# BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

| | |
|---|---|
| In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers. | **Docket No. 25-02___** |

**NEVADA POWER COMPANY D/B/A NV ENERGY**

**VOLUME 7 OF 19**

**TESTIMONY**



**Recorded Test Year ended September 30, 2024**
**Certification Period ending February 28, 2025**
**Expected Change in Circumstance Period ending September 12, 2025**

# JOHN LESCENSKI

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy (Electric)
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

**John Lescenski**

Revenue Requirement

## SECTION I: 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" or the "Company") and Sierra Pacific Power ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power.

**2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER, GENERATION ENGINEERING AND TECHNICAL SERVICES.**

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

**3. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes. I provided testimony in the Companies' past deferred energy accounting adjustments, general rate cases ("GRCs"), and integrated resource plans ("IRPs"), most recently in Docket No. 24-05041.

**4. Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?**

A. Yes, I am. In addition to my Statement of Qualifications (**Exhibit Lescenski-Direct-1**), I sponsor **Exhibit Lescenski-Direct-2**, which identifies major generation plant additions completed since the close of the Certification Period in Nevada Power's last GRC proceeding (May 31, 2023) and the projects that will be closed within the Certification Period in this filing.[1]

**5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. I support the reasonableness of Test Period operations and maintenance ("O&M") expenditures at Nevada Power's fleet of generating stations, and its request to include in rate base the costs associated with generation-related capital additions that have gone into service since the close of the Certification Period in Nevada Power's last GRC, Docket No. 23-06007.

[1] The Certification Period for this GRC is from October 1, 2024, through February 28, 2025.

In Section II, I describe the robust internal processes that govern the expenditure of both O&M dollars and capital investment.

In Section III, I support Nevada Power's investment in generation capital projects at its conventional generating stations that were completed between the close of the Certification Period in Nevada Power's last GRC and the close of the Test Period for this 2025 GRC.[2] These projects are closed to plant in service, in service, and are used and useful, providing electric service to customers.

In Section IV, I support capital projects anticipated to be placed in service and used and useful in providing electric service between October 1, 2024, and February 28, 2025, the Certification Period. The completion of these projects and their actual costs as of February 28, 2025, will be certified as a part of the Company's certification filing.

**6. Q. DO YOU SPECIFICALLY DISCUSS IN YOUR TESTIMONY ALL GENERATION PROJECTS CLOSED TO PLANT IN SERVICE SINCE THE CERTIFICATION PERIOD CLOSES IN NEVADA POWER'S LAST GRC?**

A. No. The Silverhawk Peakers Project is supported by Company witness Fady Atala. Company witness Jimmy Daghlian also supports recovery of the deferred costs associated with the Reid Gardner battery energy storage system. I support the remaining generation plant projects. While I support

[2] The Test Period for this case is from October 1, 2023, through September 30, 2024.

all generation plant investment reflected in the Company's proposed calculations of rate base, my testimony specifically discusses individual projects that cost $1.0 million or more. Nevada Power's generation team completed many projects under $1.0 million as of September 30, 2024. In recent GRCs, the Commission has accepted the $1.0 million threshold as appropriate for determining whether a project is "major," and thus, must be separately addressed in testimony. While not addressed in detail in my prepared direct testimony, project "binders" for smaller projects (greater than $500,000) completed since June 1, 2023, have been prepared. As has been Nevada Power's practice for many rate case cycles, those binders (now in electronic form) are available for review in this GRC filing.

## SECTION II: O&M AND CAPITAL COST CONTROL

**7. Q. HOW DOES NEVADA POWER MANAGE THE EXPENSES ASSOCIATED WITH OPERATING AND MAINTAINING ITS FLEET OF GENERATING PLANTS?**

A. To keep electric prices reasonable for the Companies' customers, Nevada Power maintains cost discipline for O&M expenses associated with generating plants using robust internal processes. At both Nevada Power and Sierra, cost discipline begins with a production schedule that forecasts the amount of energy that can be expected from the facility over the next 10 years. Then, each power plant management team carefully reviews all expenditures associated with running the power plants for which they are responsible. Plant directors use the production schedule, equipment condition assessments and Original Equipment Manufacturer ("OEM") recommendations to create an expenditure plan for each facility. Each power plant's expenditure plan is then rolled up into an overall expenditure plan for the fleet. Ultimately, the Companies must expend funds to maintain safe and reliable service, but an internal process is in place to exercise as much cost discipline as possible to the benefit of customers.

**8. Q. WHAT IS YOUR PROJECTION FOR FUTURE O&M EXPENSES FOR NEVADA POWER'S GENERATING FLEET?**

A. Future O&M expenses for Nevada Power's generating fleet will largely depend on variable costs and facility aging. The fixed costs to maintain generating units as reliable capacity resources remain relatively flat year over year (subject to inflation). Variable expenses are less predictable, as these costs depend on how units within the fleet are used. Most variable expenses are related to chemicals and other consumables, the costs of which increase with inflation, and the quantity of which vary according to each unit's actual operations during the year. Other variable expenses are related to wear and tear.

On a daily basis, the generating fleet cycles on and off and from low load to high load to provide the lowest cost energy supply for Nevada Power's customers. That cycling leads to wear and tear, and as the facilities age, equipment and systems will deteriorate, requiring increased maintenance expense to ensure compliance with operating standards and reliability for

Nevada Power's customers. Nevada Power's fleet is aging, and as units age, the cost of maintaining the units increases.

In this context, the Company continues to work diligently to achieve high reliability levels while maintaining O&M cost discipline so that customers benefit from reliable service at reasonable prices.

**9. Q. HOW DOES NEVADA POWER MANAGE CAPITAL INVESTMENTS IN THE GENERATING FLEET?**

A. Nevada Power plant and project managers follow a rigorous capital investment budgeting process, which guides the development of business cases and project estimates and governs how projects are managed, including through monthly reporting of schedule and budget status.

The generation team focuses on delivering the best value from the capital investment projects that are performed at the plants. Capital investment plans are developed in parallel with the expenditure plans described above. The starting point for the capital investment plan is the same unit-by-unit 10-year production forecast. Key assumptions are made concerning retirement, safety, risk management, environmental and other compliance requirements. Each plant team evaluates the current and expected performance of the units, and proposes capital investments needed to deliver reliability at a reasonable cost. The benefits of each capital investment are analyzed based on the planned remaining life of the unit.

I describe below the robust business planning and project management oversight process that Nevada Power uses to manage its capital investments.

**10. Q. WERE ALL OF THE CAPITAL PROJECTS COMPLETED SINCE THE END OF THE CERTIFICATION PERIOD IN NEVADA POWER'S 2023 GRC PRE-APPROVED BY THE COMMISSION?**

A. Except as noted below, these projects are considered maintenance capital to ensure the safe and reliable operation of the generating plants, and thus, are not presented to the Commission for pre-approval.

**11. Q. PLEASE DESCRIBE THE BUSINESS PLANNING PROCESS AS A COMPONENT OF NEVADA POWER'S INTERNAL PLANNING AND PROJECT MANAGEMENT OVERSIGHT PROCESS.**

A. Business planning begins with a 10-year Generation Capital Plan ("Capital Plan"), which includes a list of capital projects for each generating plant. The Capital Plan is updated annually. During the annual update process, each plant receives a fresh assessment, and the Company may identify new projects that are required, modify existing projects, and remove projects from the Capital Plan as appropriate.

A Business Case is developed for every project that is included in the Capital Plan. When I refer to the "Business Case," it includes documents that justify the project and include the scope, schedule and an estimated cost, as well as a cost-benefit analysis. Because the Capital Plan spans 10 years into the future, many of the initial Business Cases are based on a preliminary scope and schedule and utilize cost estimates. As a project is further developed, preliminary engineering is performed, a detailed scope of work and schedule are established, and a detailed cost estimate is prepared. The initial Business Case is updated with new information as it becomes available, and the cost-benefit analysis is reassessed to determine whether the project should remain in the Capital Plan.

All Generation capital projects and their Business Cases are reviewed by the Generation leadership team. The Generation leadership team prioritizes the entire portfolio of capital projects as part of the 10-year business planning process. Projects mandated by legal, regulatory requirements, safety, and environmental compliance receive top priority. Other factors, such as improving or maintaining reliability, costs and efficiency, are only considered after legal, regulatory, safety and environmental projects are prioritized and funded.

All capital projects from each business unit within the Companies are submitted for cross-department review and prioritization as part of the company-wide 10-year business planning process. This step subjects Generation's capital project prioritization to peer review from other business units and prioritization among the entire capital portfolio.

Capital projects that progress through the Generation business unit, peer review and the prioritization process are then submitted for funding approval by executive management. Only approved projects are included in the approved Capital Plan.

**12. Q. PLEASE DESCRIBE THE PROJECT MANAGEMENT OVERSIGHT PROCESS.**

A. Inclusion of a project in the Capital Plan does not constitute final internal project approval. Specific project approvals must still be obtained. This process begins with the assignment of a project manager, who is responsible for executing a project or projects in the Capital Plan. The project manager is required to submit an Authorization for Expenditure ("AFE") for approval prior to commencing a project. The AFE includes the most current information regarding estimated project cost, budget information, and the Business Case. The AFE serves as a business control to ensure construction projects, plant additions and significant unbudgeted expenses are reviewed and approved by the appropriate levels of management before funds are committed and spent.

Project managers may submit a preliminary AFE requesting funds to perform engineering to fully develop a capital project's scope, schedule and budget. In these situations, the project manager is then required to update the Business Case and submit a supplemental AFE for the full funding of the project prior to committing and spending additional funds.

A Standard Project Proposal ("SPP") is prepared for capital projects exceeding $1 million and submitted with the AFE for management review and approval. The SPP template is designed to provide a consistent collection of supporting information to management and regulators. Depending on the size and complexity of the proposed project, business units can append additional relevant information to the SPP template.

Project managers are responsible for monitoring actual and forecast spending against the approved project funding amounts in the AFE. Project managers provide monthly cost, schedule and scope updates for each project to Generation management. Each business unit performs a thorough review and analysis of its capital portfolio on a monthly basis. Business units review project performance with project managers. Business units forecast capital spending, analyze budget variances, perform peer reviews, and report results to Corporate Finance and to the executive team monthly.

**13. Q. PLEASE ADDRESS DISCRETIONARY SPENDING AS IT RELATES TO NEVADA POWER'S CAPITAL MANAGEMENT PROCESS.**

A. As explained above, capital is prioritized first by legal, regulatory, safety and environmental requirements, then by financial considerations including costs, reliability and efficiency. Discretion is used across the prioritization process with the exception of projects designated as mandated by legal or regulatory requirements. While safety and environmental projects are designated as a high priority, these projects often cannot be justified economically, and the number of requests for investment are usually more than the entire capital budget. Management must use discretion in selecting which safety and environmental projects (that are not otherwise required by law) are given priority to ensure safe and reliable service. These decisions are typically based on the number of impacted employees, severity of the risk as it relates to providing reliable service, and whether administrative controls, such as modified processes and procedures, are possible.

**14. Q. HOW IS DISCRETION APPLIED TO FINANCIALLY JUSTIFIED PROJECTS?**

A. Again, far more requests are made for capital investment than can be funded under the budget. While ranking of projects by financial metrics (such as cost/benefit and profitability indexes) creates a prioritized listing, other points are also considered. For instance, some capital projects are tied to planned outages or other customer requirements, which may adjust the relative ranking or proposed timing of an investment. An emerging risk (e.g., security enhancements) may also impact the relative ranking of a project. Finally, some projects may be marginally economic based on assumptions such as retirement date or expected impacts on expense or workforce. In these circumstances, discretion must be used in evaluating the financial analysis. For example, since retirement dates cannot be predicted with exact certainty, especially when the date used for planning and depreciation is several years out, this uncertainty illustrates the need for discretion in analyzing financially justified projects.

**SECTION III: GENERATION INVESTMENT BETWEEN JUNE 1, 2023, AND SEPTEMBER 30, 2024**

**15. Q. PLEASE ADDRESS THE MAJOR PROJECTS THAT WERE COMPLETED BETWEEN JUNE 1, 2023, AND SEPTEMBER 30, 2024.**

A. Nevada Power has made major investments in its generation fleet since the close of the certification period in the 2023 GRC. I discuss the following major investments in turn:

A. Chuck Lenzie Generating Station
1. CL2177 Air-Cooled Condenser ("ACC") Fan Gearbox Replacement
2. CL2178 ACC Fan Gearbox, Replacement
3. CL2352 PB1 Condensate Storage System
4. CL2353 PB2 Condensate Storage System

B. Clark Station
1. CS2199 Unit 9 - Cooling Tower Replacement
2. CS2200 Unit 10 - Cooling Tower Replacement
3. CS2204 Clark Unit 8 CT Hot Gas Path
4. CS2221 Unit 4 – 10 Distributed Control System ("DCS") Upgrade
5. CS2270 Clark Peaker Ovation Migration
6. CS2393 Unit 20 B - Gas Generator
7. CS2407 Unit # 4 - Replace Exhaust Stack

C. Harry Allen Generating Station

1. HA2139 Peaker Controls Update
2. HA2148 Air Cooled Condenser Fan Gearbox
3. HA2149 Air Cooled Condenser Fan Ge
4. HA2155 HA3 Combustion System Capital

D. Las Vegas Generating Station

1. LC2203 LVG - Heat Trace Overhaul/Upgrade

E. Silverhawk Generating Station

1. SH2199 ACC Fan Gearbox, Replacement 2023
   SH2200 ACC Fan Gearbox, Replacement 2024
2. SH2273 Combined Cycle Air Compress

F. Sun Peak Generating Station

1. SK2050 GT Wet Compression System

G. Higgins Generating Station

1. WH2159 Distributed Control System
2. WH2194 Hot Reheat Bypass VLV, Replacement
3. WH2195 Hot Reheat Bypass VLV, Replacement

H. Goodsprings Generating Station

1. GS2030 Citect Conversion

### A. Chuck Lenzie Generating Station

#### 1. CL 2177 and CL2178 – ACC Fan Gearbox Replacement

**16. Q. PLEASE DESCRIBE THE ACC FAN GEARBOX REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.**

A. The Chuck Lenzie Generating Station uses an ACC instead of the typical wet condenser. The ACC consists of 100 fans and motors for condensing steam back into water using air circulation. When fans are out of service, the unit efficiency declines significantly. One or two fans out of service will not greatly reduce efficiency of generation, however, should more fans fail, the plant would start experiencing more significantly reduced efficiency or operations given inadequate air circulation.

A new gearbox, which makes the fan operational, requires rebuilding after about five years of service. The costs to rebuild are close to 75 percent the cost of new gearboxes, but do not have the same useful life of a new unit. The gearbox housing and base components are not replaced with a rebuild and a rebuilt gearbox will require rebuilding again within three years. As such, after a few rebuilds, it is more cost effective and efficient to replace the gearbox than it is to rebuild it. Many of Chuck Lenzie ACC gearboxes were more than 15 years old, in poor condition and required replacement. Within the past couple of years, multiple gearboxes have failed and there are no replacements or spares. Borescope inspection results show that multiple other boxes have failing internal gears.

The scope of this project was the replacement of 12 gearboxes per project (24 total) through two projects CL2177 and CL2178

**17. Q. WHAT WERE THE TOTAL COSTS OF THE PROJECTS?**

A. The total plant-in-service recorded for these projects were $963,328 (CL2177) and $1,060,471 (CL2178), including allowance for funds used during construction ("AFUDC"). All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project costs were $962,626 (CL2177) and $1,057,411 (CL2178), excluding AFUDC, and were originally estimated to be $2,023,799 combined, excluding AFUDC.

**2. CL 2352 and CL2353 Condensate Storage System**

**18. Q. PLEASE DESCRIBE THE CHUCK LENZIE CONDENSATE STORAGE SYSTEM PROJECT AND WHY IT WAS NECESSARY.**

A. The Chuck Lenzie Generating Station was originally designed to operate with very few shutdowns and startups (cycling). Historically, shutting down or starting up both Power Blocks (PB1 and PB2) at the same time happened less than once per year. The current demineralized water makeup and storage system was adequate in the past due to very infrequent cycling of both power blocks simultaneously. As more renewable energy, primarily solar, has been introduced to the grid, the need to completely cycle both power blocks off and on simultaneously has dramatically increased. During non-summer months, cycling both blocks off and back on every day has become commonplace.

Startups and shutdowns necessitate a dramatic increase in the demand for demineralized water for the boilers. Between startup and shutdown, drains are opened to prevent condensation in the boiler tubes, and the boiler drums must be drained and then refilled during startup. A full single block startup utilizes the maximum flow that the water forwarding system can deliver. Additionally, a significant percentage of the demineralized water storage tank capacity is used during the startup. Multiple power block startups in a single day can heavily tax the demineralized water delivery and storage capacity. The two power blocks at the Chuck Lenzie Generation Station depended on one single source of makeup demineralized water. Running reserve capacities to low levels creates a risk of completely expending makeup water for both power blocks. To reliably meet this dramatically increased demand, and provide redundancy, equipping each power block with a dedicated storage tank and forwarding pumps was necessary.

The objective of the Condensate Storage System Installation Project was to ensure that the two power blocks have sufficient demineralized water available for the multiple startups and shutdowns the plant has experienced due to more frequent, and often simultaneous, cycling. The scope of these projects was the construction of one, 30-foot round and 26-foot tall, storage tank and all necessary appurtenances (piping, valves, pumps, electronics, etc.) to serve as a reservoir for the needed demineralized water for each individual power block.

**19. Q. WHAT WERE THE TOTAL COSTS OF THE PROJECTS?**

A. The total plant in service recorded for these projects was $2,020,314 (CL2352) and $1,886,714 (CL2353), including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project costs were $1,989,186 (CL2352) and $1,749,743 (CL2353), excluding AFUDC, and were originally estimated to be $2,075,667 (CL2352) and $2,075,667 (CL2353), excluding AFUDC.

### B. CLARK STATION

#### 1. CS2199 and CS2200 Clark 9 and 10 Cooling Towers

**20. Q. PLEASE DESCRIBE THE CLARK 9 AND 10 COOLING TOWER REPLACEMENT PROJECTS AND WHY THEY WERE NECESSARY.**

A. The Clark 9 and 10 cooling towers were commissioned in 1991 and 1993, and the existing wooden cooling tower structure had exceeded its useful life at 33 years and 31 years. The life expectancy of a wooden cooling tower is 20 years. In 2017, due to an inspection of the cooling tower, a project was completed to extend the useful life an additional seven years at a cost of $ 705,911. In November of 2023, an inspection identified expected deterioration in the structural integrity of the aging wooden cooling towers. The current estimated repairs to the wooden cooling tower structures were $ 1,400,000 each and would only extend the useful life by five years. Using a repair approach, several additional projects for an estimated $8.4 million would be required to maintain the repaired tower, on five-year intervals, to continue the operation of the aging wooden cooling tower structure and critical components until retirement in 2043.

The scope of the projects was to rebuild the existing cooling towers to extend the useful service life to 2043 using the existing concrete basins, sump, pumps, and piping systems. The design of the new cooling tower structures is low maintenance, utilizing Fiberglass Reinforced Plastic ("FRP") with a life expectancy of 34 years. Use of this FRP eliminates the future cost to maintain the aging wooden structures and the on-going safety issues associated with maintaining aging wooden cooling tower structures through a costly repair cycle until retirement in 2043.

**21. Q. WHAT WERE THE TOTAL COSTS OF THE PROJECTS?**

A. The total plant in service recorded for these projects was $3,466,870 (CS2199) and $3,669,751 (CS2200), including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project costs were $3,350,483 (CS2199) and $3,537,403 (CS2200), excluding AFUDC, and were originally estimated to be $3,124,705 (CS2199) and $3,555,886 (CS2200), excluding AFUDC.

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

**2. CS2204 Clark Unit 8 CT Hot Gas Path**

**22. Q. PLEASE DESCRIBE THE CLARK UNIT 8 CT HOT GAS PATH PROJECT.**

A. The Company owns and operates a fleet of four Siemens/Westinghouse 501B6-DNL Gas Turbines, known as Clark Units 5-8. These turbines were commissioned in the late 1970s and early 1980s and were upgraded with a third-party combustion system between 2008 and 2010 at the time of their last major inspections. The planned retirement dates for these units are in 2043.

As of September 8, 2023, Unit 8 had 1,639 starts since the last maintenance outage/inspection. Based on a risk evaluation after these starts, the unit was above a 90 percent "near certain" that a major combustion component failure would occur, resulting in a high impact outage.

The scope of this project was to complete the hot gas path inspection, which includes the disassembly, inspection, component replacement/reconditioning, and reassembly of the entire combustion turbine. As a result of the hot gas path inspection, several high wear components were replaced with new pieces while other components were reconditioned and reinstalled.

**23. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for this project was $2,702,811, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $2,658,212, excluding AFUDC, and was originally estimated to be $2,667,454, excluding AFUDC.

### 3. CS2221 Clark Unit 4-10 DCS Upgrade Project

**24. Q. PLEASE DESCRIBE THE CLARK UNIT 4-10 DCS UPGRADE PROJECT.**

A. The control system at Clark Station is more than 10 years past the expected life of the system. In addition, due to the age of the system software and security upgrades have not been available for the control system. Both the Human Machine Interface ("HMI") and server hardware have been out of production for 15 years and there are no hardware replacements available for failed HMI or server parts from certified sources.

The objective of the Clark Station Controls System Replacement Project was to engineer, procure, and construct a single DCS platform control system to replace the existing control systems for Units 4 through 10. The project was specifically designed to meet the cyber security requirements required by North American Electric Reliability Corporation Critical Infrastructure Protection ("NERC CIP") regulations, and the Companies' internal cybersecurity risk elimination strategy. The NV Energy

Operations Technology Group ("Operations Technology") developed a plan that would bring all the plants in the fleet in line with program requirements, while leveraging existing outage schedules to minimize installation costs. The project included replacement, upgrades, updates, and integration of control system hardware and software, infrastructure improvements, and reconfiguration/remodel of the control center. The completion of this controls upgrade project met the NERC CIP regulations, as well as the Companies' Operations Technology implementation plan.

**25. Q. WAS THIS PROJECT PREVIOUSLY PRESENTED IN ANOTHER DOCKET?**

A. Yes. This project was presented in my direct and certification testimony in Nevada Power's 2023 GRC, Docket No. 23-06007. I noted in my certification testimony (Q&A 13), that certain costs that were included in the original estimate would occur after May 31, 2023. This filing includes those costs that were part of that project that fell outside the certification period in that filing.

**26. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded during the Test Period for this project was $1,550,420, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $10,268,478, excluding

AFUDC, and was originally estimated to be $10,409,344, excluding AFUDC.

#### 4. CS2270 Clark Peaker Ovation Migration

**27. Q. PLEASE DESCRIBE THE CLARK PEAKER OVATION MIGRATION PROJECT.**

A. The existing Clark Peakers' Control System, used to control the engines and power turbines, is a 15-year-old Woodward Micronet system, which cannot be patched while online, does not have redundant controls, and failed to meet the Companies' cybersecurity standards. Moreover, the existing Clark Peakers' Balance Of Plant's ("BOP") Ovation DCS is version 1.9, with Solaris 10 as the operating system on the Sun Ultra 25 HMIs. This DCS is outdated and has been unsupported by the vendor resulting in the lack of security patches and replacement parts.

Executive Order 13920[3] addressing cyber security threats to the bulk power system and NERC regulations have made it nearly impossible to legally acquire parts for these systems from the online sellers of used parts. Additionally, the existing Emerson Ovation Control System and Solaris Operating System are outdated and non-compliant with NV Energy's current Vulnerability Management standard, posing significant threats to cyber security, physical safety, and system reliability.

---

[3] 2020-09695 (85 FR 26595)

The objective of this project was to replace the Woodward Micronet system with Ovation DCS version 3.7. This will bring the systems into cyber security compliance, enable security patching while online, and increase operational reliability. Additionally, the project upgraded the Emerson Ovation DCS from version 1.9 to 3.7, migrated the Solaris Operating System to the latest Windows version for both servers and HMIs, and upgraded the associated workstations. This brought the systems into cyber security compliance, enabling security patching and increased operational reliability.

**28. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for this project was $13,386,491, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the project costs were prudently incurred. The total project cost was $11,973,179, excluding AFUDC, and was originally estimated to be $12,491,374, excluding AFUDC.

### 5. CS2393 Clark Unit 20B Gas Generator

**29. Q. PLEASE DESCRIBE THE CLARK UNIT 20B GAS GENERATOR PROJECT.**

A. Clark Generating Station has 12 Pratt and Whitney Power Systems FT8 Swift Pac Units. Each unit produces 52 MW. The FT8 Swift Pac Turbine Unit uses two GG8-3 gas generators to turn a single generator. Each unit's gas generator is coupled to the generator by a power turbine. The power turbine transfers the hot gas energy from gas generator into rotating power to turn the generator. Since commissioning in 2008, the Unit 20 B gas generator has 6648.4 run hours with 1954 starts. On November 5, 2022, the Company and Mitsubishi Power Aero LLC ("Mitsubishi") determined that Unit 20 B gas generator (Model GG8-3 - SN P726442) has damage in the combustor and low-pressure turbine section. The damage consisted of distress and blade shingling observed on the second Stage LPT blades. Continued operation would result in catastrophic damage. This type of repair on an aero derivative gas generator/turbine (based on Pratt & Whitney's JT8D aircraft engine) cannot be performed on site.

The scope of work for this project was the removal of Unit 20 B gas generator from the unit and shipping the unit to Mitsubishi's shop for reconditioning. The project included installation of a rotatable spare GG8-3 gas generator and return of the unit to service. The damaged gas generator will be repaired and reconditioned and returned to the plant. It will become a spare unit for future use.

**30. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for this project was $2,387,867, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the project costs were prudently incurred. The total project cost was $2,033,712, excluding AFUDC, and was originally estimated to be $2,949,430, excluding AFUDC.

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

### 6. CS2407 Clark Unit 4 Replace Exhaust Stack

**31. Q. PLEASE DESCRIBE THE CLARK UNIT 4 EXHAUST STACK REPLACEMENT PROJECT.**

A. It was determined that effective May 1, 2024, Clark Unit 4 did not meet requirements under Environmental Protection Agency ("EPA") 40 CFR part 75 for continued operation through 2035. These requirements pertain to emission control testing to certify, record keep, and report emission data. A pre-project inspection of the existing exhaust stack found it to be structurally unsound; it needed to be replaced for continued unit operation, and to add the required sampling or monitoring ports under the new EPA's Method 1 guideline.

This project encompassed installing a new structurally sound stack to allow continued operation and testing. The new stack was configured to certify, operate, maintain, record keep, and report data in accordance with EPA's 40 CFR Part 75 for Clark Station Unit 4.

**32. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for this project was $3,686,188, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $3,670,626, excluding AFUDC, and was originally estimated to be $3,760,546, excluding AFUDC.

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

### C. HARRY ALLEN GENERATING STATION

#### 1. HA2139 Peaker Controls Upgrade

**33. Q. PLEASE DESCRIBE THE HARRY ALLEN PEAKER CONTROLS UPGRADE PROJECT AND WHY IT WAS NECESSARY.**

A. The Harry Allen Generating Station includes two peaker units (HA3 and HA4) within its system to ensure electric supply during high volume demand periods. These peaker units use a GE Mark VI system as the DCS, which was installed in 2015. The DCS, based on a Windows 7 operating system, had been updated over the years to maintain required reliability and essential cyber security.

The scope of this project was to replace the existing GE Mark VI DCS, which was outdated, unreliable, and inefficient in terms of cyber security compliance. The control system can no longer be patched as required by typical cyber security standards, creating a security vulnerability. In addition to this DCS for HA3 and HA4, all infrastructure, hardware, and software, is now at the end of its expected useful life and is no longer supported by the original equipment manufacturer. As such, the project included the upgrade, replacement, and installation of all related essential infrastructure equipment (computer hardware, wiring, connections, etc.) for the DCS, in addition to the software.

Because electric generating stations are critical, the Company adopted vulnerability management standards. The benefit of updating the peakers' control system is that it will be able to be properly maintained and patched to prevent a cyber attack. A fully updated system also will be supported by the equipment manufacturer permitting reliable repair, supply of replacement components, and support, as well as significantly reduce outage time in the event of a failure.

This replacement and update project has successfully brought the Harry Allen Peaker control system back into compliance with the Companies' standards, creating a reliable, efficient, effective, and secure control system.

**34. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant-in-service recorded for the project was $10,119,740, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $9,457,307, excluding AFUDC, and was originally estimated to be $7,872,624, excluding AFUDC. The variance from original estimates to record costs was due to additional scope that was added to include the newly installed wet compression system, as well as integrate the emission monitoring system into the DCS.

### 2. HA2148 and HA2149 Air Cooled Condenser Fan Gear Boxes

**35. Q. PLEASE DESCRIBE THE HARRY ALLEN AIR-COOLED CONDENSER FAN GEAR BOX PROJECTS AND WHY THEY WERE NECESSARY.**

A. These projects are similar to the projects discussed above for the Chuck Lenzie Station. The Harry Allen Generating Station uses an ACC system to condense steam to water instead of a wet condenser. This system utilizes 40 fans with motors and gearboxes to condense steam back into water. When a fan is out of service, the unit's efficiency declines

As discussed above, a gearbox requires rebuilding after about five years of service. Rebuild costs are close to 75 percent the cost of new gearboxes but the rebuilt unit does not have the lifespan of a new unit. A gearbox can be rebuilt two or three times before the base components can no longer be serviced or repaired. After a few rebuilds, it is more cost effective to replace the gearboxes rather than rebuild them.

Multiple gearboxes have been replaced to date at the Harry Allen Generating Station. However, borescope inspections have shown that multiple other gearboxes have failing internal gears. If multiple boxes were to fail, there would be a significant impact to the efficiency and availability of the power block. Replacing the gearboxes that are showing signs of imminent failure will maintain reliability and prevent a derate. There are 24 total gearboxes in a condition that requires replacement. This project replaced the gearboxes over a two-year period, with 12 replaced in 2023 (HA2148) and 12 replaced in 2024 (HA2149).

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

**36. Q. WHAT WERE THE TOTAL COST OF THE PROJECTS?**

A. The total plant-in-service recorded for these projects were $1,061,819 (HA2148) and $1,110,688 (HA2149), including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total cost for the projects were $1,058,729 (HA2148) and $1,110,561 (HA2149), excluding AFUDC, and were originally estimated to be $984,405 each, excluding AFUDC.

### 3. HA2155 HA3 Combustion System Capital

**37. Q. PLEASE DESCRIBE THE HARRY ALLEN UNIT 3 COMBUSTION SYSTEM CAPITAL PROJECT AND WHY IT WAS NECESSARY.**

A. The last maintenance outage and overhaul for the combustion system on the Harry Allen Unit 3 was performed in May 2018. The combustion system parts (primary and secondary fuel nozzles, combustion liners, and transition pieces) were replaced at that time. Since May 2018, the combustion parts have run for approximately 670 starts. This is beyond the OEM limit of 450 starts. The hot gas path parts that were scheduled for replacement (Stage 1 Buckets, Stage 1 Nozzles, and Stage 1 Shrouds) had not been replaced in the Unit's history. These parts have approximately 1,494 starts, which is over the OEM limit of 900 starts. The Stage 2 Shrouds required replacement based on recent borescope inspection findings.

Unit 3 has seen increased usage since the plant started participating in the Energy Imbalance Market. With more renewable energy entering the grid, reliance on fast start units for peak support is in growing demand. To remain reliable and environmentally compliant, the unit needed the combustion and hot gas path system overhauled to achieve optimal operating efficiency and reliability. This project provided the capital funds needed for a combustion and hot gas path inspection.

**38. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for the project was $3,348,867, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $3,243,226, excluding AFUDC, and was originally estimated to be $2,981077, excluding AFUDC. The variance was due to additional needed equipment repairs that were identified during the overhaul and additional tuning needed during commissioning.

### D. Las Vegas Generating Station

#### 1. LC2203 Heat Trace Overhaul/Upgrade

**39. Q. PLEASE DESCRIBE THE LAS VEGAS GENERATING STATION HEAT TRACE OVERHAUL/UPGRADE PROJECT AND WHY IT WAS NECESSARY.**

A. Between February 8 and 20, 2021, a cold weather event occurred, primarily affecting the south-central United States. Severe, extreme cold temperatures and freezing precipitation caused 1,045 individual generating units (with a combined 192,818 MW of nameplate capacity) in Texas and the south-central United States to experience 4,124 outages, derates or failures to start. Due to the problems with power plants freezing in the south, NERC and the Federal Energy Regulatory Commission ("FERC") set regulatory requirements in the report titled "The February 2021 Cold Weather Outages in Texas and the South-Central United States."[4] These regulations required generation operators to: (1) identify and protect cold-weather-critical components and retrofit existing generating units, and (2) when building new generating units, to operate to specific ambient temperatures and weather based on extreme temperature and weather data and account for effects of precipitation and cooling effect of wind.

Following these new regulatory requirements, a heat trace circuit survey was conducted at the Las Vegas Generating Station in January 2023, with the findings showing that of the 27 circuits in power block 1 panels, 25 circuits failed, and of the 128 circuits in power blocks 2/3, 125 failed.

The scope of this project was to install freeze protection measures for cold-weather-critical components and systems per the recommendations in the

[4] NERC Reliability Standard EOP-011-2, Emergency Preparedness and Operations.

NERC/FERC report, “The February 2021 Cold Weather Outages in Texas and the South-Central United States.”

**40. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant-in-service recorded for the project was $4,421,664, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $4,280,743, excluding AFUDC, and was originally estimated to be $4,100,225, excluding AFUDC.

### E. SILVERHAWK GENERATING STATION

#### 1. SH2199 and SH2200 ACC Fan Gearbox Replacement

**41. Q. PLEASE DESCRIBE THE SILVERHAWK ACC FAN GEARBOX REPLACEMENT PROJECTS AND WHY THEY WERE NECESSARY.**

A. These projects are similar to the projects discussed above for the Chuck Lenzie Generating Station and the Harry Allen Generating Station. The ACC system utilizes 40 fans with motors and gearboxes to condense steam back into water. Numerous gearboxes have already been replaced on Silverhawk’s ACC. However, borescope inspections have shown that other gearboxes were failing and beyond repair. There are 24 gearboxes in the unit that have exceeded their useful life expectancy and require replacement. This project replaced 12 gearboxes in 2023 (SH2199) and 12 gearboxes in 2024 (SH2200).

**42. Q. WHAT WERE THE TOTAL COSTS OF THESE PROJECTS?**

A. The total plant in service recorded for the projects were $1,055,529 (SH2199) and $1,072,735 (SH2200), including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total cost for the projects were $1,052,362 (SH2199) and $1,069,705 (SH2200), excluding AFUDC, and were originally estimated to be $984,405 each, excluding AFUDC.

### 2. SH2273 Combined Cycle Air Compressor

**43. Q. PLEASE DESCRIBE THE SILVERHAWK COMBINED CYCLE AIR COMPRESSOR PROJECT AND WHY IT WAS NECESSARY.**

A. The Silverhawk Generating Station currently has a redundant compressed air system (two air compressors) providing instrument and component air to two combustion turbines, and one steam turbine. Compressed air is an essential and critical commodity for the Silverhawk Station. Compressed air is used to open and close valves and is needed for solenoids to properly operate equipment. If one compressor fails or is out of service for maintenance, the plant’s air system becomes a single point of failure, relying entirely on the one remaining compressor. This critically compromises the entire power block.

A total loss of compressed air would result in the shutdown of the two combustion turbines and the one steam turbine, compromising the entire combined cycle block (520MW). The probability of the compressors failing is exponentially increasing as the equipment has surpassed its typical useful life span of 10 to 15 years. This project replaced two aging, beyond useful life, air compressors and related air dryers with more reliable new compressors.

**44. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for the projects were $1,027,277, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $1,012,649, excluding AFUDC, and was originally estimated to be $900,987, excluding AFUDC.

### F. SUN PEAK GENERATING STATION

#### 1. SK2050 GT Wet Compression System

**45. Q. PLEASE DESCRIBE THE SUN PEAK GAS TURBINE WET COMPRESSION PROJECT AND WHY IT WAS NECESSARY.**

A. Sun Peak Generating Station’s Gas Turbines, Unit 3-5, were upgraded to benefit from the installation of a wet compression system to provide additional generating output (MW), operational flexibility, and increased efficiency during the peak summer operating season. The project achieved an average output increase of 8.8MW per unit.

During hot weather (peak summer operating) periods, the overall power output and efficiency of the Company's gas turbine fleet decreases with the increase in the ambient temperature. This reduction in output and efficiency follows heat transfer engineering principles where increases in ambient temperature reduce the mass flow rate (the air density decreases). Wet compression is accomplished by micro-nozzles producing an extremely dense fog and spraying more fog than is required to fully saturate the inlet air. The excess fog droplets are carried into the gas turbine's compressor where they evaporate and produce an interior cooling effect. This intercooling effect reduces the energy consumed by the compressor and allows for more power to be available at the output shaft of the combustion turbine.

**46. Q. WAS THIS PROJECT PREVIOUSLY PRESENTED TO THE COMMISSION IN AN INTEGRATED RESOURCE PLAN FILING?**

A. Yes. The wet compression upgrade to the Sun Peak units was included in the First Amendment to the 2021 Joint IRP, Docket No. 22-03024. The wet compression upgrades to the simple cycle combustion turbines were described in the Generation Narrative but not specifically requested for approval, because they were targeted for completion prior to the summer peak of 2022.

**47. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for the project was $6,212,936, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $5,787,411, excluding AFUDC, and was originally estimated to be $8,582,792, excluding AFUDC. The large variance was due to an estimate of the required BOP work needed to be completed that was ultimately not needed.

### G. HIGGINS GENERATING STATION

#### 1. WH2159 Distributed Control System

**48. Q. PLEASE DESCRIBE THE HIGGINS DISTRIBUTED CONTROL SYSTEM PROJECT AND WHY IT WAS NECESSARY.**

A. As noted above, the Company has embraced the Vulnerability Management program. This requirement includes the need to have systems robust enough that they can be scanned for vulnerabilities and patched without compromising operational reliability. This pre-supposes that the systems are current enough that security patches are available for the system.

The Walter Higgins Generating Station had the Siemens T3000 Control System ("T3K") updated in 2017, which replaced 18 other operating platforms and consolidated them into the T3K control system. The T3K system contained several internal flaws that were readily exploitable. In addition, the Siemens platform is not the Company's fleet standard, thereby making it expensive and difficult to maintain versus the fleet platform (Emerson Ovation). Specifically, the T3K control system was only operated at the Walt Higgins Generating Station, as that control system was original to the plant, and thus was different than the other operating system(s) within the Company's fleet.

This project replaced the T3K system with the Emerson Ovation DCS platform to ensure the Walt Higgins operating system was compliant with current cyber-security standards and was part of the standardized platforms being installed throughout the Company's generating stations. The project also updated the outlying systems (individual Programable Logic Controller ("PLC")) at the Walt Higgins Generating Station into the DCS or into a compliant PLC platform.

**49. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant-in-service recorded for the project was $14,121,102, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $12,993,902, excluding AFUDC, and was originally estimated to be $13,965,590, excluding AFUDC.

**2. WH2194 and WH2195 Hot Reheat Bypass Valve Replacement**

**50. Q. PLEASE DESCRIBE THE HIGGINS HOT REHEAT BYPASS VALVE REPLACEMENT PROJECTS AND WHY THEY WERE NECESSARY.**

A. The Walt Higgins Unit 1 and Unit 2 Hot Reheat Bypass valves were leaking externally and internally and were required to be replaced. The condition of the valve was affecting the operational ability to mix the Hot Reheat and Condensate flows and control the downstream temperatures and pressures prior to its distribution into the condenser. The station had been required to revise its operating sequence to operate the station, because the valves were not performing as designed. As a result, the startup(s) and shutdown(s) procedure was impacted.

The station is a 2x1 Combined Cycle generating station (two Combustion Turbines ("CT")/Heat Recovery Steam Generators ("HRSG") and one Steam Turbine ("ST")); the Hot Reheat Bypass Valves are integral to the reliable operation of the combined cycle of the station. Over the past several years, the valves have progressively degraded such that the valves could not be effectively operated as designed.

**51. Q. WHAT WERE THE TOTAL COSTS OF THE PROJECTS?**

A. The total plant in service recorded for these projects was $1,250,295 (WH2194) and $1,253,701 (WH2195), including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total costs for the projects were $1,201,320 (WH2194) and $1,206,442 (WH2195), excluding AFUDC, and were originally estimated to be $1,390,676 (WH2194) and $1,390,676 (WH2195), excluding AFUDC.

### H. GOODSPRINGS GENERATING STATION

#### 1. GS2030 Citect Conversion

**52. Q. PLEASE DESCRIBE THE GOODSPRINGS CITECT CONVERSION PROJECT AND WHY IT WAS NECESSARY.**

A. As discussed above, the Company adopted the cyber security best practice standard of the Top 20 CSC as published by the SANS organization. This standard, discussed above, includes Vulnerability Management program requirements that the Company has adopted. These requirements include the need to have systems robust enough that they can be scanned for vulnerabilities and patched without compromising operational reliability. This pre-supposes that the systems are current enough that security patches are available for the system. The control system at Goodsprings was Citect, which was regarded as obsolete. The Citect was a one-off system that had no other cohorts for support or equipment. The existing control system was also incapable of implementing all the cyber security controls that are required. Thus, the Goodsprings Generating Station's Citect Control System was required to be replaced with the Rockwell's Factory Talk View HMI system to install a patchable (security) package and to ensure compliance with the Vulnerability Management Program ("VMP") and current NV Energy and Berkshire Hathaway Energy ("BHE") cybersecurity standards.

**53. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for the project was $1,067,915, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $1,041,788, excluding AFUDC, and was estimated to be $1,329,936, excluding AFUDC.

## SECTION IV: LONG-TERM MAINTENANCE OR SERVICE AGREEMENTS

**54. Q. PLEASE DESCRIBE THE CAPITAL COSTS FOR THE LONG-TERM SERVICE AGREEMENTS.**

A. The Long-Term Service Agreements ("LTSA") are multi-year agreements covering the Lenzie, Harry Allen, Tracy, Silverhawk and Higgins F-class combined cycle units. The LTSAs were established to assure reliability of the large-combined cycle turbines and generators while levelizing maintenance expenses over the term of the agreements. The LTSAs provide for full inspection, replace and repair coverage of the combustion turbines and inspections only for the compressors, generators and steam turbines. Needed repairs to the compressors, generators and steam turbines are not covered in the LTSA hourly fee and are considered extra work. These agreements have been discussed in rate cases for both Companies, specifically for Sierra in Docket Nos. 10-06001, 13-06002, 16-06006, 19-06002,22-06014 and 24-02026, and for Nevada Power in

Docket Nos. 11-06006, 14-05004, 17-06003,20-06003 and 23-06007. All quarterly, annual and milestone costs associated with LTSAs are allocated between O&M expense and prepaid capital according to a contract-specific predetermined allocation. Journal entries are posted for each outage to transfer the prepaid capital to construction work in progress/plant in service based on a historical capital ratio (by outage type) and overall prepaid capital expected for the agreements.

**55. Q. WERE THE LTSAS AND SUBSEQUENT OUTAGE PROJECTS PREVIOUSLY APPROVED BY THE COMMISSION?**

A. Yes. The LTSA costs and accounting methodologies for the LTSAs have been reviewed and approved by the Commission in the above-noted dockets. A revision and Generator Extra Work Agreement was executed on December 20, 2024, to the current LTSAs; however, the accounting for the LTSA has not changed since the Commission Orders in Docket Nos. 14-05004 (Nevada Power) and 16-06006 (Sierra).

**56. Q. WHAT ARE THE COSTS OF THE LTSA OUTAGE PROJECTS?**

A. I discuss below the LTSA projects completed during the Test Period and several LTSA projects that will be completed during the Certification Period and included in this Application.

**1. HA1050 Steam Turbine Overhaul**

**57. Q. PLEASE DESCRIBE THE HARRY ALLEN STEAM TURBINE OVERHAUL PROJECT AND WHY IT WAS NECESSARY.**

A. The Harry Allen Generating Station had scheduled a planned outage for its steam turbine in 2023. Turbine outages are planned for every 32,000 hours of operation to replace worn or damaged capital components. Components, such as rotating and stationary blades, valve parts, steam seals, etc., had been identified as requiring replacement through both borescope and internal inspection of the steam turbine during that planned outage. This project included replacing turbine components, requiring a complete disassembly of the turbine.

**58. Q. WAS THIS PROJECT PREVIOUSLY PRESENTED IN ANOTHER DOCKET?**

A. Yes. This project was presented as a certification period project in Nevada Power's 2023 GRC, Docket No. 23-06007. The costs presented here were costs that were incurred as part of the project to refurbish the high-pressure and intermediate-pressure turbine diaphragm during the overhaul. These costs were not included in the plant-in-service recorded at the end of the certification period for that rate case, and thus, are included in this filing.

**59. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service for the project included in the Test Period was $1,612,493, including AFUDC. The costs included in the certification filing in Nevada Power's 2023 General Rate Case, Docket No. 23-06007, were $1,315,696, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the project costs were prudently incurred. The total project cost was $2,925,353, excluding AFUDC, and was originally estimated to be $2,936,624, excluding AFUDC.

### 2. HA2299 HA7 Generator Rewind and Rotor

**60. Q. PLEASE DESCRIBE THE HARRY ALLEN UNIT 7 GENERATOR REWIND AND ROTOR PROJECT AND WHY IT WAS NECESSARY.**

A. Harry Allen Unit 7 experienced a differential relay event, which led to a trip and subsequent outage. This event was triggered by a generator protection fault. Initial testing revealed significant issues in the “A” and “B” phase windings, including oil residue. Further investigations linked these issues to significant motion within the windings, exacerbated by an oil overflow incident in June as the unit was coming out of an earlier outage. This oil infiltration led to unwanted lubrication, causing increased vibration and movement in the generator components. The complexity and severity of these issues, especially the oil diffusion throughout the generator components, had made it clear that repairing without a complete rewind would not eliminate the substantial risk of generator failure. A generator rewind was deemed essential, and thus, was completed.

**61. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The total plant in service recorded for the project was $9,795,072, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total cost for the project was $9,684,728, excluding AFUDC, and was originally estimated to be $10,268,192, excluding AFUDC.

**3. CL2521, CL2522, CL2523, CL2524 – Chuck Lenzie CT Rotor Replacements**

**62. Q. PLEASE DESCRIBE THE CHUCK LENZIE ROTOR REPLACEMENT PROJECTS AND WHY THEY WERE NECESSARY.**

A. The rotors in the combustion turbines at Chuck Lenzie were nearing the end of their designed operational life after reaching 144,000 run hours. Continued operation of these turbines beyond this limit poses a risk of catastrophic rotor failure, potentially leading to significant safety hazards and prolonged unit downtime. Proactive replacement of the rotors is crucial to maintaining turbine reliability and ensuring personnel safety.

General Electric ("GE"), the OEM, determined that upon reaching the 144,000-hour or 5,000-start threshold, there were two options for Chuck Lenzie's GE 7FA CT: (1) replace the rotor or (2) conduct a detailed inspection. Generally, industry practices lean towards replacement, given that a thorough inspection entails shipping the rotor to a specialized facility for a process known as "destacking." This involves removing bolts and disassembling all rotor components for non-destructive examination, replacing any necessary parts, and then reassembling. Given the time-intensive nature of this procedure, which requires months of unit downtime, rotor replacement can achieve the same result with less than one month of downtime.

A rotor exchange program is included in the LTSA between GE and the Company. This initiative allows for the substitution of a rotor that is nearing its operational limit with a new rotor that has the same life expectancy of 144,000 hours and 5,000 starts.

**63. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THESE PROJECTS?**

A. The current estimated cost of completion for these projects is $14,617,706 for each rotor project, including AFUDC, and the projects will be in service before February 28, 2025.

**64. Q. WERE THESE PROJECTS INCLUDED IN THE CERTIFICATION ESTIMATES PROVIDED IN THIS FILING?**

A. No. These projects were originally intended to be completed after the Certification Period in 2026, so they were not included in the Schedule H-CERT-13 when the Company developed these estimates. However, after review of the number of operating hours on the turbine rotors and consultation with GE, it was determined that these rotor replacements would need to be accelerated to ensure reliability of the units during the upcoming summer season. These replacements will be completed in January and February of this year.

Company witness Christina Hanshew addresses this in her Direct Testimony.

**4. SH2396 CTB Oil Deflector**

**65. Q. PLEASE DESCRIBE THE SILVERHAWK COMBUSTION TURBINE B OIL DEFLECTOR REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.**

A. The oil deflectors and seals on CT B at Silverhawk Generating Station were failing, resulting in significant oil consumption and leakage through the bearing casing. This poses a major safety risk due to potential fires in the exhaust section. To address this, the failing components will be replaced during the next available borescope outage. This proactive approach will mitigate the fire hazard, restore operational efficiency and eliminate excessive oil consumption.

**66. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?**

A. The current estimated cost of completion for this project is $1,757,765 including AFUDC, and the project will be in service before February 28, 2025.

**SECTION V: GENERATION INVESTMENT BETWEEN OCTOBER 1, 2024, AND FEBRUARY 28, 2025.**

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

**67. Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.**

A. In this section of my testimony, I address Nevada Power's projected major investments in generating fleet assets between October 1, 2024, and February 28, 2025. I discuss the investments as follows:

A. Clark Station
1. CS2429 Unit 19B Gas Generator
2. CS2464 Unit 6 Generator Failure

B. Harry Allen Generating Station
1. HA2160 Guard House, Entrance Gate and Security Camera

C. Las Vegas Generating Station
1. LC2247 Permeate Water Tank and Equipment, Install

D. Silverhawk Generating Station
1. SH2180 CTA Boiler Feed Pump, Install
2. SH2181 CTB Boiler Feed Pump, Install
3. SH2252 Brine Concentrator Evaporator Tubes/Vessel

E. Higgins Generating Station
1. WH2231 WH1 HRSG Liner Plate - Phase 2, Replacement
2. WH2232 WH2 HRSG Liner Plate - Phase 2, Replacement

## A. CERTIFICATION – CLARK STATION

### 1. CS2429 Unit 19B Gas Generator

**68. Q. PLEASE DESCRIBE THE CLARK PEAKER UNIT 19B GAS GENERATOR PROJECT AND WHY IT WAS NECESSARY.**

A. On October 27, 2023, Mitsubishi's annual borescope report recommended that Unit 19B's Gas Generator failed hot gas path components—combustion fuel nozzles, combustion diffuser case, transition ducts, HPT nozzle guide vanes, HPT row 1 blades, and #4, #4.5, #5 bearings with carbon seals—be replaced as soon as possible to mitigate combustion mal-distribution, hot streaks, continued thermal erosion, and liberation of combustion components that would result in catastrophic damage. Overhauls of this type on an aero derivative gas generator/turbine (based on Pratt & Whitney's JT8D aircraft engine) cannot be done on site.

The Unit 19B A gas generator (SN P743069) was sent to Mitsubishi for inspection and overhaul, which was expected to take approximately 180 to 210 days. The unit was in a forced outage for approximately 10 days until the rotatable spare GG8-3 could be installed and aligned. This project funded the emergent removal of 19B's failed GG8-3 Gas Generator, installation of the rotatable spare GG8-3 Gas Generator, and repairs to the failed Gas Generator, which will become the new rotatable spare GG8-3 Gas Generator.

**69. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?**

A. The current estimated cost of completion for this project is $3,019,589, including AFUDC, and the project will be in service before February 28, 2025.

### 2. CS2464 Unit 6 Generator Failure

**70. Q. PLEASE DESCRIBE THE CLARK UNIT 6 GENERATOR FAILURE PROJECT AND WHY IT WAS NECESSARY.**

A. On August 22, 2024, Clark Unit 6 tripped offline. Generator protective relays were engaged due to an internal fault detected in the generator stator from “A” phase to ground and from “A” phase to “B” phase. Unit 6 was in a forced outage until the generator could be returned to service. The findings during the disassembly confirmed the following three faults: (1) “A” phase turbine end winding failure, (2) “A” phase to core failure, and (3) “B” phase to core failure.

The work scope included: the partial restacking of core steel that failed, stator rewind, rotor rewind, and exciter rebuild, bearing/oil seal replacement, and instrumentation replacement.

**71. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?**

A. The current estimated cost of completion for this project is $7,705,325, including AFUDC, and the project will be in service before February 28, 2025.

### B. CERTIFICATION – HARRY ALLEN GENERATING STATION

#### 1. HA2160 Guard House, Entrance Gate and Security Cameras

**72. Q. PLEASE DESCRIBE THE HARRY ALLEN GUARD HOUSE, ENTRANCE GATE AND SECURITY CAMERAS PROJECT AND WHY IT WAS NECESSARY.**

A. The Harry Allen Generating Station has a surveillance system (security cameras) that is obsolete and non-repairable. The plant has a temporary shelter for the security guard that is rented and will need a permanent guard house, because the facility is required to be manned 24-hours a day. The guard house is rented temporarily without a water supply or restroom. This poses a safety hazard for the guard during the summer and requires the guard to step out and leave the entry unattended. The scope of the project is to replace the rental guard house with a permanent facility equipped with a bathroom while correcting known camera issues, including multiple failing systems centered around the new building, along with hardware and communications hardware.

**73. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?**

A. The current estimated cost of completion for this project is $2,588,561, including AFUDC, and the project will be in service before February 28, 2025.

### C. CERTIFICATION – LAS VEGAS GENERATING STATION

#### 1. LC2247 Permeate Water Tank and Equipment

**74. Q. PLEASE DESCRIBE THE LAS VEGAS GENERATING STATION PERMEATE WATER TANK AND EQUIPMENT INSTALLATION PROJECT AND WHY IT WAS NECESSARY.**

A. The Las Vegas Generating Station's original construction consisted of one gas turbine and HRSG, which utilized a small permeate storage tank and pumping system to produce required deionized water ("DI"). The DI water was produced by pumping permeate water through a DI vessel/polisher, then directly to the gas turbine and HRSG. In 2003, the Las Vegas Generating Station commissioned blocks 2 and 3, which consisted of four gas turbines and two steam turbines, and a DI storage tank to compensate for the additional DI water required. The additional DI storage tank does not supply DI water to the original one gas turbine and HRSG. Adding an additional permeate storage tank will allow for tying both systems together and produce the required water chemistry parameters, which greatly reduces the risk of contamination of an exhausted DI vessel/polisher. Also, tying in both systems will increase storage capacity and allow for surges during high water demands by pumping the permeate water through a DI trailer. The DI trailer is designed for higher throughput and interlocking systems to prevent contamination, which will improve availability and reliability of the plant.

**75. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?**

A. The current estimated cost of completion for this project is $1,442,540, including AFUDC, and the project will be in service before February 28, 2025.

### D. CERTIFICATION – SILVERHAWK GENERATING STATION

#### 1. SH2180 and SH2181 CTA and CTB Boiler Feed Pump, Install

**76. Q. PLEASE DESCRIBE THE SILVERHAWK COMBUSTION TURBINE A AND B BOILER FEED PUMP INSTALLATION PROJECTS AND WHY THEY WERE NECESSARY.**

A. The boiler feed pump is one of the most critical pieces of equipment and typically most power plants will have a redundant boiler feed pump that can be used in case one fails. Silverhawk Generating Station does not have a redundant boiler feed pump, which results in a forced outage when the pump fails. The repair involves reducing the system's temperatures, which typically operates at 300 degrees Fahrenheit. Given its operating temperature, the unit can take up to 12 hours to cool down to ambient temperatures for the mechanics to work on it safely. A repair or replacement can take up to 30 days, if spare parts for the failed components are not available. The losses are significant, if there is a failure during summer. This project will install a redundant boiler feed pump with all the required piping and controls on both CTA and CTB.

**77. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THESE PROJECTS?**

A. The current estimated cost of completion for these projects is $4,355,781 (SH2180) and $4,170,391 (SH2181), including AFUDC, and the projects will be in service before February 28, 2025.

**2. SH2252 Brine Concentrator Evaporator Tubes/Vessel**

**78. Q. PLEASE DESCRIBE THE SILVERHAWK BRINE CONCENTRATOR EVAPORATOR TUBES/VESSEL PROJECT AND WHY IT WAS NECESSARY.**

A. Silverhawk Generating Station is a zero-discharge facility; the brine concentrator helps the plant reuse the water and keep the levels in the ponds at the permitted level. Over the past six years, the performance of the brine concentrator has degraded. The heat transfer efficiency has dropped, causing a 30 percent drop in distillate flow. The brine concentrator tubes have developed scale, which has hardened over time and is impossible to clean chemically or by high pressure water, reducing the overall area available for heat transfer. Furthermore, the tubes have developed leaks that form an air blanket over the tubes and impede heat transfer, thus contributing to the reduction of distillate flow. Therefore, the evaporator tube bundles and vessel needed to be replaced at the earliest available opportunity. If the evaporator tube bundles and vessel are not replaced in a timely manner, the plant will not be able to maintain the pond permitted level due to the brine concentrators inability to process pond water. This would result in the plant needing to be taken offline to prevent an environmental violation.

**79. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?**

A. The current estimated cost of completion for this project is $6,540,139, including AFUDC, and the project will be in service before February 28, 2025.

### E. CERTIFICATION – HIGGINS GENERATING STATION

#### 1. WH2231 and WH2232 HRSG Liner Plate Replacement

**80. Q. PLEASE DESCRIBE THE HIGGINS WH1 AND WH2 HRSG LINER REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.**

A. The HRSG Inlet Duct floor and wall(s) liner plates were required to be replaced and secured to maintain the HRSG's casing insulation layers and mitigate its degradation. The HRSG casing surface is not temperature rated for the hot flue gases exhausted from the combustion turbine; therefore, it is designed with layers of insulation and liner plates that cover and secure it in place. The liner plates prevent the hot gas air flow from direct contact with the insulation material that would otherwise erode and disseminate throughout the HRSG.

These two projects are the second phase of projects WH2218 and WH2219 that were completed in October 2023, during the Test Period. Although none of these projects were individually over $1 million, because they are multiple phases of the same work on two units, taken together the projects exceed $1 million. Thus, the projects have been included in my testimony.

**81. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THESE PROJECTS?**

A. The current estimated cost of completion for these projects is $609,320 (WH2231) and $609,321 (WH2232), including AFUDC, and the project will be in service before February 28, 2025.

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

A. Yes, it does.

# EXHIBIT LESCENSKI-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, regulatory planning and analysis, 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.

### 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 10-year Business Plans for all generating plants in the fleet, leading plant repowering/retirement analysis and providing input 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.

