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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 integrated resource plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027.	Docket No. 24-05___

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NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

NARRATIVE

SUPPLY PLAN

NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANY
d/b/a NV ENERGY

2024 JOINT TRIENNIAL INTEGRATED RESOURCE PLAN (2025-2044)

SUPPLY PLAN

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SECTION 1. INTRODUCTION

Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy") are filing this joint integrated resource plan ("2024 Joint IRP"). The 2024 Joint IRP focuses on affordability, reliability, and sustainability. The 2024 Joint IRP continues the Companies' commitment to meeting the state's clean energy policies and goals, while also meeting the energy needs and demands of their customers. In determining their Preferred Plan and preparing the Action Plan, the Companies developed four long-term primary expansion plans for meeting customers' needs and evaluated them to determine how each performed across the range of potential load, purchased power price, fuel price and carbon policy scenarios. The Companies have selected as their Preferred Plan the Balanced Plan, the centerpiece of which is:

1) Two 200 MW (nominal) gas-fired simple-cycle combustion turbines at the Valmy Generating Station for Sierra's customers with an in-service date of June 2028, as well as associated transmission infrastructure.
2) Dry Lake East – A 200 MW PV system paired with 200 MW of battery storage for Nevada Power's customers with an in-service date of December 2026, as well as associated transmission infrastructure.
3) Boulder Solar III – A 128 MW PV system paired with 128 MW of battery storage for Nevada Power's customers with an in-service date of June 2027.
4) Libra – A 700 MW PV system paired with 700 MW of battery storage for Nevada Power's customers with an in-service date of December 2027, as well as associated transmission infrastructure.
5) Transmission projects required to meet customers' needs as presented in the Transmission Plan.

NV Energy evaluated a range of supply side investments and alternatives to address the significant load growth occurring in Nevada. The Companies' primary analysis considered four alternative plans to pursue in a long-term planning scenario. Each plan meets or exceeds the current renewable portfolio standard ("RPS") in every year, meets the planning reserve margin ("PRM"), and targets the Companies' proportionate share of the state's 2050 clean energy goal. The analyzed plans are as follows:

1) **Balanced Plan**: This plan proposes 1,028 MW of new solar generating facilities, along with 1,028 MW of co-located storage, and 411 MW of hydrogen-capable natural gas combustion turbines at the North Valmy Generating Station. These resources include Libra, Dry Lake East, Boulder Solar III, and Valmy Simple Cycle Plant projects. As the lowest cost plan, this plan achieves a renewable energy future with an approach that balances decarbonizing with affordability and reliability.

2) **Renewable Plan**: This plan proposes the same resources as the Balanced Plan excluding the 411 MW of hydrogen-capable natural gas combustion turbines at the North Valmy Generating Station. These resources include Libra, Dry Lake East, and Boulder Solar III. This plan achieves a similar renewable energy future as the Balanced Plan but with an increased market reliance risk in the near term and at a greater cost.
3) **Low Carbon Plan**: Pursuant to NRS § 704.741(3)(c)(1) and NAC § 704.937(1), this plan is required to achieve by 2030 an 80 percent reduction in carbon emissions from the 2005 levels. To achieve this carbon reduction goal, this plan builds a significant amount of renewable and energy storage projects between the years 2028 and 2030 at a substantially higher cost than the Balanced Plan.
4) **No Open Position Plan**: Pursuant to NRS § 704.741(3)(c)(2), this plan closes the Companies' capacity position by 2028 and keeps it closed for the remainder of the 26-year study period and includes a significant share of renewable energy facilities and energy storage systems owned by the Companies. This plan has the same proposed Action Plan resources as the Balanced Plan, but also includes an additional set of gas-fired simple-cycle combustion turbines located at the Harry Allen Generating Station to be in-service in 2030. This plan is the most expensive of all the plans.

NV Energy selected the Balanced Plan as its Preferred Plan and the Renewable Plan as its Alternate Plan. Both plans bolster clean energy generation in the state with a combined 1,028 MW of solar PV and 1,028 MW of battery storage. The Balanced Plan has the lowest present worth revenue requirement ("PWRR") of all plans. Its 26-year PWRR is more than $1 billion lower than the 26-year PWRR of the Renewable Plan. Moreover, the Balanced Plan has the lowest present worth of societal cost ("PWSC") of all plans. The Balanced Plan mitigates the risk of market reliance and increases system reliability. The Companies selected the Balanced Plan as the Preferred Plan as it is most closely aligned with Nevada's energy policies, delivers the resources its customers value, and provides a balance of affordability, reliability, and sustainability.

The Companies present for Commission review and continued approval an increased budget for the Greenlink project with this Joint Application. The Commission approved the Greenlink project in Docket Nos. 20-07023 and 21-06003. The Greenlink project is embedded in all four alternative plans. In recent years, the cost of transmission infrastructure construction has seen a notable increase based on inflation, supply chain constraints, and labor rate escalations. The Greenlink project has not been immune to that increase. In addition, finalization of the project routing and design, Bureau of Land Management stipulations on environmental risk mitigation, and further budget development based on detailed engineering has contributed to the increased project costs. The Companies' analysis demonstrates that the Greenlink project continues to be the best option to serve the electric needs of the state, ensure NV Energy system reliability and resiliency, increase renewable energy production and promote economic development.

SECTION 2. SUPPLY PLAN

A. GENERATION

1. Existing Generation

Together, Nevada Power and Sierra currently hold ownership interests in approximately 5,815 MW (total peak summer capacity) of generation from the following electric generating facilities (figures reflect summer peak capacities):

- Brunswick Diesel Plant – Sierra: The Brunswick Diesel Plant is a six MW peaking plant, comprised of three reciprocating diesel fired engines located in Carson City, Nevada. This plant is operational and designated as Sierra's black start capability. The plant is restricted to 50 operating hours and is used for system emergencies.

- Chuck Lenzie Generating Station – Nevada Power: Chuck Lenzie Generating Station provides 1,250 MW of total peak summer capacity. The plant is located approximately 24 miles northeast of Las Vegas, Nevada, and is composed of two 2x1 natural gas-fired combined cycle units (625 MW per block).

- Clark Generating Station – Nevada Power: Clark Generating Station provides 1,199 MW of total peak summer capacity. Clark Generating Station is composed of two 2x1 natural gas-fired combined cycle units (460 MW), one natural gas-fired combustion turbine unit (55 MW), and 12 natural gas-fired simple cycle combustion turbines (684 MW). Clark Generating Station is in Las Vegas, Nevada.

- Clark Mountain Station – Sierra: Clark Mountain Station is comprised of two dual-fuel (gas/diesel) combustion turbines with a peak summer capacity of 132 MW. The Clark Mountain units are co-located with the Tracy Station east of Reno, Nevada.

- Fort Churchill Solar – Sierra: Fort Churchill Solar is a 19.5 MW concentrating PV solar plant located adjacent to the Fort Churchill Station near Yerington, Nevada.

- Fort Churchill Station – Sierra: Fort Churchill Station is comprised of two natural gas-fired condensing steam turbine units located 10 miles north of Yerington, Nevada. Total peak summer capacity of these units is 196 MW.

- Goodsprings Heat Recovery – Nevada Power: Goodsprings Heat Recovery provides 5 MW peak summer capacity located adjacent to the Kern River Goodsprings natural gas compressor station. The waste heat recovery unit captures waste heat from Kern River Gas's natural gas-fueled compressors and uses a separate generator to produce electricity.

- Harry Allen Generating Station – Nevada Power: Harry Allen Generating Station provides 672 MW of total peak summer capacity. The Harry Allen Generating Station is comprised of the 510 MW natural gas-fired Harry Allen Combined Cycle facility and162 MW of natural gas-fired combustion turbine peak summer capacity generated by two gas-fired turbine units (81 MW each). Harry Allen Generating Station is located 24 miles northeast of Las Vegas, Nevada.

- Las Vegas Generating Station – Nevada Power: Las Vegas Generating Station provides 272 MW peak summer capacity. Formerly Las Vegas Cogen, the Las Vegas Generating Station is comprised of one (1x1) natural gas-fired aero derivative combined cycle rated at 48 MW, and two (2x1) natural gas-fired aero-derivative combined cycle units rated at 112 MW each. Las Vegas Generating Station is in North Las Vegas, Nevada.

- Nellis Solar PV II – Nevada Power: The Nellis Solar PV II plant is a single axis tracker, consisting of 10, 1.5 MW blocks, for a total of 15 MW AC capacity. Nellis Solar PV II is located on the Nellis Air Force Base in North Las Vegas, Nevada.

- North Valmy Station – Sierra: North Valmy Station ("Valmy") consists of two coal-fired condensing steam units with a peak summer capacity of 522 MW. Sierra owns 50 percent of North Valmy Station, making its share of capacity from the two units at Valmy 261 MW. North Valmy Station is located 19 miles west of Battle Mountain, Nevada. The North Valmy units will cease coal-fired operation by December 31, 2025, and be converted to operate on natural gas only by May 2026.

- Silverhawk Generating Station – Nevada Power: Silverhawk Generating Station provides 617 MW of total peak summer capacity, including duct burners. The plant is comprised of one 2x1 natural gas-fired combined cycle unit and is located approximately 26 miles northeast of Las Vegas, Nevada. The new Silverhawk Peaking Plant will add two – 220 MW simple cycle units and will be commercially operating in July 2024.

- Sun Peak Generating Station – Nevada Power: Sun Peak Generating Station provides 216 MW of summer peak capacity. Sun Peak Generating Station is comprised of three dual fuel (natural gas and No. 2 fuel oil) simple-cycle combustion turbine units (each capable of producing 72 MW). Sun Peak Generating Station is in Las Vegas, Nevada.

- Tracy Station – Sierra: Tracy Station provides 785 MW of total peak summer capacity. Tracy Station is comprised of one natural gas-fired steam unit (92 MW), and two natural gas-fired combined cycle blocks (693 MW). Tracy Station is located approximately 15 miles east of Reno, Nevada.

- Walter Higgins Generating Station –- Nevada Power: 619 MW of total peak summer capacity including duct burners. Walter Higgins Generating Station is comprised of one 2x1 natural gas-fired combined cycle unit and located approximately 35 miles southwest of Las Vegas, Nevada.

Figure GEN-1 summarizes Nevada Power's and Sierra's generating units and their respective operating characteristics including name plate ratings, winter and summer capacities, commercial operation dates, planning-based retirement dates and fuel types. Unit specific details can be found in the Confidential Technical Appendix GEN-1.

TABLE GEN-1
GENERATING UNIT SUMMARY

Unit	Commercial Operation Date	Planning Retirement Date	Prime Mover[1]	Designation	Name Plate (MW)	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Primary Fuel Storage Capacity[2]	Secondary Fuel Storage Capacity
Sierra										
Brunswick	1960	2028	Recip	Peaker	6	6	6	Diesel	44 hrs.	0
Clark Mt. 3	1994	2044	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Clark Mt. 4	1994	2044	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Ft. Churchill 1	1968	2038	Steam	Intermediate	105	113	98	Nat Gas	0	0
Ft. Churchill 2	1971	2038	Steam	Intermediate	105	113	98	Nat Gas	0	0
Fort Churchill Solar	2014	2044	Solar	PV Solar	19.5	19.5	19.5	Solar	0	0
Tracy 3	1974	2038	Steam	Intermediate	110	92	92	Nat Gas	0	0
Tracy 4&5 (Pinon)	1996	2049	CC /Steam	Intermediate	113	108	104	Nat Gas	0	0
Tracy 8, 9, 10	2008	2048	CC /Steam	Base	623	578	589	Nat Gas	0	0
North Valmy 1	1981	2049	Steam	Intermediate	127	127	127	Coal	200 days	200 days
North Valmy 2[3]	1985	2049	Steam	Intermediate	134	134	134	Coal	200 days	200 days
Nevada Power										
Clark 4	1973	2035	CT	Peaker	60	63	55	Nat Gas	0	0
Clark 5, 6, 10	1979. 1979, 1994	2044	CC /Steam	Intermediate	236	250	230	Nat Gas	0	0
Clark 7, 8, 9	1980, 1982, 1994	2043	CC /Steam	Intermediate	236	250	230	Nat Gas	0	0
Clark 11 - 22	2008	2049	CT	Peaker	726	684	684	Nat Gas	0	0
Goodsprings	2010	2040		Base	7.5	6	5	Waste Heat	0	0
Harry Allen 3	1995	2046	GT	Peaker	72	84	81	Nat Gas	0	0
Harry Allen 4	2006	2046	GT	Peaker	72	84	81	Nat Gas	0	0
Harry Allen CC	2011	2049	CC /Steam	Base	558	524	510	Nat Gas	0	0
Chuck Lenzie 1	2006	2049	CC /Steam	Intermediate	610	601	625	Nat Gas	0	0
Chuck Lenzie 2	2006	2049	CC /Steam	Intermediate	610	601	625	Nat Gas	0	0
Silverhawk CC	2004	2049	CC /Steam	Intermediate	599	599	617	Nat Gas	0	0
Walt Higgins CC	2004	2049	CC /Steam	Intermediate	688	621	619	Nat Gas	0	0
LV Gen 1	1994	2049	CC /Steam	Intermediate	61.3	51	48	Nat Gas	0	0
LV Gen 2	2004	2049	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
LV Gen 3	2004	2049	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
Sun Peak 3	1991	2041	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 4	1991	2041	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 5	1991	2041	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	180 hours[4]
Nellis Solar PV2	2015	2045	Solar	PV Solar	15	15	15	Solar	0	0

1 "CT" indicates combustion turbine, "CC" indicates combined cycle.
2 Fuel Storage Capacity Assumes Full Load Operation.
3 The two North Valmy units are 50 percent owned by Idaho Power Company. Figure GEN-1 shows only Sierra's 50 percent share of the capacity of the two North Valmy units.
4 No diesel fuel is currently stored on site

2. Other Generation Assets

Nevada Power and Sierra hold ownership interests in two other generation assets:

- Mohave Generating Station – Nevada Power: The Mohave site is in Laughlin, Nevada, and is the previous site of a 1,500 MW coal-fired generating plant. Nevada Power is a 14 percent owner in the project. Southern California Edison (majority owner and operator) and Los Angeles Department of Water and Power (who has assumed Salt River Project's original ownership share) are the other project owners. Mohave ceased operations January 1, 2006, and has been decommissioned.[5] In 2015, the co-owners agreed to proceed with selling most of the property through a public sale process. The project has been marketed for sale since 2016. If, and when, a transaction occurs and it is material, the net gains would be included in a future general rate case for the benefit of Nevada Power's customers. The owners will continue to retain approximately 500 acres of land and post-closure care associated with the closed onsite landfill.

- Navajo Generating Station – Nevada Power: The Navajo Generating Station is located near Page, Arizona, and is a previous site of a 2,250 MW total net capacity coal-fired facility. Nevada Power is a 11.3 percent participant in the Navajo Generating Station. Arizona Public Service, Los Angeles Department of Water and Power, Salt River Project, and Tucson Electric Power are other participants in the plant, with Salt River Project also holding an interest in Navajo on behalf of the United States. The coal-fired facility ceased operation in November 2019. Site decommissioning, demolition, pond, and landfill closure activities were completed in 2023. Site monitoring, post-closure care and groundwater monitoring activities, and extension lease payments will continue through the site remediation period ending December 22, 2054.

3. Status of Previously Approved Generation Projects

a. Capacity Upgrade Projects

NV Energy requested approval of upgrades to many of its combustion turbines that are part of the combined cycle units and operated as simple cycle units in Docket Nos. 21-06001 and 22-03024. The combustion turbine upgrades increased output for a limited number of operating hours during peak periods. These upgrades allow the NV Energy system to benefit from a reduction of the open position and from increased operational flexibility as additional renewables are installed. The upgrades achieve an increase in the unit's megawatt output by adding wet compression on the

[5] As defined in NRS § 704.7332.

simple cycle units, implementing turbine upgrades on the large, combined cycle plants, and implementing a peak firing mode on the large GE 7FAs at Lenzie, Tracy, and Harry Allen.

The following Table GEN-2 summarizes the turbine upgrade projects that were approved and their current status.

TABLE GEN-2

COMBUSTION TURBINE CAPACITY UPGRADES

Plant	Expected Capacity Upgrade at Peak	Actual Capacity Upgrade at Peak	PUCN Approved Project Cost	Actual or Expected Project Cost	Upgrade In-Service Date
Wet Compression					
Silverhawk CC	30 MW	34 MW	$10,000,000	$7,365,069	6/15/2022
Sun Peak 3,4,5	21 MW	TBD	$9,000,000	$5,900,000	5/31/2024
Turbine Upgrades					
Chuck Lenzie Block 2	40 MW	45.62 MW	$52,700,000	$43,716,296	12/29/2022
Tracy CC	36 MW	38.8 MW	$53,000,000	$41,519,958	5/17/2022
Silverhawk CC	40 MW	36 MW	$30,400,000	$35,380,803	6/15/2022
Harry Allen CC	45 MW	47.88 MW	$48,300,000	$46,106,988	5/22/2023
Peak Firing					
Chuck Lenzie Blocks 1 and 2	24 MW	TBD	$12,000,000	$12,000,000	2026/2027
Harry Allen CC	12 MW	TBD	$6,000,000	$6,000,000	2025
Tracy CC	12 MW	TBD	$6,000,000	$6,000,000	6/04/2024

b. Lenzie Thermal Storage Project

The Commission approved the Lenzie Thermal Storage Project in Docket No. 22-03024. This thermal energy storage project will allow the chillers to be turned off up to six (6) hours a day during peak periods and utilize chilled water made during the off-peak hours when chillers are not needed. Removing the chillers from service during the peak hours will reduce the plant auxiliary load by 18 MW. Since the Lenzie Generating Station is the only combined cycle plant that currently has chillers, it is the only plant currently being considered for this project.

The Commission approved the project with an estimated cost of $13 million and would be in-service by the summer of 2024. Due to unit outage schedules and the need to relocate natural gas lines feeding the units, the project was delayed and is expected to be in service before the summer peak period of 2025. As a result of scope changes and price escalation, the current project cost is expected to be approximately $20 million.

c. Silverhawk Peaking Plant

The Commission approved Nevada Power's proposed Silverhawk Peaking Plant in Docket No. 22-11032. The proposed Silverhawk Peaking Plant is a 400 MW (nominal rating) simple cycle generating plant, designed for peaking service, at the existing Silverhawk Generating Station. The initial estimated cost of the project was approximately $353 million (without Allowance for Funds Used During Construction ("AFUDC")). The units each have a summer peak rating (at 120 degrees F) of 210 MW, with an additional 12 MW each from operating with wet compression (total plant capacity with wet compression is 444 MW).

The Silverhawk Peaking Plant is on schedule for commercial operation by July 1, 2024. The units will have a total cost of approximately $514.9 million without AFUDC. The cost increase was a result of the final contractor pricing to achieve the project schedule, material escalation, and additional projects scope. Additionally, the original project estimate did not include sales tax and overheads. NV Energy assessed these cost adders and determined that continuing the project and maintaining the project schedule remained prudent to support the Summer 2024 schedule. The following is a summary of the major cost drivers:

- **Timing of project to meet customer energy needs** – the project was driven by a need to meet the peak summer demand in 2024 and beyond. Permitting, contracting, and engineering timing leading up to construction start resulted in a compressed schedule in order to achieve operation prior to summer 2024, increasing costs for material deliveries, labor, and additional shifts. It also amplified the effect of supply chain disruptions and material cost increases. Supply chain disruptions were intensified by worldwide unrest inhibiting normal delivery routes for material, specifically through typical sea-based routes through the Red Sea and Suez Canal.
- **Project contracting complexity** – the project shifted from a historically standard engineering, procurement, construction contracting strategy to an approach that required multiple additional contracts, entities, and procurements. This shift created changes in the process adding project complexity and time. The project also required several equipment and design changes, including the addition of a switchyard, which increased project scope and cost.
- **Market inflation and supply chain uncertainty** – the project was impacted by industrywide increases in raw material costs, supply chain disruptions, and common and

skilled labor shortages and associated labor escalations, which were not known at the time original estimate.

TABLE GEN-3
SILVERHAWK COST DIFFERENTIAL (REDACTED)

Estimate Item	Original Estimate	Actual Estimate	Delta	Reason for Delta
General contractor (Power Plant)	[redacted]	[redacted]	[redacted]	Budgetary estimate based upon engineering, procurement, construction contracting; labor escalation; procurement/design/permits/construction delays; additional engineering, procurement. The original estimate did not include contingency.
Combustion turbine generator/selective catalytic reduction system	[redacted]	[redacted]	[redacted]	Material escalation, sales tax, upgrades for cybersecurity and safety standard requirements.
Owner's Costs	[redacted]	[redacted]	[redacted]	Including NV Energy Labor and Overheads, Outside Engineering and Procurement services, Builders All Risk Insurance, Permitting/LGIA, Kern River, GSU Spare Relocation, Site Security, Water Tank. The original cost did not include overheads and indirect costs.
Switchyard (including General Contractor)	[redacted]	[redacted]	[redacted]	Material escalation, increased scope, construction, sales tax.
Generator Step-Up Transformer	[redacted]	[redacted]	[redacted]	Material escalation and sales tax .
Generating voltage equipment (GCB, non-segregate bus, isophase)	[redacted]	[redacted]	[redacted]	Material escalation and sales tax.
Plant control system	[redacted]	[redacted]	[redacted]	Addition of Ovation System for total plant control per BHE Cybersecurity requirements.
Power distribution center	[redacted]	[redacted]	[redacted]	Material escalation and sales tax.
Fuel gas conditioning	[redacted]	[redacted]	[redacted]	Material escalation, fuel gas heater addition and sales tax.
		Total Cost Delta	$169,275,374	

d. North Valmy Natural Gas Conversion

Project Overview

In Docket No. 23-08015, the Commission approved Sierra's request to convert the Valmy coal-fired Units 1 and 2 to operate on natural gas and install nitrogen oxide ("NOx") emission controls to comply with the Regional Haze Rule ("RHR") and potential Good Neighbor Plan. The project costs and continued operation assumed that Idaho Power Company will continue to participate in the Valmy Station with its 50 percent ownership, sharing 50 percent of the output and cost.

The project assumes the gas conversion of Valmy Unit 1 will be completed in the fall of 2025, with the outage of Unit 1 starting after the peak season of 2025. During the Unit 1 outage, Unit 2 would continue to operate on coal in support of the transmission system must-run requirement. The outage to complete the Unit 1 conversion to natural gas operations would be complete by December 31, 2025, to allow coal-fired operation at the Valmy plant to cease. Once the Unit 1 outage is complete and Unit 1 is capable of operation on natural gas, it would take over the must-run support and the Unit 2 outage would begin, with both units being converted to natural gas operation by June 1, 2026.

The project also assumes the permitting and installation of NOx emission controls on both units; however, the exact emissions controls will be determined by regulations and permitting and will be planned and scheduled for installation following the Environmental Protection Agency ("EPA") approval of the Nevada Regional Haze State Implementation Plan ("SIP").

Idaho Power Company Participation

Idaho Power Company has received acknowledgement of its participation in the gas conversion projects by the Idaho Public Utility Commission in Idaho Power's Integrated Resource Plan. Idaho Power Company is expecting to submit a request for a Certificate of Public Convenience with the Idaho Public Utility Commission in June 2024.

Sierra and Idaho Power Company are completing negotiations on the "Natural Gas Conversion Agreement," which governs the parties' participation in the Valmy units through the natural gas conversion and continued operations on natural gas thereafter.

Project Costs

In Docket No. 23-08015, the Commission approved $54.3 million (without AFUDC) for Sierra's share of the total cost of the Valmy conversion to natural gas and installation of additional emission controls. The Commission did not approve Sierra's request for approval of "capital projects for continued operation" and directed Sierra to include these projects in future IRP filings or general rate case filings.

Sierra has received bids from potential Engineering, Procurement and Construction ("EPC") contractors for the conversion of the Valmy Units to operate on natural gas and installation of state of the art low NOx burners and is currently estimating, based on the average of technically acceptable bids, the total cost of the conversion project at $85.3 million (without AFUDC), with Sierra's 50 percent share being $42.65 million (without AFUDC). This cost does not include the cost of additional emission controls, discussed below. Indicative bids indicate that the estimated cost of the natural gas conversion assuming Selective Catalytic Conversion ("SCR") as the most stringent control is approximately $115.4 million (without AFUDC), with Sierra's 50 percent share of $57.7 million (without AFUDC).

TABLE GEN-4
VALMY COAL TO GAS CONVERSION ESTIMATED CONSTRUCTION COSTS BY MAJOR CATEGORY (EXCLUDING AFUDC) [REDACTED]

	Commission Approval in Docket No. 23-08015		Indicative Pricing	
	Total Project	Sierra's Share	Total Project	Sierra's Share
Natural Gas Conversion	$40.8 M	$20.4 M	[redacted]	[redacted]
Supply and Install SCR	$60 M	$30 M		
Total Installed Cost	$100.8 M	$50.4 M		

Environmental Permitting and Emission Controls

As discussed in Section 5, Sierra completed an updated four-factor analysis for Valmy Units 1 and 2 in March 2024 for the purpose of complying with the RHR. After Valmy Units 1 and 2 are converted to natural gas, further reduction of NOx emissions equivalent to Selective Non-Catalytic Reduction ("SNCR") was determined to be cost-effective to install based on operations until 2049. Flue Gas Reduction ("FGR") and SCR could also meet the NOx emission limit for the purpose of the RHR.

The Nevada Division of Environmental Protection ("NDEP") is currently reviewing the revised four-factor analysis, consulting with the Environmental Protection Agency ("EPA") and Federal Land Managers ("FLMs") and preparing regulation, subject to State Environmental Commission approval, to establish legally enforceable requirements for Regional Haze compliance.

If the NOx emission limit for Valmy Units 1 and 2 is determined by NDEP to be based on SNCR for Regional Haze compliance, the regulation may also allow for SNCR, FGR, and/or SCR to be used for compliance purposes, allowing flexibility for the Companies to consider potential outcomes of the Good Neighbor Plan.

The NDEP expects to re-submit the Regional Haze SIP to the EPA in 2024. As a result of a recent consent decree between EPA and Sierra Club, National Parks Conservation Association, and Environmental Integrity Project, EPA will have until December 15, 2025, to approve or deny Nevada's Regional Haze SIP. It is expected that installation of NOx controls for Valmy Units 1 and 2 will be required within 36 months following EPA approval.

The Companies are preparing a permit application to proceed with the natural gas conversion on the currently planned timelines. The Companies expect to file a separate permit application in 2025 with NDEP to incorporate selected NOx controls following re-submittal of the Regional Haze SIP.

Natural Gas Supply

The Valmy coal-to-gas conversion will require an interconnection to the Ruby Pipeline. Tallgrass, the owner of the Ruby Pipeline received its Certificate of Public Convenience and Necessity on April 9, 2024, and continues its permitting activities with scheduled completion by December 1, 2025.

Project Schedule

The project remains on schedule for the natural gas conversion in the Spring 2026 and ceasing coal fired operation by December 31, 2025. It is expected that installation of NOx controls would be required within 36 months following EPA approval of the Regional Haze SIP. The timing to install NOx controls may also be influenced if the Good Neighbor Plan becomes effective in Nevada.

e. Tracy 4/5 Emission Controls Upgrades

Project Overview

In Docket No. 23-08015, the Commission approved extending the operating life of Tracy 4/5 to 2049, which requires additional NOx emission controls (i.e., SCR) to comply with the RHR.

Environmental Permitting and Emission Controls

As discussed in Section 5, Sierra completed an updated four-factor analysis for Tracy 4/5 in March 2024 for the purpose of complying with the RHR. For Tracy 4/5, reduction of NOx emissions, equivalent to SCR, was determined to be cost effective based on operations until 2049. The NDEP is currently reviewing the revised four-factor analysis, consulting with EPA and FLMs, and preparing regulation, subject to State Environmental Commission approval, to establish legally enforceable requirements for Regional Haze compliance.

NDEP expects to re-submit the Regional Haze SIP to the EPA in 2024. As a result of a recent consent decree between EPA and Sierra Club, National Parks Conservation Association, and Environmental Integrity Project, EPA will have until December 15, 2025, to approve or deny

Nevada's Regional Haze SIP. It is expected that installation of NOx controls for Tracy 4/5 will be required within 36 months following EPA approval.

Project Costs

In Docket No. 23-08015, the Commission approved $12 million to install SCR as NOx emission controls, without AFUDC. The project costs were estimated as detailed engineering and equipment procurement will not begin until Regional Haze SIP approval. The Commission did not approve Sierra's request for approval of "capital projects for continued operation" and directed Sierra to include these projects in future IRP filings or general rate case filings.

The current estimate for project cost remains at approximately $12 million to install SCR for NOx emissions control, without AFUDC.

4. New Generation Projects

The Companies completed a brownfield study to investigate its existing plant sites that could support a simple-cycle plant, similar to the Silverhawk Peaking Plant. This study examined the following brownfield sites: Fort Churchill, Harry Allen, Valmy and Walt Higgins. This brownfield study is included in Technical Appendix GEN-3. The information provided in this brownfield study was used to develop the alternative plans for this filing. The preferred plan includes the addition of simple cycle units at the Valmy Site, as shown below:

a. Valmy Simple Cycle Plant

Project Overview

The Valmy Simple-Cycle Plant is made up of two, 200 MW (nominal rating) simple-cycle generating units, designed for peaking service in Sierra's service territory. The estimated cost of the project is approximately $573.3 million (2024$) (without AFUDC) or $1,433/kW.

The simple-cycle generating units for the Valmy Simple-Cycle Plant are highly efficient, state-of the-art, combustion turbines. To reduce emissions, a combination of dry low-NOx combustion systems, selective catalytic reduction and carbon monoxide catalyst will be incorporated into the design. The current project plan and pricing are based on two GE 7F.05 combustion turbines; however, the turbines have not been purchased at this time and could be from a different manufacturer.

Information from the Original Equipment Manufacturer ("OEM") for this unit states that the unit is capable of operating on a 15 percent hydrogen mixture, with the OEM planning a path towards allowing the unit to operate on 100 percent hydrogen. The simple cycle 7F.05 gas turbine can reliably produce nearly 200 MW within 10 minutes and can reach full load in under 11 minutes.

The unit can also balance renewable resources by load-following at 40 MW/min ramp rates while maintaining emissions compliance. The fast start and fast ramp capabilities of these units enable the retirement of the "must -run" requirement currently applied to Valmy Units 1 and 2.

Natural Gas Supply

The Valmy Simple-Cycle Plant is expected to use the Pinyon Pipeline that is currently being permitted and constructed to support the Valmy Natural Gas Conversion noted above. The lateral proposed for the Valmy coal-to-gas conversion is capable of supplying the necessary natural gas for the simple-cycle units' operations as well. It is noteworthy that the Valmy Simple Cycle Plant does not compete for natural gas availability with Sierra's local gas distribution company in Reno/Sparks.

Permits

Sierra has begun communications with the equipment manufacturer to obtain emission profiles for the selected combustion turbines to initiate air quality dispersion modeling and permitting application with NDEP. Expected permitting timelines are 12-18 months after submittal of the air permit application.

Section 5 further discusses how these units would be regulated under the greenhouse gas ("GHG") rule and Good Neighbor Plan. The units may also be considered under Regional Haze during future decadal planning periods; however, no additional requirements would be expected as they will be constructed with SCRs for NOx emission control.

Utility Environmental Protection Act, local land use, and construction related permits can be accommodated during the overall engineering and permitting timelines.

Idaho Power Company Participation

Although Idaho Power Company is a co-owner of Valmy, it is not participating in the Valmy Simple Cycle Plant. As noted in the "Natural Gas Conversion Agreement," included as Technical Appendix GEN-3, Sierra and Idaho Power Company will work together to determine any changes necessary for the billing for common facilities that serve both the existing plant and the new simple cycle units. The simple cycle units are currently planned to be operated from the existing plant control room and utilize existing common facilities at the plant such as water supply, wastewater systems, and other electrical and control systems. Maintenance will also be supported by the existing plant maintenance staff and will be billed on a work management basis.

Project Costs

The total cost of the Valmy Simple-Cycle Plant is approximately $573 million (without AFUDC), including projected pipeline infrastructure interconnection costs. Table GEN-5 shows the construction costs by year and Table GEN-6 shows the line-item detail of the project cost. There is always a risk that material, equipment, and labor costs can increase or decrease between the time of the cost estimates and the time of contract award and procurement. Increases in construction costs in the past few years have been dramatic; however, Sierra has developed estimated costs for major contracts, based on costs seen for the Silverhawk Peaker Plant and believes that the costs to construct a Valmy Simple-Cycle Plant are accurately captured in this filing. Sierra has not yet made commitments for the turbines and generators but will be required to make down payments prior to Commission approval.

TABLE GEN-5
VALMY SIMPLE-CYCLE PLANT
ESTIMATED ANNUAL CONSTRUCTION COSTS
MILLIONS, EXCLUDING AFUDC (IN 2024$)

Year	Amount
2024	$ 38.9
2025	$ 103.2
2026	$ 148.9
2027	$ 176.3
2028	$ 106
Total	$ 573.3

TABLE GEN-6
VALMY SIMPLE-CYCLE PLANT
ESTIMATED CONSTRUCTION COSTS BY MAJOR CATEGORY
(EXCLUDING AFUDC, IN 2024$)
(redacted)

Category	**Cost**
EPC Cost	[redacted]
Combustion Turbines	[redacted]
GSUs	[redacted]
PDCs	[redacted]
Switchyard	**$ 18.6m**
Overheads including LGIA, Natural Gas Infrastructure, Warehouse	**$ 44.8m**

Taxes	**$ 23.2m**
Contingency (15% of total cost excluding Taxes)	**$ 71.8m**
Total	**$ 573.3m**

Sierra intends to limit expenditures until the Commission approves a resource plan, which includes the project. Some portions of the project are required to complete procurement and contracting prior to Commission approval due to long lead times and market limitations on supply. The expected costs that will be committed prior to Commission approval are listed in Table GEN-7.

TABLE GEN-7
VALMY SIMPLE-CYCLE PLANT
ESTIMATED COMMITED COSTS PRIOR TO COMMISSION APPROVAL
(EXCLUDING AFUDC, IN 2024$)
(redacted)

Item	Total ($ millions)	Down Payment %	2024 Payments ($ millions)	Estimated Payment Date
Owner's Engineer	[redacted]	[redacted]	[redacted]	6/1/24
EPC Contractor	[redacted]	[redacted]	[redacted]	12/31/24
Geotechnical Services	[redacted]	[redacted]	[redacted]	12/1/24
2x CTGs/SCRs	[redacted]	[redacted]	[redacted]	6/15/24
2x GSUs (345Kv)	[redacted]	[redacted]	[redacted]	6/15/24
2x PDCs (Need OE Design)	[redacted]	[redacted]	[redacted]	10/1/24
Unit Auxiliary Transformers	[redacted]	[redacted]	[redacted]	10/1/24
		Totals	[redacted]	
		Overheads	[redacted]	
		Total with OH	[redacted]	

Project Schedule

Table GEN-8 shows the preliminary project schedule for the Valmy Simple-Cycle Plant.

TABLE GEN-8

VALMY SIMPLE-CYCLE PLANT PROJECT SCHEDULE

Task Name	Start	Finish
PROJECT DEVELOPMENT AND LONG-LEAD PROCUREMENTS		
Owners Engineer	May 2024	October 2028
Prepare Engineer, Procure, Construct Bid Package	June 2024	July 2024
Long-Lead Equipment procurements		
Combustion Turbine	February 2024	July 2024
Generator Step-up Transformers (GSUTs)	May 2024	
Power Distribution Centers	October 2024	
Unit Auxiliary Transformers	October 2024	
INTERCONNECTION AND PERMITTING		
Large Generator Interconnection Agreement Process	August 2023	September 2024
Title V Air Permit	September 2024	March 2026
Utility Environmental Protection Act Permit	December 2024	April 2026
ENGINEER-PROCURE-CONSTRUCT		
Award contract	---	January 2025
Planning, Engineering, and Material Procurement	January 2025	March 2026
Construction	April 2026	March 2028
Commissioning and Startup	April 2028	June 2028

Project Cost Risks

Several key cost risks were identified that could impact project timelines and/or costs. Economic uncertainties and market volatility present considerable challenges, with fluctuations in interest rates potentially inflating equipment costs. Material price instability due to shifts in market demand and global supply chain disruptions, coupled with unpredictable global economic conditions like inflation and currency fluctuations, can directly escalate project expenses. Global supply chain disruptions could lead to delays in equipment deliveries, disrupting construction schedules, necessitating costly adjustments, and equipment quality issues may require replacements or repairs, adding to overall costs. Moreover, global risks such as geopolitical tensions, regional conflicts, trade disputes, and pandemics can disrupt supply chains and create logistical challenges.

A risk management plan with regular assessments, contingency budgets, and strategic supplier partnerships will be implemented to mitigate these risks and ensure project success.

Job Benefits

The ongoing operation of these units will be done through existing plant staff; however, during construction, the project is expected to utilize skilled labor. This project would create approximately 400 skilled jobs during construction.

5. Environmental Regulations Impacts

Certain existing, recently promulgated and proposed environmental regulations are summarized below as they directly impact or may have future impacts on the operations of the Companies' generating units. The summaries have been updated to reflect most current information since Docket No. 23-08015.

Regional Haze Rule

The RHR calls for states and federal agencies to work together to improve visibility in 156 national parks and wilderness areas. The RHR requires states, in coordination with the EPA, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce pollution that causes visibility impairment. The first state plans under the RHR were filed in December 2007. The RHR also requires comprehensive periodic revisions to these initial plans.

The RHR requires Nevada to address statewide emissions of visibility impairing pollutants that contribute to regional haze in each mandatory Class I Area ("CIA") located in Nevada and in each mandatory CIA located in nearby states. Jarbridge Wilderness Area is the only mandatory CIA located in Nevada. Under the RHR, Nevada is required to submit and maintain a SIP addressing the specific elements required in the RHR.

The Regional Haze second decadal planning period commenced in 2018. During the second decadal planning period, the NDEP identified Tracy Units 4/5 (natural gas-fired) and both Valmy units (coal-fired) as sources requiring four-factor analyses to evaluate existing emission controls and further considered potential additional emission control measures to achieve reasonable progress during the second implementation period of the RHR in Nevada if the units operated beyond the published retirement dates.

Technically feasible control options for NOx emissions control for these units and, in the case for Valmy Unit 1, additional sulfur dioxide ("SOx") emissions control were evaluated based on the four statutory factors: costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life. At the time of the evaluation, the published retirement dates of 2025 for Valmy Units 1 and 2 and 2031 for Tracy Units 4/5 were used for the remaining useful life variable of the evaluation. Due to the short remaining useful life of the units, the technically feasible controls were not cost effective (cost-effectiveness threshold, in $/ton reduced, of $10,000/ton).

Based on the four statutory factors, NDEP concluded that no new control measures were necessary to make reasonable progress towards visibility goals required by the RHR. NDEP then revised Tracy Station's and Valmy Station's Title V permits to include those federally enforceable retirement dates (to shut down and permanently cease operation) used in the four-factor analyses (December 31, 2031, for Tracy Units 4/5, and December 31, 2028, for Valmy Units 1 and 2) and filed a Regional Haze SIP revision with the EPA in August 2022. At that time, EPA had until August 2023 to act on the Regional Haze SIP revision.

Prior to the Companies filing the Fifth Amendment to the 2021 Joint Integrated Resource Plan in August 2023 (Docket No. 23-08015), NDEP partially rescinded the Regional Haze SIP revision as NV Energy was seeking Commission approval to pursue projects that would extend the operation of Valmy Units 1 and 2 and Tracy 4/5 until 2049. The extension of operation and, in the case of Valmy Units 1 and 2, conversion to natural gas operation would require revision to the original four-factor analysis. In March 2024, the Commission approved the projects to convert Valmy Units 1 and 2 to natural gas operation and install appropriate NOx emission controls and pursue NOx emission controls expected to be required for Tracy 4/5 for Regional Haze compliance.

On March 18, 2024, the Companies submitted the revised four-factor analysis for Valmy Units 1 and 2 and Tracy 4/5 to the NDEP. The revised four-factor analysis indicated that, for Valmy Units 1 and 2, further reduction of NOx emissions following natural gas conversion equivalent to SNCR emission limits was cost-effective. FGR and SCR could also meet the NOx emission limit based on SNCR operation for the purpose of the RHR. For Tracy 4/5, further reduction of NOx emissions with SCR was cost-effective.

The NDEP is reviewing the revised four-factor analysis, consulting with EPA and FLMs, and preparing regulation, subject to State Environmental Commission approval, to establish legally enforceable requirements for Regional Haze compliance. If the NOx emission limit for Valmy Units 1 and 2 is determined by NDEP to be based on SNCR, the regulation may allow for SNCR, FGR, and/or SCR to be used for compliance purposes, giving flexibility for the Companies to consider potential outcomes of the Good Neighbor Plan. The NOx emission limit for Tracy 4/5 is expected to be based on installation of SCR, if approved by NDEP.

On March 29, 2024, EPA entered a Consent Decree with Sierra Club, National Parks Conservation Association, and Environmental Integrity project for failure of EPA to act on Regional Haze SIP revisions for 33 states, including Nevada. The Consent Decree established new timelines for EPA to act on Regional Haze SIPs for each state. For Nevada, EPA has a new "Final Action Date" of

December 15, 2025, to approve or deny the Nevada's Regional Haze SIP. NDEP expects to submit a revised Nevada SIP to EPA in 2024 upon completion of the regulation, allowing sufficient time for EPA to act on the Nevada SIP.

It is expected that installation of these NOx controls for Valmy 1 and 2 and Tracy 4/5 would be required within 36 months following the EPA approval, which would be within the Regional Haze second decadal planning period based on currently known timelines.

Permitting and installation of the natural gas conversion for Valmy Units 1 and 2 can be pursued and implemented separately from installation of these NOx controls.

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards ("NAAQS")

On February 13, 2023, EPA published a final action fully or partially disapproving SIPs with respect to the 2015 Ozone NAAQS, which included disapproval of the Nevada SIP. On March 15, 2023, EPA finalized the Good Neighbor Plan for the 2015 Ozone NAAQS. The Good Neighbor Plan is also referred to as the "Ozone Transport Rule" or "Transport Rule." The Good Neighbor Plan requires upwind states to reduce emissions of the ozone precursor NOx from electric generating units ("EGUs") and certain stationary industrial sources. The Good Neighbor Plan was published in the Federal Register on June 5, 2023, with an effective date of August 4, 2023.

On July 3, 2023, the U.S. Circuit Court of Appeals for the Ninth Circuit granted a stay of the final Good Neighbor Plan based on a petition filed by Nevada Cement Company. The State of Nevada filed a motion to intervene in this petition, which was granted by the court. On May 1, 2024, the EPA published in the Federal Register a Notice of Proposed Settlement Agreement between Nevada Cement Company and EPA. The settlement would establish a process and deadlines by which Nevada Cement Company would apply to EPA for a case-by-case emissions limits request ("CBCELCR") for its Fernley, Nevada, facility in exchange for agreeing to lift a judicial stay entered by the U.S. Court of Appeals for the Ninth Circuit. Separately, the U.S. Supreme Court heard arguments by various parties challenging EPA's disapproval of state plans as well as the Good Neighbor Plan.

EPA currently is not implementing the Good Neighbor Plan in Nevada and 11 other states pursuant to temporary court orders. It is uncertain how the Nevada Cement Company settlement agreement, timing of EPA lifting the stay in Nevada, or other ongoing litigation will affect the timing of implementation of the Good Neighbor Plan in Nevada. The discussion below reflects the original timelines from the final action published in the Federal Register in 2023.

The Good Neighbor Plan currently is implemented as part of a Federal Implementation Plan ("FIP") by the EPA for 22 states, including Nevada. There currently are stays in other states and other ligation ongoing. For EGUs, the Good Neighbor Plan sets states' NOx emissions budgets and the methodology to allocate NOx allowances to individual EGUs during each control period (May to September ozone season). As originally finalized, for control periods 2023 (prorated by EPA), 2024 and 2025, EPA established state budgets based on 2021 state emissions, adjusted for known unit changes, such as a plant conversion, and assumptions on optimizing emission controls on controlled units. The EPA reduced the emission budget to allow for a new unit set aside, which was 9 percent for Nevada for 2023 through 2025 and is subsequently reduced to 5 percent in 2026. To calculate allocations to each EGU for the control periods in 2023 through 2025, EPA used heat input data reported for the control periods from 2017 through 2021 and reported emissions for the control period 2021.

For the control periods from 2026 through 2029, EPA uses a combination of preset budgets as well as a dynamic budgeting procedure. The preset budget serves as a floor and will be adjusted higher if EPA calculates the dynamic budget to be higher than the preset budget due to "heat input patterns" across the operating EGUs. For example, preset budgets for Nevada assumed that the Valmy facility will be retired in December 2025 and currently do not include Valmy operations in 2026. If Valmy continued to operate, as now intended, EPA would most likely use dynamic budgeting to establish 2026 control period budgets. For control periods 2030 and later, EPA will publish the state emission budgets based on the dynamic budgets it calculates to reflect all prior retirements and new builds.

For existing, large (serving a generator of 100 MW or more) coal-fired generation without SCR, the Good Neighbor Plan reduced unit emissions rates for the 2026 control period by 50 percent, a control stringency of 0.05 lb./MMBtu commensurate with the retrofit of SCR plus the 2021 NOx emission rate divided by two. State allowance budgets containing coal-fired EGUs are then calculated for those coal-fired EGUs using normalized unit heat inputs and the calculated 50 percent emission rate. For 2027, the unit NOx emission rates for coal-fired units reflect 100 percent control stringency and allowances are calculated based on normalized heat input and a NOx emission rate of 0.05 lb./MMBtu.

For existing, large (serving a generator of 100 MW or more) gas/oil-fired steam EGUs that have historically emitted at least 150 tons of NOx per ozone season, allowances are based on SCR installation. Emission rates used for allowance calculation for existing combustion turbines with SCR controls are based on optimized controls and, for units without controls, their 2021 control period NOx tons emitted are divided by the corresponding heat input.

For the current Nevada Power and Sierra fleet, the Good Neighbor Plan directly impacts the Valmy Units 1 and 2 and the commencement timing when NOx allowances will be to levels commensurate to installation of SCRs. The original FIP, prior to the stay, identified 2026 and 2027 as the years Nevada's allowances reflect installation of controls for applicable units. In 2026, allowances allocated to Valmy Units 1 and 2 would reflect an allowance calculation using a NOx emission rate at 50 percent of the 2021 emission rate, as previously described above, and, in 2027, would reflect an allowance calculation using a NOx emission rate reflecting full implementation of an SCR rate of 0.05 lb./MMBtu, as described above.

The remainder of the EGUs in the state, including NV Energy's fleet, would also be part of the Good Neighbor Plan based on normal emission rates for the units with the long-terms allowance budget based on a dynamic budget process by EPA. New units will become part of the program as well. The proposed Valmy-Simple Cycle units would be integrated into the program and establish NOx emission budgets through new unit set aside procedures.

Federal Greenhouse Gas Rule

On April 25, 2024, EPA finalized regulations under CAA section 111 to address GHG emissions (primarily carbon dioxide emissions) from fossil based EGUs. The final rule establishes the final best system of emissions reduction ("BSER") and resulting performance standards for new gas-fired combustion turbines, existing coal, and oil and gas-fired steam generating units. The final rule did not establish performance standards for existing gas-fired combustion turbines; however, the EPA indicated they may issue a new proposal in the future and will be gathering input through a non-regulatory docket for reducing greenhouse gas emissions from existing gas turbines at power plants.

The final standards for coal-fired steam generating units are based on carbon capture and sequestration ("CCS") technology, and natural gas co-firing, which can be applied directly to power plants that use fossil fuels to generate electricity. Coal-fired units that retire before December 31, 2031, are excluded from the final rule. Coal-fired units that are converted to natural gas by January 1, 2030, will be regulated as existing natural gas-fired steam generating units.

The final standards for existing oil or natural gas-fired steam generating units do not require installation of CCS while maintaining routine efficient operation with CO2 emission rates of less than 1,400 (if capacity factor is 45 percent or greater), or 1,600 lb. CO2 /MWh (if capacity factor is less than 45 percent). If these units operate at a capacity factor less than 8 percent, the BSER is achieved by uniform fuels with a presumptive standard of 130 lb. CO2/MMBtu for natural gas units.

The final standards for new gas units are based on capacity factor thresholds to differentiate between base load units (capacity factors greater than 40 percent), intermediate load units (capacity factors between 20 and 40 percent), and low-utilization units operating at capacity factors of 20 percent or less. Capacity factors for these categories are measured on a 12-month rolling average.

- For new base load units, the BSER is achieved in two phases. Phase 1 requires highly efficient operation achieving a performance standard of 800 lb. CO2/MWh (for units with a base load rating of 2,000 MMBtu/hr or more) to 900 lb. CO2/MWh (for units with a base load rating of less than 2,000 MMBtu/hr) through 2031. Phase 2 requires CCS at a 90 percent capture rate or meeting 100 lb. $CO2/MWh$ starting in 2032. EPA's standard of performance in technology neutral and affected sources may comply with it by co-firing hydrogen.

- For new intermediate units, the BSER is efficient operations resulting in an emissions limitation of 1,170 lb. CO2/MWh based on natural gas operation, effective upon start of operation.

- For new low-utilization units, the BSER requires the use of clean fuels (i.e., natural gas, Nos. 1 and 2 fuel oil) with a resulting standard between 120-160 lb. CO2/MMBtu, depending on unit-specific characteristics.

The final GHG standards result in the following considerations for NV Energy's fleet.

- The existing Valmy Units, converted to natural gas operation, Fort Churchill units, and Tracy Unit 3 will be regulated as existing gas-fired steam units requiring routine effective operations achieving CO2 emission rates of between 1,400 to 1,600 lb. CO2/MWH depending on each units operating capacity factor.

- The Silverhawk Peaking Plant will be considered new units under the GHG rule as construction started after May 23, 2023. The units would fall under the low-utilization category (20 percent capacity factor or less) which only require use of clean fuels (i.e., natural gas).

- The proposed Valmy simple-cycle units will be regulated under the low-utilization (if operating at a capacity factor 20 percent of less), which only require use of clean fuels (i.e., natural gas), or intermediate category (if operating at capacity factors between 20 and 40 percent), requiring efficient operations and achieving a CO2 emission rates of 1,170 lb. CO2/MWH based on natural gas operation.

- The remaining existing NV Energy units are not impacted by the April 25 final rule but may be part of future EPA proposals.

<u>Mercury and Air Toxics Standards</u>

On April 24, 2024, EPA finalized the National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology rule, commonly known as the Mercury and Air Toxics Standards, to reflect recent developments in control technologies and performance of these plants.

In the final rule, EPA revised the filterable particulate matter ("fPM") standard for all existing coal based EGUs to 0.010 lb./MMBtu, which is designed to control non-mercury hazardous air pollutants metals. EPA also finalized the requirement to demonstrate compliance with the revised fPM standard using particulate matter continuous emission monitoring systems. The revised standards will be effective three years after the effective date of the rule, which is 60 days after Federal Register publication.

This final rule does not affect Valmy Units 1 and 2. The conversion to natural gas operation will be completed ahead of the timeline of which the revised standards take effect.

B. LONG-TERM POWER PURCHASE AGREEMENTS

The Companies meet customer's energy demand with company-owned and controlled generation, as well as with a combination of long-term power purchase agreements ("PPAs") and short-term energy transactions.

Similarly, the Companies meet the requirements of Nevada's RPS through a combination of company-owned generation, Commission-approved long-term PPAs with renewable energy resources, agreements for purchase of portfolio energy credits ("PCs"), and energy efficiency programs.

Figure CON-1 lists all of Nevada Power's renewable and non-renewable long-term PPAs, PC only, and sales agreements. Figure CON-2 lists all of Sierra's renewable and non-renewable long-term PPAs, PC-only, and sales agreements.

