beyond. Trego Grid does not
20 require any BLM or federal approvals subject to the DOI Review Policy
21 Memorandum process, thereby mitigating schedule risk due to permitting. The
22 project will qualify for tax credits, which is reflected in the pricing, passing the
23 value on to Sierra's customers for the contract term.
24
25
26
27

1 **78. Q. IS THE PRICE FOR THE TREGO GRID PPA COMPETITIVE?**

2 A. Yes. The Trego Grid PPA’s capacity price is a fixed \$15,070 per MW-month, and
3 the Companies calculated an LCOS of \$151.52 per MWh. To put that in
4 perspective, this LCOS is roughly 9% lower than the LCOS of the 150 MW Dodge
5 Flat battery addition that the Commission approved previously in Docket No. 25-
6 10028.

7
8 **XX. WHITE PINE SOLAR PPA**

9 **79. Q. PLEASE DESCRIBE THE WHITE PINE SOLAR PPA.**

10 A. Sierra is requesting approval of the White Pine Solar PPA, being developed by
11 AMPYR Energy USA DevCo, LLC, through a subsidiary named White Pine Solar,
12 LLC. The PPA is for a 350 MW solar facility paired with a 350 MW, four-hour
13 BESS, capable of providing 1,400 MWh of dispatchable energy and capacity. The
14 project is located in Sierra’s service territory north of Ely, Nevada, on 1,990 acres
15 of privately owned land. The COD is planned for December 31, 2028, and the term
16 of the PPA is 25 years for the solar and 20 years for the BESS. A copy of the PPA
17 is provided as Technical Appendix REN-21-WPS(a).

18
19 **80. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE WHITE PINE
20 SOLAR PROJECT THAT SUPPORTED ITS SELECTION?**

21 A. The White Pine Solar project can deliver energy in Sierra’s system in 2028, helping
22 address systemwide open capacity needs. The project requires only a short
23 generation tie-line across BLM-managed land, thus the associated environmental
24 permitting risk is significantly lower than for generation resources sited
25 predominantly on BLM land. The project will qualify for tax credits, which is
26
27

1 reflected in the pricing, passing the value on to Sierra’s customers for the contract
2 term.

3
4 **81. Q. IS THE PRICE FOR THE WHITE PINE SOLAR PPA COMPETITIVE?**

5 A. Yes. The White Pine Solar PPA’s energy price for the solar is \$28.20 per MWh
6 with an annual two-percent escalator for the 25-year term, and the BESS rate is
7 \$11,350 per MW-month with annual two-percent escalator for a 20-year term. The
8 Companies calculated a hybrid LCOE of \$102.20 per MWh, the second-lowest
9 amongst the energy-generating 2024 RFP bids. For perspective, the Companies
10 calculated the average LCOE of other solar and BESS project proposals from the
11 2024 RFP that were not selected using the submitted cap pricing of the solar energy
12 and found that this project’s LCOE is 35 percent lower in comparison. A copy of
13 the project LCOE comparison to average LCOE using solar cap pricing of non-
14 selected solar and BESS project proposals is presented in Confidential Technical
15 Appendix REN-24.
16

17 **XXI. WINSTON SOLAR LG FACILITY AND MK FACILITY PPAs**

18 **82. Q. PLEASE DESCRIBE THE WINSTON SOLAR LG FACILITY AND MK**
19 **FACILITY PPAs.**

20 A. Sierra is requesting approval of the Winston Solar LG Facility and MK Facility
21 PPAs (collectively referred to as “Winston Solar”),, being developed by EDF
22 Renewables North America through a subsidiary named Winston FC Solar, LLC.
23 The PPAs represent two projects that, in aggregate, are for a 400 MW solar facility
24 paired with a 400 MW, four-hour BESS, capable of providing 1,600 MWh of
25 dispatchable energy and capacity. Winston Solar is located in Sierra’s service
26 territory in Lyon County, Nevada, on 2,300 acres of privately owned land. The MK
27

1 Facility PPA includes a provision for an adjustment to the size of the facility
2 pending the outcome of a Planned Unit Development permit to be issued by Lyon
3 County, Nevada. If the permit is not received as intended, the size of the solar
4 facility will be reduced, but not less than 300 MW in the aggregate solar nameplate
5 capacity of the projects. The adjustment will not affect the price of the resource or
6 the nameplate capacity of the BESS. The COD is planned for October 1, 2029, and
7 the term of the PPA is 25 years for the solar and 20 years for the BESS. A copy of
8 the PPAs are provided as Technical Appendices REN-22-WS(a)(1) and REN-22-
9 WS(a)(2).

10
11 There are aspects of the PPAs that are currently being negotiated for anticipated
12 amendments, including addressing potential impacts to COD due to necessary
13 installation of high voltage equipment identified in a recently completed DNR
14 study, as well as grid-charging capability of the BESS.

15
16 **83. Q. WHAT ARE THE SPECIFIC ATTRIBUTES OF THE WINSTON SOLAR**
17 **PROJECT THAT SUPPORTED ITS SELECTION?**

18 A. This solar and BESS resource will provide energy and capacity to Sierra's northern
19 Nevada grid in 2029, helping to cover the open capacity needs identified for that
20 year and beyond. The Winston Solar project represents one of the very few 2024
21 RFP bids for generating resources that are located entirely on private land,
22 including site access roads and generation tie-line routes. Thus, the risk of
23 permitting delays associated with DOI Review Policy Memorandum impacts is
24 eliminated, and the project is well positioned to reach COD in time to secure the
25 available solar tax credits and pass the value on to Sierra's customers for the
26 contract term.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

84. Q. IS THE PRICE FOR THE WINSTON SOLAR PPAs COMPETITIVE?

A. Yes. The price of the Winston Solar PPAs are a fixed rate of \$39.60 per MWh for the solar energy, and \$14,220 per MW-month for the BESS. Additionally, the Companies calculated the hybrid LCOE for the Winston Solar PPAs as \$111.50 per MWh. For perspective, the Companies calculated the average LCOE of other solar and BESS project proposals from the 2024 RFP that were not selected using the submitted cap pricing of the solar energy and found that this project’s LCOE is 29 percent lower in comparison. A copy of the project LCOE comparison to average LCOE using solar cap pricing of non-selected solar and BESS project proposals is presented in Confidential Technical Appendix REN-24.

85. Q. PLEASE SUMMARIZE THE COMPANIES’ REQUEST TO APPROVE THE PPAs.

A. The Companies request that the Commission approve all 23 of the PPAs presented in this filing. These projects will add approximately 4,550 MW of renewable generation capacity and 5,405 MW of BESS output capacity that will increase capacity in both Nevada Power’s and Sierra’s systems. The projects are anticipated to come online between 2027 and 2030 and can deliver power in the near term to help support native load customer energy requirements, reduce the Companies’ open position, contribute towards the RPS compliance, satisfy customer loads through energy agreements, lock in savings from the tax credits that are set to expire, provide ancillary services to enhance grid stability and reliability, and provide jobs and significant economic benefit to the state of Nevada.