- Primary point of contact for regulatory filings for generation issues: testimony, narrative, data request, witness, witness support
- 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
- 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

Master of Arts in Economics – University of Nevada, Las Vegas ▪ 2019
Professional Paper: Econometric Analysis of the Effect of Deregulation on Retail Energy Prices
Graduate Certificate in Post-Secondary Teaching – University of Nevada, Las Vegas ▪ 2019
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

# EXHIBIT LESCENSKI-DIRECT-2

# Exhibit Lescenski-Direct-2
# Long Term Service Agreement Projects

**Projects Completed Between 06/01/2020 and 05/31/2023**

| | | **LTSA Costs** |
|---|---|---|
| C. Harry Allen Generating Station | | |
| HA1050 Steam Turbine Overhaul | $ | 1,612,493 |
| HA2299 HA7 Generator Rewind and Rotor | $ | 9,795,072 |

**Projects Completed Between 10/01/2024 and 02/28/2025**

| | | **LTSA Costs** |
|---|---|---|
| A. Chuck Lenzie Generating Station | | |
| CL2521 - LZ PB1 CT1 Rotor, Replace | $ | 14,617,706 |
| CL2522 - LZ PB1 CT2 Rotor, Replace | $ | 14,617,706 |
| CL2523 - LZ PB2 CT3 Rotor, Replace | $ | 14,617,706 |
| CL 2524 - LZ PB2 CT4 Rotor, Replace | $ | 14,617,706 |
| B. Silverhawk Generating Station | | |
| SH2396 CTB Oil Deflector, Replace | $ | 3,515,530 |

# Exhibit Lescenski-Direct-2
# Test Period Projects

**Projects Completed Between 06/01/2023 and 09/30/2024**

| | | Certification Period Estimate |
|---|---|---|
| A. Chuck Lenzie Generating Station | | |
| 1. CL2177 ACC Fan Gearbox, Replacement | $ | 963,328 |
| CL2178 ACC Fan Gearbox, Replacement | $ | 1,060,471 |
| 2. CL2352 PB1 Condensate Storage System | $ | 2,020,314 |
| CL2353 PB2 Condensate Storage System | $ | 1,886,714 |
| B. Clark Station | | |
| 1. CS2199 Unit 9 - Cooling Tower Replacement | $ | 3,466,870 |
| CS2200 Unit 10 - Cooling Tower Replacement | $ | 3,669,751 |
| 2. CS2204 Clark Unit 8 - CT - Hot Gas Path | $ | 2,702,811 |
| 3. CS2221 Unit 4 - 10 DCS Upgrade | $ | 1,550,420 |
| 4. CS2270 PKR Ovation Migration | $ | 13,386,491 |
| 5. CS2393 Unit 20 B - Gas Generator | $ | 2,387,767 |
| 6. CS2407 Unit # 4 - Replace Exhaust Stack | $ | 3,686,188 |
| C. Harry Allen Generating Station | | |
| 2. HA2139 Peaker Controls Update | $ | 10,119,740 |
| 3. HA2148 Air Cooled Condenser Fan Ge | $ | 1,061,819 |
| HA2149 Air Cooled Condenser Fan Ge | $ | 1,110,688 |
| 4. HA2155 HA3 Combustion System Capital | $ | 3,348,867 |
| D. Las Vegas Generating Station | | |
| 1. LC2203 LVG - Heat Trace Overhaul/Upgrade | $ | 4,229,350 |
| E. Silverhawk Generating Station | | |
| 1. SH2199 ACC Fan Gearbox, Replacement 2023 | $ | 1,055,529 |
| SH2200 ACC Fan Gearbox, Replacement 2024 | $ | 1,072,735 |
| 2. SH2273 Combined Cycle Air Compress | $ | 1,027,277 |
| F. Sun Peak Generating Station | | |
| 1. SK2050 GT Wet Compression System | $ | 6,212,936 |
| G. Higgins Generating Station | | |
| 1. WH2159 Distributed Control System | $ | 14,121,102 |
| 2. WH2194 Hot Reheat Bypass VLV, Replacement | $ | 1,250,295 |
| WH2195 Hot Reheat Bypass VLV, Replacement | $ | 1,253,701 |
| H. Generation Support | | |
| 1. GS2030 Citect Conversion | $ | 1,067,915 |

# Exhibit Lescenski-Direct-2
# Certification Period Projects

### Projects Completed Between 10/01/2024 and 02/28/2025

| | | Certification Period Estimate |
|---|---|---|
| B. Clark Station | | |
| 1. CS2429 Unit 19B Gas Generator | $ | 3,019,589 |
| 1. CS2464 Unit 6 Generator Failure | $ | 7,705,325 |
| C. Harry Allen Generating Station | | |
| 1. HA2160 Guard House, Entrance Gate and Security Cameras | $ | 2,588,561 |
| D. Las Vegas Generating Station | | |
| 1. LC2247 Permeate Water Tank and Equipment, Install | $ | 1,442,540 |
| E. Silverhawk Generating Station | | |
| 1. SH2180 CTA Boiler Feed Pump, Install | $ | 4,355,781 |
| SH2181 CTB Boiler Feed Pump, Install | $ | 4,170,391 |
| 2. SH2252 Brine Concentrator Evaporator Tubes/Vessel | $ | 6,540,139 |
| 3. SH2298 Entrance Gate and Guard Shack, Install | $ | 1,303,462 |
| 4. SH2300 C Plant Air Compressor, Install | $ | 1,146,829 |
| E. Higgins Generating Station | | |
| 1. WH2231 WH1 HRSG Liner Plate - Phase 2, Replacement | $ | 609,320 |
| WH2232 WH2 HRSG Liner Plate - Phase 2, Replacement | $ | 609,321 |

# 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: February 14, 2025

John Lescenski

# EVELENE RICCI

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

**Evelene Ricci**

Revenue Requirement

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

A. My name is Evelene Ricci. My current position is Director, Transportation for Nevada Power Company 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 295 Edison Way in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I joined the Companies in May 2005. I have more than 30 years of experience in the electric utility industry. My prior experience at the Companies has been in leadership roles in large customer account management, NVEnergize meter deployment, human resources and accounting. My background and experience are further described in **Exhibit Ricci-Direct-1**.

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES.**

A. As Director of Transportation, I am currently responsible for the management of Fleet Services, which includes the purchase, maintenance, administration, and repair of the Companies' vehicles and fleet equipment.

**4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes, I have testified in several proceedings before the Commission, most recently in Docket Nos. 22-06014, 23-06007, 24-02026, and 24-02027.

**5. Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following Exhibits:

- **Exhibit Ricci-Direct-1 –** Statement of Qualifications

**6. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My testimony addresses vehicle and fleet equipment investment costs completed since Nevada Power's 2023 general rate case ("GRC"), Docket No 23-06007. Specifically, I discuss investment in vehicles and fleet equipment since the close of the Certification Period in the 2023 GRC through the end of this GRC Test Period,[1] as well as vehicle and fleet equipment acquisitions completed in October of 2024. I also estimate vehicle and fleet equipment investments through February 28, 2025, the close of the Certification Period.[2] I provide specific information regarding the largest categories of investments for the Fleet Services department, the buyout of vehicles and fleet equipment lease financial arrangements and the acquisition of new vehicles and fleet equipment to replace units that have exceeded their life cycles. Additionally, Nevada Power estimated investments in electric vehicle

---

[1] The Test Period for this case is June 1, 2023, to September 30, 2024.
[2] The Certification Period for this case runs from October 1, 2024, to February 28, 2025.

charging stations and safety systems for lighter duty vehicles. Combined, these expenditures represent approximately $1.0 million in plant investment for Nevada Power through February 28, 2025.

**Table Ricci-Direct-1** below provides costs as of September 30, 2024, and the estimated costs through the Certification Period.

| Table Ricci Direct -1 | | | |
|---|---|---|---|
| Division | Additions Jun-23 to Sept-24 | Additions Oct-24 to Feb-25 | Total Fleet Additions |
| Fleet Investments | $481,410 | $484,612 | $966,022 |

The total fleet additions were primarily due to the end of term lease buyouts of vehicles and fleet equipment with approximated residual value of $0.6 million[3] and the purchase of three lighter duty vehicles for $0.2 million. Nevada Power's investment during the certification period for electric vehicle charging stations and vehicle safety systems for lighter duty units are currently estimated at approximately $0.2 million.

**7. Q. WHY HAS NEVADA POWER REPLACED VEHICLE AND FLEET EQUIPMENT SINCE JUNE 1, 2023?**

A. Nevada Power's Fleet Services department performs vehicle lifecycle analysis to gauge the optimal replacement plan for each vehicle and fleet equipment class to achieve the ideal total cost to own and maintain vehicles and fleet equipment over their useful lives. Fleet Services works to limit expenditures by retaining these assets through their full useful lifecycle. The average age of Nevada Power's

[3] The residual value reflects a reduced value of the fleet vehicle or equipment at the end of the lease term.

vehicles and fleet equipment is 11.3 years, which is longer than the utility industry average of 8.2 years.

**8. Q. PLEASE DESCRIBE THE FINANCIAL ANALYSIS PERFORMED TO DETERMINE WHETHER TO PURCHASE OR LEASE REPLACEMENT VEHICLES AND FLEET EQUIPMENT.**

A. After the Commission issued its Modified Final Order in Sierra's 2022 GRC,[4] the Company re-evaluated its present worth of revenue requirement ("PWRR") fleet analysis using the weighted average cost of capital. The Company implemented a flexible approach when evaluating leasing (with subsequent end of lease buyouts) and purchasing options based upon a PWRR model using the weighted average cost of capital, lease product offerings available from vendors, vehicle/equipment class size and availability. The re-evaluated PWRR analysis the Company conducted in Spring 2023 supported the purchase of lighter duty units and equipment ($0.2 million presented for approval in this case) and the lease of larger operational units. Based on the analysis conducted in early 2023 and upon further review, in late 2023 the Company implemented an approach to conduct an analysis on a vehicle-by-vehicle basis to evaluate purchase and lease options. This is the same approach used in Sierra's 2024 GRC.

///
///
///

[4] Consolidated Docket Nos. 22-06014, 22-06015, and 22-06016, *Modified Final Order* (Feb. 16, 2023).

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

**9. Q. WHEN CONSIDERING THE EVOLUTION OF THE FLEET ACQUISITION STRATEGY, SHOULD THE THREE PURCHASED LIGHT DUTY UNITS PRESENTED FOR RECOVERY IN THIS CASE BE SUBJECT TO THE SAME RETURN LIMITATION ON THE FLEET VEHICLES AS PROVIDED IN THE MODIFIED FINAL ORDER ISSUED IN NEVADA POWER's 2023 GRC?**

A. No. The Company re-evaluated its strategy regarding purchasing versus leasing fleet vehicles and equipment. The re-evaluated PWRR analysis conducted in the spring of 2023 supported the purchase of the three lighter duty units. As stated above, this is the same analysis used in Sierra's 2024 GRC.

**10. Q. PLEASE DESCRIBE THE CURRENT ACCOUNTING PROCESS AND DOCUMENTATION FOR FLEET VEHICLE AND EQUIPMENT ACQUISTIONS.**

A. The Fleet Services department complies with the Companies' internal control policies and procedures including annual budget authorization and authorization for expenditures. All vehicle and equipment acquisition orders are approved by the vice president of the operating division and the vice president over the Fleet Services department upon obtaining a price quote and vehicle specification list through an interactive process with the Fleet Services department, Nevada Power's operational personnel, and vendors. Upon receiving senior leadership approval, a purchase order is created and routed for approval for all intended purchases and a pre-lease order is created and routed for approval for all intended leases. As stated above, in late 2023, the Company implemented an approach to conduct an analysis on a vehicle-by-vehicle basis to evaluate purchase and lease options. The approved purchase order or pre-lease order is then shared with the vendor or leasing company.

**11. Q. ARE THERE OTHER CAPITAL PURCHASES PRESENTED IN THIS CASE FOR APPROVAL?**

A. Yes, electric vehicle charging stations for Nevada Power fleet vehicles and vehicle safety systems for lighter duty units for approximately $0.2 million are included for recovery in this case.

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

A. Yes.

# EXHIBIT RICCI-DIRECT-1

# Evelene Ricci
# Nevada Power Company, d.b.a. NV Energy
# Director, Transportation

I have been employed by NV Energy for 19 years and have more than 30 years of leadership experience in the utility industry. While employed by NV Energy and other small electric distribution utilities, I have held numerous positions where I have gained expertise in asset management.

**Employment History**

Sierra Pacific Power Company, d/b/a. NV Energy

Director Transportation (2021 – present)

Directs the development, planning, and maintenance of the company's regional fleet vehicle and equipment operations.

Director Major Accounts, (2014 – 2021)

Directs the account executive programs to promote enhanced business relations and program utilization with prominent customers.

Northern Deployment Project Director (2011 – 2014)

Directs the meter deployment and operations for the implementation of the NVEnergize project.

Director, Client Services & Total Rewards (2010- 2011)

Directs the development, planning, and administration of the company's employee benefits, compensation, and employee relations functions.

Manager, PR Client Services (2008 – 2010)

Develops, implements, manages and provides counsel on human resource strategies that support the business units.

Sierra Pacific Resources

Team Leader, Operations Accounting (2006 – 2008)

Manages accounting staff in the performance of various accounting and regulatory functions for the Operations Accounting staff in the fuel and purchased power department.

Staff Consultant, Operations Accounting (2006 – 2006)

Responsible for the direct oversight of all work performed by the Operations Accounting staff in the fuel and purchased power department.

Senior Accountant, Operations Accounting (2005 – 2005)

Responsible for the proper accounting and reporting of Sierra Pacific Power Company's gas transactions.

Lassen Municipal Utility District

General Manager (2003 – 2005)

Responsible for the management of all aspects of the 12,000-customer distribution utility including: human resources, accounting, finance, regulatory reporting, power purchases, public relations, engineering, operations and customer service.

Mt. Wheeler Power

Controller/Chief Operating Officer (1991 – 2002)

Managed accounting, finance, regulatory filing, data processing and human resources areas for a 4,600-customer utility, reporting to a Board of Directors. I began as an Accountant then was promoted to the Finance Manager, Controller then Controller/Chief Operating Officer as the area of responsibilities increased.

SYSCO/General Food Service

Assistant Controller (1987 – 1991)

Managed the accounts payable section and supervised the entire accounting department (payroll, accounts payable and logistics).

**Education**

Boise State University

May, 1989 - Bachelor of Business Administration, Management

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, EVELENE RICCI, states that she 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 her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: February 14, 2025

Evelene Ricci

# ISMAEL SANCHEZ

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

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

**Ismael Sanchez**

Revenue Requirement

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

A. My name is Ismael Sanchez. My current position is Director of Telecommunications 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 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I have more than 29 years of experience at the Companies working in various roles and departments, including my current position since 2021. I graduated from New Mexico State University, Las Cruces with a Bachelor of Science in Electrical Engineering in 1991 and a Master's in Electrical Engineering in 1992. A complete description of my professional background and experience is included in my Statement of Qualifications, **Exhibit Sanchez-Direct-1.**

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, TELECOMMUNICATIONS.**

A. As Director of Telecommunications I oversee and lead the Telecommunications operation business unit, and my responsibilities include construction, maintenance, and operations of the telecommunications assets for the Companies.

**4. Q. WHAT ARE THE ROLES AND RESPONSIBILITIES FOR THE TELECOMMUNICATIONS TEAM?**

A. The Telecommunications team oversees, designs, constructs, and maintains the telecommunication system that provides the telecommunication infrastructure to enable the supervisory control and data acquisition ("SCADA") for the Company to ensure that the system operators can safely and effectively monitor and control the electric power system. This infrastructure also provides protection system communication aid (relay-to-relay) for the protection of transmission lines to enable the fastest possible clearing of transmission line power faults to maintain system stability and reduce the likelihood of asset failure due to faulted conditions. Company traffic, public safety radio, and smart meter data, among other services, are all supported by and move through the telecommunication system.

**5. Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following Exhibits:

**Exhibit Sanchez-Direct-1** Statement of Qualifications

**6. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes, I testified in the 2024 Sierra electric and gas general rate cases ("GRC"), Docket Nos. 24-02026 and 24-02027, and the 2023 Nevada Power GRC, Docket No. 23-06007.

**7. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I support the prudency and reasonableness of Nevada Power's investment in telecommunication networks and facilities since the end of the Certification Period in the last Nevada Power GRC. My testimony specifically discusses one major program under my responsibility listed in **Table Sanchez-Direct-1**. The program in the table has expenditures that exceed $1 million.

**8. Q. WHY ARE ONLY MAJOR PROGRAMS SPECIFICALLY DISCUSSED IN YOUR TESTIMONY?**

A. Descriptions of every program completed by the telecommunications team since June 1, 2023, and the documentation surrounding each program are quite voluminous. In GRC's, the Commission seeks prepared direct testimony addressing the details of and supporting expenditures on major programs. In previous GRC's, the Commission has accepted the $1 million threshold as appropriate for determining whether a program is "major." While not addressed in detail in my direct testimony, the Company has also prepared program binders for smaller programs completed since June 1, 2023. As has been the Companies' practice for many rate case cycles, those binders (now in electronic form) are available for review on the day this GRC filing is made.

**TABLE SANCHEZ-DIRECT-1**

| Program Category | 06.01.2023 to 09.30.24 | 10.01.24 to 02.28.2025 | Total |
|---|---|---|---|
| Obsolete RTU Replacement | $1,016,625 | $256,935 | $1,273,560 |
| **Grand Total** | **$1,016,625** | **$256,935** | **$1,273,560** |

**9. Q. PLEASE DESCRIBE THE REMOTE TERMINAL UNIT ("RTU") REPLACEMENT PROGRAM.**

A. The RTU Replacement program upgrades RTUs throughout the service territory that are at end of life. An RTU is a device that collects and reports system indications, receives and issues commands to equipment and collects and reports ongoing system information such as voltage, current and power among other critical information. RTUs are critical for controlling and monitoring the grid as they operate as an aggregator for this supervisory and data information and then communicate the combined data to the electric grid operations control centers. As a part of this program, RTUs are upgraded to modern units to expand functionality, improve troubleshooting capabilities, and reduce costs associated with maintaining older units.

**10. Q. WHY IS THIS PROGRAM NECESSARY?**

A. This program is needed to maintain consistent and reliable control and awareness of the electric grid. As RTUs reach the end of their service life they begin to fail at an increased rate. Additionally, certain types of RTUs are no longer supported, serviced, or supplied by the manufacturers nor are these RTUs supported by modern communication equipment. Continuing with the RTU upgrade and replacement program will reduce the risk of frequent and longer outages to SCADA information causing a loss of visibility to the Energy Management System and operator remote control.

**11. Q. WHAT WAS THE TOTAL COST OF THIS PROGRAM?**

A. The RTU Replacement program expenditures for the period from June 1, 2023, through September 30, 2024, are $1,016,625. Estimated expenditures for this program for October 1, 2024, through February 28, 2025, are $256,935. The total program costs are $1,273,560.

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

A. Yes.

# EXHIBIT SANCHEZ-DIRECT-1

**STATEMENT OF QUALIFICATIONS OF**

**Ismael Sanchez**
**Director, Telecommunication Operations**
**NV Energy**
**7155 S Lindell Road**
**Las Vegas, NV 89118**
**(702)402-5883**
**Ismael.Sanchez@nvenergy.com**

My name is Ismael Sanchez. I am the Telecommunications Director for Sierra Pacific Power Company and Nevada Power d/b/a NV Energy ("Sierra" and collectively, the "Companies"). I graduated from New Mexico State University, Las Cruces with a Bachelor of Science in Electrical Engineering in 1991 and a Masters in Electrical Engineering in 1992.

## PROFESSIONAL EXPERIENCE

2021 to Present **NV Energy** ***Director, Telecommunication Operations***

Oversee and lead the Telecommunication operation business unit. Includes communication and communication sites throughout Northern and Southern Nevada. Includes construction, maintenance and trouble response of the Telecommunication system in Nevada overseeing thirty-two employees. Develop annual and ten-year business plans. Includes, annual safety program, growth capital, operating capital, and maintenance programs. Establish the business unit's annual goals and metrics. Set and communicate telecommunications business strategy and vision.

2016 to 2021 **NV Energy** ***Director, Delivery Operations South***

Responsible for construction and maintenance for all of Southern Nevada. The responsibility included the execution, scheduling and inspection of the process to install and maintain the power lines. Responsible for developing long term plans and strategies to optimize workforce and strategize reliability. Provided plans, processes, targets and implementation and feedback mechanisms, or tools for establishing best practice operations and maintenance. Developed and monitored industry and internal benchmarks to measure continuous improvements in financial and system performance. Monitored and enforced all compliance requirements for area of responsibility. Provided support for compliance audit activities and developed long term plans and budgetary requirements to support these plans.

2014 to 2016 **NV Energy** ***Manager, Line Const. and Maint.***

Responsible for managing the construction and maintenance of transmission and distribution lines in Southern Nevada. Responsible for establishing philosophy, standards, and procedures in Southern Nevada for the installation of transmission and distribution electrical facilities. Ensured proper maintenance procedures were adhered to by following schedules developed to optimize system reliability and conformance. On-call responsibilities.

2008 to 2014 **NV Energy** ***Program Manager, O&M EWAM***
Responsible for a cross functional team to develop requirements within the allotted cost and schedule for a large-scale enterprise work and asset management system. Responsible for a cross functional team to develop and execute the user acceptance testing within the allotted cost and schedule for the enterprise work and asset management system. Developed and executed a multi month project including the requirement gathering, solution, testing and deployment within the allotted cost and schedule.

2006 to 2008 **NV Energy** ***Manager, Substation Const. and Maint.***
Responsible for a team of twenty-seven employees that constructed new substations, maintained substations, and replaced aging or failed substation equipment. Managed the preventative maintenance program through Cascade database. Coordinated and executed several large-scale equipment replacements. Reviewed, logged and trended dissolved gas analysis. Troubleshot all substation equipment. Developed and executed a reliability centered maintenance program to effectively maintain the fleet of substation assets. On-call responsibilities.

1999 to 2006 **NV Energy** ***Team Leader, Reg. Maint Supp. Services***
Responsible for a team of twelve employees in northern and southern Nevada responsible for optimizing power system reliability. Responsible for optimizing statewide power system reliability by designing and implementing innovative programs. Provided and implemented recommendations to maximize efficiencies and power system reliability through synergy of methods and work practices, for example mirroring the vegetation management program in southern Nevada to Northern Nevada Region. On-call responsibilities.

1998 to 1999 **NV Energy** ***Team Leader, T&D Maint. Services NPC***
Responsible for a team of fifteen employees in southern Nevada responsible for optimizing power system reliability. Designed and implemented innovative programs to continually improve the safe operation and reliability of the transmission and distribution system. Provided leadership and accountability for all activities related to the provision of operation and maintenance support services including analytical support; transmission, substation and distribution maintenance programs and schedules; and system improvement construction projects. On-call responsibilities.

1997 to 1998 **NV Energy** ***Distribution Maint. Coordinator, NPC***
Responsible for developing and implementing various transmission and distribution maintenance programs to improve safety and optimize reliability in Southern Nevada. Provided oversight and successfully met various time frames for existing maintenance programs. Provided

management updates regularly through budgetary reports and system performance reports

1995 to 1997 **NV Energy** ***Engineer III, Distribution Standards NPC***

Responsible for maintaining the distribution standards including the material, =installation and electric service requirements volumes. Provided review to ensure that that each standard was in accordance with applicable codes and safety requirements. Ensured acceptability and feasibility to various alternatives by ensuring involvement by various parties with a vested interest. Incorporated new materials and work methods into applicable standards or created new standards.

## EDUCATION

*New Mexico State University – Las Cruces, NM*

Masters in Electrical Engineering – 1992

*New Mexico State University – Las Cruces, NM*

Bachelor of Science in Electrical Engineering – 1991

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

<u>AFFIRMATION</u>

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ISMAEL SANCHEZ, 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: February 14, 2025

Ismael Sanchez

# VINCENT VEILLEUX

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

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony Of

**Vincent Veilleux**

Revenue Requirement

**TABLE OF CONTENTS** **PAGE**

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

## I. INTRODUCTION

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

A. My name is Vincent Veilleux. I am the Director of Transmission and Distribution Projects for Nevada Power Company 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"). I work primarily out of Nevada Power's corporate office, which is located at 6226 W. Sahara Avenue in Las Vegas, Nevada. I am filing testimony in this proceeding on behalf of Nevada Power.

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

A. I hold a Bachelor of Science degree in Computer Engineering and an Executive Masters in Business Administration, both from the University of Nevada, Las Vegas. I began my employment with Nevada Power in 2006 as a student intern within the Major Projects organization and have held various positions, which include Senior Project Control Consultant, Senior Project Manager, Major Projects Manager and now my current role as Director, Transmission and Distribution Projects. I have attached as **Exhibit Veilleux-Direct-1** a statement of qualifications that further details my background and professional experience.

**3. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY IN A REGULATORY PROCEEDING?**

A. Yes, I have testified before the Public Utilities Commission of Nevada ("Commission") on several occasions, most recently in Nevada Power's 2020 and

2023 general rate case ("GRC") filings, Docket Nos. 20-06003 and 23-06007, respectively.

**4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to demonstrate the prudence of several categories of investment in facilities that are included in the calculation of Nevada Power's revenue requirement related to the Company's transmission and distribution facilities.

**5. Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR PREPARED DIRECT TESTIMONY?**

A. Yes. I am sponsoring two exhibits:

- **Exhibit Veilleux-Direct-1** Statement of Qualification
- **Exhibit Veilleux-Direct-2** Transmission and Distribution Major Projects

**6. Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. My testimony is organized into the following sections:

**Section II**. **Nevada Power Major Transmission & Distribution Projects:** I support the prudency of Nevada Power's investment in transmission and distribution ("T&D") facilities, which are now used and useful and providing service to customers. My testimony specifically addresses the major T&D facilities whose aggregated or "linked" work orders exceed $1 million and were placed in service since the end of the certification period in Nevada Power's last GRC (May 31, 2023) through the end of the Test Period (September 30, 2024) or Certification

Period (February 28, 2025) in this filing.[1] Major T&D projects are typically comprised of several linked work orders that allow the Company to identify the scope and cost for the type of asset required to complete the project. For reference, I provide the "link" number for each of the major projects described in Section II.

Major T&D projects can include investment in multiple assets, including and generally identified as substations, transmission lines, distribution lines, telecommunications, metering, relay and protection, environmental permits, regulatory permits, and land rights. In my testimony, I describe each major T&D project, why it was necessary, if it has previously been presented to the Commission, the total cost of the project, and other information to demonstrate why Nevada Power's investment is prudent. A listing of all new T&D plant additions is provided in **Exhibit Veilleux-Direct-2.**

**Section III. Large Generator Interconnections**: I support the prudency of Nevada Power's investment in large generator interconnections that are now used and useful and providing service to these customers. Some components of the projects constituted a "Network Upgrade" in the parlance of the Federal Energy Regulatory Commission ("FERC"), while other components are defined as Transmission Provider's Interconnection Facilities ("TPIF"). The Network Upgrades include improvements to Nevada Power's system that typically include new connection points, either as new switching stations or new terminals at existing substations, or upgrades of the backbone transmission system to support the requested interconnection. The TPIF, which are funded by the interconnection customer but owned by Nevada Power, typically include the line interconnection

[1] The Test Period for this GRC is from October 1, 2023, through September 30, 2024. The Certification Period extends from October 1, 2024, through February 28, 2025.

and switch structures, customer site telecommunications, metering, associated land rights and environmental permits. In my testimony, I describe the general project purpose, scope, and cost components to be included for recovery in this GRC.

**Section IV. March 2025 T&D Projects**: To address concerns presented by Staff in prior GRCs regarding projects that were not included in the Company's estimates in the original filing but were completed during the Certification Period, **Exhibit Veilleux Direct-2**[2] has been modified to include those projects planned to be completed in March 2025 for informational purposes only. In the event that the projects are completed ahead of schedule and completed within the Certification Period, the Company wanted to give intervening parties appropriate time to allow for proper review.

These projects are currently not included in the revenue requirement as the rate base schedules only include estimated plant additions through the end for the Certification Period. The estimated plant additions for March 2025 are included in **Exhibit Veilleux Direct-2** for informational purposes in the event that a project planned for completion in March is finished earlier than expected and included in the Company's Certification filing. If these projects do complete within the Certification Period, the revenue requirement will be adjusted to include the project(s) and my Certification testimony will also reflect the project as being completed and placed in-service.

**7. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN YOUR TESTIMONY?**

---

[2] See also Exhibit Hanshew Direct-3

A. Yes, confidential information has been redacted below in my direct testimony.

**8. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.**

A. The redacted information below is customer-specific information that cannot be publicly disclosed without express permission from the customers.

**9. Q. FOR HOW LONG DOES THE COMPANY REQUEST CONFIDENTIAL TREATMENT?**

A. The Company requests confidential treatment for no less than five years.

## II. NEVADA POWER MAJOR T&D PROJECTS

**10. Q. DESCRIBE THE PROJECTS INCLUDED IN THIS SECTION.**

A. This section discusses investments for major T&D projects greater than $1 million listed in **Exhibit Veilleux-Direct-2**. These projects were placed in service after the end of the certification period in Nevada Power's last GRC and before the end of the Certification Period in this GRC. The projects are organized in order of descending total cost.

### i. CRITICAL SITE SECURITY UPGRADES - SOUTHERN NEVADA (BDJ)[3]

**11. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project provides for the acquisition, engineering, and installation of multi-sided critical transformer ballistic protective shields for 14 transformers located at two critical substations in Nevada Power's service territory.

**12. Q. WHY WAS THE PROJECT NECESSARY?**

[3] The codes referred to in headers are linked to projects listed in **Exhibit Veilleux-Direct-2.** These codes are linked to documentation provided in the data room to which interveners will have access.

A. In 2022, the utility industry experienced a concerning pattern of attacks and threats to electric substations through physical damage and service disruptions. There are numerous media examples that highlight this pattern. One example is a USA Today article from February 2023 that describes the emerging pattern on substations being attacked.[4] Another example is a Utility Dive article from December 2022 reporting on firearm attacks on Duke Energy substations.[5]

These attacks, along with widespread media coverage, highlighted the vulnerability of the power grid to physical threats. Media attention may exacerbate these threats, embolden the attackers, and inspire copycats. For example, some internet content encourages ballistic attacks against critical infrastructure, and real ballistic attacks against Pacific Gas and Electric, Duke Energy, and others. This demonstrates that the risk is not merely hypothetical. Without advanced security initiatives, ballistic attacks against critical assets represent a dangerous nexus between the relative ease of execution and high-impact damage, especially where line-of-sight vulnerabilities exist due to elevated terrain outside a substation. These projects improve the physical security posture of the Company's critical assets to mitigate impacts from ballistic attacks on the most critical substation transformers.

**13. Q. WHAT ARE BALLISTIC SHIELDS AND HOW ARE THEY MORE EFFECTIVE THAN OTHER POTENTIAL ALTERNATIVES?**

A. Ballistic shields are specifically designed to block line of sight ballistic attacks on transformers. These ballistic resistant solutions for utilities' critical equipment are

---

**4** Dinah Voyles Pulver and Grace Hauck, *Attacks on power substations are growing. Why is the electric grid so hard to protect?*, USA Today, Feb. 8, 2023, https://www.usatoday.com/story/news/nation/2022/12/30/power-grid-attacks-increasing/10960265002.

5 Robert Walton, *FBI called to investigate firearms attacks on Duke Energy substations in North Carolina; 40K without power*, Utility Dive, Dec. 4, 2022, https://www.utilitydive.com/news/fbi-investigate-firearms-attacks-duke-energy-substations-North-Carolina/637927/.

installed near the energized equipment. The 30-foot-tall non-conductive fiberglass panels provide ballistic resistant protection from vantage points around the substations. Ballistic shields offer greater protection than alternative solutions. The topography surrounding these critical substations and transformers in most cases eliminates the effectiveness of perimeter substation ballistic walls and other solutions, which are not specifically designed for closer proximity to energized equipment. These alternative options are not suitable to address a ballistic attack in all cases. For example, the line-of-sight assessment for one of these critical substations identified a nearby elevated site, external to the substation, which would require a perimeter wall with a height of nearly 70 feet to mitigate the line-of-sight ballistic threat. A ballistic shield offers a proximity solution that is more effective and feasible in such instances.

The Company also evaluated a transformer wrap solution that is installed directly on the transformer tank and foundation, requiring transformer-specific designs so each transformer can be uniquely retrofitted. Although effective for addressing the line-of-sight threat while providing ballistic protection to the transformer, control cabinet, oil pumps and fans, this solution provided no ballistic protection to the transformer bushings. Additionally, there were transformer cooling concerns with the application of this solution, and it did not appear effective in providing a non-ricochet solution. The fiberglass reinforced panel walls the Company selected are lightweight, corrosion proof, non-conductive, electromagnetically transparent, and provide a non-ricochet solution that retains the projectile.

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

**14. Q. IS THE COMPANY AWARE OF AN INCREASE IN THE NUMBER OF HUMAN-RELATED DISTURBANCES AND UNUSUAL INCIDENTS AFFECTING THE ENERGY SECTOR ACROSS THE UNITED STATES?**

A. Yes, the Company is aware of an increased number of unusual incidents and human-related disturbances against the energy sector within the United States. Based on incidents reported to the U.S. Department of Energy, there has been a material increase in events. In each year since 2017, there has been more human-related disturbances and unusual incidents than the year prior, and 2022 experienced a concerning increase in events over 2021. In 2022, the energy sector experienced about 3.8 times more incidents than occurred in 2017. The pattern experienced over this period can be viewed as a proxy for the increased threat and increased probability of an attack occurring to the Company's infrastructure.[6]

For example, as mentioned above, on December 3, 2022, a shooting attack was carried out on two electrical distribution substations located in Moore County, North Carolina. Damage from the attack left up to 40,000 residential and business customers without electrical power.[7] Forty-five days after those attacks, gunfire damaged a substation about 50 miles away in Randolph County.[8]

Additionally, the most notable substation attack carried out on Pacific Gas and Electric Company's Metcalf transmission substation included shooters firing on 17

---

**6** Dinah Voyles Pulver and Grace Hauck, *Attacks on power substations are growing. Why is the electric grid so hard to protect?*, *USA Today*, Feb. 8, 2023, https://www.usatoday.com/story/news/nation/2022/12/30/power-grid-attacks-increasing/10960265002; National Conference of State Legislatures, *Human-Driven Physical Threats to Energy Infrastructure*, May 22, 2023, https://www.ncsl.org/energy/human-driven-physical-threats-to-energy-infrastructure.

7 Robert Walton, *FBI called to investigate firearms attacks on Duke Energy substations in North Carolina; 40K without power*, Utility Dive, Dec. 4, 2022, https://www.utilitydive.com/news/fbi-investigate-firearms-attacks-duke-energy-substations-North-Carolina/637927/.

8 Federal Bureau of Investigation, *Electrical Substation Shooting*, Jan. 17, 2023, https://www.fbi.gov/wanted/seeking-info/electrical-substation-shooting.

electric transformers, resulting in an estimated $15 million worth of equipment damage.[9] Although this attack did not result in any customer outages, a similar attack to a critical substation could result in a widespread system outage.

**15. Q. HOW DID THE COMPANY DETERMINE WHICH TRANSFORMERS WERE CRITICAL AND WARRANT BALLISTIC SHIELDS?**

A. The Company utilized an existing risk assessment methodology required by the North American Electric Reliability Corporation ("NERC") on critical infrastructure protections ("CIP") physical security requirements to identify the most critical transmission substations, which if rendered inoperable or damaged due to physical attack, could result in widespread system instability, uncontrolled separation, or cascading outages within the electric grid interconnection.

The Companies utilize the guidelines specified in the CIP-014-3 standard for performing transient stability analysis, voltage stability analysis, post-transient analysis, cascading analysis, and load shed analysis based on Security Constrained Dispatch ("SCD"). The methodology will assume all lines, without regard to voltage level, are disconnected from each qualifying transmission station or substation as the result of a physical attack. Each transmission substation is then assessed individually in a transient and voltage stability simulation to assess the potential for uncontrolled separation or cascading within an interconnection.

Once these critical substations were identified, their physical threat and vulnerability assessments were re-evaluated to identify unique characteristics of the surrounding terrain that present potential line-of-sight ballistic attack

---

[9] Herman K. Trabish, *FBI: Attack on PG&E substation was not terrorism*, Utility Dive, Sept. 11, 2014, https://www.utilitydive.com/news/fbi-attack-on-pge-substation-was-not-terrorism/308328/.

vulnerabilities, which can originate from outside the high-security substation perimeter walls and electronic security system boundaries.

**16. Q. DO THESE TWO CRITICAL SUBSTATIONS HAVE A PRIOR HISTORY OF BALLISTIC ATTACKS?**

A. Yes. There have been multiple incidents where several gunshot rounds have penetrated the transformer cooling radiator of a unit that is within the scope for these ballistic shields. Although there was no direct evidence to support either unintentional or intentional coordinated attacks, these incidents demonstrate the risk and vulnerability that exists.

**17. Q. DO OTHER COMPANY SUBSTATIONS HAVE A RECENT HISTORY OF BALLISTIC ATTACKS?**

A. Yes. In the last several years, the Companies have had multiple ballistic attacks that have impacted the operations of substation or transmission lines. These substations are not identified as CIP and at this time the Company is not pursuing physical perimeter or asset protection upgrades for these locations.

**Grass Valley Substation** transformer was shot in January 2020. The primary damage was due to a bullet hole in the transformer radiator. The damage resulted in the de-energization of the substation.

The **Gonder Substation** was shot in March 2020. The shooting occurred in the evening and three rounds struck the substation. Due to the location of the shots, the substation remained operational immediately following the incident, but offline repairs were later required.

The **Mira Loma Substation** was shot in July 2020. The transformer was hit and created an oil leak. The substation had to be de-energized due to the damage.

**18. Q. IS THE COMPANY AWARE OF OTHER RECENT POTENTIAL ATTACKS TO COMPANY SUBSTATIONS?**

A. Yes. The most notable recent event occurred in 2020. Several men with ties to the U.S. military and an anti-government "boogaloo" movement planned to firebomb a Company substation to create civil unrest. The Companies worked with local and national law enforcement which ultimately led to the arrest of three men before the attack could be carried out.

**19. Q. IF ONE OF THESE CRITICAL SUBSTATIONS EXPERIENCED A COORDINATED ATTACK WHAT WOULD THE ESTIMATED COST AND LEAD TIME BE TO RESTORE SERVICE?**

A. The actual cost and lead time would be dependent on the extent of the damage. However, as a proxy, the replacement cost and lead time for a similar transformer is approximately $9 million each and up to 36 months or longer.

Although the Company has critical spares to mitigate unplanned in-service failures, an attack that results in the failure of all or the majority of the transformers at one of these critical sites could easily exceed $50 million. Beyond the replacement and construction costs, the lead time provides an unacceptable outcome due to the critical nature of these sites and is the primary driver for the project.

**20. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. Yes. The project was presented in Nevada Power's 2023 GRC in Docket No. 23-06007; however, it was rejected by the Commission as it did not qualify as an expected changes in circumstances ("ECIC") project under Nevada Revised Statutes ("NRS") 704.110(4).

**21. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $35,170,671 (without AFUDC). The at completion total cost of the project through the end of the Test Period is $32,894,214 (with AFUDC). The facilities were installed and placed in service by March 27, 2024.

**ii. <u>WEST HENDERSON LARSON SUBSTATION FEEDERS (AKJ)</u>**

**22. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project included the extension of the existing distribution network into the west Henderson area. This involved construction of the new 12 kV Larson 1207, Larson 1211, and Larson 1212 underground distribution feeders. The initial use of the Larson 1207 feeder is to relieve the Keehn 1204 feeder, but also serves new electric vehicle ("EV") charging stations being developed at the M Resort. Larson 1211 and Larson 1212 underground distribution feeders will initially be used to serve the Haas Automation development with two 1.5-mile 12 kV feeders, while also creating a feeder tie between the two.

**23. Q. WHY WAS THE PROJECT NECESSARY?**

A. This project was necessary as part of the growth in the west Henderson area and pursuant to Large Project Line Extension Agreement No. 98733 associated with the new customer, Tesla M Resort EV Charging Station, and Large Project Line

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

Extension Agreement No. 93216 associated with a new customer, Haas Automation.

**24. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an Integrated Resource Plan ("IRP"). While Nevada Administrative Code ("NAC") 704.9503(1)(a) contemplates a resource plan filing for projects that require a Utility Environmental Protection Act ("UEPA") permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**25. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $6,812,926 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $7,318,746 (with AFUDC). The projected costs during the Certification Period are $95,384. The facilities were installed and placed in service by February 10, 2024.

**iii. <u>SUNSET 1215 FEEDER (AV8)</u>**

**26. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved installing a new 12 kV feeder breaker at Sunset Substation along with a new underground 12 kV distribution feeder to create a feeder tie with Sunset 1205 for the purpose of load relief.

**27. Q. WHY WAS THE PROJECT NECESSARY?**

A. In the summer of 2023, Sunset 1205 was approximately 507A or 85 percent of the facility rating. Increases to existing customer demand, 13 Mega Volt Ampere ("MVA") of active projects, and 2 MVA of forecast EV growth are forecasted to exceed the standard loading criteria for Sunset 1205 and Whitney banks 3//4[10] and required relief by the summer of 2024. A new feeder from Sunset Substation was the closest source to relieve these facilities.

**28. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**29. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $5,591,766 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $6,424,001 (with AFUDC). The projected costs during the Certification Period are $299,901. The facilities were installed and placed in service by July 5, 2024.

**iv. <u>UHS WEST HENDERSON HOSPITAL FEEDER (AWA)</u>**

**30. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project included the extension of the existing distribution network into the west Henderson area. This involved construction of the new 12 kV Larson 1213 underground distribution feeder. The initial use of the Larson 1213 feeder will be to serve the United Health Services ("UHS") West Henderson Hospital. A new 12 kV circuit breaker was installed at Larson Substation along with the extension of a new underground 12 kV distribution feeder.

---

[10] 3//4 represents transformers that are configured in parallel

**31. Q. WHY WAS THE PROJECT NECESSARY?**

A. This project was necessary as part of the growth in the west Henderson area and pursuant to Large Project Line Extension Agreement No. 102019 associated with a new customer, UHS West Henderson Hospital.

**32. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**33. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $5,072,191 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $5,870,609 (with AFUDC). The facilities were installed and placed in service by December 19, 2023.

**v. <u>LINDQUIST-AWT TAP-WINTERWOOD 69 KV REBUILD (APF)</u>**

**34. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project included the reconductor and rebuild of approximately seven miles of the existing Lindquist to Winterwood ("LDQ-WW") 69 kV transmission line from 4/0 copper ("CU") and 336 aluminum conductor steel reinforced ("ACSR") cable to 954 ACSR to mitigate a NERC TPL-001-4 contingency.

**35. Q. WHY WAS THE PROJECT NECESSARY?**

A. NERC TPL-001-4 requires that the transmission system be capable of withstanding a P1 (N-1) event, a loss of a single element, without overloading any remaining elements. This line must be reconductored to avoid violating this standard. A loss of the Winterwood 230/138 kV transformer has been shown in NERC TPL studies to cause overloads of the LDQ-WW 69 kV line. Additionally, following the possible retirement of non-Company owned generators Nevada Cogeneration Associates ("NCA") 1 and NCA 2 in 2023, there were several more P1 contingencies that caused this overload under 2020 loading conditions. The LDQ-WW 69 kV line is 8.27 miles long and made up of the following conductor types: 0.71 miles 954 ACSR, 0.56 miles 954 all aluminum conductor ("AAC"), 0.48 miles 336 ACSR, and 6.52 miles 4/0 CU. The 336 ACSR and 4/0 CU portions of this line were required to be reconductored to 954 ACSR, which also triggered the need to replace the existing structures along the line to meet minimum loading conditions caused by the larger conductor size.

**36. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**37. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $8,515,074 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $5,461,448 (with AFUDC). The projected costs during the Certification Period are $3,330. The facilities were installed and placed in service by July 30, 2024.

vi. <u>REID GARDNER TO TORTOISE 230 KV LINE #2 (AEZ)</u>

**38. Q. PLEASE DESCRIBE THE PROJECT.**

A. The project includes a new 2.3 mile 230 kV transmission line from Nevada Power's Reid Gardner substation to Overton Power District #5's Tortoise substation. The scope included a new 230 kV substation terminal with two 230 kV power circuit breakers at the existing Reid Gardner substation and associated system protection and telecommunication equipment and facilities.

**39. Q. WHY WAS THE PROJECT NECESSARY?**

A. This project was constructed pursuant to the Stipulation and Settlement Agreement between the Company and Overton Power, effective on February 21, 2019.

**40. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. Yes. A stipulation that included this project was approved in Docket No. 19-05003, effective on August 30, 2019, for Nevada Power's Second Amendment to the 2018 Joint IRP.[11] The project was also presented in Nevada Power's 2023 GRC in Docket No. 23-06007 and was approved by the Commission for the installation of the 230 kV breaker and a half bay at Reid Gardner.

**41. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. The Company completed the installation of the 2.3 mile 230 kV transmission line between Reid Gardner and Overton's Tortoise substation, which has been tested and energized and is used and useful.

**42. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

---

[11] Docket No. 19-05003, Order, at Attachment 1 (Stipulation), 5, ¶ 12.

A. The estimated total cost of the project was $10,037,823 (without AFUDC) of which $6,405,765 is associated with the 230 kV transmission line. The total at completion cost of the project through the end of the Test Period is $44,429 (with AFUDC). The projected costs during the Certification Period are $4,990,591. All facilities for the new 230 kV transmission line were installed and placed in service by October 18, 2024.

**vii. <u>SUNRISE 138/69 KV BANK ADDITION (ALA)</u>**

**43. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 138/69 kV autotransformer at Sunrise Substation, new 69 kV and 138 kV power circuit breakers, extending the existing 138 kV main bus, and associated protection and telecommunications equipment. The scope also included stringing new 1949 aluminum conductor composite core ("ACCC") conductor on the existing transmission line between Sunrise and Winterwood substations. Upgrades at Winterwood included a new 69 kV power circuit breaker, uprating the existing disconnect switches at the proposed terminal and replacing existing capacitor coupled voltage transformers ("CCVT").

**44. Q. WHY WAS THE PROJECT NECESSARY?**

A. Identified as a NERC TPL-001-4 requirement, a loss of the existing Winterwood 138/69 kV autotransformer during summer peak would result in the Artesian - Winterwood 138 kV, Winterwood - AWT, and/or AWT - Lindquist 69 kV lines being overloaded. These are documented issues and manual operator actions ("MOAs") are now in place to prevent the overload from occurring. The addition of this project alleviates these overloading conditions.

**45. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. Yes. The project was presented in Nevada Power's 2023 GRC in Docket No. 23-06007 and was approved by the Commission for the installation of facilities as Sunrise Substation, exclusive of the transformer cost.

**46. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. The Company has completed the remaining construction of the overhead 69 kV transmission line from Sunrise to Winterwood Substation and is also including the transformer costs, which were not included as part of the previous GRC.

**47. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $9,767,796 (without AFUDC) of which $4,182,090 is associated with the transformer and 69 kV transmission line. The total at completion cost of the project through the end of the Test Period is $4,294,122 (with AFUDC). The remaining facilities were installed and placed in service by November 30, 2023.

**viii. <u>LARSON 1201 FEEDER (AQ5)</u>**

**48. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project included the installation of a new 12 kV feeder breaker at Larson substation, as well as a new 12kV underground distribution feeder with a tie to Keehn 1210 for load relief. Larson 1201 is part of the planned distribution system for the area.

**49. Q. WHY WAS THE PROJECT NECESSARY?**

A. The loads on Keehn Substation have been growing consistently for the past few years. As of last summer, the loading on Keehn 1210 was approximately 494A or 82 percent of 600A facility rating and is expected to exceed its thermal rating at 102 percent by the summer of 2024. In January 2019, the Company received a service request for commercial projects [redacted]. As a result, a new feeder from the Larson substation is required for additional capacity in the area currently served by Keehn 1210.

**50. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**51. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $2,763,146 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $4,256,206 (with AFUDC). The facilities were installed and placed in service by May 1, 2024.

**ix. <u>PROTECTIVE RELAY REPLACEMENT - SOUTH (A18)</u>**

**52. Q. PLEASE DESCRIBE THE PROGRAM.**

A. This program provides for the replacement of electromechanical ("EM") relays and older obsolete microprocessor ("MP") relays with the latest generation MP-based digital protective relays. The Company has standardized the use of Schweitzer Engineering Laboratories ("SEL") MP-based digital protective relays. These relays are state of the art technology that have significant advantages and provide better performance over EM relays and older obsolete MP relays. Through the relay replacement program, system protection engineers, technicians and leadership evaluate the performance of existing relays, supply chain for replacement relays, parts for repair, impact to the electric system, required improvement in protection schemes due to changes in the electric system, relay manufacturer support and compliance with NERC reliability standards to determine which relays should be replaced under the program. Relays that provide the most net benefit of the replacement weighed against the upgrade cost receive priority for replacement.

**53. Q. WHY WAS THE PROGRAM NECESSARY?**

A. These newer SEL MP relays are multifunctional protective relays that allow for the utilization of advance protection schemes, all while increasing both dependability and security. Unlike EM relays or older MP relays, the latest generation MP-based relays allow for the inclusion of additional protection and control logic, thereby improving the overall protection, control and remote terminal unit design. Furthermore, event reporting is a standard feature in newer MP-based relays. The data and information saved in these reports are valuable for fault locating, testing, measuring performance, analyzing problems, and identifying deficiencies in the composite protection system before a component causes future mis-operations. These newer MP relays allow for the event report data to be retrieved remotely for the majority of the substation sites as it leverages Nevada Power's extensive communication network. Lastly, NERC-compliant MP relays allow for a maximum maintenance interval of 12 calendar years for NERC PRC-005 reliability standard compliance compared to six years for NERC-compliant EM relays. All of these advantages allow for overall cost savings for substation corrective and planned maintenance, substation operations and compliance obligations.

**54. Q. HAVE THE PROJECTS WITHIN THIS PROGRAM BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of these projects in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**55. Q. HOW MANY SEPARATE PROJECTS WERE COMPLETED DURING THIS TEST AND CERTIFICATION TIME PERIOD?**

A. During the Test and Certification periods, a total of 50 separate projects were completed with a combined cost of these projects totaling greater than $1 million.

**56. Q. WHAT WAS THE TOTAL COST OF THE PROGRAM?**

A. The estimated total cost of the program was $1,000,000 annually (without AFUDC). The total at completion cost of the program through the end of the Test Period is $3,273,936 (with AFUDC). The projected costs during the Certification Period are $874,117. The facilities were installed and placed in service by the end of the Certification Period.

**x. <u>RAILROAD 1212/MCDONALD 1210/QUAIL 1213 FEEDER TIE (AVY)</u>**

**57. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new underground 12 kV distribution feeder tie between Railroad 1212 and Quail 1213, as well as McDonald 1210 to Quail 1213, in order to provide relief for Railroad 1212 and McDonald 1210.

**58. Q. WHY WAS THE PROJECT NECESSARY?**

A. The loads on Railroad 1212 and McDonald 1210 have been growing consistently for the past few years. Last summer, the system peak loading on Railroad 1212 was approximately 530A with a forecasted peak of 548A in summer of 2023, exceeding the Standard Loading Criteria[12] limits. The system peak loading on McDonald 1210 was approximately 516A with a forecasted peak of 585A in the summer of 2024 exceeding the Standard Loading Criteria limits. The Company received service requests for [redacted]. As a result, a new tie between Quail 1213 and Railroad 1212, and Quail 1213 and McDonald 1210 is required for the additional capacity needed in the area. The existing ties in the area are insufficient to relieve the Railroad 1212 and McDonald 1210 feeders.

**59. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that

[12] Standard Loading Criteria limits are a distribution planning business practice where the Company will trigger upgrades once a certain threshold is met. Those limits are currently defined as 90% of the equipment's thermal rating

require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**60. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $3,528,808 (without AFUDC). The total at completion cost of the project during the Certification Period is $3,500,000 (with AFUDC). The facilities were installed and placed in service by the end of the Certification Period.

**xi. <u>WESTSIDE SUBSTATION – GROUND GRID REPLACEMENT (BCB)</u>**

**61. Q. PLEASE DESCRIBE THE PROJECT.**

A. The purpose of this project is to upgrade and improve the existing ground grid at the Westside 230 kV substation in accordance with standards provided by the Institute of Electrical and Electronics Engineers ("IEEE"). The scope includes the installation of four 500' deep grounding wells.

**62. Q. WHY WAS THE PROJECT NECESSARY?**

A. On October 5, 2022, an electrician at Westside Substation was shocked when opening the substation gate while at the same time a transmission capacitor in the substation was being operated remotely. The voltage transients from this operation created a step potential condition that resulted in shocking the individual touching the gate. Initial visual investigation resulted in discovery of multiple stolen grounding bonding conductors. Following the above-mentioned shocking incident, a complete study of the ground grid design revealed deficiencies due to the increased load growth of the substation resulting in fault current increases which overwhelmed the original grounding mitigation from decades ago. A new design was required to alleviate future step and touch potential conditions creating a safe environment for personnel working in this substation.

**63. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**64. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $3,467,592 (without AFUDC). The total at completion cost of the project during the Certification Period is $3,488,566 (with AFUDC). The facilities were installed and placed in service by the end of the Certification Period.

**xii. <u>GILMORE 1201 FEEDER (APE)</u>**

**65. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved installing a new 12 kV feeder breaker at the Gilmore ("GLM") substation along with a new underground 12 kV distribution feeder to create a feeder tie with GLM1205 for purposes of load relief. The scope also included installation of an overhead switch between Leavitt ("LVT") 1205 and LVT1215.

**66. Q. WHY WAS THE PROJECT NECESSARY?**

A. The loads on Gilmore and Leavitt substations have been growing consistently for the past few years. In summer of 2022, loading on GLM1205, LVT1201, LVT1205, LVT1215 was approximately between 88-99 percent of the feeder loading capacity. These existing feeders are forecasted to load to 98 percent, 99 percent, 96 percent, and 98 percent, respectively, of the normal summer rating by the summer of 2023 when the forecast of increased residential and commercial growth is taken into consideration.

**67. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**68. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project is $2,720,395 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $2,980,091 (with AFUDC). The facilities were installed and placed in service by May 31, 2024.

**xiii. <u>CLARK - CONCOURSE 138 KV RECONDUCTOR (CU)</u>**

**69. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the reconductor of the 138 kV Clark – Concourse transmission line from 954 AAC to 954 ACSS to increase the rating from 237 MVA to 428 MVA. The scope also included upgrading the disconnects at Clark Substation.

**70. Q. WHY WAS THE PROJECT NECESSARY?**

A. The Western Electricity Coordinating Council ("WECC") base cases have shown the Clark – Concourse 138 kV line as heavily loaded. To prevent N-0 and N-1 overloads of the line for multiple contingencies, 138 kV generation is required to curtail during peak load to prevent an overload of the line. The Clark – Concourse 138 kV rating of 237 MVA was creating system limitations on the Clark 138 kV generation that may prove to be untenable as this generation is relied on heavily during peak loads. Once generation and load growth reach the point where Clark dispatch cannot simultaneously solve both overloads, the Company would no longer be able to maintain compliance with NERC reliability standards.

**71. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**72. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project is $3,697,572 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $2,856,364 (with AFUDC). The facilities were installed and in service by April 15, 2024.

**xiv. <u>SPEEDWAY SUB SPARE TRANSFORMER 138X69-12KV (B4B)</u>**

**73. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the purchase of a spare 33 MVA 138x69/12 kV dual voltage transformer, which also included construction of a new foundation.

**74. Q. WHY WAS THE PROJECT NECESSARY?**

A. Speedway Substation currently has three unique dual-voltage transformers in operation, with zero spare transformers that could be used at this location. A spare unit is needed due to its unique characteristics and dual-voltage configuration to mitigate risk such as transformer failure or natural disaster. Procurement of this transformer spare will ensure the ability to reliably operate the transmission and distribution system.

**75. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**76. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $1,862,048 (without AFUDC). The total at completion cost of the project during the Certification Period is $2,836,615 (with AFUDC). The facilities were installed and placed in service by December 2, 2024.

**77. Q. PLEASE EXPLAIN THE VARIANCE BETWEEN THE ESTIMATED AND ACTUAL COST OF THE PROJECT?**

A. The costs to procure and set the spare transformer came in roughly $700,000 higher than originally estimated without associated overheads.

**xv. <u>PECOS 1207 TO PECOS 1211 FEEDER TIE (AW7)</u>**

**78. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new underground 12 kV distribution feeder tie between Pecos 1207 and Pecos 1211 to provide relief for Pecos 1207.

**79. Q. WHY WAS THE PROJECT NECESSARY?**

A. The existing Pecos 1207 was forecasted to load to 106 percent of the loading capacity by the summer of 2023 considering the forecast of increased residential growth of approximately 3.5 MVA. The loads on Pecos 1207 have peaked at 550 amps with another 52 amps of load projected for addition by 2023. Using an existing feeder out of Pecos Substation was the closest source to relieve Pecos 1207 feeder without needing to build a new bus section, bank addition, or new feeder breaker.

**80. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**81. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $2,391,472 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $2,790,539 (with AFUDC). The facilities were installed and placed in service by April 22, 2024.

**xvi. <u>WASHBURN 1203 TO WASHBURN 1201 FEEDER TIE (AWB)</u>**

**82. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new underground 12 kV distribution feeder tie between Washburn 1203 and Washburn 1201 to provide relief for Washburn 1203 and Gilmore 1211.

**83. Q. WHY WAS THE PROJECT NECESSARY?**

A. In the summer of 2022, loading on Washburn 1203 was approximately 529A or 88 percent of the unit's nameplate, and the loading on Gilmore 1211 was approximately 504A or 84 percent of the unit's nameplate. Washburn 1203 and Gilmore 1211 were also forecasted to have a single high phase on each load to 99.6 percent and 99.2 percent, respectively, of the loading capacity by the summer of 2022 and both feeders would have a high phase that reaches over 100 percent by summer of 2023. Using an existing feeder out of Washburn substation was the closest source to relieve the Washburn 1203 and Gilmore 1211 feeders without needing to build a new bus section, bank addition, or a new feeder breaker.

**84. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**85. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $2,074,942 (without AFUDC). The total at completion cost of the project during the Certification Period is $2,700,000 (with AFUDC). The facilities were installed and placed in service by the end of the Certification Period.

**xvii. <u>RILEY 1215 AND 1217 FEEDERS (AVE)</u>**

**86. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project included the installation of two new 12 kV feeder breakers at Riley Substation, as well as new 12kV underground distribution feeders with ties to Tomsik 1210 and 1211 to provide load relief for Tomsik banks 2//3.

**87. Q. WHY WAS THE PROJECT NECESSARY?**

A. The loads at Tomsik Substation have been consistently growing over the past few years. The existing Tomsik transformers together have a nameplate rating of 74 MVA. For the summer of 2022, the system peak loading on Tomsik banks 2//3 was approximately 67.1 MVA with a forecasted peak of 76.4 MVA in the summer of 2023, exceeding the thermal rating. The Company received service requests for [redacted]. As a result, two new feeders installed at Riley Substation is required for the additional capacity for the new loads in the area.

**88. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of “utility facility” under NRS 704.860.

**89. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $2,112,561 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,891,717 (with AFUDC). The projected costs during the Certification Period are $487,244. The facilities were installed and placed in service by March 13, 2024.

**xviii. <u>FRIAS 138/12 KV BANK 1 (A8A)</u>**

**90. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 33 MVA 138/12 kV transformer at Frias substation with associated 12 kV bus and bank breaker, protection and communication equipment. The project also required the installation of two new concrete masonry unit ("CMU") firewalls between transformer 1, 2 and 3 to comply with the IEEE guide for substation fire protection.[13]

**91. Q. WHY WAS THE PROJECT NECESSARY?**

A. During the summer of 2020, Frias banks 2 and 3, connected in parallel, loaded to 69.4 MVA. A failure of one bank would overload the other bank to 184 percent of the capacity of a single bank. Feeder ties do not exist to switch enough load off the remaining bank in the event of a failure and customers would remain out of power until a mobile substation can be mobilized and connected.

**92. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. Yes. The project was presented and approved in Nevada Power's 2023 GRC in Docket No. 23-06007.