FIGURE CON-1
NEVADA POWER'S LONG-TERM POWER PURCHASE AGREEMENTS

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Purchase Agreements				
PPAs (Commercial)				
ACE Searchlight[QF]	Solar[S]	17.5	12/16/2014	12/31/2034
APEX Landfill[QF]	Methane	12.0	3/1/2012	12/31/2032
Boulder Solar I[EWG]	Solar[S]	100.0	12/9/2016	12/31/2036
Colorado River Commission-Hoover	Hydro	237.6	10/1/2017	9/30/2067
Copper Mountain 5[EWG]	Solar[S]	250.0	7/23/2021	12/31/2046
Desert Peak 2[QF]	Geothermal	25.0	4/17/2007	12/31/2027
Eagle Shadow Mountain[EWG]	Solar[S]	300.0	5/10/2023	12/31/2048
FRV Spectrum[QF]	Solar[S]	30.0	9/23/2013	12/31/2038
Gemini Solar[EWG]	Solar[S,X=380 (3.7 hrs)]	690.0	3/25/2024	12/31/2049
Jersey Valley[QF]	Geothermal	22.5	8/30/2011	12/31/2031
McGinness Hills[QF]	Geothermal	96.0	6/20/2012	12/31/2032
Moapa (Arrow Canyon) Solar[EWG]	Solar[S,X=75 (5 hrs)]	200.0	12/8/2023	12/31/2048
Mountain View[EWG]	Solar[S]	20.0	1/5/2014	12/31/2039
Nevada Solar One (NPC)[QF]	Solar[T,X]	46.9	6/27/2007	12/31/2027
NGP Blue Mountain[QF]	Geothermal	49.5	11/20/2009	12/31/2029
RV Apex[QF]	Solar[S]	20.0	7/21/2012	12/31/2037
Salt Wells[QF]	Geothermal	23.6	9/18/2009	12/31/2029
Silver State[EWG]	Solar[F]	52.0	4/25/2012	12/31/2037
Spring Valley[EWG]	Wind	151.8	8/16/2012	12/31/2032
Stillwater Geothermal[1,QF]	Geothermal	47.2	10/10/2009	12/31/2029
Stillwater PV[1,QF]	Solar[F]	22.0	3/5/2012	12/31/2029
Switch Station 1[EWG]	Solar[S]	100.0	8/8/2017	12/31/2037
Switch Station 2 (NPC)[EWG]	Solar[S]	0.0	10/11/2017	12/31/2037
Techren I[EWG]	Solar[S]	100.0	3/11/2019	12/31/2044
Techren III[QF]	Solar[S]	25.0	10/7/2020	12/31/2045
Techren V[EWG]	Solar[S]	50.0	12/31/2020	12/31/2045
Tuscarora[QF]	Geothermal	32.0	1/11/2012	12/31/2032
WM Renewable Energy-Lockwood[QF]	Methane	3.2	4/1/2012	12/31/2032
	Total	**2723.8**		
PC Purchase Agreements				
Sierra Pacific Power	Geothermal	2.3	10/30/2009	12/31/2028
Nellis I (Solar Star)[QF]	Solar	13.2	12/15/2007	12/31/2027
SunPower (LVVWD)	Solar	3.0	4/20/2006	12/31/2026
	Total	**18.5**		
PPAs (Pre-Commercial)[2]			**Estimated COD**	**Termination Date**
	Total	**0.0**		
Non-Renewable Purchase Agreements				
Nevada Cogeneration Associates #1[3] (Summer Only after 4/30/2023)	Natural Gas	85.0	6/18/1992	9/30/2024
Renewable and Non-Renewable Sales				
Switch NGR (Switch Station 1)	NGR Agreement (Sale of PCs)	100.0	8/8/2017	12/31/2037
Switch NGR-NPC (Switch Station 2)	NGR Agreement (Sale of PCs)	0.0	10/11/2017	12/31/2037

Notes:
1. The geothermal and solar facilities are combined into one PPA.
2. NCA1 will have a two summer period extension (June-Sep) 2023 and 2024.
3. NCA1 will have a two summer period extension (June-Sep) 2023 and 2024.
QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage

*NPC also has a short term Power Confirmation with Tonopah Solar Energy for Crescent Dunes (110 MW) effective 12/21/2021 - 9/30/2024.

FIGURE CON-2
SIERRA'S LONG-TERM POWER PURCHASE AGREEMENTS

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Energy PPAs (Commercial)				
Battle Mountain[EWG]	Solar[S,X=24.68MW (4 hrs)]	101.0	6/23/2021	12/31/2046
Beowawe[QF]	Geothermal	17.7	4/21/2006	12/31/2024
Boulder Solar II[EWG]	Solar[S]	50.0	1/27/2017	12/31/2037
Burdette[QF]	Geothermal	26.0	2/28/2006	12/31/2026
Dodge Flat[EWG]	Solar[S,X=50MW (4 hrs)]	200.0	3/2/2022	12/31/2047
Fish Springs Ranch[EWG]	Solar[S,X=24.91MW (4 hrs)]	100.0	3/15/2022	12/31/2047
Galena 3[QF]	Geothermal	26.5	2/21/2008	12/31/2028
Hooper[1,QF]	Hydro	0.75	6/23/2016	12/31/2040
Kingston[1]	Hydro	0.175	9/19/2011	12/31/2040
Mill Creek[1]	Hydro	0.037	9/1/2011	12/31/2040
Nevada Solar One (SPPC)[QF]	Solar[T,X]	22.1	6/27/2007	12/31/2027
North Valley[QF]	Geothermal	25	4/26/2023	12/31/2048
RO Ranch[1,2]	Hydro	0	3/15/2011	12/31/2040
Switch Station 2 (SPPC)[EWG]	Solar[S]	79.0	10/11/2017	12/31/2037
Techren II[EWG]	Solar[S]	200.0	10/4/2019	12/31/2044
Techren IV[QF]	Solar[S]	25.0	10/7/2020	12/31/2045
Turquoise[EWG]	Solar[F]	50.0	12/4/2020	12/31/2045
TCID New Lahontan[QF]	Hydro	4.0	6/12/1989	6/30/2025
TMWA Fleish	Hydro	2.4	5/16/2008	6/1/2028
TMWA Verdi	Hydro	2.4	5/15/2009	6/1/2029
TMWA Washoe	Hydro	2.5	7/25/2008	6/1/2028
USG San Emidio[QF]	Geothermal	11.75	5/25/2012	12/31/2037
	Total	**946.3**		
PC Purchase Agreement				
TMWRF	Methane	0.8	9/9/2005	12/12/2024
PPAs (Pre-Commercial)[3]			**Estimated COD**	**Termination Date**
North Valmy Eavor Loop	Geothermal	20.0	12/31/2026[5]	12/31/2051
Ormat Western Geothermal Portfolio (consists of the Facilities listed below under one PPA)				
Beowawe[QF]	Geothermal	20.0	1/1/2025	12/31/2053
Galena 1 (Burdette)[QF]	Geothermal	15.0	2/1/2027	12/31/2053
Desert Peak 2[QF]	Geothermal	10.0	2/1/2028	12/31/2053
Galena 3[QF]	Geothermal	15.0	1/1/2029	12/31/2053
North Valley 2[QF]	Geothermal	15.0	1/1/2026	12/31/2053
Lone Mountain[QF]	Geothermal	15.0	1/1/2026	12/31/2053
Gerlach[QF]	Geothermal	15.0	1/1/2028	12/31/2053
Pinto[QF]	Geothermal	15.0	1/1/2027	12/31/2053
	Total	**140.0**		
Non-Renewable Purchase Agreements				
Liberty (CalPeco) EBSA	Diesel	12.0	1/1/2011	12/31/2031
	Total	**12.0**		
Renewable & Non-Renewable Sales Agreements				
Liberty (CalPeco)	Full Requirements (Capacity/Energy/PCs)	See Note 4	12/30/2020	12/29/2025
NPC-SPPC	Sale of PCs (Geothermal)	2.3	10/30/2009	12/31/2028
Apple NGR (Fort Churchill Solar)	NGR Agreement (Sale of PCs)	19.5	8/5/2015	8/4/2040
Apple NGR (Boulder Solar II)	NGR Agreement (Sale of PCs)	50.0	1/27/2017	12/31/2037
Switch NGR-SPPC (Switch Station 2)	NGR Agreement (Sale of PCs)	79.0	10/11/2017	12/31/2037
Apple NGR (Techren II)	NGR Agreement (Sale of PCs)	200.0	10/4/2019	6/20/2044
Apple NGR (Turquoise)	NGR Agreement (Sale of PCs)	50.0	12/4/2020	4/30/2045

Notes:
1. The illustrative termination date shown is subject to certain conditions, which may result in termination before or after December 31, 2040.
2. RO Ranch Hydro facility is shut down indefinitely (the PPA is still active).
3. Facilities are either under development or construction (the dates shown are expected dates).
4. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December).
5. Phase One COD is 2026. Phase Four (Final) is 2028.
QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage

1. RENEWABLE PPAs

Nevada Power has executed twenty-seven long-term renewable PPAs representing a total nameplate capacity of approximately 2,723.8 MW (see Figure CON-1 above). The latest commercial addition to the portfolio is the Moapa (Arrow Canyon) project (200 MW with 75 MW of storage), which achieved commercial operation in December 2023, and the Gemini Solar project (690 MW with 380 MW of storage), which achieved commercial operation in March 2024. In addition, Nevada Power has three PC-only purchase agreements representing a total nameplate capacity of approximately 18.5 MW. Nevada Power's renewable PPAs secure a renewable energy portfolio that is a mix of solar, geothermal, hydro, methane, and wind resources.

Sierra has executed twenty-four long-term renewable PPAs, representing a total nameplate capacity of approximately 1,086.3 MW (see Figure CON-2 above). The latest commercial addition to the portfolio is North Valley, which achieved commercial operation in April 2023. Projects in development include the Ormat Western Geothermal Portfolio (140 MW) with contractual CODs of January 2025 through January 2029, and North Valmy Eavor Loop, with a contractual estimated COD of 12/31/2026. Sierra is in discussions with the counterparty on the commercial viability of the project, as further explained in the Renewables narrative of this filing. Sierra has executed one long-term PC-only purchase agreement representing a nameplate capacity of 0.8 MW. Sierra's renewable PPAs secure a renewable energy portfolio that is made up of a mix of solar, geothermal, and hydro resources.

Additional information regarding both Nevada Power's and Sierra's portfolio of renewable energy PPAs is set forth below.

2. NON-RENEWABLE PPAs

Figures CON-1 and CON-2 (above) also list non-renewable PPAs at Nevada Power and Sierra.

Nevada Power has executed one non-renewable PPA, representing a total capacity of approximately 85 MW. The agreement is for the must-take output of the Nevada Cogeneration Associates 1, gas-fueled co-generation facility. Sierra has executed one long-term non-renewable agreement with Liberty Utilities, pursuant to which Sierra purchases 12 MW of capacity from Liberty's Kings Beach diesel units for emergency purposes. This agreement expires December 31, 2031.

3. RENEWABLE AND NON-RENEWABLE SALES AGREEMENTS

Also listed on Figures CON-1 and CON-2 are long-term renewable and non-renewable sales agreements, pursuant to which Nevada Power and Sierra sell either energy, PCs, or both, to third parties.

Nevada Power currently has two NV GreenEnergy Rider ("NGR") agreements pursuant to which it sells PCs to Switch Ltd. (associated with the full output of the Switch Station 1 solar facility).

Sierra has executed four long-term agreements under the NGR program for the sale of PCs to Apple (associated with the full output of the Fort Churchill Solar Array, Boulder Solar II project, Techren Solar II project, and the Turquoise Solar project) and a fifth agreement with Switch Ltd. (associated with the full output of the Switch Station 2 project). Sierra has also executed one long-term agreement for the sale of PCs to Nevada Power. This PC-only sale agreement expires December 31, 2028.

In addition, Sierra has executed a full requirements agreement with Liberty whereby Sierra sells capacity, energy, and certain PCs to meet the needs of Liberty retail customers in California. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December). The term of the agreement is December 30, 2020, through December 29, 2025.

C. FUEL SUPPLY

1. CURRENT PHYSICAL GAS SUPPLY

The Companies are well poised to access the dominant supply basins serving the Pacific Northwest and the Desert Southwest per their existing firm gas transportation assets. These gas supply basins are the Rocky Mountain Basin, the San Juan Basin, British Columbia, Western Canada Sedimentary Basins, as well as California gas supply. The gas transportation facilities that are available to move gas from the supply basins to the Companies' respective service territories are shown in Figures GAS-1 and GAS-2

Nevada Power takes delivery of natural gas from interstate pipeline Kern River, which is connected with several major gas producing regions including the Permian, San Juan, and the Rocky Mountain supply basins, as well as California gas supply. The largest producing region with the best connectivity into and through Nevada Power's control area is the Rocky Mountain supply basin.

Sierra takes delivery of natural gas from two interstate pipelines, Great Basin and Tuscarora. Great Basin receives gas supplies upstream from Northwest Pipeline ("NWPL"), which sources its gas supplies from British Columbia, the San Juan Basin, and the Rocky Mountain region of Wyoming, Utah and Colorado. Tuscarora receives gas supplies from Gas Transmission Northwest ("GTN") pipeline, near Malin, Oregon, which is connected to the gas producing regions of Western Canada Sedimentary Basin Alberta through TC Energy's system. The gas supply source for Malin gas is predominantly in the Province of Alberta, Canada. TC Energy's Alberta pipeline system carries the gas commodity from the AECO producing areas to the Alberta/British Columbia border. There, TC Energy's Alberta system interconnects with TC Energy's Foothills system, which transports gas to GTN system at the U.S./Canadian border near Kingsgate, Idaho. Beginning in 2026 Sierra will be obtaining firm transportation on Ruby Pipeline shortly to serve the Valmy gas conversion.

FIGURE GAS-1
NEVADA POWER PIPELINE ROUTES

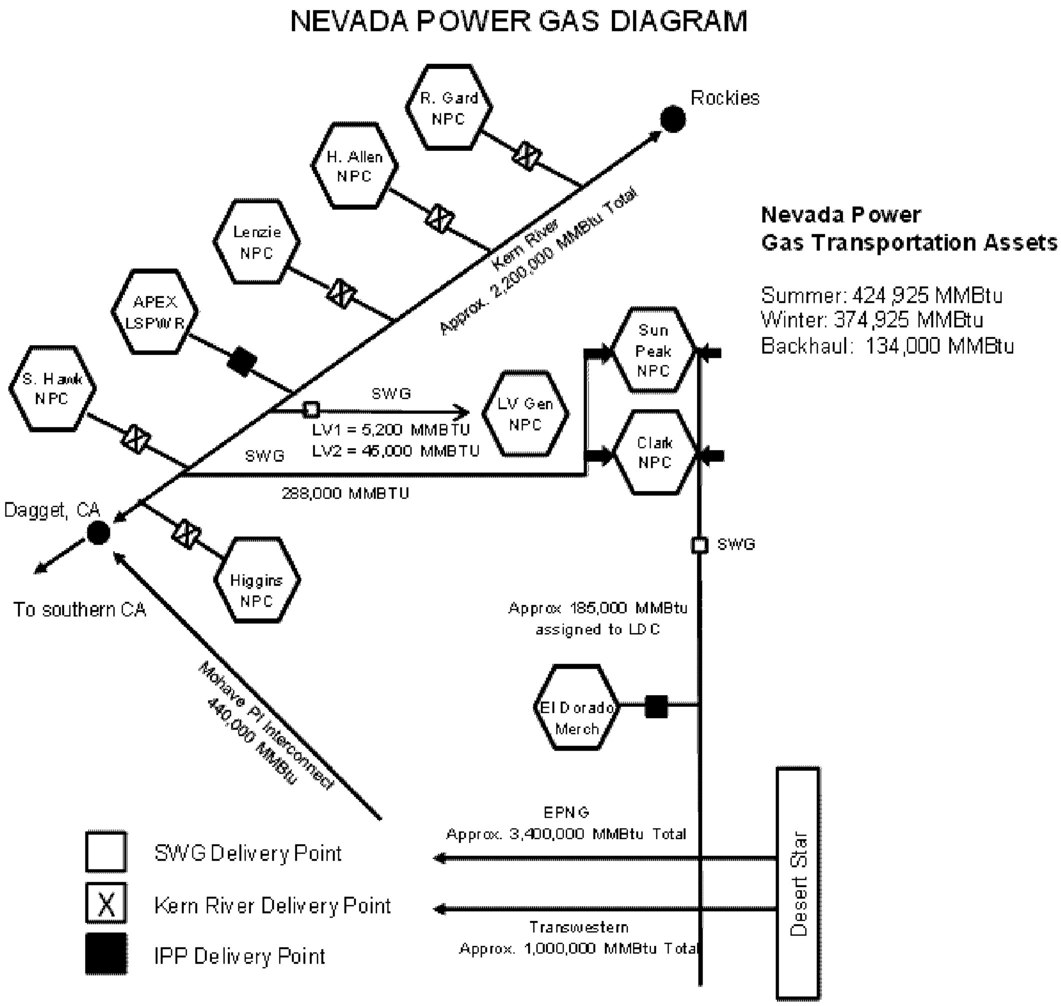
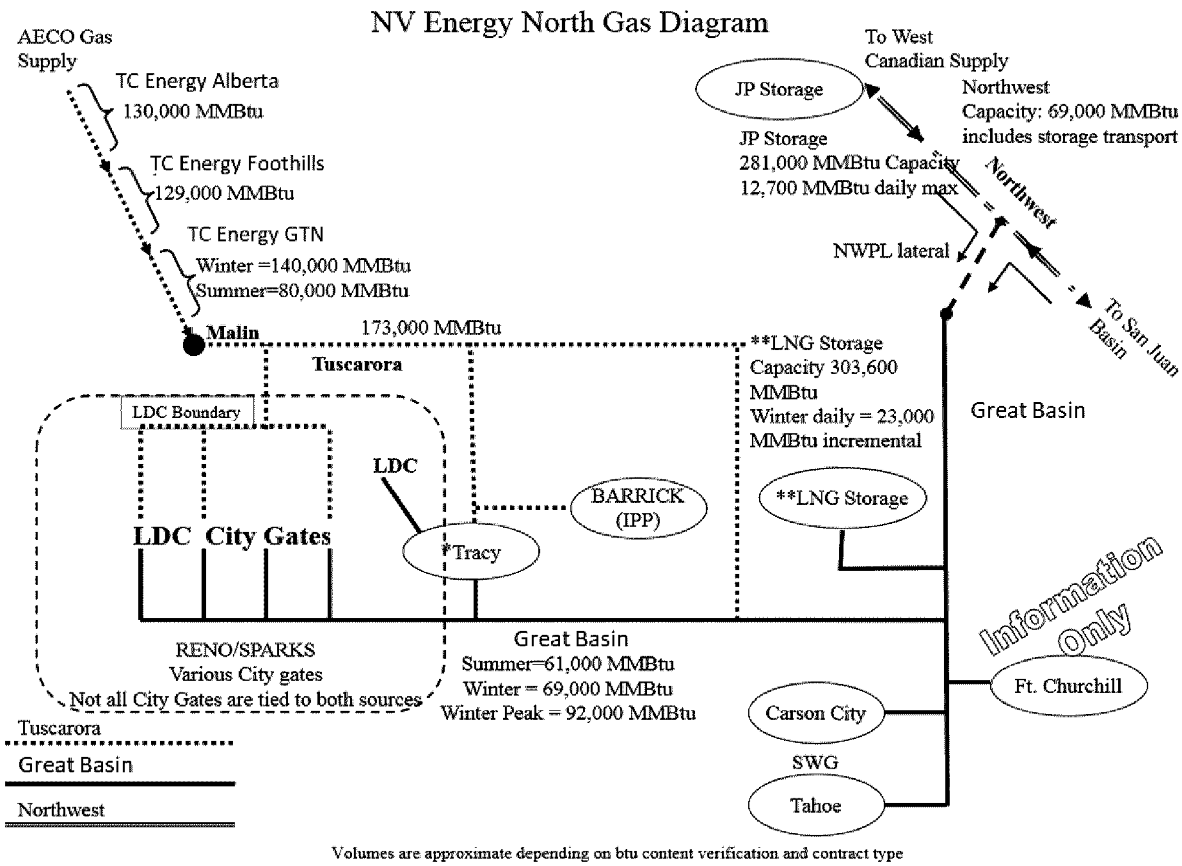


FIGURE GAS-2
SIERRA PIPELINE ROUTES



Figures GAS-3 and GAS-4 list Nevada Power's and Sierra's existing gas transportation service agreements, respectively.

FIGURE GAS-3
NEVADA POWER NATURAL GAS TRANSPORTATION CONTRACTS

Contract Type	Counterparty	Contract #	Termination Date (as of 6/1/2024)	Maximum Daily Quantity (MMBTUs) Annual	Winter	Summer	Comments
TSA	Kern River	20027	4/30/2028	75,000			
TSA	Kern River	20028	4/30/2028			50,000	
TSA	Kern River	20023	4/30/2032	12,500			
TSA	Kern River	20012	9/30/2031	10,350			
TSA	Kern River	20013	9/30/2031	11,075			
TSA	Kern River	1830	9/30/2031	266,000			Forward haul
TSA	Kern River	1617	9/30/2031	134,000			Back haul
Facilities	Kern River	Higgins Facility Charge	12/31/2039				No Volume
TSA	SW Gas	21016	4/30/2027	288,000			
TSA	SW Gas	21011	Month to Month			5,200	
TSA	SW Gas	21088	7/31/2025	45,000			

Nevada Power currently holds year-round contracts for firm forward haul gas transportation rights on Kern River totalling 374,925 MMBtu/day, with an additional 50,000 MMBtu/day in the summer that increases the maximum daily quantity to 424,925 MMBtu/day from April through October to serve a majority of its overall daily natural gas needs. Nevada Power holds rollover rights under the Kern River tariff, provided Nevada Power is willing to continue under the terms and conditions specified therein. In addition, Nevada Power has a long-term agreement with Kern River for back haul capacity of 134,000 MMBtu/day. Nevada Power may procure Topock-sourced gas for re-delivery into Kern River at Daggett, California.

Gas supplies for Nevada Power's Harry Allen, Chuck Lenzie, Higgins and Silverhawk plants are delivered directly by Kern River. The gas-fired units at Edward W. Clark Generating Station and Sun Peak Generating Station receive gas delivered under a 288,000 MMBtu/day transportation service agreement with Southwest Gas Corporation ("Southwest"). The transportation agreement with Southwest provides for receipt of Kern River supplies, as well as limited quantities of gas from sellers off the El Paso Natural Gas Company ("El Paso") and/or Transwestern Pipeline Company ("Transwestern") pipelines south of Las Vegas (if Southwest is not using its capacity rights to serve its own requirements). As part of the acquisition of Las Vegas Generating Station Units 1 and 2 in 2014, Nevada Power retained the gas transportation service agreements (LV Station Unit 1 45,000 MMBtu/day and LV Station Unit 2 5,200 MMBtu/day) with Southwest. The primary term for the LV Station Unit 2 contract with Southwest was extended through July 31, 2025.

Nevada Power meets at least once a year with Kern River to review the prior year's operations, discuss upcoming maintenance plans, and review potential expansions.

Nevada Power is seeking approval to maintain its current natural gas transportation portfolio. Nevada Power's daily gas usage requirements during July and August exceed the current contracted capacity with Kern River. Nevada Power has adequately closed prior firm gas transportation open positions by purchasing delivered natural gas and proposes to continue this strategy. Nevada Power will continue to evaluate whether there is a need to acquire new firm transportation capacity and may revisit this strategy in a future filing. Alternatively, the Companies may evaluate the possibility of deviating from an approved ESP or ESP update "to the extent necessary to respond adequately to any significant change in circumstances not contemplated by the energy supply plan" pursuant to NAC § 704.9504, should conditions warrant such an action.

FIGURE GAS-4
SIERRA NATURAL GAS TRANSPORTATION CONTRACTS

Contract Type	Counterparty	Contract #	Termination Date (as of 6/1/2024)	Units	Maximum Daily Quantity Annual	Winter	Summer
TSA							
	TC Energy - Alberta System						
		2010-447962	10/31/2025	GJ/Day	18,583		
		2010-447963	10/31/2025	GJ/Day	92,918		
		2010-447964	10/31/2025	GJ/Day	25,993		
					137,494		
	TC Energy - Foothills System						
		SPP-F1	10/31/2025	GJ/Day	32,444		
		SPP-F2	10/31/2025	GJ/Day	2,143		
		SPP-F3	10/31/2025	GJ/Day	5,572		
		SPP-F4	10/31/2025	GJ/Day	16,220		
		SPP-F5	10/31/2025	GJ/Day	10,920		
		SPP-F6	10/31/2025	GJ/Day	866		
		SPP-F7	10/31/2025	GJ/Day	26,233		
		SPP-F8	10/31/2025	GJ/Day	10,000		
		SPP-F9	10/31/2025	GJ/Day	15,826		
		SPP-F10	10/31/2025	GJ/Day	15,807		
					136,031		
	TC Energy - GTN						
		F-02842	10/31/2029	MMBTU/Day		60,000	30,000
		F-02843	10/31/2029	MMBTU/Day		20,270	10,000
		F-07027	4/30/2031	MMBTU/Day		20,000	
		F-07328	10/31/2029	MMBTU/Day	14,000		
		F-07370	10/31/2035	MMBTU/Day	15,000		
		F-07371	10/31/2035	MMBTU/Day	10,099		
		F-07567	10/31/2035	MMBTU/Day	800		
					39,899	100,270	40,000
	Northwest Pipeline						
		10046	6/30/2025	MMBTU/Day	59,696		
		10061	3/31/2025	MMBTU/Day	9,000		
					68,696		
	Great Basin Gas Transmission						
		F-29	11/30/2024	MMBTU/Day		68,696	61,044
		F-32	3/31/2025	MMBTU/Day		23,000	
						91,696	61,044
	TC Energy - Tuscarora						
		F001	12/31/2032	MMBTU/Day	105,750		
		F019	12/31/2032	MMBTU/Day	10,000		
		F024	12/31/2032	MMBTU/Day	5,661		
		F025	12/31/2032	MMBTU/Day	5,690		
		F030	12/31/2032	MMBTU/Day	5,722		
		F097	9/30/2030	MMBTU/Day	40,000		
		369	9/30/2030	MMBTU/Day	760		
					173,583		
Storage							
	Northwest Pipeline						
		126544 Storage Capacity	3/31/2046	MMBTU	281,242		
		126544 Storage Withdraw	3/31/2046	MMBTU/Day	12,687		
	Great Basin Gas Transmission						
		S-6 LNG Stor Cap	3/31/2025	MMBTU	303,604		
		S-6 LNG Daily Del Cap	3/31/2025	MMBTU/Day		23,000	

Sierra has storage assets along both Great Basin and NWPL. The NWPL storage is located at the Jackson Prairie facility and allows for unlimited injection/withdrawal cycles subject to then-current mainline pipeline operating conditions. Sierra's total firm storage rights at Jackson Prairie are just over 281,000 MMBtu and come with about 12,600 MMBtu of firm daily injection/withdrawal rights. Additionally, Sierra will evaluate opportunities to enter into an asset management agreement with an energy management company to further optimize these assets.

Sierra similarly holds rights on Great Basin of approximately 304,000 MMBtu of LNG storage capacity that comes with up to 23,000 MMBtu of firm daily withdrawal rights, including firm transport to the LDC service territory; however, the LNG supply is only available during the winter season.

Sierra meets at least once a year with all of the interstate pipeline companies from which it purchases firm transportation service. The intent of the meetings is to review the prior year's operations, discuss upcoming maintenance plans, and review potential expansions. Storage projects are included in discussions with both NWPL and Great Basin.

Many of Sierra's contracts have evergreen clauses and can be renewed for successive one-year extension periods. Given the results of the PLEXOS analysis described in Section 2.E and the requirement in NAC § 704.9099(3) to maximize the reliability of fuel supply over the term of the energy supply plan, Sierra proposes to continue to renew these contracts on an annual basis in order to ensure firm deliveries of gas supplies. The existing contracts subject to renewal are shown in Figure GAS-5.

Sierra's contracts with Great Basin expire November 30, 2024, and March 31, 2025. Great Basin filed a rate case at the Federal Energy Regulatory Commission ("FERC") on March 6, 2024. These contracts will be renewed during the rate case settlement discussions.

The GTN Pipeline, owned by TC Energy, filed a rate case at FERC on September 29, 2023. GTN began pre-hearing settlement discussions on May 10, 2023, which Sierra participated in. A settlement has not yet been reached. Sierra will continue with pre-settlement discussions and participate in and monitor this rate case if filed.

NWPL provides access to multiple hubs and is connected to the Jackson Prairie storage facility. Sierra would lose these benefits if the contracts with NWPL were not renewed.

Service reliability remains a critical focus of the LDC. Recognizing that pipeline projects, including LNG and other types of gas storage, may take several years to develop, Sierra continues to monitor potential pipeline expansion projects.

For the forecast time period, this means utilization of the full export capability of the Sierra and SWG capacity at the Great Basin LNG facility. Great Basin's LNG Tariff allows customers to share LNG storage capacity and LNG specific gas transport with each other. Sierra will continue to focus on managing relationships with holders of such storage assets. This should serve to reduce costs to Sierra's gas customers compared to the option of contracting for such storage services directly. In addition, Sierra will continue to evaluate and, as appropriate, execute parking and lending service agreements on interstate pipelines.

2. PHYSICAL GAS PROCUREMENT

The Companies employ a four-season laddering strategy for physical gas purchases, in which 25 percent of projected monthly gas requirements per season are procured, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. Physical gas volumes are to be procured at indexed prices, subject to a cap of [redacted] MMBtu on the premium. This cap could be exceeded with prior approval from the Risk Committee; however, if the Companies exceed the premium cap and the procured gas which exceeded the premium cap is not the least cost supply alternative, the Companies will provide written notice to the Regulatory Operations Staff and the Bureau of Consumer Protection indicating such. As described in the Joint ESP filing, the Companies are proposing to continue to follow the physical gas procurement strategy reviewed and approved in Docket No. 09-07003. Targeted physical gas volumes will exclude any potential gas-fired generation to meet forward sales; gas needed to meet forward sales in only procured through shortterm purchases. Figure GAS-5 reflects the planned implementation schedule for the physical gas acquisition strategy.

FIGURE GAS-5
PHYSICAL GAS ACQUISITION STRATEGY

	Delivery						
Incremental Transaction	Winter '24-'25	Summer '25	Winter '25-'26	Summer '26	Winter '26-'27	Summer '27	Winter '27-'28
Q1 '23	25%						
Q3 '23	25%	25%					
Q1 '24	25%	25%	25%				
Q3 '24	25%	25%	25%	25%			
Q1 '25		25%	25%	25%	25%		
Q3 '25			25%	25%	25%	25%	
Q1 '26				25%	25%	25%	25%
Q3 '26					25%	25%	25%
Q1 '27						25%	25%
Q3 '27							25%
Sum	100%	100%	100%	100%	100%	100%	100%

Note: Winter includes the months of November through March and Summer includes the months of April through October.

3. EMERGENCY SUPPLIES

Sierra's LDC operations rely on gas supply delivered through interstate pipelines to meet LDC customer requirements. During extreme cold weather events or during a force majeure event on an interstate pipeline, gas supply scheduled to Sierra's gas-fired electric generating plants may be diverted to support LDC gas supply operations, thereby limiting the availability of natural gas supply to meet electric generation requirements. In these infrequent situations, Sierra relies primarily on energy supplies dispatched from Nevada Power generating units and delivered from south to north using the ON Line. In addition, two of Sierra's generating units, Clark Mountain 3 and 4, are peaking units capable of burning diesel. Sierra maintains diesel inventories at the Clark Mountain facility that can be called upon as an alternate fuel during emergency events only, in order to allow the use of existing pipeline transportation capacity to support peak LDC use. The Reno/Sparks oil terminal is within 10 miles of the Clark Mountain generating units and any required diesel can be supplied on short notice, even during the winter months. Diesel use is anticipated to be minimal, if at all, in each year in the planning period. Diesel inventory replacement is procured, if necessary, utilizing current diesel specifications required ensuring compliance with any operating permit(s) or applicable rule requirements and following internal Corporate Purchasing Policies and Procedures.

D. RENEWABLES

1. Introduction.

Long-term planning to meet the energy needs of Nevada continues to be a priority for the Companies. The Companies continue to plan and execute to meet the Renewable Portfolio Standard of 50 percent by 2030 ("RPS") and a State of Nevada goal of zero carbon dioxide emission resources that match total electricity sales by 2050. In addition, load growth and customer demand for renewable energy are anticipated to continue to increase in the State of Nevada. Finally, constricted available capacity in the West makes closing the Companies' open position an important objective. The Companies must be prepared to comply with the RPS and meet the needs of their customers by providing reliable, safe, and economic renewable resources.

To meet these needs, the IRP includes a range of procurement methods to advance renewable projects that include solicitations for power purchase agreements ("PPAs"), company development, and asset acquisitions of projects. The Companies outline named placeholders in the Alternative Plans including PPAs and company-development resources that the Companies will need to meet the RPS, load growth, and customer demands for renewable energy. This balanced approach is foundational to the Companies' health and preserves customer value by pursuing the best available project options.

Due to the lack of available transmission capacity and infrastructure, adding additional renewable resources is challenging. Future development of renewables assets is limited without the addition of new transmission infrastructure. Greenlink Nevada Transmission Project, for example, will unlock renewable energy development potential that is currently not accessible due to lack of necessary transmission infrastructure. Without Greenlink Nevada Transmission Project, new renewable project development opportunities will be severely limited and will require the construction of dedicated piecemeal transmission from generation locations to load to avoid the import limitations prevalent in the Northern system today. Even with Greenlink Nevada Transmission Project adding additional renewable development potential, achieving renewable generation goals will require significant additional transmission investment.

Given the multiyear project schedule for equivalent transmission infrastructure projects, the Companies would not have the capability to diversify the renewable and thermal resources in the north and south without continued Greenlink Nevada Transmission Project development. Lack of transmission infrastructure would reduce the likelihood the Companies would comply with the RPS and could increase cost and schedule to achieve the RPS. Siting projects next to transmission lines and at a reasonable distance from substations is critical to the economic success of renewables projects.

Historically, the Companies have sought approval of generation and storage projects in IRPs only for those projects that can be placed in service during the three-year action period. Generation assets for years beyond the three-year action period were identified only by generic placeholders.

For the Companies to meet the needs of the Companies' customers and align with directive six[1] in the Fifth IRPA, named company-owned resources are included in the 2024 IRP. This longer term and more detailed integrated planning approach is critical to meeting the increasing state mandated RPS at the best value to customers through longer-term, more specific planning and project execution which will allow the Companies to plan for and deliver company-owned renewables projects.

While the Companies continue to evaluate all contractual options for renewable projects, no asset purchase agreement contracts are being brought forward for approval in this IRP. Therefore, the following narrative addresses company-owned projects and PPAs to meet the load growth, customer needs, RPS, and to close the open position.

Company-Owned Renewables

The Companies are not submitting any company-owned renewables projects in this filing. While the Companies are diligently pursuing the development of the Siera Solar Project, the Companies continue to evaluate the impact of the Commission's order in the Fifth Amendment to the 2021 Joint IRP, Docket No. 23-08015, for the Sierra Solar Project and on future company-owned renewables projects. However, the Companies do anticipate submitting company-owned renewables projects in future IRPs to strive for a balance portfolio as described in the Fifth Amendment.

Power Purchase Agreements

In this filing, the Companies seek approval of four PPAs that total approximately 1,143 MW of renewable generation capacity. Three of the four PPAs were selected from a robust request for proposal ("RFP") process, and a portion of the power and portfolio credits ("PCs") from these projects are part of Energy Supply Agreements ("ESAs"), while the remainder will serve the Companies' bundled retail load. The three bundled-load PPAs are comprised of 1,028 MW of solar PV and 1,028 MW of battery energy storage systems ("BESS"), an amount that falls short of resource needs to achieve Sierra's RPS compliance in 2027 and requires the use of banked renewable energy credits to meet the RPS. The other PPA is for 115 MW of geothermal with the commercial operation date commencing in 2030 and was the result of a bilateral proposal evaluated outside of the RFP process that is part of a sleeved ESA that will provide 100 percent of the energy and PCs to Callisto Enterprises LLC ("Callisto"), and, therefore, was not included in the economic analysis for this IRP. All ESAs are for customers applying through the pending Clean Transition Tariff ("CTT"). The Companies are seeking approval of these projects for multiple reasons.

[1] Docket 23-08015, April 9, 2024, Modified Order, Directive 6: NV Energy shall provide one version of each of its plans in the upcoming Integrated Resource Plan with placeholders adjusted as discussed in this Order for projects in progress or requested and to reflect anticipated NV Energy-owned projects. NV Energy may also provide versions using its current placeholder methodology for comparative purposes.

First, the three bundled-load PPA projects have demonstrated the ability to interconnect and achieve commercial operation by 2029. As discussed above, transmission is a major impediment for the growth of generation in Nevada. For example, of the 84 project proposals that the Companies evaluated in the RFP, over a third were identified to have critical flaws due to transmission constraints that delayed proposed in-service dates beyond the interconnection date. Additionally, most new generation projects require significant transmission network upgrades that are long duration and costly to implement.

Second, the bundled-load PPAs allow the Companies to continue to meet the increasing RPS[2] requirements and support the state's clean energy goals in the long term. The RPS is increasing, now requiring 50 percent renewable energy by 2030. Further, the state's 2050 clean energy goal targets energy production from zero carbon dioxide emission resources that match total electricity sales by 2050. While the plans in this IRP target the Companies' proportion of the state's 2050 goal, the PPAs requested for approval in this filing do not contribute to a trajectory beyond the RPS percentage compliance requirement.

Third, in addition to helping reduce the Companies' open capacity positions and meet load requirements, these projects assure a steady supply of renewable energy projects in development. While the Companies cannot publicly speculate on the eventual fate of individual projects, it is reasonable and prudent to expect and plan for a portion of the projects to reach commercial operation late and for some to never reach commercial operation, as recent experience has shown through cancelations, delays, or shortfalls of previously approved projects. However, the Companies' due diligence evaluation of these project proposals from the 2023 Open Resource RFP placed additional emphasis on many key project aspects, such as available transmission capacity and equipment supply control, to further mitigate deliverability risk. Therefore, the Companies continue to bring forth additional renewable projects that have presented a clear path to reach commercial operation, thereby ensuring a pipeline of viable projects is readily available for the Commission's consideration. The projects included for approval in this filing only include contracted resources.

Fourth, all four of these projects will allow the Companies to meet current and future customer needs and support a growing need to provide customers with sustainable green energy, namely through the Nevada Green Energy Rider ("NGR"), and the pending Clean Transition Tariff. There is increasing interest in the Nevada business community to source generation from zero-carbon, renewable sources. Although Nevada is a long-time leader in promoting renewable generation, many Nevada businesses and residential customers have their own sustainability objectives that are more aggressive than the State's policies. Having a growing pool of renewable resources enables the Companies' green energy programs to thrive. These efforts align with the Companies'

[2] Any portfolio credits generated by these projects, not allocated per an ESA, would contribute to RPS compliance.

ongoing commitment to support economic development throughout Nevada by collaborating with many partners to attract, retain, and expand the renewables industry while diversifying the economy. When a portion of the renewable energy is allocated to specific job-generating customers, it also promotes overall economic development, creates additional tax base for the state and counties, and lowers the total amount of energy that otherwise would have to come from carbon-based generating resources or would need to be imported from neighboring states.

Fifth, all of these projects provide supplemental benefits to the Companies' system, such as voltage support, load management, and other system reliability benefits that enhance Nevada's energy independence. In addition to the 24/7 geothermal resource, all the bundled-load PPA projects are capable of supplying energy after solar resources drop off in the evening hours due to the BESS.

Sixth, each of these projects are consistent with the goals of the recently passed Assembly Bill 524 ("AB524") provisions related to the assurance of electric supply reliability, availability, and affordability, as well as commitments to the state's goals of reducing reliance on power market purchases through securing energy from dedicated in-state resources while providing economic benefits to Nevadans. The projects also take advantage of the newly available Production Tax Credit ("PTC") as well as the Investment Tax Credit ("ITC") for renewables and BESS, respectively, which is reflected in the pricing of the PPAs to the benefit of customers.

Finally, the addition of these projects helps reinforce the Companies' commitment to renewables. The Companies' commitment to renewables goes beyond just meeting standards; it is about leading the way. The Companies have fostered renewable development since before the establishment of an RPS, having signed their first geothermal contract in 1986. The Companies' customers currently benefit from one of the most diverse renewable energy portfolios in the nation, including 51 long-term renewable PPAs representing a total nameplate capacity of approximately 3,810 MW. The Companies' renewable PPAs form a diverse renewable portfolio that is a mix of solar, geothermal, hydro, methane, and wind resources. The addition of the four PPAs would further strengthen the Companies' portfolio of renewable energy resources. In sum, the approval of these renewable projects benefits the environment, the citizens of Nevada, and aligns with the state's overall policy goals.

2. Renewable Energy Plan

Overview

Nevada is fortunate to have significant renewable resources throughout the state, including some of the greatest solar and geothermal generation potential in the country. The Companies' efforts to incorporate renewable energy into their generating fleet have grown substantially over the past decade, and the Companies have built a diverse and robust portfolio of renewable projects.

In their most recent annual RPS compliance filing, Docket No. 24-04017, Nevada Power and Sierra both exceeded their respective 2023 RPS credit requirements of 29 percent. Nevada Power ended 2023 at 40.2 percent, while Sierra ended 2023 with 38.5 percent. Adding to its existing renewable capacity, Nevada Power recently added two solar PV projects, Dry Lake Solar and Gemini Solar. Dry Lake Solar is a 150-MW solar PV facility with 100-MW of BESS. The project was approved by the Commission in Docket No. 20-07023. It declared commercial operation on May 2, 2024. Gemini Solar is a 690-MW solar PV facility with 380-MW of BESS. The project was approved by the Commission in Docket No. 19-06039. It declared commercial operation on March 25, 2024. In the order approving the Gemini, 40 percent of the portfolio credits ("PCs") generated by the facility will be transferred to Sierra. These facilities will increase the total amount of renewable energy and PCs available to meet the energy needs of Sierra's and Nevada Power's customers.

As of May 31, 2024, Nevada Power had approximately 2,724 MW of renewable generating resources providing renewable energy to meet the energy needs of its customers.[3]

In addition, Nevada Power and Sierra ended May 2024 with one solar PV project, Sierra Solar, under development. Sierra Solar is a 400-MW solar PV facility with a 400-MW BESS. Battery storage offers flexibility by allowing Nevada Power and Sierra to store generation when demand and prices are low and release it back to the grid when demand and prices start to rise. This helps optimize must-take renewable resources, like solar PV, where generation and load do not always align. The Sierra Solar energy and capacity will be split between Nevada Power (10 percent) and Sierra (90 percent). The project was approved by the Commission in Docket No. 23-08015.

As of May 31, 2024, Sierra had approximately 1,086 MW of renewable generating resources providing renewable energy to meet the energy needs of its customers.[4] In addition to the aforementioned Sierra Solar photovoltaic project, Sierra ended May 2024 with two geothermal projects in various stages of development.

The following is a summary of Nevada Power's and Sierra's portfolios of renewable facilities that contributed to Nevada Power and Sierra meeting the RPS requirements as of May 31, 2024. The list below does not include the community-based solar projects, short-term agreements, Nevada Power's allocation of Hoover, or projects that are dedicated to supporting commitments to meet customer-specific requirements for renewable energy under a Commission-approved NGR Option

[3] The 1,870 MW total divides the Nevada Solar One 69 MW agreement between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission. It also includes the two PC only agreements: Nellis 1(13.2 MW) and Las Vegas Valley Water District (3 MW) and Nevada Power's allocation of Hoover (237.6 MW).

[3] The 965.9 MW total divides the Nevada Solar One 69 MW agreement between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission. It also includes two small hydro projects, Kingston (.16 MW) and Mill Creek (.04 MW) as well on the credit only agreement with Truckee Meadows Waste Water (.80 MW), but it excludes Hooper Hydro (.8 MW) where Sierra does not claim the PCs from the generation and RO Ranch Hydro (0.225 MW) which was shuttered but the PPA remains active.

2 tariff.[5] The Companies made a separate compliance filing required by Schedule No. NGR in Docket No. 24-03031.

NEVADA POWER

1. Desert Peak 2 Geothermal Power
The Desert Peak 2 facility is a 25 MW geothermal project located in Churchill County, Nevada. The project was approved by the Commission in 2003. The plant began producing energy in 2007 and the PPA terminates on December 31, 2027.

2. Faulkner 1
Faulkner 1, a/k/a NGP Blue Mountain, is a 49.5 MW geothermal project located in Humboldt County near Blue Mountain, Nevada. The project was approved by the Commission in 2007. The plant began producing energy in 2009 and the PPA terminates on December 31, 2029.

3. Jersey Valley Geothermal Project
The Jersey Valley facility is a 22.5 MW geothermal project located in a remote area between Lander and Pershing counties in Nevada. The project was approved by the Commission in 2007. The plant began producing energy in 2011 and the PPA terminates on December 31, 2031.

4. McGinness Hills Geothermal Project
The McGinness Hills facility is a 96 MW geothermal project located in Lander County, Nevada. The project was approved by the Commission in 2010. The plant began producing energy in 2012. As part of the existing 20-year PPA between Nevada Power and ORNI 39, LLC (owned by Ormat Technologies, Inc.), the McGinness Hills geothermal facility was expanded to include a second 48 MW geothermal unit (included in 96 MW total). The second unit declared contractual commercial operation on February 4, 2015. The Commission approved the expansion on December 23, 2013 (Docket No. 13-11007). The PPA terminates on December 31, 2032.

[5] Nevada Power entered into a short-term purchase agreement with Tonopah Solar Energy for the output of the Crescent Dunes Solar Thermal Plant for the period December 21, 2021, through September 30, 2024, which is not expected to impact the Companies' RPS compliance outlook. The contribution of the community based solar resources (i.e., Mojave Solar, Freedom Park Solar and Moana Solar) to the RPS compliance outlook is negligible. Facilities entirely dedicated to NGR customers are Boulder Solar II, Switch Station 1, Switch Station 2, Techren Solar 2 and Turquoise Nevada.

5. <u>Salt Wells Geothermal Plant</u>
   The Salt Wells facility is a 23.6 MW geothermal project located in Churchill County east of Fallon, Nevada. The project was approved by the Commission in 2007. The plant began producing energy in 2009. The PPA terminates on December 31, 2029.

6. <u>Stillwater 2 Geothermal Plant</u>
   The Stillwater 2 facility is a 47.2 MW geothermal project located in Washoe County, Nevada. The project was approved by the Commission in 2007. The plant began producing energy in 2009. The PPA terminates on December 31, 2029.

7. <u>Tuscarora Geothermal Plant</u>
   The Tuscarora facility is a 32 MW geothermal project located in Elko County, Nevada. The capacity of the facility was expanded from 25 MW to 32 MW in Docket No. 12-06053, and the PPA was amended to allow for further capacity increases to up to 50 MW. The plant began producing energy in 2012. The PPA terminates on December 31, 2032.

8. <u>ACE Searchlight Solar</u>
   ACE Searchlight, now Searchlight Solar, is a 17.5 MW solar PV project near Searchlight, Nevada. The project was approved by the Commission in 2009. The solar farm began producing energy in 2014. The PPA terminates on December 31, 2034.

9. <u>RV Apex</u>
   RV Apex Solar facility is a 20 MW solar PV project located in Clark County north of Las Vegas, Nevada. The project was approved by the Commission in 2009. The solar facility began producing energy in 2012. The PPA terminates on December 31, 2037.

10. <u>Boulder Solar I</u>
    Boulder Solar I is a 100 MW solar PV project located in Boulder City, Nevada. The project was approved by the Commission in 2015. The solar project declared commercial operation in December 2016. The 20-year PPA terminates on December 31, 2036.

11. <u>Las Vegas Valley Water District ("LVVWD")</u>
    The LVVWD project is comprised of six Las Vegas-area small PV arrays collectively totaling 3 MW. The project was approved by the Commission in 2006. These installations began producing electricity in 2006 and 2007. LVVWD provides PCs only to Nevada Power. The agreement terminates on December 31, 2026.

12. Mountain View Solar

The Mountain View solar facility is a 20 MW solar PV plant located north of Las Vegas in Clark County, Nevada. The project was approved by the Commission in 2012. The solar project began producing energy in 2014. The PPA terminates on December 31, 2039.

13. Nellis Air Force Base ("AFB"), Solar Star

The Nellis AFB Solar Star project is a 13.2 MW solar PV project that produces energy for Nellis Air Force Base, located north of Las Vegas, Nevada. The project was approved by the Commission in 2007. The array began producing electricity in 2007, since then Nellis AFB sells only PCs to Nevada Power. The agreement terminates on December 31, 2027.

14. Nellis Solar Array II

Nellis Solar Array II is a 15 MW (nameplate AC) solar PV project located on Nellis AFB in Las Vegas, Nevada. The project was approved by the Commission in Docket No. 14-05003. The solar array began producing energy in 2015. The project is owned by Nevada Power.

15. Nevada Solar One

Nevada Solar One is a 69 MW concentrated solar thermal plant that is located in the Eldorado Valley near Boulder City, Nevada. Approximately 46.9 MW of the capacity and generation is contracted to Nevada Power. The balance of the capacity and generation is contracted to Sierra. The project was approved by the Commission in 2003. The solar thermal plant began producing energy in 2007 and the PPA terminates on December 31, 2027.

16. Silver State Solar

The Silver State Solar facility is a 52 MW solar PV project located in Clark County near Primm, Nevada. The project was approved by the Commission in 2010. The solar project began producing energy in 2012. The PPA terminates on December 31, 2037.

17. FRV Spectrum Solar

The FRV Spectrum facility is a 30 MW solar PV plant located north of Las Vegas in Clark County, Nevada. The project was approved by the Commission in 2012. The solar array began producing energy in 2013. The PPA terminates on December 31, 2038.

18. Stillwater 2 Solar

The Stillwater 2 Solar facility is a 22 MW solar PV project located in Washoe County, Nevada. The project was approved by the Commission in 2011. The solar array began producing energy in 2012. The PPA terminates on December 31, 2029.

19. Eagle Shadow Mountain Solar Farm

Eagle Shadow Mountain Solar Farm is a 300 MW solar PV facility located on the Moapa River Indian Reservation north of Las Vegas, Nevada. The solar array is online, capable of generating approximately 265 MW and declared commercial operations on May 10, 2023. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

20. Copper Mountain Solar 5

Copper Mountain Solar 5 is a 250 MW solar PV facility located in Boulder City, Nevada. The solar array declared commercial operations on July 23, 2021. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

21. Arrow Canyon Solar

Arrow Canyon Solar, formerly Moapa Solar, is a 200 MW solar PV facility with 75 MW of BESS capacity that will be located on the Moapa River Indian Reservation north of Las Vegas, Nevada. The project, including the BESS, achieved commercial operation on December 8, 2023. The energy, capacity and PCs generated by the facility will be split 70 percent to Sierra, 30 percent to Nevada Power. The 25-year PPA was approved by the Commission in Docket No. 19-06039.

22. Gemini Solar

Gemini Solar is a 690 MW solar PV facility with 380 MW of BESS capacity that will be located in Clark County, approximately 25 miles northeast of Las Vegas, Nevada. The project declared commercial operation on March 25, 2024. While 100 percent of the energy and capacity generated by the facility will go to Nevada Power, only 60 percent of the associated PCs will be assigned to Nevada Power, with the balance assigned to Sierra. The 25-year PPA was approved by the Commission in Docket No. 19-06039.

23. Techren Solar I

Techren Solar I is a 100 MW solar PV facility located in Boulder City, Nevada. The solar array declared commercial operations on March 11, 2019. The project was approved by the Commission in Docket No. 16-08026. The PPA is for 25 years.

24. Techren Solar III

Techren Solar III is a 25 MW solar PV facility located in Boulder City, Nevada. The solar array achieved commercial operation on October 7, 2020. The project was approved by the Commission in Docket No. 17-11004. The PPA is for 25 years.