1 **XXII. VALMY GEOTHERMAL RESOURCES UPDATE**

2 **86. Q. PLEASE PROVIDE AN UPDATE REGARDING GEOTHERMAL**
3 **RESOURCES AND DEVELOPMENT IN THE VALMY REGION.**

4 A. As of the date of this filing, the Companies have received two proposals: the
5 Nevada Geothermal Portfolio (OKGP), and the North Nevada Geothermal
6 Portfolio, each consisting of a portfolio of geothermal resources that include one
7 or more proposed geothermal project sites that are located near the Valmy region.
8 Both of these proposals were brought to the Companies to be sleeved PPAs
9 associated with customer energy agreements, and are discussed in detail in the
10 Renewables Section of the Supply Plan Narrative.

11
12 **87. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

13 A. Yes.
14
15
16
17
18
19
20
21
22
23
24
25
26
27

EXHIBIT SPITZER-DIRECT-1

STATEMENT OF QUALIFICATIONS

Sean Spitzer | 7155 Lindell Rd. Las Vegas, NV 89118 | (702) 402-3107
sean.spitzer@nvenergy.com

Professional with over 15 years of experience in the power industry. Recent focus on renewable energy origination activities.

EXPERIENCE

NV Energy, Las Vegas, NV

Director, Renewable Energy & Origination | 2024-Present

- Lead renewable energy procurements through competitive solicitations and bilateral opportunities, ensuring resources are cost-effective, reliable, and compliant with regulatory requirements.
- Oversee renewable energy contract negotiations to secure favorable terms that maximize customer value while maintaining project viability.
- Direct origination activities that support the Integrated Resource Plan and align procurement decisions with the company's long-term energy supply portfolio strategy.
- Provide executive leadership with analysis of market trends, risks, and opportunities to inform prudent decision-making.

Sr. Project Manager, Renewables & Origination | 2023-2024

- Procure renewable energy contracts via RFP and bilateral proposal due diligence project evaluations. Facilitate subject matter experts in completing technical analyses and utilize financial models to determine project financial viability.
- Guide renewable energy contract negotiations for enhanced value and minimal risk.
- Support Integrated Resource Plan and General Rate Case filings as key contributor for Renewables.

Environmental Services Supervisor | 2022-2023

- Managed air quality-related environmental compliance for all business operations.
- Led multidisciplinary team to secure gas and coal power plant Title V operating permits.

Sr. Environmental Advisor | 2016-2022

- Performed project impact evaluations and delivered key information to stakeholders.
- Supported environmental compliance programs to ensure regulatory integrity.

GE (General Electric Company); GE Hitachi Nuclear Energy, Sunol, CA

EHS Specialist | 2012-2016

- Executed compliance programs pertaining to air, water, waste, and industrial safety at a nuclear facility.

NV Energy, Las Vegas, NV

Environmental Engineer | 2011-2012

- Quality-assured CEMS emissions data for combined-cycle power plants; managed reporting.

Clean Harbors Environmental Services, West Sacramento, CA

Sr. Lead Chemist | 2007-2008

- Team leader for multi-day hazardous waste packaging & environmental clean-up projects.

EDUCATION

California State University, Chico

Masters of Science in Environmental Science | 2011

University of California, Santa Barbara

Bachelor of Science in Environmental Studies | 2006

EXHIBIT SPITZER-DIRECT-2

EXHIBIT SPITZER-DIRECT-2

SPONSORED TECHNICAL APPENDICES

REN-1 – Proposed Projects 12x24 Supply tables
REN-2 – Renewable Portfolio Standard Buildout Scenarios
REN-3-AEC(a)(1) – Amargosa Energy Center (Phase 1) PPA (Confidential)
REN-3-AEC(a)(1) – Amargosa Energy Center (Phase 1) PPA (Redacted)
REN-3-AEC(a)(2) – Amargosa Energy Center (Phase 2) PPA (Confidential)
REN-3-AEC(a)(2) – Amargosa Energy Center (Phase 2) PPA (Redacted)
REN-3-AEC(b) – Amargosa Energy Center Due Diligence (Confidential)
REN-3-AEC(c) – Amargosa Energy Center NAC-NRS Compliance
REN-3-AEC(d)(1) – Amargosa Energy Center (Phase 1) Key Provisions
REN-3-AEC(d)(2) – Amargosa Energy Center (Phase 2) Key Provisions
REN-4-BS3(a) – Boulder Solar III PPA (Confidential)
REN-4-BS3(a) – Boulder Solar III PPA (Redacted)
REN-4-BS3(b) – Boulder Solar III Due Diligence (Confidential)
REN-4-BS3(c) – Boulder Solar III NAC-NRS Compliance
REN-4-BS3(d) – Boulder Solar III Key Provisions
REN-5-CS(a) – Castor Storage PPA
REN-5-CS(b) – Castor Storage Due Diligence (Confidential)
REN-5-CS(c) – Castor Storage NAC-NRS Compliance
REN-5-CS(d) – Castor Storage Key Provisions
REN-6-CSB(a) – Commerce Station Energy Storage PPA (Confidential)
REN-6-CSB(a) – Commerce Station Energy Storage PPA (Redacted)
REN-6-CSB(b) – Commerce Station Energy Storage Due Diligence (Confidential)
REN-6-CSB(c) – Commerce Station Energy Storage NAC-NRS Compliance
REN-6-CSB(d) – Commerce Station Energy Storage Key Provisions
REN-7-CE1(a) – Coyote Energy 1 PPA
REN-7-CE1(b) – Coyote Energy 1 Due Diligence (Confidential)
REN-7-CE1(c) – Coyote Energy 1 NAC-NRS Compliance
REN-7-CE1(d) – Coyote Energy 1 Key Provisions
REN-8-DLE2(a) – Dry Lake East Energy Storage II PPA (Confidential)
REN-8-DLE2(a) – Dry Lake East Energy Storage II PPA (Redacted)
REN-8-DLE2(b) – Dry Lake East Energy Storage II Due Diligence (Confidential)
REN-8-DLE2(c) – Dry Lake East Energy Storage II NAC-NRS Compliance
REN-8-DLE2(d) – Dry Lake East Energy Storage II Key Provisions
REN-9-FSR(a) – Fish Springs Ranch Energy Storage PPA (Confidential)
REN-9-FSR(a) – Fish Springs Ranch Energy Storage PPA (Redacted)
REN-9-FSR(b) – Fish Springs Ranch Energy Storage Due Diligence (Confidential)
REN-9-FSR(c) – Fish Springs Ranch Energy Storage NAC-NRS Compliance
REN-9-FSR(d) – Fish Springs Ranch Energy Storage Key Provisions
REN-10-HPE(a) – Hot Pot Energy Center PPA (Confidential)