**93. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. At the time of completion for the original scope, the project utilized a spare transformer to ensure successful completion before the summer of 2023 due to

---

[13] *See* IEEE Standard 979 (2012) IEEE Guide for Substation Fire Protection. Section 7.2.2 Equipment to Equipment identifies a minimum separation distance of 50 feet.

extended transformer lead times. No transformer costs were included in the 2023 GRC revenue requirement. The replacement spare 138/12 kV transformer was shipped and received in October 2023 through the end of the Test Period for this case and the cost of the transformer is now being included in the revenue requirement for this rate case.

**94. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $2,481,908 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,960,214 (with AFUDC). The facilities were installed and in service by October 5, 2023.

**xix. <u>RILEY 138/12 KV BANK 3 (YW)</u>**

**95. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 33 MVA 138/12 kV transformer at Riley Substation with associated 12 kV bank breaker, protection and communication equipment.

**96. Q. WHY WAS THE PROJECT NECESSARY?**

A. The loads on the Riley and Mountains Edge substations have been consistently growing for the past few years. In the summer of 2021, the system peak loading on the existing Riley transformer was approximately 36.0 MVA with a forecasted peak of 39.3 MVA in the summer of 2022 and a forecasted peak of 41.6 MVA in the summer of 2023. In the summer of 2021, the system peak loading on the existing Mountains Edge transformers was approximately 71.0 MVA with a forecasted peak of 71.7 MVA in the summer of 2022 and a forecasted peak of 73.0 MVA in the summer of 2023. [redacted]

[redacted]. As a result, the Company requires a new transformer at Riley substation for the additional capacity in the area.

**97. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. Yes. The project was presented and approved in Nevada Power's 2023 GRC in Docket No. 23-06007.

**98. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. At the time of completion for the original scope, the project utilized a spare transformer to ensure successful completion before the summer of 2022 due to extended transformer lead times. No transformer costs were included in the 2023 GRC revenue requirement. The replacement spare 138/12 kV transformer was shipped and received in November 2023 during this Test Period, and the cost of the transformer is now being included in the revenue requirement under this rate case.

**99. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $1,978,787 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,660,239 (with AFUDC). The facilities were installed and placed in service by November 13, 2023.

**xx. <u>TOMSIK 138/12KV BANK 1 (KK)</u>**

**100. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 33 MVA 138/12 kV transformer at Tomsik substation with associated 12 kV bank breaker, protection and communication equipment.

**101. Q. WHY WAS THE PROJECT NECESSARY?**

A. The loads on Tomsik Substation have been growing consistently for the past few years. The existing Tomsik transformers on banks 2 and 3 have a combined nameplate rating of 74 MVA. In the summer of 2022, the system peak loading on Tomsik banks 2 and 3 was approximately 67.1 MVA with a forecasted peak of 77.1 MVA in the summer of 2024. The Company received service requests for [redacted]. As a result, a new transformer at Tomsik Substation is required for the additional capacity for the new loads in the area.

**102. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. At the time of completion for this scope, the project utilized a spare transformer to ensure successful completion before the summer of 2024 due to extended transformer lead times. The Company is seeking recovery of all costs associated with placing the spare transformer into service to provide the necessary load relief as described above. No transformer costs are being included in the current rate case revenue requirement. The replacement spare 138/12 kV transformer has been ordered and is not expected to be delivered until March of 2026. The Company will seek recovery of those costs in a future GRC.

**103. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**104. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $5,023,026 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,604,983 (with AFUDC). The facilities were installed and placed in service by May 2, 2024.

**105. Q. PLEASE EXPLAIN THE VARIANCE BETWEEN THE ESTIMATED AND ACTUAL COST OF THE PROJECT?**

A. The estimated total cost includes the future cost of the spare replacement transformer at approximately $3 million; the $1.6 million in incurred costs does not include any costs associated with either the spare transformer used or future transformer under contract.

**xxi. <u>BICENTENNIAL 138/12KV BANK 3 (BZ)</u>**

**106. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 33 MVA 138/12 kV transformer at the Bicentennial Substation with associated bus section #3, 12 kV bank breaker, protection and communication equipment. The project also required the installation of two new CMU firewalls between transformer 1, 2 and 3 to comply with the IEEE guide for substation fire protection.[14]

[14] *See* IEEE Standard 979 (2012) IEEE Guide for Substation Fire Protection. Section 7.2.2 Equipment to Equipment identifies a minimum separation distance of 50 feet.

**107. Q. WHY WAS THE PROJECT NECESSARY?**

A. The loads on Bicentennial Substation have been growing consistently for the past few years. The existing transformers in parallel have a nameplate rating of 74 MVA. In 2023, the non-coincidental peak load measured was 67.9MVA or 92 percent of the nameplate. The Company received a service request for [redacted]. As a result, a new transformer at Bicentennial Substation is required for the additional capacity for the new load in the area.

**108. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. The project utilized a spare transformer to ensure successful completion before the summer of 2024 due to extended transformer lead times. The Company is seeking recovery of all costs associated with placing the spare transformer into service to provide the necessary load relief as described above. No transformer costs are being included in the current rate case revenue requirement. The replacement spare 138/12 kV transformer has been ordered and is not expected to be delivered until February 2026. The Company will seek recovery of those costs in a future GRC.

**109. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**110. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $949,306 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,409,618 (with AFUDC). The projected costs during the Certification Period are $1,654. The facilities were installed and placed in service by March 22, 2024.

**xxii. <u>CAPACITOR SYSTEM ADDNS - TRANS (LINCOLN) (YA)</u>**

**111. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved installing a new 24 Mega Volt Amp Reactive ("MVAR") capacitor and one 138 kV circuit switcher at the existing 138 kV bus inside Lincoln substation. The remote terminal unit ("RTU") and bus differential panels were also upgraded in this project.

**112. Q. WHY WAS THE PROJECT NECESSARY?**

A. Identified as a NERC VAR-001-5 R2 and M2 requirement, a 0 MVAR interchange is to be maintained among the power grids. Nevada Power is currently reactive resource deficient and imports several hundred MVARs from neighboring entities, especially in the summer months. During the summers of 2020 and 2021, the maximum instantaneous VAR import through the transmission tie lines was approximately 950 MVAR and 750 MVAR, respectively. A deficiency also leads to depressed voltages throughout the transmission system that can then lead to depressed distribution voltage to customers. Lincoln Substation has long experienced higher VAR demand than it has reactive resources available and continually results in low voltage during summer months. In July 2021, Lincoln Substation was deficient by approximately 20 MVAR.

**113. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of “utility facility” under NRS 704.860.

**114. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $1,017,250 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,371,670 (with AFUDC). The facilities were installed and placed in service by March 4, 2024.

**xxiii. <u>PROSPECTOR 230/12 KV BANK 3 (AQT)</u>**

**115. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 33 MVA 230/12 kV transformer at Prospector Substation with associated 12 kV bank breaker, protection and communication equipment.

**116. Q. WHY WAS THE PROJECT NECESSARY?**

A. Prospector bank #2 was forecasted to load to 101 percent of the summer normal rating by November 2023. The Company has received service requests from [redacted]. As a result, a new transformer was required at Prospector Substation for the additional capacity in the Apex area.

**117. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. Yes. The project was presented and approved in Nevada Power's 2023 GRC in Docket No. 23-06007, where the Company received recovery for the replacement spare transformer.

**118. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. The Company is seeking recovery of all costs associated with placing the spare transformer into service to provide the necessary load relief as described above. No transformer costs are being included in the current GRC revenue requirement for this project. The Company utilized the existing spare 230/12 kV transformer that was delivered directly to the newly constructed pad at the Prospector Substation for the bank 3 position, which was acquired under the Prospector 230/12 kV Bank 2 project.

**119. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project is $4,020,447 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,313,270 (with AFUDC). The projected costs during the Certification Period are $893. The facilities were installed and placed in service by August 28, 2023.

**120. Q. PLEASE EXPLAIN THE VARIANCE BETWEEN THE ESTIMATED AND ACTUAL COST OF THE PROJECT?**

A. The estimated total cost includes the previously approved cost of the spare replacement transformer at approximately $2.0 million; the $1.3 million in incurred costs for this rate case does not include the costs associated with the spare transformer used.

**xxiv. <u>CMO1212 TO CMO1213 FEEDER TIE (A2U)</u>**

**121. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new underground 12 kV distribution feeder tie between Camero 1212 and Camero 1213 to provide relief for Camero 1212.

**122. Q. WHY WAS THE PROJECT NECESSARY?**

A. This project is required to improve the reliability on the existing Camero 1212 feeder, which currently supports 2.8 MVA of residential and commercial customers. A fault on the Camero 1212 circuit created a high risk of a potential long-term outage, leaving all the existing customers on the circuit without power for an extended period. The new feeder tie will allow load from Camero 1212 to be transferred to Camero 1213.

**123. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**124. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $901,246 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,241,704 (with AFUDC). The facilities were installed and placed in service by January 24, 2024.

**xxv. <u>GYPSUM 69/12KV BANK 3 (2Y)</u>**

**125. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 22 MVA 69/12 kV transformer at Gypsum Substation with associated 12 kV bank breaker, protection and communication equipment.

**126. Q. WHY WAS THE PROJECT NECESSARY?**

A. The existing transformer at Gypsum Substation has a nameplate rating of 22.4 MVA. In the summer of 2022, the non-coincidental peak load measured on Gypsum bank 2 was 10.6 MVA or 47 percent of the unit's nameplate. In November 2021, the Company received service requests for [redacted]. As a result, a new transformer at Gypsum Substation is required to provide service to the master plans. The existing 69/12kV 22.4 MVA distribution substation transformers at Gypsum Substation were forecasted to load to 109.3 percent of Summer Normal Rating by January 2024 considering the forecast of increased commercial growth.

**127. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. The project utilized a spare transformer to ensure successful completion before the expected overload in early 2024 due to extended transformer lead times. The Company is seeking recovery of all costs associated with placing the spare transformer into service to provide the necessary load relief as described above. No transformer costs are being included in the current rate case revenue requirement. The replacement spare 69/12 kV transformer has been ordered and is not expected to be delivered until July 2025. The Company will seek recovery of those costs in a future GRC.

**128. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**129. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $3,146,519 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,086,843 (with AFUDC). The projected costs during the Certification Period are $949. The facilities were installed and placed in service by February 7, 2024.

**130. Q. PLEASE EXPLAIN THE VARIANCE BETWEEN THE ESTIMATED AND ACTUAL COST OF THE PROJECT?**

A. The estimated total cost includes the future cost of the spare replacement transformer at approximately $2 million; the $1.1 million in incurred costs does not include any costs associated with either the spare transformer used or the future transformer under contract.

**xxvi. <u>BELTWAY SUB 1ST BUS SECTION (A6Z)</u>**

**131. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved the installation of a new 12 kV bus section addition at Beltway Substation.

**132. Q. WHY WAS THE PROJECT NECESSARY?**

A. The first bus section in the Beltway Substation is designed to serve load to the west and north of the substation. The Company received a service request for the [redacted] on this bus section. Service to these master plans will be from Beltway feeders 1201, 1202, 1206, and 1207, which required the first bus section to be constructed to meet the growth in the area.

**133. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**134. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $1,483,101 (without AFUDC). The total at completion cost of the project during the Certification Period is $1,026,452 (with AFUDC). The facilities are no longer expected to be placed in service by the end of the Certification Period due to delays in construction and will not be included in the revenue requirement under this GRC. The costs will be removed as part of the Certification filing.

**xxvii. <u>CAPACITOR SYSTEM ADDNS - TRANS (BURNHAM) (BU)</u>**

**135. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved installing a new 24 MVAR capacitor and one 138 kV circuit switcher at the existing 138 kV bus inside Burnham Substation. The RTUs and bus differential panels were also upgraded as part of this project.

**136 Q. WHY WAS THE PROJECT NECESSARY?**

A. Identified as a NERC VAR-001-5 R2 and M2 requirement, a 0 MVAR interchange is to be maintained among the power grids. Nevada Power is currently reactive resource deficient and imports several hundred MVARs from neighboring entities, especially in the summer months. During summer 2020 and 2021, the maximum instantaneous VAR import through the transmission tie lines was approximately 950 MVAR and 750 MVAR, respectively. A deficiency also leads to depressed voltages throughout the transmission system that can then lead to depressed distribution voltage to customers. Burnham Substation has long experienced higher VAR demand than it has reactive resources available and continually results in low voltage during summer months. In July 2021, Burham Substation was deficient by approximately 21 MVAR.

**137. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of “utility facility” under NRS 704.860.

**138. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $1,021,100 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $993,155 (with AFUDC). The facilities were installed and placed in service by June 30, 2023.

## III. LARGE GENERATOR INTERCONNECTIONS

**139. Q. DESCRIBE THE PROJECTS INCLUDED IN THIS SECTION.**

A. This section discusses investments for Large Generator Interconnection Agreements ("LGIA") under the Company's Open Access Transmission Tariff ("OATT") that are greater than $1 million listed and in **Exhibit Veilleux-Direct-2**. These projects were placed in service after the end of the certification period in Nevada Power's last GRC (May 31, 2023) and before the end of the Certification Period in this GRC. The projects are organized in order of descending total cost.

**140. Q. HOW DID NEVADA POWER ARRIVE AT THE CUSTOMER AND COMPANY COST RESPONSIBILITIES FOR THE FOLLOWING PROJECTS?**

A. The cost responsibilities for interconnecting were assigned in compliance with the requirements for interconnecting large generators to the Company's transmission system as established by FERC and provided for in Attachment N of the Company's OATT. The allocation of costs for facilities associated with the interconnection is provided in Appendix A of their respective LGIAs.

### xxviii. GEMINI SOLAR 690 MW INTERCONNECTION AT CRYSTAL 230 KV (A7Q)

**141. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved interconnecting a new 690 MW solar photovoltaic ("PV") and battery energy storage system ("BESS") owned by Solar Partners XI, LLC to Nevada Power's existing 230 kV Crystal Substation. The network upgrades at Crystal Substation included construction of a new 230 kV terminal with a power circuit breaker, switches and associated protection and communication equipment. The TPIF, which are funded by the interconnection customer but owned by Nevada Power, included the 230 kV generation tie line and switch structure, customer site telecommunications, metering and associated land rights, and environmental permits. The interconnection also required the installation of the new 230 kV Crystal to Harry Allen #4 transmission line with telecommunications fiber and an additional 230 kV power circuit breaker at Crystal and Harry Allen substations. Additional network upgrades included the replacement of 69 kV power circuit breakers and associated disconnects at Nevada Power's existing Miller and North Las Vegas substations.

**142. Q. WHY WAS THE PROJECT NECESSARY?**

A. The project was required pursuant to the OATT and LGIA No. 18-00014 between Nevada Power and Solar Partners XI, LLC.

**143. Q. WHAT IS THE COMPANY SEEKING AT THIS TIME?**

A. The Company is seeking recovery of the 230 kV Crystal to Harry Allen #4 transmission line, which includes the telecommunications fiber. This previously was not contemplated to be completed until December 2023 at the time of the previous GRC. With the completion of these facilities, it fulfils the requirements under the LGIA for the customer to achieve commercial operation.

**144. Q. WAS THIS PROJECT PREVIOUSLY PRESENTED TO THE COMMISSION?**

A. Yes. The power purchase agreement ("PPA") between Nevada Power and Gemini Solar for 690 MW was presented and approved in the 3rd IRP Amendment, Docket No. 19-06039. This included the LGIA submitted under Volume 5 – TRAN-3 Company 151 APEX Solar LGIA. This project was also presented and approved in Nevada Power's 2023 GRC in Docket No. 23-06007.

**145. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $10,841,472 (without AFUDC), of which $5,755,810 is associated with the Crystal to Harry Allen #4 transmission line. The total at completion cost of the project through the end of the Test Period is $4,485,520 (with AFUDC). The projected costs during the Certification Period are $48,965. All facilities associated with the new 230kV Crystal to Harry Allen #4 transmission line were installed and placed in service by December 18, 2023.

**xxix. <u>CO. 211 REID GARDNER BESS INTERCONNECTION (BAP)</u>**

**146. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved interconnecting a new 220 MW (440 MWh) BESS owned by Nevada Power to Nevada Power's existing 230 kV Reid Gardner substation. The network upgrades at Reid Gardner substation included construction of a new 230 kV terminal with a power circuit breaker, switches and associated protection and communication equipment. The TPIF, which are funded by the interconnection customer but owned by Nevada Power, included the 230 kV generation tie line and switch structure, customer site telecommunications, metering and associated land rights and environmental permits.

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

**147. Q. WHY WAS THE PROJECT NECESSARY?**

A. The project was required pursuant to the OATT and Provisional LGIA No. 22-00074.

**148. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. Yes, the Reid Gardner BESS project and associated interconnection facilities was presented and approved by the Commission in the Companies' 1st Amendment to its 2021 Joint IRP in Docket No. 22-03024, Nevada Power's UEPA filing in Docket No. 22-03039 and Nevada Power's 2023 GRC in Docket No. 23-06007.

**149. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $1,062,064 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $1,325,967 (with AFUDC). The facilities were installed and placed in service by December 4, 2023.

## IV. MARCH 2025 T&D MAJOR PROJECTS

**150. Q. DESCRIBE THE PROJECTS INCLUDED IN THIS SECTION.**

A. This section discusses upcoming investments for major T&D projects greater than $1 million as listed in **Exhibit Veilleux-Direct-2**. These projects are being included for informational purposes only as they have a potential of being placed in service prior to the end of the Certification Period in this GRC. The projects are organized in order of descending total cost.

### xxx. <u>LVC – HIGHLAND 138KV FOLD INTO MILLER (AND)</u>

**151. Q. PLEASE DESCRIBE THE PROJECT.**

A. This project involved expanding the existing Miller 138/69 kV Substation to support folding in the existing nearby 138 kV LV Cogen to Highland line. The scope included utilizing the adjacent undeveloped property owned by the Company and constructing a new five breaker 138 kV ring bus with associated system protection and communication equipment, a new control enclosure, station service, and transmission line work to fold in the LV Cogen – Highland 138 kV and re-terminate the existing Leavitt-Miller 138 kV line into the new switchyard. On- and off-site improvements were also necessary to expand the substation.

**152. Q. WHY WAS THE PROJECT NECESSARY?**

A. The existing loads at Tropical, Gilmore and Leavitt substations are served via two 138 kV lines from Pecos and two 138/69 kV transformers at Miller 69 kV Substation. The existing system has a temporary line tap at Pecos – Michael Way at Tropical Substation designed to prevent an N-1 of Pecos – Tropical from causing all of the 138 kV loads from being served via the 69 kV system at Millers. With the loss of the Pecos – Tropical 138 kV line and the Pecos – Michael Way – Tropical Tap 138 kV line (either a P6 or a P4 event at Tropical), the 69 kV system around Millers will overload and experience low voltage. Folding in the LV Cogen – Highland 138 kV line will provide additional 138 kV sources to Millers and mitigate overloads and voltage violations on the 69 kV system.

**153. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**154. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $15,952,790 (without AFUDC). The total at completion cost of the project through the end of the Test Period is $291,752 (with AFUDC). The potential total cost of the project that could occur within the Certification Period is an additional $17,894,730 (with AFUDC). The facilities are forecasted to be complete and placed in service in March 2025 after the Certification Period.

**xxxi. <u>CIPV14 - CRITICAL SUBSTATION H (ANV)</u>**

**155. Q. PLEASE DESCRIBE THE PROJECT.**

A. The Company added layered perimeter intrusion detection systems at Critical Substation H pursuant to NERC Reliability Standard CIP-014-2 by upgrading electronic security to include cameras, closed-circuit television ("CCTV") poles, motion detection, lighting, public address horns, and control enclosure information technology equipment.

**156. Q. WHY WAS THE PROJECT NECESSARY?**

A. This is a compliance project mandated by NERC Reliability Standard CIP-014-2, which requires transmission owners to identify and protect transmission switch stations and substations and their associated primary control centers, that if rendered inoperable or damaged due to physical attack, could result in widespread instability, uncontrolled separation, or cascading within an interconnection. The physical security requirements described in CIP 14-02 are broken down into six (6) requirements, R1 through R6. R1 is the "Where" - (Risk Assessment - Identify Critical Facilities); R2 - 3rd Party Assessment and Validation of R1; R3 - Transmission Owner & Transmission Operator Coordination; R4 – "The Who, How, When, Probability" (Evaluate the Potential Threats to Assets under R1); R5 - Develop and Implement a Documented Physical Security Plan (DDDACR - Deter, Detect, Delay, Access, Communicate, and Respond); R6 - 3rd Party Assessment and Validation of R4/R5.

**157. Q. HAS THIS PROJECT BEEN PRESENTED TO THE COMMISSION?**

A. No, Nevada Power has not sought Commission approval of this project in an IRP. While NAC 704.9503(1)(a) contemplates a resource plan filing for projects that require a UEPA permit to construct, this project does not meet the definition of "utility facility" under NRS 704.860.

**158. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?**

A. The estimated total cost of the project was $3,651,388 (without AFUDC). The potential total at completion cost of the project that could occur within the Certification Period is $2.6 million (with AFUDC). The facilities are forecasted to be completed and placed in service in March 2025 after the Certification Period but have a high likelihood of completing in February 2025.

## IV. CONCLUSION

**159. Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes, it does.

# EXHIBIT VEILLEUX-DIRECT-1

QUALIFICATION OF WITNESS

**VINCENT VEILLEUX**
Director, Trans and Dist Projects
6226 West Sahara Ave.
Las Vegas, NV 89151
702-277-8478
vincent.veilleux@nvenergy.com

## EDUCATION

*University of Nevada, Las Vegas*
Executive Master in Business Administration – 2018
*Villanova University*
Advanced Masters Certificate in Project Management – 2014
*Villanova University*
Masters Certificate in Project Management – 2013
*University of Nevada, Las Vegas*
Bachelor of Science, Computer Engineering – 2007

## PROFESSIONAL EXPERIENCE

NV Energy, Las Vegas, Nevada: October 2006 – Present
*Director, Trans and Dist Projects*: May 2023 – Present

- Provides strategic direction and leadership to the organization to build and enhance customer relationships. Develops and fosters innovative solutions that exceed customer expectations while adapting to changing regulatory environments, managing risk, and maximizing distribution and transmission system utilization. Integrates utility business planning, strategic opportunities, and business relationships to grow high voltage distribution business via regional business plans. Directs the negotiation and administration of Rule 9 contracts with large retail customers.

*Manager, Trans and Dist Projects*: January 2020 – May 2023

- Manage and support the operations of the Electric Delivery project management team who are responsible for all aspects of project management, including leading teams of multi-discipline functional groups to execute utility projects to achieve scope, schedule & budget. Aspects include: routing & siting, permitting, design, procurement, construction and commissioning, scope & contract negotiation with external customers and governmental entities including Rule 9 and Rule 15, leading teams with members from T&D Planning, Rates and Regulatory, Lands services, Legal, Substation, Transmission, Civil, Telecommunication, Environmental, Operations and Distribution.

*Manager, Distribution Energy Resources:* December 2018 – January 2020

- Develops, implements and manages strategies and ongoing operation of emerging and established distributed energy resource technologies and programs (including electric vehicles, energy storage, distributed generation assets and other customer sited technology).
- Develops and provides technical input and guidance in DER projects, customer systems, and renewable energy technologies through research, evaluation, customer trends and industry collaboration.
- Develops customer facing content related to renewable energy programs, transportation electrification, energy storage and other DER technologies, to improve brand awareness and program adoption.

*Senior Project Manager – Major Projects:* April 2014 – December 2018

- Responsible for all aspects of project management, including leading teams of multi-discipline functional groups to execute utility projects to achieve scope, schedule & budget. Aspects include: routing & siting, permitting, design, procurement, construction and commissioning, scope & contract negotiation with external customers and governmental entities including Rule 9 and Rule 15, leading teams with members from T&D Planning, Rates and Regulatory, Lands services, Legal, Substation, Transmission, Civil, Telecommunication, Environmental, Operations and Distribution.
- Managing project budget estimate review, project budget presentation and scope justification to procure funding, authorization for expenditure creation, project scheduling utilizing Primavera Project Planner (P6) software, and monthly expenditure tracking, status and variance reporting

*Senior Project Controls Consultant – Major Projects*: October 2006 – April 2014

- Supported multiple project managers by building and maintaining project schedules, analysis of cost reports, budgets and variances, new project requests, charge codes and project ID creation and status.
- Created and maintained cost and resource loaded Primavera schedules; analyze cash-flows, monitor progress using critical path method, export cost analysis reports, establish baseline projections, create annual forecasts for approval by Financial Planning & Analysis (FP&A) and the former Resource Allocation Committee (RAC) monthly meetings, as well as submit new project requests for approval.
- Led the Project Controls team in developing multi-year budgets for the entire Major Projects capital program, for submittal to FP&A, RAC, and the Board of Directors.
- Performed cash-flow analysis of capital program and coordinated efforts with project managers and project controls for rate case data requests, explanations, and/or alterations based on budget requirements. Created budget summary reports for upper management and senior directors.
- Created capital budget histograms for resource leveling, participated in meetings with team leaders and project management in reconciling project status, scope, and priority, and participated in annual forced ranking meetings for every proposed Energy Delivery project

**PRIOR TESTIMONY WITH PUCN**

Docket No. 19-02001 – 2019-2020 Annual Clean Energy Programs Plan
Docket No. 20-06003 – 2020 General Rate Case
Docket No. 23-06007 – 2023 General Rate Case

# EXHIBIT VEILLEUX-DIRECT-2

NEVADA POWER COMPANY
d/b/a NV Energy
ELECTRIC DEPARTMENT
TRANSMISSION AND DISTRIBUTION MAJOR PROJECTS
Plant Additions - June 1, 2023 to February 28, 2025
(Account 101 including AFUDC)



| Ln No | Section (a) | Link (b) | Link Description (c) | 06/01/2023 - 09/30/2024 (d) | 10/01/2024 - 02/28/2025 (e) | Total as of 02/28/2025 (d) + (e) (f) | Ln No |
|---|---|---|---|---|---|---|---|
| 1 | II. T&D | BDJ | CRITICAL SITE SECURITY UPGRADES - SOUTHERN NEVADA | $ 32,894,214 | $ (23) | $ 32,894,191 | 1 |
| 2 | II. T&D | AKJ | WEST HENDERSON LARSON SUBSTATION FEEDERS | 7,318,746 | 95,384 | 7,414,130 | 2 |
| 3 | II. T&D | AV8 | SUNSET 1215 FEEDER | 6,424,001 | 299,901 | 6,723,902 | 3 |
| 4 | II. T&D | AWA | UHS WEST HENDERSON HOSPITAL FEEDER | 5,870,609 | - | 5,870,609 | 4 |
| 5 | II. T&D | APF | LINDQUIST-AWT TAP-WINTERWOOD 69 KV REBUILD | 5,461,448 | 3,330 | 5,464,778 | 5 |
| 6 | II. T&D | AEZ | REID GARDNER TO TORTOISE 230 KV LINE #2 | 44,429 | 4,990,591 | 5,035,020 | 6 |
| 7 | III. LGI | A7Q | GEMINI SOLAR 690MW INTERCONNECTION AT CRYSTAL 230KV (CO. 151_172) | 4,485,520 | 48,965 | 4,534,485 | 7 |
| 8 | II. T&D | ALA | SUNRISE 138/69 KV BANK ADDITION | 4,294,122 | - | 4,294,122 | 8 |
| 9 | II. T&D | AQ5 | LARSON 1201 FEEDER | 4,256,206 | - | 4,256,206 | 9 |
| 10 | II. T&D | A18 | PROTECTIVE RELAY REPLACEMENT (SOUTH) | 3,273,936 | 874,117 | 4,148,053 | 10 |
| 11 | II. T&D | AVY | RAILROAD 1212/MCDONALD 1210/QUAIL 1213 FEEDER TIE | - | 3,500,000 | 3,500,000 | 11 |
| 12 | II. T&D | BCB | WESTSIDE SUBSTATION - GROUND GRID REPLACEMENT | - | 3,488,566 | 3,488,566 | 12 |
| 13 | II. T&D | APE | GILMORE 1201 FEEDER | 2,980,091 | - | 2,980,091 | 13 |
| 14 | II. T&D | CU | CLARK - CONCOURSE 138KV RE-CONDUCTOR | 2,856,364 | - | 2,856,364 | 14 |
| 15 | II. T&D | B4B | SPEEDWAY SUB SPARE TRANSFORMER 138X69-12KV | - | 2,836,615 | 2,836,615 | 15 |
| 16 | II. T&D | AW7 | PECOS 1207 TO PECOS 1211 FEEDER TIE | 2,790,539 | - | 2,790,539 | 16 |
| 17 | II. T&D | AWB | WASHBURN 1203 TO WASHBURN 1201 FEEDER TIE | - | 2,700,000 | 2,700,000 | 17 |
| 18 | II. T&D | AVE | RILEY 1215 AND 1217 FEEDERS | 1,891,717 | 487,244 | 2,378,961 | 18 |
| 19 | II. T&D | A8A | FRIAS 138/12KV BANK 1 | 1,960,214 | - | 1,960,214 | 19 |
| 20 | II. T&D | YW | RILEY 138/12KV BANK 3 | 1,660,239 | - | 1,660,239 | 20 |
| 21 | II. T&D | KK | TOMSIK 138/12KV BANK 1 | 1,604,983 | - | 1,604,983 | 21 |
| 22 | II. T&D | BZ | BICENTENNIAL 138/12KV BANK 3 | 1,409,618 | 1,654 | 1,411,272 | 22 |
| 23 | II. T&D | YA | CAPACITOR SYSTEM ADDNS - TRANS (LINCOLN) | 1,371,670 | - | 1,371,670 | 23 |
| 24 | III. LGI | BAP | CO. 211 REID GARDNER BESS INTERCONNECTION | 1,325,967 | - | 1,325,967 | 24 |
| 25 | II. T&D | AQT | PROSPECTOR 230/12KV BANK 3 | 1,313,270 | 893 | 1,314,163 | 25 |
| 26 | II. T&D | A2U | CMO1212 TO CMO1213 FEEDER TIE | 1,241,704 | - | 1,241,704 | 26 |
| 27 | II. T&D | 2Y | GYPSUM 69/12KV BANK 3 | 1,086,843 | 949 | 1,087,792 | 27 |
| 28 | II. T&D | A6Z | BELTWAY SUB 1ST BUS SECTION | - | 1,026,452 | 1,026,452 | 28 |
| 29 | II. T&D | BU | CAPACITOR SYSTEM ADDNS - TRANS (BURNHAM) | 993,155 | - | 993,155 | 29 |
| 30 | | OTHER | | 12,531,166 | 2,370,795 | 14,901,961 | 30 |
| 31 | | | | | | | 31 |
| 32 | | | **TOTAL** | $ 111,340,773 | $ 22,725,433 | $ 134,066,206 | 32 |
| 33 | | | | | | | 33 |
| 34 | **March 2025 T&D Projects - For Information Only*** | | | | | | 34 |
| 35 | IV. March | AND | LVC - HIGHLAND 138KV FOLD INTO MILLER | - | 17,894,730 | 17,894,730 | 35 |
| 36 | IV. March | ANV | CIPV14 - CRITICAL SUBSTATION H | - | 2,600,000 | 2,600,000 | 36 |
| 37 | * See Exhibit Hanshew - Direct 3 | | | | | | 37 |
| 38 | | | | | | | 38 |

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, VINCENT VEILLEUX, 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: February 14, 2025

Vincent Veilleux

# FADY ATALA

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

**Fady Atala**

Revenue Requirement

**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 Director of Engineering and Project Management 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, NV. I am filing testimony on behalf of Nevada Power.

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

A. I have more than 10 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 plant and operational performance.

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

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF ENGINEERING AND PROJECT MANAGEMENT.**

A. As Director of Engineering and Project Management, my responsibilities include leading the Large Construction Project Management team overseeing the construction of new power plants and large capital projects. My role involves directing this multidisciplinary team of project directors, managers, and project control professionals, who manage and oversee every phase of construction. This includes negotiating contracts, ensuring regulatory compliance, and providing oversight of equipment manufacturers and contractors. My team focuses on delivering projects efficiently and on schedule, while maintaining high standards of safety, quality, and budget control. My statement of qualifications is included in **Exhibit Atala-Direct-1**.

**4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. No.

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

A. The purpose of my testimony is to support the Company's actions taken to complete the Silverhawk Peakers Project ("Project") in time for the summer peak in 2024, and to demonstrate that the Company's decisions and execution throughout the Project were prudent. I will provide details on the scope, schedule, budget performance, and the challenges encountered during construction.

**6. Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following Exhibits:

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

**Exhibit Atala-Direct-2 –** Resource Planning's PLEXOS Analysis Email (July 5, 2023) and PWRR Analysis (August 3, 2023)

**CONFIDENTIAL Exhibit Atala-Direct-3 –** Resource Planning's PLEXOS Analysis, July 5, 2023 Spreadsheet

**CONFIDENTIAL Exhibit Atala-Direct-4 –** Resource Planning's PWRR Analysis, August 3, 2023 CER Spreadsheet

**CONFIDENTIAL Exhibit Atala-Direct-5 –** Resource Planning's PWRR Analysis, November 30, 2023 CER Spreadsheet

**CONFIDENTIAL Exhibit Atala-Direct-6 –** Silverhawk Power Replacement Procurement Cost for Summer 2024

**CONFIDENTIAL Exhibit Atala-Direct-7 –** Sargent & Lundy Cost Review

**7. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION PROVIDED IN THIS TESTIMONY?**

A. Yes. Confidential information is contained in **CONFIDENTIAL Exhibit Atala-Direct-3, CONFIDENTIAL Exhibit Atala-Direct-4, CONFIDENTIAL Exhibit Atala-Direct-5, CONFIDENTIAL Exhibit Atala-Direct-6,** and **CONFIDENTIAL Exhibit Atala-Direct-7.**

**8. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.**

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

A. **CONFIDENTIAL Exhibits Atala-Direct-3, Atala-Direct-4,Atala-Direct-5 and Atala-Direct-6** contain commercially sensitive power cost data and forecasts from Resource Planning that are obtained from third parties. **CONFIDENTIAL Exhibit Atala-Direct-7** contains commercially sensitive vendor cost information. Disclosure of this information could disadvantage the Company in future negotiations and competitive bidding.

**9. Q. FOR HOW LONG DOES NEVADA POWER REQUEST CONFIDENTIAL TREATMENT?**

A. The requested period for confidential treatment is for no less than five years.

**10. 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") OR OTHER INTERVENERS TO PARTICIPATE IN THIS DOCKET?**

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. In addition, intervening parties with an executed protective agreement will be provided the confidential exhibits.

**11. Q. PLEASE DESCRIBE THE PROJECT MANAGEMENT OVERSIGHT PROCESS THAT IS GENERALLY APPLICABLE TO CAPITAL PROJECTS.**

A. Initially, specific project approvals must be obtained. This process begins with the assignment of a project manager or project director, who is responsible for executing a project. The project manager is required to submit an "Authorization for Expenditure" ("AFE") for approval prior to commencing a project. The AFE includes the most current information regarding estimated project cost and budget information. The AFE serves as a business control to ensure construction projects, plant additions and expenses are reviewed and approved by the appropriate levels of management before funds are committed and spent. Project managers or project directors may submit a preliminary AFE requesting funds to perform engineering in order to fully develop a capital project's scope, schedule and budget. Project managers or project directors may also submit a preliminary AFE requesting funds to procure identified long-lead items. In these situations, the project manager or project director is then required to submit a supplemental AFE for the full funding of the project prior to committing and spending additional funds.

A Standard Project Proposal ("SPP") is prepared for capital projects exceeding $1 million and submitted with the AFE for management review and approval. The SPP template has been designed to provide a consistent collection of supporting information to management and regulators. Depending on the size and complexity of the proposed project, business units can append additional relevant information to the SPP template. Project managers or project directors are responsible for monitoring actual and forecast spending against the approved project funding amounts in the approved AFE. Project managers provide monthly cost, schedule and scope updates for each project to Generation management. The business unit performs a thorough review and analysis of its capital portfolio each month, and reviews project performance with project managers or project directors. Business units forecast capital spending, analyze budget variances, perform peer reviews and report results to Corporate Finance and the executive team monthly.

If forecasted costs exceed the original AFE approval, the AFE is revised through a supplemental AFE to ensure continuous management oversight of project expenditures. The supplemental AFE ensures that cost adjustments are reviewed and approved at the appropriate management levels, maintaining alignment with corporate financial controls.

**12. Q. PLEASE DESCRIBE THE SILVERHAWK PEAKERS PROJECT.**

A. The Project involves the installation of two General Electric 7F.05 simple-cycle combustion turbine generators, Units 3 and 4, designed to provide 444 megawatts ("MW") of peaking capacity. These units are specifically configured to support the Company's need for operational flexibility, ensuring reliable service during peak demand. The Project is located at the existing Silverhawk Generating Station, utilizing a brownfield site to leverage existing infrastructure, such as transmission lines, water systems, and control facilities. This approach optimized costs and reduced the environmental impact. The peaker units complement the existing generation fleet, ensuring grid stability while facilitating the integration of renewable energy sources. Designed with modern emission control technologies, the Project aligned with the Company's commitment to both environmental stewardship and meeting regulatory requirements.

**13. Q. HAS THE COMMISSION REVIEWED AND APPROVED THE PROJECT?**

A. Yes. The Project was requested in the Companies' Fourth Amendment to its 2021 Integrated Resource Plan ("IRP") in Docket No. 22-11032. The Commission approved this Project in its Order in that Docket.

14. Q. **AS A DIRECTOR OF ENGINEERING AND PROJECT MANAGEMENT, HOW DO YOU UNDERSTAND THE PRUDENCE STANDARD AS IT IS APPLIED TO PROJECTS UNDER YOUR SUPERVISION AND WHAT IS YOUR ANALYSIS OF PRUDENCE AS TO THE COMPANY'S ACTIONS REGARDING THE SILVERHAWK PEAKERS PROJECT?**

A. I understand that the prudence standard requires the Company's decisions to be reasonable based on the information available, or that reasonably should have been available, at the time those decisions were made. A decision is considered prudent if it reflects a reasonable course of action under the circumstances at the time the decision was made.

While I am not an attorney, I understand that the Commission's approval of the Project in the IRP meant that the Commission determined that it would be prudent for Nevada Power to move forward with Project. I testify in this case that the Company's ongoing assessment of the costs and speed of the Project—as design, engineering and construction progressed—demonstrated prudent and reasonable behavior.

15. Q. **PLEASE DESCRIBE THE KEY EVENTS LEADING TO THE SILVERHAWK PEAKERS PROJECT.**

A. The Project emerged as a response to the Company's pressing need to address the peak capacity shortfall. The Company presented details for the Project in the Fourth Amendment to the IRP, Docket No. 22-11032. As discussed in more detail in the direct testimony of Ryan Atkins in Docket No. 22-11032,[1] since the summer of

[1] See Docket No. 22-11032, Direct Testimony of Ryan Atkins, pgs. 3-6.

2020, resource adequacy risks in Nevada and the broader Western region have significantly evolved, driven by consecutive years of extreme heat, increasing weather variability, and prolonged drought conditions that have diminished hydroelectric power generation. These challenges have been exacerbated by record wildfire activity, and by shifts in the regional resource mix, with substantial retirements of coal and natural gas plants and delays in renewable energy development. Concurrently, the California Independent System Operator's rule changes—such as adjusting day-ahead export schedules and prioritizing in-state load over interstate transmission—have added market uncertainty, reducing liquidity and increasing the risks associated with real-time market purchases.

These challenges, combined with increased energy demands from native load growth and transportation electrification, exacerbated the open capacity position. Mr. Atkins's testimony in the Fourth Amendment emphasized the need for diverse projects to hedge against these uncertainties, including geothermal and combustion turbine solutions.

The Project was proposed as the only resource in the Preferred Plan capable of achieving operational status in summer 2024. These units provided exceptional operational flexibility, especially as more intermittent renewable resources come online.

In October 2021, following an extensive evaluation of potential sites and turbine technologies, the Silverhawk site was selected due to its strategic advantages, including adequate space, reliable transmission infrastructure, and accessible natural gas supply. An Owner's Engineer was engaged in March 2022 to develop preliminary designs and cost estimates, laying the foundation for the Project's execution to help meet summer 2024 demands.

The Company's efforts to expedite the approval and construction of the Project reflect the critical role these units play in addressing peak loads, reducing reliance on uncertain market capacity, and mitigating the risk of delays in renewable resource development. The Commission provided critical support in approving the Project under expedited treatment.

**16. Q. HOW DID THE PROJECT PERFORM IN TERMS OF BUDGET AND SCHEDULE?**

A. Despite challenges such as increased labor and material costs, compressed timelines, and scope modifications, the Project achieved its Commercial Operation Dates ("COD") close to the planned timeline, reflecting a successful project execution, despite the challenges encountered during the Project. Unit 4 began commercial operation on July 13, 2024, and Unit 3 followed on July 23, 2024.

It is important to note that Unit 4 started providing test energy on June 30, 2024, and Unit 3 began generating test energy on July 14, 2024. The units' commissioning and ramp-up were managed in close coordination with the Generation Desk to ensure that the units contributed to meeting peak summer demand as planned.

Regarding budget performance, while the Project faced cost adjustments due to permitting delays, supply chain disruptions, and other factors, these challenges were proactively managed and reviewed as construction proceeded on the Project.

PA Consulting Group, Inc. ("PA Consulting"), a consultancy firm that, among other things, analyzes a range of investments in the power generation sector and values portfolios of generation assets, conducted an outside third party assessment of the Company's actions associated with the Project. This assessment included: (1) a review of the Project to evaluate the factors that contributed to the cost increases; (2) an assessment of the Company's approach to key decision-making throughout Project execution; and (3) an evaluation of whether the cost increases are in-line with cost trends in the industry. PA Consulting determined that while the final cost of the Project was approximately 6 percent above the expected uncertainty band for the type of estimate conducted, Nevada Power's actions were prudent in light of the alternatives considered, and the cost of not proceeding to meet the scheduled completion date during the peak summer season. James Heidell, who is testifying in this case and is a partner at PA Consulting, confirms these findings.

The completion of the Project in July of 2024 underscores the Company's commitment to meeting system reliability and capacity needs for our customers during critical summer periods.

**17. Q. PLEASE DESCRIBE ANY CHALLENGES FACED DURING THE SILVERHAWK PEAKERS PROJECT AND HOW THEY WERE ADDRESSED?**

A. The Project encountered numerous challenges that required strategic and adaptive management to ensure its successful completion. One of the primary obstacles was the lack of bids for an Engineering, Procurement, and Construction ("EPC") contract. To address this, the Company pivoted to a multi-contract approach to move the project forward, engaging separate entities for design, procurement, and construction activities. This required the Company to assume a central coordination role, orchestrating efforts across all involved parties. A dedicated Project Management Team was established to oversee this coordination, ensuring alignment and streamlined communication between the teams.

Permitting delays also posed significant challenges.[2] The Company mitigated these delays by implementing an approved construction schedule, including extended work hours and double shifts, to ensure the project could still be constructed and deliver energy to customers during the critical summer months of 2024.

Global supply chain disruptions presented another set of challenges. Force majeure events such as Red Sea attacks, cyclonic storms in India, and COVID-19 restrictions in China delayed critical equipment deliveries. Further complications arose from severe flooding in Texas and a fire at an air filter manufacturing plant. To overcome these challenges, the Company worked closely with vendors to ensure delivery of essential materials on time or as quickly as could be achieved given the circumstances. In some cases the deliveries did not come on time, and again project schedule was ultimately reached through activities rescheduling and additional contractor work hours, which in part increased costs, but at the same time was the option that allowed the project to be delivered to benefit customers during critical summer periods. It was critical that the plant came on-line and the effort was made

[2] As detailed in Docket No. 23-01027 regarding the Utility Environmental Protection ("UEPA") permit for the Project, there was a delay in Clark County issuing the Authority to Construct Permit. This delay required the Company to separate the UEPA permit into three phases in order to commence some construction activities and not further delay the Project. Given that an amendment had to be filed to the UEPA permit to phase the Project, the Company was not able to begin site clearing, grading and other staging functions until the third quarter of 2023.

to achieve the schedule given the summer of 2024 was the hottest on record and resulted in multiple record peak load days.

The multi-contract approach necessitated careful and complex coordination, which was achieved through regular cross-functional meetings to ensure synchronization of design, procurement, and construction activities. The Company's proactive communication and enhanced coordination efforts allowed the Project to progress despite the inherent complexities of managing multiple contractors.

Adverse weather conditions, including extreme heat and storms, also impacted construction activities. To mitigate this, the Company adjusted construction and commissioning schedules to optimize productivity during favorable conditions and allocated additional resources to maintain progress as needed.

Despite these challenges, the Company successfully completed the Project, with Unit 4 achieving COD on July 13, 2024, and Unit 3 on July 23, 2024. These outcomes reflect the Company's commitment to overcoming obstacles and ensuring the timely delivery of critical infrastructure to support system reliability during peak demand periods.

**18. Q. WHAT WERE THE EXPECTED COSTS TO COMPLETE THE SILVERHAWK PEAKERS PROJECT?**

A. The initial cost estimate for the Project, developed in April 2022, was $353 million. This estimate was based on an Association for the Advancement of Cost Engineering ("AACE") Class 4 estimate with an accuracy range of -30 percent to +50 percent, reflecting market conditions from April 2021.

**19. Q. WHAT IS AN ASSOCIATION FOR THE ADVANCEMENT OF COST ENGINEERING ESTIMATE?**

A. An AACE estimate refers to a cost estimation methodology developed by the Association for the Advancement of Cost Engineering International. These estimates are categorized into five classes (Class 5 to Class 1), reflecting different stages of project definition, accuracy, and purpose. Each class serves a specific role in project planning and execution, ranging from early conceptual estimates to highly detailed and accurate forecasts for construction.

- Class 5 Estimate – Used during the initial feasibility stage, offering broad cost ranges with limited design data (typically 0-2 percent design completion).
- Class 4 Estimate – Employed during the conceptual or feasibility phase, with design completion between 1 to 15 percent. This provides a higher level of detail than Class 5 but still has a broad accuracy range of -30 percent to +50 percent.
- Class 3 Estimate – Provided during the preliminary design phase where there is 10 to 40 percent design completion.
- Class 2 Estimate – Prepared during detailed design, with 30 to 70 percent design completion, offering a narrower accuracy range.
- Class 1 Estimate – The most accurate and detailed estimate, developed when 50 to 100 percent of the design is complete, typically used for procurement and execution.

AACE estimates provide a standardized methodology, ensuring consistency in cost forecasting. As discussed below, the Company's estimate for the Project qualified as an AACE Class 4 Estimate.

**20. Q. WHAT WERE THE ACTUAL COSTS TO COMPLETE THE SILVERHAWK PEAKERS PROJECT?**

A. As the Project progressed, cost estimates were revised to reflect market realities, supply chain disruptions, and Project-specific adjustments. After receiving updated pricing and accounting for the schedule needed to get the Project online for the 2024 summer peak season, the estimated cost increased by 46 percent, reaching $514 million, excluding Allowance for Funds Used During Construction ("AFUDC"). This figure was reaffirmed by subsequent reviews conducted by external consultants, ensuring its accuracy.

The Project as a whole is comprised of several smaller projects. The table below shows the list of these projects, and the cost associated with each project.

The Project involved multiple sub-projects to support the new peaking units, ensuring safe operations. The **Chemical & Waste Oil Storage Access Road (SH2287)** was built to facilitate safe transport of chemicals and disposal of waste oil. The **Waste Oil Containment Facility (SH2294)** was expanded to accommodate additional waste oil storage needs. The **Demineralized Water Tank (SH2297)** was installed to support wet compression and evaporative cooling. The **Entrance Gate and Guard Shack (SH2298)** was relocated to prevent contractor traffic from disrupting operations, following the installation of a new gas metering station and warehouse. The **Climate-Controlled Warehouse (SH2299)** was constructed to store critical turbine and auxiliary components. The **Air Compressor System (SH2300)** was installed to support combustion turbines and auxiliary equipment. Finally, the **Switchyard Expansion (SH2305)** was completed to ensure compliance with the Large Generator Interconnection Agreement. Table

Atala-Direct-1 below outlines the financials of each project as they pertain to recovery in this GRC and are discussed in detail at the end of my testimony.

**TABLE ATALA DIRECT-1**

| **Projects** | **Plant Additions Recorded Total** |
|---|---|
| *SH2254 SH - Capacity Project* | 481,079,784 |
| *SH2297 Demineralized Water Tank* | 4,241,172 |
| *SH2299 Climate Controlled Warehouse* | 2,322,703 |
| *SH2298 Entrance Gate and Guard Shack* | - |
| *SH2287 Contractor Parking* | 1,155,783 |
| *SH2300 Plant Air Compressor* | 1,146,829 |
| *SH2294 Waste Oil Containment Facility* | 385,025 |
| *SH2305 Switchyard* | - |
| ***Grand Total (including AFUDC)*** | **491,634,759** |

This is total does not include the switchyard costs that will not be in service by the end of the test period.

**21. Q. WHY DID THE PROJECT EXCEED ITS INITIAL ESTIMATES?**

A. The Silverhawk Peakers Project exceeded its original budget of $352.8 million due to a combination of factors. The initial estimate, developed using a conceptual AACE Class 4 framework, reflected a wide accuracy range and relied on limited early-stage data. Shifts in contracting strategy, from an EPC approach to a multi-contract model, introduced coordination challenges, delays, and additional management costs.

Further contributing factors included significant escalation in material, equipment, and labor costs driven by global supply chain disruptions, inflation, and force majeure events. Taxes were also inadvertently omitted from the original estimate, leading to additional variances. As the Project progressed, scope changes such as enhanced safety measures, infrastructure adjustments, and design modifications added to the budget.

**22. Q. PLEASE PROVIDE ADDITIONAL DETAIL REGARDING WHY THE SILVERHAWK PEAKERS PROJECT EXCEEDED ITS ESTIMATES.**

A. The Project exceeded its initial budgetary estimates due to a combination of underestimated costs, evolving requirements, and external market conditions. Below is a comprehensive explanation.

***Original Estimate Accuracy and Limitations***

The initial Project budget of $352.8 million was based on an AACE Class 4 Estimate developed in April 2022 using market data from April 2021. Class 4 Estimates are typically used by construction companies, engineers and utilities during the conceptual phase of a project and provide a wide accuracy range of -30 percent to +50 percent. The actual costs trended toward the higher end of this range, reflecting the uncertainty and limited data available during the early project phase. Mr. Heidell also discussed this in his direct testimony.

***Contracting Strategy Shift***

Initially, the Project assumed an EPC approach, which typically centralizes Project responsibilities under a single contractor. However, no bids were received for the EPC request for proposal ("RFP"). This required a shift to a multi-contract strategy if the project was going to move forward for summer 2024 delivery, requiring the Company to coordinate design, procurement, and construction independently. This shift introduced challenges with coordination and additional management costs, as well as delays in engineering and procurement processes. Mr. Heidell also discusses this in his direct testimony.

***Engineering Designs Delays***

Due to the shift in contracting strategy, the contracted Owner's Engineer transitioned to the design engineer, which was responsible for developing design specifications for the Project. The combustion turbines documentation required further timeline adjustments for the design specifications and the bill of quantities, which are crucial for soliciting bids from general contractors.

***Compressed Project Schedule***

The Project's timeline was compressed to ensure that the units were available for the summer of 2024. This compressed schedule arose from delays in the contracting process, including the lack of bids for an EPC contract and the need to secure equipment to meet peak summer demand. This compressed schedule required overtime labor costs.

***Permit delays***

The permitting was delayed due to the Clark County special use permit, the drainage studies/grading permit and air permitting delays, which led to the UEPA permit to construct being obtained later than anticipated. While the Company made efforts to expediate all of these Clark County permits, the permitting process and timeline provided very little flexibility. These Clark County permit delays resulted in the UEPA permit for the first two phases of the Project being issued in September 2023 and the UEPA permit for the final phase of construction coming in December 2023.

***Material, Equipment, and Labor Cost Escalation***

Global market conditions between 2021 and 2023 significantly increased the cost of raw materials, equipment, and labor, which were not fully captured in the initial estimate. Escalations in key materials such as steel, electrical conduit, and transformers ranged from 20 percent to more than 60 percent, as detailed in a report conducted by Sargent & Lundy (**CONFIDENTIAL Exhibit Atala-Direct-7)** to ensure the competitiveness of cost projections. Skilled labor costs increased by 5.5 percent, and common labor costs rose by 1.6 percent, driven by a tight labor market and inflation.

These escalations were partly driven by global supply chain issues, including force majeure events such as Red Sea attacks, cyclonic storms in India, and COVID-19 restrictions in China, disrupting the timely delivery of critical materials and equipment. These disruptions necessitated alternate shipping routes and expedited freight services, further inflating costs.

***Scope Changes and Design Adjustments***

The scope of the Project expanded beyond the assumptions used in the original estimate, leading to additional costs. Items such as spare Generator Step-Up Transformer foundations were added to the Project. Design modifications and adjustments included increased cable sizes due to soil thermal properties and the use of stairs instead of ladders for enhanced safety. Infrastructure enhancements including wet compression, increased excavation and backfill requirements, and storm drainage improvements were added. Security enhancements, including cybersecurity requirements and site security, contributed to the cost increase. Items not anticipated in the early estimate given that more detailed engineering and planning had not been completed also contributed to the cost increase. As the Project progressed and detailed engineering was completed, these costs were included in the final cost estimate.

***Taxes***

Taxes were not captured in the original estimate, leading to significant budget variances. Specifically, the initial estimate did not include a full assessment of sales and use taxes for major equipment such as combustion turbines, transformers, and balance-of-plant components. These taxes added increases to the Project's overall cost.

***Summary***

The Project's cost increase to $514.8 million reflects a combination of early budgetary limitations, global market challenges, and necessary scope adjustments to ensure the Project's success. Despite these challenges, the Project remained the most cost-effective option to meet the Company's capacity needs and is strategically essential for enhancing system reliability and supporting customer demand during peak periods.[3]

[3] It should be noted that the scheduled completion of the Project by the summer peak of 2024 was acknowledged by Staff of the Commission as being "ambitious" during the IRP. Staff also acknowledged achieving the in-service date may require "a significant amount of overtime costs [to] be incurred" and expedited action on multiple fronts, "which can cost extra money." Docket No. 22-11032, Prepared Direct Testimony of Staff witness Mr. Gary C. Cameron, at 9-10, Q&A 13 (filed Jan. 30, 2023). "In spite of these possibilities, Staff still believes construction of the Silverhawk Peaking Plant is the best course of action." *Id.* Ultimately, Staff recommended the Commission approve the Project to "close NV Energy's open position for numerous summers to come." *Id.* at 10, Q&A 14. Mr. Cameron added that the only alternative would be to rely on market purchases "with the hope that external entities and other situations (such as wildfires) don't impact the deliveries of those market purchases which has occurred the past three summers." *Id.* In other words, even with the potential for cost overruns given the ambitious schedule that had to be achieved, Staff supported this Project.

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

**23. Q. PLEASE EXPLAIN THE CHALLENGES IN ANTICIPATING THE PROJECT COST INCREASE.**

A. As discussed in the previous Q&A, the original cost assumptions and estimates for the Project were preliminary and needed adjustment due to several unforeseen factors and challenges that could not have been fully anticipated at the time the estimates were developed. The Company relied on the expertise of the Owner's Engineer to develop the cost estimates. The omissions and underestimations occurred because the estimate was developed at a time when the design was only 1 to 15 percent complete, with limited site-specific data and reliance on generalized industry assumptions.

The initial assumptions relied on market trends from 2021, prior to major global disruptions like the extended impacts of the COVID-19 pandemic, geopolitical tensions, and raw material shortages. The rapid escalation in commodity prices and supply chain bottlenecks was unprecedented and difficult to predict at the time. It should be noted that the compounding and prolonged nature of supply chain disruptions across multiple global events was unprecedented. The timeline compression due to permitting and contracting delays further amplified the impact of supply chain challenges.

The original scope assumptions were based on conceptual-level designs, and the scope was not fully defined. As the Project moved into detailed engineering, site-specific needs and additional requirements emerged, which could not have been accounted for in early assumptions. Also, the original assumptions did not account for the impact of potential delays on the construction timeline.

Sales taxes on major equipment and materials, were not fully accounted for in the original AACE Class 4 estimate developed by the Owner's Engineer. The initial focus of the estimate was on direct material, equipment, and labor costs, which caused the inadvertent omission of taxes from being accounted for in the original estimate.

**24. Q. HOW DID THE COMPANY EVALUATE THE COST-EFFECTIVENESS AND PRUDENCY OF THE SILVERHAWK PEAKERS PROJECT AS ENGINEERING AND CONSTRUCTION PROGRESSED?**

A. In July 2023, a revised cost estimate for the Project projected an increase to $459 million. To assess the financial implications of this cost update, the Company's Resource Planning team conducted an evaluation using PLEXOS modeling (**Exhibit Atala-Direct-2 and CONFIDENTIAL Exhibit Atala-Direct-3**). This analysis compared two scenarios: one where the Project was operational during the summer of 2024, and another where the Project was delayed, requiring reliance on capacity market purchases. The results highlighted that delaying the Project would result in an additional $88.3 million in costs for the critical months of July through September 2024, underscoring the financial advantage of completing the Project on schedule.

Furthermore, a **30-year Present Worth Revenue Requirement ("PWRR")** (**Exhibit Atala-Direct-2 and CONFIDENTIAL Exhibit Atala-Direct-4**) analysis was updated to account for the revised $459 million Project cost which was estimated at that time. The analysis reaffirmed that the Project remained the lowest-cost option compared to other alternatives presented in the Fourth

Amendment of the IRP. These results strongly supported the prudency of maintaining the Project schedule and achieving commercial operation as planned.

In November 2023, following receipt of the final lump sum cost from the general contractor, and a revised total Project estimate of $514.8 million, the Company performed an **updated PWRR analysis** (**CONFIDENTIAL Exhibit Atala-Direct-5**). This reassessment evaluated the Project's economic viability in light of the revised cost. The analysis reaffirmed that, even with the increased budget, the Project remained the most cost-effective option compared to all other alternatives.

In February 2024, an additional analysis was conducted to reassess the financial implications of the Project using actual procurement data (**CONFIDENTIAL Exhibit Atala-Direct-6**), which projected the cost of filling the 440 MW capacity shortfall through market purchases during the summer of 2024. Unlike the PLEXOS analysis conducted earlier, which estimated incremental costs based on modeled scenarios, this analysis utilized real-time procurement data to provide a more grounded view of potential expenses from market purchases. The estimates highlighted higher costs if the Company was required to rely on the market as compared to what was previously modeled. The total projected cost of market purchases for the summer months (July through September 2024) was $156 million. This updated analysis reinforced the urgency and prudency of completing the Project as scheduled. By providing dispatchable capacity in time for the summer peak demand, the Project would avoid the high and volatile costs of market purchases, thereby delivering greater financial and operational stability for our customers.

To ensure the cost estimates were consistent with market conditions, the Company engaged engineering firms to review the updated estimates. These reviews confirmed that the revised costs were consistent with market conditions and the Project's defined scope. This is discussed in Mr. Heidell's testimony and analysis.

Ultimately, the Company's comprehensive evaluation demonstrated that the Project, including the timeline for completion, was both cost-effective and prudent, even with the increased costs as compared to relying on the market to address any capacity shortfalls. By managing challenges proactively, the Company ensured that the Project would provide the most reliable and economical solution for meeting system capacity needs and supporting customer demand during critical periods.