25. Techren Solar V
Techren Solar V is a 50 MW solar PV facility located in Boulder City, Nevada. The solar farm achieved commercial operation on December 31, 2020. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

26. Spring Valley Wind
The Spring Valley Wind facility is a 151.8 MW wind project located in Spring Valley near Ely, Nevada. The project was approved by the Commission in 2010. The wind farm began delivering energy in 2012. The PPA terminates on December 31, 2032.

27. Apex Landfill Facility
The Apex Landfill facility is a 12 MW landfill gas-to-energy project located in Clark County, Nevada. The project was approved by the Commission in 2009. The plant began producing energy in 2012. The PPA terminates on December 31, 2032.

28. Lockwood Renewable Energy Facility
The Lockwood facility is a 3.2 MW landfill gas-to-energy project located at the Lockwood Landfill near Reno, Nevada. The project was approved by the Commission in 2010. The plant began producing energy in 2012. The PPA terminates on December 31, 2032.

29. Goodsprings Recovered Energy Generation Station
The Goodsprings Recovered Energy Generation Station is located 35 miles south of Las Vegas, Nevada. It is a 5 MW generating plant that converts waste heat from a natural gas pipeline compressor station to electric energy. The project was approved by the Commission in 2008 and it started producing energy in 2010. The project is owned by Nevada Power.

30. Dry Lake Solar
The Dry Lake Solar project is 150 MW solar PV facility with 100 MW of BESS capacity located 20 miles northeast of Las Vegas adjacent to the Harry Allen combined cycle station and is owned by Nevada Power. The project declared commercial operations on May 2, 2024. The 25-year pricing was approved by the Commission in Docket No. 20-07023.

SIERRA

1. Beowawe Geothermal Power Plant
The Beowawe facility is a 17.7 MW geothermal facility located in Eureka County and is owned by Terra-Gen Power. The plant was placed into service in 1985 and was originally under contract with Southern California Edison. However, in 2006, Sierra entered into a contract for renewable energy that expires on December 31, 2024. Beowawe is included in Ormat's geothermal portfolio that was approved in Docket No. 22-11032 with an expiration date of December 31, 2053.

2. Burdette Geothermal Power Plant

   The Burdette facility is a 26 MW geothermal project located in Washoe County near Steamboat, Nevada. The plant went into service in 2006. Sierra has a 20-year PPA with the facility that expires on December 31, 2026. Burdette is also included in Ormat's geothermal portfolio that was approved in Docket No. 22-11032 with an expiration date of December 31, 2053.

3. Galena 3 Geothermal Power Plant

   The Galena 3 facility is a 26.5 MW geothermal project located in Washoe County south of Reno near Steamboat, Nevada. The plant went into service in 2008. Sierra has a 20-year PPA with the facility that expires on December 31, 2028. Galena 3 is also included in Ormat's geothermal portfolio that was approved in Docket No. 22-11032 with an expiration date of December 31, 2053.

4. North Valley Geothermal

   North Valley Geothermal is a 25 MW geothermal plant located in the San Emidio Desert in Washoe County, Nevada. Sierra has a 25-year PPA with Ormat to purchase the energy and associated portfolio energy credits generated by the plant. The PPA was approved by the Commission in Docket 22-03024. The plant achieved commercial operation on April 26, 2023.

5. USG San Emidio Geothermal Power Plant

   The USG San Emidio facility is an 11.75 MW geothermal project located just inside the eastern border of Washoe County, Nevada. Sierra originally entered into a 30-year long-term PPA in 1986 for a 3.8 MW geothermal power plant. Sierra received Commission approval for an amended and restated PPA in Docket No. 11-08010, which increased the capacity under the contract. Sierra has a 25-year contract with the facility that expires on December 31, 2037.

6. Battle Mountain Solar

   Battle Mountain Solar is a 101 MW solar PV facility located near Battle Mountain, Nevada. The project incorporates 25 MW of BESS. The solar array declared commercial operation on June 23, 2021. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

7. Dodge Flat Solar

   Dodge Flat Solar is a 200 MW solar PV facility located in Washoe County, Nevada. The project incorporates 50 MW of BESS. The solar farm declared commercial operation on March 2, 2022. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

8. <u>Fish Springs Ranch Solar</u>
Fish Springs Ranch is a 100 MW solar PV facility located in Washoe County, Nevada. The project incorporates 25 MW of BESS. The solar farm declared commercial operation on March 15, 2022. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

9. <u>Nevada Solar One</u>
The Nevada Solar One facility is a 69 MW concentrated solar thermal plant located in Eldorado Valley near Boulder City, Nevada. The solar thermal plant came online in 2007. Sierra purchases 22.1 MW from the facility, with the balance purchased by Nevada Power. Nevada Power's and Sierra's PPA with the facility expires on December 31, 2027.

10. <u>Techren Solar IV</u>
Techren Solar IV is a 25 MW solar PV facility located in Boulder City, Nevada and declared commercial operation on October 7, 2020. The project was approved by the Commission in Docket No. 17-11004. The PPA is for 25 years.

11. <u>Fleish Hydro Power Plant</u>
The Fleish facility is a 2.4 MW hydro-electric project located on the California/Nevada border southwest of Reno, Nevada. The hydro facility is owned by Truckee Meadows Water Authority ("TMWA") and went into commercial operation in 2008. Sierra has a 20-year PPA with the facility that expires on June 1, 2028. NV Energy provided a response to TMWA's Request for Offers concerning this hydroelectric facility on February 2nd, 2024. TMWA is currently evaluating the proposals and will inform the decisions regarding the RFO once the review process is finished.

12. <u>New Lahontan Truckee Carson Irrigation District Hydro Power Plant</u>
The New Lahontan facility is a 4 MW hydro-electric plant located in Lahontan, Nevada. The hydro facility is owned and operated by the Truckee Carson Irrigation District and went into commercial operation in 1989. Sierra has a 50-year PPA with the facility that expires June 11, 2039.

13. <u>Verdi Hydro Power Plant</u>
The Verdi facility is a 2.4 MW hydro-electric project located in Washoe County, Nevada. The hydro facility is owned by the Truckee Meadows Water Authority ("TMWA") and went into service in 2009. Sierra has a 20-year PPA with the facility that expires on June 1, 2029. Sierra provided a response to TMWA's Request for Offers ("RFO") concerning this hydroelectric facility on February 2nd, 2024. TMWA is currently evaluating the proposals and will inform the decisions regarding the RFO once the review process is finished.

14. Washoe Hydro Power Plant

The Washoe facility is a 2.5 MW hydro-electric project located in Washoe County, Nevada. The hydro facility is owned by TMWA and went into service in 2008. Sierra has a 20-year PPA with the facility that expires on June 1, 2028. Sierra provided a response to TMWA's RFOs concerning this hydroelectric facility on February 2nd, 2024. TMWA is currently evaluating the proposals and will inform the decisions regarding the RFO once the review process is finished.

15. Truckee Meadows Waste Water Facility ("TMWWF")

The TMWWF is 0.8 MW biogas facility with which Sierra has a PC-only purchase agreement. The agreement was approved by the Commission in 2006. The contract expires on December 12, 2024.

16. Kingston Hydro

Kingston Hydro is a small, 0.175 MW, hydro facility located in Lander County, Nevada. It is owned by Young Brothers. The facility received a rebate under Sierra's Hydro Demonstration Program. Under the demonstration program, the rights to the PCs are assigned to Sierra. The PCs from this facility are included in the "RENGEN" non-solar credit total designation reported in the RPS Annual Compliance filing.

17. Mill Creek Hydro

Mill Creek Hydro is a small, 0.037 MW, hydro facility located in Elko County, Nevada. It is owned by Van Norman Ranches, LLC. The facility received a rebate under Sierra's Hydro Demonstration Program. Under the demonstration program the rights to the PCs are assigned to Sierra. The PCs from this facility are included in the "RENGEN" non-solar credit total designation reported in the RPS Annual Compliance filing.

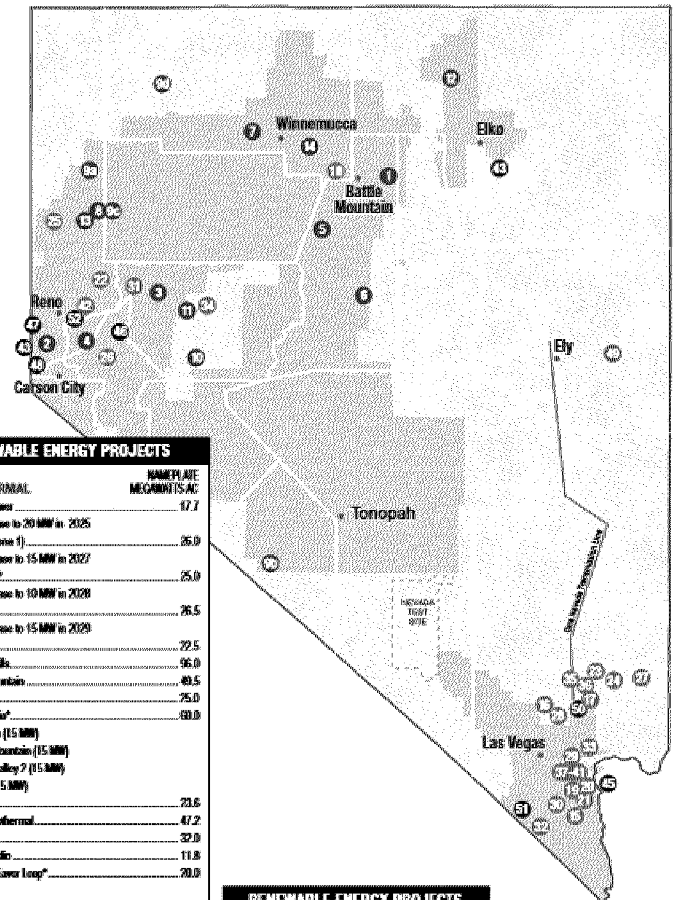
18. RO Ranch Hydro

RO Ranch Hydro is a small, 0.225 MW, hydro facility located in Churchill County, Nevada. It is owned by BTAZ Nevada, LLC. The facility received a rebate under Sierra's Hydro Demonstration Program. Under the demonstration program the rights to the PCs are assigned to Sierra. The facility was shut down indefinitely, however, the PPA is still active. If the facility is re-powered, the PCs would be included in the "RENGEN" non-solar credit total designation reported in the RPS Annual Compliance filing.

Figure REN-1 below is a map showing all renewable facilities owned by or contracted to Nevada Power and Sierra. The map includes Hoover Dam, which can now be used towards RPS compliance, as well as renewable facilities where the Companies are the counterparty to a PPA under which the PCs from the facilities are assigned to customers under an NGR agreement and cannot be used by the Companies to meet the RPS.

FIGURE REN-1 RENEWABLE ENERGY MAP

NV Energy's Clean Energy Commitment



RENEWABLE ENERGY PROJECTS

GEOTHERMAL	NAMEPLATE MEGAWATTS AC
1 Beowawe Power	17.7
• Will increase to 20 MW in 2025	
2 Burdette (Galena 1)	26.0
• Will decrease to 15 MW in 2027	
3 Desert Peak 2	25.0
• Will decrease to 10 MW in 2028	
4 Galena 3	26.5
• Will decrease to 15 MW in 2029	
5 Jersey Valley	22.5
6 McGinness Hills	96.0
7 NGP Blue Mountain	49.5
8 North Valley	25.0
9 Ormat Portfolio*	60.0
9a Gerlach (15 MW)	
9b Lone Mountain (15 MW)	
9c North Valley 2 (15 MW)	
9d Pinto (15 MW)	
10 Salt Wells	23.6
11 Stillwater Geothermal	47.2
12 Tuscarora	32.0
13 USG San Emidio	11.8
14 North Valley Eavor Loop*	20.0
SOLAR	
15 ACE Searchlight Solar	17.5
16 RV Apex	20.0
17 Moapa Arrow Canyon (75 MW Battery)	200.0
18 Battle Mountain Solar (25 MW Battery)	101.0
19 Boulder Solar I	100.0
20 Boulder Solar II	50.0
21 Copper Mountain Solar 5	250.0
22 Dodge Flat Solar (50 MW Battery)	200.0
23 Dry Lake Solar (100 MW Battery)*	150.0
24 Eagle Shadow Mountain Solar	300.0
25 Fish Springs Ranch Solar (25 MW Battery)	100.0
26 Fort Churchill Solar Array	19.5
27 Gemini Solar (380 MW Battery)*	690.0
28 Mountain View Solar	20.0
29 Nellis Solar Array 2	15.0
30 Nevada Solar One	69.0
31 Sierra Solar (400 MW Battery)	400.0
32 Silver State Solar North	52.0
33 FRV Spectrum	30.0
34 Stillwater Solar PV	22.0
35 Switch Station 1	100.0
36 Switch Station 2	79.0
37 Techren Solar I	100.0
38 Techren Solar II	200.0
39 Techren Solar III	25.0
40 Techren Solar IV	25.0
41 Techren Solar V	50.0
42 Turquoise Solar	50.0

* In development or under construction

RENEWABLE ENERGY PROJECTS

HYDRO	NAMEPLATE MEGAWATTS AC
43 Fleish (TMWA)	2.4
44 Frank Hooper	0.8
45 Hoover Dam	237.6
46 New Lahontan (TCID)	4.0
47 Verdi (TMWA)	2.4
48 Washoe (TMWA)	2.5
WIND	
49 Spring Valley Wind	151.8
BIOMASS / METHANE / OTHER	
50 Apex Landfill Renewable Energy	12.0
51 Goodsprings Energy Recovery Station	5.0
52 WM Renewable Energy Lockwood	3.2
RENEWABLEGENERATIONS PROJECTS (Statewide)	
Total Incentivized Private Rooftop Solar, etc.	316.4
Total NV Energy Clean Energy Resources (MW)	4,339.5

ENERGY EFFICIENCY

2022 Peak Demand Reduction Capacity Savings Statewide	179.3 MW
Cumulative Energy Savings Statewide	4,526,678 MWh
Calculated for Years 2005 through 2022	

NV Energy

Updated 03-20-2024

Renewable Energy Planning

The Companies vigilantly plan for their ongoing PC requirements, recognizing there are still uncertainties and risks inherent in renewable energy production and renewable project development. The planning strategy incorporates all rules, regulations, and requirements codified in NRS §§ 704.7801 through 704.7828. In determining future PC needs, the Companies carefully consider several overarching objectives:

- Full compliance with an escalating and compressed RPS schedule: 34 percent by 2024, 42 percent by 2027, and 50 percent by 2030;

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

- Developing a long-term strategy to build a generating portfolio that is capable of progressing towards the Nevada policy goal of delivering 100 percent carbon-free energy to all customers by 2050.

The annual RPS credit requirements were calculated in compliance with NRS § 704.7821, which sets forth the annual PC requirement for the Companies based on a percentage of total electricity sold to their respective retail customers during a calendar year. The expected PC supply was determined starting with the current portfolio of approved projects, both operating and under development or contemplated by the Companies. The following assumptions are built into the forecast:

- Existing PPAs expire in accordance with the contract terms and are not automatically renewed. The Companies reached out to all geothermal supplier counterparties whose contracts will be expiring in the next five years to commence discussions related to future extensions;[6] The Beowawe, Burdett, Desert Peak 2, and Galena 3 contracts have been renegotiated in the Ormat Geothermal Portfolio, Docket No.22-11032. Contracts for Salt Wells, Stillwater Geothermal are currently still being negotiated.

- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2024-2027 in cases where the historic generation, based on two or more years of data, consistently varied from that of the contractual or expected supply table. This is consistent with the methodology that the Companies used for the

[6] This does not imply that the Companies would rule out renewing existing agreements. Rather, it recognizes the uncertainty as to whether the resource could continue to support ongoing generation, and whether the Companies and the counterparties can come to terms on renewing the agreement.

past several years in developing their IRPs and Energy Supply Plans ("ESPs"). This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-term plans;

- The projected number of PCs derived from the Renewable Generations incentive programs plateaued in 2020, with the last of the incentivized solar systems now installed. Starting in 2021, the expected number of PCs from incentivized rooftop solar is forecasted to begin decreasing by 0.5 percent per year as these systems age and their output slowly begins to decline;[7]

- Solar systems placed into service before December 31, 2015, qualify for the solar multiplier; systems placed into service after do not qualify;

- The plan assumes that the percent of annual PC requirements met from Demand Side Management ("DSM") measures are limited to no more than 10 percent of the credit total for 2021 through 2024 before dropping to zero effective 2025. The plan also assumes, based on current DSM kPC projections, that Sierra may not have a sufficient number of DSM PCs to completely fill the 10 percent cap in 2024. The gap would be addressed by seeking Commission approval for Nevada Power to transfer a small number of banked, surplus DSM credits to Sierra;

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

- The plan assumes that generation from both company-owned solar PV systems and PPA projects would degrade starting the year following the first full year of operation. Annual degradation is based on project specific data provided by the solar panel suppliers or project developers. Geothermal generation would continue to qualify for station usage credits, while all other technologies would no longer qualify;

- The plan accounts for all pending and existing NGR and ESAs as of May 31, 2024, where PCs associated with all or a portion of the output from a renewable facility(ies) has been assigned to a customer under the NGR, the MPE or LCMPE tariffs, as well as the portion of the ESAs discussed in this filing under the pending CTT, and therefore, cannot be used by the Companies in meeting their RPS credit requirements. It also includes 2024 NGR Option 1 capacity submitted for Commission approval in the Companies' NGR Open Season Annual Report, Docket No. 24-03031. The NGR forecast, incorporated in the Assessment of Need discussed in the Economic Analysis

[7] Annual degradation is based on the median degradation rate published by National Renewable Energy Laboratory, available at https://www.nrel.gov/state-local-tribal/blog/posts/stat-faqs-part2-lifetime-of-pv-panels.html.

Section of the narrative, conservatively assumes the maximum amount of 100 MW and associated PCs per year are required going forward.

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

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

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

- The base plan includes the Ormat Portfolio, which consists of eight geothermal plants totaling 120 MW with staggered COD dates. Sierra will be the sole off taker of the energy and PCs from the Ormat Portfolio. The total number of PCs for the Ormat Portfolio includes estimated station usage PCs. Certain geothermal station usage, the energy for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine, is eligible for certification under the NRS § 704.78215(3)(b). Station usage PCs for these facilities were estimated at 15 percent of net;

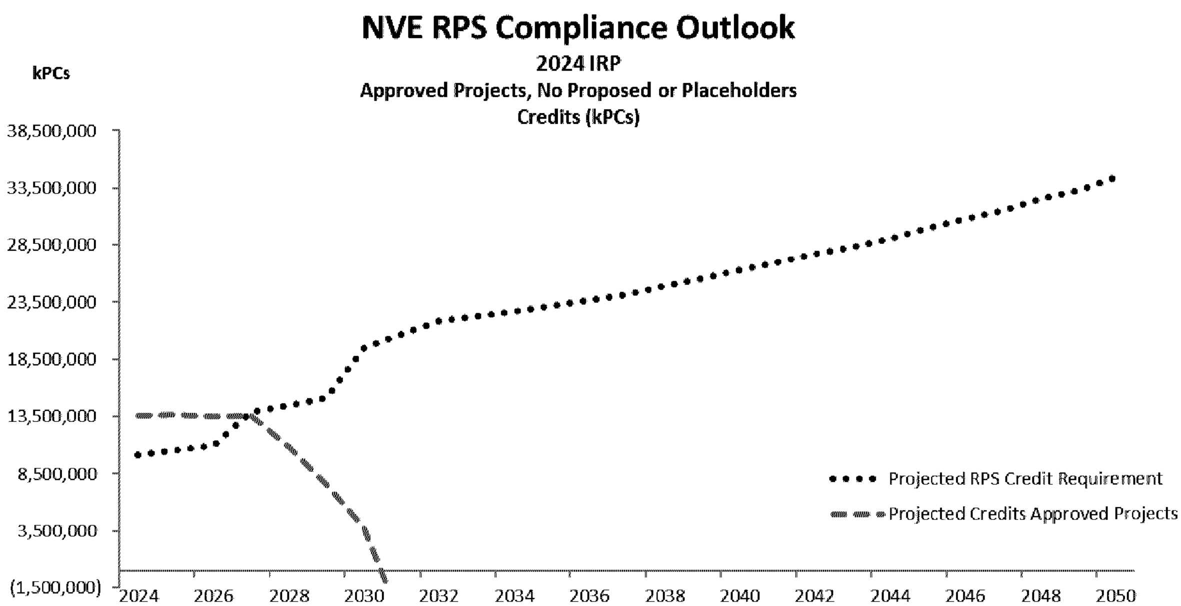
- The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery losses which is site-specific but typically further degrades by less than 1 percent annually. The adjustment recognized that not all of the energy produced by solar PV arrays paired with energy storage will be delivered real-time to the grid. Some of the energy will be stored and dispatched at a later time when needed. The process of charging and discharging the batteries will result in energy losses; and

- An adjustment has been added to the model to capture the generation and PCs lost due to curtailment. The curtailed amount is estimated by the PLEXOS model as an annual amount and varies year to year. This adjustment recognizes that as renewable energy becomes the dominant source of generation, there may be times when the transmission system cannot accommodate all of the energy being produced making generation curtailment necessary to maintain grid integrity.

The following Figures illustrate the RPS compliance projections for Nevada Power, Sierra, and the combined Companies. This first set of charts assumes that no action is taken to add new renewable resources – neither the ones requested for approval in this Amendment nor placeholders.

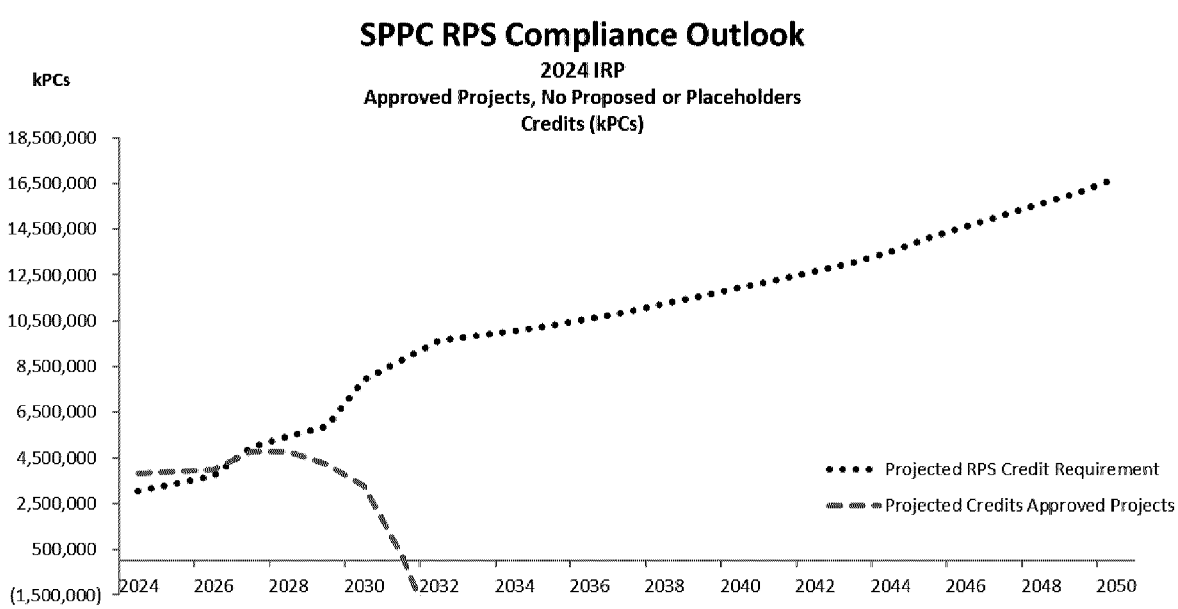
All figures are based on each company's current renewable portfolio, viable pipeline projects, and above planning protocol under a base load.

FIGURE REN-2



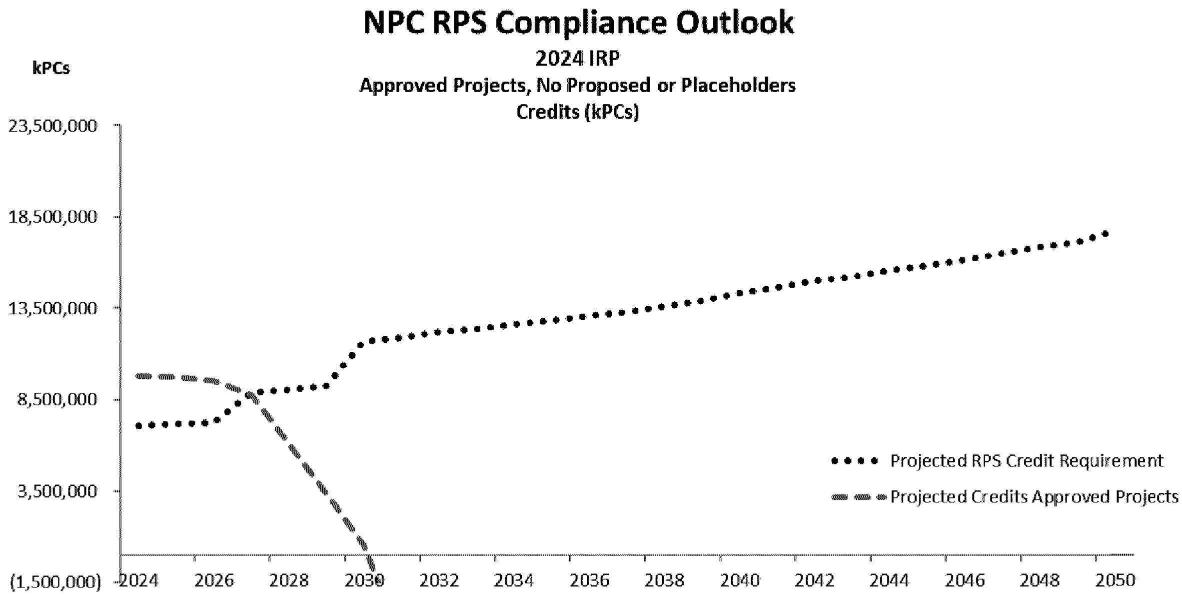
Assuming no actions to add new renewable resources are taken, the Companies are projected to be non-compliant starting in 2027.

FIGURE REN-3



Assuming that no actions to add new renewable resources are taken, Sierra is projected to be non-compliant starting in 2027.

FIGURE REN-4



Assuming that no actions to add new renewable resources are taken, Nevada Power is projected to be non-compliant starting in 2028.

The next set of figures show Nevada Power, Sierra, and the combined Companies' projected compliance under the Balanced Plan. This plan assumes the approval of Dry Lake East, Libra and Boulder Solar 3 for Nevada Power. It also includes placeholder resources.

FIGURE REN-5

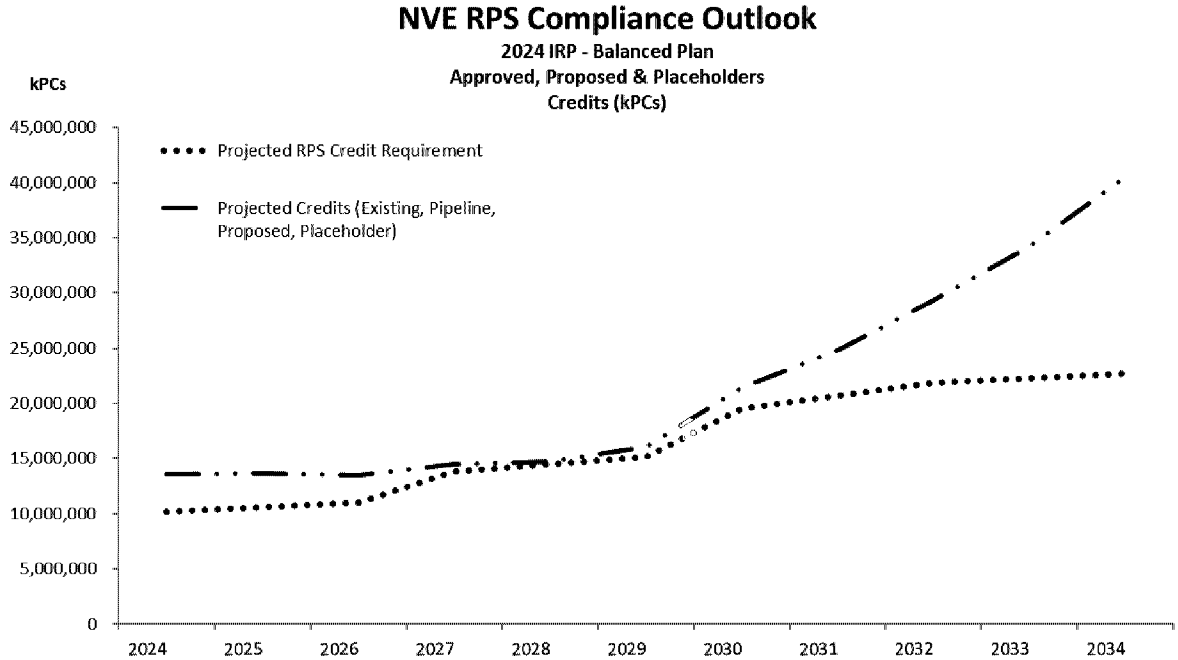


FIGURE REN-6

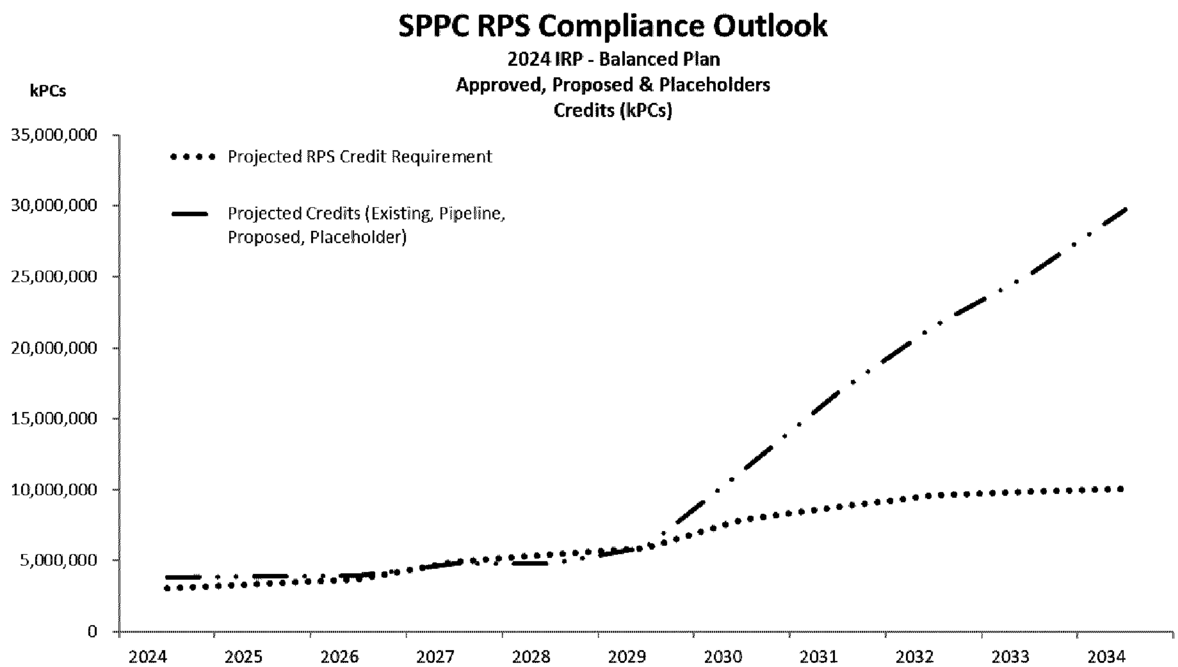
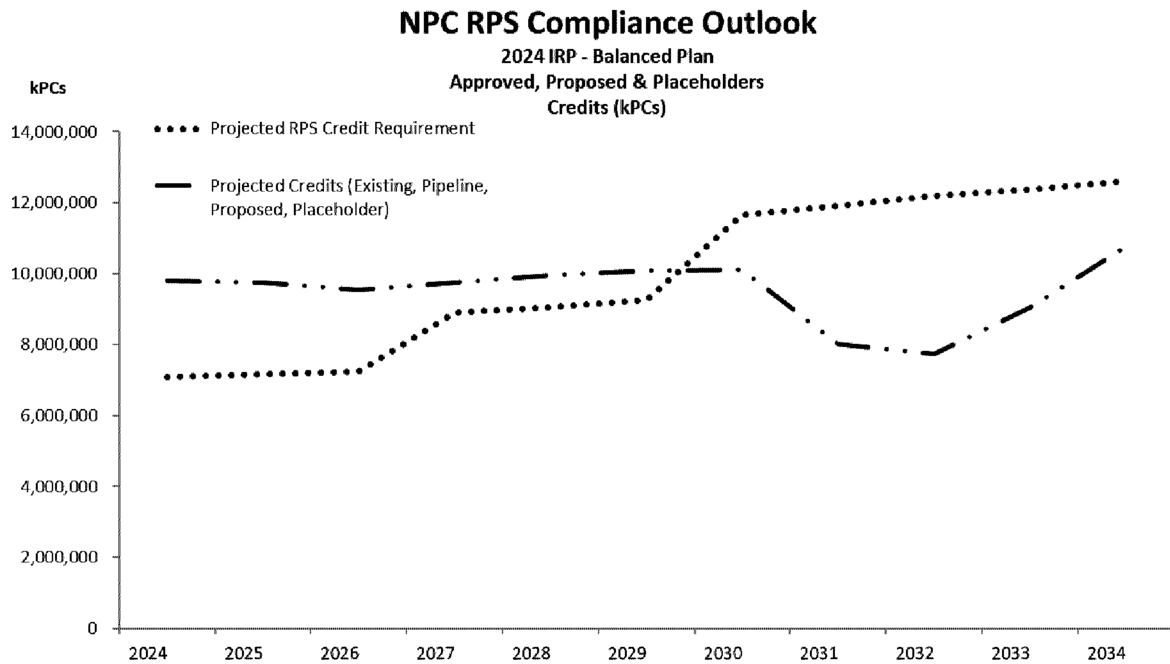


FIGURE REN-7



Under the Balanced Plan, the Companies are projected to remain compliant throughout the action plan period, 2025-2027, with PC sharing. Table REN-1 shows the projected compliance status for each utility and the Companies combined for the period 2024 through 2034. The table also shows the projected surplus/(deficit) for both utilities and for the Companies combined. Although the table below indicates that Sierra would fall short in 2027, Nevada Power has adequate credits to cover Sierra's deficit, such that the Companies combined may achieve RPS compliance in all years of the action plan. The Companies will pursue all viable plans including inter-company PC transfer and/or procurement of additional generating resources as needed to avoid a non-compliance outcome.

TABLE REN-1

IRP Alternative Plan - Balanced Plan						
	RPS STATUS			Projected Credit Surplus/(Deficit)		
	NPC	SPPC	NVE	NPC	SPPC	NVE
2024	Compliant	Compliant	Compliant	2,712,034	754,930	3,466,964
2025	Compliant	Compliant	Compliant	2,589,014	484,944	3,073,958
2026	Compliant	Compliant	Compliant	2,280,642	258,367	2,539,010
2027	Compliant	Non-Compliant	Compliant	840,584	(169,055)	671,529
2028	Compliant	Non-Compliant	Compliant	921,952	(651,273)	270,679
2029	Compliant	Compliant	Compliant	843,106	54,542	897,648
2030	Non-Compliant	Compliant	Compliant	(1,554,328)	3,422,340	1,868,012
2031	Non-Compliant	Compliant	Compliant	(3,883,483)	8,061,427	4,177,943
2032	Non-Compliant	Compliant	Compliant	(4,464,999)	11,922,588	7,457,589
2033	Non-Compliant	Compliant	Compliant	(3,345,191)	15,306,824	11,961,633
2034	Non-Compliant	Compliant	Compliant	(1,849,136)	19,629,989	17,780,854

The next set of figures shows Nevada Power, Sierra, and the combined Companies' projected compliance under the Renewable Plan. This plan assumes the approval of Dry Lake East, Libra and Boulder Solar 3 for Nevada Power. It also assumes splitting the capacity, energy, and PCs of Libra 60 percent Nevada Power, 40 percent Sierra. Like the Balanced Plan, the Renewable Plan includes placeholder resources.

FIGURE REN-8

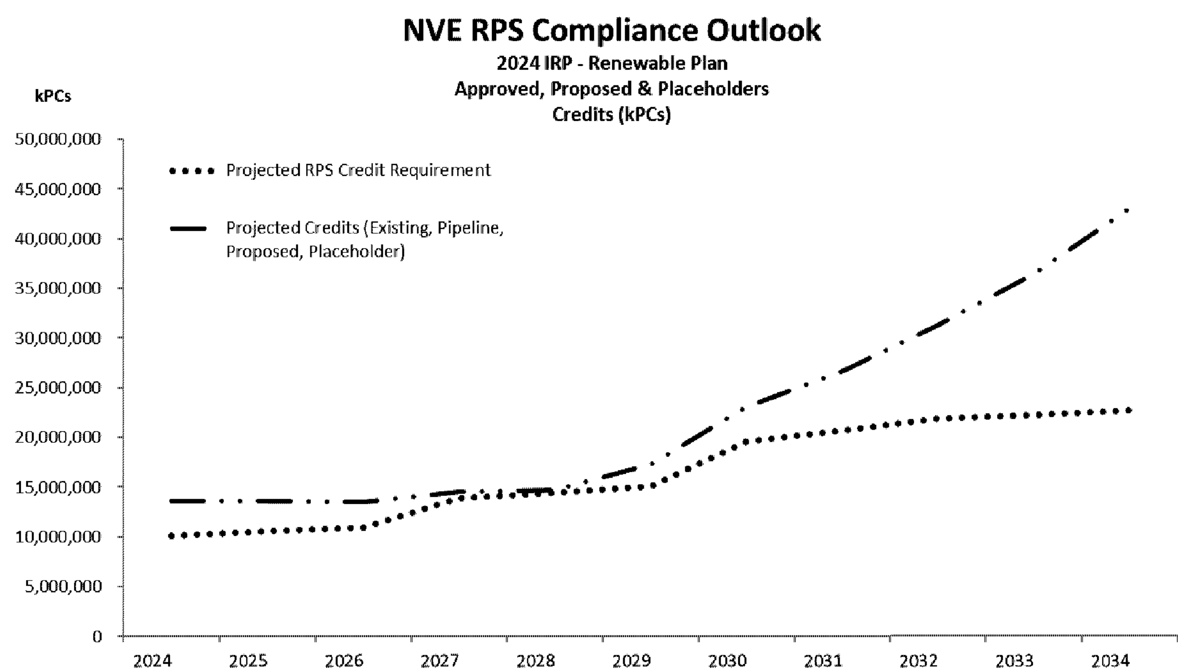


FIGURE REN-9

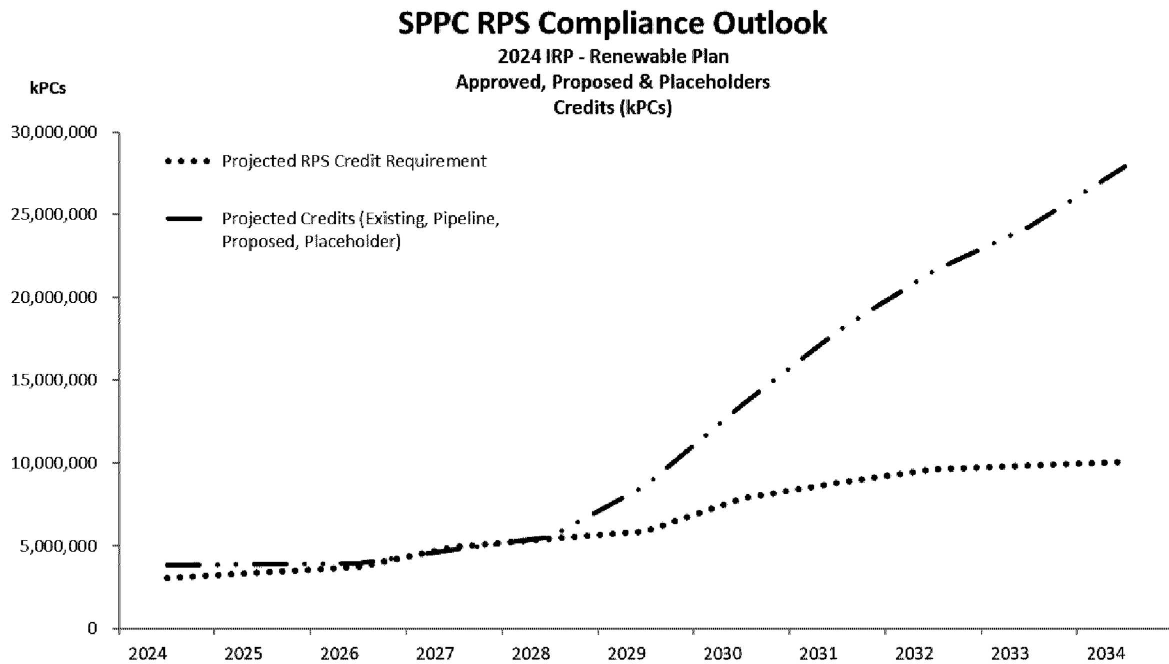
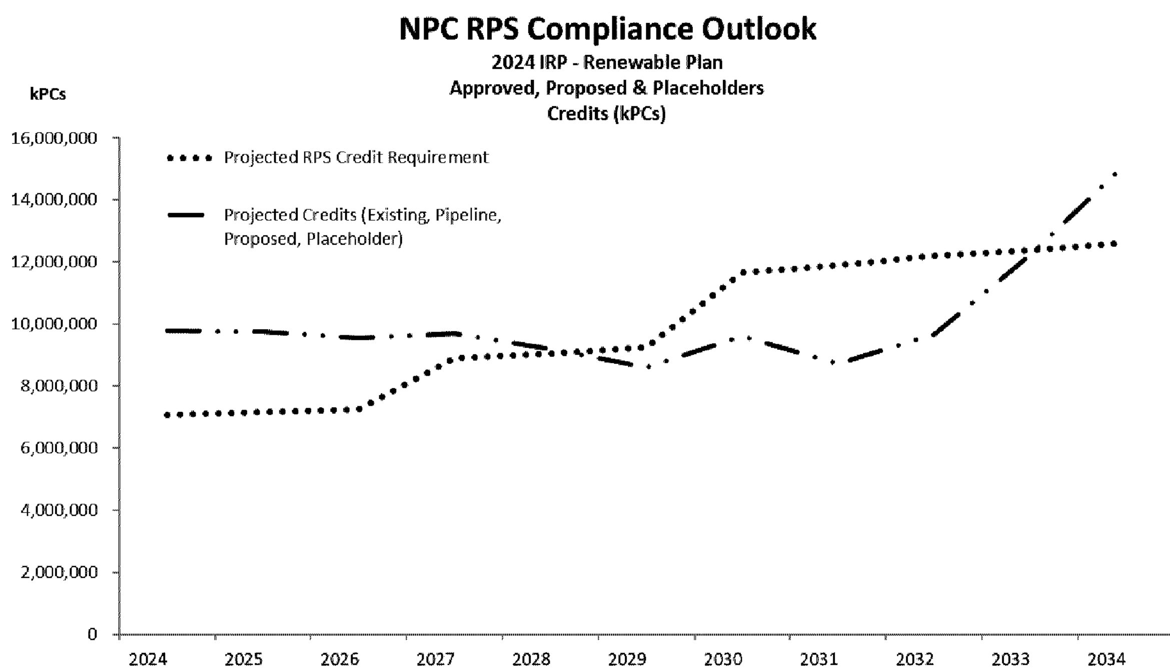


FIGURE REN-10



Under the Renewable Plan, the Companies are projected to remain compliant throughout the action period, 2025-2027, with credit sharing. Table REN-2 below shows the projected compliance status for each utility and the Companies combined for the period 2024 through 2034. The table also shows the projected surplus/(deficit) for both utilities and for the Companies combined. Although the table below indicates that Sierra would fall short in 2027, Nevada Power has adequate PCs to cover Sierra's deficit, such that the Companies combined may achieve RPS compliance in all years. The Companies will pursue all viable plans including inter-company PC transfer and/or procurement of additional generating resources as needed to avoid a non-compliance outcome.

TABLE REN-2

IRP Alternative Plan - Renewable Plan						
	RPS STATUS			**Projected Credit Surplus/(Deficit)**		
	NPC	SPPC	NVE	NPC	SPPC	NVE
2024	Compliant	Compliant	Compliant	2,712,034	754,930	3,466,964
2025	Compliant	Compliant	Compliant	2,589,014	477,490	3,066,504
2026	Compliant	Compliant	Compliant	2,280,642	247,151	2,527,793
2027	Compliant	Non-Compliant	Compliant	814,138	(156,585)	657,553
2028	Compliant	Compliant	Compliant	164,968	85,524	250,491
2029	Non-Compliant	Compliant	Compliant	(643,887)	2,785,584	2,141,696
2030	Non-Compliant	Compliant	Compliant	(2,056,439)	5,598,099	3,541,660
2031	Non-Compliant	Compliant	Compliant	(3,197,099)	9,185,785	5,988,686
2032	Non-Compliant	Compliant	Compliant	(2,524,125)	11,981,473	9,457,348
2033	Non-Compliant	Compliant	Compliant	(159,608)	14,380,857	14,221,249
2034	Compliant	Compliant	Compliant	2,538,092	17,827,681	20,365,773

The final set of figures shows Nevada Power, Sierra, and the combined Companies' projected compliance under the Low Carbon and No Open Position plans. These plans assume the approval of Dry Lake East, Libra and Boulder Solar 3 for Nevada Power. Like the Balanced Plan and Renewable Plans, the Low Carbon and No Open Position plans include placeholders.