REN-10-HPE(a) – Hot Pot Energy Center PPA (Redacted)
REN-10-HPE(b) – Hot Pot Energy Center Due Diligence (Confidential)
REN-10-HPE(c) – Hot Pot Energy Center NAC-NRS Compliance
REN-10-HPE(d) – Hot Pot Energy Center Key Provisions
REN-11-IPE(a) – Iron Point Energy Center PPA (Confidential)
REN-11-IPE(a) – Iron Point Energy Center PPA (Redacted)
REN-11-IPE(b) – Iron Point Energy Center Due Diligence (Confidential)
REN-11-IPE(c) – Iron Point Energy Center NAC-NRS Compliance
REN-11-IPE(d) – Iron Point Energy Center Key Provisions
REN-12-JVS(a) – Jersey Valley Solar and Storage PPA
REN-12-JVS(b) – Jersey Valley Solar and Storage Due Diligence (Confidential)
REN-12-JVS(c) – Jersey Valley Solar and Storage NAC-NRS Compliance
REN-12-JVS(d) – Jersey Valley Solar and Storage Key Provisions
REN-13-LSA(a) – Libra Solar & Storage Project Third Amendment PPA (Confidential)
REN-13-LSA(a) – Libra Solar & Storage Project Third Amendment PPA (Redacted)
REN-13-LSA(b) – Libra Solar & Storage Project Third Amendment Due Diligence (Confidential)
REN-13-LSA(c) – Libra Solar & Storage Project Third Amendment NAC-NRS Compliance
REN-13-LSA(d) – Libra Solar & Storage Project Third Amendment Key Provisions
REN-14-LSC(a) – Lux Solar Center PPA (Confidential)
REN-14-LSC(a) – Lux Solar Center PPA (Redacted)
REN-14-LSC(b) – Lux Solar Center Due Diligence (Confidential)
REN-14-LSC(c) – Lux Solar Center NAC-NRS Compliance
REN-14-LSC(d) – Lux Solar Center Key Provisions
REN-15-NGP(a) – Nevada Geothermal Portfolio (OKGP) PPA (Confidential)
REN-15-NGP(a) – Nevada Geothermal Portfolio (OKGP) PPA (Redacted)
REN-15-NGP(b) – Nevada Geothermal Portfolio (OKGP) Due Diligence (Confidential)
REN-15-NGP(c) – Nevada Geothermal Portfolio (OKGP) NAC-NRS Compliance
REN-15-NGP(d) – Nevada Geothermal Portfolio (OKGP) Key Provisions
REN-16-NBM(a) – NGP Blue Mountain Third Amendment PPA
REN-16-NBM(b) – NGP Blue Mountain Third Amendment Due Diligence (Confidential)
REN-16-NBM(c) – NGP Blue Mountain Third Amendment NAC-NRS Compliance
REN-16-NBM(d) – NGP Blue Mountain Third Amendment Key Provisions
REN-17-NNGP(a) – North Nevada Geothermal Portfolio PPA (Confidential)
REN-17-NNGP(a) – North Nevada Geothermal Portfolio PPA (Redacted)
REN-17-NNGP(b) – North Nevada Geothermal Portfolio Due Diligence (Confidential)
REN-17-NNGP(c) – North Nevada Geothermal Portfolio NAC-NRS Compliance
REN-17-NNGP(d) – North Nevada Geothermal Portfolio Key Provisions
REN-18-SOS(a) – Sleepy Orange PPA
REN-18-SOS(b) – Sleepy Orange Due Diligence (Confidential)
REN-18-SOS(c) – Sleepy Orange NAC-NRS Compliance
REN-18-SOS(d) – Sleepy Orange Key Provisions

REN-19-SBS(a)(1) – Southern Bighorn 1 PPA (Confidential)
REN-19-SBS(a)(1) – Southern Bighorn 1 PPA (Redacted)
REN-19-SBS(a)(2) – Southern Bighorn 2 PPA (Confidential)
REN-19-SBS(a)(2) – Southern Bighorn 2 PPA (Redacted)
REN-19-SBS(b) – Southern Bighorn 1 and 2 Due Diligence (Confidential)
REN-19-SBS(c) – Southern Bighorn 1 and 2 NAC-NRS Compliance
REN-19-SBS(d)(1) – Southern Bighorn 1 Key Provisions
REN-19-SBS(d)(2) – Southern Bighorn 2 Key Provisions
REN-20-TG(a) – Trego Grid PPA (Confidential)
REN-20-TG(a) – Trego Grid PPA (Redacted)
REN-20-TG(b) – Trego Grid Due Diligence (Confidential)
REN-20-TG(c) – Trego Grid NAC-NRS Compliance
REN-20-TG(d) – Trego Grid Key Provisions
REN-21-WPS(a) – White Pine Solar PPA (Confidential)
REN-21-WPS(a) – White Pine Solar PPA (Redacted)
REN-21-WPS(b) – White Pine Solar Due Diligence (Confidential)
REN-21-WPS(c) – White Pine Solar NAC-NRS Compliance
REN-21-WPS(d) – White Pine Solar Key Provisions
REN-22-WS(a)(1) – Winston Solar (LG Facility) PPA (Confidential)
REN-22-WS(a)(1) – Winston Solar (LG Facility) PPA (Redacted)
REN-22-WS(a)(2) – Winston Solar (MK Facility) PPA (Confidential)
REN-22-WS(a)(2) – Winston Solar (MK Facility) PPA (Redacted)
REN-22-WS(b) – Winston Solar Due Diligence (Confidential)
REN-22-WS(c) – Winston Solar NAC-NRS Compliance
REN-22-WS(d)(1) – Winston Solar (LG Facility) Key Provisions
REN-22-WS(d)(2) – Winston Solar (MK Facility) Key Provisions
REN-23 – Standalone BESS LCOS Comparison Summary
REN-24 – Paired Solar and BESS LCOE Comparison Summary (Confidential)
REN-25 – Economic Benefits Table
REN-26 – Bid Scores Summary – 2024 RFP (Confidential)