**25. Q. WERE THERE ANY POTENTIAL BENEFITS TO DELAYING THE PROJECT BEYOND THE SCHEDULED COMMERCIAL OPERATION DATE OF JULY 1, 2024?**

A. Following the receipt of the final lump sum cost from the contractor and an updated Project estimate of $514.8 million in November 2023, an assessment was conducted to evaluate whether delaying the Project could provide any financial benefits.[4] The analysis determined that any potential savings from an extended timeline would be minimal and likely outweighed by financial and operational drawbacks.

The assessment highlighted that fixed costs, which include staffing, supervision, support labor, and construction equipment form a substantial portion of the budget, and would continue to accrue regardless of the timeline, providing little opportunity

[4] This assessment was separate from the **updated PWRR analysis** (**CONFIDENTIAL Exhibit Atala-Direct-5**) referenced above, which evaluated the Project's economic viability in light of the revised cost.

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

for cost reductions. Furthermore, market conditions characterized by escalating material and labor costs would not improve with a delay, as inflationary pressures and supply chain uncertainties were expected to persist or potentially worsen. Delaying the Project would not have alleviated these challenges and might have introduced additional risks, such as extended lead times for critical equipment.

Additionally, contractual obligations with suppliers, contractors, and labor included penalty clauses for delays. Moreover, the delay would disrupt momentum, impacting team morale and productivity while increasing costs associated with ramping up operations after a pause. The delay would have prevented the Company from being able to use those units to meet the customer demand in the summer of 2024.

While the possibility of delaying the Project was analyzed, the findings reaffirmed that the risks and financial impacts of a delay far exceeded any theoretical benefits of delaying the Project. Completing the Project on schedule remained the most prudent approach to minimize costs and deliver the Project's intended benefits on time.

As the Project progressed, adjustments were made to reflect updated market data, design developments, and unforeseen challenges. Going back to July 2023, the estimated cost had increased to $459 million due to factors such as permitting delays and supply chain disruptions.

In November and December 2023, following the completion of over 60 percent of the design engineering work, ARB/Primoris, the construction contractor, provided a final lump sum cost of $180 million for its scope of work, bringing the total revised cost for the Project to $514.8 million. To ensure the revised cost estimate was reasonable, the Company engaged Sargent & Lundy and POWER Engineers to independently review and audit the Project's costs. Their analyses confirmed that the updated estimates were consistent with current market conditions, including the cost competitiveness, and the Project's anticipated in-service date. See **CONFIDENTIAL Exhibit Atala-Direct-7** for that analysis.

Despite these cost adjustments, the Company's analysis concluded that the Project remained the most cost-effective solution to meet system reliability needs and provide customers a reliable energy source during peak demand periods. This reaffirmed the Project's strategic value and justified its continuation within the revised budget framework.

**26. Q. HOW MUCH DID IT COST TO MAINTAIN THE SILVERHAWK PEAKERS PROJECT SCHEDULE, AND WHAT WAS THE VALUE OF DOING SO?**

A. Maintaining the Project schedule required $16 million, as determined by a review conducted by PA Consulting. This expenditure was necessary to address the challenges associated with compressing the Project timeline to achieve the planned COD in July of 2024. The additional costs primarily covered expedited procurement, overtime labor, extended work hours, and the implementation of double shifts to recover from delays in permitting and supply chain disruptions.

The value of maintaining the Project schedule far outweighed these additional costs. Achieving the COD in July of 2024 ensured that the Silverhawk Peakers

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

would be operational during the critical summer peak months of 2024. This avoided reliance on high-priced market capacity purchases, which were projected to cost approximately $156 million from July to September 2024.

Moreover, the timely delivery of the Project provided significant operational and strategic benefits for customers. The peaking capability of the units, combined with their ability to integrate seamlessly with renewable resources, enhanced grid reliability and flexibility during periods of high demand.

In summary, the $16 million expenditure to maintain the Project schedule was a prudent investment that delivered critical financial and operational benefits for customers, ultimately reinforcing the value of completing the Project on time. This outcome is further reinforced by hindsight that the summer of 2024 was the hottest on record and yet power was provided to customers without a single energy emergency alert, in part due to the additional capacity and energy from these units.

**27. Q. WHAT ADDITIONAL PROJECTS WERE UNDERTAKEN AS PART OF THE SILVERHAWK PEAKERS PROJECT THAT ARE INCLUDED IN THE OVERALL COST OF THE PROJECT?**

A. Several projects were completed to support the new peaking units. These included the Chemical & Waste Oil Storage Access Road (SH2287) for safe transport, the Waste Oil Containment Facility (SH2294) for expanded storage, and the Demineralized Water Tank (SH2297) to support wet compression and cooling. The Entrance Gate and Guard Shack (SH2298) was relocated to prevent disruptions, while the Climate-Controlled Warehouse (SH2299) was built for turbine component storage. The Air Compressor System (SH2300) was installed for turbine operation, and the Switchyard Expansion (SH2305) ensured proper grid interconnection. These projects are described in detail below.

**28. Q. PLEASE DESCRIBE THE CHEMICAL & WASTE OIL STORAGE ACCESS ROAD PROJECT AND WHY IT WAS NECESSARY?**

A. The chemical and waste oil storage access road was constructed as part of the Project to ensure a paved surface was available for the safe transportation of chemicals and disposal of waste oil. The original chemical and waste storage area was relocated to construct the Project.

**29. Q. PLEASE DESCRIBE THE WASTE OIL CONTAINMENT FACILITY PROJECT AND WHY IT WAS NECESSARY?**

A. As part of the Project, the existing waste oil containment facility was expanded to accommodate the increased requirements of the added General Electric 7F.05 units. These units required more waste oil containment capacity than the existing Silverhawk units. To address this, the existing facility was expanded to handle the additional waste oil volume.

**30. Q. PLEASE DESCRIBE THE DEMINERALIZED WATER TANK PROJECT AND WHY IT WAS NECESSARY?**

A. The demineralized water tank system was installed to supply water for the Project units' wet compression system, as well as for the units' evaporative cooling system during operation. By installing this demineralized water tanks, the construction of the peaking units eliminated the need for an additional pond and water treatment facility. The project scope included the installation of the tank and its foundation, tie-ins, piping, pumps, and water treatment trailer parking. Furthermore, integrating the newly installed instrumentation into the Distributed Control System (“DCS”) was required.

**31. Q. PLEASE DESCRIBE THE ENTRANCE GATE AND GUARD SHACK PROJECT AND WHY IT WAS NECESSARY?**

A. A new entrance gate and guard shack were constructed west of the existing plant entrance to redirect contractor traffic, ensuring uninterrupted operation of the existing units during maintenance and outage periods. The original contractor parking area was repurposed to accommodate the upgraded gas metering station for the peaking units and the newly constructed climate-controlled warehouse, optimizing site functionality. This project also provides long-term advantages by improving site security, ensuring better access control, streamlining traffic flow, and reducing congestion during future Peaking Units outages.

**32. Q. PLEASE DESCRIBE THE WAREHOUSE PROJECT AND WHY IT WAS NECESSARY?**

A. The warehouse was designed and constructed to store critical spare parts, components, and consumables required for the Project units. This includes materials necessary during the construction of the combustion turbines and balance of plant equipment. Climate control is essential for the proper storage of components such as GE’s combustion turbine parts, Hot Selective Catalytic Reduction systems, auxiliary equipment, and other spare parts critical to maintaining the operation of units 3 and 4.

**33. Q. PLEASE DESCRIBE THE AIR COMPRESSORS PROJECT AND WHY IT WAS NECESSARY?**

A. The air compressors system was installed to supply the compressed air required for the operation of the new combustion turbines, Hot Selective Catalytic Reduction systems, auxiliary equipment and balance of plant equipment, ensuring functionality across all components requiring compressed air.

**34. Q. PLEASE DESCRIBE THE SWITCHYARD PROJECT AND WHY IT WAS NECESSARY?**

A. The switchyard expansion was a requirement under the Large Generator Interconnection Agreement. Portions were completed to facilitate the interconnection of the new peaking units, but the remaining upgrades will be completed in August 2025, following the Certification period in this docket. This project will be included in a future rate case filing.

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

A. Yes.

# EXHIBIT ATALA-DIRECT-1

# STATEMENT OF QUALIFICATIONS
**Fady Atala**
**Director of Engineering and Project Management, Generation**
**NV Energy**
7155 Lindell Rd, Las Vegas, NV 89118

Mr. Fady Atala has been an employee of NV Energy since 2014, with over ten years of experience in the power generation industry. Mr. Atala's background spans roles in engineering, operations management, and project oversight. Mr. Atala's responsibilities include leading the Large Construction Project Management team overseeing the construction of new 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 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**
***Director of Engineering and Project Management***
June 2023 – Present

**NV Energy, Las Vegas, NV**
***Operations Manager for the Clark and Sun Peak generating stations***
July 2021 to June 2023

- Managed plant operations and coordinated maintenance activities, ensuring peak performance and compliance with safety and environmental regulations.
- Managed the Reliability Improvement Program, resolving repetitive issues and improving reliability.
- Aligned staffing and budgets with corporate goals and managed labor relations.
- Developed improved plant procedures and job aids to streamline operations.
- Provided mentorship to teams, fostering a culture of continuous improvement and collaboration.
- Collaborated with contractors and internal teams on performance testing and equipment upgrades.

**NV Energy, Las Vegas, NV**
***Engineering***
November 2014 to July 2021

- Led Management Of Change projects and RIP initiatives, addressing key operational challenges.
- Conducted advanced troubleshooting and mentored operations and maintenance staff.
- Ensured compliance with NERC WECC Requirements, ASME B31.1 standards and ISO 270001 standards.
- Conducted advanced troubleshooting of operational and mechanical issues across the generation fleet.
- Managed High Energy Piping (HEP) inspections and supported outages.
- Evaluated system designs to ensure compliance with relevant standards.
- Specialized in networking and control systems for plant equipment.

- Developed network topologies and managed control system software upgrades.

**IntelliChoice Energy, Las Vegas, NV**
***Mechanical Engineer***
June 2011 – November 2014

- Contributed to R&D for natural gas-driven heat pumps and subsystem optimization.
- Designed and managed testing plans, certifications, and P&ID diagrams.

## 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

# EXHIBIT ATALA-DIRECT-2

**Atala, Fady (NV Energy)**

**From:** Atala, Fady (NV Energy)
**Sent:** Thursday, August 3, 2023 10:18 AM
**To:** Hammons, Jason (NV Energy); Lescenski, John (NV Energy); Ostop, Ronald (NV Energy)
**Subject:** FW: Silverhawk CT Analysis 7-5-2023
**Attachments:** CER_BLBF_Amend4_single cases Updated for new SHWK CT CAPEX.xlsx

Even with the increased Capital Cost ($459m), the Silver Hawk CT project is still the lowest cost option compared to the others that were presented in the 4th Amendment for the 30 years PWRR. I will add that to the Supplemental AFE Justification Document writeup.

**4th Amendment to the 2021 IRP - Single Resource**
**Total Costs**

| | 10 Year PWRR 2022-2031 (million $) | 20 Year PWRR 2022-2041 (million $) | 30 Year PWRR 2022-2051 (million $) | 10 Year PWRR Change vs Least Cost Case (million $) | 20 Year PWRR Change vs Least Cost Case (million $) | 30 Year PWRR Change vs Least Cost Case (million $) |
|---|---|---|---|---|---|---|
| **BASE** | $ 13,268 | $ 21,104 | $ 26,973 | $ - | $ 93 | $ 178 |
| **Geo** | $ 13,401 | $ 21,410 | $ 27,436 | $ 133 | $ 398 | $ 641 |
| **north BESS** | $ 13,329 | $ 21,177 | $ 27,097 | $ 61 | $ 165 | $ 302 |
| **north CT** | $ 13,277 | $ 21,068 | $ 26,976 | $ 9 | $ 57 | $ 181 |
| **south BESS** | $ 13,534 | $ 21,476 | $ 27,342 | $ 266 | $ 465 | $ 547 |
| **south CT** | $ 13,283 | $ 21,011 | $ 26,795 | $ 15 | $ - | $ - |
| **south CT Update** | $ 13,354 | $ 21,119 | $ 26,915 | $ 86 | $ 108 | $ 120 |

**From:** Wasiuta, Matthew (NV Energy) <Matthew.Wasiuta@nvenergy.com>
**Sent:** Thursday, August 3, 2023 8:53 AM
**To:** Atala, Fady (NV Energy) <Fady.Atala@nvenergy.com>
**Cc:** Williams, Kimberly (NV Energy) <Kimberly.Williams@nvenergy.com>; Taylor, Vernon (NV Energy) <Vernon.Taylor@nvenergy.com>; Allen, Barbara (NV Energy) <Barbara.Allen@nvenergy.com>; Ostop, Ronald (NV Energy) <Ronald.Ostop@nvenergy.com>
**Subject:** RE: Silverhawk CT Analysis 7-5-2023

Hi Fady,

I have attached an updated CER that shows the impact of increasing the Silverhawk CT costs to $459m. The results for the 30 year PWRR show that the Silverhawk CTs are still the lowest cost option compared to the others that were presented in the 4th Amendment. The difference between the 30 year PWRR from the original south CT case to the updated cost in the south CT Update case is $120m. Please let me know if you have any questions.

| 4th Amendment to the 2021 IRP - Single Resource Total Costs | | | | | | |
|---|---|---|---|---|---|---|
| | 10 Year PWRR 2022-2031 (million $) | 20 Year PWRR 2022-2041 (million $) | 30 Year PWRR 2022-2051 (million $) | 10 Year PWRR Change vs Least Cost Case (million $) | 20 Year PWRR Change vs Least Cost Case (million $) | 30 Year PWRR Change vs Least Cost Case (million $) |
| **BASE** | $ 13,268 | $ 21,104 | $ 26,973 | $ - | $ 93 | $ 178 |
| **Geo** | $ 13,401 | $ 21,410 | $ 27,436 | $ 133 | $ 398 | $ 641 |
| **north BESS** | $ 13,329 | $ 21,177 | $ 27,097 | $ 61 | $ 165 | $ 302 |
| **north CT** | $ 13,277 | $ 21,068 | $ 26,976 | $ 9 | $ 57 | $ 181 |
| **south BESS** | $ 13,534 | $ 21,476 | $ 27,342 | $ 266 | $ 465 | $ 547 |
| **south CT** | $ 13,283 | $ 21,011 | $ 26,795 | $ 15 | $ - | $ - |
| **south CT Update** | $ 13,354 | $ 21,119 | $ 26,915 | $ 86 | $ 108 | $ 120 |

Thank you,

Matt

---

**From:** Atala, Fady (NV Energy) <Fady.Atala@nvenergy.com>
**Sent:** Monday, July 31, 2023 3:16 PM
**To:** Wasiuta, Matthew (NV Energy) <Matthew.Wasiuta@nvenergy.com>
**Cc:** Williams, Kimberly (NV Energy) <Kimberly.Williams@nvenergy.com>; Taylor, Vernon (NV Energy) <Vernon.Taylor@nvenergy.com>; Allen, Barbara (NV Energy) <Barbara.Allen@nvenergy.com>; Ostop, Ronald (NV Energy) <Ronald.Ostop@nvenergy.com>
**Subject:** RE: Silverhawk CT Analysis 7-5-2023

Hi Matt,

We need to re-evaluate Silverhawk Capacity (CT) project based on an updated cost of $459m. Is that project still feasible compared to not having these units at all?

Thanks,

Fady

---

**From:** Wasiuta, Matthew (NV Energy) <Matthew.Wasiuta@nvenergy.com>
**Sent:** Wednesday, July 5, 2023 1:45 PM
**To:** Atala, Fady (NV Energy) <Fady.Atala@nvenergy.com>
**Cc:** Williams, Kimberly (NV Energy) <Kimberly.Williams@nvenergy.com>; Taylor, Vernon (NV Energy) <Vernon.Taylor@nvenergy.com>; Allen, Barbara (NV Energy) <Barbara.Allen@nvenergy.com>
**Subject:** Silverhawk CT Analysis 7-5-2023

Hi Fady,

Attached are both the original analysis Barbara had put together earlier with a cost breakdown using assumptions and forecasts for calculations *(Copy of price forecasts for silverhawk peaker replacement.xlsx),* as well as a new analysis that takes the current June Risk Run PLEXOS model as the base case and compares it to a change case that removes the Silverhawk CTs in 2024 and 2025 *(June Risk Run Silverhawk CT comparison 7-5-23.xlsx).*

The results from both analyses are similar. The impact of the Silverhawk CTs not being available till 2026 **will significantly increase costs due to a need of capacity** that is no longer there and must be filled by the capacity market, which is higher priced. The original analysis concluded a cost increase of **$134.1 million** without Silverhawk CTs, and the PLEXOS analysis showed a cost increase of **$88.3 million**.

For the original analysis, the method was to create an assumed operation of how the Silverhawk CTs would generate and see what the avoided costs would be, and then compare if the Silverhawk CTs were replaced by the energy and capacity markets. Using the assumed heat rate of 9.9302 (mmBtu/MWh), the energy output (MWh), calculated from the product of the assumed operation hours and rating (MW), was multiplied together to get the fuel usage (mmBtu) to calculate the fuel costs based on SoCAL prices. Using the assumed VOM price, the total VOM cost is calculated, and the total sum for fuel and VOM costs is created.

For 2024-2025, the total fuel and VOM costs for the Silverhawk CTs is estimated at $29.8 million. Using the capacity price and the on-peak energy price at MEAD, the total market cost is calculated. For 2024-2024, the total market cost is estimated at $104.3 million. The summation between the two shows a **$134.1 million** increase if Silverhawk CTs are not available.

The PLEXOS analysis breaks down the cost and energy differences for NVE if the Silverhawk CTs were delayed to 2026 instead of 2024. The case used for this analysis is the June Risk Run that **does not include an available energy market for purchases and sales**. It **does include market block purchases for capacity**, as well as purchases that have been made in real time for 2024. This run only looks as years 2024-2025, and the only change between the two cases is the removal of the Silverhawk CTs.

Without the Silverhawk CTs, NVE shows an overall reduction in generation from all type of gas resources and battery generation due to the overwhelming increase of capacity which must be purchased from the market. Since there was more capacity purchased that is considered must-take, there was an increase in dump, as well as an increase in emergency energy. This can be partially be attributed to hours the capacity blocks are allowed to be purchased in and lack of variability the Silverhawk CTs provide.

In relation to the energy comparison, the cost comparison shows similar results. Since the total natural gas generation decreased, so did the costs, and the capacity blocks that replaced a bulk of that generation have significantly increased costs since capacity prices are much higher than our own gas generation. From 2024 to 2025, costs increased from $1.589 billion to $1.677 billion **($88.3 million increase).**

Please let me know if you have any questions.

Thank you,

Matt

# EXHIBIT ATALA-DIRECT-3

# FILED UNDER CONFIDENTIAL SEAL

# EXHIBIT ATALA-DIRECT-4

# FILED UNDER CONFIDENTIAL SEAL

# EXHIBIT ATALA-DIRECT-5

# FILED UNDER CONFIDENTIAL SEAL

**EXHIBIT ATALA-DIRECT-6**

**FILED UNDER CONFIDENTIAL SEAL**

# EXHIBIT ATALA-DIRECT-7

# FILED UNDER CONFIDENTIAL SEAL

## 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: February 14, 2025

Fady Atala

# JIMMY DAGHLIAN

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

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02__
2025 General Rate Case

Prepared Direct Testimony of

**Jimmy Daghlian**

Revenue Requirement

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

A. My name is Jimmy Daghlian. I am the Vice President of Energy Supply Project Execution for Nevada Power Company 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" or "NV Energy"). My business address is 7155 S. Lindell Road in Las Vegas, Nevada. I am filing testimony on behalf of the Nevada Power.

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

A. I hold Bachelor and Master of Science degrees in Chemical Engineering from the University of Utah and a Master of Business Administration degree from Westminster College. I have worked for the Companies since 2012 in various capacities including Director, Generation Support; Director, Delivery Operations South; and my current role as Vice President, Energy Supply Project Execution. In my role I was responsible for the construction of the Reid Gardner battery energy storage system, and I am currently responsible for overseeing the construction of the Sierra Solar project and the development and construction of NV Energy-owned renewable, thermal and energy storage projects. More details regarding my professional background and experience are set forth in **Exhibit Daghlian-Direct-1**.

**3. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes. Most recently, I provided written testimony in Docket No. 24-05041, the Companies' 2024 Joint Integrated Resource Plan ("IRP"), as well as in Docket No. 23-08015, the Fifth Amendment to the 2021 Joint IRP.

**4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I provide information related to the Reid Gardner grid-tied battery energy storage system ("BESS" or "Project") to demonstrate the prudency of the balance of Project costs not previously approved for recovery in Nevada Power's 2023 General Rate Case ("GRC"),[1] including costs incurred since the Project was placed in service. I also provide updated costs and project details related to the U.S. Department of Energy ("DOE") BESS located at the Beltway Substation.

**5. Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following Exhibit:

- **Exhibit Daghlian-Direct-1 –** Statement of Qualifications
- **Exhibit Daghlian-Direct-2 –** Reid Gardner BESS Spring 2024 Reliability Summary

---

[1] Nevada Power's last GRC was Docket No. 23-06007.

- **CONFIDENTIAL Exhibit Daghlian-Direct-3 –** Financial Benefits of 2023 Reid Gardner BESS Commercial Operations

**6. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION PROVIDED IN THIS TESTIMONY?**

A. Yes. Confidential information is contained in **CONFIDENTIAL Exhibit Daghlian-Direct-3**.

**7. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.**

A. **CONFIDENTIAL Exhibit Daghlian-Direct-3** contains certain prices paid to Electrical Consultants, Inc. ("ECI") and Energy Vault ("EV") for the Reid Gardner BESS, which, if publicly disclosed, could place the Company at a disadvantage to receive competitively priced proposals from suppliers in the future. Further, public disclosure is prohibited under confidentiality agreements between ECI and EV and Nevada Power.

**8. Q. FOR HOW LONG DOES NEVADA POWER REQUEST CONFIDENTIAL TREATMENT?**

A. The requested period for confidential treatment is for no less than 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") OR OTHER INTERVENERS TO PARTICIPATE IN THIS DOCKET?**

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. In addition, intervening parties with an executed protective agreement can come on-site at the Company's offices throughout the State and review the report.

**10. Q. PLEASE DESCRIBE THE REID GARDNER BESS.**

A. The Reid Gardner BESS is a 220-MW Lithium-Ion battery with two hours of energy storage (440 MWh). It is comprised of 208 containerized battery enclosures as well as inverters and other power electronics. The battery enclosures were manufactured by BYD, and the main Engineering, Procurement and Construction ("EPC") contractor for the site was Energy Vault ("EV"). The Project is located on reclaimed land at the former Reid Gardner facility and interconnects at 230 kV voltage to the Reid Gardner substation. Reid Gardner BESS began commercial operation on December 29, 2023.

Reid Gardner BESS was initially conditionally approved for construction by the Commission in Docket No. 22-03024 at a cost of $257 million, excluding allowance for funds used during construction ("AFUDC") and an expected in-service date on or before May 2024.[2] In its April 4, 2023, compliance filing to satisfy the conditional approval, the Company noted that the expected in-service date was December 31, 2023.[3]

**11. Q. PLEASE PROVIDE SOME BACKGROUND AS TO THE COMMISSION'S CONSIDERATION OF COSTS ASSOCIATED WITH THE REID GARDNER BESS.**

A. In the 2023 Nevada Power GRC, Docket No. 23-06007, the Company sought Commission approval to recover the expected Project costs of $255,639,666, excluding AFUDC, with an expected December 2023 in-service date, under the Expected Change in Circumstance ("ECIC") mechanism. During the certification period for that filing, the Company revised the Project's expected cost downward to $253,694,733. In its February 16, 2023, Modified Final Order from Docket No. 23-06007, the Commission approved recovery under the ECIC mechanism for most of the Reid Gardner BESS costs, but deferred recovery of certain costs, specifically $50.5 million in contractual Final Completion payments and $5 million to in-service the project from May 2024 to December 2023. Regarding the deferred costs, the Commission was clear that it was "not disallowing these costs" but rather "simply delaying the review of the cost until the next GRC."[4]

---

[2] Docket No. 22-03024, *Order*, at Ordering ¶ 1 and Attachment 1 (Stipulation) at p. 4 (July 13, 2022) .

[3] Docket No. 22-03024, Compliance Filing (filed Apr. 4, 2023).

[4] Docket Nos. 23-06007 and 23-06008, *Modified Final Order*, at 74, ¶ 228 (Feb. 16, 2024).

**12. Q. WAS THE REID GARDNER PROJECT COMPLETED UNDER THE COST CAP OF $257 MILLION?**

A. Yes, the total cost of the Project through the Test Period for this GRC was $254.2 million, including AFUDC. Of these costs, $0.807 million is representative of work performed by NV Energy Transmission and is supported by Company witness Vincent Veilleux's Prepared Direct Testimony filed in this case.[5]

**13. Q. WAS THE REID GARDNER BESS SYSTEM COMPLETED IN 2023?**

A. Yes, the Reid Gardner BESS was placed in service before the end of the ECIC period for Docket No. 23-06007 on December 29, 2023, after successfully completing commissioning and performance testing. It has continued to provide service through 2024. **Exhibit Daghlian-Direct-2** summarizes its performance from commercial operation through the summer of 2024.

**14. Q. WHAT COSTS OF THE REID GARDNER BESS HAVE ALREADY BEEN APPROVED BY THE COMMISSION?**

A. The Commission approved $198.2 million in Project costs, which were placed in rates on January 1, 2024. The balance of costs through this rate case is being sought for recovery in this docket.

**15. Q. WHAT COSTS OF THE REID GARDNER BESS HAVE NOT PREVIOUSLY BEEN APPROVED BY THE COMMISSION?**

A. As stated above, the Final Completion payments (defined below) totaling $50.5 million, costs incurred after the ECIC period, as well as $5 million to in-service the

[5] The $0.807 million is a portion of the $1,325,967 amount referenced by Mr. Veilleux regarding the project referenced as CO.211 Reid Gardner BESS Interconnection (BAP).

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

project from May 2024 to December 2023, were not approved for inclusion in rates and were instead deferred to a future GRC, which is this instant docket.

**16. Q. WHAT ARE FINAL COMPLETION PAYMENTS?**

A. Final Completion Payments are defined by the Project construction contracts. Final Completion is one of several milestones associated with the payment schedules contained in the contracts, and they outline how contractors get paid. Final Completion of a project occurs after the project is placed is service, which occurred on December 29, 2023. While the value of Final Completion Payments represent a large percentage of a project's overall cost, it is not intended to, nor does it approach the value of the work remaining to close out the project. Instead, such milestone payments are valued to provide sufficient incentive to contractors to timely complete remaining project work. As previously explained by the Company in Docket No. 23-06007, this work is typically comprised of punchlist items (small corrective work, housekeeping, etc.) and document finalization and turnover, none of which impact the ability of the Project to serve customers.[6] Though the value of the outstanding Final Completion Payments was largely received by customers beginning in 2023, their recovery in rates was deferred.

**17. Q. WHAT WERE THE FINAL COMPLETION PAYMENTS FOR REID GARDNER BESS?**

A. The Project's Final Completion Payments were comprised of a $6,162,678 payment to EV, a $41,212,262 payment for the BYD batteries and a $1,276,89 Final Completion payment to ECI, the EPC contractor responsible for site grading and

---

[6] Docket No. 23-06007, Rebuttal testimony of Shane Pritchard, at Q&A 7.

substation construction. Note that $530,816 of the ECI Final Completion payment has not yet been made, awaiting their closure of a grading permit, and is not included in the costs sought in this filing.

**18. Q. THE COMMISSION ALSO DEFERRED RECOVERY OF $5 MILLION ATTRIBUTABLE TO PROJECT SCHEDULE ACCELERATION. DID CUSTOMERS RECEIVE A COMMENSURATE BENEFIT?**

A. Yes. The Commission deferred recovery of $5 million in contractor schedule acceleration costs pending "a more thorough accounting" by Nevada Power in this GRC,[7] which I provide below.

**19. Q. WHY DID NEVADA POWER TARGET A 2023 IN-SERVICE DATE FOR REID GARDNER BESS?**

A. There were several reasons why the Company moved the in-service date from May 2024 to December 2023. Some parties in Nevada Power's last rate case focused on the idea that the Company accelerated the schedule to complete the Project in time to include it as an ECIC. While it is true that getting the Project approved in the ECIC reduced the regulatory lag on an asset with a very short, depreciable life, Nevada law clearly permits the inclusion of such projects if it can meet the ECIC standard, which the Commission found in that proceeding was the case with respect to the project. However, the acceleration was predicated on customer and operational experience benefits.[8]

---

[7] Docket Nos. 23-06007 and 23-06008, *Modified Final Order*, at 74, ¶ 230.
[8] Docket No. 23-06007, Direct Testimony of Janet Wells, at p. 13, Q&A 13.

As discussed in the 2023 Nevada Power GRC, a primary benefit was operational in nature. By bringing this facility online in December, the Company gained significant operational experience with its first Company-owned and -operated BESS of this size before the summer peak period. The Reid Gardner BESS was the first of its size and the first BYD battery the Company owned and operated. Previous to the Reid Gardner battery, the largest grid tied battery operated on the NV Energy system was the 10 megawatt Chukar battery, a much smaller facility. As such it was unclear what issues might arise during construction, commissioning and operation during the first few months of service. Targeting the December 2023 in-service date allowed time for issues to be identified and resolved prior to the critical summer peak. It is difficult to fully quantify all operational benefits and gained experience, because the operational practices for a BESS of this size are not the same as operating more traditional thermal generation, capacity resources or smaller batteries like the 10 MW Tesla battery already on the Company's system. The Reid Gardner BESS availability was, in fact, somewhat low the first month of service, as shown in **Exhibit Daghlian-Direct-2**, however those early issues were resolved quickly and a lengthy period of sorting out issues was avoided. Looking back, having the time with the Reid Gardner battery to ensure it was fully operational and integrated was critical for meeting customer needs during the record high loads experienced in the summer of 2024.

But the most important reason, as stated in the rebuttal testimony of Shane Pritchard at Q&A 8 from Docket No. 23-06007, is that a December 2023 in-service date provided many material benefits to customers.[9] The Company estimates that during

[9] Docket No. 23-06007, Prepared Rebuttal Testimony of Shane Pritchard, at 4-5, ¶ 8 (Oct. 9, 2023).

the period of January 1, 2024 to June 1, 2024, the December in-service date for the BESS saved approximately $5.2 million in energy, capacity and portfolio energy credit (“PC”) costs that the Company would have been required to purchase via the market (or otherwise foregone in the case of RECs) by having the BESS supporting the system in December 2023 as shown in **Table Daghlian-Direct-1**.

**Table Daghlian-Direct-1: Summary of Quantifiable Operational Benefits**

| **Operational Benefit** | **Amount** |
|---|---|
| Production Costs | $2,063,860 |
| EIM Benefits | $2,594,101 |
| Renewable Energy Credits | $154,330 |
| Must Buy Avoided Cost | $227,975 |
| Flex Ramp Test Savings | $136,070 |
| **Sub-total Operational Benefits** | **$5,176,336** |

After analysis of actual performance of the BESS and system conditions, an in-service date of December 2023 resulted in the Reid Gardner BESS absorbing approximately 30,866 MWh (506 MWh of charge energy per day x 61 days) of solar generation that would have otherwise been curtailed, and an equal number of PCs counting towards the Renewable Portfolio Standard. James Heidell also discusses in more detail in his testimony each of the components of the operational benefits listed above.

Other miscellaneous impacts from the schedule compression resulted in cost savings of $0.2 million comprised of lower owner’s engineer costs and reduced overhead cost. Also, as result of the schedule compression and the resulting earlier in-service date, AFUDC was lower than it otherwise would have been, had the project completed on the original time schedule. This eliminated an additional $1.3 million in costs that would have been capitalized to rate base. Netting the above amounts results in the total impact of schedule compression on Project costs to be $10.0 million.

Lastly, customers have received the benefit of this facility since December 29, 2023 even though the Company was not permitted to fully recover on 100 percent of its investment amount as a result of the deferral ordered by the Commission. The Company earns a return of invested capital when depreciation expense is permitted to be recovered in customer rates. The Company also earns a return on invested capital when that capital is permitted to be included in the rate base. As a result of the ordered deferral, customer rates, since January of 2024, have not included either a return of capital or a return on capital related to the deferral amount, despite this capital having been deployed and the related asset operating on a daily basis for the benefit of the Company's customers. The Company estimates that deferred recovery of the $55.5 million estimate from the prior Nevada Power GRC will ultimately result in $10.2 million of uncollected revenue in present value terms.[10] Thus, there can be no doubt that customers have received a significant benefit from the use of this facility without paying the full cost of the facility. See **CONFIDENTIAL Exhibit Daghlian-Direct-3** for additional details.

[10] This $10.2 million amount represents the Present Worth Revenue Requirement ("PWRR") amount for what was excluded from recovery in rates given the deferral. *See* **Exhibit Daghlian-Direct-3**. Mr. Heidell calculates similar numbers in his direct testimony, although he does not use a PWRR analysis.

In summary, customers benefitted by the combination of quantified operational benefits, reduced AFUDC, and the deferred recovery savings, which far outweigh the costs the Company incurred to accelerate the Project.

**20. Q. WHAT INDEPENDENT REVIEWS OR AUDITS HAVE BEEN CONDUCTED TO VALIDATE THE COMPANY'S POSITION ON COST SAVINGS FOR THE REID GARDNER BESS?**

A. The Company engaged PA Consulting Group to conduct a review of the costs incurred and the benefits received by maintaining a December 2023 commercial operation date. Its analysis, provided in the testimony of Mr. Heidell, indicates that the costs incurred to compress the schedule were reasonable and provided commensurate benefits to customers.

**21. Q. PLEASE DESCRIBE THE DOE BESS.**

A. The DOE BESS is a 1-MW Lithium-Ion battery facility with 4 megawatt-hours of energy storage. It supports a DOE-sponsored project to demonstrate the provision of grid services from aggregated distributed energy resources ("DER"). The BESS is comprised of four containerized battery enclosures as well as inverters and other power electronics. The main EPC contractor for the project was ELM. The project is located in the northeast corner of the NV Energy Beltway Substation and interconnects at 12 kV to the Beltway substation. The project was approved by the Commission in Docket No. 21-06001 and was updated in Docket No. 22-09001. The project was also discussed in the Company's prior GRC, Docket 23-06007. The DOE BESS began commercial operation on April 29, 2023.

**22. Q. DESCRIBE THE TOTAL COST OF THE DOE BESS PROJECT.**

A. The total cost of the project through the Test Period is $2.923 million. Additional costs associated with the interconnection of the project are described separately within this rate case application in Company witness Vincent Veilleux's prepared direct testimony.

**23. Q. WHAT ARE THE BENEFITS DOE BESS PROJECT**

A**.** The installation of the DOE BESS battery at the Beltway Substation supports various grid services, including energy and capacity management at both the system level and distribution level. The BESS continues to support ongoing development and testing of additional services including frequency regulation and energy arbitrage in which the BESS operates as a utility-owned front-of-the meter asset that participates in an aggregation of behind-the-meter distributed energy resources. It also supports testing and development of community storage offerings, or energy storage-as-a-service.

**24. Q. WHY IS THE COMPANY BRINGING FORWARD THE DOE BESS IN THIS DOCKET?**

A. The Company is requesting recovery of the DOE BESS in this case because the project entered service during the certification period of the Company's prior GRC in Docket 23-06007. These costs were not put forward in certification in that case, however, and as such, the cost of the project is being requested for recovery in this case. While presented in the previous Nevada Power GRC, the costs were not placed into rates then and are now updated to reflect costs since that filing.

**25. Q. PLEASE SUMMARIZE NEVADA'S REQUESTS FOR APPROVAL.**

A. The Companies request that the Commission approve the balance of the Reid Gardner BESS project costs incurred since the Company's last GRC, totaling $254.2 million, including AFUDC. The Companies also request the Commission approve the costs of the DOE BESS project in rates.

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

A. Yes.

# EXHIBIT DAGHLIAN-DIRECT-1

# STATEMENT OF QUALIFICATIONS

Jimmy Daghlian
7155 Lindell Rd Las Vegas, NV 89146
Jimmy.Daghlian@nvenergy.com | (702) 402-6750

## PROFESSIONAL EXPERIENCE

**NV Energy,** Las Vegas, NV
*Vice President, Energy Supply Project Execution,* January 2025 - Current
- Responsible for the development and construction of NV Energy-owned renewable, thermal and energy storage projects including Sierra Solar and the Valmy Peaker projects.

*Vice President, Renewables,* December 2022 – January 2025
- Oversee the origination and development of Companies' Renewables resources. Including the construction of the Reid Gardner Battery Energy Storage System, to meet capacity requirement, Renewable Portfolio Standards requirements, and address resource adequacy. Manage contract management department for pre-commercial and post-commercial execution of Purchase Power Agreements.

*Director, Delivery Operations South,* July 2021 - December 2022
- Directed Las Vegas Lines operations for the construction and maintenance of overhead and underground distribution and transmission circuits.

*Director, Generation Support,* December 2017 -July 2021
- Directed technical, operational, and economic analyses to support energy supply generating resources and related processes.

*Manager, Plant Engineering and Technical Services,* August 2013 - December 2017
- Managed corporate engineering services for Companies' generating stations. Supported the reliability improvement plans, managed inspection and repair standards, resolved fleet issues and developed programs for long term reliable and safe operations of generating assets.

*Engineering Staff,* January 2012 - August 2013
- Provided engineering, and project management support of power generation's mechanical system. Completed reliability inspections, equipment testing and outage restoration support for all the Companies' generating stations.

**TAQA Energy,** El Jadida, Morocco
*Technical Advisor,* May 2010-Januaty 2012
- Supervised and managed major retrofits projects, inspection/maintenance programs and upgrades to improve plant performance at a large ~1300 MW coal fired plant.

**Clyde Bergemann/Anthony Ross,** Portland, OR
*Business Development Manager,* November 2008 -May 2010
- Provided guidance and leadership in the development of coal combustion systems, equipment, parts, and services for the reduction of Nitrogen Dioxide emissions.

**PacifiCorp Energy,** Salt Lake City, UT
*Lead/Senior Engineer,* June 2004 - November 2008
- Developed corporate-wide asset management combustion maintenance and operational plan best practices for equipment, fuels, and combustion related issues to increase fleet availability and decrease unplanned outages.

**Alstom Power,** Salt Lake City, UT
*Lead/Senior Engineer,* December 2001 -June 2004

- Provided project management guidance and support on several large-scale Low Nitrogen Dioxide and burner installation and retrofit projects for various utilities in the western United States.

## EDUCATION

**Westminster College,** Salt Lake City, UT
Master of Business Administration, December 2006

**University of Utah,** Salt Lake City, UT
Master of Science in Chemical and Fuels Engineering, December 2001

**University of Utah,** Salt Lake City, UT
Bachelor of Science in Chemical Engineering, May 1999

# EXHIBIT DAGHLIAN-DIRECT-2

| Summary - Energy Capacity Availability | |
|---|---|
| Jan-24 | 78% |
| Feb-24 | 100% |
| Mar-24 | 98% |
| Apr-24 | 100% |
| May-24 | 93% |

| | | | | |
|---|---|---|---|---|
| Start | 1/1/2024 | | Energy FROM Grid | 0.0 |
| End | 2/1/2024 | | Energy TO Grid | 0.0 |
| Int | 1m | | Losses - Total | 0.0 |
| | | Hours | % Loss - From Grid | #DIV/0! |
| Interval Duration | 744.0 | | % Loss - To Grid | #DIV/0! |
| Period Potental Capacity | 327,360 | MWh | **Round Trip Efficiency (RTE)** | **#DIV/0!** |
| Period Potential Charge/Discharge | 163,680 | MWh | | |

| | | | | |
|---|---|---|---|---|
| Start | 2/1/2024 | | Energy FROM Grid | -10724.4 |
| End | 3/1/2024 | | Energy TO Grid | 9690.5 |
| Int | 1m | | Losses - Total | -1033.9 |
| | | Hours | % Loss - From Grid | 9.6% |
| Interval Duration | 696.0 | | % Loss - To Grid | -10.7% |
| Period Potental Capacity | 306,240 | MWh | **Round Trip Efficiency (RTE)** | **-90.4%** |
| Period Potential Charge/Discharge | 153,120 | MWh | | |

| | | | | |
|---|---|---|---|---|
| Start | 3/1/2024 | | Energy FROM Grid | -13631.0 |
| End | 4/1/2024 | | Energy TO Grid | 11758.0 |
| Int | 1m | | Losses - Total | -1873.0 |
| | | Hours | % Loss - From Grid | 13.7% |
| Interval Duration | 744.0 | | % Loss - To Grid | -15.9% |
| Period Potental Capacity | 327,360 | MWh | **Round Trip Efficiency (RTE)** | **-86.3%** |
| Period Potential Charge/Discharge | 163,680 | MWh | | |

| | | | | |
|---|---|---|---|---|
| Start | 4/1/2024 | | Energy FROM Grid | -14007.0 |
| End | 5/1/2024 | | Energy TO Grid | 11970.3 |
| Int | 1m | | Losses - Total | -2036.7 |
| | | Hours | % Loss - From Grid | 14.5% |
| Interval Duration | 720.0 | | % Loss - To Grid | -17.0% |
| Period Potental Capacity | 316,800 | MWh | **Round Trip Efficiency (RTE)** | **-85.5%** |
| Period Potential Charge/Discharge | 158,400 | MWh | | |

| | | | | |
|---|---|---|---|---|
| Start | 5/1/2024 | | Energy FROM Grid | -15799.5 |
| End | 6/1/2024 | | Energy TO Grid | 13243.2 |
| Int | 1m | | Losses - Total | -2556.2 |
| | | Hours | % Loss - From Grid | 16.2% |
| Interval Duration | 744.0 | | % Loss - To Grid | -19.3% |
| Period Potental Capacity | 327,360 | MWh | **Round Trip Efficiency (RTE)** | **-83.8%** |

| | | | | | |
|---|---|---|---|---|---|
| Period Potential Charge/Discharge | 163,680 | MWh | | | |
| | | | | | |

Exhibit Daghlian-Direct-2 Reid Gardner BESS Spring 2024 Reliability

| | | | | | |
|---|---|---|---|---|---|
| -13149.3 | MWH | **EIA-923 Input** | | Monthly Total Ener | |
| 12198.9 | MWH | Fuel Consumptio | 13,149.3 | Monthly Total Energy I | |
| -950.4 | MWH | Gross Generatio | 12,198.9 | | Cha |
| 7.2% | | Net Generation | (950.4) | | Discha |
| -7.8% | | | | Monthly Ch | |
| | | | | Monthly Disch | |

| | | | | | |
|---|---|---|---|---|---|
| -12844.7 | MWH | **EIA-923 Input** | | Monthly Total Ene | |
| 11095.8 | MWH | Fuel Consumptio | 12,844.7 | Monthly Total Energy | |
| -1748.9 | MWH | Gross Generatio | 11,095.8 | | Cha |
| 13.6% | | Net Generation | (1,748.9) | | Discha |
| -15.8% | | | | Monthly Ch | |
| | | | | Monthly Disch | |

| | | | | | |
|---|---|---|---|---|---|
| -13682.9 | MWH | **EIA-923 Input** | | Monthly Total Ener | |
| 11794.3 | MWH | Fuel Consumptio | 13,682.9 | Monthly Total Energy I | |
| -1888.7 | MWH | Gross Generatio | 11,794.3 | | Cha |
| 13.8% | | Net Generation | (1,888.7) | | Discha |
| -16.0% | | | | Monthly Ch | |
| | | | | Monthly Disch | |

| | | | | | |
|---|---|---|---|---|---|
| -14053.2 | MWH | **EIA-923 Input** | | Monthly Total Ener | |
| 12006.6 | MWH | Fuel Consumptio | 14,053.2 | Monthly Total Energy I | |
| -2046.7 | MWH | Gross Generatio | 12,006.6 | | Cha |
| 14.6% | | Net Generation | (2,046.7) | | Discha |
| -17.0% | | | | Monthly Ch | |
| | | | | Monthly Disch | |

| | | | | | |
|---|---|---|---|---|---|
| -15847.7 | MWH | **EIA-923 Input** | | Monthly Total Ener | |
| 13279.4 | MWH | Fuel Consumptio | 15,847.7 | Monthly Total Energy I | |
| -2568.3 | MWH | Gross Generatio | 13,279.4 | | Cha |
| 16.2% | | Net Generation | (2,568.3) | | Discha |
| -19.3% | | | | Monthly Ch | |
| | | | | Monthly Disch | |

| | | |
|---|---|---|
| rgy Charge: | 13.15 | GWh |
| Discharge: | 12.20 | GWh |
| rge Hours: | 184.6 | Hour |
| rge Hours: | 135.4 | Hour |
| arge Rate: | 71.2 | MWh/h |
| arge Rate: | 90.1 | MWh/h |

| Reid Gardner - BESS | |
|---|---|
| Charge Rate Availability: | 0.0% |
| Discharge Rate Availability: | 0.0% |
| Energy Capacity Availability: | 77.8% |
| Performance Index: | 25.9% |
| Round Trip Efficiency (RTE) | #DIV/0! |
| AGC Accuracy: | 79.9% |

| | | |
|---|---|---|
| rgy Charge: | 12.84 | GWh |
| Discharge: | 11.10 | GWh |
| rge Hours: | 363.0 | Hour |
| rge Hours: | 144.8 | Hour |
| harge Rate: | 35.4 | MWh/h |
| harge Rate: | 76.6 | MWh/h |

| Reid Gardner - BESS | |
|---|---|
| Charge Rate Availability: | 78.2% |
| Discharge Rate Availability: | 80.6% |
| Energy Capacity Availability: | 100.0% |
| Performance Index: | 86.3% |
| Round Trip Efficiency (RTE) | 90.4% |
| AGC Accuracy: | 99.8% |

| | | |
|---|---|---|
| rgy Charge: | 13.68 | GWh |
| Discharge: | 11.79 | GWh |
| rge Hours: | 300.7 | Hour |
| rge Hours: | 139.9 | Hour |
| arge Rate: | 45.5 | MWh/h |
| arge Rate: | 84.3 | MWh/h |

| Reid Gardner - BESS | |
|---|---|
| Charge Rate Availability: | 94.0% |
| Discharge Rate Availability: | 98.2% |
| Energy Capacity Availability: | 98.4% |
| Performance Index: | 96.9% |
| Round Trip Efficiency (RTE) | 86.3% |
| AGC Accuracy: | 99.7% |

| | | |
|---|---|---|
| gy Charge: | 14.05 | GWh |
| Discharge: | 12.01 | GWh |
| rge Hours: | 182.5 | Hour |
| rge Hours: | 134.8 | Hour |
| arge Rate: | 77.0 | MWh/h |
| arge Rate: | 89.1 | MWh/h |

| Reid Gardner - BESS | |
|---|---|
| Charge Rate Availability: | 89.1% |
| Discharge Rate Availability: | 92.1% |
| Energy Capacity Availability: | 100.0% |
| Performance Index: | 93.7% |
| Round Trip Efficiency (RTE) | 85.5% |
| AGC Accuracy: | 99.8% |

| | | |
|---|---|---|
| rgy Charge: | 15.85 | GWh |
| Discharge: | 13.28 | GWh |
| rge Hours: | 186.7 | Hour |
| rge Hours: | 126.6 | Hour |
| arge Rate: | 84.9 | MWh/h |
| arge Rate: | 104.9 | MWh/h |

| Reid Gardner - BESS | |
|---|---|
| Charge Rate Availability: | 91.9% |
| Discharge Rate Availability: | 99.9% |
| Energy Capacity Availability: | 92.5% |
| Performance Index: | 94.8% |
| Round Trip Efficiency (RTE) | 83.8% |

| | |
|---|---|
| AGC Accuracy: | 99.9% |

**EXHIBIT DAGHLIAN-DIRECT-3**

**FILED UNDER CONFIDENTIAL SEAL**

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JIMMY DAGHLIAN, 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: February 14, 2025

Jimmy Daghlian
JIMMY DAGHLIAN

# JAMES HEIDELL

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

**James Heidell**

Revenue Requirement

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

A. My name is James Heidell. My current position is Partner at PA Consulting Group, Inc. ("PA"). My business address is 1700 Lincoln St., Suite 3550, Denver, Colorado. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power or the "Company").

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

A. My academic background includes a bachelor of science in civil engineering from Tufts University, a masters of science in engineering economics from Stanford University, and a masters of business administration in finance from the University of Washington. I am a CFA Charterholder.

I have worked in the energy industry for 45 years starting as an engineer focusing on energy at the U.S. Department of Energy's Pacific Northwest Laboratory. I have worked at multiple consulting firms focusing on electricity and natural gas advising a range of utility clients, private investors, and regulators. I also worked for Puget Sound Energy, a combined electric and natural gas utility, serving in various capacities including its Director of Federal and State Regulation and Director of Finance. My qualifications are provided in **Exhibit Heidell-Direct-1.**

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS PARTNER AT PA.**

A. As Partner, my responsibilities include working with clients to analyze a range of investments in the power generation sector, valuation of portfolios of generation assets, providing due diligence on a range of transactions in the power and gas sector, conducting reviews of utility generation investments on behalf of the Advocacy Staff of the North Dakota Public Service Commission, and evaluating a range of energy technologies. In addition to providing consulting services to clients, I have a range of responsibilities related to developing PA's consulting staff and being part of the PA's U.S. Energy Practice management team.

**4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes, I testified on behalf of Solar City in Docket No. 16-06006, Sierra Pacific Power Company d/b/a NV Energy's 2016 general rate case.

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

A. The purpose of my testimony is to present my analysis of the construction costs associated with the Silverhawk Capacity Project ("Silverhawk" or "Silverhawk Project"). I also present my analysis of the benefits to Nevada Power customers associated with the Company's decision to accelerate the construction of the Reid Gardner battery energy storage system project ("BESS" or "BESS Project"). Silverhawk includes the addition of two 220 MW combustion turbines ("CTs") and associated facilities at the existing Silverhawk Generating Station. Silverhawk had an initial construction cost estimate of approximately $353M but ultimately cost $514M (excluding AFUDC). My analysis of the Silverhawk construction costs focused on reviewing and classifying the factors that led to the difference between the initial Advancement of Cost Engineering ("AACE") Class 4 cost estimate of $353M and the final costs. In addition, I evaluated whether the final construction cost was reasonable based upon the cost of contemporaneous CTs that were constructed. Regarding the Reid Gardner BESS Project, I assessed eight areas of benefits associated with construction to achieve a commercial operation date of December 29, 2023, versus the original schedule of May 31, 2024.

**6. Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following Exhibits:

| | |
|---|---|
| **Exhibit Heidell-Direct-1** | Statement of Qualifications |
| **Exhibit Heidell-Direct-2** | Nevada Power Silverhawk Cost Review |
| **Exhibit Heidell-Direct-3** | Reid BESS Acceleration Benefits Review |

**7. Q. WOULD YOU PLEASE SUMMARIZE THE ORGANIZATION OF YOUR TESTIMONY?**

A. Yes. My testimony is organized into two sections. In section one, I discuss my analysis of the Silverhawk construction costs. In section two, I discuss my analysis of the Reid Gardner BESS. Within both of those sections, my testimony is organized into four subparts:

- I provide a summary of my findings,
- I provide a description of the scope of PA's studies that support the Company's actions regarding the Silverhawk costs and Reid Gardner BESS,

- I summarize the approach used to analyze the drivers of the Silverhawk cost increase and the approach used to analyze the benefits of accelerating the completion of the Reid Gardner BESS, and
- I explain the results of my analysis.

I note that additional detail is provided in the full reports presented in **Exhibit Heidell-Direct-2 and Exhibit Heidell-Direct-3.**

## I. SILVERHAWK

### A. Summary of Findings

**8. Q. WOULD YOU PLEASE SUMMARIZE THE FINDINGS OF YOUR ANALYSIS OF THE SILVERHAWK CONSTRUCTION COSTS?**

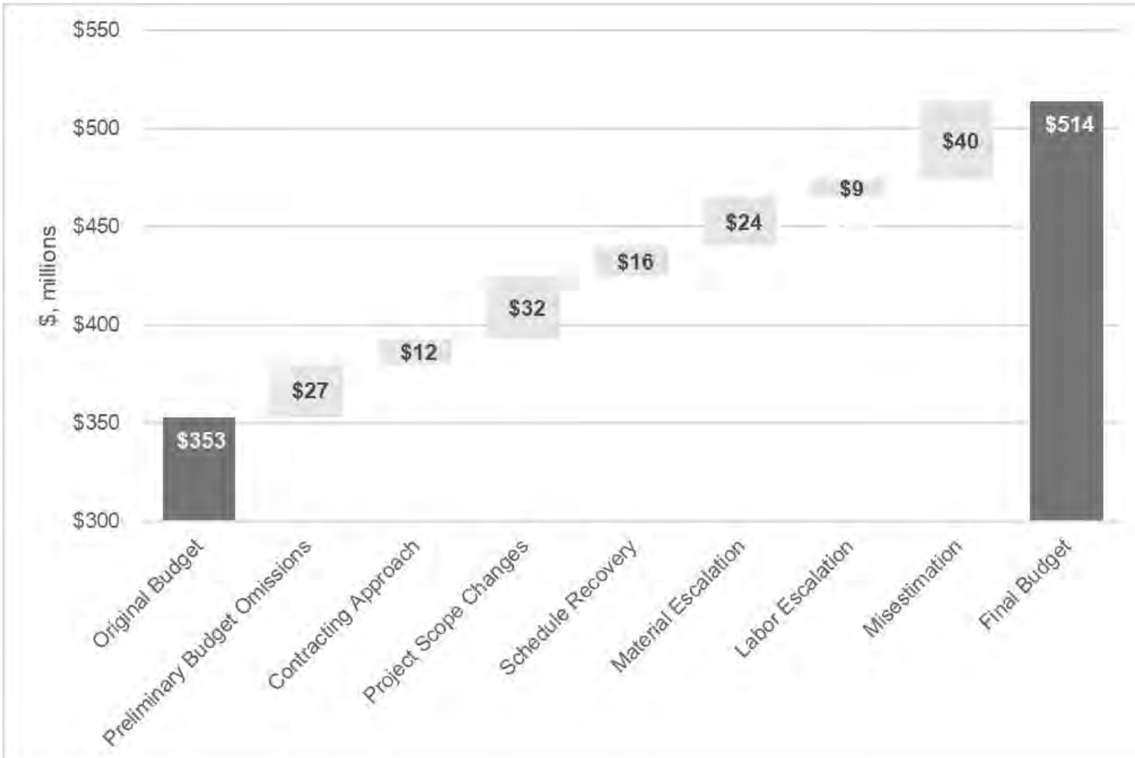
A. Yes. I analyzed the $161M in cost increase over the original budget, and I classified the increase into seven categories. The results are summarized in the following **Figure Heidell-Direct-1**.

///

///

///

**Figure Heidell-Direct-1**
**Silverhawk Cost Waterfall – Original Budget to Final Budget**




**9. Q. DO THE SEVEN CATEGORIES OF INCREASE INDICATE THAT NEVADA POWER DID NOT PROPERLY MANAGE THE SILVERHAWK PROJECT COSTS?**

A. No. It is important to understand that the initial estimate was a Class 4 estimate, meaning that the estimate was made before detailed engineering. A Class 4 estimate has an estimated deviation range of +50 percent on the high side and -30 percent on the low side. Even with these deviations, 20 percent of the estimates can be expected to fall outside of the range.[1]

[1] *See* https://aheinc.ca/wp-content/uploads/2018/12/AACE-Cost-Estimate-Classification-System.pdf.

**10. Q. WAS IT REASONABLE TO PROCEED WITH THE SILVERHAWK PROJECT BASED UPON A CLASS 4 ESTIMATE?**

A. Yes, the different categories of cost estimates defined by AACE are in part intended to convey the relative accuracy of the cost estimate as a project proceeds from conceptual design through detailed engineering and development of bid documents. A major power plant development project will go through multiple stages of evaluation from a conceptual project through detailed bid documents. It is reasonable that the Company estimated the costs during the project feasibility stage. As the project design progresses, cost estimates become more accurate and are updated, as was the case with Silverhawk.

As a point of reference, utilities typically develop their integrated resource plans based upon Class 5 estimates, which is concept screening. Based upon those estimates, the utility, often with the public utility commission, provide initial approval of generation expansion plans. In instances where the utility seeks further commission approval or even an advanced determination of prudence, the cost estimates are still at the Class 4 or 3 level and the utility has not incurred the cost of more detailed design that is necessary to reduce the uncertainty in the cost estimates.

**11. Q. WAS IT REASONABLE FOR NEVADA POWER TO PROCEED WITH AN ACCELERATED CONSTRUCTION SCHEDULE GIVEN THE COST ESCALATION BETWEEN THE INITIAL AND REFINED ESTIMATES?**

A. Yes. Nevada Power conducted studies of the incremental value of having the Silverhawk Project in commercial operation by the summer of 2024 versus after the summer peak and determined that the cost of accelerating the schedule was reasonable. The studies evaluated the cost of procuring alternative capacity for the summer of 2024.

**12.** **Q.** **IS THE FINAL CONSTRUCTION COST IN THE RANGE OF OTHER CTs CONSTRUCTED IN THE SAME TIME PERIOD?**

A. Yes. Silverhawk cost $1,168/kW. I reviewed estimates of costs of specific comparable generation projects available from public sources. For example, the U.S. Energy Information Administration estimate for a 419 MW frame CT is $952/kW and Wisconsin Electric estimates the cost will be $1,208/kW. Sections 5.1 and 5.2 of **Exhibit Heidell-Direct-2** provide additional detail regarding comparable constructions costs. In summary, while Silverhawk construction costs may be on the high side of the range of construction costs of other contemporaneous projects, the costs incurred by NV Energy are within a reasonable range.

**B. Silverhawk Study Scope**

**13.** **Q.** **WOULD YOU PLEASE SUMMARIZE THE SCOPE OF YOUR SILVERHAWK COST STUDY?**

A. Yes, Nevada Power hired PA in April 2024 to review Silverhawk to evaluate the factors leading to an anticipated completion cost of $530 million. The initial focus was on evaluating the economic factors driving the cost escalation and whether the cost increases were in-line with other contemporaneous projects. Our scope also included review of project management, and the decision-making process associated with the continuation of the project as costs escalated.

**14.** **Q.** **WERE THERE CHANGES IN SCOPE AFTER THE START OF THE STUDY?**

A. Yes, after the kick-off meeting and review of initial material, we understood that there were other factors beyond relevant industry material and labor escalation benchmarks that factored into the cost increase. As a result, PA adjusted the scope of its study to include other explanatory cost escalation factors.

**15.** **Q.** **DID YOU PERFORM THE STUDY BY YOURSELF?**

A. No. I led the study, but I was supported by a team of PA employees and Trent Markell of PF Engineers, a subcontractor working under my direction. Thus, in my testimony, when I use the word "I" that refers collectively to me and the PA project team.

**C. Silverhawk Study Approach**

**16.** **Q.** **WOULD YOU PLEASE SUMMARIZE YOUR APPROACH TO EVALUATING THE SILVERHAWK COST ESCLATION?**

A. The initial effort was focused on understanding who was involved in the construction process and the various roles played by Nevada Power and its contractors. After gaining an appreciation of the contracting process, the next step was to develop a timeline for the contracting process, identifying key decision points and when different contractors became involved in the Silverhawk Project. The next step was to request key documents to review and analyze.

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

**17.** **Q.** **HOW DID YOU IDENTIFY THE VARIOUS ROLES PLAYED BY NEVADA POWER AND CONTRACTORS?**

A. I identified the roles based upon a series of meetings and interviews of Nevada Power personnel and Nevada Power's project management contractor, IEM Energy Consultants.