FIGURE REN-11

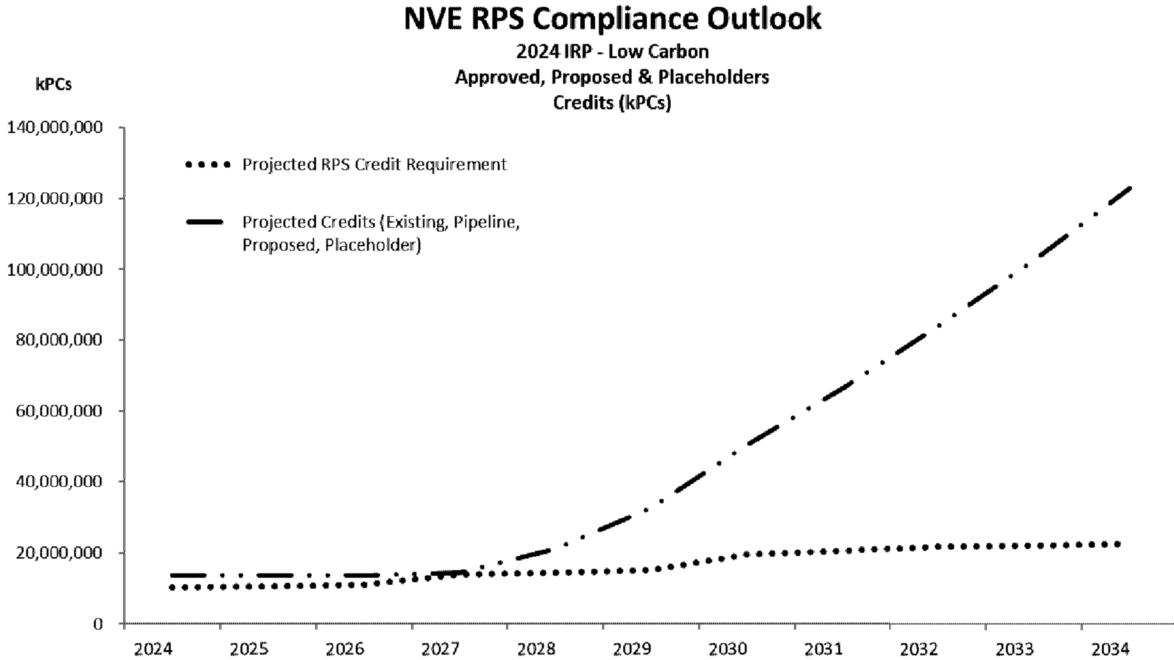


FIGURE REN-12

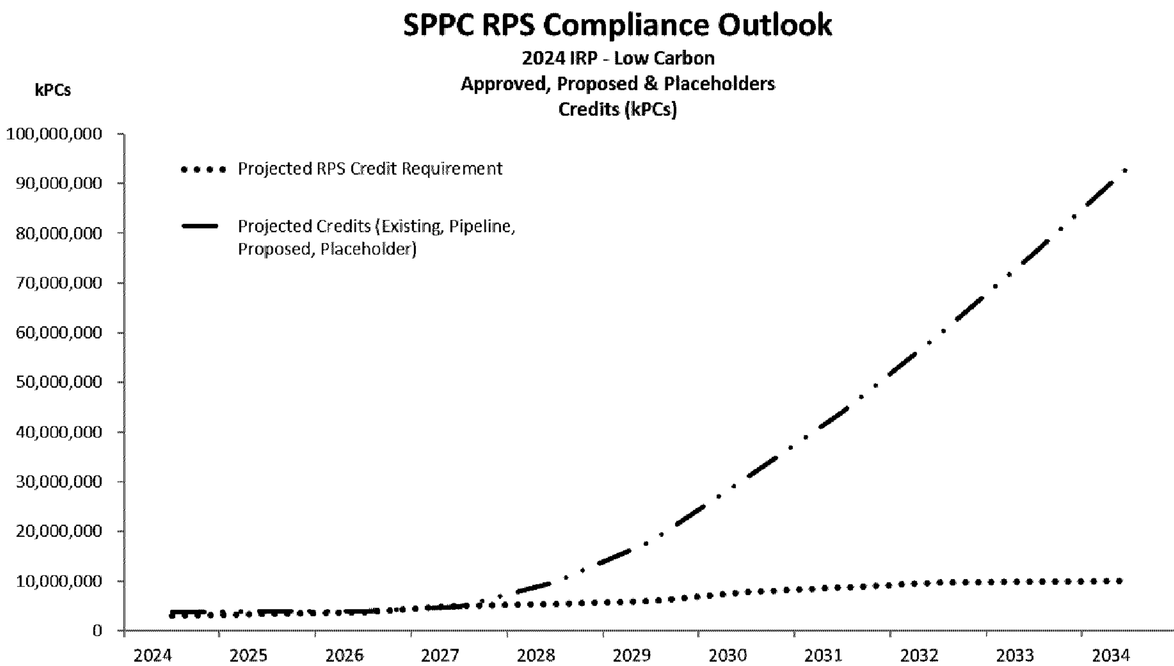


FIGURE REN-13

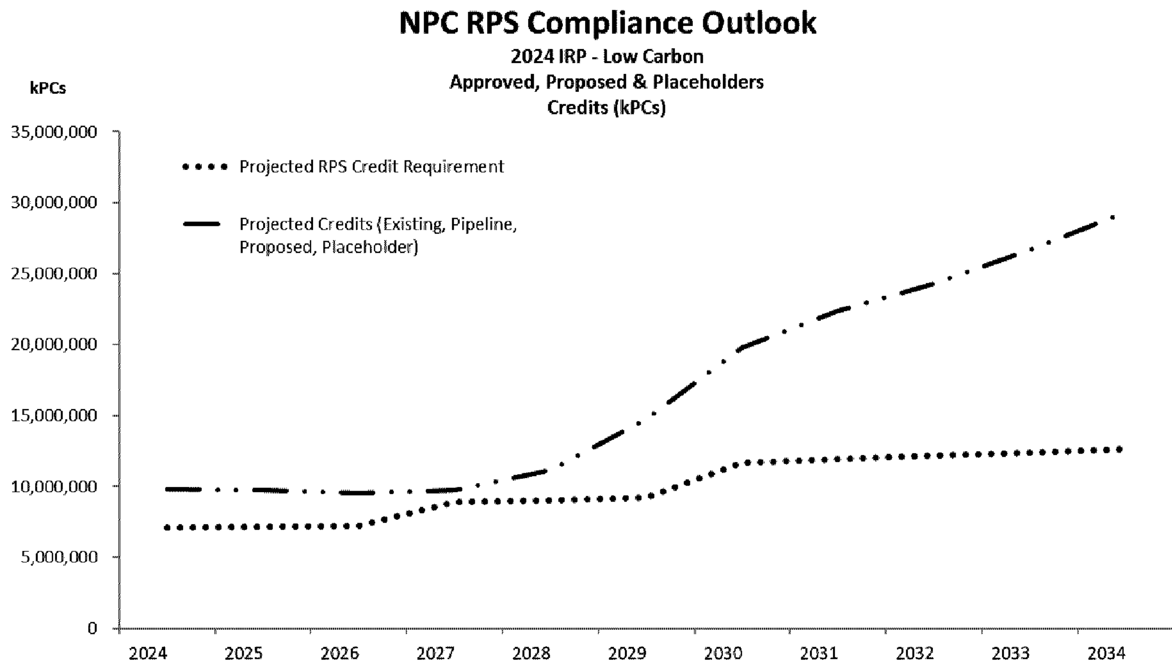


FIGURE REN-14

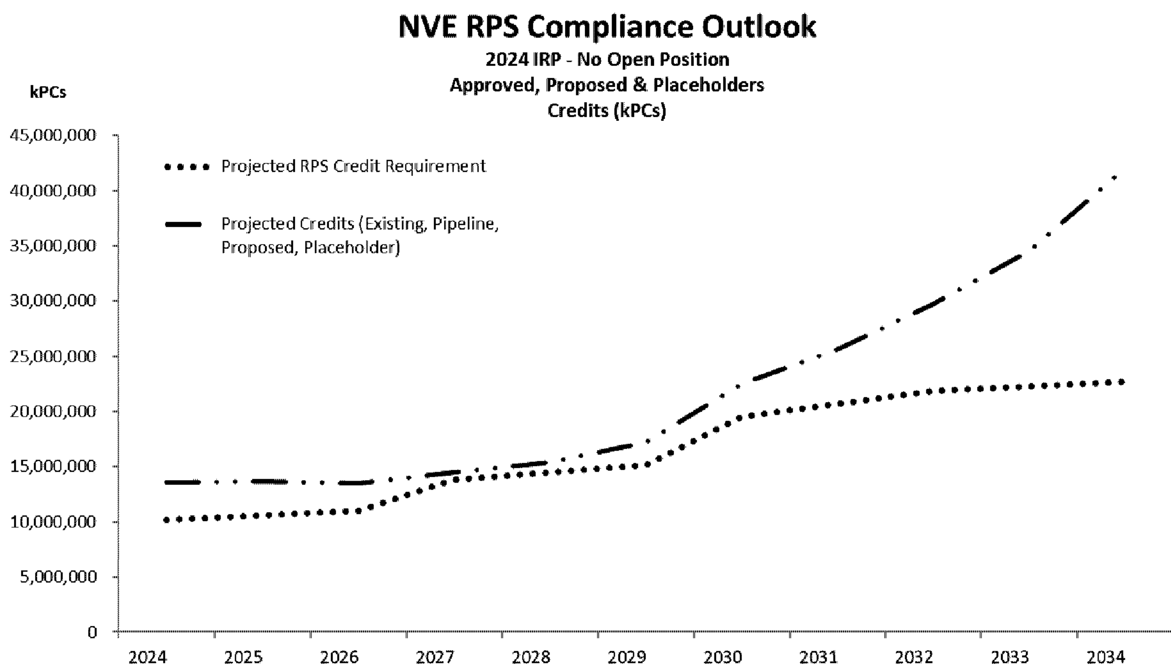


FIGURE REN-15

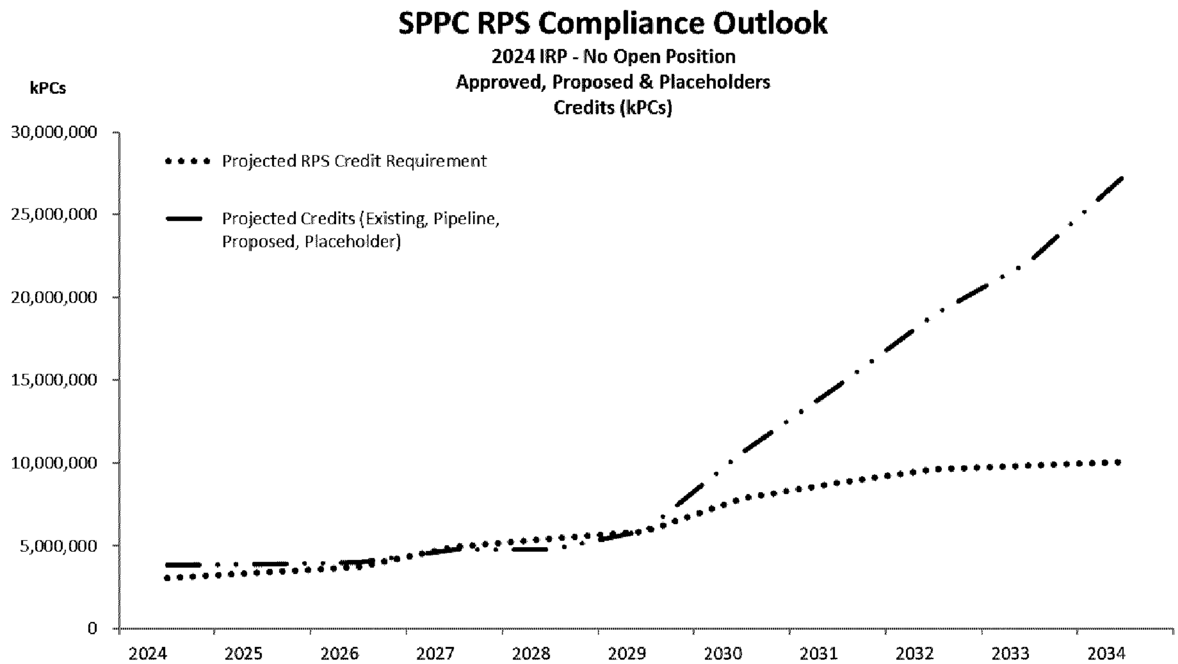
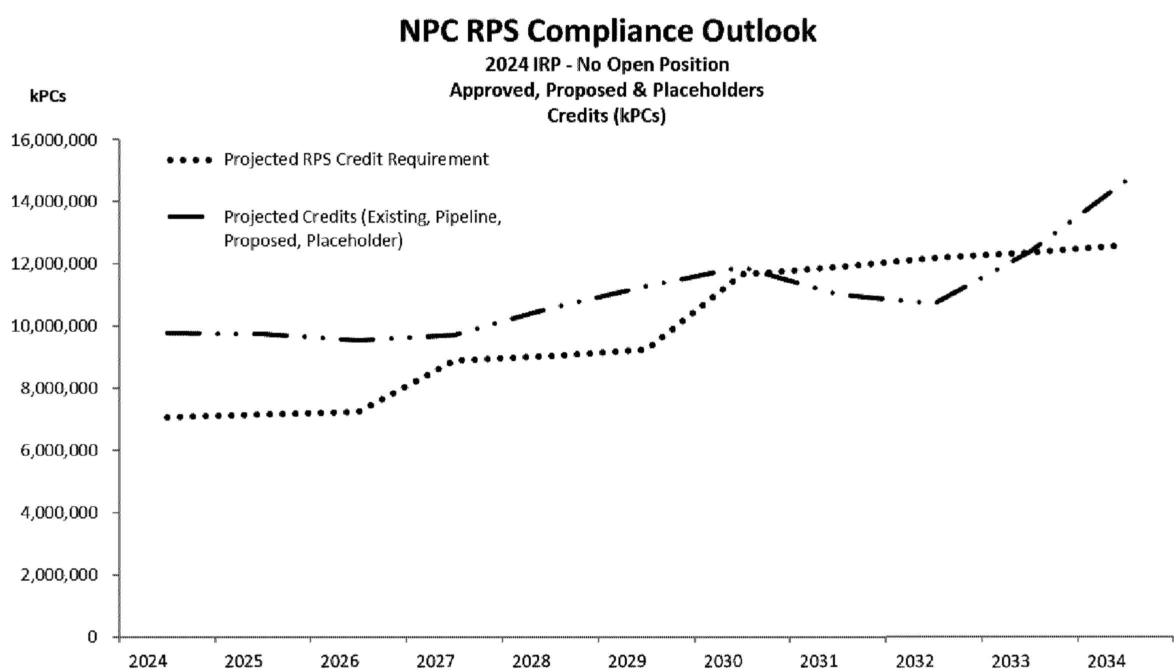


FIGURE REN-16



Under the Low Carbon and No Open Position plans, the Companies are projected to remain compliant throughout the action period, 2025-2027, with credit sharing. Table REN-3 and Table REN-4 below shows the projected compliance status for each utility and the Companies combined for the period 2024 through 2034. The tables also show the projected surplus/(deficit) for both utilities and for the Companies combined. Although the tables below indicate that Sierra would fall short in 2027, Nevada Power has adequate PCs to cover Sierra's deficit, such that the Companies combined may achieve RPS compliance in all years. The Companies will pursue all viable plans including inter-company PC transfer and/or procurement of additional generating resources as needed to avoid a non-compliance outcome.

TABLE REN-3

IRP Alternative Plan - Low Carbon Plan						
	RPS STATUS			Projected Credit Surplus/(Deficit)		
	NPC	SPPC	NVE	NPC	SPPC	NVE
2024	Compliant	Compliant	Compliant	2,712,034	754,930	3,466,964
2025	Compliant	Compliant	Compliant	2,589,014	485,025	3,074,039
2026	Compliant	Compliant	Compliant	2,280,642	258,448	2,539,090
2027	Compliant	Non-Compliant	Compliant	840,372	(168,286)	672,086
2028	Compliant	Compliant	Compliant	2,136,492	4,368,705	6,505,197
2029	Compliant	Compliant	Compliant	5,531,245	12,021,871	17,553,115
2030	Compliant	Compliant	Compliant	8,098,336	22,869,043	30,967,379
2031	Compliant	Compliant	Compliant	10,437,609	35,222,296	45,659,905
2032	Compliant	Compliant	Compliant	12,109,870	49,911,979	62,021,850
2033	Compliant	Compliant	Compliant	14,266,101	66,043,306	80,309,407
2034	Compliant	Compliant	Compliant	16,701,175	83,509,441	100,210,616

TABLE REN-4

IRP Alternative Plan - No Open Position						
	RPS STATUS			Projected Credit Surplus/(Deficit)		
	NPC	SPPC	NVE	NPC	SPPC	NVE
2024	Compliant	Compliant	Compliant	2,712,034	754,930	3,466,964
2025	Compliant	Compliant	Compliant	2,589,014	484,941	3,073,955
2026	Compliant	Compliant	Compliant	2,280,642	258,364	2,539,006
2027	Compliant	Non-Compliant	Compliant	841,340	(169,783)	671,557
2028	Compliant	Non-Compliant	Compliant	1,528,381	(639,527)	888,853
2029	Compliant	Compliant	Compliant	2,038,262	69,008	2,107,270
2030	Compliant	Compliant	Compliant	241,145	2,719,232	2,960,378
2031	Non-Compliant	Compliant	Compliant	(898,003)	5,881,810	4,983,806
2032	Non-Compliant	Compliant	Compliant	(1,471,446)	9,333,274	7,861,829
2033	Compliant	Compliant	Compliant	31,845	12,287,033	12,318,878
2034	Compliant	Compliant	Compliant	2,069,982	17,319,247	19,389,229

Compliance Outlook

NEVADA POWER

Nevada Power's RPS compliance outlook is cautious. The limited available land for development, multiyear project permitting timelines, and lack of available transmission capacity are key constraints in the renewable project pipeline. The completion of costly requisite network upgrades, procurement of long-lead critical equipment such as breakers and transformers, as well as project permit issuance and transmission interconnectivity capability, are interdependent project milestones that are subject to various independent external forces that cannot be easily mitigated even with diligent planning. Nevada's renewable project pipeline therefore carries some amount of inherent risk, as most recently demonstrated by the termination of the Boulder Solar III PPA previously approved in Docket No. 20-07023. To this end Nevada Power will continue to explore all options, including continuing to issue renewable energy RFPs, self-developing projects, conducting bilateral asset purchase and other commercial transactions and exploring short-term purchase agreements that benefit customers, so that it can procure the renewable generating and storage resources needed to continue its commitment to becoming carbon-free. Nevada Power's challenge is to make certain that it has sufficient renewable resources, existing and pipeline, to satisfy all credit and energy needs for at least five years. A five-year time frame provides the cushion needed to methodically seek, submit for approval, and construct new renewable resources. In summary, with the approval of the proposed projects in this filing, Nevada Power should be positioned to meet all of its future credit commitments (RPS, NGR, and ESA) for the next five years.

SIERRA

Sierra's RPS compliance outlook is uncertain. This is different from 2023's outlook of positive for several reasons. First and primarily, it is the projected load growth. Sierra's current retail load outlook is significantly higher than that of the previous approved plan. Referring to Table REN-5 below under the current load forecast, while Nevada Power's retail sales are projected to increase slightly, Sierra's retail sales are projected to increase significantly. Because the RPS credit requirement is tied directly to retail sales, this increases Sierra's forecasted RPS credit requirement.

TABLE REN-5

	Sierra (MW hours)			NPC (MW Hours)		
	5th IRPA*	2024 IRP	Difference	5th IRPA*	2024 IRP	Difference
2024	9,308,816	10,034,208	7.79%	21,608,171	21,626,127	0.08%
2025	9,596,795	11,009,034	14.72%	21,963,555	21,913,643	-0.23%
2026	9,851,290	11,960,163	21.41%	22,173,512	22,293,028	0.54%
2027	10,123,938	12,813,167	26.56%	22,371,526	22,674,591	1.35%
2028	10,395,713	13,979,271	34.47%	22,633,211	23,156,708	2.31%
2029	10,602,683	15,029,269	41.75%	22,874,396	23,538,671	2.90%
2030	10,680,569	16,804,925	57.34%	23,043,445	24,042,248	4.33%

	Increase / (Decrease)	RPS %	Credit Impact	Increase / (Decrease)	RPS %	Credit Impact
2024	725,392	34.00%	246,633	17,956	34.00%	6,105
2025	1,412,239	34.00%	480,161	-49,912	34.00%	-16,970
2026	2,108,873	34.00%	717,017	119,516	34.00%	40,636
2027	2,689,229	42.00%	1,129,476	303,065	42.00%	127,287
2028	3,583,558	42.00%	1,505,094	523,497	42.00%	219,869
2029	4,426,586	42.00%	1,859,166	664,275	42.00%	278,996
2030	6,124,356	50.00%	3,062,178	998,803	50.00%	499,401

* Docket No. 23-08015 Sales Forecast

The second reason for Sierra's uncertain compliance is cancelled projects by developers. Table REN-6 below shows the PCs Sierra has recently lost due to canceled projects. Additional detail related to the Valmy Eavor project is discussed in the Informational Updates in Section E below, which the energy and credits from the facility were to be assigned to Sierra, thus, the loss impacts Sierra's RPS and capacity. While Nevada Power was hit by the same wave of canceled projects, it has not faced the same degree of projected sales growth. While every project is entered into with the expectation of success, events can and do happen that make once-viable projects unviable. The primary driver for the latest wave of cancelations was cost. Most of the canceled projects were negotiated pre-COVID, and the supply disruptions and related increases in component and labor costs made the projects too costly to move forward.

TABLE REN-6

Lost Projects, Lost Generation

Projects [a.]	Docket No.	Original COD	Date Terminated	MW AC	2024	2025	2026	2027
Iron Point (44% SPPC)	21-06001	12/31/23	06/22/23	250	313,240	311,244	309,949	308,652
Hot Pot (44% SPPC)	21-06001	12/01/24	06/22/23	350	18,368	440,048	438,440	436,610
Southern Bighorn (40% SPPC)	19-06039	09/01/23	11/13/23	300	406,619	404,267	403,025	401,783
North Valmy Eavor Loop	22-11032	12/31/26	TBD[b.]	20	0	15,246	92,223	173,039
				920	740,251	1,172,830	1,245,662	1,322,111

Table Notes:

a. The energy/credits of the project as allocated between Nevada Power and Sierra per the order

b. Eavor has provided notification that the project is not commercially viable; therefore the Company has removed Eavor's projected PCs from the RPS compliance forecast.

A third contributing factor to Sierra's uncertain RPS compliance outlook is transmission constraints. Currently there is limited ability to move energy to load in Sierra' service territory in the near term, requiring completion of contingent facilities and significant additional transmission infrastructure to remedy. The completion of Greenlink West and Greenlink North will allow for a significant addition of renewable energy capacity in Sierra's territory when it goes into service. It is the combination of the three forces that changed Sierra's outlook from positive to uncertain.

Nevada Power and Sierra will continue to closely monitor their RPS compliance outlooks, recognizing that there are many factors, some outside of the Companies' control, which will ultimately determine whether the Companies will have a sufficient number of PCs to satisfy their respective RPS credit obligations. The objective is to never be put into a reactive position where the Companies must acquire a large number of PCs in a short time frame in order to maintain compliance. Time expands options, which in turn increases the Companies' ability to negotiate favorable contracts to acquire renewable generating resources to meet the needs of their customers and to meet or exceed all regulatory and internal requirements. While the Companies are not requesting any projects for the purpose of meeting the state's 2050 clean energy goal, the Companies will continue to target their proportionate share of this goal in their long-term planning.

3. Origination

The Companies are seeking approval of four new utility-scale projects that are PPAs, summarized in Table REN-7. The Companies present the PPAs with the intent of growing its portfolio of renewable energy resources to meet several business and policy objectives including: 1) demonstrated ability to interconnect and achieve COD by 2029, 2) comply with the Nevada RPS, 3) support reducing the Companies' open capacity positions, 4) meet other customers' sustainability business goals for renewable energy, including providing innovative new ESAs filed under the pending CTT, 5) provide supplemental benefits to the Companies' system, including load management and voltage support, and 6) satisfy goals of AB524 provisions such as assurance of dedicated in-state electric supply and reduced reliance on power market purchases. The timing of these projects was driven by the Companies' open position and RPS need, Callisto ESA, and outcome of the 2023 Open Resource RFP.

Table REN-7 New Contracts Summary

Project Description	Technology	Capacity (MW)[1]	Expected Commercial Operation	Term (years)	Network Upgrade costs ($M)	PPA Price ($/MWh)	BESS Price ($/MW-month)	LCOE ($/MWh)
NextEra – Dry Lake East	Solar PV/BESS	200	12/1/2026	25 PV 20 BESS	$ 4.0	$ 36.78	$ 13,440	$ 101.41
174 PowerGlobal – Boulder Solar III		127.9	6/1/2027	25 PV 25 BESS	$ -	$ 34.60	$ 15,460	$ 84.64
Arevia – Libra Solar &		700	12/1/2027	25 PV 25 BESS	$ 3.9	$ 34.97	$ 13,350	$ 93.69
Fervo – Corsac Generating Station	Geothermal	115	1/30/2030	15	$ 2.0	$ 107.00	N/A	$ 107.69

1. Each PV/BESS resource will have a 1:1 PV/BESS ratio

All of the Companies' proposed renewable projects are located in Nevada,[8] and will be delivering renewable energy to meet the needs of the Companies' customers. The three paired solar PV and BESS PPAs originated from the Companies' 2023 Open Resource RFP, which included proposals for multiple sources of energy. A summary of the bid scores, including the Companies' calculated Levelized Cost of Energy ("LCOE"), is presented in Confidential Technical Appendix REN-8. A cost comparison of solar plus storage RFP bids to PPA pricing is included in Technical Appendix REN-7. In addition to the projects included in Table REN-7, the Companies further evaluated the solar plus storage, standalone storage, wind, and geothermal project proposals shown in Table REN-8 below.

Table REN-8 Additional RFP and Bilateral Projects Evaluated

Project Name	Technology	Capacity (MW)[1]	Expected Commercial Operation	Term (years)	Network Upgrade costs ($M)	PPA Price ($/MWh)[2]	BESS Price ($/MW-month)	LCOE ($/MWh)
Solar-2	Solar PV/BESS	200	3/31/2028	25 PV 20 BESS	[redacted]	[redacted]	[redacted]	[redacted]
Solar-1		57	4/30/2026	25 PV 20 BESS	[redacted]	[redacted]	[redacted]	[redacted]
Battery-1	Standalone Storage	80	5/31/2026	20 BESS	[redacted]	[redacted]	[redacted]	[redacted]
Wind-1	Wind	500	12/31/2028	25	[redacted]	[redacted]	[redacted]	[redacted]
Geo-1	Geothermal	150	2027-2033	25	[redacted]	[redacted]	[redacted]	[redacted]

1. Each PV/BESS resource proposed a 1:1 PV/BESS ratio
2. Geothermal PPA pricing includes annual price escalation based on CPI

[8] Securing projects located within Nevada brings jobs and economic benefits to the state.

However, the Companies' evaluation, including but not limited to due diligence and commercial negotiations, could not be completed in time to bring any of these projects forward in this filing but remain candidates for future filings. These and other available projects will continue to be evaluated as part of subsequent Open Resource RFPs and bilateral discussions.

In this filing, the Companies are requesting Commission approval of four PPAs totaling 1,143 MW. Three of the PPAs are included in the Companies' economic analysis; the Corsac Generating Station 2 PPA is not included in the economic analysis as it is part of a sleeved ESA with Callisto to offset 100 percent of its load pursuant to an ESA. Approval of these projects is a significant step for the Companies to meet increasing resource adequacy needs, customer demand for renewable generation, maintain compliance with an increasing RPS, and meet the state's 2050 clean energy goal. The addition of these cost-effective renewable energy projects, which also includes 1,027.9 MW of battery storage with 4,111.6 MWh[9] of energy delivery capability, is consistent with the Companies' strategy of delivering energy and services that customers value at low and reasonable rates. The majority of these PPAs were selected from the Companies' 2023 Open Resource RFP, while Corsac Generating Station 2 was a bilateral opportunity, which was outside the RFP but was subjected to the same technical due diligence process utilized for the RFP. The due diligence summaries for Dry Lake East, Boulder Solar III, Libra Solar & Storage, and Corsac Generating Station 2 are included as Confidential Technical Appendices REN-3-DLE(b), REN-4-BS3(b), REN-5-LS(b), and REN-6-CS2(b), respectively.

The addition of these resources furthers the transformation of the Companies' energy supply portfolio, reducing both carbon emissions and fuel price risk. Finally, as noted above in the introduction and below in the discussion about the selection of the Balanced Plan, the Balanced Plan positions the Companies to meet the needs of customers, including the needs of large commercial and industrial customers.

As discussed above, new, large commercial customers are increasingly seeing Nevada as a good place to do business, in no small part due to its competitive energy rates and the Companies' increasing ability to find solutions to assist in their sustainability goals. Historically, the Companies' sustainability solution was limited to the NGR program, which successfully drove the development of renewable resources and the program continues to successfully fulfill the PC needs of a few large customers. In the last few years, customers such as the Las Vegas Raiders, Resorts World, and Google have requested tailored solutions to meet their respective energy goals that incorporate renewable energy resources. Such customers, and the programs they helped foster, are some of the reasons behind the addition of renewable resources.

A portion of the power and PCs from the paired solar and BESS projects are part of ESAs for existing customers applying through the pending CTT. The Corsac Generating Station 2

[9] Cumulative over an approximate four-hour period

Geothermal project sought in this filing exclusively supports the energy demands of Callisto but provides economic and environmental benefits to all customers. The customers that these renewable projects attract, and the projects themselves, bring jobs to Nevada.

a. DRY LAKE EAST SOLAR ENERGY PROJECT

The proposed Dry Lake East project is to be located approximately 20 miles northeast of Las Vegas in Clark County, Nevada. It is being developed by a wholly owned subsidiary of NextEra Energy Resources ("NEER"), Dry Lake East Energy Center, LLC. NEER owns and operates 53 utility-scale solar facilities across the United States and Canada and has more than 1,300 MW of energy storage projects in operation and more than 1,600 MW of energy storage projects with signed long-term contracts. Most recently, in March 2022, NEER commissioned Dodge Flat Solar Energy Center (200 MW PV + 50 MW BESS) and Fish Springs Ranch Solar Energy Center (100 MW PV + 25 MW BESS). This PPA was executed as a result of NV Energy's 2023 Open Resource RFP.

The Dry Lake East project will consist of a 200 MW solar PV facility with a horizontal single-axis tracking mounting system. The Dry Lake East project will consist of approximately 418,230 new high-performance monocrystalline, bifacial solar PV modules mounted on single-axis trackers for optimal energy generation. The trackers rotate in the East-West direction following the sun's azimuth throughout the day. The proposed design uses strings of 30 modules wired in series and aggregated into combiner boxes. The combiner boxes are connected to inverters which convert the DC energy to AC energy that will be delivered to Nevada Power's system through transformers or to the integrated BESS via inverters for later use.

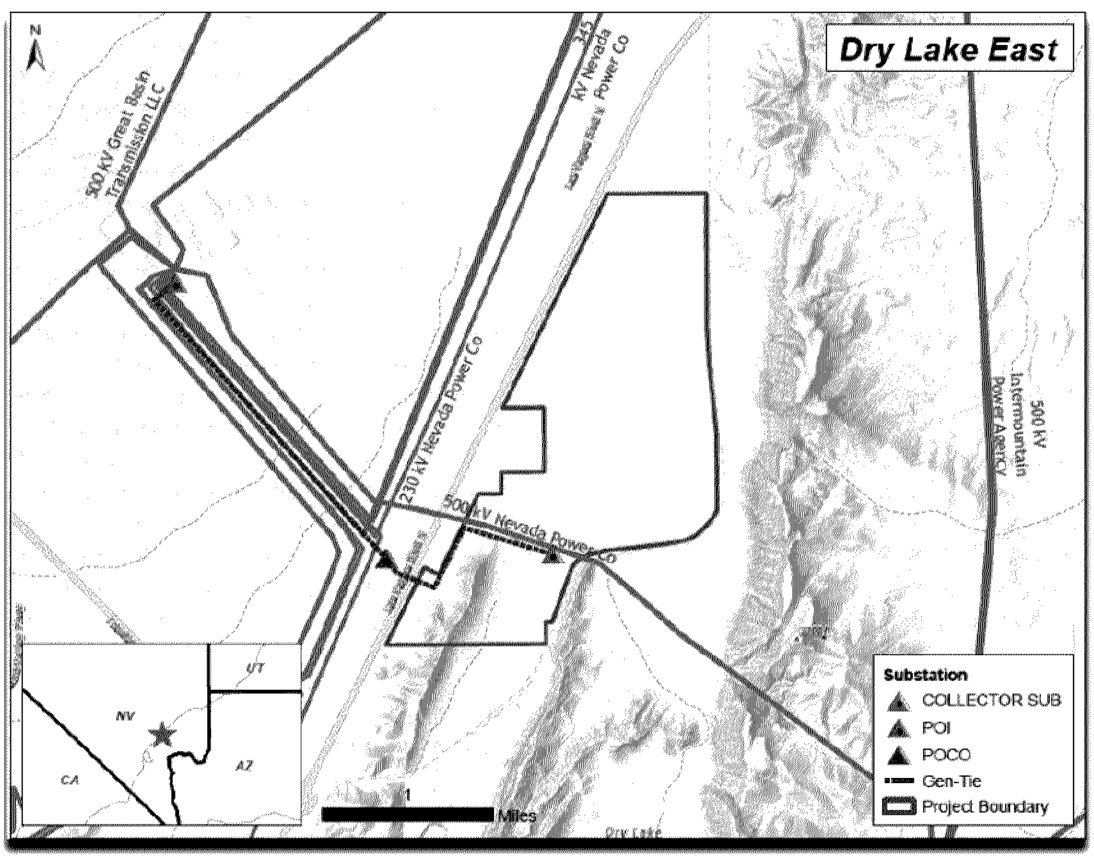
The project will utilize lithium-ion battery technology consisting of 200 MW with four-hour duration (800 MWh). Each battery will have its own battery management system to communicate and actively manage performance and safety. Cooling and safety systems are integrated into the battery containers. Lithium-ion batteries are a well-established technology, modular in design, and highly flexible, allowing the overall BESS to provide multiple use cases as needed.

The project substation consists of a Generation Step-up Transformer ("GSU"), station control building, SCADA and telecommunications, battery DC power system for protection devices and critical switching elements. Transmission to the utility substation is provided by an overhead 230 kV gen-tie line from the project site to the Harry Allen Substation, located approximately 3.5 miles from the project site.

NEER estimates that the Dry Lake East project will provide more than 250 construction jobs over a one-year construction period. After commercial operation in December 2026, the facility is expected to provide six permanent jobs with an average annual salary of $125,000, for an estimated annual payroll of $748,000 and a total payroll of approximately $18.7 million over the 25-year term of the PPA. Overall, based on information provided by NEER, the Companies estimate that the total investment in Nevada's economy directly associated with the Dry Lake East project will be more than $150 million. A work site agreement, in the form included in the executed PPA, will be executed between either NEER or its primary construction contractor and IBEW Local Union 357 and IBEW Local Union 396.

The PPA is with Nevada Power for a 25-year term at a flat energy price of $36.78 per MWh. The project has an expected net capacity rating of 200 MW (ac). It is expected to generate 577,194 MWh and PCs in the first year. Annual solar energy production and credits are projected to degrade at approximately 0.5 percent per year. The 200-MW, 800 MWh battery rate is $13,440 per MW-month for a term of 20-years. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-3-DLE(a). Figure REN-17 shows a map of the project site.

FIGURE REN-17
DRY LAKE EAST PROJECT SITE



The Companies' due diligence summary for the Dry Lake East project is included as Confidential Technical Appendix REN-3-DLE(b). Technical Appendix REN-3-DLE(c) contains detailed information about the Dry Lake East project, including the information required by NAC § 704.8885 and NAC § 704.8887. Key provisions of the Dry Lake East PPA are summarized in Technical Appendix REN-3-DLE(d).

b. BOULDER SOLAR III

The proposed Boulder Solar III project is located on approximately 760 acres in Boulder City, in Clark County, NV. It is being developed by a majority-owned subsidiary of 174 Power Global ("174PG") in partnership with KOMIPO America Inc ("KA"), Boulder Solar III, LLC. 174PG and KA are currently developing or have developed more than 678 MW of capacity in the Boulder City area. Most recently, in April 2020, Boulder Solar III signed a PPA with Nevada Power to develop the Boulder Solar III project, but the agreement was terminated in March 2024. The current PPA brought forth in the filing between Boulder Solar III and the Companies is for a substantially similar project with updated pricing and COD. This PPA was executed as a result of NV Energy's 2023 Open Resource RFP.

The Boulder Solar III project will consist of a 127.9 MW solar PV facility with a horizontal single-axis tracking mounting system. The Boulder Solar III project will consist of new high-performance bifacial solar PV modules mounted on single-axis trackers for optimal energy generation. The trackers rotate in the East-West direction following the sun's azimuth throughout the day. The proposed design uses strings of modules wired in series and aggregated into combiner boxes. The combiner boxes are connected to inverters which convert the DC energy to AC energy that will be delivered to Nevada Power's system through transformers or to the integrated BESS via inverters for later use.

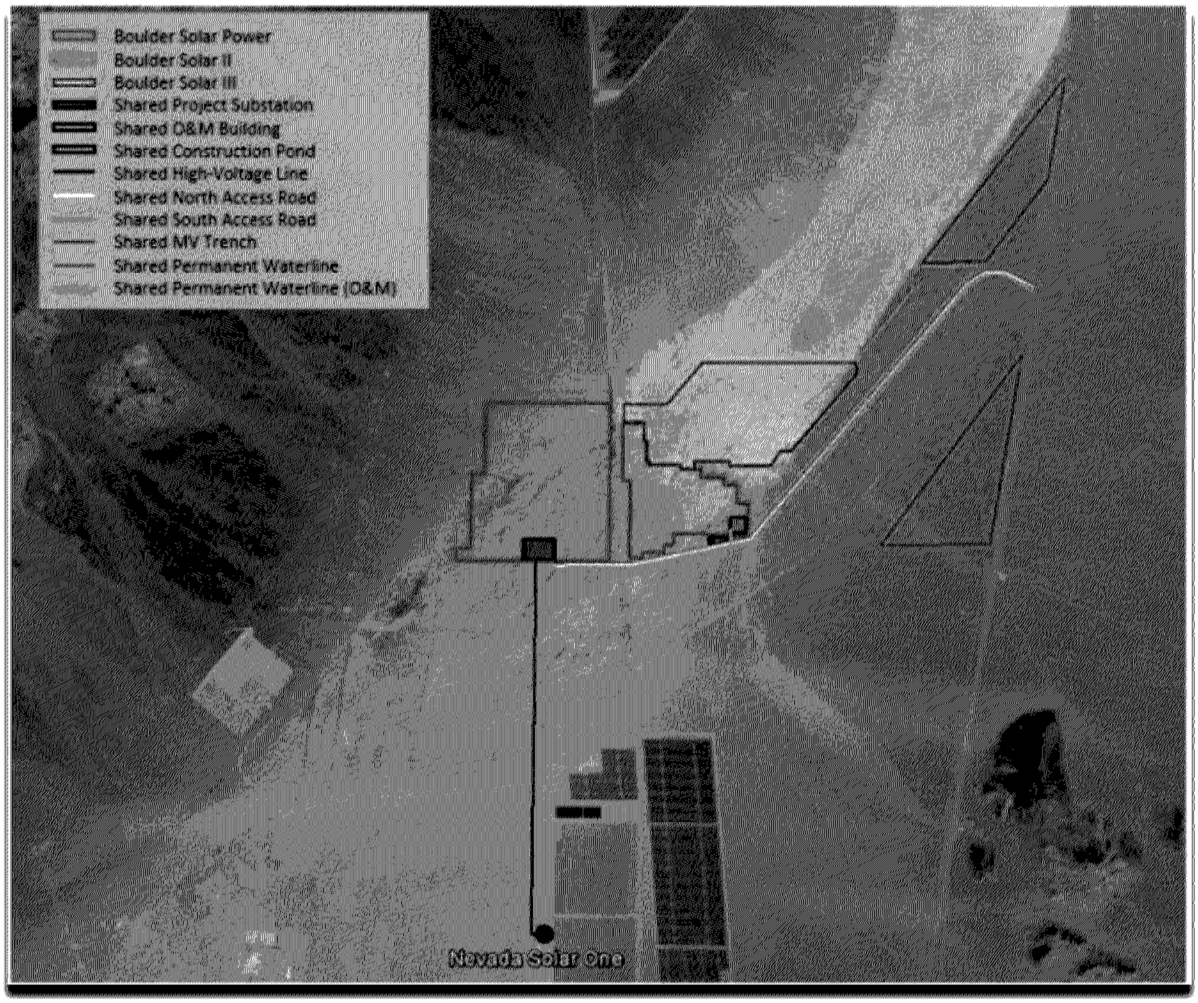
The project will utilize lithium-ion battery technology consisting of 127.9 MW with four-hour duration (511.4 MWh). Each battery will have its own battery management system to communicate and actively manage performance and safety. Cooling and safety systems are integrated into the battery containers. Lithium-ion batteries are a well-established technology, modular in design, and highly flexible, allowing the overall BESS to provide multiple use cases as needed.

The project substation consists of a GSU, station control building, SCADA and telecommunications, battery DC power system for protection devices and critical switching elements. Transmission to the utility substation is provided by an overhead 230 kV gen-tie line from the project site to the Nevada Solar One Substation, located approximately 2.2 miles from the project site. The project will utilize the same gen-tie line as the Boulder solar Power and Boulder Solar II projects currently in service.

174PG and KA estimate that the Boulder Solar III project will provide more than 350 construction jobs over the construction period. After commercial operation in June 2027, the facility is expected to provide two permanent jobs with an average annual salary of $66,650, for a total payroll of approximately $3.3 million over the 25-year term of the PPA. Overall, based on information provided by Boulder Solar III, the Companies estimate that the total investment in Nevada's economy directly associated with the Boulder Solar III project will be more than $326 million. A work site agreement, in the form included in the executed PPA, will be executed between either Boulder Solar III LLC or its primary construction contractor and IBEW Local Union 357 and IBEW Local Union 396.

The PPA is with Nevada Power for a 25-year term at a flat energy price of $34.60 per MWh. The project has an expected net capacity rating of 127.9 MW (ac). It is expected to generate 471,461 MWh and PCs in the first year. Annual solar energy production and credits are projected to degrade at approximately 0.5 percent per year. The 127.9-MW, 511.4 MWh battery rate is $15,460 per MW-month for a term of 20-years; however, for years 21-25, the remaining battery capacity will be available exclusively to Nevada Power at a price of $0.00 per MW-month. This extra five years of BESS capacity at no cost adds significant additional value. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-4-BS3(a). Figure REN-18 shows a map of the project site.

FIGURE REN-18
BOULDER SOLAR III PROJECT SITE



The Companies' due diligence summary for the Boulder Solar III project is included as Confidential Technical Appendix REN-4-BS3(b). Technical Appendix REN-4-BS3(c) contains detailed information about the Boulder Solar III project, including the information required by NAC § 704.8885 and NAC § 704.8887. Key provisions of the Boulder Solar III PPA are summarized in Technical Appendix REN-4-BS3(d).

c. LIBRA SOLAR PROJECT

The proposed Libra Solar project is to be developed by Arevia Power LLC ("Arevia") and is located approximately 20 miles south of the Fort Churchill Substation near the Mineral County/Lyon County border, in northern Nevada. Arevia is an independent U.S. utility-scale solar and wind developer with a 9 GW solar and wind project pipeline in various stages of development. Most recently, in May 2019, Arevia signed a PPA with Nevada Power to develop the Gemini Solar and Storage Project (690 MW PV and 380 MW BESS). The Libra Solar PPA was executed as a result of NV Energy's 2023 Open Resource RFP.

The Libra Solar project will consist of a 700 MW solar PV facility with a horizontal single-axis tracking mounting system. The Libra Solar project will consist of new high-performance bifacial solar PV modules mounted on single-axis trackers for optimal energy generation. The trackers rotate in the East-West direction following the sun's azimuth throughout the day. The proposed design uses strings of modules wired in series and aggregated into combiner boxes. The combiner boxes are connected to inverters which convert the DC energy to AC energy that will be delivered to Sierra Pacific Power's system through transformers or to the integrated BESS via inverters for later use.

The project will utilize lithium-ion battery technology consisting of 700 MW with four-hour duration (2,800 MWh). Each battery will have its own battery management system to communicate and actively manage performance and safety. Cooling and safety systems are integrated into the battery containers. Lithium-ion batteries are a well-established technology, modular in design, and highly flexible, allowing the overall BESS to provide multiple use cases as needed.

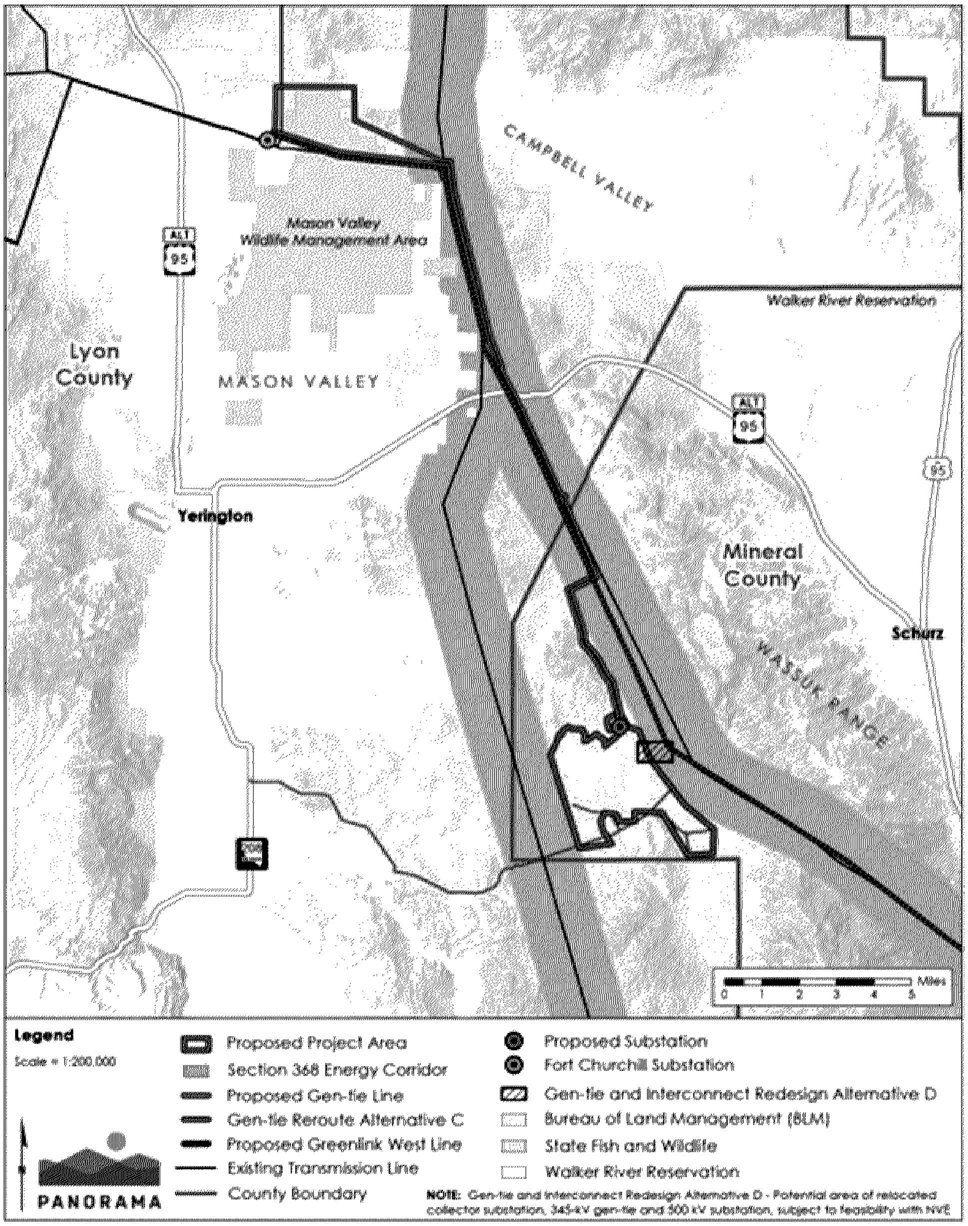
The project substation consists of a GSU, station control building, SCADA and telecommunications, battery DC power system for protection devices and critical switching elements. Transmission to the utility substation is provided by an overhead 345 kV gen-tie line from the project site to the Fort Churchill Substation, located approximately 22 miles from the project site.

Arevia estimates that the Libra Solar project will provide more than 1,100 construction jobs over a two-year construction period. After commercial operation in December 2027, the facility is expected to provide 30 permanent jobs with an average annual salary of $138,314, for an estimated first year annual payroll of $4,149,420 and a total payroll of approximately $107.2 million over the 25-year term of the PPA. Overall, based on information provided by Arevia, the Companies estimate that the total investment in Nevada's economy directly associated with the Libra Solar project will be more than $579 million. A work site agreement, in the form included in the executed PPA, will be executed between Libra Solar LLC, IBEW Local Union 1245, IBEW Local Union 401 and Labors Local 169.

The PPA is with Nevada Power for a 25-year term at a flat energy price of $34.97 per MWh for the solar. The storage system has a capacity price of $13,350 per MW-month for a term of 20 years; however, for years 21-25, the remaining battery capacity will degrade annually to a nameplate of not less than 500 MW and made available exclusively to the Companies at a price of $0.00 per MW-month. This extra five years of 500 MW BESS capacity at no cost adds significant additional value.

The project has an expected net capacity rating of 700 MW (ac), including a 700-MW, 2,800 MWh battery. It is expected to generate 1,948,197 MWh and 1,798,716 PCs in the first year. Annual solar energy production and credits are projected to degrade at approximately 0.4 percent per year. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-5-LS(a). Figure REN-19 shows a map of the project site.

FIGURE REN-19
LIBRA SOLAR PROJECT SITE



The Companies' due diligence summary for the Libra Solar project is included as Confidential Technical Appendix REN-5-LS(b). Technical Appendix REN-5-LS(c) contains detailed information about the Libra Solar project, including the information required by NAC § 704.8885 and NAC § 704.8887. Key provisions of the Libra Solar PPA are summarized in Technical Appendix REN-5-LS(d).

d. CORSAC GENERATING STATION 2 GEOTHERMAL PROJECT

The proposed Corsac Generating Station 2 Geothermal project is located outside the city of Fernley, in Churchill County, Nevada. It is being developed by FEC Development LLC ("Fervo"). Fervo is an independent U.S. utility-scale next-generation geothermal developer founded in 2017 and has a 1GW geothermal project pipeline in various stages of development, including a 400 MW geothermal facility in Beaver County, Utah, known as Cape Station. The Corsac geothermal PPA was executed as part of a 'sleeved' ESA with Callisto. The ESA has been executed at the time of this filing and is expected to be filed under the CTT by the Companies in a separate docket.

The Corsac Generating Station 2 project will consist of a new 115 MW geothermal power generating facility. The project's geothermal wells will utilize Fervo's proprietary and innovative drilling technology, consisting of horizontal drilling at depth to maximize reservoir volume and surface area. The unique well pattern enables energy capture from many more permeable zones than is generally possible in conventional vertical geothermal wells. Injection and production wells are connected in the subsurface by a set of hydraulically conductive fractures. These fractures act as flow pathways between the wells and provide sufficient levels of contact area with the geothermal reservoir to enable sustained heat recovery over the life of the system. Fiber-optic sensing cables are installed along the well casing to enable real-time monitoring of the downhole flow characteristics. Automated control valves are installed at the wellhead of each injection and production well, which enable the operator to adjust the flow rate and pressure at each well independently.

The major components of the system in addition to geothermal wells include: well pumps, a gathering system of pipes, the generator, and air cooled condensers. The Organic Rankine Cycle ("ORC") turbogenerator converts thermal energy from geothermal brine into electric energy using a turbine coupled with an electric generator. Thermal energy is supplied at high temperature to the ORC by a heat transfer fluid, consisting of geothermal brine and steam. The part of thermal energy that is not converted into electric energy, apart from the heat losses, is discharged at low temperature to an air condenser. The ORC turbogenerator operation is automatic, so continuous monitoring by personnel during operation is not required. In case of a fault, the ORC turbogenerator automatically and safely stops, and the electric generator disconnects from the grid. When operating at partial load the process parameters and the electric power output automatically change, company-adapting to the available thermal power.

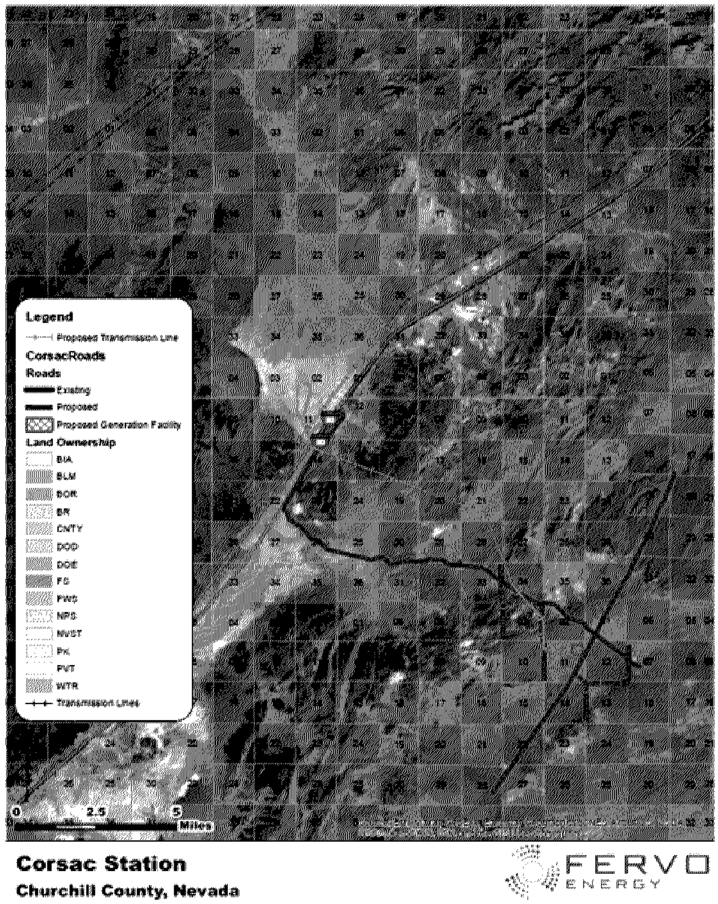
The project substation includes a GSU, where transmission to the utility is provided by an overhead 345 kV gen-tie line from the project site to the Valmy-East Tracy #2 345kV line, located approximately 19 miles from the project site.

Fervo estimates that the Corsac Generating Station 2 geothermal project will provide more than 1,114 construction jobs over a two-year construction period. After commercial operation in

January 2030, the facility is expected to provide 36 permanent jobs with an average annual salary of $106,801, for an estimated annual payroll of $3,844,839 and a total payroll of approximately $66.5 million over the 15-year term of the PPA. Overall, based on information provided by Fervo, the Companies estimate that the total investment in Nevada's economy directly associated with the Corsac geothermal project will be more than $307 million. A Work Site Agreement , as required by the PPA, will be executed between either Corsac Generating Station 2 LLC or its primary electrical contractor.

The PPA is with Sierra for a 15-year term at a flat energy price of $107.00 per MWh, that will provide 24/7 renewable energy and PCs to Callisto via an ESA. The project has an expected net capacity rating of 115 MW (ac). It is expected to generate 872,140 MWh of renewable energy, and 910,804 MWh of associated PCs inclusive of station usage, annually. Annual geothermal energy production and credits are projected to degrade at approximately 1 percent per year. The PPA includes ratepayer protections from the ESA through various provisions such as Sierra's ability to collect damages from either party due to termination or production shortfalls. Additionally, the PPA does not include options for Sierra to purchase the asset at any time during or after the term. In addition to the requisite approval from the Commission, the PPA is not effective until the ESA with Callisto has been fully executed and all conditions to its effectiveness have been satisfied. A copy of the PPA can be found in Technical Appendix REN-6-CS2(a). Figure REN-20 shows a map of the project site.

FIGURE REN-20
CORSAC PROJECT SITE



The Companies' due diligence summary for the Corsac Generating Station 2 project is included as Confidential Technical Appendix REN-6-CS2(b). Technical Appendix REN-6-CS2(c) contains detailed information about the Corsac Generating Station 2 geothermal project, including the information required by NAC § 704.8885 and NAC § 704.8887. Key provisions of the Corsac Generating Station 2 PPA are summarized in Technical Appendix REN-6-CS2(d).

4. Named Placeholders in the Alternative Plans

Historically, the Companies have sought approval of generation and storage projects in IRPs only for those projects that can be placed in service during the three-year action plan. As discussed above, the Companies are taking a longer term and more detailed integrated planning approach to meet the RPS, load growth and customer needs for renewable energy at the best value to customers through more efficient planning and project execution. In addition, more detailed long-term planning will allow the Companies to plan for and develop company-owned renewable projects.

The 2024 IRP Alternative Plans primarily rely on PPAs, which will continue to be a component of supplying low-cost renewable energy. However, in addition, the Companies are identifying "named placeholder" projects under the Alternative Plans. All Alternative Plans include "named placeholders" that address Directive 6 of the Commission's April 9, 2024, Modified Final Order in the Fifth Amendment to the 2021 Joint IRP. Named placeholders are provided to represent reasonably known projects in progress or requested, and to reflect anticipated company-owned projects. These are presented with estimated cost/pricing data, including anticipated associated transmission infrastructure costs, and are described further in the Renewables Section. The Companies are not requesting approval of any of the named placeholders, and placeholders are subject to change as needs and circumstances change.