EXHIBIT SPITZER-DIRECT-3

EXHIBIT SPITZER-DIRECT-3

TECHNICAL APPENDICES OF CONFIDENTIAL DUE DILIGENCE

REN-3-AEC(b) – Amargosa Energy Center Due Diligence (Confidential)
REN-4-BS3(b) – Boulder Solar III Due Diligence (Confidential)
REN-5-CS(b) – Castor Storage Due Diligence (Confidential)
REN-6-CSB(b) – Commerce Station Energy Storage Due Diligence (Confidential)
REN-7-CE1(b) – Coyote Energy 1 Due Diligence (Confidential)
REN-8-DLE2(b) – Dry Lake East Energy Storage II Due Diligence (Confidential)
REN-9-FSR(b) – Fish Springs Ranch Energy Storage Due Diligence (Confidential)
REN-10-HPE(b) – Hot Pot Energy Center Due Diligence (Confidential)
REN-11-IPE(b) – Iron Point Energy Center Due Diligence (Confidential)
REN-12-JVS(b) – Jersey Valley Solar and Storage Due Diligence (Confidential)
REN-13-LSA(b) – Libra Solar & Storage Project Third Amendment Due Diligence (Confidential)
REN-14-LSC(b) – Lux Solar Center Due Diligence (Confidential)
REN-15-NGP(b) – Nevada Geothermal Portfolio (OKGP) Due Diligence (Confidential)
REN-16-NBM(b) – NGP Blue Mountain Third Amendment Due Diligence (Confidential)
REN-17-NNGP(b) – North Nevada Geothermal Portfolio Due Diligence (Confidential)
REN-18-SOS(b) – Sleepy Orange Due Diligence (Confidential)
REN-19-SBS(b) – Southern Bighorn 1 and 2 Due Diligence (Confidential)
REN-20-TG(b) – Trego Grid Due Diligence (Confidential)
REN-21-WPS(b) – White Pine Solar Due Diligence (Confidential)
REN-22-WS(b) – Winston Solar Due Diligence (Confidential)

EXHIBIT SPITZER-DIRECT-4

EXHIBIT SPITZER-DIRECT-4

TECHNICAL APPENDICES OF PPAS WITH CONFIDENTIAL EXHIBITS

REN-3-AEC(b) – Amargosa Energy Center Due Diligence (Confidential)
REN-4-BS3(b) – Boulder Solar III Due Diligence (Confidential)
REN-5-CS(b) – Castor Storage Due Diligence (Confidential)
REN-6-CSB(b) – Commerce Station Energy Storage Due Diligence (Confidential)
REN-7-CE1(b) – Coyote Energy 1 Due Diligence (Confidential)
REN-8-DLE2(b) – Dry Lake East Energy Storage II Due Diligence (Confidential)
REN-9-FSR(b) – Fish Springs Ranch Energy Storage Due Diligence (Confidential)
REN-10-HPE(b) – Hot Pot Energy Center Due Diligence (Confidential)
REN-11-IPE(b) – Iron Point Energy Center Due Diligence (Confidential)
REN-12-JVS(b) – Jersey Valley Solar and Storage Due Diligence (Confidential)
REN-13-LSA(b) – Libra Solar & Storage Project Third Amendment Due Diligence (Confidential)
REN-14-LSC(b) – Lux Solar Center Due Diligence (Confidential)
REN-15-NGP(b) – Nevada Geothermal Portfolio (OKGP) Due Diligence (Confidential)
REN-16-NBM(b) – NGP Blue Mountain Third Amendment Due Diligence (Confidential)
REN-17-NNGP(b) – North Nevada Geothermal Portfolio Due Diligence (Confidential)
REN-18-SOS(b) – Sleepy Orange Due Diligence (Confidential)
REN-19-SBS(b) – Southern Bighorn 1 and 2 Due Diligence (Confidential)
REN-20-TG(b) – Trego Grid Due Diligence (Confidential)
REN-21-WPS(b) – White Pine Solar Due Diligence (Confidential)
REN-22-WS(b) – Winston Solar Due Diligence (Confidential)

EXHIBIT SPITZER-DIRECT-5

EXHIBIT SPITZER-DIRECT-5

TECHNICAL APPENDICES OF NAC-NRS COMPLIANCE

- REN-3-AEC(c) – Amargosa Energy Center NAC-NRS Compliance
- REN-4-BS3(c) – Boulder Solar III NAC-NRS Compliance
- REN-5-CS(c) – Castor Storage NAC-NRS Compliance
- REN-6-CSB(c) – Commerce Station Energy Storage NAC-NRS Compliance
- REN-7-CE1(c) – Coyote Energy 1 Project NAC-NRS Compliance
- REN-8-DLE2(c) – Dry Lake East Energy Storage II NAC-NRS Compliance
- REN-9-FSR(c) – Fish Springs Ranch Energy Storage NAC-NRS Compliance
- REN-10-HPE(c) – Hot Pot Energy Storage NAC-NRS Compliance
- REN-11-IPE(c) – Iron Point Energy Center NAC-NRS Compliance
- REN-12-JVS(c) – Jersey Valley Solar and Storage NAC-NRS Compliance
- REN-13-LSA(c) – Libra Solar & Storage Project Third Amendment NAC-NRS Compliance
- REN-14-LSC(c) – Lux Solar Center NAC-NRS Compliance
- REN-15-NGP(c) – Nevada Geothermal Portfolio (OKGP) NAC-NRS Compliance
- REN-16-NBM(c) – NGP Blue Mountain Third Amendment NAC-NRS Compliance
- REN-17-NNGP(c) – North Nevada Geothermal Portfolio NAC-NRS Compliance
- REN-18-SOS(c) – Sleepy Orange NAC-NRS Compliance
- REN-19-SBS(c) – Southern Bighorn 1 and 2 NAC-NRS Compliance
- REN-20-TG(c) – Trego Grid NAC-NRS Compliance
- REN-21-WPS(c) – White Pine Solar NAC-NRS Compliance
- REN-22-WS(c) – Winston Solar NAC-NRS Compliance

EXHIBIT SPITZER-DIRECT-6

EXHIBIT SPITZER-DIRECT-6

TECHNICAL APPENDICES OF KEY PROVISIONS

REN-3-AEC(d)(1) – Amargosa Energy Center (Phase 1) Key Provisions
REN-3-AEC(d)(2) – Amargosa Energy Center (Phase 2) Key Provisions
REN-4-BS3(d) – Boulder Solar III Key Provisions
REN-5-CS(d) – Castor Storage Key Provisions
REN-6-CSB(d) – Commerce Station Energy Storage Key Provisions
REN-7-CE1(d) – Coyote Energy 1 Project Key Provisions
REN-8-DLE2(d) – Dry Lake East Energy Storage II Key Provisions
REN-9-FSR(d) – Fish Springs Ranch Energy Storage Key Provisions
REN-10-HPE(d) – Hot Pot Energy Storage Key Provisions
REN-11-IPE(d) – Iron Point Energy Center Key Provisions
REN-12-JVS(d) – Jersey Valley Solar and Storage Key Provisions
REN-13-LSA(d) – Libra Solar & Storage Project Third Amendment Key Provisions
REN-14-LSC(d) – Lux Solar Center Key Provisions
REN-15-NGP(d) – Nevada Geothermal Portfolio (OKGP) Key Provisions
REN-16-NBM(d) – NGP Blue Mountain Third Amendment Key Provisions
REN-17-NNGP(d) – North Nevada Geothermal Portfolio Key Provisions
REN-18-SOS(d) – Sleepy Orange Key Provisions
REN-19-SBS(d)(1) – Southern Bighorn 1 Key Provisions
REN-19-SBS(d)(2) – Southern Bighorn 2 Key Provisions
REN-20-TG(d) – Trego Grid Key Provisions