**18.** **Q.** **WHAT DOCUMENTS DID YOU REVIEW?**

A. I reviewed summaries of costs/work orders provided by Nevada Power, its categorization of costs, and its documents used to approve design, engineering, and construction of Silverhawk.

### D. Silverhawk Study Results

**19.** **Q.** **WHAT WAS THE INITIAL $353M COST ESTIMATE BASED UPON?**

A. The initial cost estimate was developed by Power Engineers ("POWER") in 2022. POWER was the Company's initial Owner's Engineer hired to help develop Silverhawk. As noted above, the estimate developed was classified as a Class 4 estimate, which provides a preliminary estimate absent specific project documents and engineering. Class 4 estimates are described as 80 percent of the projects will fall within a band of -30 percent on the low side to +50 percent on the high side of the cost estimate.[2]

[2] The classification of the anticipated accuracy of costs is often referenced in cost estimates in the power industry per AACE International Recommended Practice No. 18R-97. *See* https://aheinc.ca/wp-content/uploads/2018/12/AACE-Cost-Estimate-Classification-System.pdf. My understanding is that the American Society of Civil Engineers, the Project Management Institute, and Construction Management Association of America all recognize the AACE guidelines.

**20**. **Q.** **DID NEVADA POWER PROCEED BEYOND THE INITIAL PLANNING PHASE BASED UPON THE INITIAL COST ESTIMATE?**

A. Yes, in September 2022 there was internal approval based upon a $353M project. (There were prior approvals for approximately $1.6M to engage POWER and to start developing project documents.)

**21**. **Q.** **AT WHAT POINT DID COSTS CHANGE FROM THE $353M ESTIMATE?**

A. Costs started to substantially exceed the estimate in May of 2023 when more refined cost estimates were developed by the general contractor. With specific construction documents, it was reasonable that a more refined cost estimate could be developed. The cost also increased in November 2023 when Nevada Power converted the construction contract to a firm fixed-price bid. I detail these cost increases on page 8 of **Exhibit Heidell-Direct-2**, as well as the Company's efforts to confirm that proceeding with Silverhawk Project was the most prudent option available to meet reliability needs during peak season.

**22**. **Q.** **PLEASE ELABORATE ON YOUR PREVIOUS DISCUSSION INFERRING TO THE COMPLEXITY OF THE CONTRACTING PROCESS.**

A. Nevada Power's initial plan was to rely on the frequently used approach of hiring an Owner's Engineer ("OE") who would assist in hiring an EPC contractor. Nevada Power did not receive any suitable bids for the EPC contractor resulting in the Company hiring a General Contractor and managing more of the contracting process directly.

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

**23.** **Q.** **WERE THERE ADDITIONAL COMPLICATIONS ASSOCIATED WITH STARTING CONSTRUCTION OF THE SILVERHAWK PROJECT?**

A. Yes, when construction started it was initially done on an open book basis as a result of the drawn-out contracting process, delays in receiving permits, and the need to complete construction on a timely basis.[3] The open-book contract was changed to a fixed price after there was sufficient time to develop detailed engineering documents.

As noted above, there were delays in securing necessary permits that put the start of construction behind schedule.[4] In turn, this led to the Company approving a more accelerated construction schedule and additional contractor overtime in order to meet the target commercial operation date. These complications are explained in further detail along with an associated graphic and a discussion on page 21 in **Exhibit Heidell-Direct-2**.

**24.** **Q.** **DID NEVADA POWER EVALUATE THE BENEFIT OF ACCELERATING CONSTRUCTION TO MEET THE COMMERCIAL OPERATION DATE?**

A. Yes, the Company evaluated the benefit of having the Silverhawk capacity available for the summer of 2024 versus the summer of 2025. The Company estimated that there were $88M in savings for customers if the capacity was available in 2024 versus having to procure an alternative source of capacity. My analysis concluded that the cost to accelerate the construction was $22M.

[3] An open book contract is one in which there is an agreement that outlines the costs of a project and the supplier's profit margin, but the contract is not fixed price. It is reasonable to use open book contracting when parties need the work to begin given construction timelines, but not all of the engineering and specifications of the project are finalized. Given the delays in permitting, for example, it was reasonable for the Company to use an open book contract.

[4] As discussed by Company witness Mr. Fady Atala, the permitting was delayed due to local government delays associated with issuing the special use permit, the drainage studies/grading permit and the air permit.

Therefore, my conclusion is that the acceleration resulted in net benefits to customers.

**25**. **Q.** **WERE THERE OTHER FACTORS BEYOND THE CONTRACTING APPROACH AND CONSTRUCTION SCHEDULE COMPRESSION THAT DROVE COST INCREASES?**

A. Yes, I identified five other general categories of construction cost escalation and variances from the initial estimate in addition to construction acceleration (called schedule recovery in PA's study) and changes to the contracting approach. These factors are: 1) omissions from POWER's budget estimate, 2) project scope changes, 3) material cost escalation, 4) labor cost escalation, and 5) misestimation. My testimony and the testimony of Nevada Power witness Fady Atala discusses the construction cost complications.

**26**. **Q.** **WHAT MAJOR COSTS WERE OMITTED FROM THE INITIAL $353M COST ESTIMATE?**

A. The three major omitted costs that I identified were: sales tax on major equipment including the combustion turbines, Nevada Power's project overhead costs, and project close-out costs to update Company records.

**27**. **Q.** **WHAT WERE THE MAJOR CHANGES IN SCOPE THAT LEAD TO INCREASED COSTS?**

A. The three major scope changes leading to increased cost were: the civil work associated with preparing the site was a larger job than originally identified, development of a ring bus configuration at the Silverhawk Switchyard, and changes to the specifications for the combustion turbines.

**28**. **Q.** **WHAT WERE THE SCHEDULE RECOVERY COSTS ALREADY DISCUSSED ABOVE?**

A. This category reflects costs incurred to accelerate the project to get it back on schedule following delays in receiving necessary permits. Specific schedule acceleration costs include authorizing more contractor overtime, paying GE to expedite delivery of the turbines, and relocating a spare generator step-up transformer needed for the project to be online. While GE was paid to expedite the delivery, delivery was delayed and liquidated damages offset the recovery costs.

**29**. **Q.** **WHAT WERE THE MATERIAL COST ESCALATIONS?**

A. The original estimate was based upon 2021 costs and significant portions of the project were constructed in 2023 with work in 2024. In the intervening years, there were significant cost increases due to inflation in power plant electrical equipment and transmission equipment. There were multiple drivers of inflation that impacted the power industry, including the supply chain disruption associated with the COVID-19 pandemic. Also, inflation in critical raw materials, including steel and concrete, was significant.

**30**. **Q.** **WHAT WERE THE LABOR COST ESCALATIONS?**

A. Similar to material cost escalations, labor costs also experienced significant escalations between the 2021 estimate and the construction in 2023 and 2024. Labor inflation during the period was also impacted by a multitude of factors including labor shortages as well as the increased demand for craft labor due to the increased demand associated with renewable energy projects and expansion and hardening of the power grid.

**31. Q. WHAT DO YOU MEAN BY MISESTIMATION?**

A. Misestimation refers to differences in cost between the original estimate and the final project costs, which cannot be attributed to the other six categories. We note that the largest deviations were associated with the cost estimates for the Selective Catalytic Reduction system associated with the turbines.

**32. Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE CAUSES OF THE COST INCREASES.**

A. The following Table Heidell-Direct-1 illustrates how the seven categories of cost increases explain the difference between the original estimate of $353M and the final cost of $514M.

**Table Heidell-Direct-1**
**Summary of Cost Increases**

| Category | Cost Increase ($M) | Description |
|---|---|---|
| Preliminary Budget Omissions | $27 | Cost which was omitted from the original cost estimate developed by POWER and used for budgeting by NV Energy. |
| Contracting Approach | $12 | Cost incurred as a result of the multi-contract strategy used to execute the project, which would not have been expected under a traditional EPC contract arrangement. |
| Project Scope Changes | $32 | Cost associated with adjustments to the project scope as executed when compared to the scope understood to be budgeted for in the original cost estimate. |
| Schedule Recovery | $16[5] | Cost incurred to construct the project more quickly than typical in order to meet the required in-service date for Silverhawk following a three-month permitting delay. |
| Material Escalation | $24 | Increased cost due to inflation of materials as compared to the overnight cost assumptions in the original cost estimate |

[5] This $16 million amount includes and the liquidated damages on the turbines to offset the acceleration payment.

| | | |
|---|---|---|
| Labor Escalation | $9 | Increased cost due to inflation of labor as compared to the overnight cost assumptions in the original cost estimate. |
| Misestimation | $40 | Cost in excess of the original budget not attributable to one of the other six categories. Variance between estimates and actual costs is to be expected in any complex cost estimate. |

**33. Q. GIVEN YOUR SUMMARY OF THE COST INCREASES, ARE THE COST INCREASES REASONABLE?**

A. Yes, while the cost increases result from a myriad of factors, my assessment is that the Company did a reasonable job managing costs given the circumstances. Regarding each of the factors that resulted in a cost increase, I note as follows:

- **Preliminary budget omissions and project scope changes –** It was reasonable to start the Silverhawk Project with a Class 4 estimate and rely on the cost estimation expertise of a third party (POWER Engineers) who is consistently active in the development, engineering, and construction of similar projects. It is typical for there to be changes in scope and specifications as a complex project evolves and detailed design is completed. Omissions such as excluding sales tax was the result of a misunderstanding regarding whether they were excluded from the estimate. It did not impact the design or integrity of the Silverhawk Project .
- **Contracting approach –** The Company intended to use a traditional EPC contracting approach but did not receive any suitable bids given the required project schedule. This necessitated a more involved, multi-contract strategy to be executed by the Company to complete construction by the summer of 2024. The approach was reasonable and necessitated by the limited market interest expressed by EPC firms.

- **Schedule recovery –** Permitting delays are common and difficult to predict. In this instance, the delays compressed the construction schedule. Given the delay, the Company evaluated the economic benefits of maintaining the schedule so that the project capacity would be available for the summer 2024 peak season and determined that following a compressed schedule was a lower cost option than purchasing replacement capacity.
- **Material and labor escalation –** Labor and material escalation costs are based upon market factors and not controlled by the Company; the Company continued to evaluate the reasonableness of proceeding with the Silverhawk Project in light of these escalations.
- **Misestimation –** In estimating costs for large, complex projects, it is inevitable that there will be variances that occur as the project is executed that are not attributable to a specific change of circumstance or estimation error. The level of cost change due to misestimation which occurred is reasonable for a Class 4 estimate.

**34. Q. BASED UPON YOUR INTERVIEWS WITH THE COMPANY, WHAT IS YOUR CONCLUSION REGARDING THE PROCESSES USED TO MONITOR CONSTRUCTION COSTS?**

A. My conclusion is that the costs were reasonably managed. There were check points where increased costs were approved by senior management through the Authorization for Expenditure process, and the Company also tracked the increased costs versus the benefits of completing the Silverhawk Project . I note that while there were $29M in costs omitted from the preliminary estimate (primarily associated with sales tax and company overheads), Nevada Power has not constructed a conventional power plant since 2011, and most of the institutional knowledge left as a result of personnel retirements.

## II. REID GARDNER BESS

### A. Summary of Findings

**35. Q. WOULD YOU PLEASE SUMMARIZE THE FINDINGS OF YOUR ANALYSIS OF THE REID GARDNER BESS SCHEDULE ACCELERATION?**

A. Yes, I assessed eight areas of benefits associated with acceleration of construction to achieve a commercial operation date of December 29, 2023, versus the original schedule of May 31, 2024. The eight categories of benefits are summarized in the following **Table Heidell-Direct-2**.

**Table Heidell-Direct-2: Examination of Benefits**

| Benefit | Value ($MM) | Comments |
|---|---|---|
| Production Cost | 2.063 | Savings from not curtailing solar energy generation |
| EIM[6] Benefits | 2.594 | Savings from using BESS for five-minute balancing versus an alternative resource |
| Must Buy Avoided Costs | 0.228 | Savings from use of BESS instead of market purchases |
| Portfolio Energy Credits | 0.154 | Value of RECs from not curtailing production |
| Avoided Flex Ramp Costs | 0.136 | Avoided failure costs based upon fast ramping of the BESS |
| Avoided AFUDC[7] | 1.314 | Lower project financing costs due to shorter construction period |

[6] California Independent System Operator's ("CAISO") Western Energy Imbalance Market ("EIM").
[7] Allowance for Funds Used During Construction ("AFUDC").

| | | |
|---|---|---|
| Depreciation Expense Paid by Shareholders | 4.721** | Deferred recovery of plant placed in service in January 2024 |
| Avoided ROI[8] Compensation | 4.209** | Lost ROI on plant placed in service in January 2024 |
| Risk Adjusted Capacity Cost Savings | Not Quantified | Calculated risk of underperformance in first six months of operation |
| **Total** | **15.419** | |

**See Q&A 66 below. These figures do not reflect the tax and O&M implications addressed by Company witness Daghlian.

**36. Q. WAS IT REASONABLE FOR NEVADA POWER TO TARGET A 2023 IN-SERVICE DATE FOR REID GARDNER BESS?**

A. Yes. The Reid Gardner BESS is the first BESS of this size that the Company owns and operates. This was also the first BESS from BYD America LLC ("BYD") for the Company, meaning this was the Company's first exposure to BYD's system. Thus, at the start of the BESS Project, it was not known what operational adjustments or modifications would have to be made and how long those adjustments would take to achieve the full capacity benefits of the BESS or how the BESS would actually dispatch and interact with grid conditions. Given the concerns with lack of experience with batteries of this size by this manufacturer, the Company was concerned that if BESS was not fully operational for the 2024 summer peak and if there was shortfall of capacity in that timeframe, any issues with the battery would result in the Company having to purchase replacement capacity at high summer pricing. It was a reasonable decision by the Company to ensure the battery was fully tested and integrated into grid operations well ahead of peak summer demand in 2024. In addition, as discussed by Company witness

[8] Return on Investment ("ROI").

Jimmy Daghlian in his direct testimony, there were other customer benefits associated with accelerating the BESS Project.

**B. Reid Gardner BESS Study Scope**

**37. Q. WOULD YOU PLEASE SUMMARIZE THE SCOPE OF YOUR STUDY?**

A. Yes. The Company hired PA in December 2024 to review the BESS Project as an independent entity to determine the benefits to Nevada Power customers associated with the accelerated construction to achieve commercial operation in December 2023. I also reviewed the construction schedule, the BESS Project operations in 2024, and the range of benefits to customers given the actual performance of the BESS.

**38. Q. DID YOU COLLECT THE DATA USED IN THE ANALYSIS THAT YOU HAVE RELIED UPON TO ESTIMATE CUSTOMER SAVINGS?**

A. My role was primarily to review the analysis developed by Nevada Power and identify any recommend areas that in my opinion should be adjusted, supplemented, or removed. I requested and reviewed analyses but relied on the Company to collect the data and perform the calculations.

**39. Q. DID YOU PERFORM YOUR STUDY BY YOURSELF?**

A. No. I lead the study, but I was supported by a team of PA employees working under my direction. As noted in Section I, when I use the word "I," that refers collectively to myself and the PA project team.

### C. Reid Gardner BESS Study Approach

**40. Q. WOULD YOU PLEASE SUMMARIZE YOUR APPROACH TO EVALUATING THE CUSTOMER BENEFITS?**

A. I started with a conference call with Company personnel within Nevada Power to understand the BESS Project and the analyses developed by the Company to date. Based upon the initial call, the Company followed up with relevant documentation of the BESS Project. Subsequent to my review of the initial material, there were a series of conference calls, and I made requests for additional information and analysis in order to better understand the BESS Project and evaluate potential customer benefits from the accelerated construction schedule.

**41. Q. WHAT DOCUMENTS DID YOU REVIEW?**

A. The documents that I reviewed included: the Integrated Resource Plan ("IRP") testimony related to the BESS Project (Docket No. 22-03024); testimony related to the BESS Project filed in Nevada Power's 2023 General Rate Case (Docket No. 23-06007); the Commission's Modified Final Order in 2023 General Rate Case ("2023 Nevada Power Order"); and models developed by the Company to estimate the customer benefits of the accelerated construction schedule.

**42. Q. WHAT SPECIFIC MODELS DEVELOPED BY THE COMPANY DID YOU REVIEW?**

A. I reviewed an Excel model of calculations of the energy cost savings and a separate model that evaluated financing benefits. In addition to reviewing the models, I had discussions with the appropriate Company experts who developed the analyses contained within the models.

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

**D. Reid Gardner BESS Study Results: Categories of Benefits**

**43. Q. WOULD YOU PLEASE SUMMARIZE THE TYPES OF BENEFITS ASSOCIATED WITH ACCELERATED COMPLETION OF THE BESS PROJECT?**

A. Yes, I group the benefits into four overall categories: (1) Energy cost savings, (2) PC benefits, (3) financing-related benefits, (4) and other benefits. I briefly summarize these benefits and follow-up with more detailed descriptions.

- **Energy benefits** include savings from using the batteries to store solar energy and avoid using gas generation. Additional benefits of the BESS include: avoiding the curtailment of solar production; increasing the ability to make incremental electricity market sales in the Western EIM; and achieving savings from reducing must-buy electricity and decreasing must-sell market electricity purchases and sales.
- **Portfolio Energy Credit benefits** include the use of the BESS to avoid curtailment of solar, thus producing more portfolio energy credits.
- **Financing benefits** include reducing the period of accruing AFUDC costs and recognizing the benefits of the Investment Tax Credit one year earlier.
- **Other Benefits** comprise costs absorbed by shareholders as a result of putting the BESS Project into service in the end of December 2023; the deferred recovery of the contractual final completion payments, including a return on that deferred recovery amount, in conformance with the Commission's 2023 Nevada Power Order; and the unquantified benefit of reducing the risk that the Company would have had to purchase replacement capacity for the summer of 2024. My testimony addresses these other benefits below in more detail.

**44. Q. WHAT ARE THE AVOIDED GAS GENERATION COSTS?**

A. The BESS is used to store energy during peak solar production hours and deliver that energy to the grid during higher production cost hours. BESS charging and discharging during January through May 2024 was monitored and production cost savings were evaluated using the PLEXOS model based upon actual wholesale market energy prices, as well as actual natural gas prices.

**45. Q. WHAT ARE THE AVOIDED PRODUCTION COSTS?**

A. The Company estimated the savings from having the BESS on-line from January through May 2024 by using the PLEXOS model to evaluate the change in production costs with and without the BESS. The forecast is based upon an hourly dispatch analysis with the use of actual market electricity costs, actual loads, and actual natural gas costs. The resulting calculation yielded a fuel savings of $2,063,860. The savings estimate reflects the charge and discharge efficiency of the BESS system in conjunction with the storage optimization logic incorporated into PLEXOS. The optimization logic identifies opportunities to store low-cost electricity in the BESS such as from the PV systems and discharge that electricity when more expensive thermal generation would otherwise be needed to meet the system loads

**46. Q. HOW WERE THE PLEXOS MODEL INPUTS DEVELOPED?**

A. Nevada Power started with the modeling inputs used in the 2024 IRP (Docket No. 24-05041) and updated the inputs to reflect actual gas costs and market energy prices, running the model with and without the BESS online for the January through May period. The savings estimate is based the difference in power costs between

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

the PLEXOS simulation that incorporates the BESS at the start of the year versus the counter-factual case of the BESS not in operation until June 1.

**47. Q. IS PLEXOS A REASONABLE APPROACH TO ESTIMATE THE ENERGY SAVINGS BENEFITS?**

A. Yes, using an energy market dispatch model is a reasonable approach to model what costs would be in the counter-factual that the BESS was not available. PLEXOS is a widely used sub-hourly market model, and my understanding is that the Company has used PLEXOS since 2021 in a variety of applications including developing optimized expansion portfolios for the IRP as well as forecasting power costs.

**48. Q. DOES THE MODELING INDICATE THAT CUSTOMERS RECEIVED THE BENEFITS OF LOWER PRODUCTION COSTS?**

A. Yes, while the actual energy costs in the counter-factual case, that there was no BESS, is not known with certainty, the modeling is a reasonable way to calculate the savings to customers.

**49. Q. WHAT WESTERN EIM BENEFITS ARE ASSOCIATED WITH THE BESS PROJECT?**

A. The BESS provides fast response energy services to participate in the Western EIM to sell power in five-minute increments. The dispatch of the BESS resulted in incremental electricity market sales revenues. Absent the BESS, the utility either would not have received the revenues or would have had higher costs if the utility dispatched higher variable cost generators.

**50. Q. HOW WERE THE WESTERN EIM BENEFITS FROM ACCELERATING COMPLETION OF THE BESS PROJECT CALCULATED?**

A. The cost of using the BESS for real-time balancing was calculated based upon actual five-minute charging and discharging data for the BESS. Actual five-minute Locational Marginal Prices ("LMP") were used to calculate the cost of charging and the revenues from discharging the batteries. The result of the analysis is that over the four-month period, the BESS netted $2,594,100 of margin.

**51. Q. HAVE CUSTOMERS RECEIVED THE WESTERN EIM COST SAVINGS?**

A. Yes, Western EIM charges and revenue credits are realized as part of the fuel and purchased power cost calculation. Savings are realized through the Base Tariff Energy Rates ("BTER").

**52. Q. PLEASE EXPLAIN WHAT THE MUST-BUY AVOIDED COST SAVINGS ARE.**

A. If the Company does not have sufficient generation to meet its hourly load, then the Company must make wholesale market purchases to meet its resource adequacy requirements. Due to the Company having the BESS online in January, it had an additional resource that was used to reduce the amount of must-buy market purchases. In summary, the must-buy avoided costs are based upon the savings from using electricity charged in the BESS instead of having to make system purchases.

**53. Q. HOW WERE THE MUST-BUY AVOIDED COST SAVINGS CALCULATED?**

A. The Company reviewed the hours where it made market purchases to address resource adequacy requirements. The Company then assumed that those purchases over the day would have been 440 MW higher absent the BESS. This assumption was made given that 440 MWH is the BESS discharge capacity. The Company used the average electricity purchase price over the respective day to calculate the savings associated with avoiding must-buy purchases as a result of the discharge capability of the Reid Gardner BESS.

**54. Q. ARE THE MUST-BUY AVOIDED PURCHASE SAVINGS A CONSERVATIVE ESTIMATE?**

A. Yes, the customer savings estimate is based upon only nine days where the Company had net avoided purchase power cost requirements. There may have been hours that, but for using the 440 MWH of discharge capacity, there would have been a need to purchase energy and an associated Nevada Power cost.

**55. Q. WHAT ARE THE PORTFOLIO ENERGY CREDIT BENEFITS?**

A. Nevada Power reviewed actual hours of solar curtailment during the January through May 2024 period. The Company determined how much larger the curtailment would have been based upon the charging of the batteries during those curtailment hours. The avoided energy curtailed creates a corresponding increase in portfolio energy credits or RECs that the Company otherwise would not have been credited with.

**56. Q. WHAT IS THE ESTIMATED VALUE OF THE ADDITIONAL PORTFOLIO ENERGY CREDIT?**

A. The estimated value of the incremental portfolio energy credits associated with avoided curtailment is $0.154 million. This calculation is based upon the product of 30.9 GWH of solar that was not curtailed during March through May 2024 and $5 per MWH per portfolio energy credits. The GWHs not curtailed is the product of 61 days of curtailment and 506 MWH of stored solar energy in each day.

**57. Q. DID CUSTOMERS REALIZE SAVINGS FROM THE GENERATION OF ADDITIONAL PORTFOLIO ENERGY CREDITS?**

A. No, not immediately. The Company banks the portfolio energy credits to comply with its Nevada clean energy requirements. The estimate of value is based upon what the Company could have sold the portfolio energy credits for had they not been banked for regulatory compliance.

**58. Q. PLEASE EXPLAIN WHAT THE AVOIDED FLEX RAMP COST SAVINGS ARE.**

A. The Western EIM requires that the utility has sufficient generation ramping capability to meet changes in real time load requirements versus the utility's daily hourly demand forecast. This is referred to as Flex Ramp Requirements. Nevada Power must have sufficient ramp capacity in each 15-minute period to cover its load, or alternatively, it will face charges of varying amount based upon specific market conditions.

**59. Q. HOW WERE THE AVOIDED FLEX RAMP SAVINGS CALCULATED?**

A. The Company reviewed the hourly load and the scheduled generation in each hour and assumed that if it did not have at least 200 MW of ramp capacity that it would fail the CAISO test. Each MW of shortage of ramp capacity was assumed to incur a $1,000 per MWH charge for 10% of the occurrences.

**60. Q. DID THE COMPANY ACTUALLY HAVE ANY FLEX RAMP TEST FAILURES DURING JANUARY THROUGH MAY OF 2025?**

A. Yes.

**61. Q. WHAT ARE THE ESTIMATED SAVINGS ASSOCIATED WITH NEVADA POWER HAVING AN ADDITIONAL 440 MW OF RAMP CAPACITY AS A RESULT OF THE BESS?**

A. The calculated savings are $136,070. These savings are reflected in the total fuel and purchased power costs in BTER rates during the period of the must-sell transactions.

**62. Q. WHAT ARE THE AFUDC BENEFITS ASSOCIATED WITH THE DECEMBER IN-SERVICE DATE OF THE BESS PROJECT?**

A. Nevada Power is allowed to recover the deployed cost of capital associated with the construction expenditures during construction of the BESS Project. A shorter construction period translates into a shorter financing period of construction and lower financing costs. Those savings are realized by customers through a lower total cost of the BESS Project once in service.

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

**63. Q. HOW WAS THE AFUDC BENEFIT CALCULATED?**

A. Actual monthly construction expenditures were tracked over the period of March 2022 through December 2023 and AFUDC was calculated using an approximate 7% cost of capital (depending on the month). This calculation resulted an AFUDC cost of approximately $5.276 million. A separate calculation was completed assuming a construction schedule of March 2022 through May 2024 using the same AFUDC rate. This calculation resulted in an AFUDC cost of $6.590 million. The difference, $1.314 million, is the savings customers realized by accelerating the in-service date by six months.

**64. Q. WHAT ARE THE DEPRECIATION COST SAVINGS ASSOCIATED WITH THE DECEMBER IN-SERVICE DATE OF THE BESS PROJECT?**

A. Per the Commission's 2023 Nevada Power Order, the revenue requirement reflects book depreciation of $198,211,000, which reflects the total cost of the BESS less the investment held for review in a future rate case. However, the BESS was operational in January 2024, so the Company's actual depreciation was based upon the full $252,215,748 investment. Not only did Nevada Power customers not have to pay the incremental depreciation expense from January 2024 through September 2025, they also did not pay a rate of return on the full amount of the BESS during that time period.

**65. Q. HOW MUCH DEPRECIATION EXPENSE DID CUSTOMERS AVOID PAYING?**

A. The customers avoid $4,721,500 over the 21-month period. The depreciation costs were absorbed by shareholders.

**66. Q. DID CUSTOMERS AVOID PAYING A RETURN ON RATE BASE ASSOCIATED WITH PART OF THE BESS INVESTMENT RECOVERY BEING DEFERRED?**

A. Yes, despite the fact that the BESS Project was in service in January of 2024, the Company did not recover $4,209,689 associated with the weighted average cost of capital of 7.43% approved in the 2023 Nevada Power Order.

**67. Q. DID YOU EVALUATE THE FULL EXTENT OF REVENUE REQUIREMENT SAVINGS?**

A. No, I did not evaluate the tax and O&M implications that are addressed by Mr. Daghlian. Mr. Daghlian also presents a present value of revenue requirements; my analysis of benefits is not discounted.

**68. Q. DID YOU CONSIDER ADDITIONAL POTENTIAL BENEFITS?**

A. Yes, in addition to the actual benefits, the earlier in-service date reduced the risk that the Company would have had to purchase replacement capacity for the summer of 2024 in the event that it took multiple months for the BESS system to operate at full capability. As the Company did not know how long it would take to achieve full operational capability, the decision to accelerate construction was in part a decision to mitigate the risk that the BESS would not be fully operational during the summer peak demand period. In interviews with the NV Energy, the Company indicated that the Reid Gardner BESS was their first battery system of significant size, as well as the Company's first time working with the BYD system.

**69. Q. HOW LONG DID IT TAKE NV ENERGY TO ACHIEVE FULL OPERATIONAL CAPABILITY OF THE REID GARDNER BESS?**

A. It took approximately one month based upon the operational data that I reviewed. However, at the time of the decision to accelerate the BESS Project, it was not known if it would take multiple months to reach full performance. Consequentially, there was a risk that the utility would need to procure another source of peaking capacity to meet the summer peak demand.

**70. Q. IF THE BESS PROJECT WAS NOT ACCELERATED COULD THERE HAVE BEEN ADDITIONAL COSTS TO CUSTOMERS?**

A. Yes, there was the risk that 220 MW of replacement capacity would have to be purchased for the summer. I have not estimated that cost due to challenges of identifying what an alternative capacity purchase would have cost.

**71. Q. IF NEVADA POWER HAD TO PURCHASE ALTERNATIVE CAPACITY, WOULD THE COMPANY HAVE RECOVERED THE COSTS THROUGH LIQUIDATED DAMNGES?**

A. It is not known whether liquidated damages would apply, as that would depend on the type of operational issues encountered. In my scenario of assuming an additional two months to work out operational issues, I am not assuming that liquidated damages would apply as the contract is specific regarding the application of liquidated damages.[9]

---

[9] I reviewed Article 17.4 of the Energy Vault Contract, and while I am not offering a legal opinion, it appears that there are many situations where the BESS Project would have achieved Substantial Completion and the contractual Performance Levels but the BESS Project was not operating at full capacity.

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

**72. Q. WOULD YOU PLEASE SUMMARIZE THE BENEFITS THAT CUSTOMERS REALIZED AS A RESULT OF THE DECEMBER IN-SERVICE DATE?**

A. Yes, the following table summarizes the benefits provided to customers based upon information and calculations provided by Nevada Power and the models and analysis that I reviewed.

**Table Heidell-Direct-3: Summary of Benefits**

| **Benefit** | **Value ($)** | **Delivery of Benefits** |
|---|---|---|
| Production Cost | 2,063,860 | Benefits passed to customer through BTER rates. |
| Western EIM Benefits | 2,594,101 | Benefits passed to customer through BTER rates. |
| Renewable Energy Credits (PCs) | 154,330 | Estimated value, credits not monetized but banked. |
| Must Buy Avoided Costs | 227,975 | Benefits passed to customer through BTER rates. |
| Avoided Flex Ramp Costs | 136,070 | Benefits passed to customer through BTER rates. |
| Avoided AFUDC | 1,314,493 | Reflected in lower Project cost recovered in rates. |
| Customer Avoided Depreciation Expense | 4,721,500 | Depreciation not recovered from customers between January 2024 and September 2025. |
| Return on Investment | 4,209,689 | ROI not recovered from customers between January 2024 and September 2025. |
| Risk Adjusted Capacity Cost Savings | Not quantified | Estimate of risk of not having a longer period to achieve performance levels. |
| **Total** | **$15,422,018** | |

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

A. Yes.

# EXHIBIT HEIDELL-DIRECT-1

# JIM HEIDELL

PARTNER

Jim Heidell specializes in electric and gas utility regulation, distributed energy, evaluation of renewable energy technologies and financial analysis of complex investments. Mr. Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. He has extensive financial and energy market modeling experience coupled with a deep understanding of regulated and competitive markets that he applies to the valuation of energy assets. Mr. Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. His regulatory experience and testimony includes rate design, cost of service, resource planning, and merger conditions. Mr. Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. Prior to working at PA Consulting he held positions as the Director of Finance and Director of Federal and State Regulation at Puget Sound Energy. Mr. Heidell is a CFA and has an MBA in finance from the University of Washington, a MS in Engineering Economics from Stanford University, and a BSE in civil engineering from Tufts University.

## PRIMARY EXPERTISE

- Electric and natural gas utility regulation and finance
- Analysis of wholesale electric markets
- Renewable Energy Technologies
- Asset valuation / M&A Advisor
- Damages estimation for civil litigation
- Strategic planning
- Financial modelling of complex investments
- Financial planning

## CLIENTS

- Public Service Company of Colorado
- New Mexico Gas Company
- Solarcity
- Canada Pension Plan Investment Board
- North Dakota Public Service Commission

## QUALIFICATIONS

- 40-years' experience with electric & gas utilities and electricity markets
- MBA University of Washington
- MSE Engineering Economics, Stanford University
- BSE, Civil Engineering, Tufts University
- CFA

## EXPERIENCE SUMMARY

- **Utility Regulatory Support –** Prepare expert testimony in regulatory hearings related to resource acquisition, QF issues, rate impacts, load growth, marginal and embedded cost of service, and rate design. Developing marginal and embedded cost studies for regulated utilities.
- **Financial Analysis** – Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.
- **Analysis of Energy Markets** – Develop energy and capacity forecasts for U.S. power markets to support: strategic investments by utilities and major energy companies, development of utility risk management strategies, and corporate strategies for generation asset acquisition and disposition.

- **Evaluation of Distributed Energy and Behind the Meter Generation** – Forecast of margins of community solar projects, portfolios of customer sited PV projects, and analysis of regulatory policies and rules associated with community solar projects and behind the meter PV projects.
- **Renewable Energy Technologies** – Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.
- **Asset Valuation / M&A Advisor** – Provide valuation advice for acquisition of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.
- **Damages Estimation for Civil Litigation Testimony** – Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages.

## EXPERIENCE

### CIVIL LITIGATION TESTIMONY & SUPPORT

Rebuttal of claims of economic damage associated with the cancellation of a water desalination project in Monterey California.

Prepared an analysis of claims of economic damage associated with the performance of an anaerobic digester designed to provide gas for an electric generation project. Analysis included evaluation of performance, revenues and costs, and cost of capital used to discount projected future earnings. Prepared expert report and testified in jury trial in federal district court.

Developed an analysis of material and labor cost increases on EPC costs for a natural gas fired power plant located in New Mexico. The analysis was used to refute a claim that cost overruns were not reasonable in a cost plus EPC contract. The analysis demonstrated how much of the total project cost increases was associated with labor and material costs beyond the control of the general contractor.

Prepared an analysis of loss of margins at two coal plants during periods when there were alleged violations of EPA opacity emission limits. The analysis demonstrated that client did not receive any economic benefit associated with the periods of alleged violations.

Prepared an analysis of the commercial distributed solar sector in the 2010 – 2011 time frame and demonstration of the unreasonableness of the plaintiff's claims for economic damages associated with the defendant's decision not to pursue participation in an equity fund.

Prepared an analysis of the U.S. wholesale electric power markets in the 2008 – 2010 time frame to demonstrate why the plaintiff's decision to terminate construction of a coal fired power plant was due to cost increases in the EPC contract and not due to the changing natural gas prices and emission laws.

Prepared an estimate of lost margins associated with the extended outage of a Canadian nuclear reactor. The analysis included an estimate of what Ontario wholesale power prices would have been but-for the outage and estimates of the total damages including repair and inspection costs.

Prepared an Expert Report regarding rate making and financial policies of the Southern Minnesota Municipal Power Agency in conjunction with a contract dispute regarding a power contract and investments in new generation resources to serve full requirements customers.

Assisted expert witness by the preparation of a report on how a third party would value the Trans-Alaska Pipeline as part of a property tax dispute with the municipality of Anchorage.

Prepared an analysis of damages associated with claims for losses associated with the interruption of business of a Texas gas-fired power plant as a result of the rupture of a natural gas pipeline use to supply the power plant.

Prepared of an analysis of the economic benefits that accrued to the defendant associated with the purported delay of implementation of measures to correct water pollution discharge violations associated with a power plant.

### ANALYSIS OF RENEWABLE ENERGY INVESTMENTS

Preparation of multiple Independent Market Expert Reports to support financing of community solar projects in Illinois, Maine, Massachusetts, New York, New Jersey, and Maryland.

Prepared an Independent Market Expert Report to support the debt financing of BrightSource Energy's Ivanpah solar thermal projects with purchased power agreements with California investor owned utilities.

Prepared an Independent Market Expert Report to support the debt financing of Solona, a large solar thermal project with molten salt storage, with a purchased power agreement with an Arizona Public Service.

Prepared an Independent Market Expert Report to support the expansion of a CdTe PV manufacturing facility in Colorado including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a c-Si PV manufacturing facility including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a polysilicon manufacturing facility including the analysis of the business plan and projection of long-term prices for polysilicon and the associated raw materials.

Prepared an evaluation of the global market for concentrating solar power plants as of 2012 as part of a client analysis of a potential purchase of a solar mirror manufacturing company.

Prepared an evaluation of the U.S. solar PV market to support evaluation of a Japanese firm's potential expansion in the U.S. markets.

Assisted client with a bid into a utility's renewable energy procurement program. The analysis included an assessment of competitors and analysis of pricing to support the bid of a renewable energy resource into 2011 Entergy RFP for renewable resources.

Prepared long range forecasts of multiple wind portfolios with an emphasis on the valuation of post PPA revenues and the value or renewable energy credits.

Prepared an analysis of the market for future expansion of the wind business of a major U.S. wind developer based upon an assessment of the competitiveness of wind generation with gas fired generation.

Prepared a fair market value analysis of associated with the purchase of a minority position in a wind project located in Ontario, Canada.

Prepared an Independent Market Expert Report to support the debt financing of a geothermal power project located in the Pacific Northwest.

Prepared an Independent Market Expert Report to support the debt financing of the Beacon flywheel energy storage project in New York.

Prepared an Independent Market Expert Report to support the debt financing of the AES battery energy storage project in New York. Development of an Independent Market Expert Report to support the financing of the Kemper IGCC plant including an analysis of the regulatory structures being relied upon to support cost recovery as well as wholesale electric prices to support wholesale power sales.

## UTILITY REGULATORY SUPPORT

Analysis and testimony on behalf of Constellation Energy Group related to typical merger and acquisition conditions required by regulators in utility and non-utility transactions. Testimony related to the EDF / Constellation joint venture.

Testimony related the use and design of ratchet rates on behalf of Northern Indiana Public Service Company. Testimony related to the application of ratchets to the client's unique position and appropriate recovery of costs.

Analysis of the economics of an electric utility's interruptible rates including the value of interruptions versus the payments received by customers. Developed recommendations for pricing interruptible rate programs that were consistent with the utility's avoided costs and ISO markets.

Developed electric cost-of-service studies, rate design, and testimony to support Puget Sound Energy in multiple general rate cases in Washington. The engagements included addressing issues such as special rates for strategic customers with competitive options, line extension policies, and rates to address revenue attrition.

Developed natural gas cost-of-service studies, rate design, and testimony to support Puget Sound Energy in a general rate case in Washington.

Prepared marginal cost of service studies and testimony to support Montana-Dakota utilities in multiple Montana rate cases.

Assist Montana-Dakota Utilities in development of its integrated resource plan through analysis of options using the Strategist planning model.

Supported Montana-Dakota Utilities in answering a complaint in front of the South Dakota Public Utilities Commission regarding a wind generator requesting a contract under the provisions of PURPA.

Provided expert testimony related to Montana Dakota's proposed participation in the Big Stone II power plant. Prepared and delivered testimony provided in multiple hearings in North Dakota and Minnesota.

Prepared testimony on behalf of Hydro One Networks regarding rate shock and how to address necessary rate changes associated with the restructuring of the electric utility business in Ontario.

Developed an analysis or weather risk associated with the retail power sales of IPALCO. Effort was conducted as part of a comprehensive risk assessment conducted by AES. Models of the weather / load relationship were developed and then integrated with the rate structures and cost adjustment mechanisms to assess the utility's overall exposure to weather risk.

Advised Old Dominion Electric Cooperative on options for acquiring new generation in a depressed power market and incorporation of the analysis in their long-term resource planning.

## M&A and BANKRUPTCY ADVISOR

Prepared an analysis of New Mexico Gas Company to support a prospective buyer. We assisted multiple clients with due diligence related to the acquisition of gas LDCs. Assisted the client with a review of the deal model including: assumptions about rate cases, assumptions regarding ROE, sales growth by rate class, and revenue by rate class. The engagement also included an assessment of the regulatory climate and potential conditions and costs associated with obtaining regulatory approval of the transaction.

Prepared a valuation of the Mountaineer Gas Company including the analysis of regulatory issues to support the debt financing associated with the purchase of the energy company.

Assisted an infrastructure fund in valuing power contracts and reviewed the regulatory model used in conjunction with establishing the price to bid for the acquisition of Northwestern Utility.

Prepared an analysis of Duquense Light to support an infrastructure fund's bid for the utility. The analysis included projections of growth opportunities through distribution & transmission investment, analysis of the POLR load obligation, and a review of key regulatory issues.

Developed a valuation model of Mirant including analysis of debt carrying capacity to assist a strategic player in the U.S. Power Industry determine whether to make an unsolicited offer to purchase Mirant.

Assisted an international oil company in development of modelling processes and assumptions to support a corporate effort to acquire a fleet of U.S. merchant generating assets.

Support a strategic player in valuing the Lake Road Generation Plant as part of their bid to acquire the asset in a competitive auction. Effort involved projection of future gross margins of the plant, analysis of the ISO-NE Forward Capacity Market, and analysis of transmission constraints.

Directed the valuation of the entire NRG portfolio on behalf of the bank creditors in the NRG bankruptcy hearings. The valuation work included advising on a range of types of generation assets in the U.S. as well as in Europe, South America, and the Asia-Pacific region. Mr Advised on the fairness of offers for assets being disposed of by NRG. Assisted creditors in the valuation of assets in the NEG bankruptcy including the options for completing unfinished gas-fired generation assets. Served as the interim finance manager for the Lake Road Generation facility.

Member of team that advised Calpine as part of the company's restructuring and plan of reorganization. Assignment included analysis of the Canadian portfolio, advising on the sale of generation assets, modelling of long-term turbine maintenance costs, and the valuation of complex power contract.

Assisted the lenders on valuation and strategy related to AES' turn-back of the Granite Ridge Power Plant to the lender group.

Advised the bank and lender group on valuation and strategy related to the bankruptcy of the Kendall Power Plant.

## ASSET APPRAISALS

Prepared a valuation of a large eastern coal plant as a third party appraiser required in a transaction where the lessee wanted to exercise a buy-back provision in a sale lease-back agreement.

Prepared a valuation of a California cogeneration plant for the purposes of identifying the tax loss.

Completed an appraisal to support the transfer of the Trans Bay Cable from the development arm to a separate fund managed by the infrastructure fund. The appraisal addressed the California power markets, operations of the CA ISO high voltage transmission and a forecast of revenues given the FERC and CA-ISO regulatory schemes as part of the income approach. The appraisal also incorporated a comparable sales and replacement cost analysis.

Developed an appraisal of a nuclear power plant based upon discounted cash flow, replacement costs, and comparable sales as part of an effort to determine the fair market value under a lease agreement that contained a buy-back provision.

Completed multiple appraisals of the KeySpan generation assets on Long Island that were subject to a generation repurchase agreement with LIPA. The appraisals were part of the ongoing process for KeySpan to develop a strategy to address the LIPA repurchase option.

Development of an Independent Market Expert Report to support the financing of the Kemper IGCC plant including an analysis of the regulatory structures being relied upon to support cost recovery as well as wholesale electric prices to support wholesale power sales.

**ELECTRIC GENERATION FINANCE SUPPORT**

Market expert report for the Landfill Energy Systems, a national 66 MW portfolio of fourteen landfill gas power plants. The market expert report included a discussion of the key attributes of each of the power markets that the portfolio encompasses, long-term forecasts of wholesale electricity prices, and forecasts of gross margins.

Independent Market Expert Report to support the financing of the repowering and development of a fleet of combined cycle and simple cycle power plants in the ERCOT market. The independent market expert report was used to support the syndication of loans and obtaining debt ratings associated with investing over $1 billion in the Barney Davis, Nueces Bay, and Laredo Energy Center facilities.

Independent Market Expert Report to support the financing of Sequent Power's purchase of the Wolf Hollow 730 MW combined cycle power plant located in ERCOT. The report was used to support the syndication and rating of over $400M of primary and mezzanine debt. The report incorporated forecast of gross margins for both the contracted and non-contracted portions of the facility as well as providing a detailed description of the ERCOT market conditions and key assumptions to the financial analysis.

Independent Market Expert Report to support the financing of Invenergy's purchase of the partially completed Grays Harbor 620 MW combined cycle power plant located in the Pacific Northwest. The report was used to support the syndication and rating of over $100M of debt. The analysis included valuing both hedged and unhedged positions for the facility and conducting extensive due diligence regarding how NW power markets are likely to evolve and the role of independent power in a market dominated by vertically integrated public and investor-owned utilities.

Independent Market Report to support the refinancing of the Dynegy corporate revolver. The effort included analysis of multiple U.S. power markets, valuation of the fleet of generation assets and associated contracts, and review of regulatory conditions impacting the Company's ability to realize earnings in markets with competitive auctions to serve load.

Multiple forecasts of California power market prices including support of a bid for a cogeneration facility located in the San Francisco Bay area and sale of La Rosita.

Forecast of the New England power markets to support a bid for the First Light Generation Assets.

Forecast of the California and SPP power markets to support a bid for assets from the EIF portfolio.

Analysis of the ERCOT, PJM and MISO markets for multiple bids for merchant gas fired generation plants.

Development of multiple Confidential Information Memorandums to support the sale of power plants. CIMs included description of the wholesale power markets and summaries of the key attributes of the assets to be sold in auction.

Preparation of sale offering of the Audrain power plant in response to Ameren solicitation to acquire new resources. Effort included evaluation of likely competitors and the development of the bid strategy.

Advise on pricing for offering power contracts as well as the sale of gas-fired combined cycle power plant in the South-East. Pricing and sale price based upon projections of the value of the power plant as a merchant unit, assessment of potential competitors, and the analysis of transmission constraints.

**ELECTRIC MARKETS RISK MODELING**

Provided support to a bond insurance company to prepare an assessment of the distribution of income from a fleet of peaking power plants in the South-East. Analysis used to review the provision for loss reserves.

Supported a bond insurance agency in determining the probability that a fleet of Mid-West generation assets would generate insufficient cash to meet debt payments and reserve requirements.

Developed an Excel based model for a mid-west public utility to assist in developing annual targets for the amount of surplus generation capacity to be sold as merchant and in contracts of varying tenor. The model was integrated into the corporate financial model to assist in identifying the appropriate risk profile to support building the reserve fund and to delay future rate increases.

**DSM ADVISORY SERVICES**

Advised Con Edison on the status of electric decoupling and incentive mechanisms in the United States as part of the New York state initiative to reintroduce decoupling.

Advised a private equity fund on the status of demand side management in New England, likely projections of growth, and probability of successful implementation as part of an evaluation of long-term supply and demand conditions in the New England electric markets.

Worked with Montana-Dakota utilities regarding the incorporation of projections of demand side management potential into the utility's long-term resource plan.

## ADDITIONAL EXPERIENCE – EXPERT TESTIMONY

Before the North Dakota Public Service Commission, Direct Testimony & Rebuttal Testimony and Schedules of James A. Heidell, In the Matter of Otter Tail Power Company Advance Determination of Prudence – Astoria Station Onsite Fuel Inventory System, Case No. PU-23-066.

Before the Louisiana Public Commission, Direct Testimony and Schedules of James A. Heidell in Re: Application of 1803 Electric Cooperative, Inc. For Approval of Power Purchase Agreements and For Cost Recovery, Docket No. U-35927.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter of Northern States Power Company Advance Prudence – Heartland Divide II Wind Project, Case No. PU-20-433.

California-American Water Company, a California Corporation; Monterey County Water Resources Agency, Plaintiffs, vs. Marina Cos Water District; RMC Water and Environment, a California Corporation; and DOES 1 through 10, inclusive, Defendants, Case No. CGC-15-546632. Report and Deposition on behalf of RMC Water and Environment addressing alleged economic damages as a result of a cancelled desalination project.

Before the Hawaii Public Service Commission, Direct Testimony of James A. Heidell, Docket No. 2017-0105 In The Matter Of The Application of Hawaii Gas Company Application for a General Rate Increase. Testimony on behalf of Hawaii Gas addressing rate spread and rate design.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Otter Tail Power Company Advance Determination of Prudence Astoria Natural Gas Project, Merricourt Wind Project and Certificate of Public Convenience and Necessity Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, & PU-17-143,

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – Dakato Range Wind Project, Case No. PU-17-372.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – 1,550 MW Wind Portfolio, Case No. PU-17-120.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – BIOMASS APPLICATION FOR DEFERRED ACCOUNTING, Case Nos. PU-17-270, PU-17-271, & PU-17-322.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company A Minnesota Corporation D/B/A XCEL Energy Jurisdictional Cost Allocation Matters, Case Nos. PU-12-813 et. al.

Before the Arizona Corporation Commission, Direct and Settlement Testimony Of James A. Heidell, Docket No. E-01345A-16-0036 and Docket No. E-01345A-16-0123 In The Matter Of The Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return.

Before the Public Utilities Commission of Nevada, Direct and Rebuttal Testimony Of James A. Heidell, Docket No. 16-06006, In The Matter of the Application of Sierra Pacific Power Company, d/b/a NV Energy, Filed pursuant to NRS 704.110(3), addressing its annual revenue requirement for general rates charged to all classes of Electric customers.

Amana Society, Inc. and Amana Farms, Inc. v. GHD, Inc. and Excel Engineering, Inc. Testimony on behalf of GHD, INC regarding the economic performance of a manure digester and evaluation of claims of damages by Amana. Expert Report 2012, Jury Trial September 2012.

Affidavit of James A. Heidell & Mark Repsher, Appropriate Approach to Calculating the Weighted Cost of Capital, Docket No. ER14-2940-0000, U.S. Federal Energy Regulatory Commission, October 15, 2014.

Affidavit of James A. Heidell & Mark Repsher, on behalf of Peabody Energy Corporation to stay the final Clean Power Plan rule, September 9, 2015.

Declaration and report of James A. Heidell & Mark Repsher, Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule, October 16, 2015.

City of Rochester, Minnesota v. Southern Minnesota, State of Minnesota, County of Olmsted File No: 55-C3-05-002712. Testimony on behalf of the City of Rochester regarding the interpretation of a power contract. Testimony and deposition 2008.

Before the Public Service Commission of Maryland, Rebuttal Testimony of James A. Heidell, Case No. 9173, Phase II In The Matter Of The Current And Future Financial Condition Of Baltimore Gas And Electric Company.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony in Northern Indiana Public Service Company's request to raise rates in Cause No. 43526. Testimony on behalf of the utility related to ratchets and other mechanisms appropriate to recover costs allocated to large energy using customer classes.

Before Public Service Commission of the State of North Dakota, Direct and Rebuttal Testimony in Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. On behalf of Montana-Dakota Utilities. 2007 & 2008. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2010.8.82. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2007.7.79. On behalf of Montana-Dakota Utilities.

Before the Minnesota Public Utilities Commission, Direct and Rebuttal testimony on behalf of Montana-Dakota Utilities regarding a Certificate of Need for the Big Stone II Power Plant, Docket No. CN-05-619. On behalf of Montana-Dakota Utilities.

Before the Ontario Electric Board, Expert Report regarding the 2006 Electric Rate Distribution Handbook and Rate Mitigation, on behalf of Hydro One Networks, Inc. January 2005.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2004 General Rate Case Regarding Electric Cost of Service & Rate Design and Gas Rate Design, April 2004. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2001 General Rate Case Regarding Electric Cost of Service & Rate Design, November 2001. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Testimony Regarding the Need for a Special Competitive Rate for Intel. Docket No. UE-960299, 1996. On behalf of Puget Power.

Before the Washington Utilities and Transportation Commission, Rebuttal Testimony in the Merger of Puget Power and Washington Natural Gas Regarding Electric Rates, Docket Nos. UE-95-1270 & UE-960185, 1995. On behalf of Puget Power.

# EXHIBIT HEIDELL-DIRECT-2

# Silverhawk Cost Review

Prepared for NV Energy

February 5, 2025

Bringing Ingenuity to Life.
paconsulting.com

**Denver Office**

PA Consulting Group Inc.
Suite 3550
1700 Lincoln Street
Denver
CO 80203
USA
+1 720 566 9920

**paconsulting.com**

**Prepared by: PA Consulting**

**Reference: P081781**

**Version: 1**

# Contents

# Figures



# Tables

# License Agreement

PA Consulting Group, Inc. ("PA") has prepared this Report (the “Report”) for the use of NV Energy (“NV Energy”, or the “Client”) solely with respect to support a cost review of the Silverhawk Capacity Project (“Silverhawk” or the “Asset”) located in NV Energy’s service territory (the “Cost Review”). PA has agreed that the Client may share this Report with their officers, directors and employees; the officers, directors and employees of their subsidiaries and affiliates; their advisors; and certain other third parties, namely, the Public Utilities Commission of Nevada (“PUCN”), in each case who have a need to review the Report for the purpose of their understanding of Silverhawk’s costs (each an “Authorized Third Party”). Review or use of this Report by any other party or for any other purpose is strictly prohibited and must be authorized by PA in writing. All use and reliance on this Report by any Authorized Third Party is subject to the following terms and conditions.

- No Authorized Third Party may change, alter, or adapt the Report or further distribute the Report. Authorized Third Parties shall be subject to confidentiality obligations to the Client, which obligations require, among other things, such Authorized Third Parties to keep the Report confidential.
- Authorized Third Parties acknowledge that the Report is not an audit and was not undertaken to express a financial opinion or to provide investment advice, and that PA does not express an opinion on the financial information (or any other information) contained in the Report. Authorized Third Parties further acknowledge that had PA performed additional due diligence beyond the agreed-upon scope of work, other matters might have come to its attention that would have been reported.
- Authorized Third Parties acknowledge that: (i) some information in the Report is necessarily based on predictions and estimates of future events and behavior; (ii) such predictions or estimates may differ from that which other experts specializing in the electricity industry might present; (iii) PA’s analysis and findings are current as of the date of the Report and, where applicable, incorporate underlying market data as of September 3, 2024; (iv) the provision of a Report by PA does not obviate the need for the Client or the PUCN to make further appropriate inquiries as to the accuracy of the information included therein, or to undertake an analysis on their own; and (v) the Report is not intended to be a complete and exhaustive analysis of the subject issues and therefore will not consider some factors that are important to understanding the entirety of Silverhawk. Nothing in the Report should be taken as a promise or guarantee as to the occurrence of any future events.
- Authorized Third Parties release PA from any claims arising from their review, use of or reliance on the Report, including by way of example only, any claim for the negligent provision of information. In no event and under no circumstances shall PA be liable to Authorized Third Parties for any principal, interest, loss of anticipated revenues, earnings, profits, increased expense of operations, loss by reason of shutdown or non-operation due to late completion, or for any consequential, indirect or special damages.

# 1 Executive Summary

NV Energy ("NV Energy" or the "Client") engaged PA to serve as a third-party reviewer of the construction costs associated with the Silverhawk Capacity Project (Silverhawk). Silverhawk includes the addition of two 220 MW combustion turbines (CTs) and associated facilities at the existing Silverhawk Generating Station, providing new capacity resources for NV Energy. The initial construction budget completed in July 2022 indicated an expected build cost of ~$353mm for Silverhawk (inclusive of CTs, balance of plant, and required switchyard upgrades) with an accuracy of -30% to +50% based on the cost estimate classification. The cost estimate was subsequently revised to a firm build cost estimate of ~$515mm in December 2023. PA understands that the actual cost costs to complete[1] the project will be ~$514mm[2]. Silverhawk achieved its commercial operation date (COD) in July of 2024.

PA's third-party review summarized in this report encompasses 1) a review of the project to evaluate the factors that contributed to the cost increases, 2) an assessment of NV Energy's approach to key decision making throughout the project with respect to management of cost, and 3) an evaluation of whether the cost increases are in-line with cost trends in the industry.

*Table 1-1: Summary of the Asset*

| Asset | Technology Type | Commercial Operation Date | Summer Rated Capacity (MW) | Location |
|---|---|---|---|---|
| **Silverhawk Capacity Project** | 2 x GE 7FA.05 | July 2024 | 440 | Nevada Power Region |

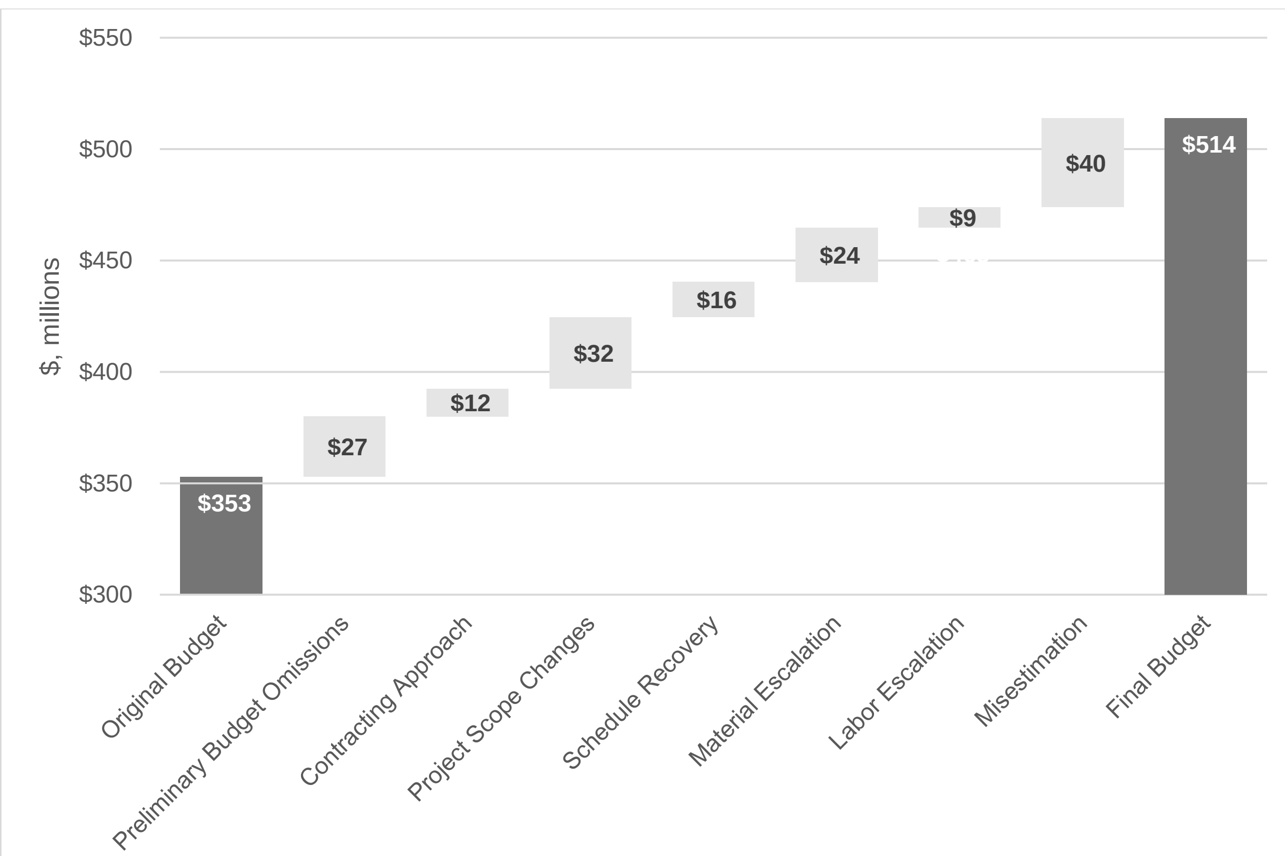
[1] As of January 17, 2025, PA understands Silverhawk is expected to be completed at a total cost of no more than $514mm per NV Energy's most recent reported budget.
[2] Budget values shown do not include AFUDC, which is outside the scope of PA's Silverhawk review.