The two Alternative Plans developed from combination cases were purposely created to differ from the combination cases only in that named placeholders are included to facilitate comparison.

The Companies are naming placeholder resources for seven new utility-scale projects: two that are not located on company-owned or controlled land, and five that are located on company-owned or controlled land. The Companies present the company-owned resources with the intent of growing its portfolio of renewable energy resources to meet several business and policy objectives including: 1) support closing the Companies' open capacity positions, 2) comply with the Nevada RPS while providing additional security against PPA cancelations, delays and shortfalls, 3) meet customers' sustainability business goals to be carbon-free, 4) reduced exposure to market price volatility, 5) progressing towards the State of Nevada's 2050 clean energy goal, as described in the ECON narrative, and 6) long-term customer benefits from continued operation after Company-Owned assets are fully depreciated. The timing of these projects was driven by the Companies' open position and RPS need. All of the Companies' proposed renewable projects are located in Nevada and will be delivering renewable energy to meet the needs of the Companies' customers.

Table REN-9 Named Placeholder Summary

Technology	Project Description	Type	Generation Capacity (MW)	Storage Capacity (MW)	Expected Commercial Operation	Term	NREL Cost (1)		Transmission Cost (4)
						(years)	Generation (2)	Storage (3)	
Wind	Idaho Wind	PPA	952	NA	4/1/2029	25	$63.04	NA	$0
Solar PV/BESS	Sierra Solar II	PPA	600	100	4/1/2030	30 PV 20 BESS	$34.84	$118.9	$2
	Amargosa I	Owned	200	200	4/1/2031	30 PV 20 BESS	$2,064	$1,453	$2
Standalone BESS	Sierra Solar III	Owned	NA	500	4/1/2032	20	NA	$1,472	$0
Solar PV/BESS	Amargosa II	Owned	400	200	4/1/2033	30 PV 20 BESS	$1,992	$1,433	$0
	Amargosa III	Owned	200	200	4/1/2034	30 PV 20 BESS	$1,955	$1,423	$2
Pumped Hydro	White Pine	PPA	NA	1000	6/17/2035	TBD	NA	$223.1	$118

Footnotes:
(1) Cost estimates are based on National Renewable Energy Laboatories cost data and are subject to change
(2) PPA Generation costs are in $/MWh; Owned Solar costs are in $ per kW (capital)
(3) PPA Storage costs are in $ per kW-year; Owned BESS costs are in $ per kW (capital)
(4) Tansmission costs quoted in millions

As discussed in the Economic Analysis narrative, the Companies modeled both future candidate resources and the named placeholder costs based on National Renewable Energy Laboratory ("NREL") published cost data that was adjusted based on recent RFP proposal pricing as applicable. Idaho Wind, one of two projects not located on Company-owned or controlled land, is included due to the Companies' allocation of 952 MWs of transmission rights on the Southwest Intertie Transmission Project ("SWIP North"), that is currently under development and expected to become operational in 2027. There are several large wind projects proposed in Idaho that are well in excess of the 952 MWs of Idaho wind in the Alternative Plans. Idaho wind projects are anticipated to have high capacity factors that are complimentary to the Companies' existing resource mix. The Companies anticipate bringing projects forward in the next IRP to satisfy the SWIP North allocation. Sierra Solar II-III is included due to land rights owned by NV Energy for these phases. Amargosa I-III is included due to BLM land rights that NV Energy has acquired. White Pine, the other project not located on Company-owned or controlled land, is included based on a previous IRP filing enabling study money for the project.

The Companies plan on submitting these named placeholders for regulatory approval in future IRP filings. Additionally, the request for approval of named placeholders in future IRP filings will accommodate the evolving needs of the Companies such as updated load forecasts and other changes that impact the Companies resource needs.

Renewable energy projects, such as solar plus storage projects, require advanced planning that can take approximately three to five years to plan, develop, procure, design and construct. The companies have been taking steps to develop company-owned projects such as procuring land rights, executing interconnection agreements, and purchasing critical equipment for future company-owned renewables projects. Some of these potential company-owned renewables projects are identified as named placeholder in the latter years of the Energy Supply plan. The Companies have taken these actions to position the Companies to be able to deliver these projects when the energy and capacity is needed for its customers.

The historical practice of identifying projects only within the three-year action period limits the Companies' ability to achieve key project development milestones that de-risk schedule and cost. The identification of named place holders past the three-year action period will provide regulators, stakeholders, and customers transparency into the Companies' company-owned renewables project plans.

Company-owned renewables projects offer several benefits: (i) provide control of the development timeline and delivery of the asset to be placed in services, (ii) allow for greater control of supply chain to mitigate potential delays or cost overruns that can jeopardize delivery of projects (particularly with respect to long lead-time equipment), (iii) allows for a measured and coordinated development of projects consistent with available transmission, and (iv) leverages the Companies' historic experience to operate and maintain generation assets to the benefit of customers.

Once project costs and schedules are refined, and design and performance specifications are confirmed, the company-owned renewables projects past the three-year action period will be brought to the Commission for formal approval.

5. Informational Updates

Voltage Support Agreement Update

The Companies are also providing an informational update regarding the origination of a Voltage Support Agreement (the "Agreement") between Sierra and Nevada Gold Mines ("NGM"). In May 2023, NV Energy Renewables began discussions with NGM to determine whether NGM's planned TS Solar facility can provide VAR support in the Carlin Trend to serve as a cost-effective solution for the voltage issues in the area described by the Companies in previous filings. NGM expressed its willingness to proceed, and as of March 2024, the parties have finalized and executed the Agreement. The Agreement allows for the Companies to provide compensation to NGM for VARs produced outside of the power factor range required by the Companies' Open Access Transmission Tariff ("OATT"), provided that the compensation for reactive power shall be in accordance with a FERC-approved rate schedule. NGM is currently preparing to file the rate specified in the Agreement with FERC for approval. The FERC rate filing requirements under the Federal Power Act section 205(d) specify a 60-day approval timeline. Following FERC approval, currently expected in Q3 2024, the Agreement would take effect.

White Pine Update

White Pine Pumped Storage Hydro ("White Pine") is a 1,000 MW pumped storage hydro facility with eight hours of energy storage located in northern Nevada. The project developer is working towards FERC licensure, which is currently anticipated to be received in November 2026. Commercial operation date (COD) of the project is expected in mid-2035.

The Companies continue to see value in this facility and are evaluating several options to best add it to the Companies' system. These options include purchasing and building the project as a company-owned asset, a tolling agreement with a purchase option, or a tolling agreement without a purchase option. The developer has provided proposals for a variety of these options, but an agreement has not yet been reached. As the Companies performed due diligence for the potential purchase, it was determined that a tolling agreement with a purchase option would be a preferred method to acquire the capacity of the project. This approach reduces cash flow requirements and the Companies' exposure to development and construction risks compared to ownership.

Given the desire to seek a tolling agreement for the project, the Companies anticipate including long-duration storage (including pumped storage hydro and specifically White Pine) in future RFPs. This approach will allow the Companies to examine the market for long-duration storage, compare long-duration storage solutions across technologies and assure the most cost-competitive projects for customers of the Companies.

Crescent Valley Update

The Companies do not currently intend to resubmit the Crescent Valley project to the Commission for approval. At the time of this writing, the Companies are evaluating the Commission order in the Fifth Amendment to the 2021 Joint IRP and the conditions placed on the Sierra Solar project. There is inadequate time to prepare a detailed cost and design for the Crescent Valley project to be included in the present filing.

Valmy Geothermal Resources Update

The Companies entered into a PPA with Eavor on November 4, 2022, for a 16-20 MW enhanced geothermal project near Valmy. Enhanced geothermal systems, like Eavor, bring the promise of 24/7 renewable energy that uses less water than traditional geothermal operations. Since the contract execution, Eavor has conducted gravity survey, a magneto-telluric survey, LiDAR and geologic field studies of the area. Eavor's geothermal engineers and scientists have determined that multiple subsurface faults exist and there will be a need to drill a deeper depth than initially contemplated prior to PPA execution. The subsurface geologic conditions increase the complexity of drilling and casing, and on May 22, 2024, Eavor provided formal notification to the Companies that the project is not commercially viable. Therefore, the Companies have removed Eavor from the economic analysis modeling and projected PCs from the RPS compliance forecast. Eavor has stated that it anticipates it will be able to build an Eavor system at Valmy in the future. If and when their technology does advance where this is possible, the Companies will work with Eavor to bring forth a newly negotiated PPA to the Commission for approval.

In the Companies' 2023 Open Resource RFP, only one geothermal bid was received. The proposal included a collection of geothermal project sites; two of which were located near the Valmy region. However, the Companies calculated the LCOE of this proposal and determined that it was more than 100 percent higher than the calculated LCOE of the Companies' most recent geothermal portfolio approved in Docket No. 22-11032. As discussed in the Economic Narrative, the results of the Economic Analysis of Geothermal Comparison for Individual Project Screening showed that this geothermal proposal option resulted in over $200 million additional cost compared to the Base Case. Furthermore, the LT model for geothermal did not select any geothermal resources until 2045, as also discussed in the Economic Analysis section of the narrative. The cost of geothermal resources considered in this filing were not competitive to other sources of renewable energy.

More generally, the long development periods for greenfield geothermal resources can add significant schedule risk. The Companies' experience with geothermal developers has shown that, even for a successful site, to go from exploration to commercial operation can take 7 to 10 years. Over time, as more of Nevada's prime geothermal potential sites are developed, the availability of high value geothermal sites suitable for development is diminished. The Companies cannot speculate on the underlying factors that geothermal developers use to determine their pricing proposals but will continue to work with the pool of geothermal developers actively bidding Nevada geothermal projects for the Companies' consideration to achieve the most cost-competitive outcome.

As of the date of this filing, the Companies have not received any viable proposals for geothermal resources in the Valmy region for evaluation. The Companies will pursue any bilateral opportunities as well as continue to solicit RFPs for renewable energy including geothermal resources in areas including, but not limited to, the Valmy region.

Option Agreements Update

To position the Companies to be able to develop projects and continue to meet anticipated load growth, RPS and to help close the open positions, the Companies have entered into Option Agreements for approximately 4,400 acres of land. These options provide the Companies with the flexibility to acquire lands in potentially favorable proximity to transmission assets at favorable prices for future development to meet customer's needs.

E. TRANSMISSION PLAN

1. INTRODUCTION

The regulations governing integrated resource planning require that the Companies include in their triennial IRPs (Integrated Resource Plan) a 20-year plan to meet the transmission needs of native load customers[1] and service requests from third parties.[2] This transmission plan is built upon the load forecasts, system characteristics, existing and future transmission facilities and obligations as described in this section. Based in part on these key system characteristics, the transmission plan examines the capabilities of the existing transmission system to determine the need for and timing of any additional transmission facilities.

In order to meet increasing large customer needs, the transmission plan includes several new projects. Transmission projects driven by customers have controls in place at each phase, meant to reduce the risk to both the Companies and native load customers. These project controls include the customer providing security, construction deposits, reduction in service charges and customer's construction milestones. These controls are defined in each customer's Rule 9 agreement. The reduction of service charge in the Rule 9 agreements require funds to be drawn on the customers' security, if customers' load does not achieve their load forecast up to the agreed upon percentage. Reduction in service charge offsets the lost revenue that is required to recoup the expense of the network upgrades built for the customer. The largest customer loads can also be broken into phases, which will also serve to mitigate the risk of customer loads not materializing as forecast.

The Companies are requesting Action Plan approval to begin network upgrades associated with the following projects summarized in Figure TP-1.

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[1] The term "Native Load Customer" comes from regulations established by the Federal Energy Regulatory Commission ("FERC") creating and maintain their open access transmission policies. Nevada Power and Sierra operate a single Balancing Area Authority or ("BAA"), which is responsible for serving both native load and transmission-only customers. Native load customers are the bundled retail customers of both Nevada Power and Sierra. Native load customers do not plan for and purchase transmission access directly from the BAA. Instead, Nevada Power and Sierra plan for and reserve transmission access on their behalf, consistent with the FERC's open access transmission policies, and pursuant to the Companies' Open Access Transmission Tariff or "OATT".

[2] *See* NAC § 704.9385(3).

FIGURE TP-1
PROJECTS LIST SUMMARY

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Greenlink	Customer transmission service requests, FERC-jurisdictional generation interconnection requests, addresses increased transmission capacity need. The north's simultaneous import limit is increased from 1,275 MW to 2,800 MW.	Construction **4,238.60[4]** North and South System ISD Greenlink West May 2027 ISD Greenlink North December 2028
Tolson Substation transformer #2 336 MVA 230/138 kV	Required per the 2023 transmission planning study results in compliance with NERC[5] transmission planning standard TPL 001-5.	Construction **9.60** South System ISD March 2028

[3] 2024 dollars, no escalation factor.
[4] The amount includes $97.40 million separately requested for approval of construction of the Ft Churchill to Comstock 345 kV line #2.
[5] North American Electric Reliability Corporation.

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Reid Gardner – Harry Allen 230 kV line #3 & separation of #1 and #2 lines	Required per the FERC[6] jurisdictional LGIA[7] which is executed per the Companies' OATT.[8] Security will be provided by the customer. The new 230 kV line will double the firm transmission capacity between the Reid Gardner and Harry Allen Substation from 860 MVA to 1,720 MVA.	Construction **24.20** South System ISD May 2026

[6] Federal Energy Regulatory Commission.

[7] Large Generator Interconnection Agreement.

[8] Open Access Transmission Tarriff.

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Lantern-Comstock 345 kV line	Required to fulfill the Companies' contractual obligation to serve the area's large Rule 9 HVD[9] or MPC[10] customer loads. Required per the FERC jurisdictional LGIA and NITSA[11] which is executed per the Companies' OATT. The line increases capacity into TRIC approximately 1,031 MVA. Required per the area transmission master plan to satisfy native customers' forecasted loads.	Construction **105.00** North System ISD December 2029
Comstock Meadows transformer #2 280 MVA 345/120 kV	Required to serve a large customer per Rule 9 HVD agreement. Required per the area transmission master plan to satisfy native customers' forecasted loads.	Construction **13.00** North System ISD May 2027
West Tracy transformer #1 (second installed) 280 MVA 345/120 kV	Required per the area transmission master plan to satisfy native customers' forecasted loads.	Construction **13.00** North System ISD May 2028
Machacek two (2) - 230 kV line breakers	Required to improve system reliability and improve customer satisfaction. The addition of a ring bus protection and three breakers will eliminate customer outages due to line outages and eliminate outages for maintenance consistent with the rest of the 230 kV system in the north. (No additional capacity is gained.)	Construction **14.80** North System ISD June 2027

[9] High Voltage Distribution.
[10] Master Planned Community Umbrella Agreement.
[11] Network Integrated Transmission Service Agreement.

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Darling Substation two (2) 37 MVA 230/12 kV	Required for native load customers in northwest side of Las Vegas. The new substation will increase capacity and relieve the distribution system overloads.	Construction **43.50** South System ISD June 2028
Log Cabin Substation 37 MVA 230/12 kV	Required for native load customers in northwest side of Las Vegas. The new substation will increase capacity and relieve the distribution system overloads.	Construction **33.75** South System ISD June 2028
Spring Canyon Substation Three (3) 37 MVA 230/12 kV	Required for new distribution loads in the Eldorado Valley. The new distribution substation will provide distribution capacity to a previously unserved area of the state.	Construction **49.60** South System Conditional approval requested. Construction approval will be based on the Companies and a customer entering into an MPC agreement. ISD December 2026
Ft Churchill-Comstock Meadow 345 kV line #2 and Ft Churchill third and fourth 600 MVA 525/345 kV transformers	Required to serve new Rule 9 customers with signed HVD agreements. This project increases transmission capacity in the Silver Springs, Fernley, TRIC,[12] Tracy and Reno areas. (The $110.2 MM line estimate includes the previously approved design, permitting and land acquisition $12.8 MM.) The line increases capacity into TRIC approximately 1,031 MVA.	Construction **(110.2 + 12.00 + 12.00) = 134.20** North System Transformers' construction conditional approval requested, based on actual load growth. ISD December 2027

[12] Tahoe Reno Industrial Center.

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Mackay 345 kV switching station	Required to serve **phase one** of a new Rule 9 customers with MPC and or HVD agreements. The customer will provide security and fund the project in part.	Construction **28.00** North System Conditional approval requested. Construction approval will be based on the Companies and customer entering into Rule 9 agreement. ISD December 2027
Gosling 345 kV switching station	Required to serve **phase one** of new Rule 9 customers with MPC and or HVD agreements. The customer will provide security and directly funding the project in part.	Construction **5.00** North System Conditional approval requested. Construction approval will be based on the Companies and customer entering into Rule 9 agreement. ISD April 2027

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Ft Churchill –Veterans 525 kV line (siting and permitting only)	Required to serve the Rule 9 customer's **phase two** and is required as a contingent facility for subsequent customers loads which are also new Rule 9 customers with MPC or HVD agreements. The customer is responsible for providing the permitting and right of way. The new line will increase capacity north of Ft Churchill to TRIC by approximately 2,000 MVA.	Construction **14.00** North System Conditional approval requested. Construction approval will be based on the Companies and customer entering into Rule 9 agreements. ISD May 2031
Naniwa 345 kV (new) switching station	Required to fulfill the Companies' contractual obligation to serve a large customer load in TRIC. The customer will provide security and fund the project in part.	Construction **26.00** North System ISD March 2027
Nighthawk 345/120 kV Substation	Required to fulfill the Companies' contractual obligation to serve a large customer load. The customer will provide security and fund the project in part.	Construction **67.00** North System ISD December 2028
Vaquero 345/120 kV Substation	Required to serve new Rule 9 customer's HVD agreement. The customer will provide security and directly fund the project in part.	Construction **30.00** North System Conditional approval requested. Construction approval will be based on the Companies and customer entering Rule 9 agreements. ISD May 2029

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Viking 345 kV switching station	Required to serve new Rule 9 customer's HVD agreement. The customer will provide security and directly fund the project in part.	Construction **55.00** North System Conditional approval requested. Construction approval will be based on the Companies and customer entering Rule 9 agreements. ISD May 2029
Veterans 345/120 kV Substation	Required to serve new Rule 9 customer's MPC agreement. Required to meet the transmission needs of native load customers growth in TRIC, Fernley and Fallon areas. Required to complete the 60 kV to 120 kV conversion between Tracy – Silver Springs – Lahontan – Fallon and Lahontan – Hazen – Eagle Substations, which is required per the Companies' N-0, N-1 voltage transmission planning standards for N-0, N-1 voltage limits. This will also increase transmission capacity for load growth.	Construction **40.00** North System ISD May 2030
Prospector 230 kV line terminal	Required to fulfill the Companies' contractual obligation to serve a large customer load.	Construction **2.20** South System ISD December 2026

Project Name	Justification for the Project	Approval Requested **Total Cost Estimate $MM[3]** North and/or South System Planned In-Service Date (ISD)
Valmy CTs 411 MW	Required Substation expansion and 345 kV line terminal addition for the generator interconnection.	Construction **5.22** North System ISD June 2028
Dry Lake East II PV/BESS 200/200 MW	Required 230 kV line terminal at Harry Allen Substation for the generator interconnection.	Construction **4.00** South System ISD December 2026
Boulder Solar III and IV PV/BESS 128/128 MW[13]	Using their existing lead line.	None - Using an existing shared lead line ISD June 2027
Libra PV/BESS 700/700 MW	Required 345 kV line terminal at Ft Churchill bus for the generator interconnection.	Construction **3.90** North System ISD December 2027
Corsac Geothermal Geothermal 115 MW	Required 345 kV line terminal at Lantern bus for the generator interconnection.	Construction **2.00** North System ISD January 2030

In Section D, a table is provided to inform the Commission on previously approved projects costs to date. The project update table does not infer any additional approval by the Commission. The project update table is provided for informational purposes only.

2. OVERVIEW OF THE COMPANIES' TRANSMISSION SYSTEM

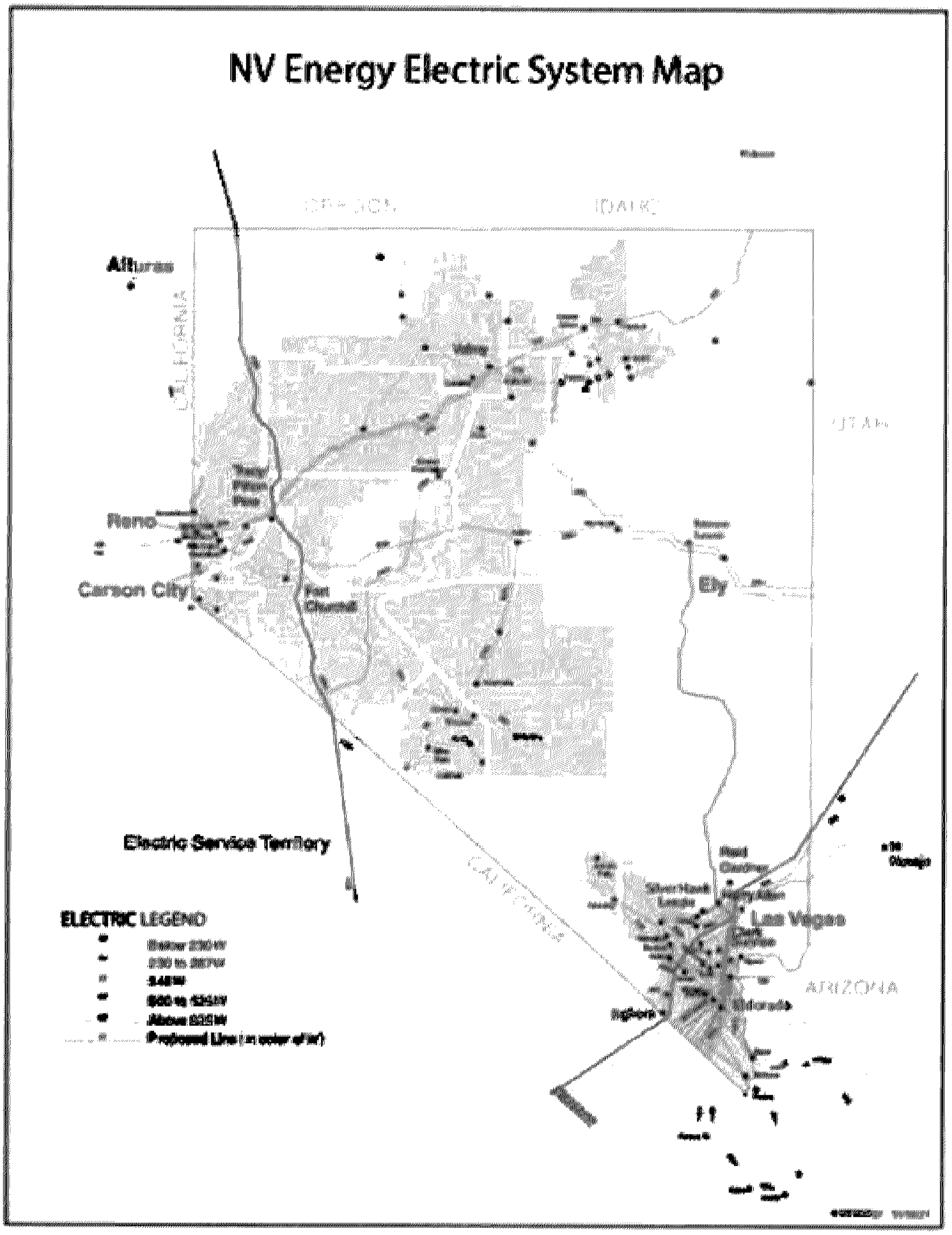
Section 704.9321(3)(e) of the NAC requires the Companies to provide maps depicting facilities required for the transmission of electric energy. This information is set forth in the map marked as Figure TP-2 below. This map shows the transmission system in both the northern and southern parts of Nevada, at each voltage.

[13] Boulder Solar III PV/BESS is using their existing lead line; therefore, there are no network upgrades required. The cost of a 230 kV interconnection was included in the analysis performed in the selection of the preferred plan resources but this change would not have a negative impact on this resource's selection. The interconnection cost used in the analysis conducted to determine the preferred plan was $2.00 MM.

The consolidated Nevada Power and Sierra transmission balancing authority area ("BAA") encompasses approximately 45,000 square miles. The Nevada Power service area covers approximately 4,500 square miles, with approximately 1,071,000 electric customers and 1,969 miles of FERC-jurisdictional transmission lines with voltages ranging from 69 kV to 525 kV. The Sierra transmission service area encompasses more than 40,000 square miles, with approximately 386,000 electric customers and 3,036 miles of FERC-jurisdictional transmission lines ranging from 55 kV to 525 kV.[14]

[14] Total Sierra transmission line mileage for both FERC-jurisdictional and Nevada-jurisdictional facilities is 4,157 miles with voltages ranging from 55 kV to 345 kV. This excludes the 235-mile, 500 kV One Nevada Transmission Line ("ON Line"). ON Line is included as part of Nevada Power's overall transmission system.

FIGURE TP-2
NV ENERGY TRANSMISSION SYSTEM DIAGRAM



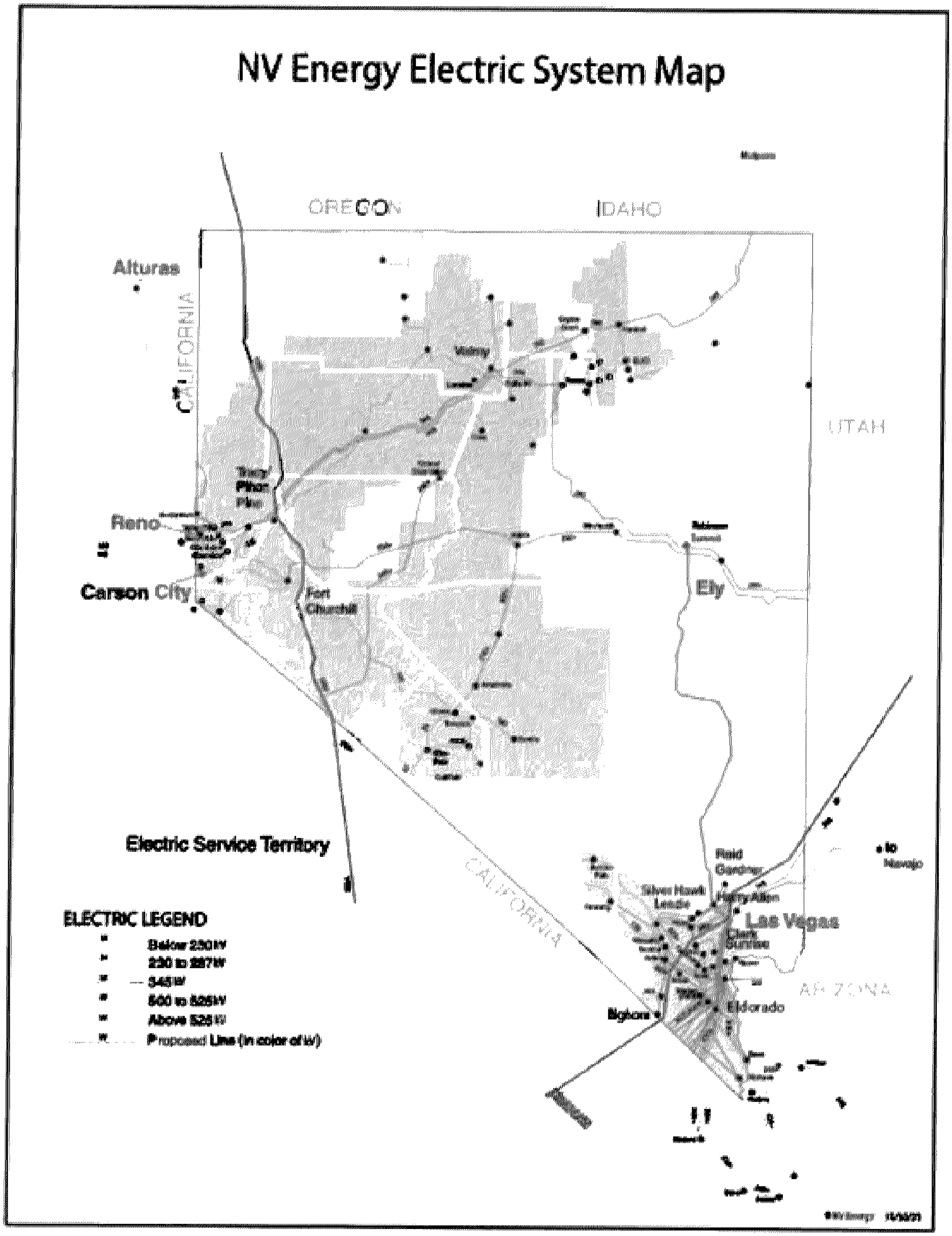
a. NEVADA POWER TRANSMISSION SYSTEM

The Nevada Power transmission system can be described in three sections, each shown in Figure TP-4 and TP-5. The first section, generally referred to as the Nevada Power internal system, is designated by the "#1," and is shown as the area between the cut plane lines (the heavy dashed lines). A cut plane is a reference to a combination of lines, either internal or external to a transmission system, which due to loading capabilities are collectively monitored or examined for limitations. The Nevada Power internal system is located within the Las Vegas Valley where the majority of Nevada Power's customers reside.

The second section, designated with a "#2," is identified by the dashed line on the bottom-right of Figure TP-3. This transmission path is known as the Southern Cut Plane ("SCP") and shows the transmission lines Nevada Power uses to transfer power through major substations on the southern interface of its transmission system – namely Mead, McCullough, and Eldorado – located south of Las Vegas in the Eldorado Valley. As detailed later under the Transmission Path Ratings portion of this plan, the SCP has been replaced by the formally accepted Western Electricity Coordinating Council ("WECC") path known as the Southern Nevada Transmission Interface ("SNTI"). The SNTI is composed of numerous transmission lines electrically situated in parallel with each other. These lines are connected to the Mead, McCullough, and Eldorado Substations, which are prominent trading hubs south of Nevada Power's transmission system and are used to import and export energy that is scheduled across this rated path.

The third section is represented by the dashed line on the top-right of Figure TP-5, designated with a "#3," is referred to as the Northern Cut Plane ("NCP"), and comprises the Red Butte-Harry Allen 345 kV interconnection with PacifiCorp, and the Crystal interconnection with the Navajo-Crystal-McCullough 525 kV line. Annual studies are conducted in coordination with PacifiCorp to verify the capability of this cut plane.

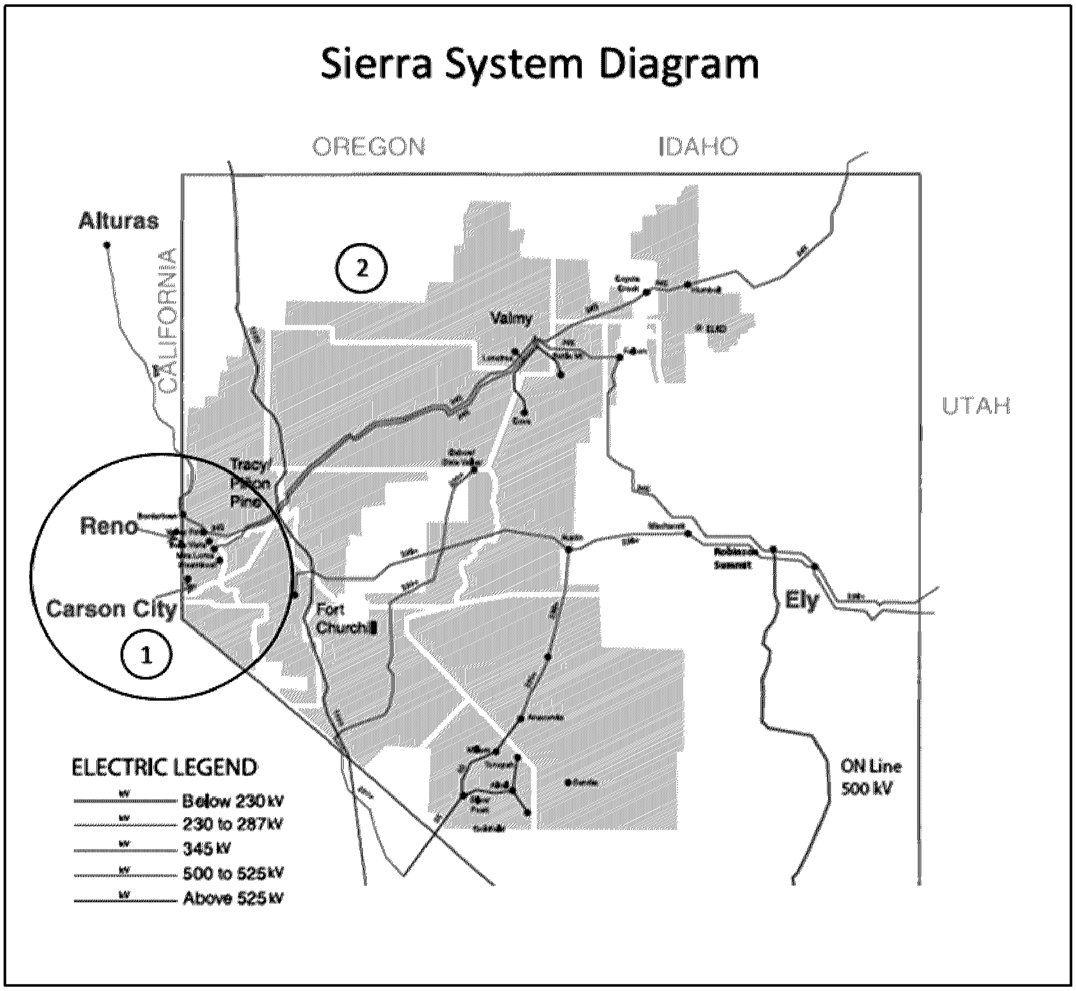
FIGURE TP-3
NEVADA POWER TRANSMISSION SYSTEM DIAGRAM



b. SIERRA TRANSMISSION SYSTEM

The Sierra system is best described as two sections as shown in the map in Figure TP-4. The first section, depicted as the area within the circle, encompasses the Reno, Tracy, and Carson City areas. Designated with a "1", this section represents the majority of the Sierra system load and is where the majority of Sierra's customers reside. The second section of the Sierra service area is the area outside the inner circle, designated with the "2", in the northern portion of the state. This section is characterized by long transmission lines serving heavy industrial (i.e., mining) and rural load widely dispersed throughout the northern portion of the state.

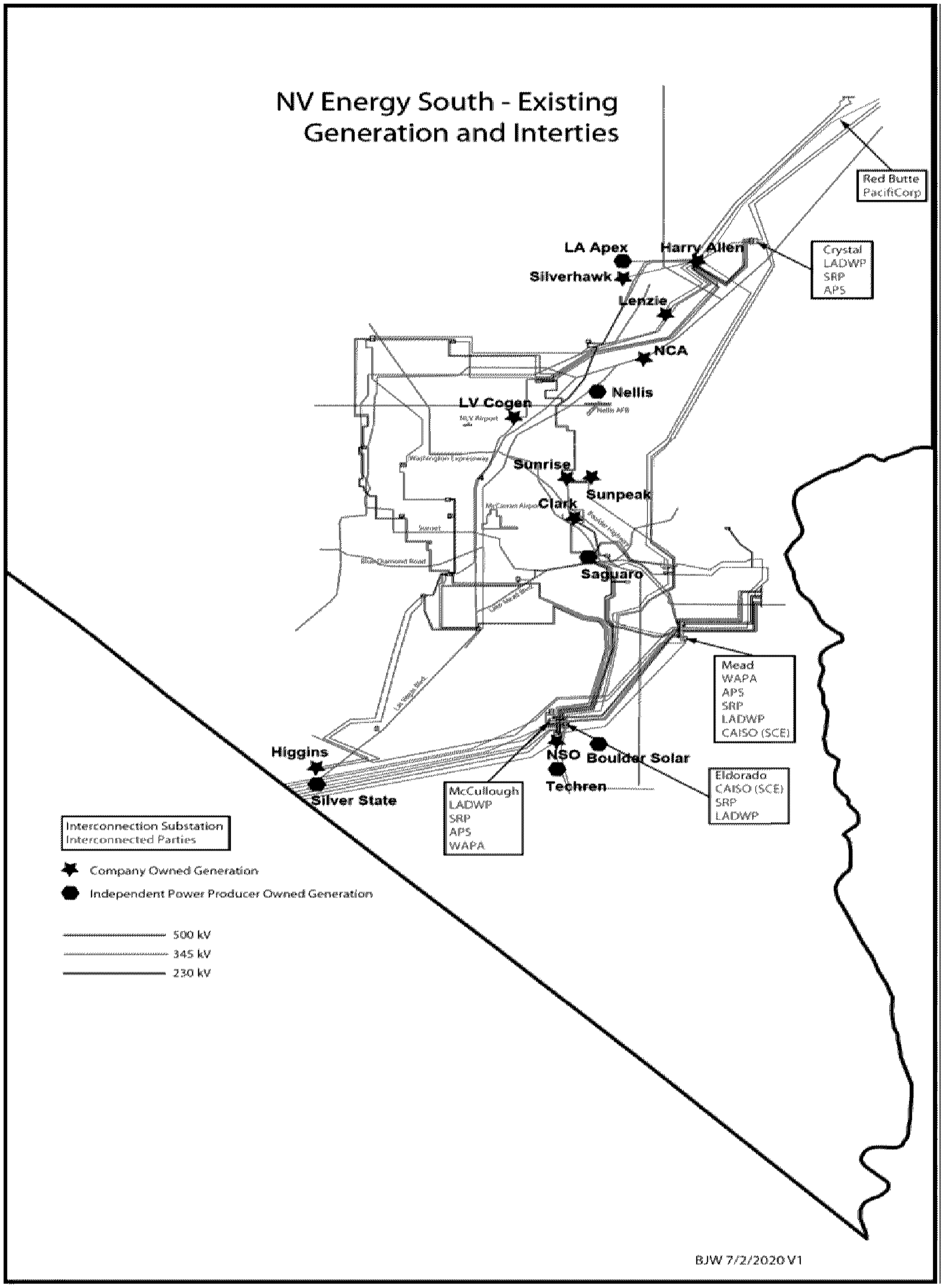
FIGURE TP-4
SIERRA TRANSMISSION SYSTEM DIAGRAM



TRANSMISSION PATH RATINGS

Per NAC §704.9385(3)(a), the Transmission Plan must provide a summary of the capabilities of the transmission system, including import and export capabilities and the rating of significant transmission paths. NAC §704.9321(3)(d) requires the Companies to provide information regarding interconnections with other utilities and independent power producers. Nevada Power owns three significant rated transmission paths, as shown below in Figure TP-5, each consisting of one or more transmission lines that are granted a rating by the WECC. Nevada Power is a partial owner of one additional WECC-rated transmission path, that being the WECC East of River ("EOR") Path 49.

FIGURE TP-5
DIAGRAM OF NEVADA POWER TIE LINES, EXISTING COMPANY-OWNED GENERATION, AND EXISTING INDEPENDENT GENERATION



Crystal 525 / 230 kV Path (WECC Path # 77). The Crystal 525/230 kV path allows energy to be moved from the Navajo-Crystal-McCullough 525 kV transmission line into the northeast boundary of the Nevada Power system via its Crystal Substation. This path is rated for 950 MW of inbound flow measured at the Crystal Substation. This is a 230 kV phase shifter-controlled path.

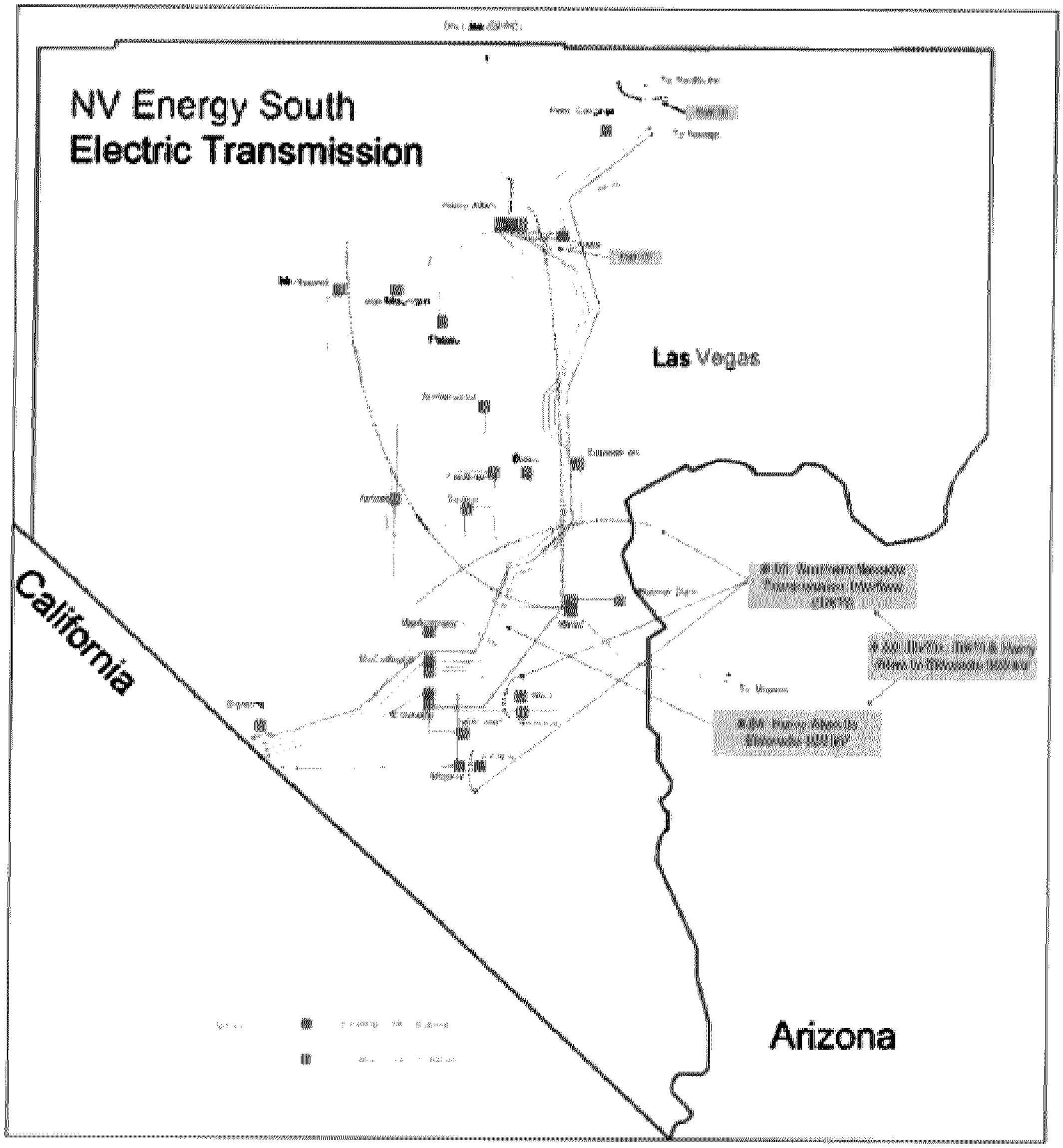
Harry Allen – Red Butte 345 kV Path (WECC Path # 35 – TOT2C). The Harry Allen to Red Butte 345 kV path allows energy to be moved to and from Utah (PacifiCorp – East) and the northeast corner of the Nevada Power system at the Harry Allen switching station. The two phase shifters at Harry Allen control the flow on this path and they are occasionally used to mitigate unscheduled flow in the WECC interconnection. This path has a north to south rating of 600 MW and a south to north rating of 580 MW

Southern Nevada Transmission Interface (WECC Path #81). Nevada Power owns and operates the Southern Nevada Transmission Interface, or SNTI, shown below in Figure TP-6. SNTI is comprised of 21 transmission tie-lines between the Nevada Power/Sierra combined BAA and the neighboring BAAs in southern Nevada (Western Area Power Administration, Lower Colorado, Los Angeles Department of Water and Power or "LADWP", and the California Independent System Operator Corporation ("CAISO"). This can be seen in Figure TP-6. The SNTI represents existing lines, and the path is routinely evaluated and annually updated as a part of the NV Energy seasonal operating studies. The accepted SNTI rating as approved by WECC is 4,533 MW North-to-South and 3,970 MW South-to-North.

Harry Allen – Eldorado 525 kV Path (WECC Path #84). The newly completed Harry Allen to Eldorado 525 kV path connects Nevada Power and Southern California Edison. It represents a connection between Nevada Power and CAISO Balancing Authorities. This path is represented in Figure TP-6 below. The path has a North-to-South rating of 3,496 MW and a South-to-North rating of 1,390 MW.

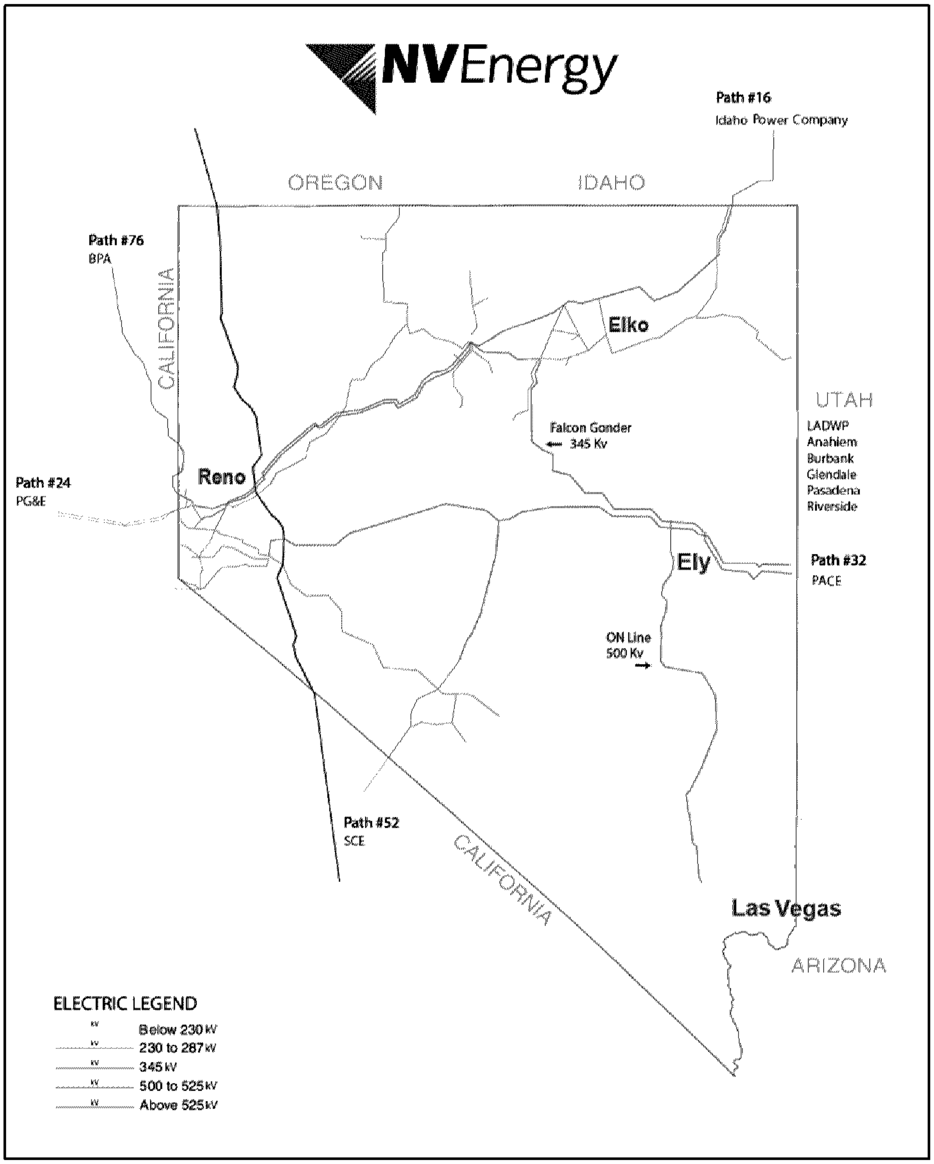
Southern Nevada Transmission Interface+ (WECC Path #89). Nevada Power owns and operates the Southern Nevada Transmission Interface+, or SNTI+, which is SNTI (WECC Path #81) and Harry Allen to Eldorado 525 kV (WECC Path #84) combined. The SNTI represents existing lines, and the path is routinely evaluated and annually updated as a part of the NV Energy seasonal operating studies. The accepted SNTI+ rating as approved by WECC is 6,257 MW North-to-South and 4,681 MW South-to-North.

FIGURE TP-6
SOUTHERN NEVADA TRANSMISSION INTERFACES



Sierra owns five WECC rated transmission paths, each consisting of one or more transmission lines. Rated transmission paths are identified in Figure TP-7 below. Ratings are established through the WECC process on a non-simultaneous basis. These transmission path ratings may be subject to change over the twenty-year planning period, depending on changes to the system configuration. Operation of the paths are based on simultaneous limits described as Operational Transfer Capabilities and are posted on Sierra's Open Access Same-time Information System ("OASIS").

FIGURE TP-7
SIERRA RATED TRANSMISSION PATHS



Idaho – Sierra (WECC Path # 16). This path is rated for 525 MW of inbound flow and 360 MW of outbound flow. The path is a 345 kV line from Idaho Power's Midpoint Substation, near Twin Falls, Idaho that connects to Sierra's Humboldt Substation in the northeast corner of the Sierra's transmission system.

Pacific Gas and Electric – Sierra (WECC Path # 24). This path has two 120 kV lines and one 60 kV line and is rated for a total flow of 160 MW in-bound and 150 MW out-bound. The path connects Pacific Gas and Electric's 115 kV system near Donner Summit, California, to Sierra's 120 kV and 60 kV transmission near Truckee, California. This path has a 150 MVA phase shifter at California Substation near Verdi, Nevada, to control the path flow.

<u>Pavant – Gonder 230 kV and Intermountain – Gonder 230 kV (WECC Path #32).</u> This path has two 230 kV tie lines. Total flow is rated 440 MW in-bound and 235 MW out-bound. PacifiCorp's Pavant and Los Angeles Department of Water and Power's Intermountain substations are both in Utah and each has a 230 kV line that connects to the Gonder Substation near Ely, Nevada. A 150 MVA 120 kV phase shifter at the Ft. Churchill Substation near Yerington, Nevada, has some control of the line flows on this rated path.

<u>Silver Peak – Control 55 kV (WECC Path #52</u>). This path is rated 17 MW bi-directionally. The path starts at Silver Peak, Nevada and ends at SCE's Control Substation, which is located near Bishop, California. This path includes two 60 kV lines and two 17 MVA phase shifters in series to control the path flows.

<u>Alturas Project (WECC Path # 76).</u> This path is rated at 300 MW bi-directionally. The Alturas path is connected to Bonneville Power Authority's 230 kV transmission at Hilltop 230 kV Substation near Alturas, California. Voltage is stepped-up to 345 kV at Hilltop with a 300 MVA transformer. From Hilltop, the path continues south where it interconnects with Ft. Sage Substation. This path has a 300 MVA phase shifter at Bordertown Substation to control the path flows.

IMPORT CAPABILITY

Section §704.9385(3)(a) of the NAC requires that the Transmission Plan describe the import capability of the transmission system. The term "import capability" is defined as the energy that can be transferred into a BAA. Import capability is determined in accordance with WECC, and North American Electric Reliability Corporation ("NERC") reliability criteria. Accordingly, the system must be capable of meeting all performance criteria for steady state and single contingency outage conditions at the stated import level. The Companies' system import capability is dependent on transmission line flows, generation dispatch patterns, and system loads.

Figure TP-7 below shows the individual system import capabilities using the FERC's prescribed methods. These values reflect the system import limit using balanced line flows with internal generation adjusted to allow maximum system import capability. This figure does not provide a complete representation of each system's real-time import capabilities, as imports are dependent on load and the generation used to meet such load. Imports equal load plus losses minus internal generation, or:

$$\text{Imports} = \text{load} + \text{losses} - \text{internal generation}$$

In real time, when all available generating units are being used to serve system load, imports will be equal to the difference between load, losses and generation. Whether the system has the capacity to perform a system wheel (*i.e.*, an import at one location in the system with a corresponding export at a different location in the system) under these circumstances is determined through studies, which the Companies routinely complete in response to transmission service requests.