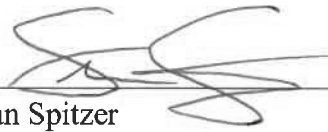
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, SEAN SPITZER, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026


Sean Spitzer

MICHAEL HOLLAND

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26-05 ____

Prepared Direct Testimony of

Michael Holland

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Michael Holland. I am the Vice President, Resource Optimization for Sierra Pacific Power Company d/b/a NV Energy (“Sierra”) and Nevada Power Company d/b/a NV Energy (“Nevada Power” and, together with Sierra, the “Companies”). I work primarily out of Nevada Power’s office at 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. My experience includes more than 18 years in the energy sector with positions in several areas, including power and natural gas trading and the oversight of energy trading activities in multiple markets. I have been in various leadership roles overseeing activities related to energy trading, retail natural gas and electric supply, origination and market operations. My statement of qualifications is attached as **Exhibit Holland-Direct-1.**

1 3. Q. **WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**
2 **CURRENT POSITION?**

3 A. My current responsibilities involve the oversight of the Resource Optimization
4 team. Resource Optimization is responsible for a number of activities, including,
5 but not limited to, all power and natural gas trading activities, short-term production
6 cost modeling, the development of trading analytics to support energy marketing
7 and origination activities, participation in the Western Energy Imbalance Market
8 (“WEIM”), renewable resource origination, contract management, and wholesale
9 market design efforts.

10
11 4. Q. **HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
12 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
13 **(“COMMISSION”)?**

14 A. Yes. Most recently, I prepared testimony in proceedings before the Commission in
15 Nevada Power and Sierra’s 2026 Deferred Energy Accounting Adjustment
16 (“DEAA”) filings, Docket Nos. 26-02035, 26-02036 and 26-02037. I also have
17 prepared testimony in the first amendment to the 2024 Triennial Joint Integrated
18 Resource Plan (“IRP”) filing in Docket No. 25-10028, in Nevada Power and
19 Sierra’s joint application for an amendment to the 2025-2027 Energy Supply Plan
20 (“ESP”) filing in Docket No. 25-10025, in Nevada Power’s 2025 General Rate Case
21 filing in Docket No. 25-02016, and in the Companies’ 2025 DEAA filings, Docket
22 Nos. 25-02033 and 25-02034.

23
24
25
26
27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the renewable energy landscape in Nevada, list and describe the status of the named placeholders, describe the Companies’ market design efforts, and discuss the open position limits.

I. RENEWABLE ENERGY LANDSCAPE

6. Q. PLEASE DESCRIBE THE RENEWABLE ENERGY LANDSCAPE IN NEVADA AS IT IMPACTS THE COMPANIES’ RENEWABLE ENERGY SUPPLY PIPELINE.

A. Nevada’s renewable energy landscape continues to evolve in the context of sustained load growth, increasing Renewable Portfolio Standard (“RPS”) obligations, and mounting development and delivery challenges that directly affect the Companies’ renewable supply pipeline. While Nevada possesses strong underlying solar and geothermal resource potential, the ability to translate that potential into operating renewable generation on schedules aligned with RPS requirements has become increasingly constrained and uncertain.

Policy and Regulatory Drivers

Nevada’s RPS requirements necessitate the continued expansion of the Companies’ renewable and energy storage portfolios over time, increasing reliance on a steady and deliverable pipeline of new renewable resources. The Companies’ challenge is to ensure that they have sufficient renewable resources, existing and pipeline, to satisfy RPS credit and energy needs over a multi-year planning horizon, recognizing that project development timelines are long and subject to material execution risk.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

In parallel, changes in federal policy—including evolving tax law, tariff exposure, and federal land-use requirements—have introduced additional cost and schedule uncertainty for renewable development. Developers have consistently indicated that these factors increase execution risk and financing uncertainty, which has reduced the number of market-ready projects available for utility procurement and contributed to higher and more volatile bid pricing in recent solicitations.

Recent federal legislation commonly referred to as the One Big Beautiful Bill Act (“OBBBA”) has further increased uncertainty in the renewable development landscape. Developer feedback and internal analysis indicate that the OBBBA has introduced material risk related to the availability, timing, and value of federal tax credits that are foundational to renewable project economics. Under the OBBBA, renewable projects must achieve commercial operation by statutory deadlines—generally prior to December 31, 2030, for solar resources and December 31, 2033 for battery energy storage systems—to retain full tax-credit eligibility. Projects that fail to meet these deadlines face materially higher costs, which developers have reflected in higher bid prices.

The OBBBA has also introduced uncertainty related to foreign entity of concern (“FEOC”) requirements, particularly for battery energy storage systems. The absence of final federal guidance on these provisions has increased developer risk premiums and further constrained the pool of financeable projects, compounding existing tariff exposure and global supply-chain pressures.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Resource Potential and Development Constraints

Although Nevada has some of the strongest solar and geothermal resources in the country, renewable development is constrained by several structural barriers that have been consistently identified in prior IRP and ESP proceedings. These include limited available land for development proximate to existing transmission infrastructure, multi-year permitting timelines, and a lack of available transmission capacity to interconnect new projects within required timeframes.

These constraints have intensified competition for viable interconnection points and transmission upgrades, narrowing the pool of feasible renewable projects available for procurement. As a result, even projects with otherwise favorable economics face increased risk related to deliverability and schedule certainty.

Transmission and Infrastructure Limitations

Transmission availability remains a central bottleneck to renewable development in Nevada. Many prospective projects are dependent on the completion of costly network upgrades, procurement of long-lead critical equipment such as breakers and transformers, and the timely completion of interdependent permitting and interconnection milestones. These project milestones are subject to multiple external forces outside of the Companies' control and cannot be fully mitigated through planning alone.

Accordingly, the Companies' renewable project pipeline carries inherent execution risk, even for projects that have been approved or are otherwise economically viable.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Supply Chain and Project Execution Risk

Renewable project execution risk has increased due to global supply-chain disruptions affecting solar modules, battery systems, and critical electrical equipment. These disruptions—combined with rising labor and material costs—have contributed to delays and cancellations of previously approved renewable projects in Nevada.

These outcomes reinforce the inherent uncertainty associated with relying on future project development to meet near-term compliance needs and directly affect the depth, timing, and reliability of the Companies’ renewable supply pipeline.

Implications for Renewable Procurement Strategy

Given these conditions, reliance on short-term market purchases is not a viable substitute for securing the renewable energy and capacity needed to meet the Companies’ RPS and resource adequacy obligations. Short-term market availability does not provide the scale, certainty, or long-term deliverability required to support sustained compliance amid continued load growth and increasing reliance on variable renewable resources.