## Key Findings

PA's review of the project costs and key decision making associated with Silverhawk resulted in the following key findings:

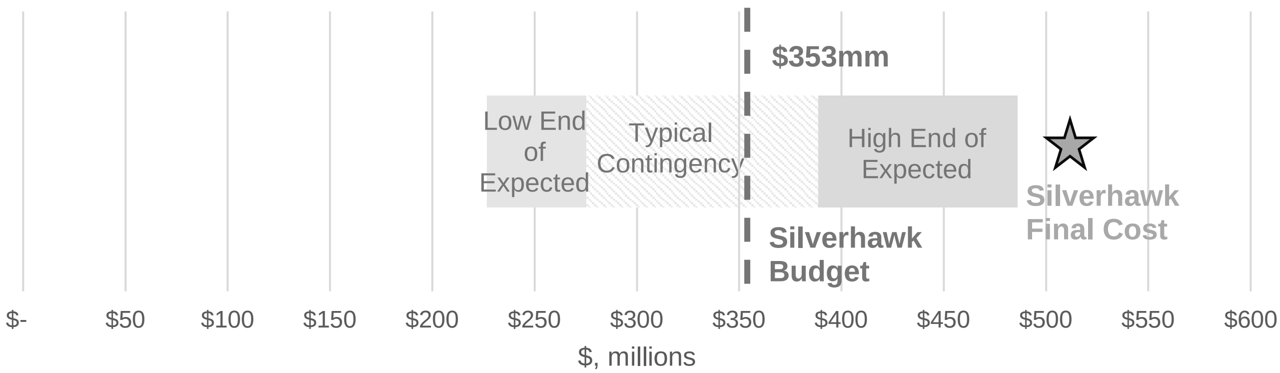
- **Silverhawk's forecasted cost increased approximately $161mm from the original Power Engineers (POWER) cost estimate to the final project budget.** PA found the key drivers of this increase, as shown in Figure 1-1, to be:
  - Preliminary Budget Omissions ($27mm) – Cost which was omitted from the original cost estimate developed by POWER and used for budgeting by NV Energy.
  - Contracting Approach ($12mm) – Cost which were incurred as a result of the multi-contract strategy used to execute the project which would not have been expected under a traditional Engineering, Procurement, and Construction (EPC) contract arrangement.
  - Project Scope Changes ($32mm) – Cost associated with adjustments to the project scope as executed when compared to the scope understood to be budgeted for in the original cost estimate.
  - Schedule Recovery ($16mm) – Cost which was incurred to construct the project more quickly than typical in order to meet the required in-service date for Silverhawk following a 3-month permitting delay.
  - Material Escalation ($24mm) – Increased cost due to inflation of materials as compared to the overnight cost assumptions included within the original cost estimate.
  - Labor Escalation ($9mm) – Increased cost due to inflation of labor as compared to the overnight cost assumptions included within the original cost estimate.
  - Misestimation ($40mm) – Cost in excess of the original budget not attributable to one of the other six categories. Variance between estimates and actual costs is to be expected in any complex cost estimate.

*Figure 1-1: Silverhawk Cost Waterfall – Original Budget to Final Budget*



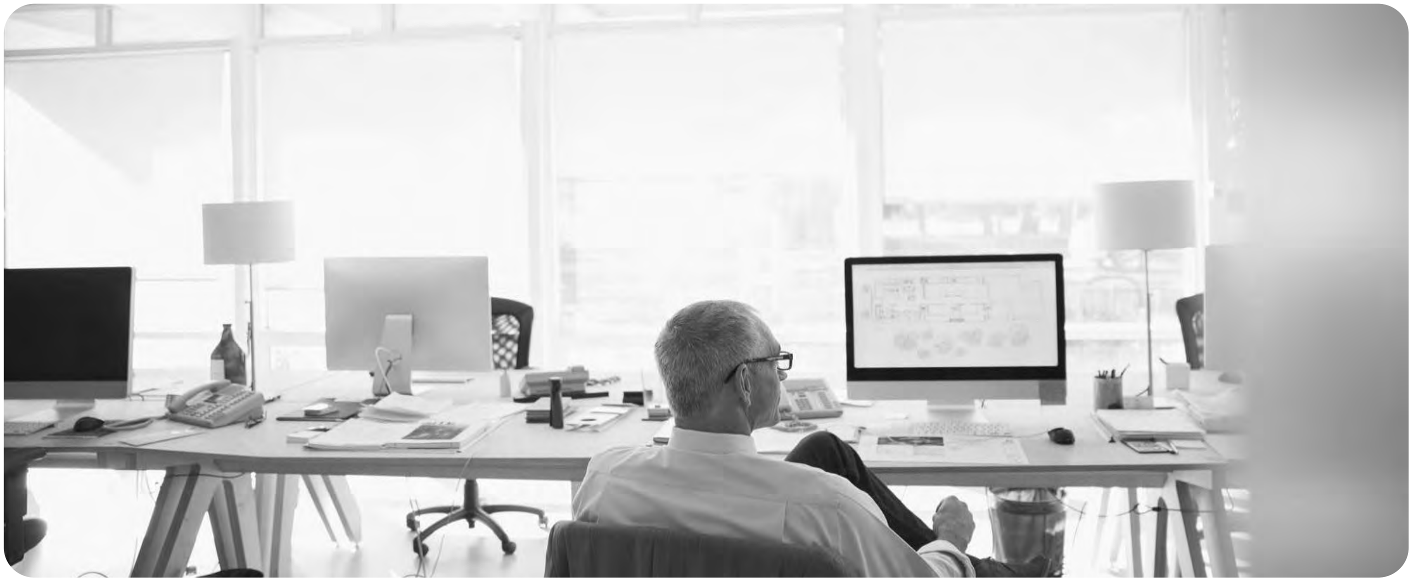
- **Silverhawk's forecasted completion cost of $514mm is approximately 6% above the expected uncertainty band of the Class 4 cost estimate[3] originally produced by POWER.**
  - While Silverhawk costs increased materially during project development, the final cost is only marginally outside the accepted range of accuracy for the cost estimate as shown in Figure 1-2. PA notes that 20% of projects are anticipated by AACE[4] to fall outside of the accepted range.

*Figure 1-2: POWER Class 4 Silverhawk Estimate vs Final Budgeted Cost*




- **Given the project cost escalation information and NV Energy's projected ratepayer benefits, PA is of the opinion that NV Energy's decisions to proceed with Silverhawk at key points were prudent.**
  - In May 2023, the first major cost increase was identified when the general contractor (GC) agreement with ARB/Primoris (ARB) was estimated at approximately $126mm, materially more than initially budgeted.
    - NV Energy subsequently reviewed both Silverhawk's value for upcoming 2024 and 2025 summer seasons (seeking to understand the impact of delay) and the comparison of Silverhawk to alternatives outlined in the fourth amendment of the 2021 Integrated Resource Plan (IRP) (seeking to understand if a different resource could better serve ratepayers).
    - Based upon the analysis completed, NV Energy confirmed that proceeding with Silverhawk was the most prudent option available to meet reliability needs during peak season.
  - In November 2023, the second major cost increase materialized when the firm fixed bid from ARB came in at approximately $180mm, an increase of $54mm from the earlier estimate.
    - NV Energy subsequently received independent evaluations from both Sargent & Lundy and POWER (seeking to understand the market competitiveness of the current cost projection), assessed the potential cost saving of delaying Silverhawk's COD, reviewed Silverhawk's value for the upcoming 2024 summer season, and compared Silverhawk to alternatives outlined in the fourth amendment of the 2021 IRP.
    - Based upon the evaluations noted above, NV Energy concluded that the most appropriate action was to proceed with Silverhawk and executed the firm fixed contract with ARB.
- **Silverhawk's cost is reasonable when compared to relevant National Renewable Energy Laboratory (NREL) and US Energy Information Administration (EIA) cost benchmarks.**
  - Silverhawk's budgeted cost at completion of $514mm for a 440-MW project implies a cost of $1,170/kW which is within approximately 2% of the relevant benchmark from NREL and within the range of relevant CT benchmarks available from the EIA.

[3] PA understands that use of a Class 4 estimate is not atypical during the initial stages of project budgeting before key contracts have been awarded and detailed design work has begun.
[4] Association for the Advancement of Cost Engineering (AACE) is an internationally recognized organization which sets standards and seeks to advance the field of cost engineering.



# 2 Project Background

NV Energy as a vertically integrated utility and load serving entity (LSE), has an obligation to plan for and procure adequate generation resources to meet anticipated customer peak demand and energy use. NV Energy maintains a Resource Planning group and a Generation group in order to project and fulfill these obligations. The utility undergoes an IRP process that includes modeling and forecasting electric demand and the appropriate set of generation resources to meet the energy and capacity requirements. As part of this process the utility collaborates with stakeholders and the Public Utilities Commission of Nevada (PUCN). The need for new generation capacity to meet load growth was identified in this planning process along with the decision to construct new CTs at the Silverhawk generation site. PA's review did not involve any assessment of the decision to build the CTs. Our review started with the process to build the CTs.

## 2.1 NV Energy Generation Development

NV Energy has historically developed and constructed power generation projects to serve native load requirements. The Generation group is responsible for executing on the development and construction of new resources which are determined to be necessary within the then-current IRP, as well as operating and maintaining the existing generation fleet.

### 2.1.1 Past Projects & Internal Capabilities

NV Energy has limited recent experience in the development and construction of conventional power plants. An overview of the conventional power plants owned by NV Energy which entered operations in the last 30 years[5] is shown in Table 2-1.

[5] NV Energy's more recent development and construction experience is associated with solar and storage projects which have been developed in the past decade.

*Table 2-1: NV Energy's Past Generation Projects*

| Name | Technology | Fuel | Operating Capacity (MW) | Online Year |
|---|---|---|---|---|
| **Harry Allen Generating Station** (Units 5 / 6 / 7) | Combined Cycle | Natural Gas | 524 | 2011 |
| **Frank A. Tracy Generating Station** (Units 8 / 9 / 10) | Combined Cycle | Natural Gas | 578 | 2008 |
| **Edward W. Clark Generating Station** (Units 11 – 22) | Combustion Turbine | Natural Gas | 684 | 2008 |
| **Chuck Lenzie Generating Station** (Units 1 / 2) | Combined Cycle | Natural Gas | 1,202 | 2006 |
| **Harry Allen Generating Station** (Unit 4) | Combustion Turbine | Natural Gas | 84 | 2006 |
| **Silverhawk Power Project** | Combined Cycle | Natural Gas | 599 | 2004 |
| **Walter M. Higgins Generating Station** (Units 1 / 2 / 3) | Combined Cycle | Natural Gas | 600 | 2004 |
| **Las Vegas Generating Station** (Units 2 / 3) | Combined Cycle | Natural Gas | 230 | 2003 |
| **Frank A. Tracy Generating Station** (Units 4 / 5) | Combined Cycle | Natural Gas | 108 | 1996 |
| **Harry Allen Generating Station** (Unit 3) | Combustion Turbine | Natural Gas | 84 | 1995 |

The most recent conventional power generation project completed by NV Energy was the Harry Allen Expansion (Units 5 / 6 / 7), a combined cycle gas turbine (CCGT) which began operations in 2011. Through discussions with the Generation group, PA understands that the key personnel at NV Energy who developed and oversaw construction of the Harry Allen Expansion are no longer with the company. The most recent CT plant which was developed by NV Energy entered operations in 2008. Therefore, there is limited direct experience developing and constructing gas-fired generation assets at NV Energy within the Generation group today.

PA does not find this to be atypical within the industry, given a multitude of factors including an aging work force, the changing nature of generation technologies being deployed, and the relative volume of projects required within the service territory. PA notes that it is to be expected that the Generation group does not maintain a full staff of personnel with deep experience developing and constructing each type of generation resource which may be required in the future. Similar to other utilities, it is expected that NV Energy would rely on outside resources (e.g., engineering firms) to leverage the latest technological trends, market conditions, and construction realities at the time a particular new project is considered. As further explained in this report, NV Energy hired an Owner's Engineer (OE) to oversee the design and construction of

Silverhawk, as well as specialist procurement support and engineering support from firms that are active in the CT market today and able to leverage their latest experience.

### 2.1.2 Company Policies & Procedures for Generation Projects

NV Energy maintains policies and procedures which are required to be adhered to during the planning and execution of projects by the Generation group. The Capital Projects Policy[6] and the corresponding Capital Projects Procedure[7] were identified as the most pertinent to the development of Silverhawk and therefore reviewed by PA.

The Capital Projects Policy outlines NV Energy's overall philosophy for capital projects associated with generation which is to identify and budget for projects as early as practical, with opportunity for inclusion of emerging projects throughout a given year as deemed necessary. The policy identifies and defines the roles and responsibilities of key personnel associated with a given project including the project manager, project owner, and project controls lead. The policy provides specific guidance with respect to levels of estimating accuracy and risk to be applied (contingency) within Authorizations for Expenditures (AFEs) – 50% at Scoping, 25% at Planning, 15% at Design, and 5% at Construction. The policy provides specific guidance for projects which are modifications to generation facilities or replacement-in-kind, with no direct guidance or mention of wholly new generation projects which may be larger and more complex in nature.

The Capital Projects Procedure outlines the key steps, requirements, and responsibilities associated with each process which must be followed for a generation capital project. The overall project workflow is broken down into five main processes:

1. Initiate Project
2. Perform Preliminary Engineering
3. Execute Project
4. Control Project
5. Close Project

Within each of the five main processes, the procedure includes process diagrams for a variety of sub-processes which should be followed. The processes described and the details included within the procedure are most aligned with capital projects at existing power generation facilities rather than wholly new generation projects; However, the procedures and workflows outlined do appear to be usable for larger-scale projects with appropriate interpretation.

Included within the various processes are specific requirements for budget approval (via an initial or supplemental AFE). The procedure also explicitly defines the signature authority for particular AFEs based upon budget, wherein the VP of Generation is the signatory for up to $5 million, the CEO of NV Energy is the signatory for up to $50 million, and all requests in excess of $50 million require approval by the CEO of Berkshire Hathaway Energy (BHE, NV Energy's parent company). No specific regulatory approvals are directly identified within the procedure, and it is understood that these would be considered by the signatory in considering their approval of the relevant AFE for any given project.

PA is of the opinion that NV Energy's policy and procedures for capital projects within the Generation group as described above are reasonable and consistent with typical industry practices.

## 2.2 Silverhawk Project

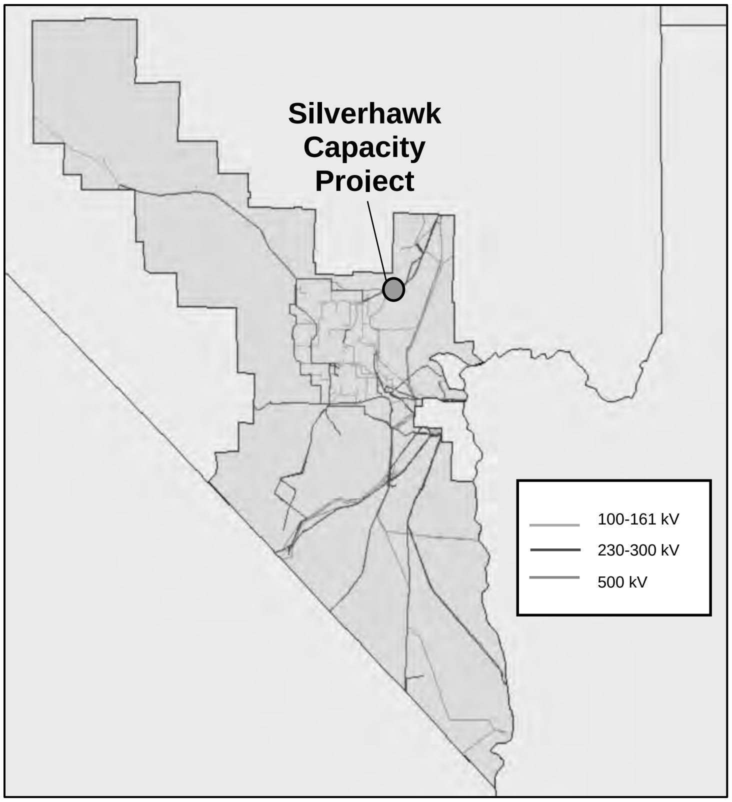
NV Energy's Resource Planning group identified a need for additional dispatchable resources to meet summer peak loads. In the summer of 2021, NV Energy's peak open position exceeded 1,000 MW which was managed through market purchases. To minimize price fluctuations and manage the risk of regional supply shortfall, Resource Planning initiated an exploration of new dispatchable resource options in June of 2021.

[6] GMP-228: NV Energy Generation Policy, Capital Projects Policy, REV 0 (02/08/2021)
[7] GMP-228-001: NV Energy Generation Procedure, Capital Projects Procedure, REV 0 (02/08/2021)

## 2.2.1 Identification

As NV Energy evaluated dispatchable resource options to reinforce system reliability, the addition of gas-fired generating units at various potential sites was considered. The screening of sites included a number of existing NV Energy power generation sites including Higgins, Silverhawk, Lenzie, Reid Gardner, Clark, Sun Peak, and Harry Allen. A variety of CT technologies were considered, with a focus on aeroderivative units given their availability at the time (supply chain issues were noted with larger frame units). Silverhawk, shown in Figure 2-1, was identified by NV Energy as the most appropriate site to install the new gas-fired resources via this internal site screening process.

*Figure 2-1: Location of the Asset*




## 2.2.2 Intended Execution Approach

NV Energy planned to complete Silverhawk via a traditional EPC approach. Under this method, which is typical for utilities, the utility would be expected to first contract with a professional engineering firm to serve as an OE. The OE would then support the utility in the initial design development, technical elements of contract negotiation (equipment and other suppliers), and oversight of detailed design, construction, and commissioning activities. The utility would typically then be expected to engage with select major equipment providers and enter agreements for the supply of the largest equipment (likely limited to CTs and associated equipment plus high-voltage components such as transformers or breakers). Lastly, the utility would be expected to complete a bid process for an EPC contractor who would be responsible for the detailed design of the facility, procurement of most equipment and materials, construction, and commissioning of the plant.

Under this approach, the EPC contractor is relied upon to bring scale and recent / ongoing expertise to bear to deliver the power plant project more efficiently than can be reasonably expected of the utility itself which does not constantly develop and construct such projects. Utility staff and the OE serving as the utility's representative provide active oversight and management throughout the project, though a significant portion of the responsibilities of execution are delegated via contract to the EPC contractor and the major equipment suppliers.

As discussed later in this report, NV Energy was not able to follow a traditional EPC approach as intended given the required project schedule and availability of suitable EPC contractors.

# 3 Project Timeline & Key Decisions

NV Energy selected the site of the existing Silverhawk Power Project for potential expansion in October of 2021 after the need for additional firm capacity was identified within the 2021 IRP. PA reviewed documentation that highlights the key activities and decisions which occurred during the development and construction of Silverhawk from October 2021 through July 2024 when the project achieved COD. An overview of the Silverhawk project is shown in Figure 3-1.

PA has deconstructed the project into three phases for the assessment of activities and decisions made by NV Energy: the planning phase, the contracting phase, and the construction phase. Critical analysis, commitments, and decisions were made by NV Energy during each of these phases which ultimately led to Silverhawk achieving COD in July 2024 at an increased cost from the originally anticipated budget.

## 3.1 Planning Phase

The planning phase of the Silverhawk project began in October 2021 with the decision to move forward with evaluation of a potential addition at the site to serve as a gas-fired peaking resource. The site was chosen given location, space availability, transmission adequacy, and natural gas availability. Technology selection had not yet occurred, and both aeroderivative and frame units were to be considered for installation.

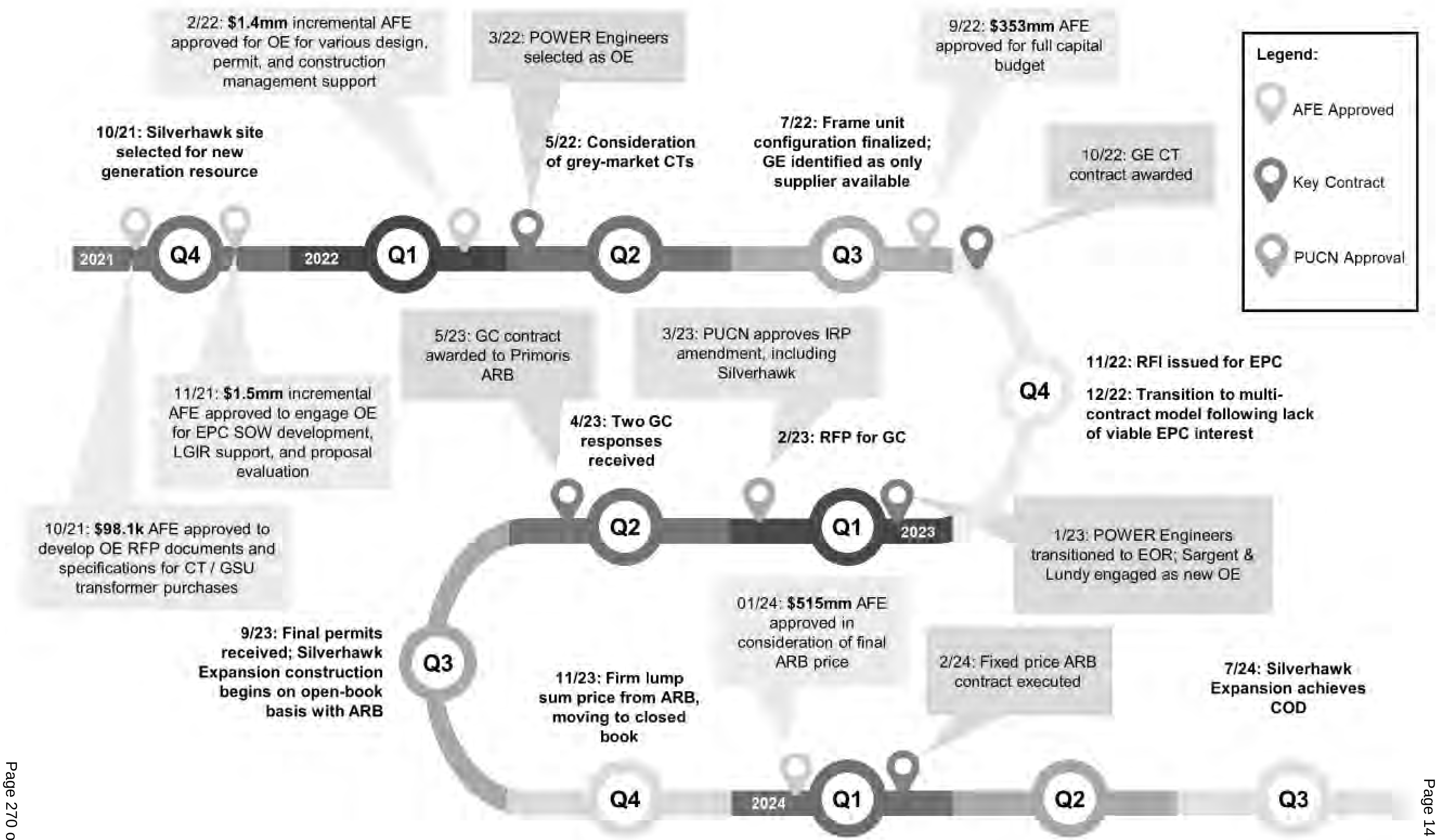
NV Energy's first AFE associated with Silverhawk was approved in October, 2021 enabling the development of a scope of work and RFP documents for owner's engineering services and to develop the specifications for purchase of the required combustion turbines and generator step up transformers (GSUs).

In November of 2021, a second AFE was approved to expand the OE scope to include development of the project scope of work required to contract with an EPC, prepare documents for the Large Generator Interconnection Request (LGIR), support the IRP amendment associated with Silverhawk[8], and support NV Energy's evaluation of proposals for CTs and GSUs.

In February of 2022, a third AFE was approved to further expand the OE scope to include conceptual design of BOP equipment, prepare site plans for CTs / GSUs / switchyard modifications, provide engineering support for permitting, provide engineering support for interconnection, define scope of work for natural gas interconnection, and ultimately provide construction management services during construction of Silverhawk.

[8] Filed as Docket No. 22-11032, for approval of the fourth amendment to NV Energy's 2021 Joint IRP

*Figure 3-1: Silverhawk Development & Construction Timeline*



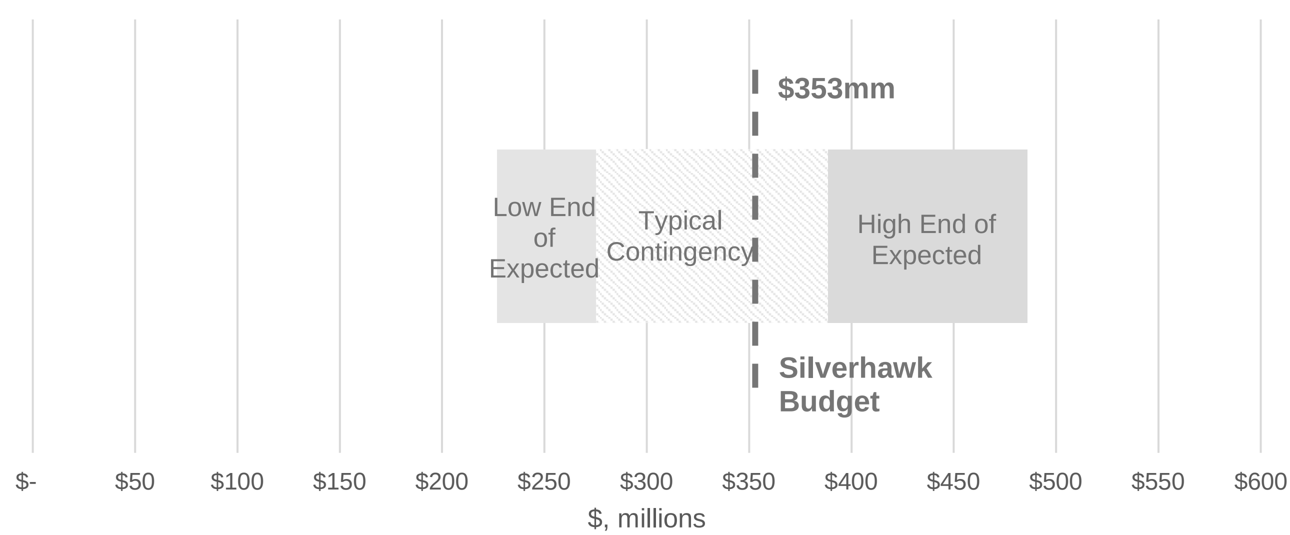
In March of 2022, POWER Engineers (POWER) was selected to serve as the OE and facilitate NV Energy's development of the new peaking resource at Silverhawk. POWER immediately began supporting the team at NV Energy in the planning at Silverhawk, including with the development of preliminary project cost estimates and the selection of aeroderivative vs frame unit technology.

In May of 2022, NV Energy identified GE 7F units which were placed on the grey market by Calpine and saw an opportunity to both satisfy Silverhawk project needs and benefit ratepayers. Negotiations were initiated to pursue these CTs, but they fell out of the market in early June. This represented a brief excursion from the typical approach of procuring CTs directly from a major OEM. PA does not believe this excursion to potentially use grey market CTs materially impacted the schedule or cost of Silverhawk.

In July of 2022, NV Energy decided to install hydrogen-capable frame units as the technology of choice at Silverhawk, future-proofing the infrastructure and avoiding operational challenges associated with deploying a large count of aeroderivative units. POWER delivered a preliminary project cost estimate at this time, estimating a cost of $353mm[9] at a Class 4 accuracy[10]. The estimate from POWER included a total of approximately $311mm for an EPC contractor (including major equipment and contingency) and $42mm of owner's costs to be borne by NV Energy (including contingency). PA notes that approximately $29mm of contingency was included (approximately 9%), resulting in a contingency-free budget of $324mm to complete Silverhawk.

Figure 3-1 depicts the Silverhawk cost estimate produced by POWER and the ultimate cost range expected for projects using a Class 4 estimate. POWER indicated that this level of estimate should be expected to have a final cost range of 15-30% under on the low end and 20-50% over on the high end which PA understands to be in line with AACE guidance. PA further understands that AACE Class 4 estimates are intended to have approximately 80% of estimated projects fall within these cost bands, meaning that up to 20% of projects may exceed the lower or upper bounds shown here. Given the class of estimate completed, the estimate classification indicates that there should be an 80% likelihood of the Silverhawk project ultimately costing between approximately $226mm and $486mm.

*Figure 3-2: POWER Class 4 Silverhawk Estimate*




Leveraging the POWER estimate for Silverhawk, NV Energy completed financial planning and budgeting activities while the execution plan for constructing the plant was refined in parallel. In mid-September of 2022, an AFE was submitted covering the full anticipated project budget of $353mm. Given NV Energy's procedures for large generation projects, the approval of BHE's CEO was sought.

The final contract with General Electric Company (GE) for the provision of the CTs, SCRs, and associated equipment was signed by GE on September 27, 2022 and subsequently delivered to NV Energy. This

---

[9] Excludes AFUDC; AFUDC not included within estimates or actuals presented in this report.
[10] Class 4 as defined by Association for the Advancement of Cost Engineering (AACE)

contract included a total budget of approximately $182mm (excluding tax) for GE-supplied equipment, $14mm more than budgeted for in the POWER estimate (which included $168mm for this equipment). PA notes that this budget change was not reflected in the $353mm AFE request approved by NV Energy three days later.

Authority to approve the Silverhawk project was delegated by BHE's CEO to NV Energy's CEO, who subsequently approved the project to proceed on September 30, 2022.

## 3.2 Contracting Phase

The contracting phase of the Silverhawk project began in October 2022 immediately after the approval of the full-budget Silverhawk AFE by NV Energy's CEO. During this phase, NV Energy anticipated executing two key agreements: a supply agreement for CTs from GE and an EPC agreement to provide detailed engineering, procurement, and construction services for the project.

NV Energy executed a contract on October 3, 2022 for the provision of CTs, SCRs, and associated equipment by GE. The contract had been slated for execution in August but was delayed due to ongoing negotiations. This contract finalized the major equipment selection and positioned NV Energy to be able to move forward with delivery of Silverhawk.

By mid-October of 2022, NV Energy initiated discussions with potential EPC contractors to understand availability to meet the required schedule (which included a summer 2023 start date and COD by July 2024, roughly a 14-month construction period). Discussions initially included Black & Veatch, Burns and McDonnell, and Kiewit. Black & Veatch and Burns and McDonnell were not interested due to the schedule and existing project commitments; Kiewit was interested in receiving the formal RFI when available. NV Energy issued an RFI in November to 10 potential EPC partners and had follow-up discussions with each potential bidder including Kiewit, ARB/Primoris, Relevant Power Solutions, Gemma, Sundt, Haskell, The Ross Group, Ryan Mechanical, MasTec, and Yates.

As EPC discussions were ongoing in November of 2022, the Title V permit was submitted to the EPA requesting Authority to Construct at Silverhawk. This permit application was originally intended to be submitted in July, was ready for submission in August, but was delayed until November given that the project was not yet public. The submission was timed to coincide with NV Energy's filing of an IRP Amendment[11] with the PUCN which included the regulatory approval request for Silverhawk.

By December of 2022, none of the potential EPC partners expressed in interest in the project given the required schedule. Rather than proceed with a formal RFP for an EPC contractor when no clear interest had been identified, NV Energy shifted strategy. Instead of contracting with a single EPC vendor, NV Energy would engage separate firms for design engineering, construction, procurement, project management, and construction management; NV energy would also take on more direct project management and oversight internally than typical for a project delivered via a traditional EPC contract approach.

In January of 2023, the first tranche of contracts was executed with suppliers to deliver on the new construction strategy. To expedite detailed design and engineering, POWER transitioned from the OE role to become the engineer of record (EOR) and perform detailed design services. Sargent & Lundy was contracted to backfill the OE role, providing independent reviews and support as NV Energy's representative. Given the expanded direct procurement that would need to be undertaken by NV Energy, IEM Energy Consultants (IEM) was hired to work closely with the NV Energy team to provide procurement services, construction management, and commissioning support.

In February of 2023, an RFP was issued to identify a GC for Silverhawk. The RFP was issued to ARB, HPI, and The Ross Group and each bidder attended a pre-bid site walk which included discussion of required scope and schedule for the project.

The PUCN approved the development of Silverhawk in March 2023 through NV Energy's IRP Amendment, finding that "the Silverhawk Peaking Plant is necessary for reliable electric service in both the short and the long term."

Proposals for the GC role were received in April of 2023 from ARB and The Ross Group. NV Energy determined during initial evaluation that the proposal from The Ross Group was "technically unacceptable"

[11] Filed as Docket No. 22-11032, for approval of the fourth amendment to NV Energy's 2021 Joint IRP

in that it was incomplete in required details to evaluate. Negotiations began immediately with ARB and the GC contract was awarded to ARB in May. Given that engineering design was still at less than 15% complete, the contract with ARB was structured to be on an open book basis until the engineering design reached a level of at least 60% complete. This allowed for construction to begin to meet the required schedule as engineering work continued in parallel. At the time of the open book contract signing, ARB estimated their work as GC would have a total cost of approximately $126mm.

Given this new cost information, NV Energy initiated a review of Silverhawk to evaluate the current cost and schedule expectations in the context of the asset's value to ratepayers in reducing market purchases of energy during the summer peak season. To inform decision making with respect to Silverhawk, NV Energy conducted two key evaluations:

- **Review of Silverhawk's value for upcoming 2024 and 2025 summer seasons, seeking to understand the impact of delaying the project.** Delay or cancellation of Silverhawk was estimated by NV Energy to lead to an additional cost of over $88mm in capacity market purchases during the 2024 and 2025 summer seasons[12].
- **Review of Silverhawk as compared to alternatives outlined in the fourth amendment of the 2021 IRP, seeking to understand if a different resource could better serve ratepayers.** Despite the increased cost forecast for Silverhawk, NV Energy's analysis concluded that it remained "the most cost-effective solution among all the options presented in the IRP amendment."

Based upon the internal review and analysis completed, NV Energy's internal analysis confirmed that proceeding with Silverhawk was the most prudent option available to meet reliability needs during peak season.

**PA is of the opinion that NV Energy took appropriate steps to consider the impact of elevated Silverhawk cost in light of the new cost information available from the GC. Given the estimated market purchase costs and lack of better alternatives, PA believes that the decision to move forward with the construction of Silverhawk at this time was prudent.**

## 3.3 Construction Phase

The construction phase of the Silverhawk project began in September 2023 immediately after receipt of the required Utility Environmental Protection Act (UEPA) permit from PUCN. NV Energy indicated that the UEPA permit was delayed due to several factors including the need for a special use permit from Clark County and complexities related to drainage studies and the grading permit. PA notes that construction at Silverhawk had been intended to start in June and it appears that the permitting challenges experienced further compressed the required construction schedule. ARB began construction activities with an aggressive site work schedule that sought to counteract the delayed start date.

In November of 2023, ARB provided a final lump sum estimate to complete the work following receipt of 60% engineering designs. The lump sum price quoted by ARB was $180mm, an increase of approximately $54mm from the indicative bid provided in May 2023 which was the basis of beginning open book construction at Silverhawk. The updated ARB proposal included mechanical completion dates in late May and early June for the two units, allowing for a path to COD by July 1 of 2024.

Given the substantial cost increase, NV Energy initiated a comprehensive review of Silverhawk. To inform decision making with respect to Silverhawk, NV Energy conducted (or commissioned) four key evaluations:

- **Independent evaluation of total project cost by both Sargent & Lundy (OE) and POWER (EOR), seeking to understand the market competitiveness of the current cost projection and confirm full required scope was reflected.** Sargent & Lundy provided a report which outlined some of the reasons for cost increases at Silverhawk; NV Energy indicated that Sargent & Lundy and POWER both confirmed that the updated estimate was accurate and complete.

[12] Assessment of NV Energy's analysis of the cost of short-term capacity purchases that would be required absent Silverhawk achieving COD in the summer of 2024 was beyond the scope of PA's cost review.

- **Assessment of the potential cost savings associated with delaying Silverhawk's COD, allowing the pace of construction to be reduced.** NV Energy determined that delaying the project would not reduce costs materially, particularly given fixed costs, contractual obligations, supply chain and labor uncertainties, and opportunity costs associated with not having the asset for summer 2024.
- **Updated review of Silverhawk's value for upcoming 2024 summer seasons, seeking to understand the impact of delaying the project.** Using current market data available in January 2024, NV Energy estimated that filling the capacity position left open without Silverhawk could cost as much as approximately $180mm for summer 2024.
- **Updated review of Silverhawk as compared to alternatives outlined in the fourth amendment of the 2021 IRP, seeking to understand if a different resource could better serve ratepayers.** NV Energy confirmed that Silverhawk, with elevated construction cost, was still the best alternative resource available (noting that other CT build options would be impacted by similar cost challenges).

Based upon the evaluations noted above, NV Energy concluded that the most appropriate action was to proceed with Silverhawk and executed the firm fixed contract with ARB.

**PA is of the opinion that NV Energy took appropriate steps to consider the impact of elevated Silverhawk cost in light of the new cost information available from the GC. Given the estimated market purchase costs, lack of better alternatives, and low likelihood of cost savings via project delay, PA believes that the decision to move forward with the construction of Silverhawk at this time was prudent.**

In January of 2024, a revised AFE reflecting the ARB contract was approved at a total Silverhawk budget of approximately $515mm. The fixed price contract with ARB was subsequently executed in February for a total value of approximately $180mm.

In April of 2024, NV Energy provided a briefing to PUCN staff which discussed the magnitude and nature of the cost deviations which had occurred at Silverhawk. The revised budget of $515mm was shared with PUCN staff, along with descriptions of the decision-making process and analysis that NV Energy had undertaken to conclude that continuing with the project was the prudent decision.

The first unit at Silverhawk connected to the grid on June 30th and achieved COD on July 13th. The second unit was connected to the grid on July 14th and achieved COD on July 23rd. While the project extended past these dates to reach final completion[13], both units at Silverhawk reached commercial operations within two to three weeks of the original schedule which enabled the facility to contribute to NV Energy's delivery of service reliability in the summer of 2024 as originally planned. NV Energy has estimated that the slight delay in reaching commercial operation may have reduced the forecasted $180mm benefit by approximately $29.8mm ($10.5mm for U4 and $19.3mm for U3).

[13] As of January 8, 2025, PA understands that Silverhawk is expected to reach final completion, inclusive of both generation and interconnection facilities, in late 2025. NV Energy indicated that ring bus completion is the primary outstanding item which will continue until late 2025.

# 4 Drivers of Increased Cost

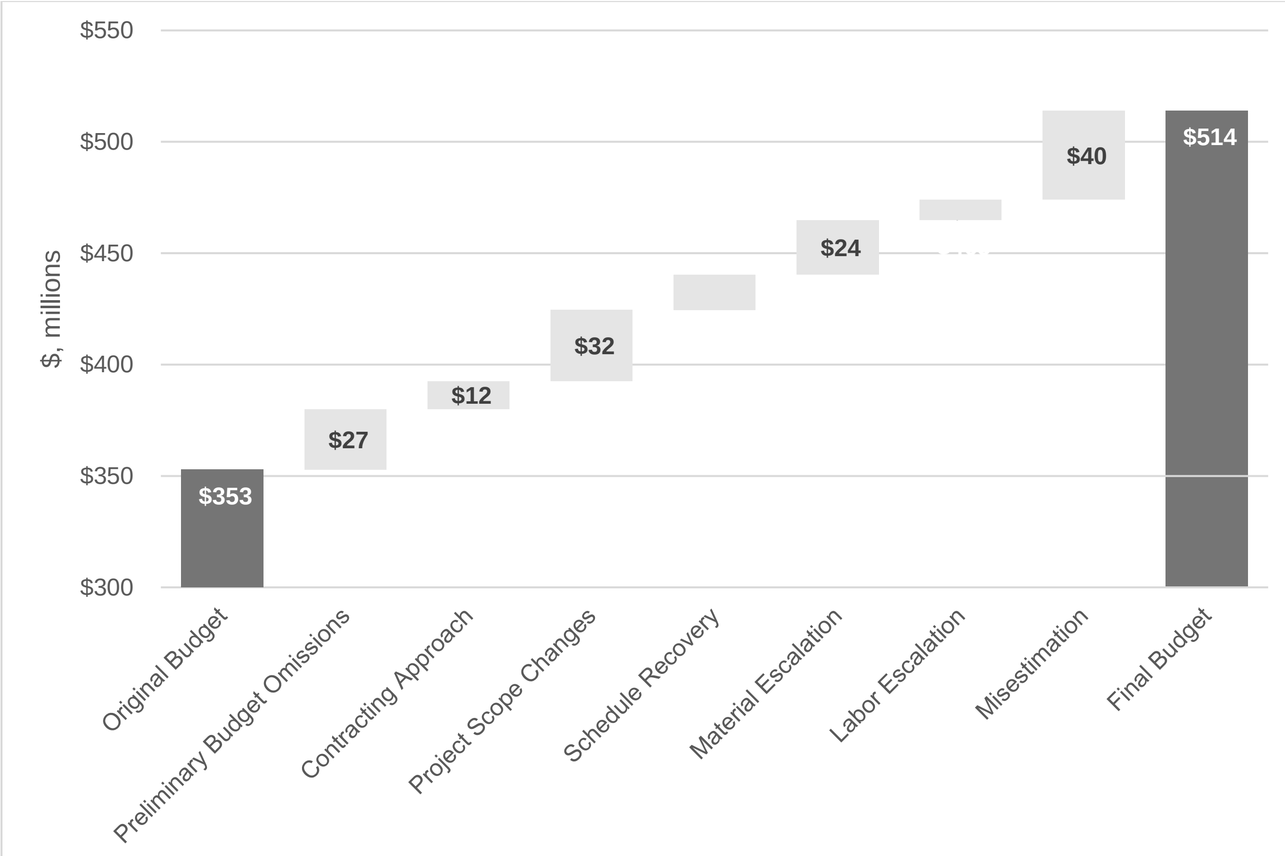
PA has reviewed documentation from throughout the Silverhawk project to understand the underlying drivers of cost increase from the originally budgeted $353mm to the final budget of $514mm. PA recognizes that there are a number of contributing factors which drove the ultimate cost of the project and has sought to break down the overall increase into seven areas of interest:

- **Preliminary Budget Omissions –** Cost which was omitted from the original cost estimate developed by POWER and used for budgeting by NV Energy.
- **Contracting Approach –** Cost which were incurred as a result of the multi-contract strategy used to execute the project which would not have been expected under a traditional EPC contract arrangement.
- **Project Scope Changes –** Cost associated with adjustments to the project scope as executed when compared to the scope understood to be budgeted for in the original cost estimate.
- **Schedule Recovery –** Cost which was incurred to construct the project more quickly than typical in order to meet the required in-service date for Silverhawk following a 3-month permitting delay.
- **Material Escalation –** Increased cost due to inflation of materials as compared to the overnight cost assumptions included within the original cost estimate.
- **Labor Escalation –** Increased cost due to inflation of labor as compared to the overnight cost assumptions included within the original cost estimate.
- **Misestimation –** Cost in excess of the original budget not attributable to one of the other six categories. Variance between estimates and actual costs is to be expected in any complex cost estimate.

PA notes that due to the granularity and consistency of project data available, highly certain estimation was not always possible during the cost review. The analysis presented herein represents PA’s best understanding of the drivers which contributed to the cost deviations of Silverhawk given the information which existed and was made available at the time of this review.

An overview of PA's findings is shown in Figure 4-1. Overall, the six key drivers identified are estimated to have caused approximately $121mm of cost increases as compared to the original Silverhawk budget. The remaining $40mm is attributed to misestimation of costs within the original estimate from POWER.

*Figure 4-1: Silverhawk Cost Waterfall – Original Budget to Final Budget*




## 4.1 Preliminary Budget Omissions

PA estimates that approximately $27mm of cost increase is attributable to preliminary budget omissions. These are costs which were omitted from the original cost estimate developed by POWER and used for budgeting by NV Energy.

The largest items identified within this category were:

- **Sales Tax on Major Equipment –** No sales tax for the CTs or other major equipment was included within the original budget. Approximately $18mm of sales tax appears to have been omitted from the estimate, with sales tax on GE-furnished equipment totaling over $15mm.
- **NV Energy Project Supervision & Overheads –** Cost for NV Energy overheads was not included within the original budget. These overheads represent approximately $8mm in cost to Silverhawk.
- **Project Closeout in Maximo –** Cost for necessary updates to the enterprise asset management ecosystem associated with the project appear to have been omitted from the original budget. This represents approximately $1mm in cost.

No additional, smaller cost items were identified within this category.

## 4.2 Contracting Approach

PA estimates that approximately $12mm of cost increase is attributable to the ultimate contracting approach utilized for Silverhawk. These are costs which were incurred as a result of the multi-contract strategy used to execute the project (to meet the required in-service date) which would not have been expected under a traditional EPC contract arrangement.

The largest items[14] identified within this category were:

- **Outside Services, EPC Scope –** Inclusive of a variety of services from engineering and procurement to construction management and commissioning. PA assumes that direct procurement of these services by NV Energy was more expensive than it would have been for an EPC contractor given the volume of projects and scale that such a contractor would bring. PA estimates that the use of multiple entities represents approximately $7mm of cost.
- **NV Energy Labor & Overhead –** Cost for NV Energy staff time and associated overheads that would not have been required if an EPC contractor were engaged and NV Energy was able to take a less active role in the execution of Silverhawk. This labor represents approximately $5mm of cost.
- **Builder's Risk Insurance –** Typically provided by the EPC contractor. PA assumes that direct procurement of this product by NV Energy was more expensive than it would have been for an EPC contractor given the volume of projects and scale that such a contractor would bring. PA estimates that this inefficiency represents approximately $1mm of cost.

No additional, smaller cost items were identified within this category.

## 4.3 Project Scope Changes

PA estimates that approximately $32mm of cost increase is attributable to project scope changes. These are costs associated with adjustments to the project scope as executed when compared to the scope understood to be budgeted for in the original cost estimate.

The largest items identified within this category were:

- **Excavation & Backfill –** Materially more excavation was required than anticipated (approximately 139% change from initial GC RFP to final bid) and backfill installation was greater as well (approximately 755% change from initial GC RFP to final bid). PA estimates that this expanded civil scope represents approximately $9mm of added cost.
- **Switchyard Ring Bus Configuration –** The switchyard scope required to interconnect Silverhawk in compliance with applicable reliability standards necessitated the upgrade to a ring bus configuration, requiring additional high-voltage breakers and bus material as compared to the initial cost estimate. PA estimates that the modified switchyard scope represents approximately $8mm of added cost.
- **CT OEM Modifications –** A variety of changes were made to the major equipment being supplied by GE, ranging from added HSCR scope and control system changes to the addition of stair access and an initial stock of critical spares for Silverhawk. These scope adjustments with GE represent approximately $11mm of added cost.

PA identified several smaller-value scope adjustments as well which collectively represent approximately $4mm of cost added to Silverhawk.

[14] PA notes that the sum of cost increases for key items shown exceeds the category total of $12mm only due to rounding the cost of each item.

## 4.4 Schedule Recovery

PA estimates that approximately $16mm of cost increase is attributable to schedule recovery. These are costs which were incurred to construct the project more quickly than typical in order to meet the required in-service date for Silverhawk following a permitting delay[15] and while managing equipment delivery schedules.

The largest items identified within this category were:

- **GC & Subcontractor Labor –** Construction was undertaken at a faster pace than typical, including 60-hour weeks as standard (vs 50-hour weeks more typical) and even greater labor acceleration efforts for civil work and electrical work specifically. PA estimates that labor cost increases associated with the accelerated schedule due to a combination of expanded overtime pay and reduced hourly productivity represent approximately $16mm of added cost.
- **Spare GSU Relocation –** To meet the required schedule, NV Energy elected to relocate an existing spare GSU from Chuck Lenzie Generating Station for temporary use at Silverhawk before the arrival of the GSUs ordered for the project (which would have delayed the online date). Temporary relocation of the spare GSU represents approximately $2mm of added cost.
- **Expedited Delivery & Testing of CTs –** The GE scope was modified to include expedited delivery of the CTs (to ensure delivery was in line with project timing requirements) and double shifts for performance testing. These scope adjustments with GE represent approximately $2mm of added cost. However, GE paid $4mm in liquidated damages to NV Energy due to delayed delivery under their contract. Therefore, the net cost attributable to schedule recovery from GE is approximately negative $2mm.

No additional, smaller cost items were identified within this category.

## 4.5 Material Escalation

PA estimates that approximately $24mm of cost increase is attributable to escalation of material costs. These are increased costs due to inflation of materials as compared to the overnight cost assumptions included within the original cost estimate[16].

The largest items[17] identified within this category were:

- **Power Plant Electrical –** Materials used within the electrical portion of the power plant build experienced significant cost escalation and PA has estimated an inflation rate of approximately 47% for the period of interest based upon available PPI data[18]. PA estimates that this material escalation represents approximately $7mm of added cost.
- **Transmission Voltage Equipment –** High-voltage equipment including the GSU transformer and 500 kV circuit breakers experienced significant cost escalation and PA has estimated an inflation rate of approximately 56% for the period of interest based upon available PPI data. PA estimates that this material escalation represents approximately $5mm of added cost.
- **Power Distribution Center –** Electrical equipment such as the power distribution center utilized by the project experienced significant cost escalation and PA has estimated an inflation rate of approximately

[15] NV Energy indicated that the UEPA permit was delayed due to several factors including the need for a special use permit from Clark County and complexities related to drainage studies and the grading permit. Construction at Silverhawk began in September instead of June, necessitating aggressive schedule recovery during construction.
[16] Escalation assumed to cover cost differences between April 2021 and timing of Silverhawk construction. NV Energy has stated that cost values included within the POWER cost estimate were based upon market data from April 2021 and are assumed to be overnight build costs which do not include escalation.
[17] PA notes that the sum of cost increases for key items plus smaller cost items shown is below the category total of $24mm only due to rounding the cost of each item.
[18] Producer Price Index Commodity Data made available from the Bureau of Labor Statistics. PA utilized various relevant indices for each category of materials utilized.

56% for the period of interest based upon available PPI data. PA estimates that this material escalation represents approximately $2mm of added cost.

PA identified many categories of smaller-value scope adjustments as well which collectively represent approximately $9mm of cost added to Silverhawk.

## 4.6 Labor Escalation

PA estimates that approximately $9mm of cost increase is attributable to escalation of labor costs. These are increased costs due to inflation of labor as compared to the overnight cost assumptions included within the original cost estimate[16].

The largest items identified within this category were:

- **GC & Subcontractor Labor –** Labor across all categories to construct Silverhawk experienced cost escalation and PA has estimated an inflation rate of approximately 10% for the period of interest based upon available ECI data[19]. PA estimates that this labor escalation represents approximately $9mm of added cost.

PA identified smaller-value scope adjustments as well which collectively represent less than $0.5mm of cost added to Silverhawk.

## 4.7 Misestimation

PA sought to identify and estimate specific cost elements which comprise each of the areas noted above. In addition to these six areas, there is a portion of the cost deviation which is simply due to misestimation. After accounting for as much of the cost deviation as possible via attribution to the six areas, the remaining cost deviation has been assumed to be reasonably attributable to misestimation. Given the class of estimate produced and the completeness of the design at that time, it is expected that there is some amount of cost variance which is not attributable to a specific change of circumstance or error, but is simply due to the estimate not being completely accurate (which is always the case).

PA estimates that approximately $40mm of cost increase is attributable to misestimation. In particular, PA identified that the cost of SCRs (part of GE's equipment supply scope) was directly misestimated by approximately $15mm within Silverhawk's budget. The remaining $25mm of misestimation is attributable to a wide variety of items throughout the cost estimate and could not be clearly identified by PA with a reasonable degree of confidence.

[19] Employment Cost Index data made available from the Bureau of Labor Statistics for Private Industry Construction Workers.


# 5 Combustion Turbine Power Plant Cost Trends

PA reviewed available industry literature and data sources to understand current industry-wide cost trends which may be relevant to Silverhawk. Specifically, PA sought to understand both actual cost trends for similar facilities over the past several years and third-party estimates of expected cost for such facilities being built today. To do this, PA assessed actual and estimated cost data for CT power plants which came online in the US over the past 5 years. Industry cost projections from both the EIA[20] and NREL[21] which are applicable to new build CT power plants were also considered.

## 5.1 Recent CT Power Plant Costs

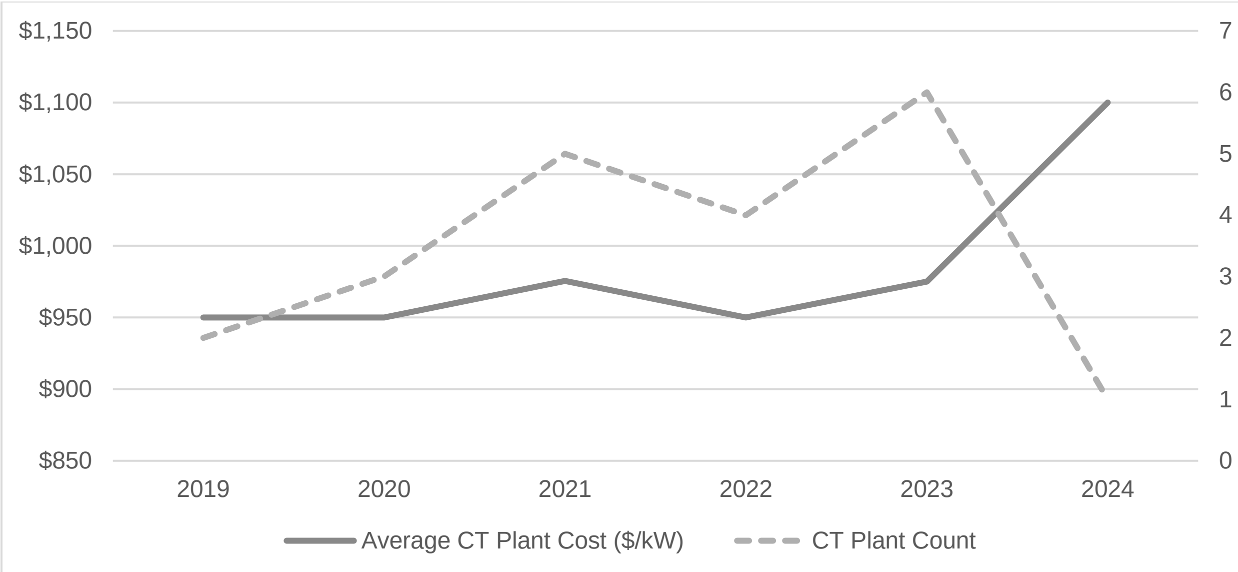
PA reviewed capital cost data available from S&P Global for CT power plants in the US which entered operations in the past 5 years. A total of 21 plants were identified with capacities ranging from 100 MW to over 900 MW which could be considered comparable to Silverhawk[22]. The resulting power plants had a range of costs $950/kW to $1,100/kW as estimated by S&P Global (actual costs were not available). An overview of these power plant costs is shown in Figure 5-1.

Given that these are estimated project costs (not actuals) and that there may be a variety of reasons for differing cost outcomes as compared to Silverhawk, PA does not believe that a direct comparison is appropriate. However, PA notes the upward cost trend shown for these CT power plant projects which is relevant to understanding the cost increases experienced by Silverhawk between the initial budgeting in 2022 and the construction scheduled to be completed in 2025.

---

[20] Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies published by the US Energy Information Administration, January 2024.
[21] Electricity Annual Technology Baseline (ATB) published by the National Renewable Energy Laboratory, 2023.
[22] Data from S&P Global Market Intelligence platform with PA analysis. PA removed CTs plants associated with cogeneration, those less than 100 MW capacity, and plant expansions given that they are less appropriate comparisons to Silverhawk.

*Figure 5-1: Recent CT Power Plant Costs – S&P Global Estimates*




## 5.2 Projected CT Power Plant Costs

PA compared Silverhawk to multiple available estimates for generic power plants which are similar in nature. Certain required elements of Silverhawk including the use of hot SCRs and wet compression, the need for material switchyard upgrades, and the quicker-than-typical construction schedule make it a more expensive project than the generic assets typically included within industry estimates. This should be taken into consideration when comparing Silverhawk's cost to the absolute cost values from relevant industry estimates.

The EIA published the most recent 'Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies' report in January 2024. The report is inclusive of capital cost estimates for 19 electric generation types and is intended to be used to reflect the changing cost of new power plants within the forthcoming 'Annual Energy Outlook 2025' which will be published by the EIA. In addition to baseline capital costs for each technology, location-specific adjustments are included within the analysis for both capital cost and performance characteristics. The report was prepared by Sargent & Lundy on behalf of the EIA.

While the report does not specifically include a simple-cycle CT plant composed of (2) F-class turbines (Silverhawk's configuration), two similar configurations of interest are included: a 211-MW net simple-cycle plant utilizing (4) aeroderivative units and a 419-MW net simple-cycle plant utilizing (1) H-class frame unit. Adjusting for a Las Vegas, Nevada costs and performance characteristics, the report estimates the following overnight capital costs on a $/kW net basis:

- **211-MW Aeroderivative CT Power Plant –** Estimated at an overnight capital cost of $1,797/kW[23].
- **419-MW Frame CT Power Plant –** Estimated at an overnight capital cost of $952/kW[23].

Silverhawk's budgeted cost at completion of $514mm implies a cost of $1,170/kW. In general, direct comparison of unit costs for frame units and aeroderivative units should be avoided although directional comparison can be considered. The second EIA configuration is a better comparison point for Silverhawk, noting that a two-unit plant (such as Silverhawk) should be expected to cost more than a one-unit plant (such as the EIA H-class configuration) all else equal. Therefore, PA notes that Silverhawk's cost appears reasonable when considering the two units estimated above within the EIA's report.

[23] Originally provided as 2023$, adjusted by PA to 2024$.

Separately, NREL publishes the 'Electricity Annual Technology Baseline (ATB)' each year. The ATB includes a variety of forecasts related to power plant costs and performance characteristics, including overnight capital costs.

While the 2023 ATB does not specifically include a simple-cycle CT plant composed of (2) F-class turbines (Silverhawk's configuration), one similar configurations of interest is included: a 233 MW net simple-cycle plant utilizing (1) F-class frame unit. While the ATB does not include a location-specific adjustment for Nevada, the ATB estimates the following overnight capital costs on a $/kW net basis for a generic US location:

- **233-MW Frame CT Power Plant –** Estimated at an overnight capital cost of $1,146/kW[24].

Silverhawk's budgeted cost at completion of $514mm implies a cost of $1,170/kW. Given that Silverhawk's cost is within approximately 2% of the benchmark cost estimate, PA notes that Silverhawk's cost appears reasonable when considering the ATB's estimated costs for this type of facility as provided by NREL.

[24] Originally provided as 2021$, adjusted by PA to 2024$.