FIGURE TP-8
SUMMARY OF SYSTEM IMPORT CAPABILITY

Summary of Import Capability (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Nevada Power	5200	5200	5200	6200	6200
Sierra	1275	1275	2000	2000	2800

Maximum import capability should not be confused with long-term, firm transmission capability under the OATT. Maximum import capability is measured using maximum load and minimum generation, where actual imports are highly dependent on load, generation, and available voltage support. Long-term, firm transmission service under the OATT must be available without limits imposed by load variations or other transmission customers' actions.

EXPORT CAPABILITY

Section 704.9385(3)(a) of the NAC also requires that the Transmission Plan describe the export capability of the transmission system. Nevada Power's and Sierra's system export capability are set forth in Figure TP-9 below. Export capability is limited by the capability of the transmission system, including load and generation. Export capability of the system is limited by the loss of the highest rated intertie. The export capability for Nevada Power and Sierra has been recently analyzed, and the Export Capability for Nevada Power has decreased to 4120 MW, as discussed further in the Technical Appendix TRAN-1.

Maximum export capability should not be confused with the Companies' long-term, firm transmission capability under the OATT. Each system's maximum export capability is determined using minimum load and maximum generation resources within the system. Actual exports are highly dependent on load and generation. Long-term, Firm Transmission Service under the OATT must be deliverable without limits imposed by load variations or other transmission customers' actions.

FIGURE TP-9
SUMMARY OF EXPORT CAPABILITY

Summary of Export Capability (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Nevada Power	4120	4120	4120	7090	7090
Sierra	1125	1125	2000	2000	2800

TRANSMISSION SERVICE OBLIGATIONS

Per NAC §704.9385(3)(c) and NAC §704.9385(3)(d), the Transmission Plan must identify the transmission capacity required to serve bundled and unbundled retail transmission customers, and wholesale transmission customers the Companies are obligated to serve, as well as all existing and proposed transmission service agreements ("TSAs"), with transmission customers, the expiration dates of those obligations and their impacts on the transmission capacity available for use by bundled retail customers. Nevada Power and Sierra are obligated to provide transmission-only service to several transmission-only customers under TSAs. Existing Nevada Power TSAs are listed in Figures TP-10 and TP-11. Figure TP-10 lists Nevada Power's long-term transmission obligations for import into the BAA. Figure TP-11 lists Nevada Power's long-term transmission obligations for exports out of the BAA. Existing Sierra TSAs are listed in Figures TP-12 and TP-13. Figure TP-12 shows Sierra's long-term transmission obligations for import into the BAA, and Figure TP-13 shows Sierra's long term transmission obligations for exports out of the BAA. The impact of these combined TSAs on the amount of import transmission capacity available for use by bundled retail customers is reflected in the Transmission portion of the Load & Resource tables in Figures TP-14 and TP-15.

FIGURE TP-10
NEVADA POWER'S LONG-TERM BAA TRANSMISSION IMPORT OBLIGATIONS (NETWORK CUSTOMERS)

Agreement	Delivery Interface	MW	Term
SNWA	Mead 230 kV	30	6/1/2013 - 5/31/2028
LVVWD	Mead 230 kV	60	6/1/2013 - 5/31/2028
City of Las Vegas	Mead 230 kV	8	6/1/2013 - 5/31/2028
City of Henderson	Mead 230 kV	12	6/1/2013 - 5/31/2028
City of North Las Vegas	Mead 230 kV	4	6/1/2013 - 5/31/2028
Clark County Water Reclamation District	Mead 230 kV	13	6/1/2013 - 5/31/2028
Wynn Las Vegas	Mead 230 kV	31	10/1/2021 - 10/1/2032
MGM Resorts Inc.	Mead 230 kV	161	10/1/2021 - 10/1/2026
Switch Ltd.	Mead 230 kV	178	6/1/2017 - 6/1/2047
Caesar's Enterprises	Mead 230 kV	83*	11/1/2023 - 9/1/2027
Sahara Las Vegas	Mead 230 kV	5	1/1/2020 – 1/1/2025
Georgia Pacific Gypsum	Mead 230 kV	4	2/1/2020 – 2/1/2025
Rio Las Vegas	Mead 230 kV	9*	11/1/2023 - 11/1/2028
Hard Rock	Mead 230 kV	14	1/1/2023 - 1/1/2028
Air Liquide	Mead 230 kV	14	6/1/2021 - 4/1/2025

*Caesars Enterprises sold the Rio Las Vegas and assigned 9 MW from its Network Integration Transmission Service Agreement to the Rio Las Vegas during the sale.

FIGURE TP-11.1
TRANSMISSION SERVICE REQUESTS NOT CONFIRMED

Customer	POR	POD	MW	Start Date	Stop Date
PWX	Captain Jack / Bonanza Sub (Northsys)	MEAD230	66	1/1/2031	1/1/2041
PWX	Captain Jack / Bonanza Sub (Northsys)	MEAD230	100	1/1/2031	1/1/2041
PWX	Captain Jack / Bonanza Sub (Northsys)	MEAD230	134	1/1/2031	1/1/2041
PWX	Captain Jack / Bonanza Sub (Northsys)	MOENKOPI500	150	1/1/2031	1/1/2041
PWX	Captain Jack / Bonanza Sub (Northsys)	NAVAJO500	100	1/1/2031	1/1/2041
PWX	Captain Jack / Bonanza Sub (Northsys)	MCCULLOUG500	100	1/1/2031	1/1/2041
PWX	Captain Jack / Bonanza Sub (Northsys)	HA500	150	1/1/2031	1/1/2041
PWX	Mead230 kV	Captain Jack / Bonanza Sub (Northsys)	100	1/1/2031	1/1/2041
PWX	Mead230 kV	Captain Jack / Bonanza Sub (Northsys)	200	1/1/2031	1/1/2041
PWX	Moenkopi500	Captain Jack / Bonanza Sub (Northsys)	150	1/1/2031	1/1/2041
PWX	HA500	Captain Jack / Bonanza Sub (Northsys)	150	1/1/2031	1/1/2041
PWX	HA500	Captain Jack / Bonanza Sub (Northsys)	200	1/1/2031	1/1/2041
PWX	Mead230 kV	M345	50	1/1/2028	1/1/2038
PWX	Mead230 kV	M345	50	1/1/2028	1/1/2038
PWX	Mead230 kV	M345	100	1/1/2028	1/1/2038
PSEM	Mead230 kV	M345	98	6/1/2027	6/1/2032
PSEM	Mead230 kV	HILLTOP345	181	1/1/2028	1/1/2033
PSEM	Southsys	HILLTOP345	181	1/1/2028	1/1/2033
PSEM	Valmy 345 kV (Northsys)	HILLTOP345	181	1/1/2028	1/1/2033

FIGURE TP-11.2
DESIGNATED NETWORK RESOURCE REQUESTS NOT CONFIRMED

Customer	POR	POD	MW	Start Date	Stop Date
Caesars	Southsys	Southsys	3	2025-06-01	2027-09-01
Caesars	Midpoint 345 kV	Northsys	7	2027-09-01	2033-01-01
Switch	Midpoint 345 kV	Northsys	1460	2024-06-01	2034-01-01
Switch	Mead 230 kV	Northsys	1460	2025-01-01	2034-01-01
Switch	Mead 230 kV	Southsys	449	2024-06-01	2034-01-01
Mt Wheeler	Gonder Pavant	Northsys	80	2029-01-01	2034-01-01
Mt Wheeler	Gonder IPP	Northsys	25	2029-01-01	2034-01-01
NGM - Barrick	Mead 230 kV	Northsys	55	2027-01-01	2041-01-01
NGM - Newmont	Mead 230 kV	Northsys	12	2027-01-01	2041-01-01
NGM - TS Solar	Falcon 120 kV (Northsys)	Northsys	100	2024-07-01	2042-02-01
Plumas Sierra	Gonder Pavant	Northsys	28	2025-01-01	2056-01-01
NVPM - Pinto	Northsys	Northsys	17	2027-01-01	2054-01-01
NVPM - Desert Peak 2	Northsys	Northsys	11	2028-01-01	2054-01-01
NVPM - Beowave	Northsys	Northsys	23	2025-01-01	2054-01-01
NVPM - Galena 1	Northsys	Northsys	17	2027-01-01	2054-01-01
NVPM - North Valley 2	Northsys	Northsys	17	2026-01-01	2054-01-01
NVPM - Galena 3	Northsys	Northsys	17	2029-01-01	2054-01-01
NVPM - Gerlach	Northsys	Northsys	17	2028-01-01	2054-01-01
NVPM - Lone Mountain	Northsys	Northsys	17	2026-01-01	2054-01-01
NVPM - Ceresola	Northsys	Northsys	1000	2025-05-01	2060-06-01
NVPM - 3F Solar	Northsys	Northsys	280	2029-01-01	2069-01-01
NVPM - Bobcat Ranch	Northsys	Northsys	385	2029-01-01	2069-01-01
NVPM - Borba	Northsys	Northsys	270	2029-01-01	2069-01-01
NVPM - Amargosa	Southsys	Northsys	685	2027-04-01	2062-12-01
NVPM -Valmy simple 1&2	Northsys	Northsys	444	2027-02-01	2057-02-01
NVPM - Amargosa	Southsys	Southsys	1200	2027-04-01	2062-12-01
NVPM -M345_2029	Midpoint 345	Northsys	952	2029-04-01	2054-04-01
NVPM -M345_2029	Northsys	Southsys	952	2029-04-01	2054-04-01
NVPM - Dry Lake East	Southsys	Southsys	200	2026-12-01	2052-01-01
NVPM - Eavor Valmy	Northsys	Northsys	20	2026-12-01	2052-01-01
NVPM - Libra	Northsys	Southsys	700	2027-12-01	2053-01-01
NVPM - Corsac Gen Station	Northsys	Northsys	115	2030-01-01	2046-02-01
NVPM - Boulder Solar 3	Southsys	Southsys	128	2027-06-01	2053-01-01

FIGURE TP-11.3
NEVADA POWER POINT OF DELIVERY LONG-TERM BAA TRANSMISSION EXPORT OBLIGATIONS

TSA	MW	POD	Term
MSCG	50	Midpoint345 – EDE230	3/1/2021 - 3/1/2026
OME - Humboldt House 1	20	EDE230	6/1/2027 - 6/1/2032
STPK - Humboldt House 2	25	EDE230	1/1/2027 - 1/1/2032
STPK - Whitegrass No. 2	6	EDE230	6/1/2027 - 6/1/2032
OME - Fish Lake	13	EDE230	1/1/2028 - 1/1/2033
LMUD	1	MD230	6/1/2023 - 9/1/2025
Tenaska	50	MD230	1/1/2027 - 1/1/2032
STPK - Star Peak	8	MCC500	1/1/2027 - 12/1/2032
OME - Whitegrass No. 1	3	MCC500	12/1/2022 - 1/1/2025
OME - Whitegrass No. 1	2	MCC500	1/1/2021 - 1/1/2025
STPK - Star Peak	6	MCC500	12/1/2022 - 12/1/2027
Salt River Project	25	NAV500	12/1/2023 -12/01/2028
SCAPPA	500	MCC500	8/1/2023 - 8/1/2030
ONGP	12	CRY500	2/1/2023 - 2/1/2028
ONGP	2	CRY500	12/1/2023 - 2/1/2028
ONGP	30	CRY500	12/1/2023 - 12/1/2028
ONGP	24	CRY500	1/1/2024 - 1/1/2029
ONGP	6	CRY500	1/1/2020 - 1/1/2025
ONGP	8	CRY500	1/1/2020 - 1/1/2025
ONGP	16	CRY500	1/1/2020 - 1/1/2025
ONGP	24	CRY500	1/1/2020 - 1/1/2025
ONGP	24	CRY500	1/1/2021 - 1/1/2026
ONGP	21	MD230	1/1/2021 - 1/1/2026
ONGP	10	CRY500	1/1/2022 - 1/1/2027
ONGP	16	CRY500	8/1/2022 - 8/1/2027
ONGP	24	CRY500	9/1/2022 - 9/1/2027
ONGP	24	CRY500	12/1/2022 - 12/1/2027
ONGP	25	CRY500	12/1/2024 - 12/1/2029
ONGP	25	CRY500	1/1/2025 - 1/1/2030
ONGP	24	MD230	1/1/2014 - 1/1/2034
ONGP	3	MD230	10/1/2016 - 1/1/2034
Powerex	25	MD230	4/1/2024 - 4/1/2025

FIGURE TP-12
SIERRA LONG TERM BALANCING AREA
TRANSMISSION IMPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
Truckee Donner PUD	Gonder Pavant	41	11/1/2016 - 1/1/2025
City of Fallon	Gonder Pavant	22	4/1/2022 - 4/1/2029
Barrick	M345	82	1/1/2016 - 1/1/2028
Barrick	Gonder Pavant	25	1/1/2014 - 1/1/2041
Barrick	Gonder Pavant	12	1/1/2014 - 1/1/2033
Barrick	M345	6	1/1/2016 - 1/1/2028
Barrick	M345	68	1/1/2016 - 1/1/2028
Barrick	M345	156	1/1/2028 - 1/1/2040
Mt Wheeler	Gonder IPP	25	1/26/2017 - 1/1/2029
Mt Wheeler	Gonder Pavant	80	6/1/2016 - 1/1/2029
BPA – Wells	HILLTOP	85	10/1/2016 - 10/1/2028
BPA – Harney	HILLTOP	35	10/1/2016 - 10/1/2028
BPA – Harney	HILLTOP	7	10/1/2016 - 10/1/2028
Switch Ltd.	M345	58	6/1/2017 - 1/1/2028
Caesar's Enterprises	M345	7	9/1/2017 - 9/1/2022
Peppermill Resorts	M345	9	1/1/2018 - 1/1/2048
Reno City Center	M345	3	10/1/2020 - 10/1/2025
Liberty Utilities	M345	145	1/1/2021 - 1/1/2029
BPA – Wells Gold Rush - Hilltop	HILLTOP	26	10/1/2016 - 10/1/2028
BPA – Harney - Hilltop	HILLTOP	86	10/1/2016 - 1/1/2029
LMUD	Gonder.IPP	30	10/1/2025 - 10/1/2045
Switch Ltd. - M345	M345	31	1/1/2029 - 1/1/2032

All Agreements with a term of 5 or more years are subject to roll over rights.

The following clarifications are applicable to all of the above Long Term import obligations listed above:

Network Customers import rights are equal to Designated Network Resources ("DNRs") and may not have a termination date based on contract and roll-over rights.

Subject to availability.

Capacity reservations change by month for Network Customers, peak values provided are for the specified path.

FIGURE TP-13
NORTHERN POINT OF DELIVERY LONG TERM BAA TRANSMISSION EXPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	18	10/1/2018 - 10/1/2023
Idaho Valmy	Midpoint 345 kV	262	4/1/2023-termination pursuant to the Valmy Agreement with Idaho Power
Amor Soda Lake	Gonder Pavant	7	10/1/2021 - 10/1/2026
Amor Soda Lake	Gonder Pavant	13	10/1/2021 - 10/1/2026
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	1	10/1/2021 - 10/1/2026
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	18	10/1/2023 - 1/1/2025
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	18	1/1/2025 - 1/1/2030
Vitol Inc. - Midpoint	Summit 120 kV	2	10/1/2021 - 10/1/2026
AmpRenew - Midpoint	Summit 120 kV	2	11/1/2020 - 10/1/2025
			10/1/2025 - 10/1/2030
OME--Silverpeak	Gonder IPP	13	1/1/2023 - 1/1/2028
Ormat--Dixie Comstock	Summit 120 kV	15	1/1/2025 - 1/1/2026
	Summit 120 kV	29	1/1/2026 - 1/1/2030
Ormat--Dixie Comstock	Gonder IPP	15	1/1/2025 - 1/1/2030
Ormat--Baltazor	Gonder IPP	20	6/1/2024 - 6/1/2029
Ormat--Beowawe	Gonder IPP	24	1/1/2026 - 1/1/2031
OME - Whitegrass	Gonder IPP	6	12/1/2024 - 12/1/2029
OME - Humboldt House	Gonder IPP	20	3/1/2025 - 3/1/2023
P66T	Midpoint 345 kV	50	10/1/2025 - 10/1/2030

All Agreements with a term of 5 or more years are subject to roll over rights.

Figure TP-14 below is a summary of the long-term transmission import and export obligations at each point of delivery in Figures TP-10 through TP-13.

FIGURE TP-14
LONG TERM BAA TRANSMISSION OBLIGATIONS SUMMARY

		Point of Delivery	MW Total
Nevada Power	**Import Obligations**	Mead 230 kV	**626**
	Export Obligations	Crystal 525 kV	**270**
		Eldorado 230 kV	**114**
		McCullough 525 kV	**519**
		Mead 230 kV	**199**
		Navajo 525 kV	**25**
Sierra	**Import Obligations**	Gonder/ Pavant 230 kV	**180**
		Gonder IPP	**25**
		Hilltop 345 kV	**239**
		Midpoint 345 kV	**565**
	Export Obligations	Hilltop 345 kV	**55**
		Gonder/ Pavant 230 kV	**20**
		Gonder IPP	**98**
		Summit 120 kV	**48**
		Midpoint 345 kV	**262**

NAC 704.9385(3)(e) requires the Companies provide “a table identifying all the transmission capacity that the utility has secured for its bundled retail transmission customers on both its transmission system and the transmission systems of other utilities.” Figure TP-15 and TP-16 below show the Companies’ long-term secured transmission capacity for bundled retail customers.
NAC 704.9385(3)(e) requires the Companies provide “a table identifying all the transmission capacity that the utility has secured for its bundled retail transmission customers on both its transmission system and the transmission systems of other utilities.” Figure TP-15 and TP-16 below show the Companies’ long-term secured transmission capacity for bundled retail customers.

FIGURE TP-15
NEVADA POWER TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Capacity Reserved by Nevada Power for Native Load									
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Mead (Hoover)	375	375	375	375	375	375	375	375	375	375
Red Butte	0	0	0	0	0	0	0	0	0	0
McCullough	0	0	0	0	0	0	0	0	0	0
Crystal (Navajo)	260	260	260	260	260	260	260	260	260	260
Eldorado	0	0	0	0	0	0	0	0	0	0
Mohave (Laughlin)	54	54	54	54	54	54	54	54	54	54
ON Line (Sierra)	526	526	526	526	526	526	526	526	526	526
GL Nevada Projects	0	0	0	836	836	836	836	836	1207	1207
Total	1215	1215	1215	2051	2051	2051	2051	2051	2422	2422
	Firm Capacity Reserved by Nevada Power on Other Systems									
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	0	0	0	0	0	0	0	0	0	0

FIGURE TP-16
SIERRA TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Capacity Reserved by Sierra for Native Load									
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Nevada Power (ON Line)	600	600	600	600	600	600	600	600	600	600
GL Nevada Projects	0	0	0	44	44	623	623	623	844	844
Total	600	600	600	644	644	1223	1223	1223	1444	1444
	Firm Capacity Reserved by Sierra on Other Systems									
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	0	0	0	0	0	0	0	0	0	0

NAC § 704.945(4) requires "a graph or table" that depicts "the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers." This information is provided for the Companies in TP-17, below.

FIGURE TP-17
NV ENERGY TRANSMISSION SYSTEM CAPACITY ALLOCATION

	Nevada Power		**Sierra**	
Transmission Allocation	**MW**	**Percentage**	**MW**	**Percentag e**
Unbundled/ Wholesale Transmission	626	11.70%	500	41.20%
Bundled Transmission	1215	23.80%	600	47.10%
Transmission Reliability Margin	200	3.40%	175	11.80%
Unallocated Transmission	3214	61.80%	0	0.00%
Total Import Capacity	**5,200**		**1,275**	

3. SPECIFIC REQUESTS FOR COMMISSION APPROVAL FOR NEW TRANSMISSION PROJECTS

NAC § 704.9385(3)(b) requires that the Transmission Plan include a description of transmission projects that the Companies are considering expanding or upgrading. NAC § 704.9355(1)(b) and (1)(c) require that the utilities develop a set of analyses of its options for supply to be considered for meeting the expected future demand on its system. These analyses must include an examination of the environmental impact of each option, considering the best available technologies and the environmental benefit of renewable resources, including construction of new transmission facilities or upgrades to existing transmission facilities and purchase of long-term transmission rights on third-party transmission facilities.

The Companies are requesting Action Plan Approval to begin network upgrades required to support the development of the following.

GREENLINK NEVADA TRANSMISSION PROJECT

The Companies are continuing to develop Greenlink Nevada Transmission project, which consists of both Greenlink West and Greenlink North. Based on the BLM's permitting schedule, the Companies expect to begin construction on Greenlink West in December 2024. Greenlink West and the associated Common Ties are planned to be in service by May 31, 2027. Greenlink North and Harry Allen – Northwest component of Greenlink West are planned to be in service by December 31, 2028. As of the first quarter of 2024, the Companies have secured contracts or have received final proposals for all long-lead-time materials, transmission line construction, substation construction, and telecommunications construction. An updated forecast for Greenlink Nevada Transmission project based on received proposals and executed contracts is provided below in Figure TP-18.

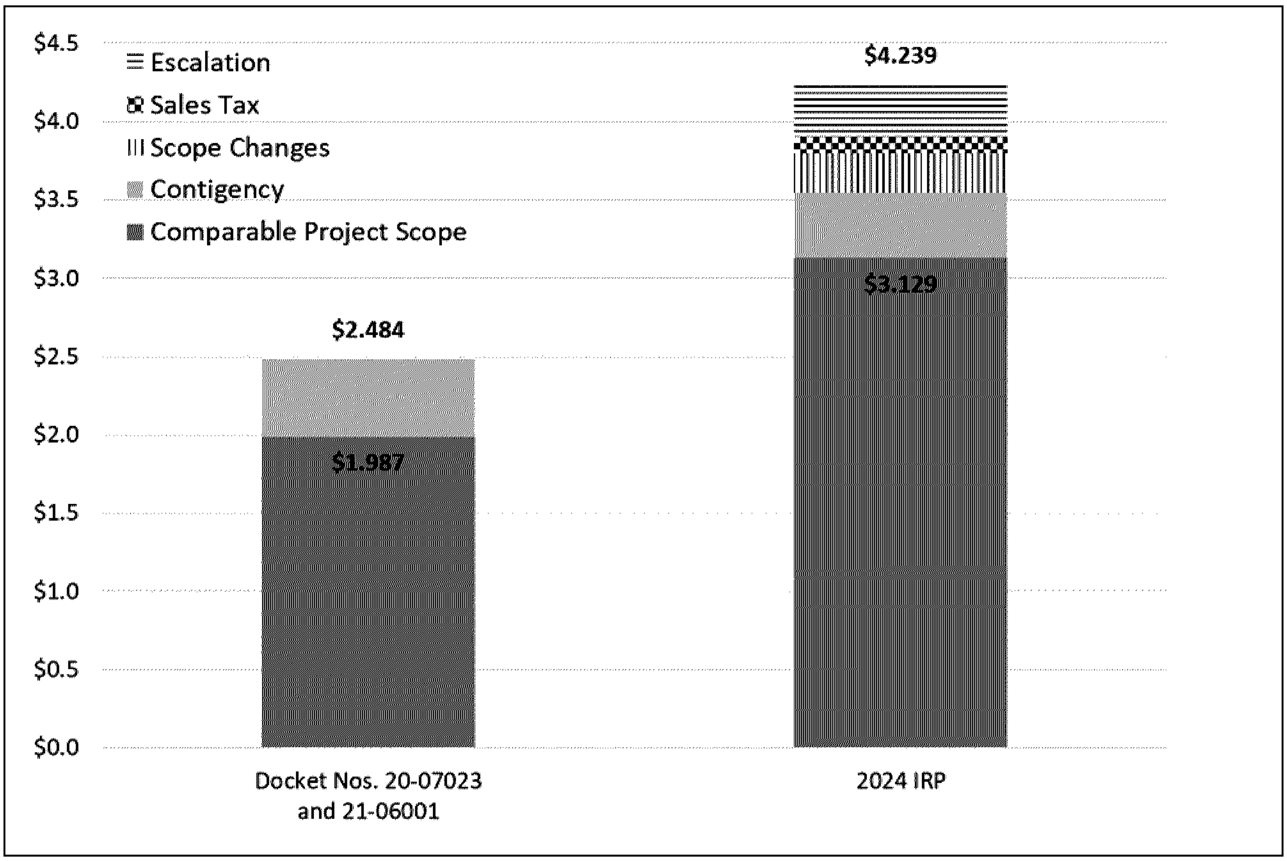
FIGURE TP-18
GREENLINK NEVADA TRANSMISSION FORECAST (EXCLUDES AFUDC)

	Original Estimate as Approved	July 2023 Update (Docket 23-08015)	May 2024 Update	Change from Original Estimate ($)	Change from Original Estimate (%)
Greenlink West	$1,219.9m	$1,415.1m	$1,904.7m	$684.8m	56
Greenlink North	$854.1m	$1,050.6m	$1,492.5m	$638.4m	75
Common Ties	$410m	$461.5m	$841.4m	$431.4m	101
Total	$2,484m	2,927.2m	$4,238.6m	$1,754.6m	71

The cost summary includes construction of Fort Churchill – Comstock Meadows #2 345kV transmission line, approval for which is being requested as a part of this filing. The Commission had previously approved permitting, preliminary design, and engineering for this line at a cost of $12.8 million. Construction costs associated with this requested for approval project ($97.4 million for construction only) are included in the forecast to provide a complete Greenlink forecast as of the date of this filing.

Figure TP-19 below provides a visual comparison of the cost categories within the original Greenlink estimates presented in Docket Nos. 20-07023 and 21-06001 and the updated estimate presented in this filing.

FIGURE TP-19
GREENLINK PROJECT COST INCREASE SUMMARY
(NOMINAL)



As Figure TP-19 shows, price increases in materials and labor contributed around $1,100 million to the estimated project price increase, as the Greenlink project was originally designed and scoped. The updated estimate also includes a $340 million escalation that is part of the executed contracts and proposals from 2024 through the anticipated completion of the Greenlink Nevada Transmission project in December 2028. For construction labor, the escalation is based on contractual increases in the International Brotherhood of Electrical Workers ("IBEW") Local 396 and Local 1245 wage rates through the project execution. For materials, the escalation is based on value of agreed upon commodity indices at the time of execution of the contract. Similar annual escalation is applied to non-IBEW labor (back office, project oversight and leadership) and equipment rental. Increases or decreases in an index value will be reflected as an increase or a decrease in the overall contract value, respectively. For escalation calculation on materials, the Companies have assumed an index value increase of 3.5 percent per year.

Further, the cost summary includes different contingency levels for Greenlink West, the common ties and Greenlink North. The contingency values are based on the Monte Carlo analysis performed on strategic risks associated with each segment of the project, with a 75 percent confidence interval. The updated estimate includes a $416 million contingency.

The Bureau of Land Management 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 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. The sales taxes are added after the proposals and associated charges are finalized.

Combined, the contingency ($416 million), escalation from 2024 through 2028 ($340.8 million), construction of Fort Churchill–Comstock #2 transmission line ($97.4 million), increase in the use of H-Frame structures ($124 million), increased environmental mitigation required by the Bureau of Land Management ($30.7 million), and sales and use taxes ($101 million) represent $1,109.9 million in costs as represented in this updated forecast.

The dark blue bars in Figure TP-19 (Materials, Labor, Land and Permitting) show an increase from $1.987 billion in the original estimate to $2.890 billion in this updated estimate for the Greenlink project as originally designed and scoped. Comparing the estimated costs to complete the project as originally scoped provides an apples-to-apples analysis of how the core estimated costs of Greenlink have changed since 2021. Based on the same project scope as in 2021, the estimated costs of Greenlink have increased by approximately 13 percent per year from 2021 to 2024. This is less than the cost increases experienced in the industry for transmission infrastructure over the same period. Based on the data supplied by the Bureau of Labor Statistics ("BLS”), the costs of equipment and labor have increased on average by 62 percent between 2021 and 2024, which translates to a compound annual growth rate of 17 percent. This average industry cost increase is derived by consulting (1) the BLS Producer Price Index (PPI) for categories representing the majority of the components that would contribute to Greenlink costs, including Electric Power and Specialty Transformer Manufacturing, Power Wires and Cables, Power and Distribution Transformers, and Switchgear and Switchboard Apparatus, and (2) BLS wage growth indices for Private industry construction workers. If the estimated cost of Greenlink grew at the same rate as the related PPIs, the most recent estimated cost of the project (based on the original scope and without sales tax, contingency, or escalation) would have grown from roughly to $3.18 billion, instead of to $2.89 billion. In other words, the change in the estimated costs for Greenlink between 2021 and 2024 is about $292 million lower than it would be if estimated costs had grown at the pace of the relevant PPI.

The Companies request approval to construct Greenlink based on the cost forecast provided above, as the Greenlink Transmission project continues to be the best option for the Companies to provide optimal resource options to its retail, interconnection, and network customers.

With contracts or firm proposals in place for construction services and long-lead-time materials that amount to $3,314 million, including sales taxes and shipping costs, the Companies are confident in the current forecast related to controllable items at this stage of the project.

For construction related services, the Companies have received proposals for transmission line construction, substation construction, and telecommunications construction from two technically qualified contractors. The Companies intend to negotiate contract terms and execute construction with the lowest-cost technically qualified bidder. The Companies also have an executed contract for comprehensive project services that include permitting, design, engineering, environmental monitoring, procurement support, material management, and construction oversight for the project.

For long-lead-time materials, the Companies have contracted or have received firm proposals from lowest cost technically qualified bidders for fixed series capacitors, steel structures, conductor, transformers, reactors, power circuit breakers, switches, shield wire, control enclosures, and microwave towers. Based on location and pricing of the materials, sales taxes and shipping costs have also been estimated and included in the forecast.

The Companies have included the estimated cost of escalation through the duration of the project to provide a fully comprehensive forecast. The risk-based contingency is allocated to the project to mitigate known strategic risks to the project.

To achieve higher construction efficiency and associated cost savings, the Companies are currently evaluating proposals for combined construction of transmission line, substations, and telecommunications infrastructure associated with the Greenlink Nevada Transmission project through a single technically qualified contractor.

As of the end of April 2024, the Companies have spent $213.3 million on Greenlink Nevada transmission project. By the end of 2024 the Companies forecast to spend $625.7 million on Greenlink Nevada transmission project.

Evaluation of Greenlink Nevada Alternatives

In Docket No. 20-07023, the Fourth Amendment to the 2018 IRP, a number of alternatives were evaluated to meet the need to expand the transmission system for the Companies to increase the import and export capacity and provide reliable service to their customers. Transmission capacity is also needed to access renewable energy zones that will be necessary to meet the state's renewable portfolio standard and clean energy goals. In addition, under the OATT, the Companies have an obligation to plan for the electric service to all existing and future network customers. Network customers, which take Network Integration Transmission Service ("NITS") under the OATT, are treated with the same priority as the Companies' native load and pay for transmission service based on their proportionate share of the total system load. The Companies' native load is the largest network customer. The import limit in northern Nevada is currently 1,275 MW and is fully reserved based on 150 MW of Transmission Reliability Margin, 600 MW of ON Line allocation and 525 MW of third-party firm reservations. The 525 MW of third-party reservations is forecasted to increase by 681 MW within 10 years. Investment in transmission infrastructure is the only possible way to increase the import into northern Nevada to meet this increasing transmission load growth. The addition of Greenlink West will increase the northern Nevada system limit to 2,000 MW which all this additional system import capacity except, for 44 MW, has been allocated to existing NITS customers based on prior queued transmission service requests.

In addition, FERC expanded the reliability-related elements of the federal regulatory structure beyond just the OATT when it implemented the reliability directives contained in the Energy Policy Act of 2005. FERC did this by instituting mandatory reliability standards that all users of the bulk electric system ("BES") must follow, including transmission providers.

The mandatory reliability standards, particularly NERC's TPL-001-4 standard, require the Companies to have a forward-looking transmission plan to reliably serve current and anticipated customer demands under all expected operating conditions, including normal system operations (all system elements in service) and during system contingencies (where multiple elements of the transmission system are out of service), both planned or otherwise.

The Companies perform annual reliability assessments to determine whether the transmission system complies with minimum mandatory system performance standards, which require that during loss of any single transmission system element ("N-1 single contingencies") that firm service is maintained, no system overloads exist, and there is no loss of customer demand. The Companies must also plan how they will respond to the second outage (this type of scenario is referred to as an N-1-1 condition). Greenlink has been included in the Companies' annual TPL-001-4 assessment as part of their short- and long-term plans to dependably meet NERC and WECC reliability requirements. The Greenlink segments are particularly effective in increasing system reliability under the various multiple contingency categories of the TPL-001-4 standard.

In addition, the base load forecast for northern Nevada forecasts that the peak load will increase by 1,615 MW over the next 10 years. The Companies are planning resource additions to serve this level of load growth. However, there are also executed Rule 9 agreements for 4,000 MW of additional load and an additional 6,000 MW of proposed load additions in northern Nevada over the next 10 years. The Companies do not expect all of these loads to actually materialize. However, if actual load growth is higher than forecast, the Greenlink Nevada Transmission project provides additional system import capacity that can be used to serve the load growth. Without the additional system import capacity, it likely will not be possible to serve additional load growth beyond the load forecast.

Much of the additional generation being proposed to serve the forecasted load growth in northern Nevada is solar PV resources. During winter storms, there can be extended periods of cloud cover and snow. Energy output from these facilities could be curbed for a number of days due to weather conditions. The Greenlink Nevada Transmission project provides additional system import capacity that can be used to serve the load with resources from other regions that may not be impacted by weather. Without the additional system import capacity, it may not be possible to serve all of the load in northern Nevada during periods when solar PV generation is not producing at its full output for extended periods due to weather conditions.

Due to the forecast in cost increases required to construct the Greenlink project, the Companies have reevaluated whether there is a lower cost transmission alternative that would provide the benefits provided by the Greenlink project. In Docker No. 20-07023, the Companies evaluated nine transmission alternatives to provide additional transmission capacity. These alternatives included:

#1: Falcon to Midpoint 345 kV line. This 230-mile 345 kV project would provide a second parallel line from the Companies' system into Idaho Power. Midpoint Substation has the electrical strength to support this additional interconnection, however, currently Midpoint is not a major transactional hub for energy trading. This project would be within Department of Energy defined 368 corridors.

#2: Robinson to Valmy 345 kV line. This 210-mile 345 kV project would provide a second parallel line from the Companies' system into Robinson Summit Substation. Because both terminations of this project are internal to the Companies, it does not access new electric providers. Both Valmy and Robinson Summit Substations have the electrical strength to support this additional interconnection. Currently neither location is a major transactional hub for energy trading however, with the planned reinforcements of the TransCanyon's Cross-Tie and/or SWIP-North facilities, Robinson Summit Substation could become a major trading hub. This project would not be within Department of Energy defined 368 corridors. Initial environmental analysis was performed for the existing line in 2003 but these studies will provide a limited base for permitting and need to be updated.

#3: Alturas 345 kV Reinforcement. This project would reinforce the existing Alturas 345 kV intertie by constructing a 70-mile Captain Jack to Hilltop 345 kV line, and 45-mile East Tracy to Fort Sage 345 kV line. Captain Jack Substation is considered part of the California Oregon Border trading hub, so an interconnection at the substation would access multiple new electric providers. In addition, Captain Jack Substation has the electrical strength to support this additional interconnection but would require significant substation upgrades to support the addition of a 525 to 345 kV XFMR and 345 kV terminals. This project would significantly help voltage regulation for the Reno area loads. Some elements of his project would be within Department of Energy defined 368 corridors. Some of these identified segments are defined as corridors of concern by the Department of Energy so permitting complexity would be higher. Additionally, the Tracy to Fort Sage segment is locally defined but not a Department of Energy 368 corridor.

#4: Ft. Churchill to Robinson 525 kV line. (Greenlink North) This already approved 235-mile project will provide a second parallel line from Robinson Summit Substation to Fort Churchill, effectively strengthening the existing ON Line 525 kV project. Because both terminations of this project are internal to the Companies' system, it does not access new electric providers. Robinson Summit has the electrical strength to support this additional interconnection and, as discussed above, with the planned reinforcements of the Cross-Tie and/or SWIP-North facilities, Robinson Summit could become a major trading hub. Fort Churchill, however, would need to be upgraded to both 525 kV and 345 kV and interconnected to the Reno area 345 kV facilities. This project would not be within Department of Energy defined 368 corridors but would follow existing transmission.

#5: Ft. Churchill to Northwest to Harry Allen 525 kV line (Greenlink West). This already approved project will provide a new line within the Companies' system by providing a second strong path between northern and southern Nevada on the western part of the state. This interconnection here would not access new electric providers. Harry Allen has the electrical strength to support this additional interconnection but Fort Churchill would need to be upgraded to 525 kV and 345 kV and interconnected to the Reno area 345 kV facilities. This project would be within Department of Energy defined 368 corridors. One of the identified segments is defined as a Corridor of Concern by the Department of Energy. This segment is within Clark County around the Northwest Substation. Permitting of this segment will be highly complex. This line route is adjacent to three Bureau of Land Management identified Solar Energy Zones that currently have no significant transmission for interconnection. These Solar Energy Zones are Millers, Gold Point and Amargosa

Valley. Over 29,000 total acres have been identified as developable through this designation process at these sites.

#6: Ft. Churchill to Captain Jack 525 kV line. This 300-mile project would provide a new line from the Companies' system into Captain Jack Substation. As stated above, Captain Jack is considered part of the California Oregon Border trading hub so an interconnection at this substation would access multiple new electric providers. Captain Jack has the electrical strength to support this additional interconnection but Fort Churchill would need to be upgraded to 525 kV and 345 kV and interconnected to the Reno area 345 kV facilities. This project would be within Department of Energy defined 368 corridors. Some of the identified segments are defined as Corridors of Concern by the Department of Energy so permitting complexity would be higher.

#7: Robinson to Midpoint 525 kV (SWIP-N). This 280-mile 525 kV project would provide a new line from the Companies' system at Robinson Summit to Midpoint. Because both terminations of this project are existing points of energy receipt for the Companies, the project does not access new electric providers. Both Midpoint and Robinson Summit have the electrical strength to support this additional interconnection. Currently, neither location is major transactional hub for energy trading. While this project does enhance ON Line capacity in both directions, it essentially bypasses the northern system and provides little to no additional import capacity. This project would be within Department of Energy defined 368 corridors. Several segments are defined as Corridors of Concern by the Department of Energy. LS Power has secured significant permitting for this project and is currently planning to move forward with the construction of this project.

#8 Robinson to Clover 525 kV (Cross-Tie). This project would provide a new 215-mile line from the NV Energy system at Robinson Summit to the planned Clover Substation in central Utah. Because both terminations of this project are existing points of energy receipt for the Companies, the project does not access new electric providers. Both Mona and Robinson Summit have the electrical strength to support this additional interconnection. Currently, neither location is major transactional hub for energy trading. While this project does enhance ON Line capacity in both directions, it essentially bypasses the northern system and provides little to no additional import capacity. This project would be within Department of Energy defined 368 corridors. Several segments are defined as Corridors of Concern by the Department of Energy.

#9: Robinson to Harry Allen #2 (ON Line #2). This 231-mile project would provide a new line in parallel with the existing ON Line project between Robinson Summit and Harry Allen. Because both terminations of this project are existing, it does not access new electric providers. Harry Allen has the electrical strength to support this additional interconnection. Currently, Robinson Summit does not. If both Cross-tie and SWIP-N are constructed, NV Energy would likely capture significant Point-to-Point revenues by constructing this line. This project would be within Department of Energy defined 368 corridors. Several segments are defined as Corridors of

Concern by the Department of Energy. NV Energy has secured a record of decision on this path that is currently held in abeyance by the Bureau of Land Management.

In Docket No. 20-07023, a detailed evaluation of each of the above transmission alternatives was performed to determine that the Greenlink project was the best alternative to provide the necessary transmission capacity. This evaluation was provided as technical appendix TRAN-1 in that filing. The information provided in Docket No. 20-07023 TRAN-1 has been revised and a copy of this technical appendix is provided in the filing also as technical appendix TRAN-1. In Docket No. 20-07023, a scoring system was developed for ranking the transmission options based on several factors, the result of this scoring is shown in Figure TP-20 below.

FIGURE TP-20
TRANSMISSION OPTIONS COMPARISON MATRIX

Transmission Options Analysis Matrix												
#	Project	Increases Import <100=0, 100-500=1, 500-1000=2	Renewable Integration in Nevada	Nevada Joint Dispatch	Relieves Congested Path	Accesses Existing Available Capacity	Facilitates Fossil Fuel Retirement	No Third Party Transmission Rate	Supports Major Load Pockets, Reno & Tracy	Access to Renewable Energy Zones	Follows existing Transmission	Total Score
1	Falcon - Midpoint 345kV	1	0	0	0	0	1	0	0	0	1	**3**
2	Robinson - Valmy 345kV	1	0	1	0	1	1	1	0	0	1	**6**
3	Alturas 345kV Capacity Upgrade	1	0	0	0	0	0	0	0	0	0	**1**
4	Fort Churchill - Robinson 525kV	2	1	1	0	1	1	1	1	0	1	**9**
5	Fort Churchill - Northwest - Harry Allen 525kV	2	1	1	1	1	1	1	1	1	0	**10**
6	Fort Churchill - Captain Jack 525kV	2	1	0	0	0	1	0	1	0	0	**5**
7	Robinson - Midpoint 525kV (SWIP North)	0	0	0	0	0	0	0	0	0	0	**0**
8	Robinson - Clover 525kV (Cross-Tie)	0	0	0	0	0	0	0	0	0	0	**0**
9	Harry Allen - Robinson 525kV #2 (ON Line #2)	0	0	0	1	1	0	1	0	1	1	**5**

The Greenlink project remains the best alternative to meet the Companies' future transmission needs. Although the Greenlink transmission project has experienced significant cost escalation, there is no reason to believe that any of the other transmission alternatives would not also experience similar cost escalation. As stated above, the industry for transmission infrastructure has experienced costs increases in excess of those estimated for Greenlink between 2021 and 2024, 17 percent annually for the industry versus 13 percent for Greenlink.

The only other potential alternative to the construction of Greenlink is the construction of additional generation closer to the load centers. This alternative, named the No Greenlink illustrative case, is also evaluated in this filing. However, this alternative would not provide any additional system import and export capacity, transfer capacity between northern and southern Nevada or the ability to access additional renewable energy zones. It would also not meet the Companies' obligations under the OATT to provide necessary system import capacity to serve the forecasted load growth for transmission Network customers. Thus, this alternative is being presented for illustrative purposes only.

The evaluation of constructing additional generation capacity closer to the load center showed that generation additions at Amargosa, Esmeralda and Lander are required. To connect this generation to the load, the Amargosa-Northwest, Esmeralda-Ft. Churchill, Lander-Ft. Churchill and the Common Ties segments of the Greenlink project would still be needed. There are potentially adequate renewable resources at Esmeralda to meet the resource requirements for northern Nevada. Placing all of the resources at Esmeralda would eliminate the need for a generator lead line from Lander. However, this would result in up to 1,200 MW of generation on a single radial generator lead line. A N-1 contingency that resulted in the loss of this line would result in the loss of 1,200 MW of generation in northern Nevada. This would overload the remaining tie lines in northern Nevada likely resulting in a collapse of the northern Nevada system. This would be a violation of the NERC transmission planning criteria. The estimated cost of these transmission segments is shown in the Figure TF-21 below. Figure TP-22 presents a relevant map of the Nevada transmission pathways.

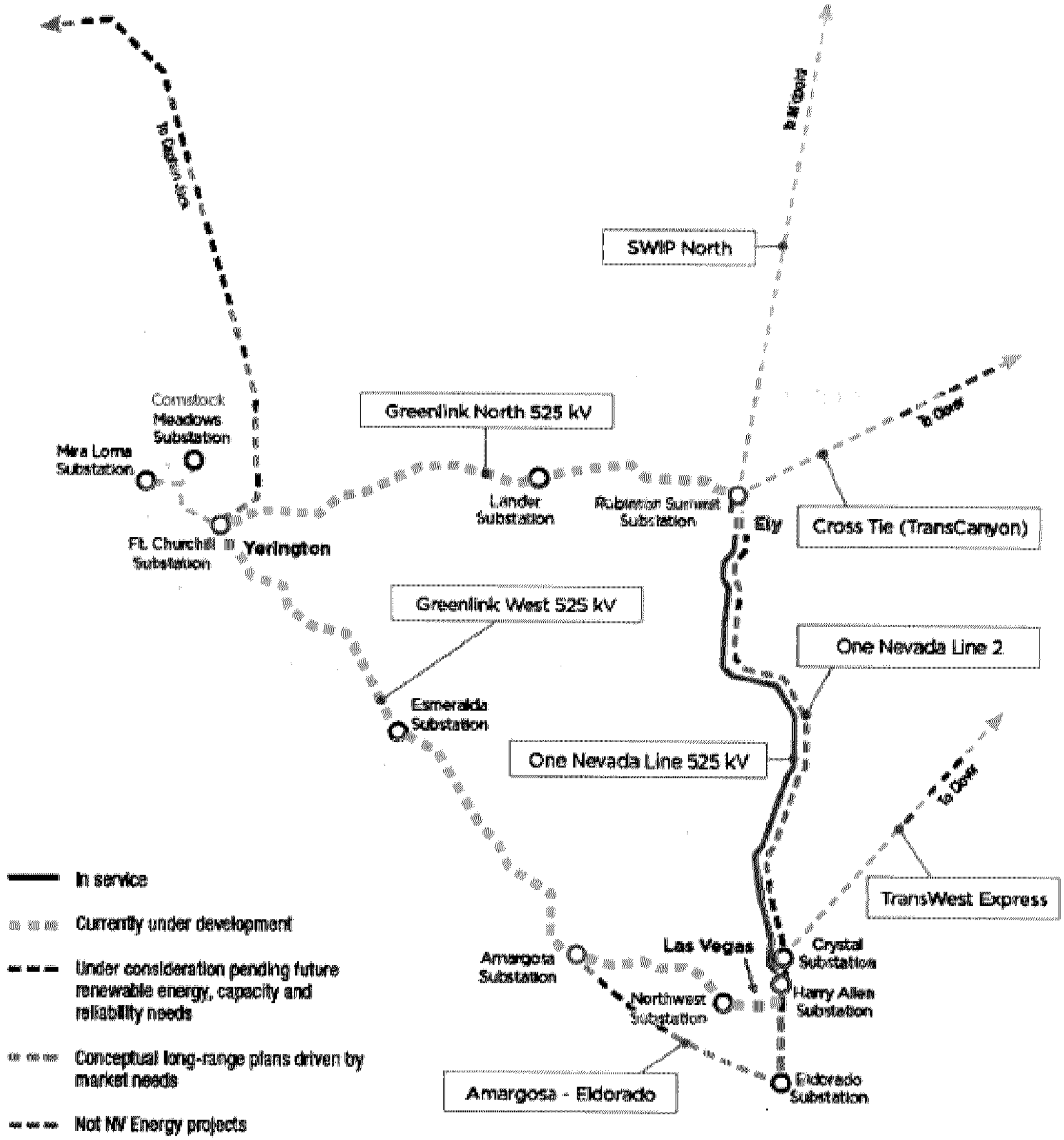
FIGURE TP-21
NO GREENLINK CASE TRANSMISSION SEGMENT COST TO INTERCONNECT GENERATION[15]

FACILITY	FORECAST
Amargosa to NPC:	**683,202,565**
Amargosa 525 kV Substation with planned FSC and Reactors	208,300,904
Amargosa-Northwest 525 kV transmission line	363,026,126
Northwest 525 kV Substation expansion with planned FSC and Reactors	111,875,536
Esmeralda to SPPC	**674,353,132**
Esmeralda 525 kV Substation with planned FSC and Reactors	178,831,133
Esmeralda 230 kV Buildout	45,395,392
Esmeralda to Fort Churchill 525 kV transmission line	450,126,608
Lander to SPPC	**900,372,442**
Lander 525 kV Substation with planned FSC and Reactors	187,570,727
Lander 230 kV Buildout	76,671,306
Lander to Fort Churchill 525 kV transmission line	636,130,409
Common Ties	**828,808,910**
Ft Churchill 525/345/230/120 kV Substation with planned FSC and Reactors	442,906,057
Mira Loma to Ft Churchill 345 kV line w/Mira Loma Substation expansion	151,144,588
Comstock Meadows to Ft Churchill 345 kV line #1 w/Comstock Meadows Substation expansion	129,142,844
Comstock Meadows to Ft Churchill 345 kV line #2 w/Comstock Meadows Substation expansion	105,615,420
TOTAL	**3,086,737,050**

The Figure TP-21 demonstrates that pursuing a generation-based alternative to Greenlink still results in significant transmission costs without providing the comprehensive benefits of Greenlink. The Economic Analysis Section of the Narrative provides a detailed analysis of the No Greenlink illustrative case.

[15] The estimates represented in this table are based on development of individual transmission and substation segments of Greenlink required to interconnect generation in a "no-Greenlink" case. These estimates are different compared to comprehensive Greenlink forecast if the Greenlink transmission project was fully developed.

FIGURE TP-22
REGIONAL TRANSMISSION PROJECTS CONNECTING TO NV ENERGY



Critical Facility Designation

The Commission may designate a facility as a critical facility for the purpose of:

(a) Protecting reliability;
(b) Promoting diversity of supply and demand side sources;
(c) Developing renewable energy resources;
(d) Fulfilling specific statutory mandates;
(e) Promoting retail price stability; or

(f) Any combination of paragraphs (a) to (e), inclusive.

The Commission has already designated Greenlink North and the Harry Allen to Northwest 525 kV project as critical facilities.16 NV Energy has an obligation to maintain required system reliability. The Greenlink project is required to protect system reliability. All recent transmission planning studies have included the Greenlink project. Without the Greenlink project, it may not be possible to comply with mandatory reliability standards and the system would not have the required level of flexibility to respond to potential system contingencies. The Greenlink project promotes diversity of supply by allowing for the interconnection of a diverse range of resources including additional renewable energy resources and conventional thermal generation. It also allows for the transfer of energy between northern and southern Nevada. Greenlink is critical to the development of additional renewable energy resources. It provides access to renewable energy resources located at located at Amargosa, Esmeralda and Lander Substations. For the illustrative generation expansion without Greenlink plan, it was still necessary to build 2/3 of the Greenlink West and half of Greenlink North projects to access these resources. The Greenlink project is needed to fulfill statutory mandates. It is needed to comply with the Renewable Energy portfolio standard and it is also needed to comply with FERC OATT provisions that require transmission expansion to provide additional system import capacity for NITS customers. The Greenlink project is needed to promote retail price stability. It allows for the development of the most economic portfolio of generation resources. As shown in the Economic Analysis section of the filing and in Brattle's analysis, it also allows for the economic exchange of power between northern and southern Nevada and external markets resulting in substantial cost savings for retail customers. Therefore, the Commission should designate the remaining portions of Greenlink as critical facilities, which include Greenlink West and common ties.

<u>Critical Facility Incentives</u>

The Companies are requesting to use two of the incentives allowed under the critical facility designation: (1) construction work in progress ("CWIP") in rate base during construction and (2) deferral of the depreciation expense into a regulatory asset from the time the Greenlink projects are put in service until they are put in rates. The requested accounting mechanisms provide financial support to the Companies until the Companies have the ability to get the Greenlink costs into rates. The financial support can be necessary to avoid any further credit downgrades as Sierra was recently downgraded from Baa1 to Baa2 and one of the reasons was related to not obtaining regulatory support for a project construction phase.