Accordingly, long-term power purchase agreements (“PPAs”) and carefully vetted renewable projects with demonstrated deliverability remain the most reliable means of securing renewable energy supply for customers. To manage development and delivery risk, the Companies continue to strengthen their screening and due-diligence processes, prioritizing projects that demonstrate features of delivery assurance including:

- an achievable interconnection schedule and feasible transmission capability;
- control over land use, critical equipment supply and construction timelines; and
- cost-competitive, market-appropriate pricing consistent with prevailing market conditions.

Overall Impact on the Renewable Supply Pipeline

In summary, Nevada’s renewable energy landscape is characterized by strong underlying resource potential offset by significant near- and mid-term development and delivery challenges. The Companies’ renewable supply pipeline therefore carries inherent risk related to permitting, transmission availability, equipment procurement, and evolving policy requirements.

To address these challenges, the Companies continue to pursue a diversified procurement strategy—including competitive solicitations, self-development, and bilateral transactions—while emphasizing projects with credible schedules, secured transmission solutions, and demonstrated financing viability. These efforts are necessary to maintain a reliable renewable supply pipeline and support ongoing RPS compliance and Nevada’s broader clean-energy objectives.

7. **Q. PLEASE DESCRIBE THE COMPANIES’ OUTLOOK FOR ANY SPECIFIC POTENTIAL CONCERNS ASSOCIATED WITH ALREADY CONTRACTED RESOURCES.**

A. The Companies continue to closely monitor the progress of all contracted projects and assess risks to schedule, financing, permitting, and equipment procurement.

1 Where concerns arise, the Companies evaluate mitigation steps such as identifying
2 alternative resources, adjusting procurement timelines, or pursuing additional
3 competitive solicitations.

4
5 The Boulder Solar III project, contracted under a May 3, 2024 PPA, experienced
6 material development delays beginning in mid-2025. These delays prevented
7 timely execution of construction contracts, financing, and issuance of a notice to
8 proceed, resulting in multiple missed critical milestones between September and
9 December 2025 and formal Events of Default. As a result, NV Energy and the
10 developer entered into a settlement, and on March 20, 2026, the PPA was
11 terminated after NV Energy received a settlement payment equal to the project’s
12 full development security.

13
14 **8. Q. PLEASE DESCRIBE THE REASONING FOR REQUESTING APPROVAL**
15 **OF THE POWER PURCHASE AGREEMENTS INCLUDED IN THIS**
16 **FILING.**

17 A. The Companies seek approval of the proposed PPAs as part of a long-term resource
18 strategy designed to meet projected energy and capacity needs, support compliance
19 with the Nevada RPS, and advance the State’s policy objectives for carbon
20 reduction. Each selected project demonstrates readiness to interconnect within the
21 IRP planning horizon, provides meaningful contributions toward reducing open
22 capacity positions, and offers competitive pricing consistent with market
23 conditions.

24
25 These PPAs also enhance system reliability, diversify the Companies’ resource
26 portfolios, and support customer sustainability objectives—including those served
27

1 through Energy Supply Agreements and large-customer renewable programs.
2 Collectively, the PPAs represent additions to the long-term resource plan and
3 support progress toward achieving a carbon-free portfolio by 2050.
4

5 **9. Q. PLEASE DESCRIBE THE COMPANIES’ APPROACH TO RENEWABLES**
6 **AND STORAGE REQUESTS FOR PROPOSALS (“RFP”) AND ENERGY**
7 **SUPPLY CONTRACTS.**

8 A. The Companies employ a flexible, technology-neutral procurement approach that
9 includes All-Source RFPs, bilateral negotiations, and Company-owned
10 development options to meet future resource needs. Procurement activities are
11 designed to address system reliability, RPS compliance, customer renewable
12 demand, and broader long-term planning requirements.
13

14 While RFPs remain central to identifying cost-effective renewable and storage
15 resources, the Companies continually evaluate all ownership models and
16 contractual structures—including PPAs, build-transfer options, and utility-owned
17 development—to ensure alignment with the Companies’ planning objectives and
18 market conditions. Results from these procurement activities are incorporated into
19 the IRP and future regulatory filings to ensure transparency and ongoing alignment
20 with customer and system needs.
21

22 **II. NAMED PLACEHOLDERS**

23 **10. Q. PLEASE DESCRIBE THE NAMED PLACEHOLDERS IN THE**
24 **ALTERNATIVE PLANS.**

25 A. The Companies’ named placeholders for the 2026 IRP consist of individual
26 renewable and storage resources. These include:
27

- Sierra Solar II BESS (battery storage),
- Sierra Solar II PV (solar photovoltaic),
- Multiple annual tranches of Wind-ID resources, with commercial operation dates spanning 2029 through 2041.

These named placeholders, which vary in size and timing among the plans, reflect resources under active development, resources located on Company-owned or managed land, or resources for which transmission capacity (e.g., SWIP North) enables realistic future procurement. Their inclusion supports Commission expectations for transparency and long-term planning consistency. The named placeholders are being included in response to Commission Order in Docket No. 23-08015.¹

11. **Q. PLEASE DESCRIBE THE WIND-ID PLACEHOLDER AND WHY IT IS INCLUDED AS A NAMED PLACEHOLDER.**

A. Idaho has a demonstrably strong and commercially viable wind resource, with over 1,100 megawatts (“MW”) of existing operating capacity. The cancellation of the ~1,000 MW Lava Ridge project in 2025²—driven by federal, state and local opposition rather than economics—has materially altered the development outlook, creating elevated political and permitting risk for large new wind projects in Idaho.

Idaho wind’s primary relevance to NV Energy is export optionality enabled by new transmission, particularly the Southwest Intertie Project–North (“SWIP-N”). SWIP-N, on which the Companies hold 952 MW of transmission rights, materially enhances transfer capability between Idaho, Nevada, and CAISO, increasing the

¹ April 9, 2024, Modified Final Order at 144, para. 333, and 150, para 6.

² Department of Interior Press Release, available at <https://www.doi.gov/pressreleases/interior-department-moves-cancel-reckless-biden-era-approval-lava-ridge-wind-project>.

1 value of geographically diverse renewable resources and improving market
2 liquidity for CAISO’s Extended Day-Ahead Market (“EDAM”) participants. Idaho
3 wind delivered over SWIP-N would complement Nevada solar by providing
4 seasonal and diurnal diversity, improving export value into western markets during
5 non-solar hours.

6
7 Idaho wind as a placeholder is being treated as long-dated, contingent supply
8 dependent on transmission and permitting resolution. This treatment appropriately
9 de-risks near-term plans while preserving optionality for NV Energy to access
10 lower-cost wind exports in the 2030s if conditions improve.