# A Glossary

**AACE** – Association for the Advancement of Cost Engineering
**AFE** – Authorization for Expenditure
**AFUDC** – Allowance for Funds Used During Construction
**ARB** – ARB/Primoris
**ATB** – Annual Technology Baseline
**BHE** – Berkshire Hathaway Energy
**CCGT** – Combined Cycle Gas Turbine
**COD** – Commercial Operation Date
**CT** – Combustion Turbine
**EIA** – Energy Information Administration
**EOR** – Engineer of Record
**EPC** – Engineering, Procurement, and Construction
**GC** – General Contractor
**GE** – General Electric Company
**GSU** – Generator Step Up Transformer
**HSCR** – Hot Selective Catalytic Reduction
**IEM** – IEM Energy Consultants
**IRP** – Integrated Resource Plan
**LGIR** – Large Generator Interconnection Request
**LSE** – Load Serving Entity
**NREL** – National Renewable Energy Laboratory
**OE** – Owner’s Engineer
**POWER** – Power Engineers
**PUCN** – Public Utilities Commission of Nevada
**RFP** – Request for Proposal
**SCR** – Selective Catalytic Reduction
**UEPA** – Utility Environmental Protection Act

## About PA.

We believe in the power of ingenuity to build a positive human future.

As strategies, technologies, and innovation collide, we create opportunity from complexity.

Our diverse teams of experts combine innovative thinking and breakthrough technologies to progress further, faster. Our clients adapt and transform, and together we achieve enduring results.

We are over 4,000 strategists, innovators, designers, consultants, digital experts, scientists, engineers, and technologists. And we have deep expertise in consumer and manufacturing, defense and security, energy and utilities, financial services, government and public services, health and life sciences, and transport.

Our teams operate globally from offices across the US, UK, Ireland, Nordics, and Netherlands.

## PA. Bringing Ingenuity to Life.

Bringing Ingenuity to Life.
paconsulting.com

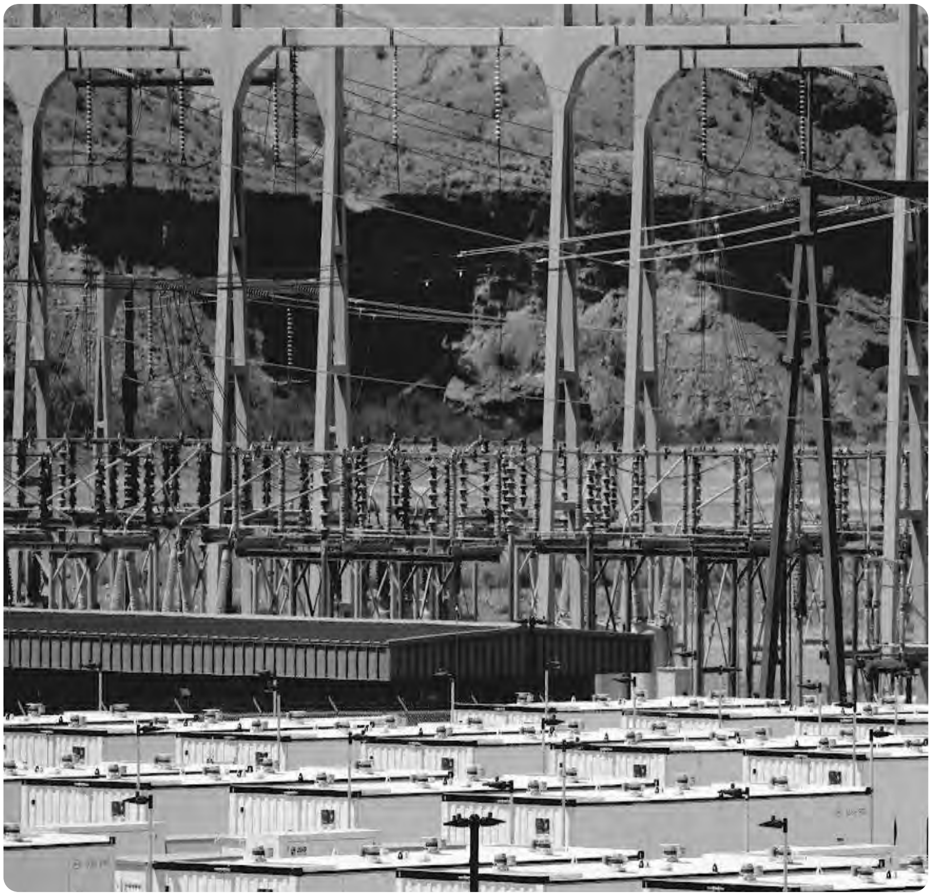
Discover more at paconsulting.com and connect with PA on LinkedIn and Twitter.

**Denver Office**
PA Consulting Group Inc.
Suite 3550
1700 Lincoln Street
Denver
CO 80203
USA
+1 720 566 9920



**paconsulting.com**

# EXHIBIT HEIDELL-DIRECT-3



# Reid Gardner Schedule Acceleration Benefits Review

Prepared for NV Energy

February 12, 2025

Bringing Ingenuity to Life.
paconsulting.com

**Denver Office**

PA Consulting Group Inc.
Suite 3550
1700 Lincoln Street
Denver
CO 80203
USA
+1 720 566 9920

**paconsulting.com**

**Prepared by: PA Consulting**

**Reference: P089542**

**Version: 1**

# Contents

# Figures



# Tables

# License Agreement

PA Consulting Group, Inc. ("PA") has prepared this Report (the “Report”) for the use of NV Energy (“NV Energy”, or the “Client”) solely with respect to support a review of the benefits associated with accelerated construction of the Reid Gardner BESS Project (“Reid Gardner” or the “Asset”) located in NV Energy’s service territory (the “Benefits Review”). PA has agreed that the Client may share this Report with their officers, directors and employees; the officers, directors and employees of their subsidiaries and affiliates; their advisors; and certain other third parties, namely, the Public Utilities Commission of Nevada (“PUCN”), in each case who have a need to review the Report for the purpose of their understanding of the acceleration benefits associated with the construction of Reid Gardner (each an “Authorized Third Party”). Review or use of this Report by any other party or for any other purpose is strictly prohibited and must be authorized by PA in writing. All use and reliance on this Report by any Authorized Third Party is subject to the following terms and conditions.

- No Authorized Third Party may change, alter, or adapt the Report or further distribute the Report. Authorized Third Parties shall be subject to confidentiality obligations to the Client, which obligations require, among other things, such Authorized Third Parties to keep the Report confidential.
- Authorized Third Parties acknowledge that the Report is not an audit and was not undertaken to express a financial opinion or to provide investment advice, and that PA does not express an opinion on the financial information (or any other information) contained in the Report. Authorized Third Parties further acknowledge that had PA performed additional due diligence beyond the agreed-upon scope of work, other matters might have come to its attention that would have been reported.
- Authorized Third Parties acknowledge that: (i) some information in the Report is necessarily based on predictions and estimates of future events and behavior; (ii) such predictions or estimates may differ from that which other experts specializing in the electricity industry might present; (iii) PA’s analysis and findings are current as of the date of the Report and, where applicable, incorporate underlying market data as of February 7, 2025; (iv) the provision of a Report by PA does not obviate the need for the Client or the PUCN to make further appropriate inquiries as to the accuracy of the information included therein, or to undertake an analysis on their own; and (v) the Report is not intended to be a complete and exhaustive analysis of the subject issues and therefore will not consider some factors that are important to understanding the entirety of Silverhawk. Nothing in the Report should be taken as a promise or guarantee as to the occurrence of any future events.
- Authorized Third Parties release PA from any claims arising from their review, use of or reliance on the Report, including by way of example only, any claim for the negligent provision of information. In no event and under no circumstances shall PA be liable to Authorized Third Parties for any principal, interest, loss of anticipated revenues, earnings, profits, increased expense of operations, loss by reason of shutdown or non-operation due to late completion, or for any consequential, indirect or special damages.

# 1 Executive Summary

NV Energy ("NV Energy" or the "Client") engaged PA to serve as a third-party reviewer of the benefits associated with construction acceleration at the Reid Gardner BESS Project (Reid Gardner). Reid Gardner includes the addition of a 220 MW / 440 MWh battery energy storage system (BESS) and associated facilities at the retired Reid Gardner Generating Station, providing a new capacity resource for NV Energy. The initial PUCN approval required an in-service date on or before May 31, 2024 and Reid Gardner achieved its commercial operation date (COD) on December 29, 2023.

PA's third-party review summarized in this report provides an assessment of NV Energy's approach to identifying and quantifying benefits associated with the schedule acceleration.

*Table 1-1: Summary of the Asset*

| Asset | Technology Type | Commercial Operation Date | Summer-Rated Capacity | Location |
|---|---|---|---|---|
| **Reid Gardner BESS Project** | Li-Ion BESS | December 2023 | 220 MW / 440 MWh | Nevada Power Region |

## Key Findings

PA's review of the project acceleration benefits associated with Reid Gardner resulted in the following key findings:

- **By placing Reid Gardner in service in December 2023, the project benefitted ratepayers via operational savings achieved during the January 2024 through May 2024 period. Operational savings to ratepayers have an estimated value of $5.2mm.**
  - Reduced System Production Cost ($2.1mm) – Lower system production costs achieved over a five-month period due to Reid Gardner being in service, directly benefitting ratepayers via reduced Deferred Energy Adjustment (DEA).
  - Increased WEIM Revenues ($2.6mm) – Higher Western Energy Imbalance Market (WEIM) revenues achieved over a five-month period due to Reid Gardner being in service, directly benefitting ratepayers via reduced DEA.

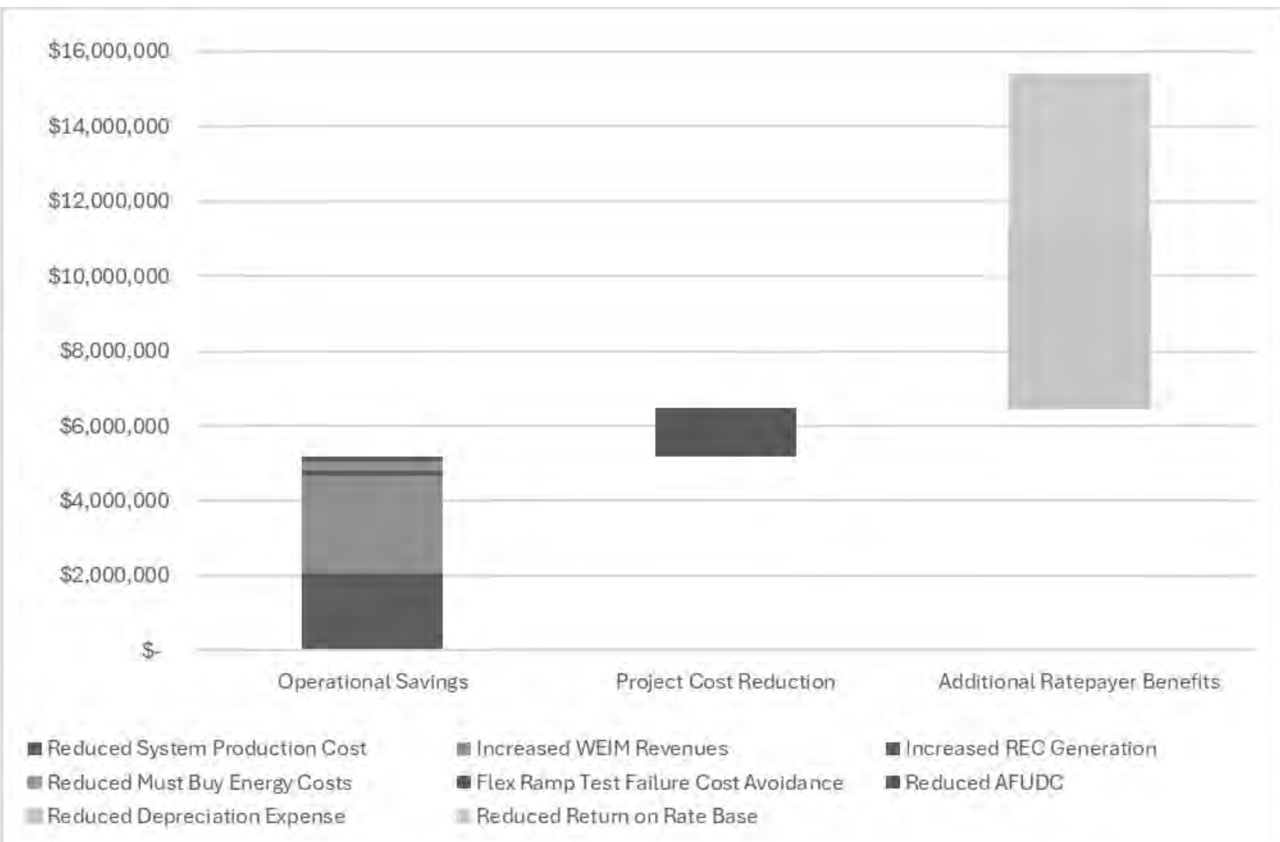
- Increased REC Generation ($154k) – Higher renewable energy credit (REC) creation achieved over a five-month period due to Reid Gardner being in service, benefitting ratepayers by supporting renewable portfolio standard (RPS) compliance.
- Reduced Must Buy Energy Costs ($228k) – Reduced energy purchase costs achieved over a five-month period due to Reid Gardner being in service, directly benefitting ratepayers via reduced DEA.
- Flex Ramp Test Failure Cost Avoidance ($136k) – Avoided flex ramp failure costs estimated over a five-month period due to Reid Gardner being in service, benefitting ratepayers via reduced DEA.

• **By placing Reid Gardner in service in December 2023, the project benefitted ratepayers via reduced project capital cost. The cost reduction benefitting ratepayers has an estimated value of $1.3mm.**
  - Reduced AFUDC ($1.3mm) – Lower AFUDC cost due to accelerated project schedule, directly benefitting ratepayers via reduced plant in service translating into reduced rates.

• **By placing Reid Gardner in service in December 2023 and recovering costs as directed by the Public Utilities Commission of Nevada (PUCN) per the February 2024 order, ratepayers received additional benefits from Reid Gardner as compared to costs incurred. The additional ratepayer benefits have an estimated value of $8.9mm.**
  - Reduced Depreciation Expense ($4.7mm) – Depreciation expense borne by NV Energy shareholders for a 21-month period (January 2024 – September 2025) that directly benefits ratepayers via reduced rates.
  - Reduced Return on Rate Base ($4.2mm) – Return on rate base not provided to NV Energy shareholders for a 21-month period which directly benefits ratepayers via reduced rates.

• **The project acceleration benefits associated with the earlier in-service date for Reid Gardner are summarized in Figure 1-1.**

*Figure 1-1: Reid Gardner Project Acceleration Benefits*



# 2 Project Timeline & Key Decisions

NV Energy proposed the re-development of the retired Reid Gardner coal-fired power plant as a Company-owned BESS facility in March of 2022 within the First Amendment to the 2021 Joint Integrated Resource Plan (IRP). PA reviewed documentation that highlights the key activities and decisions which occurred during the development and construction of Reid Gardner from March 2022 through September 2024 when the project achieved final completion.[1] An overview of the Reid Gardner project is shown in Figure 2-1.

PA evaluated the project in three phases for the assessment of activities and decisions made by NV Energy: the planning phase, the contracting phase, and the construction phase. Critical analysis, commitments, and decisions were made by NV Energy during each of these phases which ultimately led to Reid Gardner achieving COD on December 29, 2023 and beginning to serve customer needs in advance of the 2024 summer peak season.

## 2.1 Planning Phase

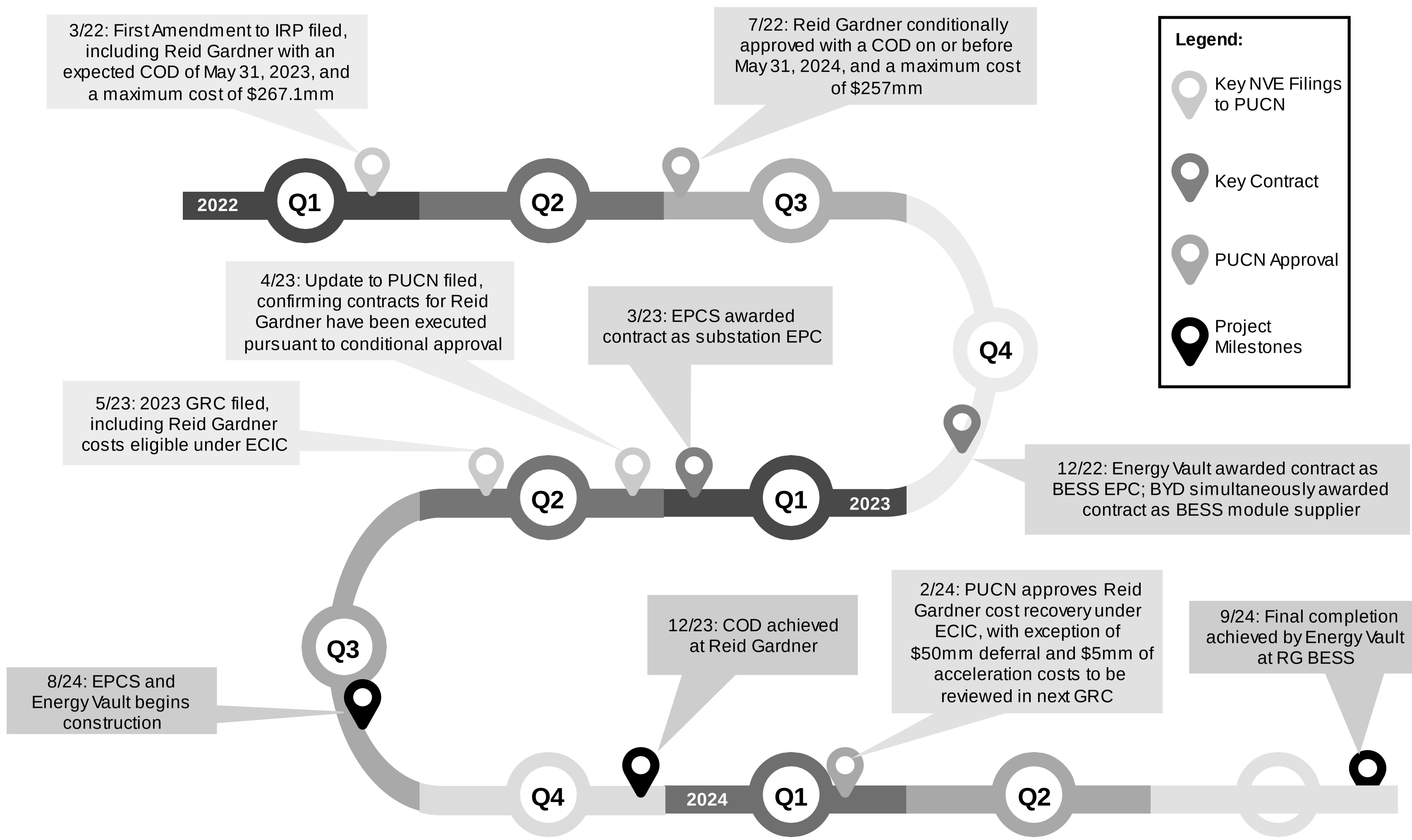
The planning phase of the Reid Gardner project began indirectly via NV Energy's 2020 BESS RFP that resulted in the proposal of three smaller BESS assets within the 2021 Joint IRP. Though these proposed projects[2] were later withdrawn to improve upon costs and benefits, the analysis completed provided the foundation for the ultimate development of Reid Gardner. Multiple sites were assessed for BESS installation and different configurations were evaluated to enhance the operational value of a BESS asset. NV Energy's analysis resulted in the development of the Reid Gardner project at the site of a retired coal power plant as a shorter duration, 2-hour BESS to maximize the operational value in meeting the evening peak.

In March of 2022, the 220 MW, 2-hr Reid Gardner project was proposed within the First Amendment to the 2021 Joint IRP. The project was projected to achieve COD by May 31, 2023 and have a cost of approximately $217.1mm, noting that the estimated cost was indexed to the price of a lithium carbonate commodity price index and subject to adjustment (maximum increase of $50mm, for a maximum project cost of $267.1mm). Tesla was expected to supply the BESS modules, construct the facility, and provide initial operations & maintenance (O&M) services.

---

[1] Final completion was achieved by Energy Vault in September 2024. NV Energy indicated that EPCS had not yet achieved final completion as of January 21, 2025.
[2] Chukar Phase 2, Brunswick, and Steamboat BESS projects described in Docket 21-06001.

*Figure 2-1: Reid Gardner Development & Construction Timeline*



In July of 2022, the PUCN approved NV Energy's plan to move forward with Reid Gardner. Specifically, the PUCN approval was conditioned upon the price of the project not exceeding $257mm (excluding AFUDC) and the project achieving COD on or before May 31, 2024. The PUCN ordered that NV Energy file a memorandum on or before June 1, 2023 stating whether the Reid Gardner project would move forward given these conditions, be cancelled, or be modified and re-submitted for approval.

## 2.2 Contracting Phase

The contracting phase of the Reid Gardner project began in earnest following PUCN approval of the project. Given the stipulations within the conditional approval, NV Energy was required to execute contract(s) for the delivery of the Reid Gardner BESS no later than June 1, 2023.

In alignment with these stipulations, NV Energy executed an agreement with Energy Vault, Inc. (Energy Vault) in December of 2022 wherein Energy Vault would be the EPC contractor for the BESS portion of the project. Energy Vault concurrently executed a BESS module supply contract with BYD America LLC (BYD) to provide the required equipment.

In March of 2023, NV Energy executed a separate agreement with EPC Services Company (EPCS) for provision of EPC services associated with the project substation and grid interconnection. When combined with the Energy Vault agreement, this completed the major contracting for the completion of Reid Gardner.

In April of 2023, NV Energy submitted the requested memorandum to the PUCN which confirmed that the Reid Gardner BESS would be pursued at an estimated cost of $248.4mm (excluding AFUDC)[3] and be placed in service by December 31, 2023. **These terms were wholly consistent with the PUCN's conditional approval, confirming that Reid Gardner would be constructed for no more than $257mm and be placed in service no later than May 31, 2024.**

In May of 2023, NV Energy submitted a request to recover costs associated with the Reid Gardner project due to an Expected Change in Circumstance (ECIC) in accordance with NRS 704.110(4). At the time of filing, NV Energy estimated that the project would cost $255.6mm inclusive of AFUDC.

## 2.3 Construction Phase

The start of the construction phase was delayed as compared to the baseline construction schedules utilized within the contracts with project delivery partners. NV Energy indicated that the UEPA permit was delayed and not received from Clark County until August 7, 2023. PA notes that construction at Reid Gardner had been intended to start in May (Energy Vault mobilization per agreement) and June (EPCS construction start per agreement) of 2023.

The construction phase of the Reid Gardner project began on August 8, 2023, immediately after receipt of the required UEPA permit from the PUCN. This start date reflected a delay of approximately 15 weeks as compared to NV Energy's baseline schedule for the project.

**Reid Gardner successfully achieved COD on December 29, 2023, in line with the projected schedule and consistent with the cost and schedule conditions included within the PUCN approval. Operation of the project at full capacity immediately began delivering benefits to NV Energy customers, as outlined in Section 3.**

In February of 2024, the PUCN approved Reid Gardner as appropriate for cost recovery under ECIC with the following modifications: Approximately $50.5mm was approved but deferred until the next general rate case (GRC) on the basis that final completion payments were due after the ECIC period and not appropriate for recovery under this mechanism, $5mm was deferred pending review of acceleration cost prudency in the next GRC[4], and a regulatory liability account was to be established in the event that COD was not achieved at Reid Gardner by December 31, 2023.

[3] Estimated to be $255.6mm with AFUDC included.

[4] Specific acceleration costs (or elevated costs for earlier project delivery) were not identified by the PUCN. Rather, the expected COD adjustment from May 31, 2024 to December 29, 2023 was identified as a potential cause for additional cost that may or may not be beneficial to ratepayers.

Final completion by Energy Vault was achieved in September of 2024, triggering final payments under their agreement. This represents the completion of punch list items and other construction activities required to close out the project (but which were not impacting the facility's ability to be fully operated by NV Energy and benefitting customers in the interim).

NV Energy indicated that as of January 21, 2025, final completion had not yet been achieved by EPCS. However, PA understands that the facility was fully operational throughout 2024 and the remaining work to be completed by EPCS has not impacted the facility's ability to be fully operated by NV Energy and benefitting customers in the interim.

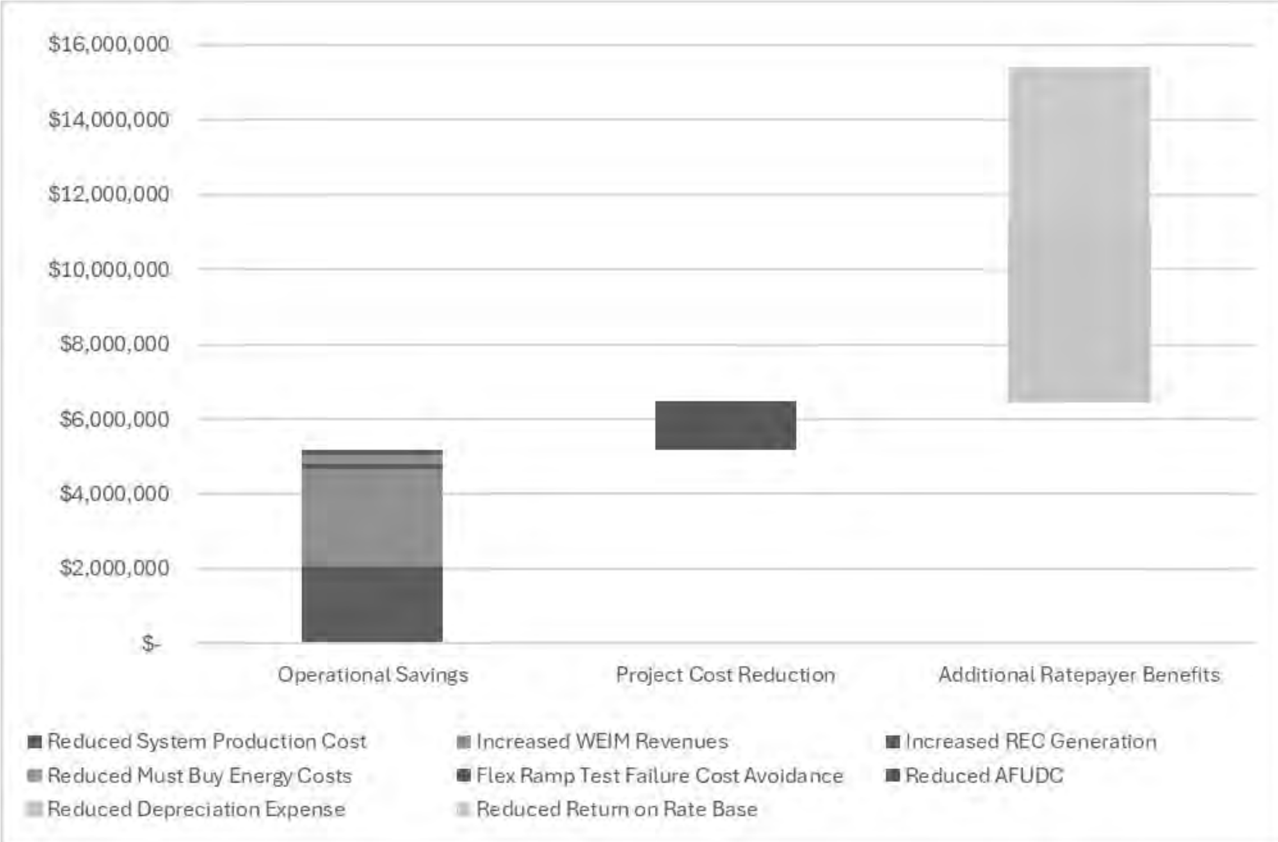
# 3 Project Acceleration Benefits

PA reviewed the benefits of accelerating the Reid Gardner construction schedule that have been identified and quantified by NV Energy. The benefits include operational savings delivered by the availability of Reid Gardner for five additional months, project cost reduction achieved due to the shorter construction schedule, and additional ratepayer benefits that result from a combination of the accelerated schedule and treatment of the project's costs by the PUCN. An overview of each benefit delivered by Reid Gardner being placed in service on December 29, 2023 instead of May 31, 2024 is included below.

- **Operational Savings**
  - **Reduced System Production Cost –** Lower system production costs achieved over a five-month period due to Reid Gardner being in service, directly benefitting ratepayers via reduced DEA.
  - **Increased WEIM Revenues –** Higher WEIM revenues achieved over a five-month period due to Reid Gardner being in service, directly benefitting ratepayers via reduced DEA.
  - **Increased REC Generation –** Higher REC creation achieved over a five-month period due to Reid Gardner being in service, benefitting ratepayers by supporting RPS compliance.
  - **Reduced Must Buy Energy Costs –** Reduced energy purchase costs achieved over a five-month period due to Reid Gardner being in service, directly benefitting ratepayers via reduced DEA.
  - **Flex Ramp Test Failure Cost Avoidance –** Avoided flex ramp failure costs estimated over a five-month period due to Reid Gardner being in service, benefitting ratepayers via reduced DEA.
- **Project Cost Reduction**
  - **Reduced AFUDC –** Lower AFUDC cost due to accelerated project schedule, directly benefitting ratepayers via reduced plant in service translating into reduced rates.
- **Additional Ratepayer Benefits**
  - **Reduced Depreciation Expense –** Depreciation expense borne by NV Energy shareholders for a 21-month period which directly benefits ratepayers via reduced rates.
  - **Reduced Return on Rate Base –** Return on rate base not provided to NV Energy shareholders for a 21-month period which directly benefits ratepayers via reduced rates.

The review of NV Energy's benefits quantification analysis summarized in this report represents PA's evaluation of the impact of each benefit area and the value delivered to ratepayers. An overview of the project acceleration benefits is shown in Figure 3-1.

*Figure 3-1: Reid Gardner Project Acceleration Benefits*




## 3.1 Operational Savings

By placing Reid Gardner in service in December 2023, the project benefitted ratepayers via operational savings achieved during the January 2024 through May 2024 period. NV Energy and PA have quantified several distinct operational benefits delivered by Reid Gardner during this five-month period which would not have been provided to ratepayers had the asset been placed in service on May 31, 2024. PA has reviewed each benefit realized, including the methodology and assumptions for quantification, and opined as to whether the quantified benefit was reasonably delivered to ratepayers due to the earlier in-service date of Reid Gardner.

### 3.1.1 Reduced System Production Cost

NV Energy estimated that availability of Reid Gardner reduced system production costs to serve native load on a day-ahead basis by approximately $2.1mm during the five months from January through May of 2024. This reduced production cost directly benefits ratepayers via a positive impact on the DEA which is assessed, reducing ratepayer costs[5].

To estimate the reduced system production costs achieved due to Reid Gardner being in service, NV Energy ran two parallel scenarios of system production cost modelling for the period. In the first scenario, the Reid Gardner asset is not included (given that it would not have been in service absent the schedule acceleration). In the second scenario, Reid Gardner is assumed to be fully in service. NV Energy then estimates the reduced system production cost by considering the difference in cost between the two scenarios. The system production cost modelling was completed in PLEXOS at an hourly granularity and represents optimal dispatch

[5] PA notes that while most reductions in system production cost are likely to flow back to ratepayers via DEA, certain system cost reductions which are reflected in the system production cost modelling may not flow through DEA and benefit ratepayers in this direct manner.

to meet day-ahead load. Both scenarios utilize the PLEXOS model and assumptions used within NV Energy's 2023 IRP, with the exception being the inclusion of actual fuel costs, load, market prices, and unit outages experienced during the period[6]. This adjustment allows the analysis to directly value the reduced system production cost actually delivered by Reid Gardner during the period. A summary of the estimated system production cost reduction is shown in Table 3-1.

*Table 3-1: System Production Cost Comparison – Total Cost ($)*

| | Jan | Feb | Mar | Apr | May | Jan-May |
|---|---|---|---|---|---|---|
| Without Reid Gardner In-Service | $116,196,950 | $64,607,760 | $63,159,470 | $61,607,510 | $69,742,210 | $375,313,900 |
| With Reid Gardner In-Service | $115,569,060 | $64,356,310 | $62,998,670 | $60,962,870 | $69,363,130 | $373,250,040 |
| **System Production Cost Savings** | **$627,890** | **$251,450** | **$160,800** | **$644,640** | **$379,080** | **$2,063,860** |

Based upon our review, PA is of the opinion that the $2.1mm of reduced system production costs are appropriately quantified and reasonable to assume as directly resulting from the accelerated Reid Gardner COD. PA believes it is reasonable to assume that there were reduced system production costs that directly benefit ratepayers via the DEA.

### 3.1.2 Increased WEIM Revenues

NV Energy estimated that Reid Gardner enabled approximately $2.6mm of additional WEIM revenues from elevated participation in the real-time market during the five months from January through May of 2024. These increased WEIM revenues directly benefit ratepayers via a positive impact on the DEA which is realized by offsetting fuel and purchased power costs.

NV Energy estimated the increased WEIM revenues realized by Reid Gardner being in service by reviewing the actual operations of Reid Gardner (charging and discharging) as compared to the actual 5-minute WEIM locational marginal price (LMP) at the project node. NV Energy assumed that all Reid Gardner operations were additive to their participation in WEIM as without the asset in service, none of this participation could have occurred. For each 5-minute interval during the period, NV Energy quantified the operations at Reid Gardner as either a cost (charging at positive market prices) or a benefit (discharging at positive market prices or charging at negative market prices). For this analysis, NV Energy removed nine days during the period wherein the utility was in a must buy position; The operational value of Reid Gardner during those days is separately quantified as described in section 3.1.4. The estimated value represents incremental WEIM revenue achieved by the NV Energy generating fleet, not necessarily WEIM revenue that was earned specifically by Reid Gardner. The resulting benefits quantification is summarized in Table 3-2 on an energy basis and Table 3-3 on a revenue basis.

[6] The PLEXOS modelling utilizes typical solar generation shapes and not the actual solar resource / generation experienced during the five-month period.

*Table 3-2: Reid Gardner Enabled Market Operations – Energy (MWh)*

| | Jan | Feb | Mar | Apr | May | Jan May |
|---|---|---|---|---|---|---|
| Discharging | 11,745 | 10,269 | 11,789 | 10,489 | 12,720 | **57,012** |
| Charging at Positive Market Price | (11,259) | (5,268) | (2,861) | (2,010) | (6,710) | **(28,108)** |
| Charging at Negative Market Price | (1,388) | (6,612) | (10,817) | (10,217) | (8,497) | **(37,530)** |
| Net Energy Loss | (902) | (1,610) | (1,889) | (1,738) | (2,488) | **(8,627)** |
| Road Trip Efficiency | 92.9% | 86.4% | 86.2% | 85.8% | 83.6% | **86.9%** |

*Table 3-3: Reid Gardner Enabled Market Operations – Revenue ($)*

| | Jan | Feb | Mar | Apr | May | Jan-May |
|---|---|---|---|---|---|---|
| Discharging | $862,502 | $413,710 | $400,065 | $315,254 | $372,645 | **$2,364,176** |
| Charging at Positive Market Price | $(462,707) | $(122,189) | $(84,854) | $(28,568) | $(98,648) | **$(796,966)** |
| Charging at Negative Market Price | $30,601 | $166,322 | $322,681 | $294,953 | $212,332 | **$1,026,890** |
| **Net Revenue** | **$430,396** | **$457,843** | **$637,893** | **$581,640** | **$486,329** | **$2,594,101** |

PA's conclusion is that the $2.6mm of increased WEIM revenues are appropriately quantified, reasonable to assume as directly resulting from the accelerated Reid Gardner COD, and reasonable to assume as a direct benefit to ratepayers via the DEA.

### 3.1.3 Increased REC Generation

NV Energy estimated that Reid Gardner enabled the generation of approximately 31,000 additional RECs valued at approximately $154k by reducing curtailment of solar resources during the five months from January through May of 2024. While the creation of these additional RECs does not immediately benefit ratepayers via direct cost reduction, the RECs support NV Energy's obligation to fulfill RPS goals and therefore ultimately benefits ratepayers.

To estimate the increased REC creation enabled by Reid Gardner, NV Energy first evaluated the frequency of solar curtailment during the five-month period. NV Energy identified a total of 36 days where solar production was curtailed, noting that this number would likely have been higher if Reid Gardner was not in service. In addition, NV Energy evaluated the frequency of "must sell" days during the five-month period, highlighting when NV Energy had more available generation resources (including solar) than native load and was therefore required to sell power. A total of 42 days were identified where the utility was in a must sell position. To avoid double counting, NV Energy then removed days which overlapped between solar curtailment and must sell positions, resulting in a total of 61 days where Reid Gardner directly increased the creation of RECs by being in operation.

For each of these 61 days, NV Energy assumed that Reid Gardner enabled the generation of 506 incremental RECs, which is equivalent to the charging energy required[7] for one full cycle of the facility. Therefore, an additional 30,866 RECs were estimated to be created due to Reid Gardner being online. This estimate may be conservative given that operations of Reid Gardner may have also helped avoid solar curtailment on days not included within this 61-day group.

NV Energy does not typically monetize (sell) RECs in the market but rather banks them to ultimately fulfill RPS obligations of the company. Given that the RECs are not typically sold, a value was required to estimate the value of the incremental RECs generated. The Renewables team at NV Energy determined $5/REC to be a reasonable value for estimating the value of the RECs to the company and ultimately to ratepayers as the RECs support required RPS fulfillment. This led to an estimated value of $154,330 for the incremental RECs created.

Based upon our review, PA is of the opinion that the $154k of increased REC generation is appropriately quantified and reasonable to assume as directly resulting from the accelerated Reid Gardner COD. PA also concludes that it is reasonable to assume that the incremental RECs provide value to NV Energy's customers given the utility's obligation to fulfill the RPS.

### 3.1.4 Reduced Must Buy Energy Costs

NV Energy estimated that Reid Gardner reduced must buy energy costs to serve native load[8] on a day-ahead basis by approximately $228k during the five months from January through May of 2024. This reduced need for market energy purchases directly benefits ratepayers via a positive impact on the DEA which is assessed, reducing ratepayer costs.

To estimate the must buy energy cost reductions delivered by Reid Gardner, NV Energy reviewed the days where the utility was required to purchase at least 440 MWh of energy from the market to meet native load and reserve margin requirements. It was determined that there were nine such days during the five-month period where market energy purchases were required and the full energy capacity of Reid Gardner could be utilized to offset otherwise required purchases. NV Energy did not estimate the value of Reid Gardner in reducing must buy energy costs for days where less than 440 MWh was purchased and therefore the cost saving estimate may be understated.

For each of the nine identified must buy days, NV Energy calculated the actual weighted average purchase price ($/MWh) for market purchases completed. The reduced must buy energy costs were then calculated by multiplying this weighted average purchase price by the output of a single full discharge cycle of Reid Gardner (440 MW), reflecting an assumed single cycle per day operation. NV Energy assumed that charging costs for the BESS were negligible given the presence of negative and near-zero prices during high solar production hours. Using this approach, NV Energy estimated the reduced must buy energy costs to be $227,975 during the five-month period. Operational data from Reid Gardner confirms that the asset was utilized on each of the nine must buy days, demonstrating its activity in reducing must buy energy costs which would have been higher had it not been for the availability of Reid Gardner.

Based upon our review, PA concluded that the $228k of reduced must buy energy costs are appropriately quantified, reasonable to assume as directly resulting from the accelerated Reid Gardner COD, and reasonable to assume as a direct benefit to ratepayers via the DEA.

### 3.1.5 Flex Ramp Test Failure Cost Avoidance

NV Energy estimated that Reid Gardner reduced the risk of failing an upward ramp test (required for participation in WEIM) and that the approximate value expected failure cost avoidance was $136k during the five months from January through May of 2024. While the reduced upward ramp failure cost expectation does not immediately benefit ratepayers via direct cost reduction, this reduced risk should benefit ratepayers through a reduced expectation of failure costs which would be borne by the ratepayers through the DEA.

To estimate the value of expected failure cost avoidance, NV Energy first identified the number of upward ramp tests during the period that were passed by less than 200 MW. NV Energy assumed that given average

[7] Given a round trip efficiency of approximately 87%, Reid Gardner typically operates in a manner that 506 MWh is used to charge the BESS and 440 MWh is delivered during full discharge of the BESS.
[8] Including required reserve margin.

state of charge and ramping capability, this is a reasonable assumption for the amount of upward ramping which could be provided by Reid Gardner. This level of upward ramp test was identified as occurring 92 times during the five-month period. NV Energy then determined the amount of capacity which would have been short for each of these events based on actual metered load, representing the capacity that would need to potentially be settled as a failure cost. NV Energy then assumed a value of $1,000/MWh in failure costs for the potentially failed ramp[9]. Lastly, given that failure costs would not always be at the $1,000/MWh rate or that emergency energy would be required, NV Energy assumed that this failure costs would be realized 10% of the time (which NV Energy believes to be conservative). This results in an expected failure cost avoidance of $136,070 for the five-month period.

Based upon our review, PA is of the opinion that the $136k of flex ramp test failure cost avoidance is quantified in a reasonable manner and it is reasonable to assume as directly resulting from the accelerated Reid Gardner COD. PA notes that the benefits provided to ratepayers are hypothetical in nature as this reflects an expected value of avoided failure costs and it is not possible to fully know the failure costs which may or may not have occurred in the absence of Reid Gardner.

## 3.2 Project Cost Reduction

By placing Reid Gardner in service in December 2023, the project had reduced overall costs which ultimately benefit ratepayers via lower total costs included in rate base. NV Energy quantified the reduced project cost achieved due to schedule acceleration which would not have occurred had the asset been placed in service on May 31, 2024. PA has reviewed the benefit purportedly delivered, including the methodology and assumptions for quantification, and opined as to whether the quantified benefit was reasonably delivered to ratepayers due to the earlier in-service date of Reid Gardner.

### 3.2.1 Reduced AFUDC

NV Energy estimated that accelerating construction and placing Reid Gardner in service five months earlier reduced AFUDC by approximately $1.3mm. This reduced project cost directly benefits ratepayers via a reduction in project costs put into rate base (a direct offset to project acceleration costs), directly reducing ratepayer costs.

To estimate the reduction in AFUDC, NV Energy compared the actual financial results of the project with the originally planned financial results. Monthly AFUDC requirements in each scenario were calculated and compared. NV Energy found that under the originally planned project schedule, a total of approximately $6.6mm would have been required for AFUDC. Due to the acceleration of the actual project schedule, realized AFUDC requirements were determined to be approximately $5.3mm. The difference of $2,690,594 between the two scenarios represents a direct project cost reduction delivered due to the accelerated project schedule.

Based upon our review, PA concurs that the $1.3mm of reduced AFUDC is appropriately quantified, reasonable to assume as directly resulting from the accelerated Reid Gardner COD, and reasonable to assume as a direct benefit to ratepayers via reduced cost required to be included in rate base.

## 3.3 Additional Ratepayer Benefits

By placing Reid Gardner in service in December 2023 and recovering costs as directed by the PUCN per the February 2024 order, ratepayers received additional benefits from Reid Gardner as compared to costs incurred. NV Energy quantified the additional ratepayer benefits delivered as a result of both the project schedule executed and the PUCN order regarding cost recovery. PA has reviewed the this assessment of the benefits delivered, including the methodology and assumptions for quantification, and opined as to whether the quantified benefits were reasonably delivered to ratepayers due to the earlier in-service date of Reid Gardner and compliance with PUCN’s cost recovery order.

[9] NV Energy has indicated that costs for ramp failure are variable in nature and challenging to quantify in the absence of a ramp failure event occurring; Therefore, the $1,000/MWh assumption was made as a reasonable estimate of potential WEIM ramp failure costs.

## 3.3.1 Reduced Depreciation Expense

NV Energy calculated that approximately $4.7mm of depreciation expense at Reid Gardner was borne by NV Energy shareholders instead of ratepayers during the 21 months from January 2024 through October of 2025[10]. This reduced depreciation expense directly benefits ratepayers via lower rates given that the expense is covered by shareholders and not included in the revenue requirement.

To estimate the reduced depreciation expense, NV Energy compared financial results for two scenarios: The first scenario in which NV Energy recovered all Reid Gardner costs under the ECIC period of the 2023 GRC and the realized scenario in which approximately $55.5mm of Reid Gardner costs were deferred until the 2025 GRC. Monthly depreciation expense in each scenario was calculated and compared. NV Energy calculated that under the scenario where all costs were recovered under the ECIC period of the 2023 GRC, a total of approximately $22.1mm would have been required from ratepayers to cover depreciation expense during the period. Considering the scenario which was actually realized, a total of approximately $17.3mm was required from ratepayers to cover depreciation expense during the period. Therefore, NV Energy shareholders paid $4,721,500 of depreciation expense that would have otherwise been borne by ratepayers, directly reducing ratepayer costs over the 21-month period.

Based upon our review, PA is of the opinion that the $4.7mm of reduced depreciation expense was quantified in a reasonable manner and is reasonable to assume as a direct benefit to ratepayers.

## 3.3.2 Reduced Return on Rate Base

NV Energy estimated that ratepayers saved approximately $4.2mm via reduced requirements for return on rate base associated with Reid Gardner during the 21 months from January 2024 through October of 2025[11]. This reduced return on rate base directly benefits ratepayers via lower rates given that this return is not provided to shareholders and therefore not paid by ratepayers.

To estimate the reduced return on rate base, NV Energy compared financial results for two scenarios: The first scenario in which NV Energy recovered all Reid Gardner costs under the ECIC period of the 2023 GRC and the realized scenario in which approximately $55.5mm of Reid Gardner costs were deferred until the 2025 GRC. Monthly return on rate base in each scenario was calculated and compared. NV Energy found that under the scenario where all costs were recovered under the ECIC period of the 2023 GRC, a total of approximately $19.7mm would have been required from ratepayers to cover return on rate base during the period. Based upon the PUCN decision, a total of approximately $15.5mm was required from ratepayers to cover return on rate base during the period. Therefore, ratepayers paid $4,209,689 less for return on rate base than would have otherwise been required, directly reducing ratepayer costs over the 21-month period.

Based upon our review, PA is of the opinion that the $4.2mm of reduced return on rate base was quantified in a reasonable manner.

[10] To estimate this benefit, NV Energy has assumed that Reid Gardner costs deferred from the 2023 GRC will not impact customer rates until October of 2025 (following the 2025 GRC).
[11] To estimate this benefit, NV Energy has assumed that Reid Gardner costs deferred from the 2023 GRC will not impact customer rates until October of 2025 (following the 2025 GRC).

# A Glossary

**AFUDC** – Allowance for Funds Used During Construction
**BESS** – Battery Energy Storage System
**BYD** – BYD America LLC
**COD** – Commercial Operation Date
**DEA** – Deferred Energy Adjustment
**ECIC** – Expected Change in Circumstance
**Energy Vault** – Energy Vault, Inc.
**EPC** – Engineering, Procurement, & Construction
**EPCS** – EPC Services Company
**GRC** – General Rate Case
**IRP** – Integrated Resource Plan
**LMP** – Locational Marginal Price
**NERC** – North American Electric Reliability Corporation
**O&M** – Operations & Maintenance
**PUCN** – Public Utilities Commission of Nevada
**REC** – Renewable Energy Credit
**UEPA** – Utility Environmental Protection Act
**WEIM** – Western Energy Imbalance Market

## About PA.

We believe in the power of ingenuity to build a positive human future.

As strategies, technologies, and innovation collide, we create opportunity from complexity.

Our diverse teams of experts combine innovative thinking and breakthrough technologies to progress further, faster. Our clients adapt and transform, and together we achieve enduring results.

We are over 4,000 strategists, innovators, designers, consultants, digital experts, scientists, engineers, and technologists. And we have deep expertise in consumer and manufacturing, defense and security, energy and utilities, financial services, government and public services, health and life sciences, and transport.

Our teams operate globally from offices across the US, UK, Ireland, Nordics, and Netherlands.

### PA. Bringing Ingenuity to Life.

Bringing Ingenuity to Life.
paconsulting.com

Discover more at paconsulting.com and connect with PA on LinkedIn and Twitter.

Denver Office
PA Consulting Group Inc.
Suite 3550
1700 Lincoln Street
Denver
CO 80203
USA
+1 720 566 9920



paconsulting.com

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JAMES HEIDELL, 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: February 14, 2025

J Heidell
James Heidell

**SHAHZAD LATEEF**

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

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

**Shahzad Lateef**

Revenue Requirement

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

A. My name is Shahzad M. Lateef. My current position is Senior Project Director, Transmission Development for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company ("Sierra," and together with Nevada Power, the "Companies"). My business address is 6226 West Sahara, Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I have been employed by the Companies for 29 years. I received my Bachelor of Science degree in Electrical Engineering in 1994 and Master of Science degree in Electrical Engineering in 1997. I began my career at Nevada Power as an engineer in the Bulk Power Operations department in 1995. Since then, I have worked as an engineer in Operational Planning, Resource Planning, Distribution Planning, and Distribution Operations, and in various roles of increasing responsibility (supervisor, manager, director, vice president) within Transmission and Distribution System Operations. Prior to my current role as Senior Project Director for Transmission Development, I was Vice President of Electric Delivery. I am a

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

registered professional engineer in the State of Nevada. A copy of my statement of qualifications is provided as **Exhibit Lateef-Direct 1**.

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS SENIOR PROJECT DIRECTOR OF TRANSMISSION DEVELOPMENT.**

A. I am currently the Senior Project Director of Transmission Development. In my role, I am responsible for overseeing the development of Greenlink West and Greenlink North transmission projects (collectively the "Greenlink Nevada" transmission project).

**4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes, I provided written testimony in the 2024 Joint Integrated Resource Plan ("IRP"), the Fifth Amendment to the Companies' 2021 IRP, the 2020 Natural Disaster Protection Plan and previous Deferred Energy Accounting Adjustment filings with the Commission. I have also participated in several workshops with the Commission associated with Docket No. 12-10013.

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

A. The purpose of my testimony is to provide an update on the status of the Greenlink Nevada transmission project to support Construction Work in Progress ("CWIP") accounting treatment. I provide the cost of the Greenlink Nevada transmission project incurred to date. I also provide cost management controls applied to the contracts that have been executed for the Greenlink Nevada transmission project.

6. Q. **ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following Exhibits:

**Exhibit Lateef–Direct-1 –** Statement of Qualifications

**Exhibit Lateef–Direct-2** – Response to Staff DR 232, Docket No. 21-06001 (Greenlink Nevada Transmission Cashflow)

**Exhibit Lateef-Direct-3 –** Greenlink Nevada Transmission Project Status Summary

**Exhibit Lateef-Direct 4-** Greenlink Nevada Transmission Project Material and Apparatus Contracts

## I. GREENLINK NEVADA TRANSMISSION PROJECT OVERVIEW

7. Q. **PLEASE DESCRIBE THE GREENLINK NEVADA TRANSMISSION PROJECT.**

A. The Greenlink Nevada transmission project is a combination of transmission lines and substations that improves electric system reliability in Nevada by providing additional high voltage transmission lines across the State, enabling renewable energy interconnections from areas within the State which are not currently accessible through the high-voltage electric system transmission system, and providing the required transmission import capacity into the Companies' electric system to support retail and network load growth within the State.

8. Q. **WHAT ARE THE COMPONENTS OF THE GREENLINK NEVADA TRANSMISSION PROJECT?**

A. The Greenlink Nevada transmission project consists of Greenlink West, Greenlink North, and the Common Ties.

**9. Q. PLEASE DESCRIBE GREENLINK WEST.**

A. Greenlink West includes a 525 kV transmission line from the Harry Allen Substation in Las Vegas to the Northwest Substation in Las Vegas; a 525 kV transmission line from the Northwest Substation in Las Vegas to the Fort Churchill Substation in Yerington, Nevada; the Amargosa collector substation; and the Esmeralda collector substation. Greenlink West also includes expansion of the existing Harry Allen Substation, the Northwest Substation, and the Fort Churchill Substation. The planned in-service date for all components of Greenlink West, except the Harry Allen – Northwest 525 kV transmission line, is May 2027. The planned in-service date for the Harry Allen – Northwest 525 kV transmission line is December 2028.

**10. Q. PLEASE DESCRIBE GREENLINK NORTH.**

A. Greenlink North includes a 525 kV transmission line from the Fort Churchill substation in Yerington, Nevada, to the Robinson Summit substation in Ely, Nevada, and the Lander collector substation. Greenlink North also includes expansion of the Fort Churchill substation and the Robinson Summit substation. The planned in-service date for Greenlink North is December 2028.

**11. Q. PLEASE DESCRIBE THE COMMON TIES.**

A. The Common Ties include a set of three 345 kV transmission lines from the Fort Churchill Substation to load centers in northern Nevada at the Mira Loma Substation (one 345 kV transmission line) and the Comstock Meadows Substation (two 345 kV transmission lines). The planned in-service date for the Common Ties is May 2027.

**12. Q. WHAT COMPONENTS OF THE GREENLINK NEVADA TRANSMISSION PROJECT WERE APPROVED BY THE COMMISSION IN DOCKET NO. 20-07023?**

A. In its Order dated March 21, 2021, the Commission approved the following:

- Construction of Greenlink West, 525 kV transmission line from the Northwest Substation to the Fort Churchill Substation;
- Conceptual design, permitting, and land acquisition for the 525 kV transmission line from the Harry Allen Substation to the Northwest Substation;
- Expansion of the Northwest Substation;
- Construction of the Fort Churchill substation;
- Construction of the Fort Churchill – Mira Loma 345 kV transmission line;
- Construction of the Fort Churchill – Comstock Meadows #1 345 kV transmission line;
- Conceptual design, permitting, and land acquisition for the Fort Churchill – Comstock Meadows #2 345 kV transmission line; and
- Conceptual design, permitting, and land acquisition for the 525 kV transmission line from the Fort Churchill Substation to the Robinson Summit Substation.

**13. Q. WHAT COMPONENTS OF THE GREENLINK NEVADA TRANSMISSION PROJECT WERE APPROVED BY THE COMMISSION IN DOCKET NO. 21-06001?**

A. In its Order dated January 26, 2022, the Commission accepted a stipulation between the parties with the following findings and approvals:

- The Companies' filing met the requirements of Senate Bill 448 (2021);
- Construction of Greenlink North, 525 kV transmission line from the Fort Churchill Substation to the Robinson Summit Substation. Conceptual design,

permitting, and land acquisition for the line was previously approved in Docket No. 20-07023; and

- Construction of the 525 kV transmission line from the Harry Allen Substation to the Northwest Substation. Conceptual design, permitting, and land acquisition for the line was previously approved in Docket No. 20-07023.

**14. Q. WHAT COMPONENTS OF THE GREENLINK NEVADA TRANSMISSION PROJECT WERE APPROVED BY THE COMMISSION IN DOCKET NO. 23-08015?**

A. In its Order dated March 1, 2024, the Commission conditionally approved the 230 kV buildout of the Amargosa and Esmeralda substations. The Amargosa and Esmeralda substations are collector substations that are part of the Greenlink West transmission line. The Commission directed the Companies to record the costs of the 230 kV buildout in plant held for future use until the 230 kV facilities are serving additional customer load or related large generator interconnection agreements are entered into that would make use of this equipment, whichever comes first.

**15. Q. WHAT WAS THE ORIGINAL COST ESTIMATE FOR GREENLINK NEVADA TRANSMISSION AS APPROVED BY THE COMMISSION AND WHEN WAS IT PREPARED?**

A. The original estimate for Greenlink Nevada transmission was prepared in 2019 and submitted in Docket No. 20-07023 on July 20, 2020. It was subsequently supplemented with revised cashflows on October 7, 2020, to reflect a modification in the sequence of in-service dates for Greenlink West and Greenlink North. The Commission's Order dated March 22, 2021, approved Greenlink West and the original estimate for the Greenlink Nevada transmission project was updated to include additional transmission and substation elements, including construction of Greenlink North, the Transmission Infrastructure for a Clean Energy Economy Plan ("TICEEP") pursuant to the Nevada Senate Bill 448 and filed with the Commission as an amendment to Docket No. 21-06001 on September 1, 2021. The Commission approved a stipulation to construct the TICEEP facilities on January 26, 2022. The estimated costs as approved by the Commission in Docket Nos. 20-07023 and 21-06001 were $2,484 million. This included a 20 percent contingency and did not include Allowance for Funds Used During Construction ("AFUDC").

## II. GREENLINK NEVADA TRANSMISSION COST FORECAST

**16. Q. WHICH DOCKET PRESENTED THE COMPANIES' ORIGINAL GREENLINK NEVADA TRANSMISSION PROJECT COSTS ESTIMATE OF $2.484 BILLION?**

A. In response to Staff DR 232, in Docket No. 21-06001, the Companies provided cost estimates for the Greenlink Nevada transmission project. A copy of the response is provided as **Exhibit Lateef-Direct-2 –** Response to Staff DR 232, Docket No. 21-06001 (Greenlink Nevada Transmission Cashflow). The Greenlink Nevada transmission project costs identified in this response total $2.471 billion, excluding previously approved conceptual design, permitting, and land acquisition of the Fort Churchill – Comstock Meadows #2 345 kV transmission line.[1] The combined cost estimate from the response to Staff DR 232 in Docket No. 21-06001 ($2.471 billion) and previously approved (in Docket No. 20-07023) costs for conceptual

[1] Docket No. 20-07023, March 22, 2021, Order at 270, para. 593.

design, permitting, and land acquisition for the Fort Churchill – Comstock Meadows #2 transmission line ($12.8 million) comes to $2.484 billion, which represents the original costs estimate for the Greenlink Nevada transmission project.

**17. Q. WHAT IS THE MOST RECENT COST ESTIMATE FOR GREENLINK NEVADA TRANSMISSION?**

A. As discussed and presented to the Commission in the Companies' 2024 Joint IRP, the Companies estimate the cost of the Greenlink Nevada transmission project to be $4,239 million. The updated estimate includes a $416 million contingency. This updated estimate also adds to the originally estimated project cost of $340 million in escalation, $252.1 million in costs caused by the project scope changes, and $101 million in sales and use taxes. Inflation has played a major role in the price escalation. Development of detailed engineering design and changes to the scope of the project compared to what was originally estimated also contributed to an increase in project cost forecast. In line with the original estimate, the updated estimate does not include AFUDC. The Companies presented the updated costs of the Greenlink Nevada transmission project to the Commission as a part of the Companies' 2024 IRP filing (Docket No 24-05041).

**18. Q. HAS THE GREENLINK NEVADA TRANSMISSION PROJECT FORECAST CHANGED FROM WHAT WAS PRESENTED TO THE COMMISSION IN THE COMPANIES 2024 IRP, DOCKET 24-05041?**

A. No. The current Greenlink Nevada Transmission Project forecast is consistent with forecast that was presented by the Companies to the Commission in its 2024 IRP filing (Docket No. 24-05041).

**19. Q. WHAT IS THE BASIS FOR THE REVISED ESTIMATE FOR THE GREENLINK NEVADA TRANSMISSION PROJECT?**

A. The revised estimate for the Greenlink Nevada transmission project is based on contracts and final proposals for all long lead time materials and construction of transmission lines, substations and telecommunications infrastructure. The revised estimate includes a contingency of $416 million based on a Monte Carlo analysis of strategic risks with 75 percent confidence interval.

The revised estimate adds to the original estimate an estimated $340.8 million in cost escalation through the completion of the projects in December 2028. The cost escalation is based on several items including increases in contractual labor rates per the International Brotherhood of Electric Workers Local 396 and Local 1245 contracts with NV Energy. The material/equipment cost escalation tracks commodity indices and is based on an estimated 3.5 percent per year increase. The combined labor and material escalation results in an increase of $340.8 million in the total project forecast. This category of forward-looking costs was not included in the original Greenlink Nevada transmission project estimate or the updated estimate provided in Docket No. 23-08015.