The Companies are requesting the CWIP in rate base incentive to shore up their financial strength and generate higher cashflows for the Companies during the construction phase. Requesting this incentive is a prudent financial decision to utilize the mechanisms in place to provide the financial

[16] Docket No. 21-06001, November 26, 2022, Order at 9-10.

support and help withstand any future downgrade that could happen barring any unforeseen financial event. It is good business practice to be prepared in the event of adversity, versus reacting when it might be too late. For example, since the Companies are subject to seasonal weather conditions, a year or two of mild, below normal, weather can impose significant pressure on the Companies' cash flows and, subsequently, exert more pressure on the credit metrics. Constructing Greenlink will involve significant construction expenditures and, without CWIP in rate base or favorable cost recovery until the project is in rates, it will put additional pressure on the Companies' credit metrics. Sierra has already been downgraded. It is important to ensure that Nevada Power does not get downgraded next or, even worse, Sierra gets downgraded again. Allowing CWIP in rate base has traditionally been a solution for this circumstance.

CWIP in rate base can provide a cost benefit to customers. The Companies conducted modeling that demonstrates that, over the life of the Greenlink projects, having CWIP in rate base is a benefit to customers as the resulting overall present worth of revenue requirement is lower than with the traditional AFUDC method. The modeling did not include higher interest costs if the Companies were to be downgraded from their current ratings. Therefore, there could be even more benefits that are not modeled in this case. This was modeled to show that, even in the current conditions, there is a benefit to customers for CWIP in rate base.

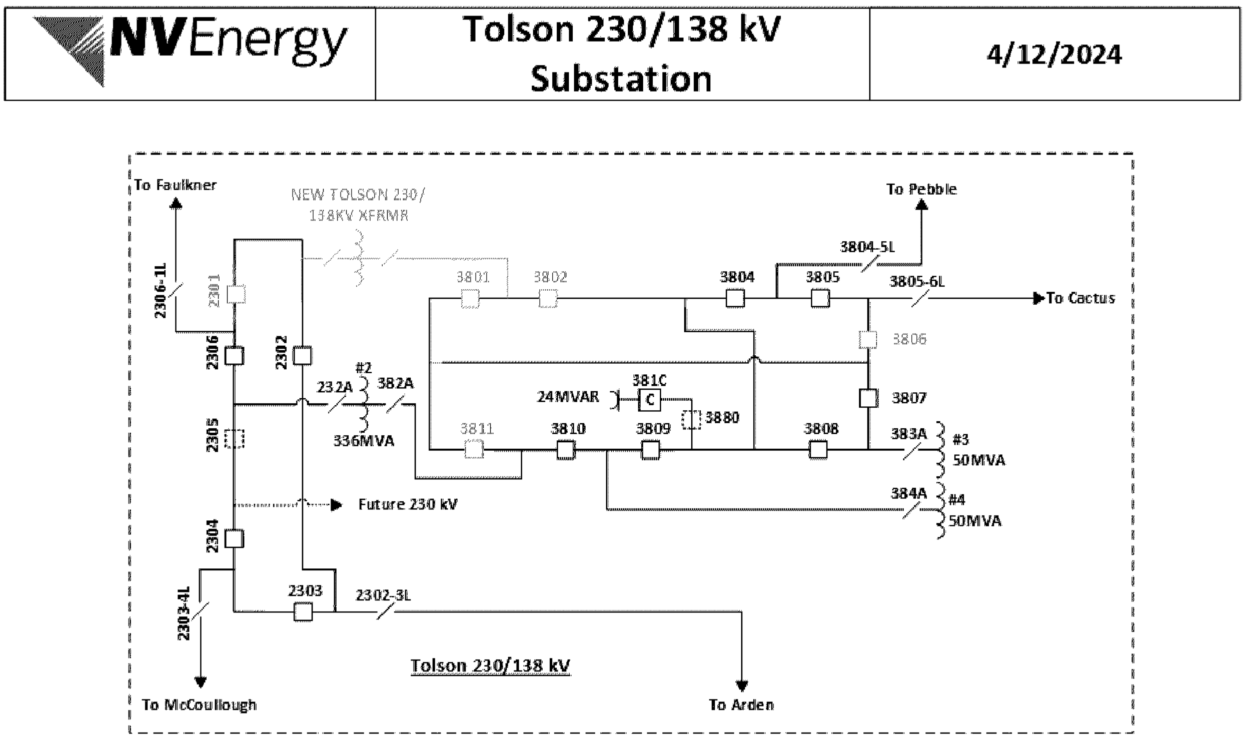
In addition, the Companies are requesting approval to include the Greenlink depreciation expense in a regulatory asset, with no carrying charges. The regulatory asset will record depreciation expense from the Greenlink projects' in-service date until the costs of the Greenlink projects are included in rates. The depreciation expense is part of the Companies' costs to construct the projects. Accordingly, the Companies are requesting just recovery of all their costs to construct. This project is distinguishable from many other projects because of the significant cost to construct. In addition, as Nevada Power and Sierra are precluded from having more than one rate case pending at the same time, and the Greenlink costs are split between the Companies, it is inevitable that a substantial portion of the Greenlink projects costs will face a significant regulatory lag. Authorizing the requested regulatory asset allows for recovery of the depreciation costs that will be incurred by the Companies.

TOLSON SUBSTATION 336 MVA 230/138 KV TRANSFORMER #1

The Companies are required to install the Tolson 336 MVA 230/138 kV transformer #1 due to a NERC TPL-001-5 corrective action plan. This second transformer will mitigate the overloads associated with each of the various P1 (N-1) events observed in the 2027 sensitivity planning case. The Companies request approval to install a second transformer at Tolson Substation required per transmission planning standards and native load growth.

Construction Scope: Install a second 336 MVA 230/138 kV transformer at Tolson Substation with the associated bus work, disconnect switches, breakers control house protection panels, communications and controls.

FIGURE TP-23
ONE LINE DIAGRAM OF TOLSON SUBSTATION



Budget and Cost Responsibility: The Companies will be responsible for the cost associated with the addition of the transformer at Tolson Substation because it is required for system reliability as identified by NERC. Figure TP-24 shows the total project costs.

FIGURE TP-24
PROJECTED CASH FLOWS FOR
TOLSON SUBSTATION 336 MVA 230/138 KV TRANSFORMER #1

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
9.60	0.00	1.00	0.50	8.00	9.50	0.10

REID GARDNER – HARRY ALLEN 230 KV LINE #3

The permitting of Reid Gardner – Harry Allen 230 kV line #3 was previously approved in the Companies' Fourth Amendment to its 2021 IRP, Docket No 22-11032. The new 230 kV line will double the firm transmission capacity between the Reid Gardner and Harry Allen Substation from 860 MVA to 1,720 MVA. The #3 line will be financially secured as required by the customer's large generator interconnection agreement ("LGIA"). The area around Reid Gardner Substation has more than 3,500 MW of large renewable generation projects that have requested interconnection at Reid Gardner Substation. The existing Reid Gardner – Harry Allen line's unsubscribed capacity is less than 50 MW. This new 230 kV line will provide an opportunity for 860 MW of renewable generation to become viable alternatives in future resource plans.

The construction of Reid Gardener – Harry Allen 230 kV line #3 will cause a NERC TPL-001-5, P7 violation. This is because the Reid Gardner – Harry Allen #1 and Reid Gardner – Harry Allen #2 230 kV lines are on doubled circuit poles near Harry Allen Substation. Therefore, a single structure's failure is a plausible N-2 contingency (or P7). When the #3 line is placed in service and then the N-2 (or P7) contingency occurs all the power from the Reid Gardner Substation's new generators flows on the remaining #3 line which then overloads. This N-2 (or P7) will be mitigated by separating #1 and #2 lines onto single circuit poles as part of the construction scope of the #3 line. The Companies request approval to construct Reid Gardner – Harry Allen 230 kV line #3 to increase transmission capacity for new renewable generation resources as required per customer's LGIA.

Construction Scope: Construct a new 230 kV transmission line with line terminals at Reid Garnder and Harry Allen Substations, with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. The new line will be approximately 25 miles. A map of the proposed line is shown below in Figure TP-25, one-line diagrams of Reid Gardner Substation and Harry Allen Substation are included below in Figures TP-26 and TP-27, respectively.

FIGURE TP-25
PROXIMITY MAP REID GARDNER – HARRY ALLEN 230 KV LINE #3

FIGURE TP-26
HARRY ALLEN 230 KV BUS

NVEnergy	Harry Allen 230 kV Substation	4/12/2024

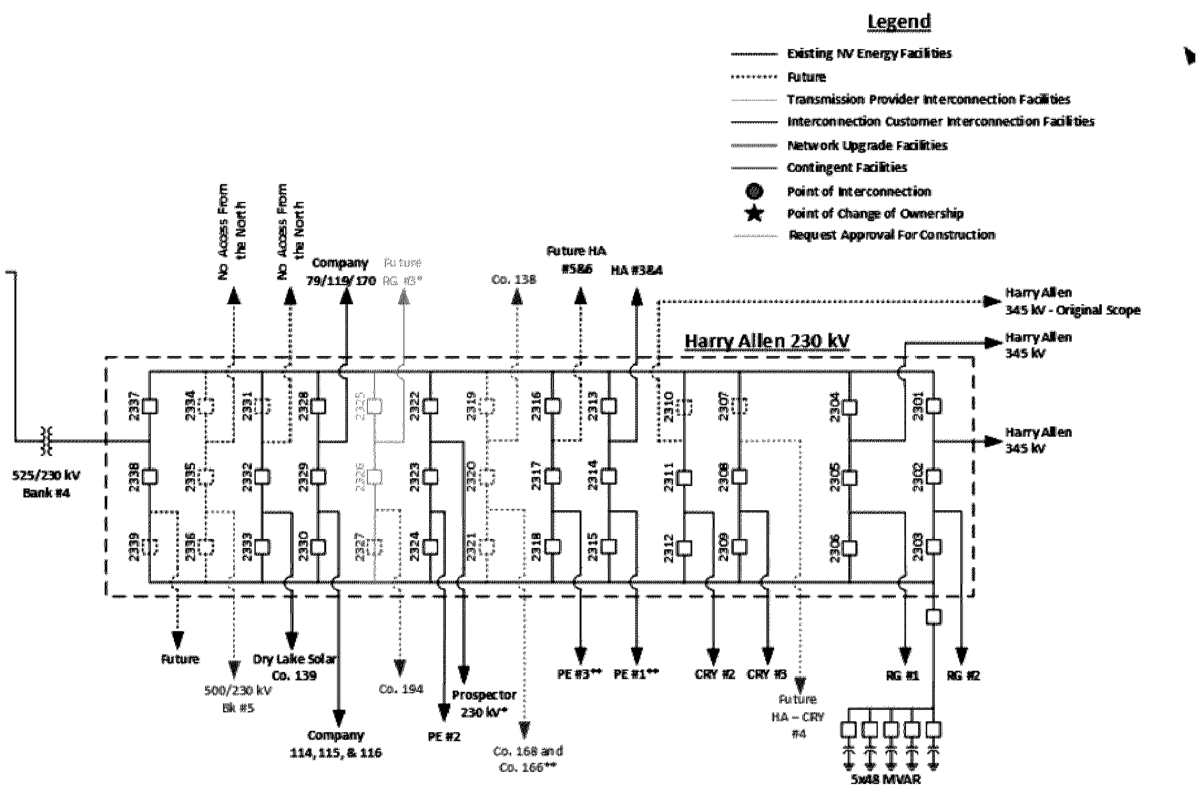
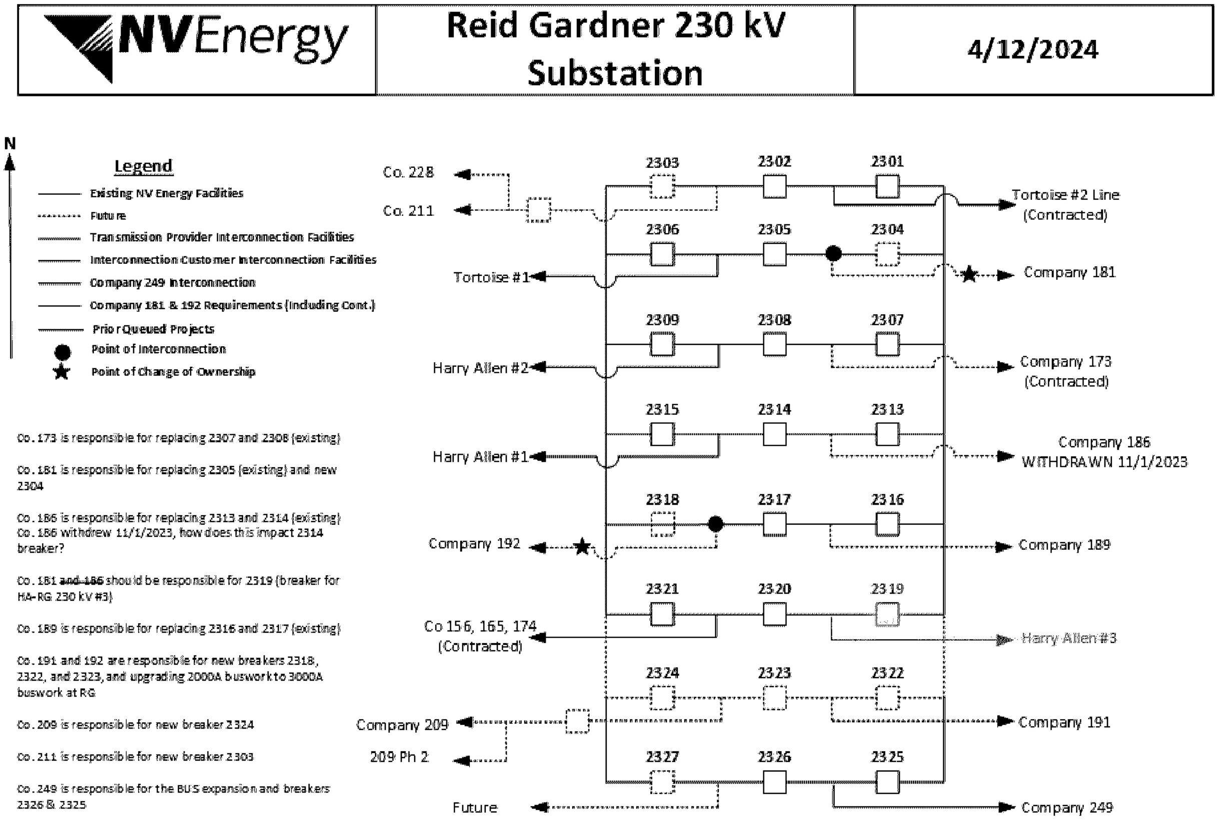


FIGURE TP-27
HARRY ALLEN 230 KV BUS



Budget and Cost Responsibility: The Companies will be responsible for the cost associated with the construction of the Reid Gardener – Harry Allen 230 kV line #3, as they are considered Network Upgrades under the OATT. However, the interconnection customer will be responsible for the cost of the rights of way and to securitize the project. The projected costs are shown in Figure TP-28.

FIGURE TP-28
PROJECTED CASH FLOWS FOR REID GARDNER – HARRY ALLEN #3 230 KV LINE

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
24.20	0.00	10.10	14.10	0.00	24.20	0.00

LANTERN – COMSTOCK MEADOWS 345 KV LINE

The Lantern – Comstock Meadows 345 kV line is important infrastructure for the TRIC/Fernley area master plan for load service and new generation resources. This line's permitting was approved as part of the Fernley Area Master Plan in the Companies' Fourth Amendment to their 2021 IRP, Docket No. 22-11032. The new line will be routed to pass adjacent to the future Vaquero Substation, Veterans Substation and the existing Chukar Substation and future Viking Substation so that the line can be folded into these substations as the loads come on line. Sierra Solar generation is limited to 400 MW until Lantern - Comstock Meadows 345 kV line is in service. The Companies have entered into LGIAs for the Sierra Solar 1,000 MW projects that require the construction of Lantern – Comstock Meadows 345 kV line to deliver the generation reliably. NV Energy would wait to construct this line until Sierra Solar 600 MW phase II is approved. Except that, Lantern – Comstock Meadows 345 kV line is also a contingent facility for most of the Rule 9 customers in this area, who have recently signed their high voltage distribution ("HVD") and master planned community ("MPC") agreements. The Companies now request approval to construct the Lantern – Comstock Meadows 345 kV line for both the load growth and future generation resource.

Construction Scope: Construct a new 345 kV line with terminals at both Lantern Substation and Comstock Meadows including breakers, disconnection switches, dead end structures, control house protection panels, communications, and controls equipment. The new 345 kV line will be approximately 30 miles long. One line diagrams are shown in Figures TP-29 and 30.

FIGURE TP-29
525 KV & 345 KV LINE DIAGRAM OF TRANSMISSION PLAN

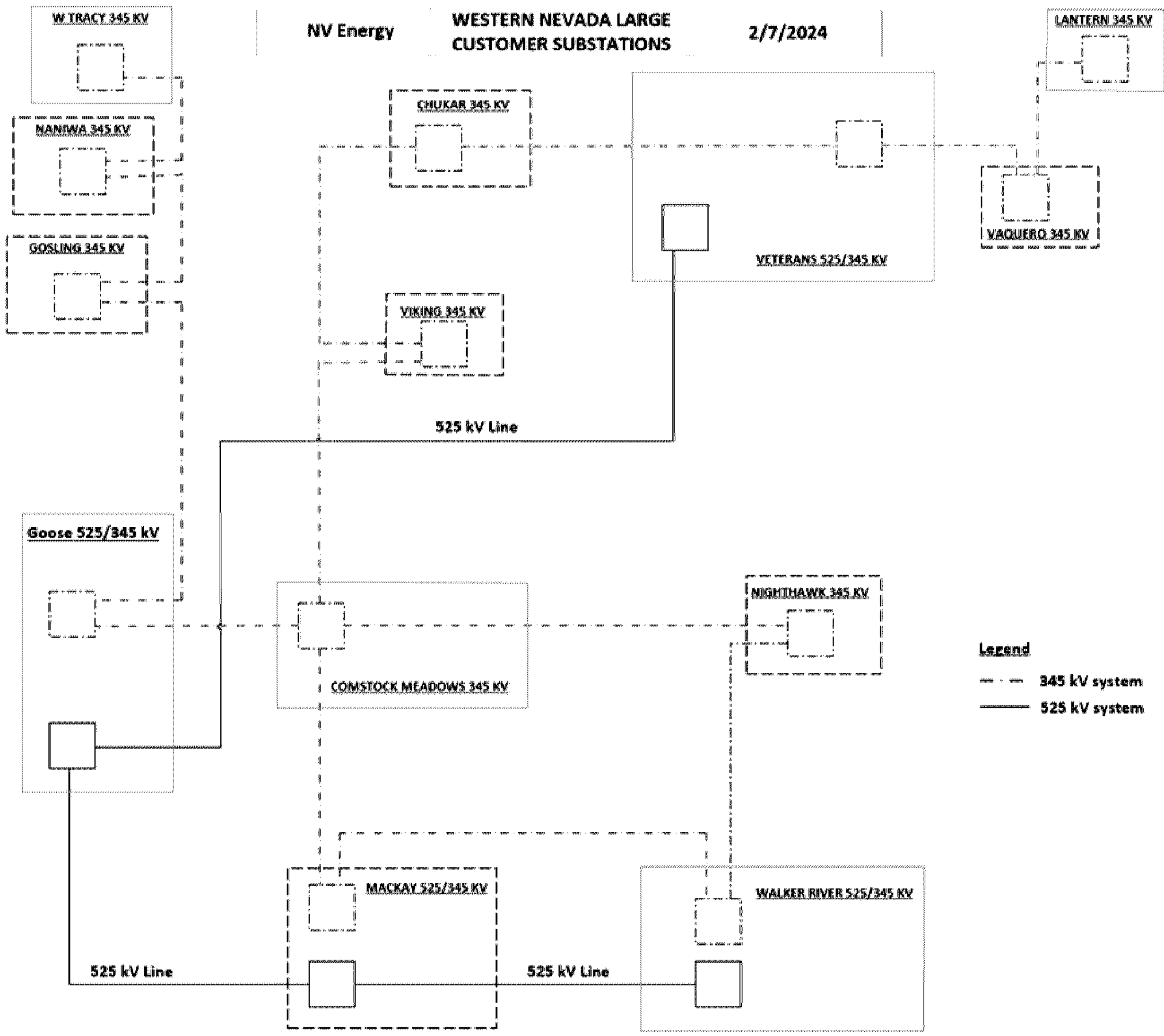
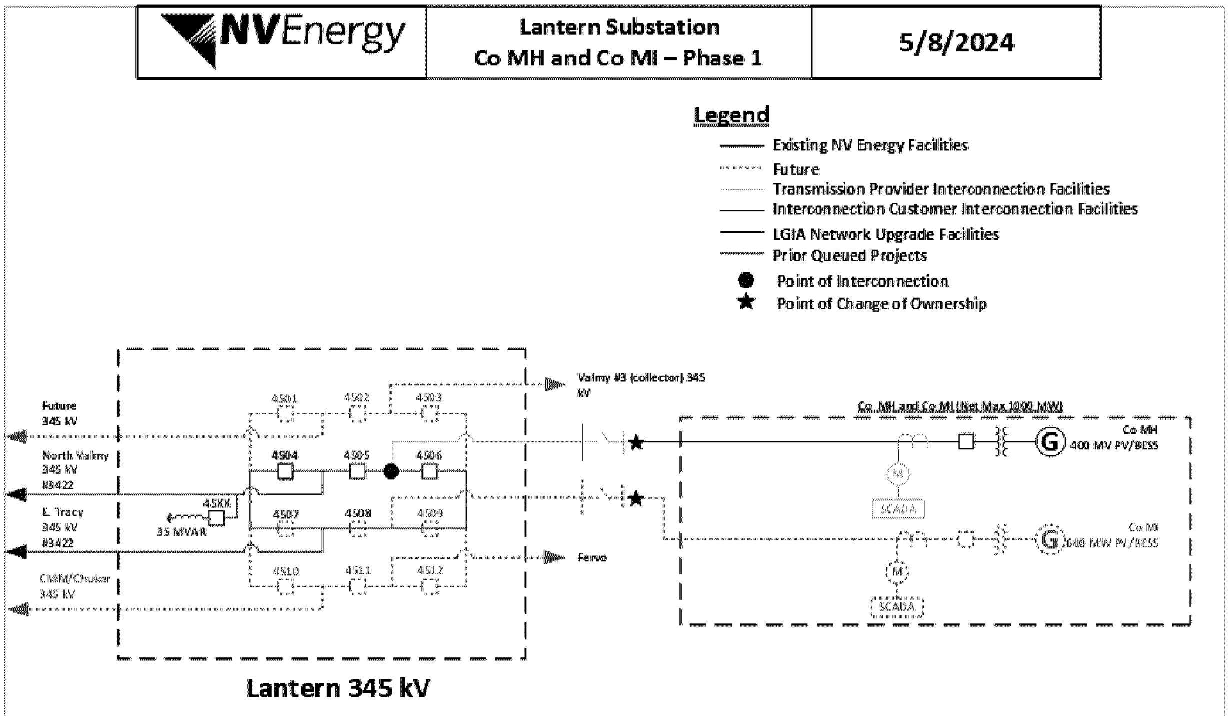


FIGURE TP-30
LANTERN SWITCHING STATION 345 KV BUS DIAGRAM



Budget and Cost Responsibility: The Companies will be responsible for the cost of building the Lantern – Comstock Meadows 345 kV line. Sierra Solar as part of the LGIA will be responsible for paying for the acquisition of all associated rights of way in coordination with the Companies. The projected costs for the project are shown in Figure TP-31.

FIGURE TP-31
PROJECTED CASH FLOWS FOR LANTERN – COMSTOCK 345 KV LINE

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
105.00	0.00	0.00	1.05	10.50	11.55	93.45

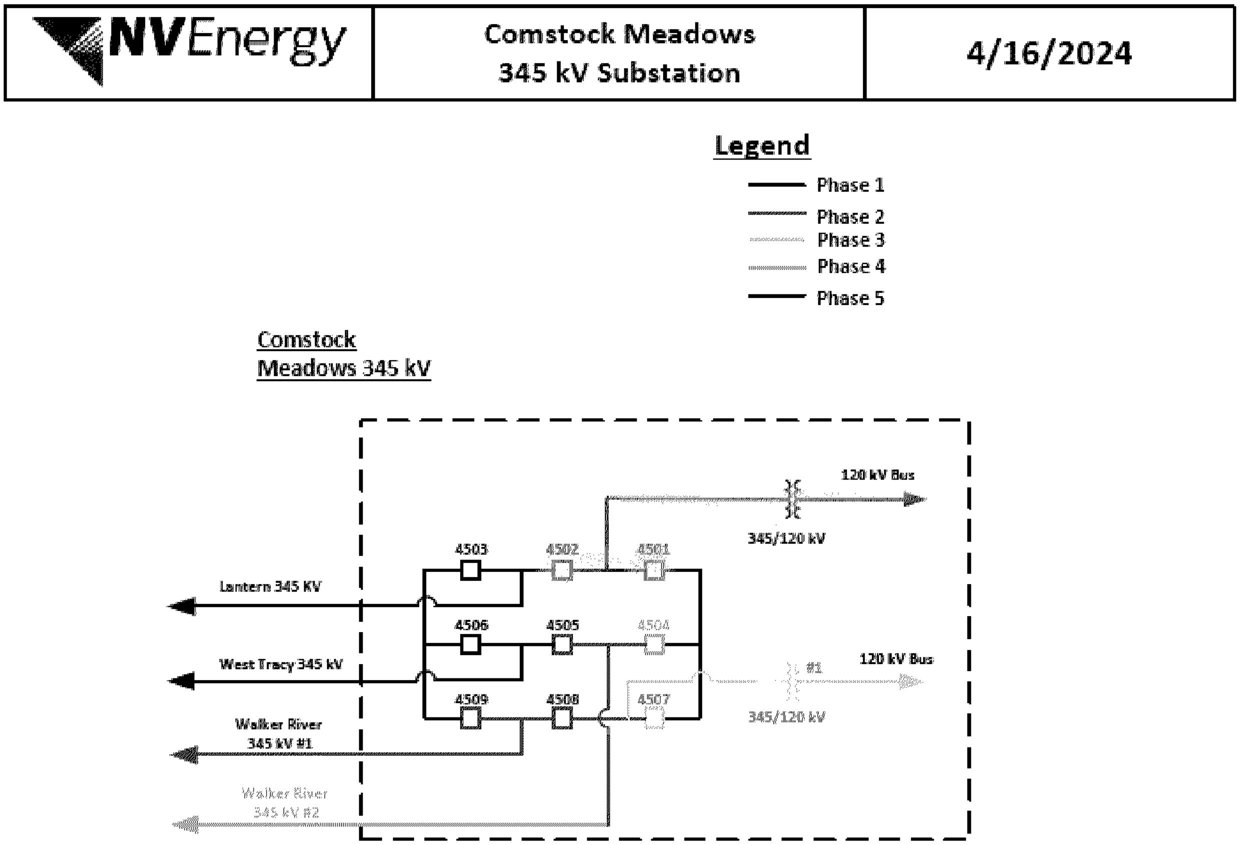
COMSTOCK MEADOWS SUBSTATION 280 MVA 345/120 KV TRANSFORMER #2

The Companies will need to install the Comstock Meadows 280 MVA 345/120 kV transformer #2 as required in the customer load studies or when existing customers loads on the Comstock Meadows 120 kV reach between 460 MW and 500 MW, depending on the locations of the loads. The timing of this transformer's construction approval request is based on the current customer[17] load forecast of the existing customers in and around TRIC. Transformer lead times are approaching three years therefore the Commission cannot delay this transformer's approval without also delaying the corresponding customers' business plans. If the customers' 120 kV loads fail to materialize as forecasted, it may be possible to delay the transformer installation. It is required to get this transformers construction approval at this time to accommodate all the customers' requests. The Companies will conduct an annual review of the requests to determine if it is appropriate to delay or accelerate the various scheduled projects. The Companies request approval to construct Comstock Meadows 345/120 kV 280 MVA transformer #2 to serve the native customer loads in 2027.

<u>Construction Scope</u>: Install a second 345/120 kV 280 MVA transformer at Comstock Meadows Substation with the associated bus work, disconnect switches, breakers control house protection panels, communications, and controls equipment. A one line diagram of the project is included in Figure TP-32.

[17] The customer load forecasts were discounted in preparation of the integrated resource plan's system load forecast.

FIGURE TP-32
ONE LINE DIAGRAM OF COMSTOCK MEADOWS SUBSTATION



<u>Budget and Cost Responsibility</u>: The Companies will be responsible for the cost associated with the addition of the transformer at Comstock Meadows Substation to provide safe and reliable service. The projected costs for the project are provided in Figure TP-33.

FIGURE TP-33
PROJECTED CASH FLOWS FOR COMSTOCK MEADOWS 345/120 KV TRANSFORMER #2

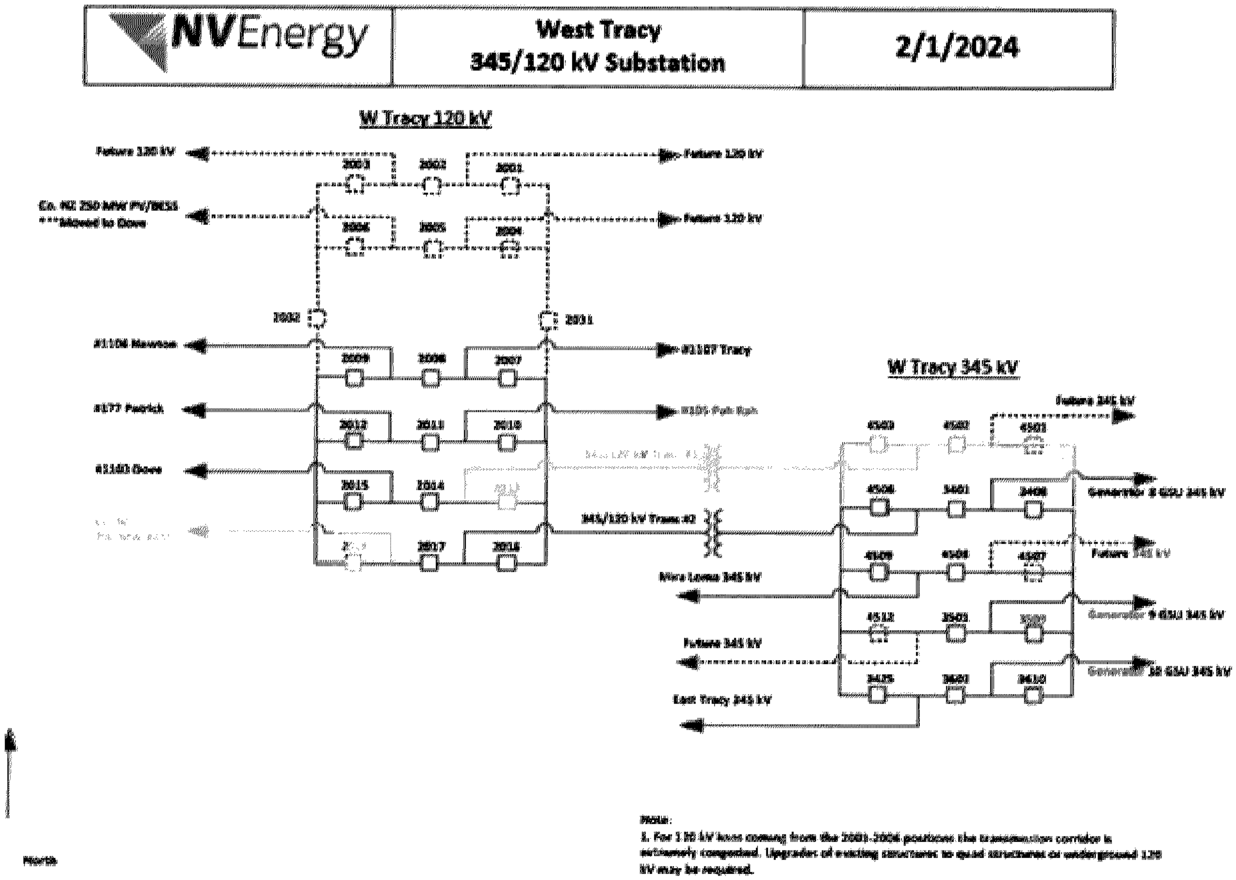
Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
13.00	0.00	2.00	6.00	5.00	13.00	0.00

WEST TRACY SUBSTATION 280 MVA 345/120 KV TRANSFORMER #1

The Companies are required to install West Tracy 345/120 kV 280 MVA transformer #1 to meet existing customers' load growth as provided by customer load studies in and around TRIC. The project is not intended to serve the new large customers. This transformer will be installed in addition to the Comstock Meadows 345/120 kV transformer previously discussed. This transformer is required when loads on the 120 kV transmission system in TRIC exceed 600 MW. The long lead time of transformers and the manufacturer's requiring large deposits necessitate that the Companies seek approval to order this transformer inside this Action Plan. If the customers' 120 kV loads fail to materialize, the transformer installation will be delayed. Transmission planning will be updated annually based on the study results in compliance with the NERC TPL-001-5 transmission planning standard, which incorporates the load forecast annual updates. The Companies request approval to construct the West Tracy 345/120 kV 280 MVA transformer #1 for native load growth in 2028.

Construction Scope: Install a second 280 MVA 345/120 kV transformer at West Tracy Substation with the associated bus work, disconnect switches, breakers control house protection panels, communications, and controls equipment. Figure TP-34 provides a one-line diagram of the project.

FIGURE TP-34
ONE LINE DIAGRAM OF WEST TRACY SUBSTATION



<u>Budget and Cost Responsibility</u>: The Companies will be responsible for the cost associated with the addition of the transformer at West Tracy Substation to provide safe and reliable service. The estimate of the project costs is provided in Figure TP-35.

FIGURE TP-35
PROJECTED CASH FLOWS FOR WEST TRACY SUBSTATION
280 MVA 345/120 KV TRANSFORMER #1

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
13.00	0.00	0.00	2.00	6.00	8.00	5.00

MACHACEK SUBSTATION 230 KV LINE BREAKERS

In the Third Amendment to the 2018 Joint Integrated Resource Plan designated as Docket No. 19-06039, the Companies requested approval to install a new 230-kV breakers ring bus at the Machacek 230 kV Substation to improve reliability and safety. In that docket, the Commission found that the need to install a new 230 kV ring bus at Machacek 230 kV Substation was not adequately justified. The Commission also found that replacement of the current motor-operated switches with new properly functioning motor-operated switches is the most economical way to increase reliability and address safety concerns. In addition, the Commission indicated that nothing in the order precluded the Companies from proposing its preferred solution in an appropriate resource planning proceeding.

Since 2019, Machacek Substation has continued to have reliability issues. Any outage on the Frontier-Gonder 230 kV line causes service to the entire Machacek Substation to be interrupted. This substation serves up to 28 MW of load. The Frontier-Gonder 230 kV line is 115 miles long resulting in substantial line exposure and potential for line outages. Since 2012, there have been seven forced outages of this line with five of the outages resulting in a sustained outage of around three hours each. In addition, there have been 39 planned outages for line maintenance resulting in a temporary outage while line switching is performed. Mt. Wheeler Rural Electric Association has continued to express concern about the reliability of service to the Machacek Substation and outages of their customer load that could be avoided.

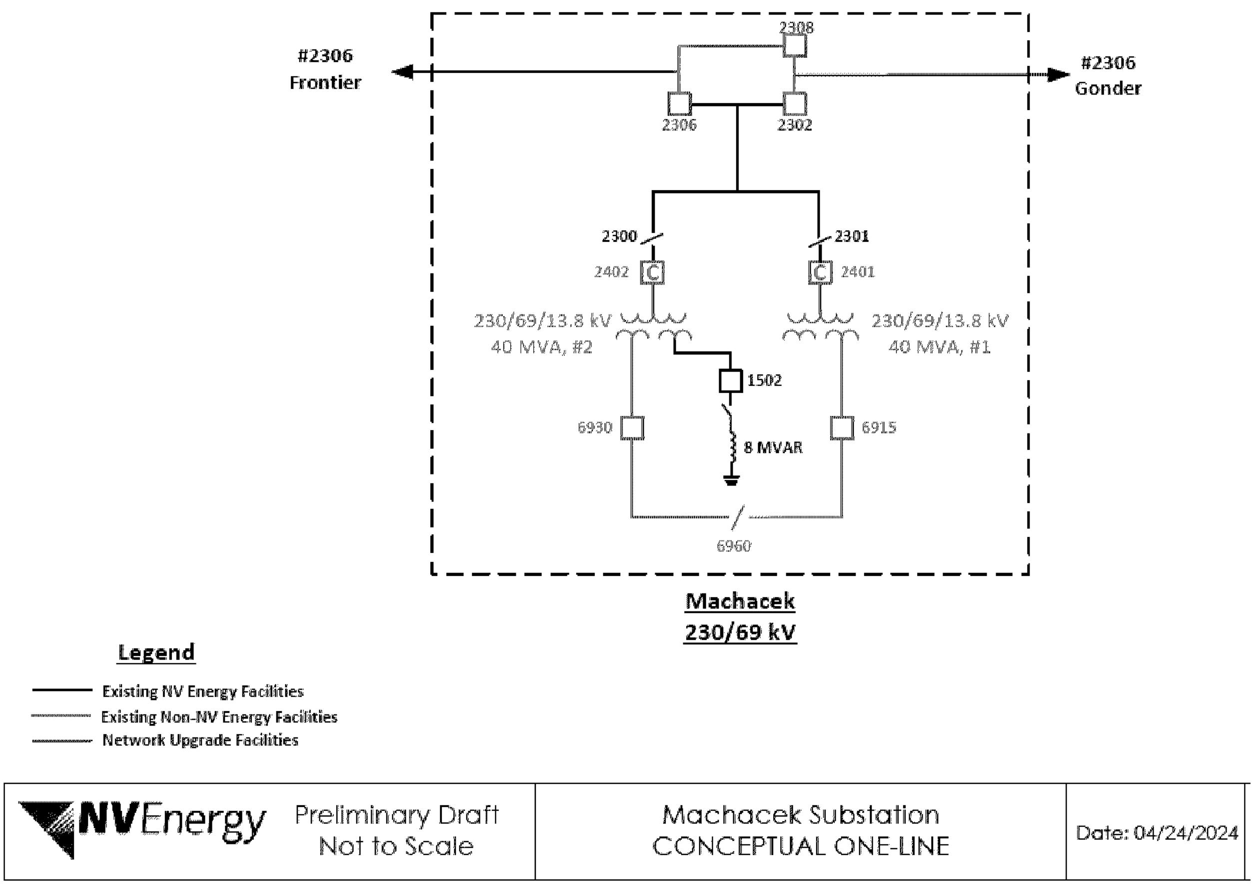
Per the OATT and FERC regulations, the Companies carry an obligation to provide transmission service to all transmission customers on a non-discriminatory basis. There is no other location on a major path on the Companies' system where a single line outage will result in the interruption of this magnitude of load. Mt Wheeler pays the same transmission rate as other transmission customers but does not receive the same level of reliable service. The addition of new properly functioning motor-operated switches will not prevent any of these outages. However, the new switch would allow for more rapid restoration of service during sustained outages.

The Companies' preferred alternative to provide Machacek Substation with a similar level of reliability as other substations on the Companies' system is the installation of a three-breaker ring bus. A lower cost alternative would be to install a single 230 kV breakers on the Machacek-Gonder #2302 230 kV line at Machacek Substation and a second 230 kV breaker on the Machacek-Frontier #2306 230 kV line at Machacek Substation. The two breaker alternative would provide the same level of reliability for the Machacek Substation load as the three breaker ring bus at a lower cost. The disadvantage of the two-breaker alternative is that anytime maintenance is required on either breaker it would be necessary to open the 230 kV line between Machacek Substation and Frontier Substation or Gonder Substation. This 230 kV line is a major path and the primary northern Nevada interconnection with PacifiCorp and The Los Angeles Department of Water and Power. It should not be necessary to open this path when breaker maintenance is required.

The Companies are committed to resolving the customer's concerns, increasing customer satisfaction, and improving transmission reliability. The Companies request approval to construct either a three breaker ring bus or the two 230 kV line breakers at Machacek Substation to improve reliability and improve customer satisfaction.

Construction Scope: The preferred plan: Construct 230 kV ring bus with three breakers, which will require the substation yard to be expanded. Alternate mitigation: Install two 230 kV line breakers at Machacek. Both alternatives will require the addition of bus work, disconnect switches, communications, control house protection panels and control equipment. A one-line diagram of the project is included in Figure TP-36.

FIGURE TP-36
ONE LINE DIAGRAM OF MACHACEK 230/69 KV SUBSTATION



Budget and Cost Responsibility: The Companies will be responsible for the cost associated with the 230 kV improvements at Machacek Substation. The estimated costs of the preferred recommendations for project are included in Figure TP-37, and the estimated costs for the alternative are included in Figure TP-38.

FIGURE TP-37
PROJECTED CASH FLOWS FOR MACHACEK SUBSTATION RING BUS AND BREAKERS

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
14.8	0.00	0.50	10.30	4.00	14.80	0.00

FIGURE TP-38 ALTERNATE
PROJECTED CASH FLOWS ALTERNATE MITIGATION FOR MACHACEK SUBSTATION LINE BREAKERS

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
7.00	0.00	0.50	6.50	0.00	7.00	0.00

DARLING 230/12 KV SUBSTATION

Darling Substation with two 230/12 kV 37 MVA transformers is required in 2028. Darling Substation is a distribution area upgrade project that will provide relief to existing facilities at Elkhorn Substation (five feeders and two substation transformers) and Northwest Substation (one feeder) and serve new loads in the northwest Las Vegas area. The existing facilities in Elkhorn and Northwest Substations are forecasted to exceed capacity by 35.6 MVA, requiring relief from the new Darling Substation in June 2028. In addition, the Companies received a request for service to 3011004285 -- BLM 500 Master Plan totaling 23.6 MVA with a requested in-service date of June 1, 2026. The manufacturers of transformers of this size have a lead time approaching three years. The manufacturers are requiring large deposits to reserve the transformers production slots. These deposits are required inside the three-year action plan. If the distribution load forecast is reduced in the future, then the timing and size of substation project will similarly be adjusted, such as reducing the substation to one 37 MVA transformer. The Companies request approval to construct the Darling 230/12 kV Substation.

Construction Scope: Install a new 230 kV line fold of the Northwest – Westside 230 kV line, install a four-breaker ring bus and two 230/12 kV 37 MVA transformers with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. A map of the location of the new substation is included in Figure TP-39.

FIGURE TP-39
PROXIMITY MAP FOR DARLING 230/12 KV SUBSTATION

Budget and Cost Responsibility: The Companies will be responsible for the cost associated with the construction of the Darling 230/12 kV Substation to meet their obligation to provide safe and reliable electric service. The estimated costs of the project are included in Figure TP-40.

FIGURE TP-40
PROJECTED CASH FLOWS FOR DARLING 230/12 KV SUBSTATION

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
43.50	0.00	4.35	4.35	21.75	30.45	13.05

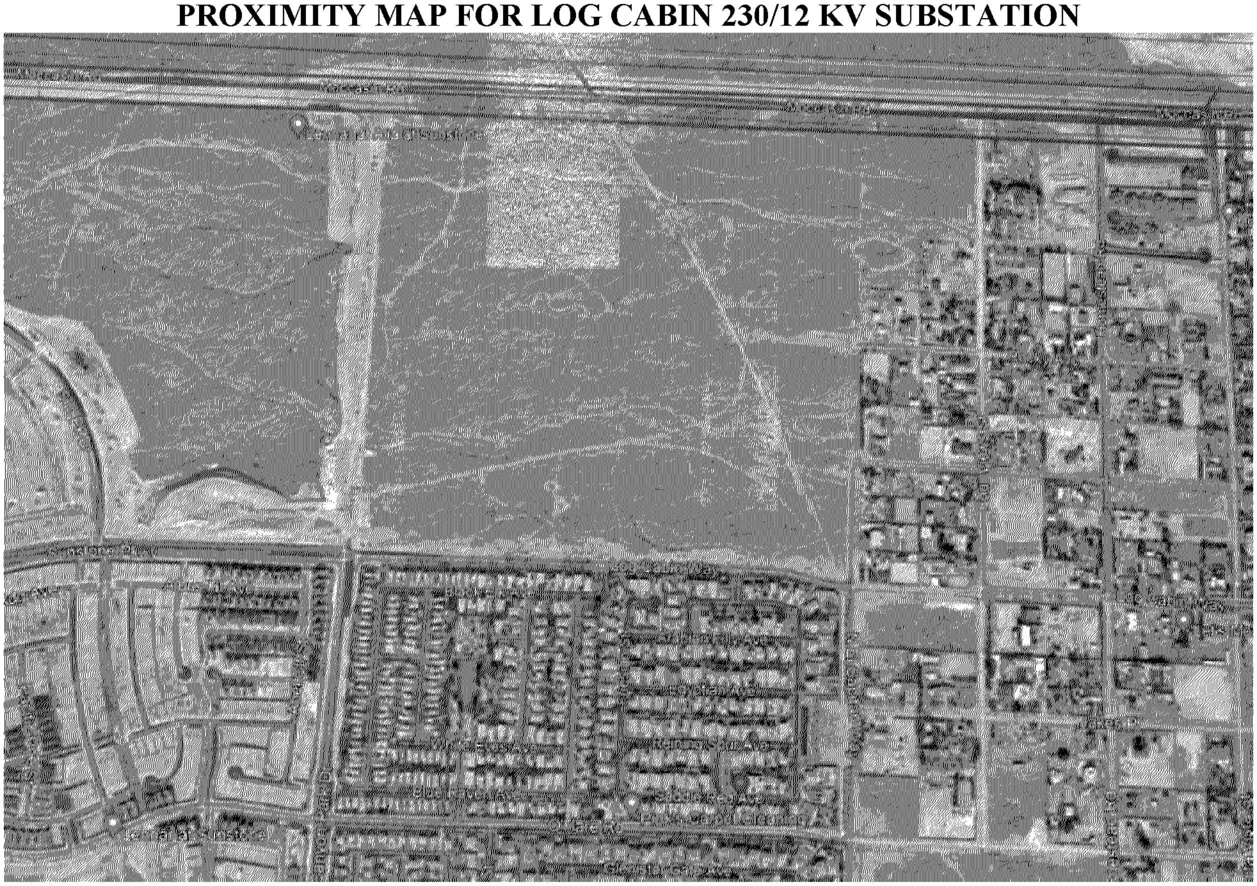
LOG CABIN 230/12 KV SUBSTATION

Log Cabin Substation with a 230/12 kV 37 MVA transformer is required in summer 2028. Log Cabin Substation is a regional upgrade project that will provide relief to existing facilities at

Northwest Substation (two feeders and two substation transformers) and serve new loads in the northwest Las Vegas area. Facilities in Northwest Substation are forecasted to exceed capacity by 10.4 MVA, requiring relief from the new Log Cabin 230/12 kV Substation before June 1, 2028. Contributing in part to the need for Log Cabin, NV Energy received a request for service to 3010603085 -- BLM 940 Master Plan totaling 36 MVA with a requested in-service date of June 1, 2025. The lead time for the manufacturers of transformers of this size is approaching three years. The manufacturers are also requiring large deposits to reserve the transformers production slots. The deposit is required inside the three-year action plan. The Companies request approval to construct Log Cabin 230/12 kV Substation.

Construction Scope: Install a new 230 kV line fold of the Iron Mountain – Northwest 230 kV line, install a four-breaker ring bus and a 230/12 kV 37 MVA transformer with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. A map of the location of the new substation is provided in Figure TP-41.

FIGURE TP-41
PROXIMITY MAP FOR LOG CABIN 230/12 KV SUBSTATION



Budget and Cost Responsibility: The Companies will be responsible for the cost associated with the construction of the Log Cabin 230/12 kV Substation to meet its obligation to provide safe and reliable service. The estimated costs of the project are included in Figure TP-42.

FIGURE TP-42
PROJECTED CASH FLOWS FOR LOG CABIN 230/12 KV SUBSTATION

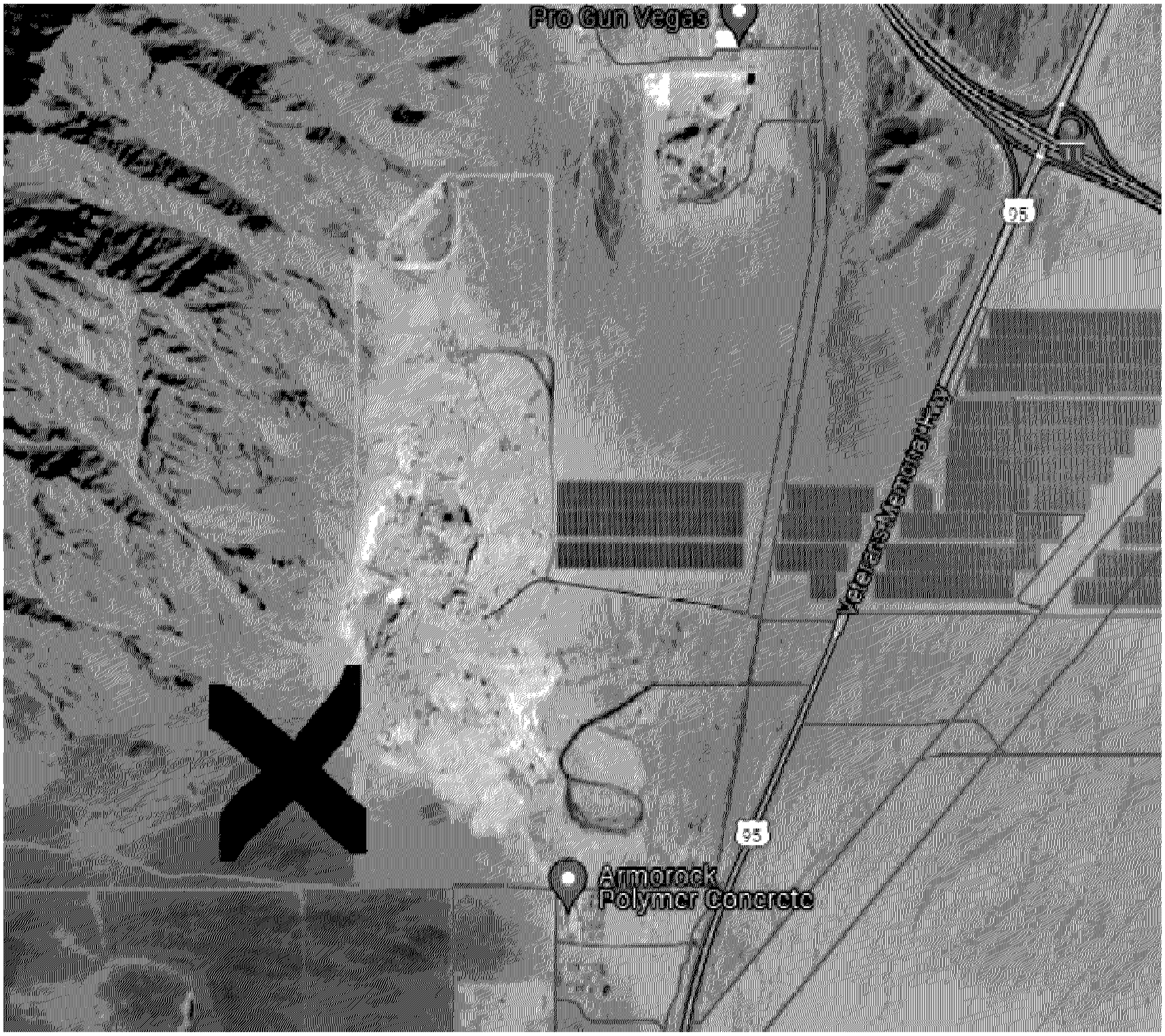
Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
33.75	0.00	3.38	3.38	16.88	23.64	10.13

SPRING CANYON 230/12 KV SUBSTATION

Spring Canyon Substation with three 230/12 kV 37 MVA transformers is required in summer 2026. Spring Canyon 230/12 kV Substation is an area upgrade project to source several MPCs in the Eldorado Valley area. Eldorado Valley is a growing commercial and industrial center in southern Henderson. The Companies have received requests totaling 83 MVA for service in Eldorado Valley from warehousing, manufacturing, data centers, and mixed development customers. The Eldorado Valley area is currently being served from the 69/12 kV 88 MVA Mission Substation, which is fully contracted with no available capacity. Greenway Substation can support approximately 30 MVA of load growth but is eight miles from the proposed Spring Canyon site, which creates an entry barrier for customers due to line extension cost and feeder route permitting time. Active projects justifying construction of Spring Canyon Substation include 3010885444 – Eldorado Industrial, requested in-service date: November 29, 2024, 5.7 MVA; 3010840442 – Eldorado Hills Master Plan, requested in-service date: December 1, 2026, 8.8 MVA; 3010833586 – Panattoni Eldorado Valley Master Plan, requested in-service date: December 1, 2026, 31.1 MVA; 3010047083 – WDA Innovative Park at Eldorado Master Plan, requested in-service date: December 1, 2026, 37.3 MVA. Two Master Planned Umbrella ("MPU") agreements have been issued, one of which is actively progressing. The manufacturers of transformers of this size are quoting a lead time approaching three years. The Companies request approval to construct Spring Canyon 230/12 kV Substation.