11
12 **12. Q. HOW DID THE COMPANIES DEVELOP PRICING ESTIMATES FOR**
13 **THE NAMED PLACEHOLDER PROJECTS?**

14 A. Pricing estimates for each named placeholder resource—such as Sierra Solar II PV,
15 Sierra Solar II BESS, and Wind-ID—were developed using the most current
16 National Renewable Energy Laboratory (“NREL”) cost data. Conservative
17 assumptions were applied to reflect uncertainties in the market caused by federal
18 policies applicable to solar and wind projects interfacing with federal land—
19 disproportionately affecting Nevada—as well as uncertainties related to tariffs, and
20 changes to tax credit eligibility of renewable and storage technologies, including
21 restrictions on supply chain requirements affecting energy storage technologies
22 such as BESS, as further described in the Renewables Section. These cost estimates
23 were uniformly applied across all individual named placeholders to ensure
24 consistent evaluation in long-term modeling.

1 **13. Q. PLEASE DESCRIBE THE COMPANIES’ APPROACH TO RENEWABLES**
2 **AND STORAGE RFP AND ENERGY SUPPLY CONTRACTS IN**
3 **CONJUNCTION WITH COMPANY-OWNED NAMED PLACEHOLDERS.**

4 A. In the 2026 IRP, individual named placeholders such as Sierra Solar II BESS, Sierra
5 Solar II PV, and the Wind-ID tranches are not being requested for approval. In
6 future IRP filings, projects will be advanced for regulatory approval only after full
7 project cost details are known and after each resource has demonstrated
8 cost-competitiveness through future renewable and storage RFP processes. The
9 Companies will continue using competitive solicitations to benchmark the
10 performance and cost of Companies-owned and third-party-owned resources before
11 seeking approval for any project.

12
13 **III. MARKET DEVELOPMENT**

14 **14. Q. WHAT IS THE STATUS OF THE WESTERN RESOURCE ADEQUACY**
15 **PROGRAM (“WRAP”), AND ARE THE COMPANIES STILL MOVING**
16 **FORWARD WITH PARTICIPATION?**

17 A. The Companies expressed their intent to withdraw from and laid out the reason for
18 withdrawing from WRAP in Docket 25-08027.³ The Companies formally notified
19 the Western Power Pool Board of Directors of its withdrawal on October 24, 2025.⁴
20 The Companies continue to monitor the WRAP program to evaluate changes and
21 developments that may make future participation advantageous.
22
23
24
25

26 ³ Docket No. 25-08027, 2025 ESP Update, Prepared Direct Testimony of Lindsey Schlekeway.

27 ⁴ NV Energy Notice of Withdrawal from the Western Resource Adequacy Program, available at
https://www.westernpowerpool.org/private-media/documents/NV_Energy_WRAP_Withdrawal.pdf.

1 **15. Q. WHAT IS THE STATUS OF DAY-AHEAD MARKET DEVELOPMENT?**

2 A. The Companies sought approval from the Commission to join the CAISO EDAM
3 on October 22, 2025.⁵ The Commission issued its decision on April 3, 2026,
4 granting the request. Subject to the Commission’s order on the Companies’ Petition
5 for Reconsideration, the Companies are targeting the Fall of 2028 to join EDAM.
6

7 **16. Q. HOW DO THE COMPANIES PLAN TO MEET SENATE BILL 448 (“SB
8 448”) REQUIREMENTS TO JOIN A REGIONAL TRANSMISSION
9 ORGANIZATION (“RTO”) BY 2030?**

10 A. The Companies recognize the statutory obligation under SB 448 to seek and
11 evaluate viable RTO options and continue to assess the evolving landscape of
12 Western market expansion. Joining EDAM is consistent with an incremental
13 pathway toward broader regional market integration.
14

15 The Companies will continue evaluating future Western market developments,
16 including EDAM evolution, Markets+, and any emerging RTO proposals, to ensure
17 compliance with SB 448 and to identify a market structure that delivers
18 cost-effective reliability benefits for Nevada customers.
19

20 **17. Q. WOULD JOINING A REGIONAL RESOURCE ADEQUACY PROGRAM,
21 A DAY-AHEAD MARKET, OR AN RTO IMPACT THE COMPANIES’
22 NEED FOR THE GENERATING RESOURCES PROPOSED IN THIS
23 FILING?**

24 A. No. Regardless of the Companies’ participation in external market structures,
25 including the Companies’ withdrawal from WRAP, joining EDAM, or any future
26 RTO participation, the Companies must maintain sufficient physical resources to

27 ⁵ Docket No. 25-10025.

1 meet forward-showing requirements and to ensure reliable service to Nevada
2 customers.

3
4 Market participation does not eliminate the requirement to demonstrate resource
5 sufficiency, nor does it reduce the capacity needed to meet the Companies' load
6 plus applicable uncertainty margins. Organized markets are designed to prevent
7 leaning on other participants; therefore, physical resource development remains
8 essential to compliance, reliability, and cost mitigation—irrespective of the
9 Companies' chosen market pathway.

10
11 **18. Q. WHAT RESOURCE ADEQUACY PROGRAMS ARE THE COMPANIES**
12 **CURRENTLY EXPLORING?**

13 A. The Companies are actively evaluating two resource adequacy (“RA”) program
14 structures across the Western Interconnection to ensure compliance with evolving
15 reliability requirements and to support long-term planning objectives. Although the
16 Companies have withdrawn from active participation in the WRAP program, they
17 continue to monitor WRAP’s progress, including refinement of RA rules, forward
18 showing requirements, and participation levels among Western balancing
19 authorities.

20
21 In addition, the Companies’ filing to join EDAM positions them to participate in
22 the EDAM Resource Adequacy framework, which is currently under development
23 by prospective EDAM entities. This EDAM RA initiative is expected to establish
24 standardized capacity requirements, enhanced deliverability rules, and improved
25 regional coordination for capacity procurement.

1 The Companies will continue monitoring and assessing WRAP and EDAM RA, to
 2 ensure alignment with Nevada’s long-term reliability needs, statutory obligations,
 3 and market participation objectives.

4
 5 **IV. OPEN POSITION LIMITS**

6
 7 **19. Q. WHAT ARE THE MAXIMUM OPEN POSITIONS THAT COULD**
 8 **REASONABLY BE FILLED WITH MARKET ENERGY?**

9 A. The Companies set systemwide open capacity position targets that step down from
 10 2,000 MW in 2027 to no more than 500 MW in 2031 and every year thereafter.

Year	2027	2028	2029	2030	2031	2032+
Open Position Target (MW)	2,000	1,250	1,000	750	500	500

11
 12
 13
 14 **20. Q. HOW DID THE COMPANIES CALCULATE THE OPEN POSITION**
 15 **LIMITS?**

16 A. The Companies consulted multiple market reports, conducted a Request for
 17 Information (“RFI”), and had bilateral discussions with other market participants
 18 to attempt to estimate the future availability of market energy.