The revised estimate also adds to the original estimate of $97.4 million for the construction of the Fort Churchill–Comstock Meadows #2 345 kilovolt (“kV”) transmission line. The Commission had originally approved permitting and preliminary engineering only for the Fort Churchill–Comstock Meadows #2 transmission line in the amount of $12.8 million. The construction cost of this line was not included in the original Greenlink Nevada transmission project estimate or the updated estimate provided in Docket No. 23-08015.

The Bureau of Land Management ("BLM") has stipulated use of H-Frame structures in expanded Desert Tortoise and Sage Grouse habitats. This has resulted in an additional 160 miles of H-Frame structures. The cost of H-Frame structures is 42 percent higher than the cost of guyed-V lattice structures originally planned. The cost difference is based on shorter span length and higher cost of materials associated with H-Frame structures. This environmental risk mitigation has resulted in an increased cost of $124 million for the project.

The updated forecast also includes an estimated $20 million for Nevada Sage Grouse habitat mitigation, $9 million for federal land wilderness characteristics mitigation and $1.7 million for Desert Tortoise Section 7 mitigation.

The revised estimate also includes $101 million in sales and use taxes based on planned procurement of materials. This cost category was not included in the original Greenlink Nevada transmission project estimate or the updated estimate provided in Docket No. 23-08015.

Combined, the contingency ($416 million), escalation from 2024 through 2028 ($340.8 million), construction of the Fort Churchill–Comstock #2 transmission line ($97.4 million), increase in the use of H-Frame structures ($124 million), increased environmental mitigation required by BLM ($30.7 million), and sales and use taxes

($101 million) represent $1,109.9 million in costs as represented in the updated forecast.

**20. Q. HAS THE COMMISSION APPROVED CRITICAL FACILITY DESIGNATION FOR GREENLINK NEVADA TRANSMISSION PROJECT?**

A. Yes. Critical Facility designation for Greenlink North and Harry Allen – Northwest 525 kV transmission line was approved by the Commission in Docket No. 21-06001. Critical Facility designation for Greenlink West and the Common Ties was approved by the Commission in Docket No. 24-05041.

**21. Q. HAVE THE COMPANIES DETERMINED THE COST IMPACT OF RECENT EXECUTIVE ORDER IMPOSING IMPORT TARIFFS ON MEXICO, CANADA, AND CHINA, ON GREENLINK NEVADA TRANSMISSION PROJECT?**

A. The Companies have executed several procurement contracts to import long lead time materials for Greenlink Nevada transmission project from Mexico. The Companies are currently in the process of determining the cost impact of potential tariffs on imports from Mexico. The Companies do not have existing contracts to import any Greenlink Nevada transmission project materials from Canada or China.

## III. GREENLINK NEVADA TRANSMISSION PROJECT COST MANAGEMENT CONTROLS

**22. Q. WHAT ARE THE KEY STEPS THAT THE COMPANIES HAVE TAKEN TO CONTROL COSTS OF THE GREENLINK NEVADA TRANSMISSION PROJECT?**

A. The Companies have sought competitive bids from multiple providers for all materials and services required for the Greenlink Nevada transmission project. In all cases, the Companies have selected the lowest cost technically qualified bidder to provide materials and services.

The Companies have procured the services of an independent organization to provide an ongoing review of their engineering and design specifications to ensure that the specifications for materials and services are based on the Companies' standards and are in line with industry practices.

The Companies have adjusted their project overhead, administrative, and general accounting rates to make those in-line with similar past large transmission projects. The overhead, administrative and general accounting rates for Greenlink Nevada transmission project are based on ON Line, the 525 kV transmission line between Robinson Summit and Harry Allen substations that was placed in-service in 2013. ON Line accounting was subject to a successful Federal Energy Regulation Commission review, with no concerns identified. These adjustments have resulted in significantly lower overhead, administrative and general accounting charges being applied to the Greenlink Nevada transmission project.

To achieve the lowest possible cost of construction of transmission line, substations, and telecommunications infrastructure, the Companies have requested and received proposals for combined construction of these facilities by the same contractor. The Companies are currently reviewing the combined construction proposals from two technically qualified bidders.

**23. Q. WHAT IS THE REASON FOR USING INDICES FOR THE PROPOSALS?**

A. Due to supply chain disruptions witnessed in 2020 through 2023, the commodity (e.g. steel, copper, aluminum, fuel) prices fluctuated widely during the period. In order to prevent potential bidders from including the commodity volatility risk in their proposals for this long-term project and considering that several commodity prices have receded from their highest levels, the Companies requested that bidder proposals be tied to an agreed-upon and specific commodity index that relate to bidder proposals. The bidder proposals are based on an index value on the date of the proposal. If the index value increases or decreases from the date of the proposal, the bidders will increase or decrease their overall proposal value. In this forecast, the Companies have included an estimated 3.5 percent per year increase in the value of all indices.

## IV. GREENLINK NEVADA TRANSMISSION PROJECT STATUS AND PRICE CERTAINTY

**24. Q. WHAT IS THE CURRENT STATUS OF THE GREENLINK NEVADA TRANSMISSION PROJECT?**

A. The Companies received BLM's National Environmental Policy Act Notice to Proceed for Greenlink West on December 27, 2024. The Companies received the Nevada Utilities Environmental Permit Act Permit to Construct for the first segment of Greenlink West on January 7, 2025. The first segment of Greenlink West includes the Northwest Substation and 525 kV transmission line from

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

Northwest Substation to Amargosa Substation. Pre-construction activities on the private parcel at Fort Churchill Substation are underway. Development of material laydown yards for the first segment of Greenlink West is ongoing. Pre-construction surveys for construction along the first segment of Greenlink West are being completed.

The Companies received BLM's draft Environmental Impact Statement ("EIS") for Greenlink North on September 9, 2024. The Final EIS for Greenlink North is expected in June 2025. The Companies expect BLM to issue a National Environmental Permit Act Notice to Proceed for Greenlink North in December 2025. Construction on Greenlink North is planned to start in December 2026.

A summary of the current status of engineering, design, procurement of material by the Companies, and construction work as of January 2025, is provided as **Exhibit Lateef -Direct 3 –** Greenlink Nevada Transmission Project Status Summary.

**25. Q. WHAT IS THE STATUS OF PROCUREMENT OF LONG LEAD TIME MATERIALS FOR THE GREENLINK NEVADA TRANSMISSION PROJECT?**

A. The Companies have completed the procurement of all long lead time materials for the Greenlink Nevada transmission project. Procurement of these materials was the Companies' responsibility to provide to the construction contractor. A full list of executed contracts for long lead time materials and apparatus is provided in **Exhibit Lateef -Direct 4 –** Greenlink Nevada Transmission Project Material and Apparatus Contracts.

**26. Q. HOW ARE THE COMPANIES ABLE TO COMPLETE ENGINEERING AND DESIGN OF GREENLINK NEVADA TRANSMISSION PROJECT WITHOUT A RECORD OF DECISION?**

A. The Companies completed partial design and engineering of Greenlink North based on a proposed route, verified by the BLM-published draft EIS. For example, BLM may adjust the location of Lander Substation based on environmental considerations and comments from cooperating agencies and the public. However, the design and engineering of Lander Substation will remain consistent. Similarly, BLM may adjust the location and/or length of the transmission line based on environmental considerations and public comments. The Companies' contracts for long lead time materials allow for a change in quantities of materials (e.g. poles, conductor, insulators etc.) based on agreed per-unit costs. The designs will be finalized after the BLM Notice to Proceed is issued and prior to issuance of construction packages.

**27. Q. WHAT PERCENTAGE OF THE GREENLINK NEVADA TRANSMISSION PROJECT COST FORECAST IS COVERED BY EXECUTED CONTRACTS?**

A. The Companies have executed contracts for materials and services, representing approximately 70 percent of the Greenlink Nevada transmission project cost forecast.

**28. Q. WHAT COSTS HAVE THE COMPANIES INCURRED TO DATE THAT ARE BEING REQUESTED FOR CWIP ACCOUNTING TREATMENT?**

A. The Companies are seeking CWIP accounting treatment for the following costs, as allocated to Nevada Power:

First, the Companies have incurred costs associated with the National Environmental Protection Act permitting process, including evaluation of alternatives as a part of the BLM process. The Companies have conducted pre-construction surveys to support permitting, engineering and design.

Second, as the Companies have executed contracts for approximately 70 percent of long lead time materials and apparatus, the Companies have incurred costs associated with manufacturing milestones of these materials and apparatus. A list of executed contracts for materials and apparatus is provided in **Exhibit Lateef - Direct 4 –** Greenlink Nevada Transmission Project Material and Apparatus Contracts.

Third, the Companies have incurred costs associated with engineering and design that has been completed to date. The current level of engineering and design completion for different segments of Greenlink Nevada transmission project is provided in **Exhibit Lateef -Direct 3 –** Greenlink Nevada Transmission Project Status Summary.

Finally, the Companies have executed contracts for construction of Greenlink Nevada transmission, substations and telecommunications infrastructure. The construction work on Greenlink West is currently underway at Cactus Springs, Amargosa and Northwest material laydown yards, Northwest substation expansion, Fort Churchill substation expansion, Amargosa substation, and Northwest to Amargosa 525 kV transmission line. The Companies have incurred costs associated with mobilization and construction activities.

**29. Q. HOW ARE THE COMPANIES ALLOCATING COSTS FOR NEVADA POWER COMPANY?**

A. The cost allocations of current costs requested for CWIP accounting treatment are based on the Commission's previous orders.

Costs associated with Greenlink West are allocated 70 percent to Nevada Power Company.[2] Costs associated with the Fort Churchill – Mira Loma 345-kilovolt transmission line[3], the Fort Churchill – Comstock Meadows #1 – 345-kilvolt transmission line,[4] and the Fort Churchill – Comstock Meadows #2 – 345-kilovolt transmission line are not allocated to Nevada Power. Costs associated with the Fort Churchill substation are allocated 70 percent to Nevada Power.[5]

Cost associated with the Harry Allen – Northwest 525-kilovolt transmission line are allocated 70 percent to Nevada Power.[6]

Cost associated with Greenlink North are allocated 70 percent to Nevada Power.[7]

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

A. Yes.

[2] Docket No. 20-07023, March 22, 2021, Order at 265, para. 580.
[3] Docket No. 20-07023, March 22, 2021, Order at 269, para. 589.
[4] Docket No. 20-07023, March 22, 2021, Order at 269, para. 590.
[5] Docket No. 20-07023, March 22, 2021, Order at 269, para. 591.
[6] Docket No. 21-06001, January 26, 2022, Attachment A, at 4, section 3(b).
[7] Docket No. 21-06001, January 26, 2022, Attachment A, at 4, section 3(a).

# EXHIBIT LATEEF-DIRECT-1

## STATEMENT OF QUALIFICATIONS

**Shahzad M. Lateef**
**Senior Project Director – Greenlink Nevada Transmission**
**NV Energy**
**6226 West Sahara**
**Las Vegas, Nevada 89146**
**(702) 402-6652**

My name is Shahzad M. Lateef. My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am the Senior Project Director for Greenlink Nevada Transmission Project being developed by Nevada Power Company and Sierra Pacific Power Company.

I graduated from the University of Nevada – Las Vegas in May of 1994 with a Bachelor of Science degree in Electrical Engineering. I received a Master of Science Degree in Electrical Engineering from University of Nevada – Las Vegas in December of 1997.

In March of 1995, I joined the Nevada Power Company as an associate Engineer with Bulk Power Operations. In this role, my primary activities were to analyze unit commitment for Nevada Power Company's generation fleet, and nominate natural gas needed for the generation plants.

In January of 1997, I transferred to Distribution Planning as an engineer. This role involved distribution facility loading assessment, and planning and design for capital projects to support the load growth.

In January of 1998, I accepted the position of senior engineer with Resource Planning department. Within this role, I was responsible for the support of Nevada Power Company's resource plans utilizing various short-term and long-term production cost models. I also performed mid to long term power contract evaluations as a part of this role.

In March of 1999, I transferred to Distribution Operations as a senior engineer. In this role, I was responsible for resolution of power quality issues across Nevada Power Company service region. I also provided support to distribution system operations and real-time dispatch services.

In November of 2005, I was selected as Supervisor for Transmission and Distribution Operations for Nevada Power Company. In this role, I was responsible for real time operation of Nevada Power Company's transmission and distribution systems. The role also included oversight of operational engineering function.

In December of 2008, my role within Transmission and Distribution System Operations was expanded to include the Distribution Operations Technology, Electric Dispatch, and Gas dispatch for Sierra Pacific Power Company. My title with this expanded role was changed to Manager, Transmission and Distribution System Operations.

In October of 2013, I was transferred to the role of Manager of Distribution Operations. In this role, I had the responsibility of overseeing Distribution System Operations for Nevada Power Company and Sierra Pacific Power Company, Trouble Dispatch for electric and gas dispatch at both companies, Distribution Operations Technology, and Operations Engineering.

In May of 2014, I accepted the position of the Director of Transmission and Distribution System. In this role, I was responsible for Balancing Authority, Transmission Operations, Distribution Operations, Electric Trouble Dispatch, Network and Operations Engineering for Nevada Power Company and Sierra Pacific Power Company.

In October of 2017, I accepted the position of Vice President of Transmission. In this role, I had the responsibility for Balancing Authority Operations, Transmission Operations, Distribution Operations, Electric Trouble Dispatch, Transmission Planning, Substations Operations and Engineering, Transmission Policy, and Telecommunication Operations.

In May of 2020, I accepted the position of Vice President of Electric Delivery. In this role, I had the responsibility for safe and reliable operation of all of NV Energy's electric system. My area of responsibility included Transmission and Distribution Operations, Substations Operations, Metering Operations, Telecommunications Operations, New Business, Vegetation Management, and Fleet Operations.

In February of 2022, I accepted by current role as the Senior Project Director for the development of Greenlink Nevada Transmission Project. In this role, I have the overall responsibility for safe, compliant, and efficient development of all aspects of Greenlink Nevada Transmission Project.

I am a licensed profession engineer in the State of Nevada.

# EXHIBIT LATEEF-DIRECT-2

# NV Energy

## RESPONSE TO INFORMATION REQUEST

| | | | |
|---|---|---|---|
| **DOCKET NO:** | 21-06001 | **REQUEST DATE:** | 11-15-2021 |
| **REQUEST NO:** | Staff 232 | **KEYWORD:** | phase 4 greenlink project; monthly cashflow expenditure projections january 2022 |
| **REQUESTER:** | Maguire | **RESPONDER:** | Johns, Mathew |

**REQUEST:**

Reference: Phase 4 Green Link Project

Question: Please provide Staff with Monthly cash flow expenditure projections for the entire Green Link Project starting in January 2022 and going through 2028 when the Greenlink North project is projected to be in-service. These monthly cash flows of expenditures should tie back to the total estimated cost of the Green Link Project and should also include any money spent prior to January 2022.

**RESPONSE CONFIDENTIAL (yes or no):** No

**TOTAL NUMBER OF ATTACHMENTS:** One (Zipped)

**RESPONSE:**

Attached Table 1 provides the estimated project expenditures, excluding AFUDC, for the entire Greenlink Project as of September 2021 on an annualized basis. Project expenditures were not refined to a monthly basis. The September 2021 project cost estimates were used in the Capital Expense Recovery Model (“CER”) developed for the Transmission Infrastructure for a Clean Energy Economy Plan (“TICEEP) filing on September 21, 2021. As shown on Table 1, the forecasted cost for Greenlink Project expenditures prior to January 2022 was estimated to be $18.5 million at the time of the TICEEP filing. The current forecast expenditures prior to January 2022 remains within this forecast. Overall Greenlink Nevada project costs are within the cost estimates presented in Docket No. 20-07023.

**Staff Data Request 232**

TABLE 1
GREENLINK NEVADA TRANSMISSION PROJECT COST ESTIMATE EXCLUDING AFUDC
TRANSMISSION INFRASTRUCTURE FOR A CLEAN ENERGY ECONOMY PLAN ("TICEEP")
DOCKET NO. 21-06001 PHASE 4

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ln No | Greenlink Nevada Project | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Total |
| 1 | **Greenlink West** | 40,579 | 1,372,863 | 10,800,499 | 26,989,126 | 89,467,757 | 486,059,097 | 280,489,773 | 198,820,574 | 19,873,094 | 105,024,605 | 1,036,749 | 1,219,974,717 |
| 2 | Greenlink West* | 40,579 | 1,372,863 | 10,481,961 | 25,002,162 | 57,781,626 | 422,180,494 | 270,702,722 | 198,803,833 | 3,151,416 | - | - | 989,517,656 |
| 3 | Northwest Substation* | - | - | 175,193 | 1,102,919 | 24,653,051 | 56,918,237 | 4,472,782 | - | - | - | - | 87,322,182 |
| 4 | **Northwest Substation - Harry Allen - Northwest termination** | - | - | - | - | - | - | 5,200,000 | - | - | - | - | 5,200,000 |
| 5 | **HA - NW permitting / land*** | - | - | 143,346 | 884,045 | 7,033,080 | 6,239,530 | - | - | - | - | - | 14,300,000 |
| 6 | **Harry Allen - Northwest construction*** | - | - | - | - | - | 720,836 | 114,269 | 16,741 | 16,721,679 | 105,024,605 | 1,036,749 | 123,634,879 |
| 7 | **Greenlink North** | - | - | 53,257 | 5,639,600 | 10,026,596 | 10,385,844 | 46,469,564 | 103,072,572 | 329,007,799 | 347,909,593 | 1,555,128 | 854,119,953 |
| 8 | **Greenlink North permitting/land*** | - | - | 22,286 | 5,532,898 | 7,923,558 | 7,048,543 | 5,872,714 | - | - | - | - | 26,400,000 |
| 9 | **Greenlink North construction** | - | - | 30,971 | 106,701 | 2,103,038 | 3,337,302 | 40,596,849 | 103,072,572 | 329,007,799 | 347,909,593 | 1,555,128 | 827,719,954 |
| 10 | **Common Ties** | - | - | 6,270,893 | 24,549,601 | 40,125,285 | 76,931,942 | 207,991,946 | 41,464,857 | - | - | - | 397,334,523 |
| 11 | Ft Churchill Substation* | - | - | 3,479,413 | 13,994,687 | 17,167,542 | 54,786,993 | 92,654,831 | 17,758,530 | - | - | - | 199,841,995 |
| 12 | Ft Churchill Sub Phase 2 | - | - | - | - | - | - | 23,398,706 | 23,398,706 | - | - | - | 46,797,412 |
| 13 | Ft Churchill - Mira Loma* | - | - | 1,309,598 | 5,223,277 | 10,852,031 | 15,239,406 | 50,688,196 | 126,857 | - | - | - | 83,439,366 |
| 14 | Ft. Churchill - Comstock #1* | - | - | 1,481,882 | 5,331,637 | 12,105,712 | 6,905,543 | 41,250,213 | 180,764 | - | - | - | 67,255,751 |
| 15 | **Annual Spend** | 40,579 | 1,372,863 | 17,124,650 | 57,178,327 | 139,619,638 | 573,376,883 | 534,951,282 | 343,358,002 | 348,880,894 | 452,934,198 | 2,591,877 | 2,471,429,194 |
| 16 | **Cumulative Spend** | 40,579 | 1,413,442 | 18,538,092 | 75,716,419 | 215,336,057 | 788,712,940 | 1,323,664,222 | 1,667,022,224 | 2,015,903,118 | 2,468,837,317 | 2,471,429,194 | |

17

18 **Notes**

19 *Projects were approved by the Commission as part of Docket No. 20-07023 in March 2021

20 (a) Project costs were current estimates, excluding AFUDC, as of September 2021 used in Capital Recovery Forecast ("CER") modeling for the TICEEP filing.

21 (b) Total cumulative expenditures for Greenlink Nevada Projects through 2021 were forecasted to be $18.5 million at the time of the filing (see columns b + c + d above)

22 (c) The Harry Allen to Northwest 525 kV transmission line project cost estimates, excluding AFUDC, are shown in lines 4, 5, and 6 as summarized in the TICEEP filing below

23 - Total Project estimate for the transmission line is $137.9 million = $126.6 million (line 6) + $14.3 million (line 5)

24 - Total Project estimate for the Northwest interconnection is $5.2 million (line 4)

25 (d) The Fort Churchill to Robinson Summit 525 kV transmission line project cost estimates, excluding AFUDC, are shown in lines 7, 8, and 9 as summarized in the TICEEP filing below

26 - Total Project estimate for the transmission line is $854.1 million (line 7) = $26.4 million (line 8) + $827.7 million (line 9)

27 (e) The Fort Churchill Substation project cost estimates, excluding AFUDC, are shown in lines 11 and 12, as summarized in the TICEEP filing below

28 - Total Project estimate for the initial substation build-out is $199.8 million (line 11) and $48.6 million to complete (line 12)

29 (f) Ft. Churchill - Comstock #2 transmission line not included in the above summary

# EXHIBIT LATEEF-DIRECT-3

# Greenlink Nevada Transmission Project – Lines

Greenlink Nevada Transmission project comprises of three primary line segments.

**Greenlink West:**

- Harry Allen – Northwest 525 kilovolt transmission line
- Northwest – Amargosa 525 kilovolt transmission line
- Amargosa – Esmeralda 525 kilovolt transmission line
- Esmeralda – Fort Churchill 525 kilovolt transmission line

**Greenlink North:**

- Fort Churchill – Lander 525 kilovolt transmission line
- Lander – Robinson Summit 525 kilovolt transmission line

**Common Ties:**

- Fort Churchill – Comstock Meadows #1 – 345 kilovolt transmission line
- Fort Churchill – Comstock Meadows #2 – 345 kilovolt transmission line
- Fort Churchill – Mira Loma – 345 kilovolt transmission line

# Greenlink Nevada Transmission Project – Telecommunications

Greenlink Nevada Transmission project includes several telecommunication sites along transmission line routes. The telecommunication technology, locations, and equipment to be installed at these telecommunication terminals is currently being designed and engineered.

# Greenlink Nevada Transmission Project – Substations

***** Material and construction costs associated with the 2 – 525/230 kV transformers, 6 – 230 kV circuit breakers, and 14 – 230 kV CCVTs (highlighted above) at Esmeralda and Amargosa substations are not included in Greenlink forecast as provided in this docket. The 230 kV buildout of Amargosa and Esmeralda substations was approved by the Commission in Docket # 23-08015, based on large generator interconnection agreements or customer load needs. NV Energy intends to order materials and start construction on the 230 kV sections of Amargosa and Esmeralda substations once such interconnection agreements are executed.

# Greenlink Nevada Transmission Project

| Line Segment/Substation | Current Status and Percentage Completion (Engineering & Design) | Current Status and Percentage Completion (Owner Provided Procurement) | Current Status and Percentage Completion (Construction) | Budget Forecast ($ thousand) |
|---|---|---|---|---|
| Harry Allen – Northwest 525 kilovolt transmission line | 30%<br>In Progress | 5%<br>Required Contracts in Place | 0%<br>Not Started | $173,921.4 |
| Northwest – Amargosa 525 kilovolt transmission line | 100%<br>Design Package Issued | 15%<br>Purchase Orders Issued | 1%<br>Access Review Started | $342,432.9 |
| Amargosa – Esmeralda 525 kilovolt transmission line | 90%<br>In Progress | 15%<br>Purchase Orders Issued | 1%<br>Access Review Started | $408,743.4 |
| Esmeralda – Fort Churchill 525 kilovolt transmission line | 80%<br>In Progress | 10%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $458,095.9 |
| Fort Churchill – Robinson Summit 525 kilovolt transmission line | 15%<br>In Progress | 5%<br>Required Contracts in Place | 0%<br>Not Started | $1,159,130.7 |
| Fort Churchill – Comstock Meadows #1 – 345 kilovolt transmission line | 40%<br>In Progress | 5%<br>Required Contracts in Place | 0%<br>Not Started | $121,492.8 |
| Fort Churchill – Comstock Meadows #2 – 345 kilovolt transmission line | 50%<br>In Progress | 5%<br>Required Contracts in Place | 0%<br>Not Started | $100,030.7 |
| Fort Churchill – Mira Loma – 345 kilovolt transmission line | 60%<br>In Progress | 5%<br>Required Contracts in Place | 0%<br>Not Started | $135,494.6 |
| Fort Churchill Substation | 85%<br>Design Package Issued and In Progress | 17%<br>Delivery of Material Started | 5%<br>In Construction | $448,234.3 |
| Amargosa Substation | 90%<br>In Progress | 12%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $203,653.9 |

# Greenlink Nevada Transmission Project

| | | | | |
|---|---|---|---|---|
| Amargosa Substation (230 kV Buildout) | NA | NA | NA | (Not Included in Forecast as presented in this docket) |
| Esmeralda Substation | 100%<br>Design Package Issued | 12%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $182,307.4 |
| Esmeralda Substation (230 kV Buildout) | NA | NA | NA | (Not Included in Forecast as presented in this docket) |
| Lander Substation | 10%<br>In Progress | 12%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $264,635.9 |
| Northwest Substation | 100%<br>Design Package Issued | 15% | 1%<br>Access Review Started | $109,730.2 |
| Robinson Summit Substation | 10%<br>In Progress | 12%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $68,695.1 |
| Harry Allen Substation | 10%<br>In Progress | 11%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $25,499.5 |
| Comstock Meadows Substation | 50%<br>In Progress | 11%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $19,176.8 |
| Mira Loma Substation | 100%<br>Design Complete | 11%<br>Partial Purchase Orders Issued | 0%<br>Not Started | $16,964.7 |

**Notes:**

# Greenlink Nevada Transmission Project

## Engineering/Design

1) Design percent completes are based on IFC prints obtaining 100%. Construction support services and material procurement support is not considered in the engineering % complete.
2) Key milestone percentages were used and then interpolated between based on the effort to date towards the next milestone
   a. 10% - DCM complete
   b. 30%, 60%, 90% - based on 30%, 60%, 90% submittals to NVE
   c. 100% - IFC complete
3) Additional engineering/design work may follow 100% design status based on value activities proposed by the contractor or scope changes.

## Procurement

1) Represents Owner provided material only
2) 5% - Required Contracts Developed
3) 15% - All Purchase Orders Issued (Interpolated down based on the number outstanding purchase orders)
4) 15%-100% - Materials Manufactured to Delivered (Professional Judgment)

## Construction

1) Represents the work effort on the ground.
2) 1% credit given for access review on Transmission / Substation projects

| Microwave / OA Site | Current Status and Percentage Completion (Engineering & Design) | Current Status and Percentage Completion (Owner Provided Procurement) | Current Status and Percentage Completion (Construction) | Budget Forecast ($ thousand) |
|---|---|---|---|---|
| Esmeralda Substation 525 kV | 80%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Harry Allen Substation 525 kV | 10%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |

**Greenlink Nevada Transmission Project**

| | | | | |
|---|---|---|---|---|
| | | | | |
| Northwest Substation 525 kV | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Amargosa Substation 525 kV | 60%<br>In Progress | 10%<br>Some Purchase Orders Issued | 0%<br>Not Started | |
| OA 1 Mercury | Scope Removed | Scope Removed | 0%<br>Not Started | |
| OA 2 Scotty's Junction | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| OA 4 Tamarack | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Amargosa MW | 100%<br>Design Complete | 10%<br>Some Purchase Orders Issued | 0%<br>Not Started | |
| Angel Peak Substation & Existing MW | 100%<br>Design Complete | 10%<br>Some Purchase Orders Issued | 0%<br>Not Started | |
| Stonewall Pass MW | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Montezuma MW | 95%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Pilot Peak MW | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Sawtooth MW | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Spotted Range MW | 100%<br>Design Package Issued | 12%<br>Some Purchase Orders Issued | 0%<br>Not Started | |
| TV Hill MW | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |

**Greenlink Nevada Transmission Project**

| | | | | |
|---|---|---|---|---|
| Silver Peak MW | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Booker MW | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Beltway Service Center & OHM | 75%<br>In Progress | NA | 0%<br>Not Started | |
| Beltway Sub | 100%<br>Design Complete | NA | 0%<br>Not Started | |
| Lenzie Sub | 10%<br>In Progress | NA | 0%<br>Not Started | |
| Comstock Meadows Sub 345 kV | 75%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Mira Loma Sub 345 kV | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Fort Churchill Sub 120 kV | 100%<br>Design Package Issued | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Fort Churchill Sub 525 kV | 10%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Fort Churchill Sub 345 kV | 100%<br>Design Complete | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Fort Churchill Sub 230 kV | 75%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| OA 8 Whiskey Flats | 60%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| FCT 230/120/60 kV & Plant | 100%<br>Design Package Issued | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Pinenut Peak MW | 10%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |

**Greenlink Nevada Transmission Project**

| | | | | |
|---|---|---|---|---|
| Dove Sub, East Tracey Sub, Wildhorse, Greg St. Sub | 100%<br>Design Complete | NA | 0%<br>Not Started | |
| Geiger MW & Billboard | 85%<br>In Progress | NA | 0%<br>Not Started | |
| Bella Vista Sub & GOB | 50%<br>In Progress | NA | 0%<br>Not Started | |
| Lander Sub 525/230 kV | 10%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Robinson Summit Sub 525/345 kV | 20%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| OA 5 Carson Lake | Scope Removed | Scope Removed | 0%<br>Not Started | |
| OA 6 Augusta | 60%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| OA 7 Ruby Hill | 60%<br>In Progress | 5%<br>Contracts in Place | 0%<br>Not Started | |
| Austin Sub, Cape Horn OA, Edwards creek OA, Eureka OA, Moorman Ranch OA, Lahontan OA, Salt Flats OA | 75%<br>In Progress | NA | 0%<br>Not Started | |

**Notes:**

**Engineering/Design**

1) Design percent completes are based on IFC prints obtaining 100%. Construction support services and material procurement support not considered in the engineering % complete.

**Greenlink Nevada Transmission Project**

2) Key milestone percentages were used and then interpolated between based on the effort to date towards the next milestone
    a. 10% - DCM complete
    b. 30%, 60%, 90% - based on 30%, 60%, 90% submittals to NVE
    c. OA sites at minimum 60% based on design reuse from previous sites
    d. 100% - IFC complete
3) Additional engineering/design work may follow 100% design status based on value activities proposed by the contractor or scope changes.
4) New IFC packages may be required if sites are moved after IFC prints are issued.

**Procurement**

1) Represents Owner provided material only
2) NA represents minimal to no additional owner provided equipment necessary to complete the work
3) 5% - Required Contracts Developed
4) 15% - All Purchase Orders Issued (Interpolated down based on the number outstanding purchase orders)
5) 15%-100% - Materials Manufactured to Delivered (Professional Judgment)

**Construction**

1) Represents the work effort on the ground.

# EXHIBIT LATEEF-DIRECT-4

**Greenlink Nevada Transmission Project**

**Long Lead Time Materials and Apparatus Contracts**

| Material/Service | Contracted Manufacturer |
|---|---|
| Substation Shaped Steel and Insulators | Meyer, Wesco and Siemens |
| Fixed Series Capacitors | General Electric |
| Power Transformers and Shunt Reactors | BEST, Fortune, Hyundai |
| Circuit Breakers | Hitachi and GE |
| Substation and Transmission Tubular Steel Pole Structures | SAE and TAPP |
| Transmission Lattice Steel Structures | Karamtara |
| Instrument Transformers and Neutral Reactors | Koncar, GE |
| Disconnect Switches | Southern States, Royal Switchgear |
| Conductor and Shield Wire | Midal, Prysmian, and National Strand |
| Control Enclosures and Panels | Instrument Control Company |
| OPGW | AFL |
| Microwave Towers | Valmont |
| Sales and Use Tax | Estimated sales and use taxes on material |
| Shipping | Estimated shipping and demurrage costs on material |
| Environmental Permitting | AECOM and Logan-Simpson |

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, SHAHZAD LATEEF, 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: February 14, 2025

Shahzad Lateef

# DANYALE HOWARD

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02____
2025 General Rate Case

Prepared Direct Testimony of

**Danyale Howard**

Revenue Requirement



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

A. My name is Danyale Howard. My current position is Director, Natural Disaster Protection 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 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I have 28 years of experience in the utility industry. I joined Sierra in May 1996. Before assuming my current role, I held the role of Director, Distribution Design Services, responsible for the electric and gas design and project management of distribution line extensions subject to Rule 9 Line Extension tariffs, local governmental franchise agreements, and electric distribution reliability projects for northern Nevada. In June 2021, I assumed the role of Director, Natural Disaster Protection, responsible for system hardening, grid ruggedization, and the circuit patrols and detailed inspection programs. In October 2023, I assumed the Natural Disaster Protection Plan ("NDPP") operations and compliance responsibilities, consisting of emergency management, situational awareness, vegetation management, and fire season operations protocols. My statement of qualifications is attached as **Exhibit Howard-Direct-1.**

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, NATURAL DISASTER PROTECTION.**

A. As Director, Natural Disaster Protection, my responsibilities include implementation of the Companies' NDPP pursuant to NRS 704.7983. The NDPP drives the mitigation of potential wildfires and other natural disasters that could impact or be caused by the Companies electric facilities.

**4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes. I have submitted testimony and appeared before the Commission multiple times, most recently in the 2024 NDPP Regulatory Asset Recovery, Docket No. 24-03006.

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

A. I support the reasonableness of the Company's capital investment projects related to fire mitigation and other natural disaster risk mitigation. For the Test Period through September 30, 2024, and the Certification Period of October 1, 2024, through February 28, 2025, those investments are identified in **Table Howard-Direct-1.** Certification Period estimates will be updated to reflect the actual costs as part of the Company's Certification filing.

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

**TABLE HOWARD-DIRECT-1**
**CAPITAL MAINTENANCE INVESTMENT**

| Budget ID | Budget ID Description | Actuals through September 30, 2024, (in millions) | Estimates through February 28, 2025 (in millions) | Total (in millions) |
|---|---|---|---|---|
| **D4234** | Pole Replacements - GRC Circuit Resilience Dist NPC | $ 1.20 | $ 12.34 | $ 13.54 |
| **D4226** | Overhead Rebuild - GRC Tier 3 Poles NPC | $ - | $ 1.98 | $ 1.98 |
| **D2870** | Sectionalization - GRC – Mt. Charleston Tripsaver | $ 0.08 | $ - | $ 0.08 |
| | **Total** | **$ 1.28** | **$ 14.32** | **$ 15.60** |

**6. Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following Exhibits:

**Exhibit Howard-Direct-1** Statement of Qualifications

**Exhibit Howard-Direct-2** Angel Peak Circuit Segment Rebuild Map

**7. Q. PLEASE DESCRIBE THE POLE REPLACEMENTS REPRESENTED AS BUDGET IDENTIFICATION (“ID”) D4234.**

A. Costs associated with budget ID D4234 shown in **Table Howard-Direct 1** represent single pole replacements performed as part of the NDPP Circuit Resilience Patrol and Inspection Program (“Circuit Resilience Program”). The Circuit Resilience Program identifies impacted distribution circuits in high-threat areas (“HTA”) that typically experience extreme wind, flood, microburst, and monsoon events. The Circuit Resilience Program consists of the top 20 worst performing circuits, where “worst performing circuits” analysis is an industry standard for gauging infrastructure health that is broadly applied to identifying vulnerability to natural disasters. Identification of these “worst performing circuits” is based on a review of the past five years of nature-caused outages.

**Table Howard-Direct 2** shows a list of circuits where the single pole replacements were performed from June 1, 2023, through September 30, 2024, and are anticipated to be in-serviced by February 28, 2025.

**TABLE HOWARD-DIRECT-2**

**NDPP CIRCUIT RESILIENCE SINGLE POLE REPLACEMENTS**

| Nevada Power Circuits<br>Circuit Resilence Pole Replacements | |
|---|---|
| Alta 1213 | North Las Vegas 1211 |
| Anthem 1212 | Pawnee 1204 |
| Artesian 1206 | Pearl 1206 |
| Balboa 1204 | Pearl 1206 |
| Highland 1206 | Sahara 1212 |
| Lincoln 1206 | Sahara 1212 |
| Lorenzi 1210 | San Francisco 1217 |
| Mayfair 1215 | Searchlight 1201 |
| Michael Way 1207 | Shadow 1209 |
| Michael Way 1211 | Spencer 1214 |
| N. Las Vegas 1209 | Tonopah 1201 |
| North Las Vegas 1209 | |

The total cost of assets in service for Circuit Resilience single pole replacements for Budget ID D4234 through September 30, 2024, is $1,200,000. Estimated expenditures for the Circuit Resilience Program for the period of October 1, 2024, through February 28, 2025, are $12,340,000.[1]

**8. Q. WHY ARE THE POLE REPLACEMENTS NECESSARY?**

A. Replacement of the poles is necessary because these poles reside in a HTA, and they are identified as having a risk condition(s) requiring correction as part of the worst performing circuit review discussed above.

[1] Pole replacements began in the fall of 2024. The recording of the in-serviced date for these pole replacements was not complete as of the end of the Test Period. All complete, in-serviced pole replacements will be updated with the Certification filing.

Circuit Resilience pole inspections are performed by qualified lines personnel using a standardized criteria to assess equipment condition and associated risk. Conditions for correction are classified as either needing minor hardware repairs or requiring full capital pole replacements. These poles were identified and documented as having risk conditions warranting full pole replacement.

**9. Q. PLEASE DESCRIBE THE OVERHEAD REBUILD REPRESENTED AS BUDGET IDENTIFICATION ("ID") D4226?**

A. Costs associated to Budget ID D4226 shown in **Table Howard-Direct-1** represent a segment rebuild of the Angel Peak 3402, a 34.5 kV overhead distribution circuit located at Mt. Charleston. This circuit resides in Tier 3, the highest fire risk area in the Nevada Power service territory. **Exhibit Howard-Direct-2** shows the location of the rebuild. The total cost of the overhead rebuild for Budget ID D4226 through September 30, 2024, is zero dollars and estimated expenditures for this project for the period of October 1, 2024, through February 28, 2025, are $1,980,000.

**10. Q. WHY IS A SEGMENT OF THE ANGEL PEAK 3402 BEING REBUILT?**

A. This segment of the Angel Peak 3402 distribution circuit is being rebuilt because each of the 23 poles were identified through the NDPP Circuit Patrol and Inspection program ("Circuit Patrol" program) as having a risk condition requiring full capital pole replacement. The legacy poles reside in sequence, are an identified fire risk and are in the highest fire risk tier, Tier 3. The poles are 1960s vintage and have exceeded their useful life. While in queue pending replacement, these poles suffered additional damage during the 2023 tropical storm Hillary. As a result of the damage, and the restoration efforts that occurred following the tropical storm, the Companies were able to collaborate with the U.S. Forest Service ("USFS") to perform repairs, including upgrading repairs to a full rebuild of this segment to meet the Company's modern fire mitigation design standard. The rebuild for this section consists of replacing bare wire with covered conductor and installing fire mesh on the new wood poles.

This rebuild is one segment of a larger plan to convert Mt. Charleston electric infrastructure to a modern fire mitigation standard. The Mt. Charleston rebuild plan was included in the Second Triennial NDPP in Docket No. 23-03003.[2] The Mt. Charleston rebuild plan consists of four phases and the Commission, in Docket No. 23-03003, approved NDPP funding for design of the first phase. The Angel Peak 3402 segment rebuild that is targeted for recovery in this GRC docket is also represented, in part, as the third phase of the Mt. Charleston rebuild plan.

Construction of phase three was anticipated to occur in future years, beyond the term of the currently approved Second Triennial NDPP. However, as stated previously, the Companies were able to accelerate construction for this section because the USFS supported expedited repairs after tropical storm Hillary, thereby eliminating what is typically a long lead-time for permitting under normal circumstances. The Companies opted to perform a segment rebuild of the line versus single pole replacements due to the high fire risk location of the line and the future plan to convert Mt. Charleston infrastructure to a modern fire mitigation standard.

[2] Docket No. 23-03003, 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 Joint 2024-2026 Natural Disaster Protection Plan (filed Mar. 1, 2023) ("Second Triennial NDPP").

It should be noted that as part of the recent filing of the First Amendment ("First Amendment") to the Second Triennial NDPP, Docket No. 24-12016, the Companies requested an amendment to the Mt. Charleston rebuild, seeking funding for the first of four phases of the Mt. Charleston rebuild. The Angel Peak 3402 segment rebuild represented in this recovery docket is outlined as part of phase three in the NDPP First Amendment. No construction funding associated with the Angel Peak 3402 segment rebuild is requested in the First Amendment application.

**11. Q. PLEASE DESCRIBE THE TRIPSAVER WORK PERFORMED AT MT. CHARLESTON.**

A. During 2023, the Companies implemented fast trip fire mode ("FTFM") capability throughout Tier 3. FTFM describes increasing system protection settings to a rapid 0.1-second near instantaneous trip (when a fault occurs) to further prevent the potential of an equipment caused ignition. A rapid trip significantly decreases the energy release component and subsequently reduces the potential the energy release component may ignite surrounding fuels within the vicinity of energized equipment. FTFM capable areas of the system are enabled seasonally to enhance fire season protocols in addition to the traditional seasonal single-reclose setting, Public Safety Outage Management and the Emergency De-Energization Wildfire policy ("EDEN"). The biproduct of FTFM is the loss of relay coordination to devices located downstream of a trip, meaning outages are wider spread than necessary. In addition to being a non-expulsion fuse, TripSavers serve as a mini-recloser that can be programed to reduce the effects of downstream outages, offering improved reliability for customers that would otherwise be de-energized due to the loss of relay coordination.

**12. Q. WHY WAS THIS WORK NECESSARY?**

A. The Companies installed TripSavers at key locations at Mt. Charleston to improve reliability during activation of FTFM during fire season. The TripSavers help sectionalize outage areas by limiting unnecessary outages where possible, specifically outages that would occur downstream of a trip activated by FTFM activation in the high fire risk area of Mt. Charleston.

**13. Q. WAS A DIGITAL BINDER CREATED FOR THE TRIPSAVER PROJECT?**

A. No, a digital binder for this work was not created. Project "binders" for smaller projects (less than $500,000) completed since June 1, 2023, are not prepared. However, for transparency of NDPP-related matters that are typically recovered via another rate mechanism, my testimony discusses these costs.

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

A. Yes.

# EXHIBIT HOWARD-DIRECT-1

# Statement of Qualifications
# for
# DANYALE M. HOWARD

## Professional Experience

***Director, Natural Disaster Protection, Compliance and Operations***
*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy*
*October 2023 – Present*

Responsible for planning and support for electric system operations and emergency management, including public safety de-energization events to mitigate the risk of wildfires and other natural disasters. Responsible for ensuring the compliance of the natural disaster protection program with existing statutes, codes, and regulations. Provides oversite and management for situational awareness, and vegetation management, including traditional arial line maintenance and hazardous ground fuels management.

***Director, Natural Disaster Protection, Program Execution***
*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy*
*June 2021 - Present*

Responsible for developing and implementing the Natural Disaster Protection Plan mitigation programs and projects, controls, technology development, engineering, resource allocation and program effectiveness. Provides oversite and management for system hardening, grid ruggedization and circuit inspection and maintenance.

***Director, Distribution Design Services, Northern Nevada***
*Sierra Pacific Power Company d/b/a NV Energy*
*April 2018 – June 2021*

Responsible for electric and gas design engineering and project coordination for distribution line extensions subject to Public Utilities Commission of Nevada ("PUCN") Rule 9 tariff, local government franchise agreements and planned capital maintenance targets. Managed staff across five northern Nevada district offices.

***Manager, Distribution Design Services, Northern Nevada***
*Sierra Pacific Power Company d/b/a NV Energy*
*January 2016 – April 2018*

Responsible for electric and gas design engineering and project coordination for distribution line extensions subject to PUCN Rule 9 tariff, local government franchise agreements and planned capital maintenance targets. Managed staff across five northern Nevada district offices.

***Supervisor, Distribution Design Services***
*Sierra Pacific Power Company d/b/a NV Energy*
*March 2013 – January 2016*

Responsible for electric and gas design engineering and project coordination for distribution line extensions and facility relocation projects subject to PUCN Rule 9 tariff, local government franchise agreements and electric planned capital maintenance targets. Managed Truckee Meadows and Carson City offices.

***Team Leader, Field Services, Northern Nevada***
*Sierra Pacific Power Company d/b/a NV Energy*
*January 2011 – March 2013*

Responsible for developing, implementing, and supervising procedures for reading and data collections, accurate and cost-effective installation of electric meters and gas AMI modules. Managed staff across nine rural district locations.

***Utility Design Administrator II***
*Sierra Pacific Power Company d/b/a NV Energy*
*October 2004 – January 2011*

Responsible for performing design and project management of electric and gas distribution projects. Participated in the implementation of the Enterprise Work Asset Management (“EWAM”) project, creating business test scenarios, regression and user acceptance testing, and facilitated training across all northern Nevada districts.

***Analyst II, Revenue Protection***
*Sierra Pacific Power Company d/b/a NV Energy*
*December 1997 – October 2004*

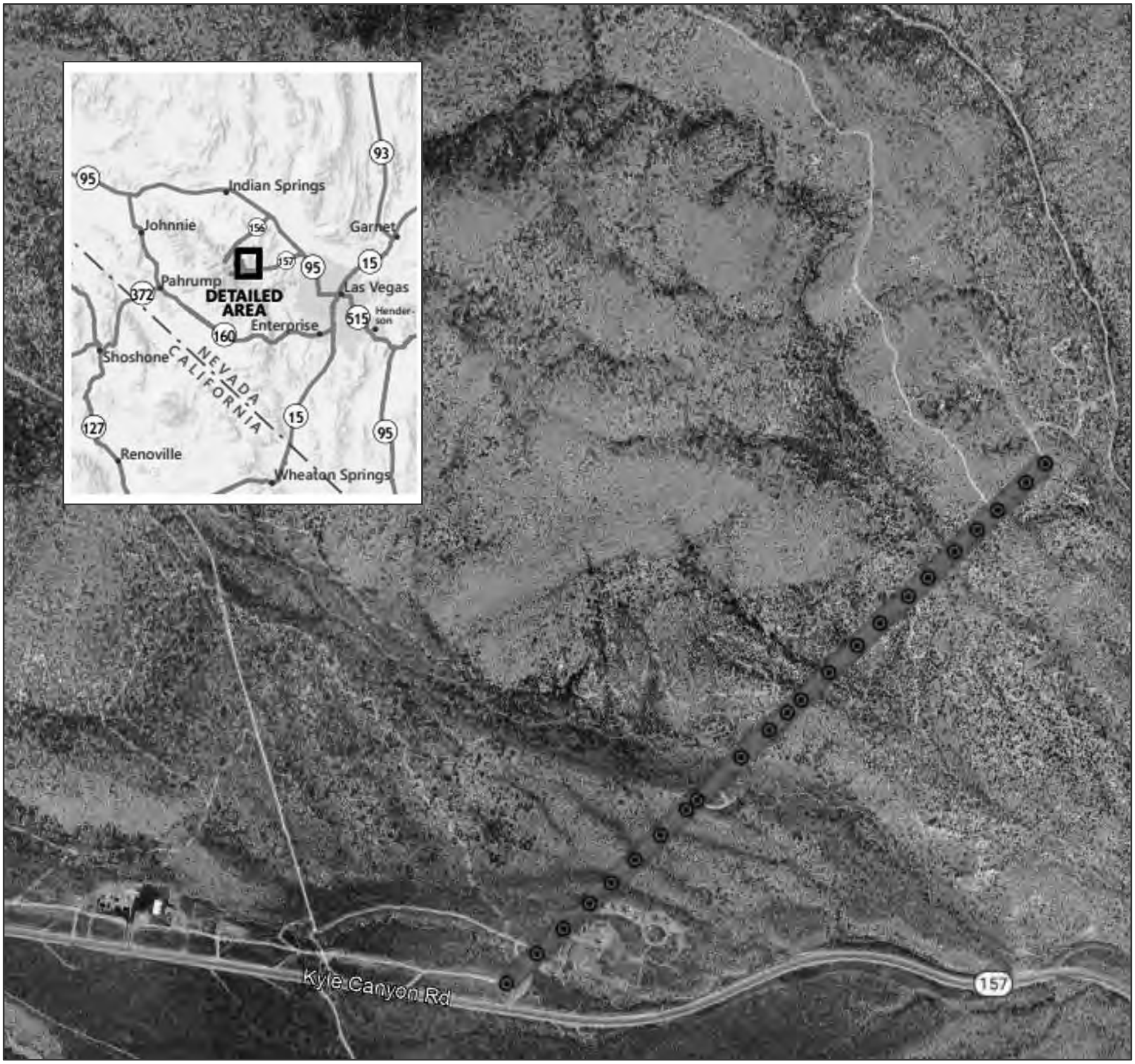
Responsible for preparing and submitting exhibits, reports and legal documents related to utility theft and fraud. Past president of Western States Utility Theft Association (“WSUTA”), responsible for coordinating training and certification to utility investigators nationally.

***Meter Reader***
*Sierra Pacific Power Company d/b/a NV Energy*
*May 1997 – December 1997*

Responsible for collecting and recording accurate meter reads for electric and gas meters.

# EXHIBIT HOWARD-DIRECT-2

**Exhibit Howard-Direct-2 Angel Peak Circuit Segment Rebuild Map**




**Red Section** – Overhead Rebuild – Project ID 3010902345

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, DANYALE HOWARD, states that she 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 her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: February 14, 2025

Danyale Howard

Danyale Howard

# DEBORAH J. FLORENCE

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

**Deborah J. Florence**

Revenue Requirement

## I. INTRODUCTION BACKGROUND AND PURPOSE OF TESTIMONY

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

A. My name is Deborah J. Florence. My current position is Director of Corporate Taxes 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 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. Before coming to Sierra in 1997, I worked for seven years in the certified public accounting firm of Deloitte & Touche, LLP. As a tax manager there, I was responsible for all areas of tax compliance, research and planning for several large corporate clients. I have a Bachelor of Science Degree in Accounting and a Master of Science Degree in Taxation, both from Weber State University. I am a Certified Public Accountant in Nevada.

With the merger of the Companies, I was promoted from a Senior Tax Analyst with Sierra to Corporate Tax Manager for the Companies. On January 2, 2005, I was promoted to the Director of Corporate Taxes. I have more than 25 years of utility tax experience and I supervise a staff of six tax professionals. My statement of qualifications is attached as **Exhibit Florence-Direct-1**.

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF CORPORATE TAXES.**

A. As Tax Director, I am responsible for all areas of taxation for the Companies. This includes federal and state compliance, planning and forecasting. I oversee all tax accounting and tax-related regulatory reporting. Additionally, I represent the Companies in regulatory filings on all tax related matters.

**4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?**

A. Yes, I have testified before the Commission in many proceedings, most recently in Sierra's Electric and Gas 2024 General Rate Cases ("GRC") (Docket Nos. 24-02026 and 24-02027) and Nevada Power's 2023 GRC (Docket No. 23-06007).

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

A. I am sponsoring the calculations of income taxes and taxes other than income taxes in this GRC filing. I am also providing testimony on the calculation of excess deferred taxes and the related Average Rate Assumption Method ("ARAM") adjustments.

Specifically, I am sponsoring the following Statements and Schedules:

- Statement M, Calculation of Federal Income Tax for the Test Period Ended September 30, 2024;
- Schedule M-1, Reconciliation of Book Income to Taxable Income for the Tax Year 2023 and the Three Preceding Years;
- Schedule M-2, Comparison of Tax Depreciation to Book Depreciation for the Tax Year 2023 and the Three Preceding Years;
- Schedule M-3, Consolidated Income and Deductions Summary for the Tax Year Ended December 31, 2023;
- Schedule M-4, Monthly Book Balance of Accumulated Deferred Income Taxes from October 2023 to September 2024;
- Schedule M-5, Taxes Other Than Income;
- Schedule H-CERT-08, Taxes Other Than Income for the Test Period Ended September 30, 2024, and for the Certification Period Ended February 28, 2025;
- Schedule H-CERT-09, Income Tax M-1 Items for the Test Period Ended September 30, 2024, and for the Certification Period Ended February 28, 2025;
- Schedule H-CERT-10, Deferred Income Tax Expense for the Test Period Ended September 30, 2024, and for the Certification Period Ended February 28, 2025;
- Schedule H-CERT-11, Income Tax Rate Base Adjustments for the Test Period Ended September 30, 2024, and for the Certification Period Ended February 28, 2025;
- Schedule H-CERT-15, Amortization of Investment Tax Credits ("ITC") for the Test Period Ended September 30, 2024, and for the Certification Period Ended February 28, 2025;

- Schedule I-EC-09, Income Tax M-1 Items for the Expected Change in Circumstance ("ECIC") Period Ending September 12, 2025. The updated information is provided in Schedule I-EC-09.
- Schedule I-EC-10, Deferred Income Tax Expense for the ECIC Period Ending September 12, 2025. The updated information is provided in Schedule I-EC-10.
- Schedule I-EC-11, Income Tax Rate Base Adjustments for the ECIC period Ending September 12, 2025. The updated information is provided in Schedule I-EC-11.
- Statement P Item 1, change in method of reporting ARAM amortization from H-CERT-09 Perm Tax Return Items at Gross to H-CERT-10 Flow Thru, ARAM and Tax Credits (Stated at 21 percent).

**6. Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes, I am sponsoring the following exhibit:

- **Exhibit Florence-Direct-1** Statement of Qualifications;

## II. <u>STATEMENTS AND SCHEDULES</u>

**7. Q. PLEASE DESCRIBE STATEMENT M AND SCHEDULES M-1 THROUGH M-5.**

A. Statement M has been prepared in accordance with Nevada Administrative Code ("NAC") sections 703.2411 through 703.2435. Statement M shows the computation of allowances for federal income tax for the 12 months ending September 30, 2024, along with related schedules that:

- Reconcile book and tax income for the last four filed tax returns (M-1);

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

- Detail the difference between tax and book depreciation for the last four filed tax returns (M-2);
- Provide details of the last filed consolidated tax return (M-3);
- Provide monthly balances by deferred income tax account for each month of the Test Period (M-4); and
- Provide details of taxes other than income taxes for the Test Period and the projected period (M-5).

**8. Q. PLEASE DESCRIBE SCHEDULE H-CERT-08.**

A. H-CERT-08 shows the adjustment relating to taxes other than income for the change between the Test Period ending September 30, 2024, and the Certification Period ending February 28, 2025.

**9. Q. PLEASE DESCRIBE SCHEDULE H-CERT-09.**

A. Schedule H–CERT-09 reflects the tax adjustments for cost-of-service items for the Test and Certification periods. The cost-of-service tax adjustments are divided into two categories: (1) permanent and (2) normalized. Permanent differences are those which increase or decrease taxes based on the actual amount due to the Internal Revenue Service ("IRS"). Adjustments for normalized items do not increase or decrease total tax expense because offsetting deferred taxes are provided on Schedule H-CERT-10, which I describe below. The Certification adjustments shown on Schedule H-CERT-09 result from the annualization of certain tax items and from the tax effect of other adjustments included in the test period.

**10. Q. PLEASE DESCRIBE SCHEDULE H-CERT- 10.**

A. Schedule H-CERT-10 reflects adjustments for deferred income taxes associated with liberalized depreciation and various other normalized items as shown on Schedule H-CERT-09. Additionally, H-CERT-10 includes the reduction in tax expense associated with book amortizations including ARAM and Excess Deferred Income Taxes. The Certification adjustments shown on Schedule H-CERT-10 result from the annualization of certain tax items and from the tax effect of other adjustments included in the Test Period.

**11. Q. PLEASE DESCRIBE SCHEDULE H-CERT-11.**

A. Schedule H-CERT-11 reflects the adjustment to rate base resulting from income taxes generated by items included in rate base, such as deferred taxes on the differences between book and tax depreciation. Schedule H-CERT-11 also includes the ITC balances allowed as a rate base deduction. Nevada Power elected to opt out of normalization for both the Reid Gardner Battery Energy Storage System ("RG BESS") and the Department of Energy BESS assets in its 2023 federal income tax return. This allowed for both the reduction of tax expense for the ITC amortization (see H-CERT-10 Line 56) and the inclusion of the unamortized ITC balance in rate base (H-CERT-11 Line 56).

**12. Q. PLEASE DESCRIBE SCHEDULE H-CERT-15.**

A. Schedule H-CERT-15 reflects the adjustments to the amortization of investment tax credits. The Statement N adjustment in column (c) lowers ITC amortization due to the deferral of the RG BESS project in Nevada Power's last GRC order (Docket No. 23-06007). However, the full amount of ITC amortization is included in the Certification Period estimate for February 28, 2025 (no reduction for the deferral).

**13. Q. PLEASE DESCRIBE SCHEDULE H-EC-09.**

A. Schedule H–EC-09 reflects the tax adjustments for cost-of-service items for the Certification and ECIC periods. The cost-of-service tax adjustments are divided into two categories: (1) permanent and (2) normalized. Permanent differences are those, which increase or decrease taxes based on the actual amount due to the IRS. Adjustments for normalized items do not increase or decrease total tax expense, because offsetting deferred taxes are provided on Schedule H-EC-10, which I describe below. The adjustments shown on Schedule H-EC-09 result from the annualization of certain tax items and from the tax effect of other adjustments included in the ECIC period.

**14. Q. PLEASE DESCRIBE SCHEDULE H-EC-10.**

A. Schedule H-EC-10 reflects adjustments for deferred income taxes associated with liberalized depreciation and various other normalized items as shown on Schedule H-EC-09. Additionally, H-EC-10 includes the reduction in tax expense associated with book amortizations including ITC, ARAM and Excess Deferred Income Taxes. The adjustments shown on Schedule H-EC-10 result from the annualization of certain tax items and from the tax effect of other adjustments included in the ECIC period.

**15. Q. PLEASE DESCRIBE SCHEDULE H-EC-11.**

A. Schedule H-EC-11 reflects the adjustment to rate base resulting from income taxes generated by items included in rate base during the ECIC period, such as deferred taxes on the differences between book and tax depreciation.

**16. Q. PLEASE DESCRIBE STATEMENT P ITEM 1**

A. In prior filings, the ARAM amortization was presented as a gross number and included on H-CERT-09 as a permanent book to tax difference. In this filing, the ARAM amortization was included in H-CERT-10 in the section titled Flow Thru, ARAM and Tax Credits, and it is stated at net. This presentation does not change total tax expense, just the location (H-CERT-10 rather than H-CERT-09) of the ARAM amortization. This is a better representation of the tax related items as ARAM is an amortization method that is done for accounting purposes and does not show up on a tax return as a gross change to taxable income.

**17. Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?**

A. Yes, it does.

# EXHIBIT FLORENCE-DIRECT-1

# STATEMENT OF QUALIFICATIONS
# DEBORAH J. FLORENCE

My name is Deborah J. Florence. I am the Director of Corporate Taxes for NV Energy Inc. (formerly Sierra Pacific Resources), Nevada Power Company and Sierra Pacific Power Company. My business address is 6100 Neil Road, Reno, Nevada.

I graduated from the Weber State University in 1990 with a Masters of Science Degree majoring in taxation and a Bachelor's of Science Degree majoring in accounting. I am a Certified Public Accountant in the state of Nevada.

From August of 1990 until April of 1997, I was employed by the Certified Public Accounting firm of Deloitte & Touche LLP. As a tax manager, I was responsible for all areas of tax compliance, research, and planning for several large corporate clients. I supervised up to 10 staff members.

In April of 1997, I was employed by Sierra Pacific Power Company as a Senior Tax Analyst in the Corporate Tax Department. In December of 2000, I was promoted to Corporate Tax Manager for Sierra Pacific Resources. In January of 2005, I was promoted to Corporate Tax Director. I supervise six people and I am responsible for all areas of taxation for Nevada Power Company, Sierra Pacific Power Company and multiple subsidiaries.

## AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, DEBORAH FLORENCE, states that she 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 her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: February 14, 2025

D Florence

Deborah Florence