19
 20 Reports from the Western Electricity Coordinating Council (“WECC”) and the
 21 North American Electric Reliability Corporation (“NERC”) highlight increasing
 22 resource adequacy risks across the Western Interconnection.⁶

23
 24
 25
 26 ⁶ The Western Interconnection stretches from Western Canada South to Baja California in Mexico, reaching eastward
 27 over the Rockies to the Great Plains. All of the electric utilities in the Western Interconnection are electrically tied
 together during normal system conditions and operate at a synchronized frequency operating at an average of 60Hz.
 More information is available at <https://www.energy.gov/oe/learn-more-about-interconnections>.

1 WECC’s 2024 Western Assessment of Resource Adequacy (“2024 WARA”)⁷
2 identifies material reliability challenges over the next eight years due to rapidly
3 rising loads, changing resource portfolios, and increasing operational complexity.
4 WECC projects electricity demand to grow nearly 20 percent between 2025 and
5 2034; more than double the growth forecasted just a few years earlier.

6
7 WECC also notes that the region’s shift toward variable renewable generation and
8 storage heightens exposure to multi-day periods of low renewable output and
9 extreme weather. At the same time, the Western Interconnection anticipates
10 roughly 172 gigawatts (“GW”) of new generation additions over the next decade,
11 more than twice the amount added in the preceding decade, yet WECC warns of
12 significant execution risks due to permitting, transmission constraints, supply chain
13 challenges, and workforce limitations. WECC further emphasizes that transmission
14 development and regional coordination are not keeping pace with system needs,
15 limiting the ability to rely on neighboring regions during stressed conditions.

16
17 The 2025 NERC Long-Term Reliability Assessment (“2025 LTRA”),⁸ released in
18 January 2026, provides supporting information that justifies concerns related to
19 resource adequacy in the Western Interconnection, including WECC-Southwest.
20 While WECC-Southwest is not currently designated as an Elevated- or High-Risk
21 area, NERC concludes that reliability conditions across the West are becoming
22 more challenging due to accelerating demand growth, ongoing retirements of
23

24 ⁷ The 2024 Western Assessment of Resource Adequacy, released on December 3, 2024, with the reliability outlook
25 for 2025 and subsequent nine years, is available at <https://feature.wecc.org/wara/>; the 2025 Western Assessment of
26 Resource Adequacy, released at the end of 2025, with the outlook for 2026 and subsequent nine years, is available at
27 <https://feature.wecc.org/2025wara/>.

28 ⁸ NERC’s 2025 Long-Term Reliability Assessment, released in January 2026, available at
https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf; NERC’s 2024 Long-Term Reliability
Assessment, released in December 2024 and corrected on July 11, 2025, available at
https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

1 dispatchable generation, and an increasing reliance on variable and energy-limited
2 resources. NERC emphasizes that these factors heighten exposure to energy
3 adequacy risk, particularly during summer peak and evening net-load conditions.

4
5 For WECC-Southwest specifically, the 2025 LTRA shows that planning reserve
6 margins remain above reference levels, but trend downward over time as load
7 growth and resource mix changes continue. The growing dependence on solar
8 resources shifts reliability risk into late-afternoon and evening hours, when load
9 remains elevated but solar output declines, creating conditions under which
10 resource adequacy may be stressed during extreme heat events.

11
12 The 2025 LTRA further supports concern by identifying neighboring WECC
13 subregions—such as WECC-Basin and WECC-Northwest—as projected to
14 experience Elevated or High Risk later in the assessment period. Because Western
15 systems rely heavily on interregional transfers, NERC notes that simultaneous
16 stress across the Western Interconnection can limit the availability of imports
17 during critical periods. As a result, regions like WECC-Southwest, even when
18 internally adequate under planning assumptions, may face increased vulnerability
19 during widespread Western heat events or other coincident system stresses.

20
21 Overall, both WECC and NERC conclude that accelerating load growth, resource
22 retirements, the evolving resource mix, and slow transmission development are
23 narrowing reliability margins and increasing the likelihood of capacity and energy
24 shortages under stressed system conditions.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

The Companies did not rely solely on market reports in making the determination. The Companies also used internal research to determine potential market depth. An RFI was issued in November of 2023 to determine market depth once the WRAP market became live. Utilizing the responses, bilateral discussions, and the above-mentioned reports, the Companies determined that capacity much greater than 500 MW after 2030 could be difficult to procure.

21. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT HOLLAND-DIRECT-1

STATEMENT OF QUALIFICATIONS

Michael Holland

Vice President, Resource Optimization

NV Energy

6226 West Sahara Avenue

Las Vegas, NV 89151

702.321.0796

Michael.Holland@NVEnergy.com

Professional Experience

NV Energy, Las Vegas, NV

Vice President, Resource Optimization, December 2024-Present

- Responsible for directing the development and execution of strategies to maximize the value of NV Energy's portfolio of energy supply resources through oversight of NV Energy's day ahead and real time operations analytics and trading activities around power, natural gas, carbon credit allowances, and coal
- Oversight of NV Energy's renewable origination activities
- Oversight of the contract management tasks for NV Energy's owned and contracted resources

BHE Renewables, Des Moines, IA

Director, Energy Trading, August 2022-December 2024

- Managed a team of power traders responsible for a generation portfolio spread across six markets
- Managed a team of natural gas traders responsible for retail and gas generation supply
- Responsible for trading capacity and renewable energy credits in multiple markets across the United States
- Directed teams responsible for onboarding new generation and coordinating market integration
- Provided due diligence expertise in both pricing and transmission for potential acquisitions and projects

NV Energy, Las Vegas, NV

Manager, Power and Gas Trading, July 2021-August 2022

- Managed a team of power traders responsible for managing both the short and long-term power positions
- Managed a team of gas traders responsible for the procurement of natural gas to supply both power plants and end-use customers
- Responsible for multiple Requests for Proposals (RFPs) yearly to ensure power and natural gas needs are met at the best price

Senior Power Trader, June 2018-July 2021

- Optimized NV Energy's generation portfolio and executed day-ahead power transactions consistent with the Company's risk management guidelines
- Administered multiple RFPs to fill seasonal power needs

Macquarie Energy, Houston, TX

Senior Real-Time Trader, November 2010-June 2018

- Traded hourly physical and virtual power in PJM, MISO, CAISO, SWPP, ERCOT, MIDC, and NYISO markets

Ameren UE, St. Louis, MO

Real-Time Power Trader, May 2008- October 2010

- Utilized various generation assets, physical trades, and virtual bids and offers to actively manage the real-time position to maximize profits and mitigate risk.

Education

Tulane University, Freeman School of Business, New Orleans, LA

Master of Business Administration – 2008

United States Naval Academy, Annapolis, MD

Bachelor of Science, English - 1999

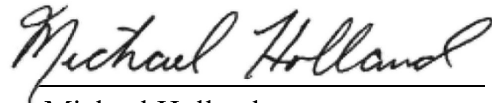
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MICHAEL HOLLAND, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: May 4, 2026


Michael Holland