<u>**Construction Scope**</u>**:** Construct a new 230 kV line fold of the Mead – Greenway 230 kV line, install ring bus and transformer with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. A map of the proposed location for the new substation is provided in Figure TP-43.

FIGURE TP-43
PROXIMITY MAP FOR SPRING CANYON 230/12 KV SUBSTATION



<u>Budget and Cost Responsibility</u>: The Companies will be responsible for the cost associated with the construction of the Spring Canyon 230/12 kV Substation to meet its obligation to provide safe and reliable electric service. An estimate of the costs to develop the project is included in Figure TP-44.

FIGURE TP-44
PROJECTED CASH FLOWS FOR SPRING CANYON 230/12 KV SUBSTATION

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
49.60	0.00	25.50	24.10	0.00	49.60	0.00

FT CHURCHILL - COMSTOCK MEADOWS 345 KV LINE #2

Ft Churchill-Comstock Meadows 345 kV line #2 will be the second 345 kV line constructed between Ft Churchill and Comstock Meadows Substations and is required pursuant to a signed Rule 9 agreement. The Ft Churchill-Comstock Meadows 345 kV line #2 will provide the required redundancy and capacity to the 345 kV transmission system in and around the TRIC. The Ft Churchill–Comstock Meadows #2 line is also a contingent facility for multiple subsequently queued large load customers in the area. The Ft Churchill-Comstock Meadows line #2 permitting, land acquisitions and design ($12.8 MM) were approved by the Commission as part of Greenlink West in Docket No. 20-07023.

With the approximately 4,000 MW of signed Rule 9 agreements, the Companies are also seeking conditional approval of the third and fourth 600 MVA 525/345 kV transformers at the Ft Churchill Substation, so that the transformers could be constructed in time to meet customers' load forecasts. The transformers are requested in conjunction with Ft Churchill-Comstock Meadows 345 kV #2 line because the loads that are contingent on this line also require these new transformers per the customer load forecasts. The condition of the Commission's approval is that, when the total load on the two existing Ft Churchill 525/345 kV transformers reaches 600 MVA, a third transformer will be constructed. Subsequently, when the total load on Ft Churchill 525/345 kV transformers reaches 1,200 MVA, a fourth transformer will be constructed. The transformers are required to accommodate the N-1 loss of a single Ft Churchill 600 MVA 525/345 kV transformer. NERC TPL-001-5 planning standards require an annual study be conducted, wherein it will be determined in what year the transformers must be constructed, based on the annual load forecasts.

Also driving the need for Ft Churchill - Comstock Meadows 345 kV line and the third and fourth Ft Churchill transformers is a new RC West (RC) procedure that requires load shedding in northern Nevada for N-1 loss of 345 kV tie lines. Loads to be shed include up to 150 MW in Reno, 40 MW in Carson City, 40 MW at Winnemucca, and 65 MW at Maggie Creek (Carlin Trend). The potential contingencies include N-1 loss of 345 kV lines, Falcon - Robinson, Humbolt – Rogerson, Rogerson-Midpoint. This is because the RC requires that the transmission system be configured to withstand the next worst-case contingency or N-1-1 contingency. The construction of Greenlink West with the three common tie 345 kV lines and the third and fourth 525/345 kV transformers at Ft Churchill will mitigate the risk of the RC West procedure being activated because, in combination with Greenlink West, it will significantly improve voltage stability in the north.

The Ft Churchill – Comstock Meadows 345 kV line #2 cannot replace or delay the need for the Ft Churchill – Comstock Meadows 345 kV line #1. The Ft Churchill – Comstock Meadows line #1 is required for a second specific customer pursuing an MPC agreement under Rule 9 for 450 MW in their first phase. The Companies request conditional approval to construct third and fourth 600 MVA 525/345 kV transformers at Ft Churchill as described for new loads and request approval to construct Ft Churchill – Comstock Meadows 345 kV line #2 as required, per a signed Rule 9 agreement. One line diagrams of the Ft. Churchill Substation are included in Figure TP-45 and Figure TP-46.

FIGURE TP-45
ONE LINE DIAGRAM
FT CHURCHILL 525/345 KV SUBSTATION

NVEnergy	**Fort Churchill 525 kV**	**4/16/2024**

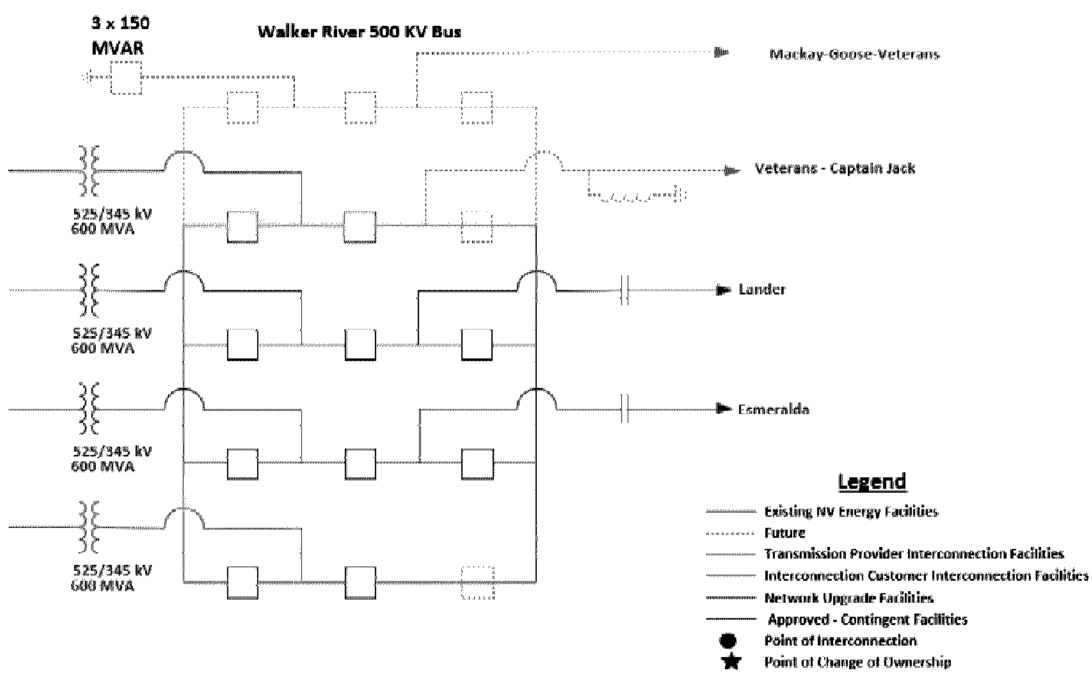
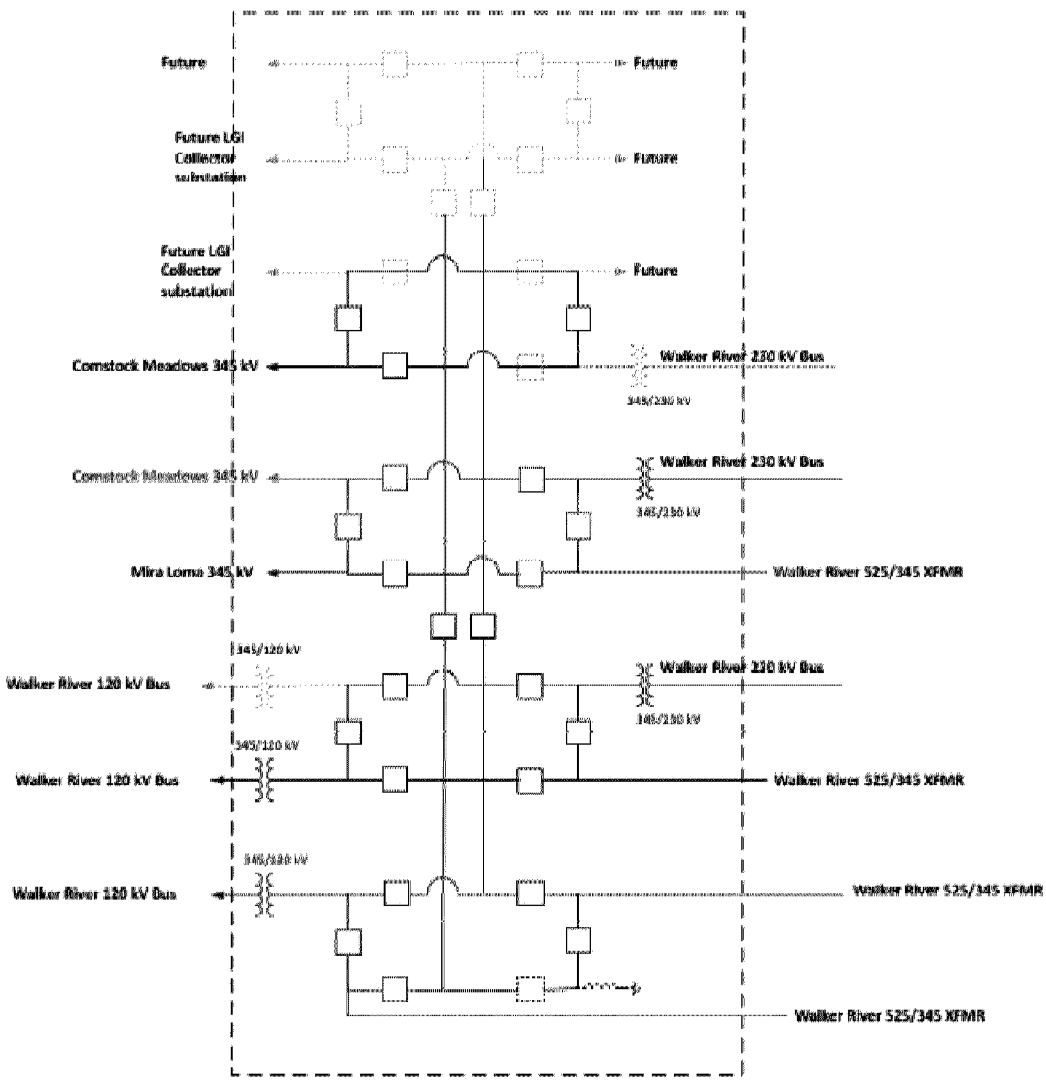


FIGURE TP-46
ONE LINE DIAGRAM
FT CHURCHILL 345/230/120 KV SUBSTATION

NVEnergy	Fort Churchill (Walker River) 525 kV	4/16/2024



<u>Construction Scope:</u> Construct a new 37-mile 345 kV line between Ft Churchill and Comstock Meadows Substation. Construct line terminals at Ft. Churchill and Comstock Meadows with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. As needed, construct the third and fourth 600 MVA 525/345 kV transformer at Ft Churchill with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment.

Budget and Cost Responsibility: The Companies will be responsible for the costs of Ft Churchill – Comstock Meadows 345 kV line #2 and the third and fourth 600 MVA 525/345 kV transformer at Ft Churchill. Estimates of the transmission project are included in Figure TP-47 and cost estimates for the conditional transformers are included in Figures TP-48 and TP-49.

FIGURE TP-47
PROJECTED CASH FLOWS FOR FT CHURCHILL – COMSTOCK MEADOWS 345 KV # 2 LINE

Cash Flow ($MM)						
Project Total[18]	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
110.2	0.00	41.26	52.00	16.94	110.2	0.00

FIGURE TP-48
PROJECTED CASH FLOWS FOR FT CHURCHILL
***THIRD* 600 MVA 525/345 KV TRANSFORMER (CONDITIONAL ON 600 MW LOAD ON FT CHURCHILL 525/345 KV TRANSFORMERS)**

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
12.00	0.00	1.00	2.00	9.00	12.00	0.00

FIGURE TP-49
PROJECTED CASH FLOWS FOR FT CHURCHILL
***FOURTH* 600 MVA 525/345 KV TRANSFORMER (CONDITIONAL ON 1200 MW LOAD ON FT CHURCHILL 525/345 KV TRANSFORMERS)**

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
12.00	0.00	0.00	0.00	1.00	1.00	11.00

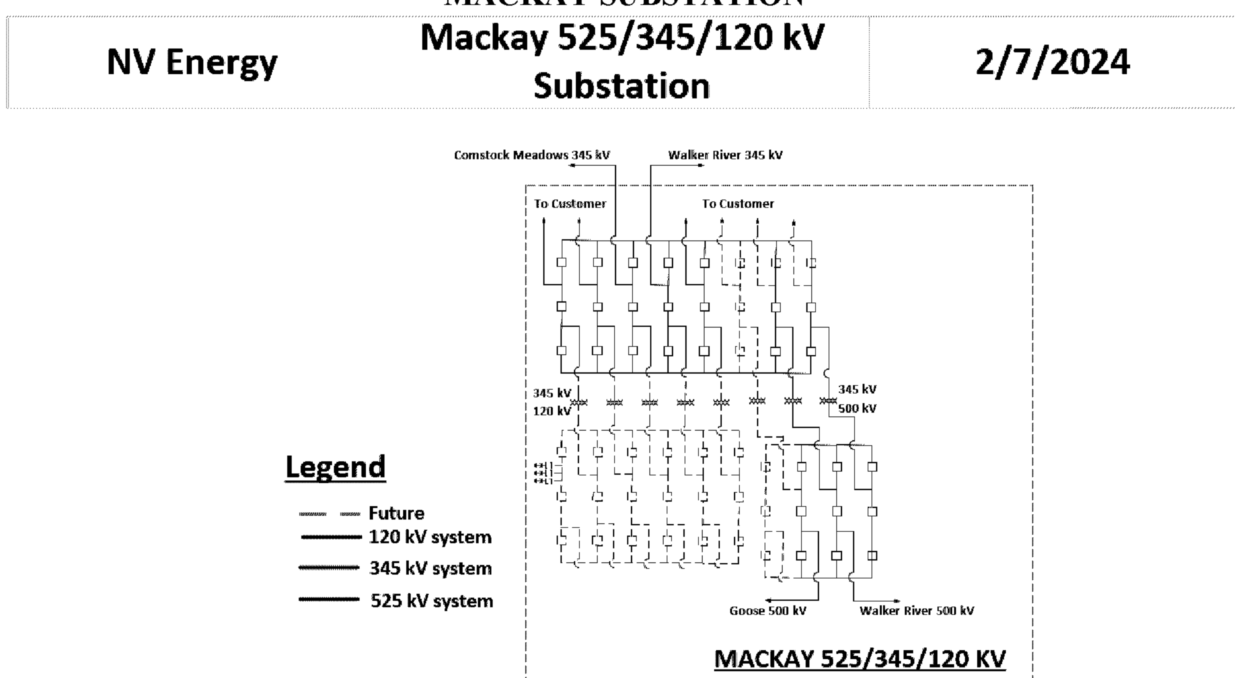
[18] Total includes the previously approved $ 12.8 MM for design, permitting and land acquisition for Ft Churchill – Comstock Meadows 345 kV line #2.

MACKAY SUBSTATION

A fold of the proposed Ft Churchill - Comstock Meadows 345 kV line #1 into the new Mackay Substation is required to serve the first phase of the MPC contracted request for 450 MW (total request for 1,215 MW) discussed above. The Companies and MPC customer will be responsible for portions of the cost of Mackay Substation based on executed Rule 9 agreement. The new Mackay Substation will deliver 345 kV capacity to future customers within the MPC. The Companies request approval to construct the Mackay Substation to serve the new customers' loads.

<u>Construction Scope:</u> Construct new Mackay Substation to deliver 345 kV to the MPC by folding Ft Churchill – Comstock Meadows 345 kV line #1. Construct line terminals at Mackay Substation with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. A one-line diagram of the project is included in Figure TP-50.

FIGURE TP-50
FT CHURCHILL – COMSTOCK MEADOWS 345 KV #1 LINE AND MACKAY SUBSTATION



<u>Budget and Cost Responsibility</u>: The Companies will be responsible for the costs of the fold of Ft Churchill – Comstock Meadows 345 kV line #1 into Mackay Substation. The Companies and MPC customer will be responsible for portions of the cost of Mackay Substation based on executed Rule 9 agreement. The Companies' portion of the project costs estimates are provided in Figure TP-51.

FIGURE TP-51
PROJECTED CASH FLOWS FOR MACKAY (PHASE 1) SUBSTATION

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
28.00	0.00	1.00	5.00	22.00	28.00	0.00

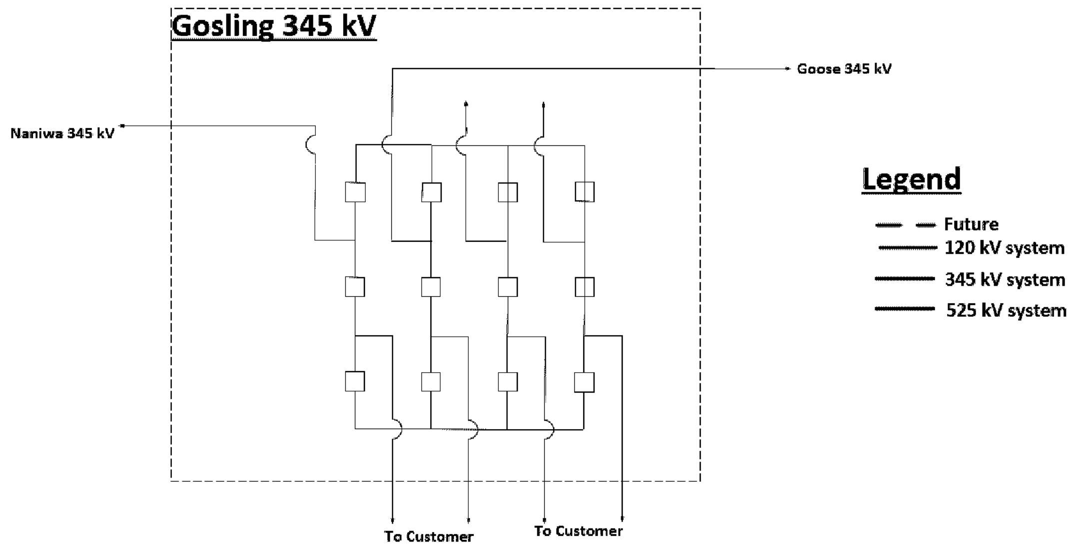
GOSLING 345 KV SWITCHING STATION

The West Tracy - Comstock Meadows 345 kV line will be folded into the new Gosling 345 kV switching station. This is required to serve the first phase of an MPC customer request for 450 MW (total request for 810 MW). The Companies and MPC customer will be responsible for portions of the cost of Gosling Substation based on executed Rule 9 agreement. The new Gosling switching station will deliver 345 kV capacity to future customers within the MPC. The Companies request approval to construct the Gosling switching station to serve the new customers' loads.

Construction Scope: Construct the new Gosling 345 kV switching station to deliver 345 kV to the MPC, folding the West Tracy – Comstock Meadows 345 kV line into Gosling 345 kV switching station. Construct line terminals at Gosling 345 kV switching station with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. The one-line diagram of the new switching station is provided in Figure TP-52.

FIGURE TP-52
GOSLING 345 KV SWITCHING STATION

NV Energy	Gosling 345 kV Switching Station	2/7/2024



Budget and Cost Responsibility: The Companies will be responsible for the cost to fold the new West Tracy – Comstock Meadows 345 kV line into Gosling switching station. The Companies and MPC customer will be responsible for portions of the cost of Gosling switching station based on the executed Rule 9 agreement. The customer will securitize the project. The Companies' portion of the cost estimates for the project are included in Figure TP-53.

FIGURE TP-53
PROJECTED CASH FLOWS FOR
GOSLING 345 KV (PHASE 1) SWITCHING STATION

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
5.00	0.00	1.00	1.00	3.00	5.00	0.00

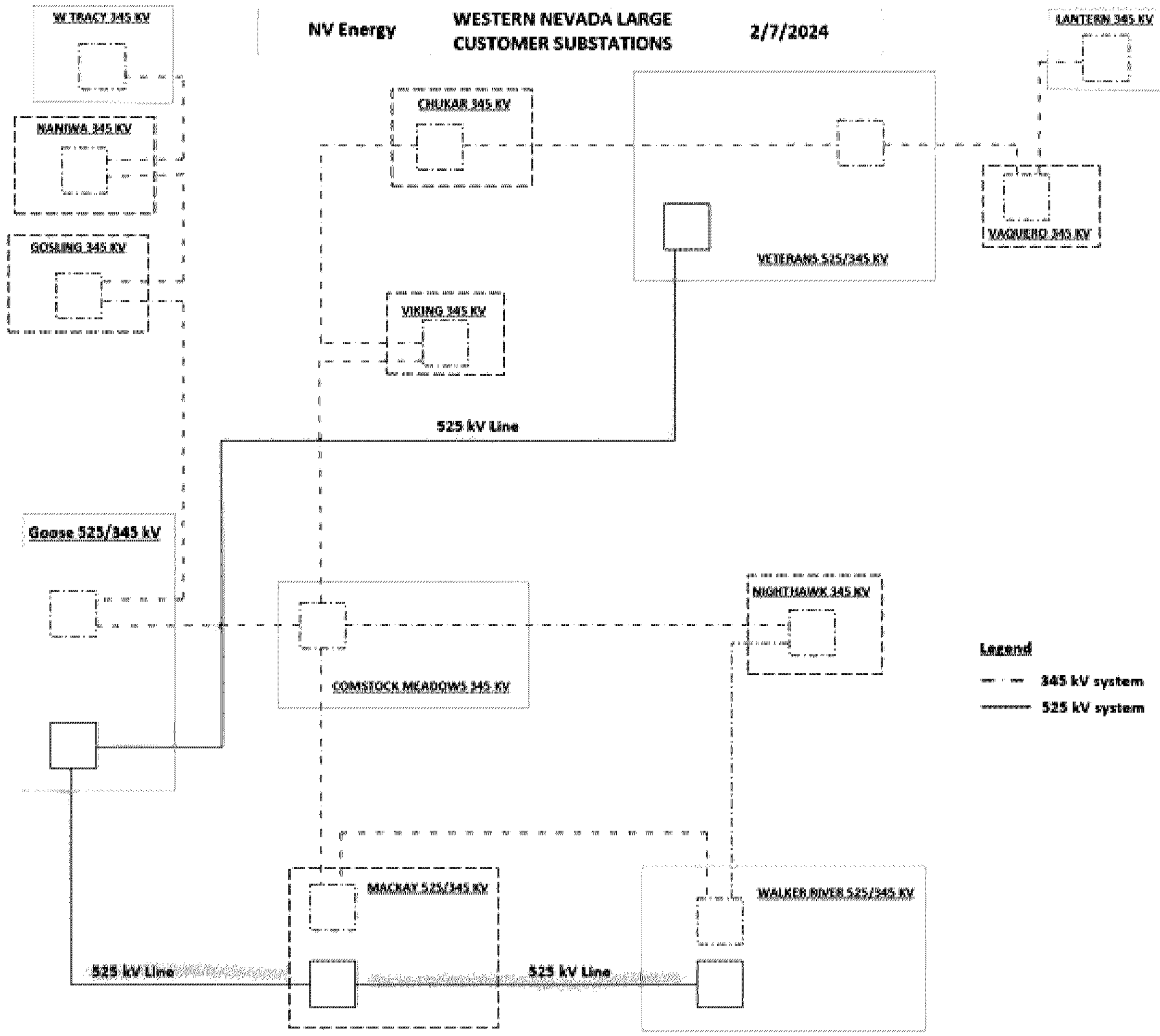
FT CHURCHILL – VETERANS 525 KV LINE - PERMITTING ONLY

When Greenlink West and North are completed, the Ft Churchill – Veterans 525 kV line will provide the necessary capacity for the MPC's Rule 9 customer's phase of additional 1,125 MW load at Mackay and Goose Substations and will be required to exceed the first phase's 450 MW of load at both Gosling switching station and Mackay Substation. The Mackay, Goose and Veterans 525/345 kV transformers are also required for the MPCs and subsequently queued Rule 9 customers to provide the needed 345 kV system redundancy and capacity for both 525 kV and 345 kV systems at the forecast full loads. The modularity of this plan will allow construction to be phased in as the MPC loads grow. Annual NERC TPL-001-5 studies will provide an annual review to determine when the 525 kV line, substations, and transformers are required to be constructed.

To meet the customers' load forecasts in-service dates, the routing and siting study and then permitting of the 525 kV line must commence as soon as possible. This request is an expansion of the permitting of the TRIC area master plan approved in Docket No. 20-07023, the Fourth Amendment to the 2018 IRP. The 525 kV line will be integrated in the area master plan, which can be implemented in phases and "just in time" as the loads develop. The exact location of the load growth will impact the order of in which substation the transformers should be constructed to be the most beneficial. Additional information and requests for construction approval will be provided to the Commission as there is more certainty surrounding individual projects or phases. This line will also mitigate the risk of the RC West's N-1-1 procedure, discussed previously, being activated. The Companies request approval to permit the Ft Churchill – Veterans 525 kV line for the anticipated MPC contracts and existing subsequently queued HVD customers load requests.

Construction Scope: Complete routing and siting study then assist the customer in acquiring permitting for the Ft Churchill – Veterans 525 kV line, which will be routed adjacent to Mackay and Goose substations, to be folded into these substations as needed. Siting and permitting requires the completion of 30 percent engineering plans by the Companies. The customer will be responsible for the costs to secure the permitting and right of way. The Companies are required to assist the customer to ensure standards and the transmission master planning is adhered to. A one line diagram of the project is included in Figure TP-54.

FIGURE TP-54
FT CHURCHILL – VETERANS 525 KV LINE



Budget and Cost Responsibility: The customer will be responsible for the costs of the new 525 kV line rights of way and permitting. The Companies portion of the cost estimate of the project is included in Figure TP-55.

FIGURE TP-55
PROJECTED CASH FLOWS FOR PERMITTING ONLY –
FT CHURCHILL – VETERANS 525 KV LINE

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
14.00	0.00	0.00	2.00	5.00	7.00	7.00

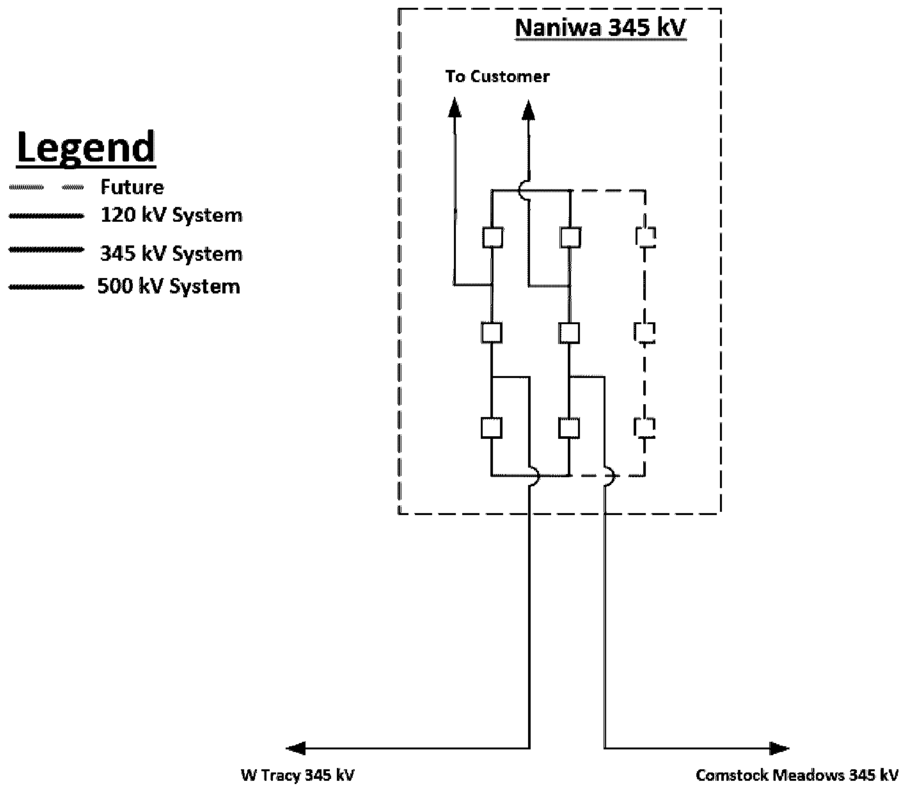
NANIWA 345 KV SWITCHING STATION

The West Tracy - Comstock Meadows 345 kV line will be completed in 2025. The new line will be folded into the "new" rebuilt Naniwa 345 switching station. The existing Naniwa site is decommissioned. A particular TRIC customer is impacted by higher queued Rule 9 customers. The customer signed an HVD Rule 9 agreement for a total load of 625 MW. The customer's load is limited to 110.5 MW until Ft Churchill – Comstock Meadows 345 kV line #1 is completed. After that #1 line is completed, the limitation will increase to 367 MW until Ft Churchill – Comstock Meadows 345 kV line #2 is completed. After the #2 line is completed, the load limitation will increase to 547 MW until Lantern - Comstock Meadows 345 kV line and Ft Churchill – Veterans 525 kV line is completed, with Veterans 525/345 kV transformers installed. At that time, the load limitation will reach the full 625 MW in the customer's Rule 9 agreement. The line fold and Naniwa switching station are required to serve the Rule 9/HVD customer's requested first phase of 110.5 MW. The Companies request approval to construct the Naniwa 345 kV switching station to serve the signed HVD Rule 9 customer.

Construction Scope: Construct the new Naniwa 345 switching station with a fold of the West Tracy – Comstock Meadows 345 kV line into Naniwa 345 switching station. Construct line terminals at Naniwa 345 switching station with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. A one line diagram of the project is included in Figure TP-56.

FIGURE TP-56
NANIWA 345/120 KV SUBSTATION

NV Energy	**Naniwa 345 kV Switching Station**	**2/7/2024**



<u>Budget and Cost Responsibility</u>: The Companies will be responsible for the cost to fold the new West Tracy – Comstock Meadows 345 kV line into Naniwa 345 switching station. The Companies and HVD customer will be responsible for portions of the cost of Naniwa 345 switching station based on the executed Rule 9 agreement. The Companies' portion of the estimate of the costs is included in Figure TP-57.

FIGURE TP-57
PROJECTED CASH FLOWS FOR NANIWA 345/120 KV SUBSTATION

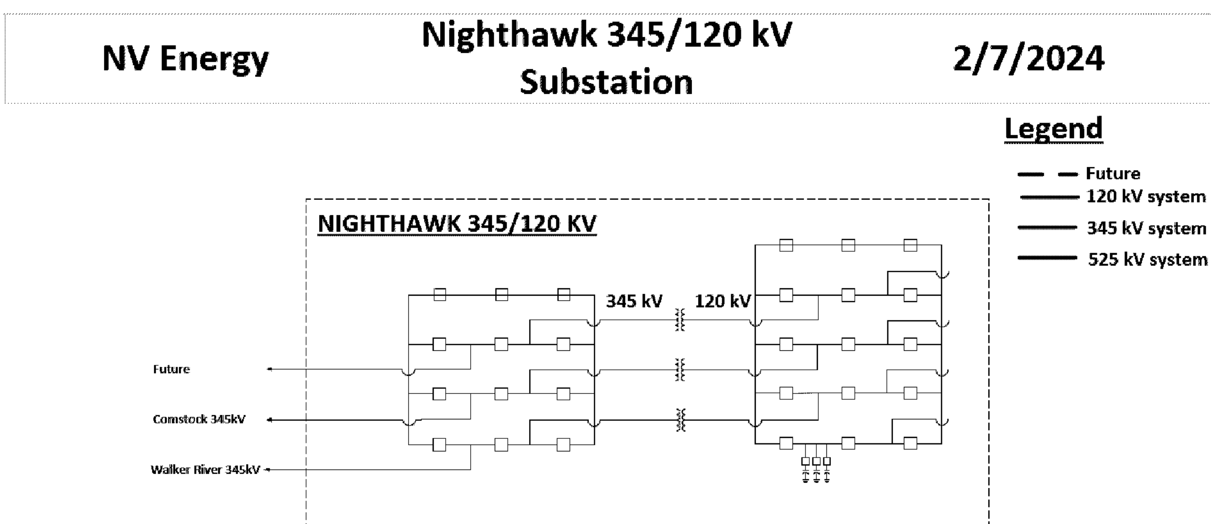
Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
26.00	0.00	6.40	17.50	2.10	26.00	0.00

NIGHTHAWK 345/120 KV SUBSTATION

The Ft Churchill - Comstock Meadows 345 kV line #2 will be completed in 2027 as part of the Greenlink West's 345 kV common tie lines. The new line will be folded into the new Nighthawk 345/120 kV Substation. This is required to serve a signed HVD Rule 9 agreement request of 461 MW of new load. It is important to note there is an ancillary benefit to this substation. It will be a 120 kV source that will be nearby the existing Silver Spring Substation to provide an opportunity to add a 120/60 kV transformer that, in the future, will improve voltage performance and capacity on the existing 60 kV system to the south and west of Silver Springs. The substation is a strong alternate 120 kV source, that is required to complete the 60 kV to 120 kV conversion between Tracy – Silver Springs – Lahontan – Hazen – Eagle and Lahontan – Fallon Substations. The 120 kV conversion is required per NERC N-0 and N-1 voltage transmission planning standards. The Companies request approval to construct the Nighthawk 345/120 kV Substation to serve the signed Rule 9 HVD agreement loads.

Construction Scope: Construct new Nighthawk 345/120 kV Substation, with a fold of the Ft Churchill – Comstock Meadows 345 kV #2 line into Nighthawk 345/120 kV Substation. Construct line terminals at Nighthawk 345/120 kV Substation with 120 kV line terminals for customer service with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment A one line diagram of the new substation is included in Figure TP-58.

FIGURE TP-58
NIGHTHAWK 345/120 KV SUBSTATION



Budget and Cost Responsibility: The Companies will be responsible for the cost to fold the new Ft Churchill – Comstock Meadows 345 kV line #2 into Nighthawk 345/120 kV Substation. The Companies and HVD customer will be responsible for portions of the cost of Nighthawk 345/120 kV Substation based on the executed Rule 9 agreement. The customer is required to securitize the project. Figure TP-59 provides a cost estimate for this project, for which the Companies are responsible.

FIGURE TP-59
PROJECTED CASH FLOWS FOR NIGHTHAWK 345/120 KV SUBSTATION

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
67.00	0.00	0.50	2.00	52.00	54.50	12.50

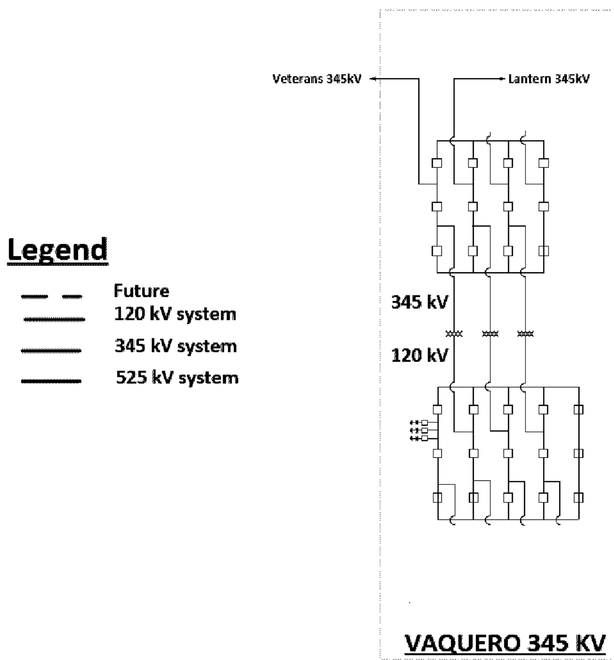
VAQUERO 345/120 KV SUBSTATION

The future Lantern – Comstock Meadows 345 kV will be folded into the new Vaquero 345/120 kV Substation. The new substation would be between the future Veterans and Lantern Substations. The substation's location and pad preparation will be paid for by the customer. This is required to serve a Rule 9 HVD agreement customer request of 461 MW. The Companies request approval to construct the Vaquero 345/120 kV Substation to serve the Rule 9 customer's HVD agreement loads.

Construction Scope: Construct new Vaquero 345/120 kV Substation, with a line fold of the Lantern – Comstock Meadows 345 kV line into Vaquero 345/120 kV Substation with 120 kV line terminals for customer service with associated line disconnects, breakers, bus work, control house protection panels, communications, and control. A one line diagram of the project is included in Figure TP-60.

FIGURE TP-60
VAQUERO 345/120 KV SUBSTATION

NV Energy	**Vaquero 345/120 kV Substation**	**2/7/2024**



Budget and Cost Responsibility: The Companies will be responsible for the cost to fold the new Lantern – Comstock Meadows 345 kV line into Vaquero 345/120 kV Substation. The Companies and HVD customer will be responsible for portions of the cost of Vaquero 345/120 kV Substation based on executed Rule 9 agreement. The Companies' portion of the cost estimate for the project is included in Figure TP-61.

FIGURE TP-61
PROJECTED CASH FLOWS FOR VAQUERO 345/120 KV SUBSTATION

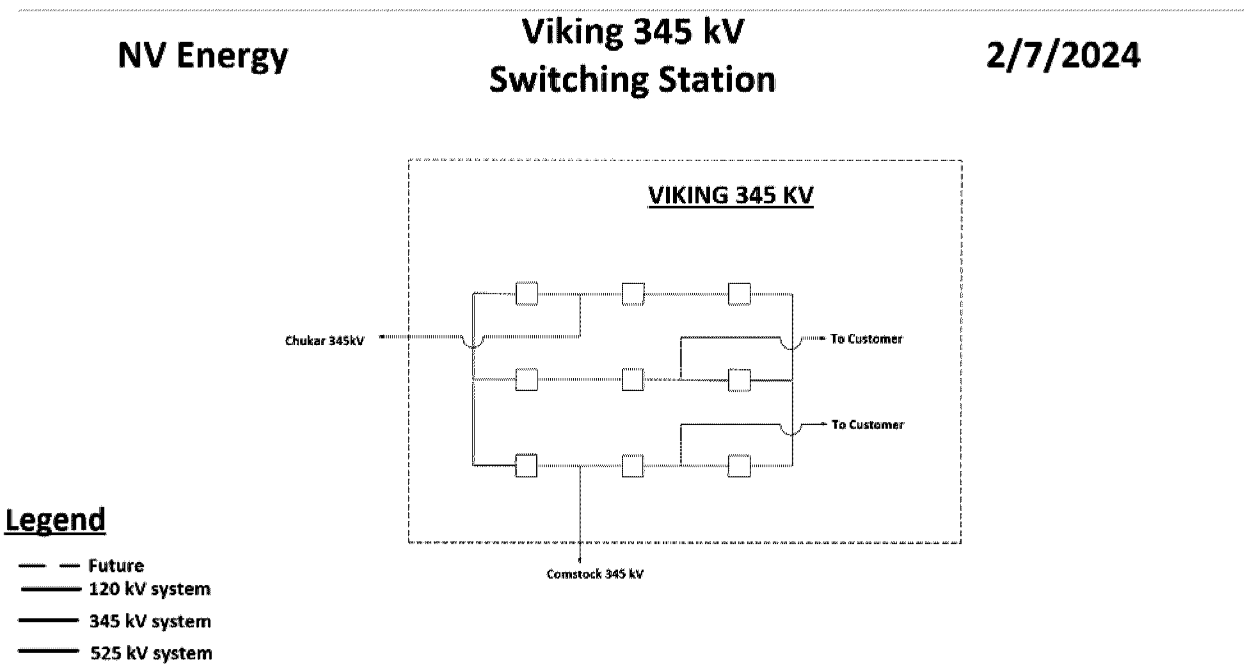
Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
30.00	0.00	0.50	2.50	22.00	25.00	5.00

VIKING 345 KV SWITCHING STATION

The new Viking 345 kV switching station is incorporated into the TRIC area transmission master plan for a single large load. The customer will take delivery at 345 kV because there is not enough capacity on the 120 kV transmission system to accommodate this new load plus the existing customer forecasts, that are inside TRIC. This large load will require the proposed Lantern – Comstock Meadows 345 kV line to be folded into the new Viking 345 switching station. The substation's location and pad preparation will be paid for by the customer. This is required to serve the Rule 9 HVD agreement for 461 MW. The Companies request approval to construct the Viking 345 switching station to serve the HVD loads.

Construction Scope: Construct the new Viking 345 switching station to deliver 345 kV to the HVD, with a line fold of the Lantern – Comstock Meadows 345 kV line into Viking 345 switching station. Construct line terminals at Viking 345 switching station with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. A one-line diagram of the project is included in Figure TP-62.

FIGURE TP-62
VIKING 345 SWITCHING STATION



Budget and Cost Responsibility: The Companies will be responsible for the cost to fold the new Lantern – Comstock Meadows 345 kV line into the Viking 345 switching station. The Companies and HVD customer will be responsible for portions of the cost of Viking 345 switching station based on the executed Rule 9 agreement. The customer will provide security for the entire project. Figure TP-63 provides a cost estimate for the project, for which the Companies are responsible.

FIGURE TP-63
PROJECTED CASH FLOWS FOR VIKING SWITCHING STATION

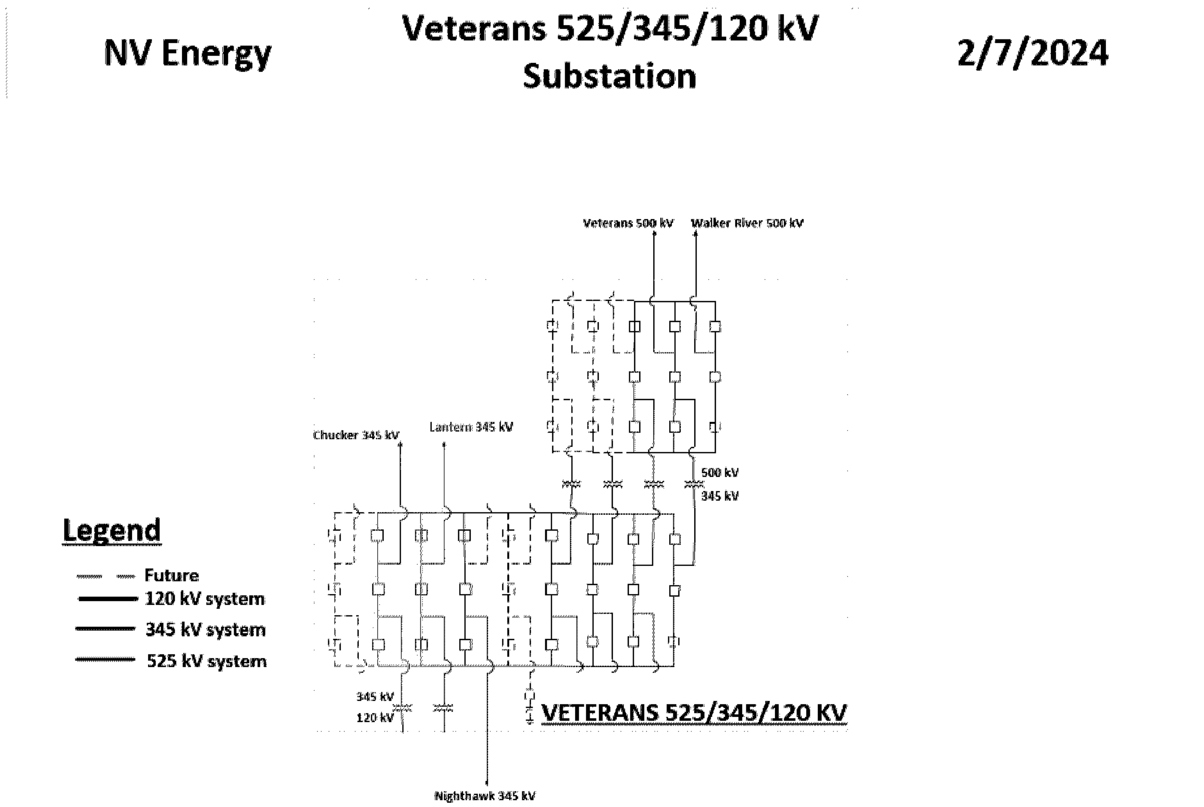
Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
55.00	0.00	1.00	2.00	12.00	15.00	40.00

VETERANS 345/120 KV SUBSTATION

The Lantern – Comstock Meadows 345 kV line will be folded into the new Veterans 345/120 kV Substation. This is required to serve to a Rule 9 MPC agreement for 70 MW, as well as provide redundancy and capacity to the greater Fernley and Fallon area. Also, the Fernley and Fallon area substations have historically experienced extremely low voltages under N-1 loss of generation, that are below transmission planning standard requirements. There is little transmission capacity in the Silver Springs, Fernley, Lahontan, and Fallon area's 60 kV transmission. Thus, customers consistently express interest in adding new loads in the area if capacity is available. Veterans 345/120 kV Substation will increase the area's transmission capacity on the 120 kV system and the underlying 60 kV system. To mitigate low voltage in the area and increase transmission capacity, the Companies are planning to complete a 60 kV to 120 kV line conversion from Comstock Meadows to Lahontan to Eagle/Veterans Substations, with a radial 120 kV line from Lahontan Substation to a new 120/60 kV substation near the existing Fallon Substation. The Companies are not requesting approval of this project as it is under 200 kV, but will present it in a future general rate case. The construction of Veterans 345/120 kV Substation is an integral part of the greater Fallon 60 to 120 kV transmission area master plan. The Companies request approval to construct the new Veterans 345/120 kV Substation to serve the HVD loads, increase transmission capacity in the area for load growth and improve power quality.

Construction Scope: Construct new Veterans 345/120 kV Substation by folding the planned Lantern – Comstock Meadows 345 kV. Construct line terminals at Veterans 345/120 kV Substation with associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. The one-line diagram for the new substation is provided in Figure TP-64.

FIGURE TP-64
Veterans 345/120 kV Substation



<u>Budget and Cost Responsibility</u>: The Companies will be responsible for the cost to fold the new Lantern – Comstock Meadows 345 kV line into Veterans 345/120 kV Substation. The Companies will be responsible for Veterans 345/120 kV Substation. Figure TP-65 provides the cost estimate for the project.

FIGURE TP-65
PROJECTED CASH FLOWS FOR VETERANS 345/120 KV SUBSTATION

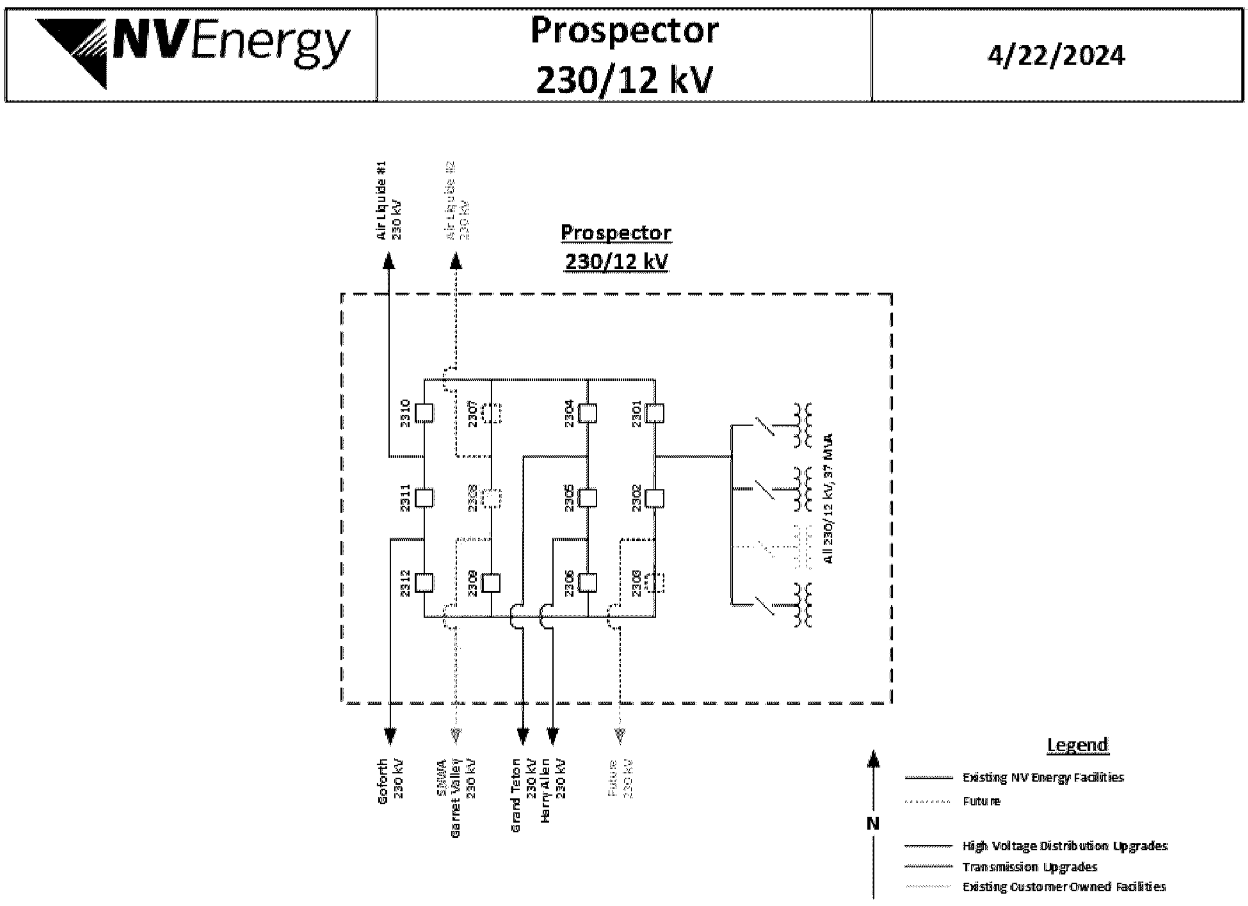
Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
40.00	0.00	.50	3.00	9.00	12.50	27.50

PROSPECTOR 230 KV LINE POSITION

The existing Prospector Substation will require adding a line position to serve a signed Rule 9 HVD agreement load of 7 MW. The Companies request approval to construct the new Prospector Substation 230 kV line position to serve the HVD load.

Construction Scope: Construct the new 230 kV line position to deliver 230 kV to the HVD customer. Including associated line disconnects, breakers, bus work, control house protection panels, communications, and control equipment. The one line diagram for the new line position is included in Figure TP-66.

FIGURE TP-66
PROSPECTOR 230/12 KV SUBSTATION



Budget and Cost Responsibility: The Companies will be responsible for the cost of the 230 kV line position. The HVD customer will be responsible for the cost of the line based on the executed Rule 9 agreement. Figure TP-67 provides the cost estimates for the project, for which the Companies are responsible.

FIGURE TP-67
PROJECTED CASH FLOWS FOR PROSPECTOR 230 KV SUBSTATION

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
2.20	0.00	0.80	1.40	0.00	2.20	0.00

VALMY 345 KV BUS POSITION FOR 411 MW COMBUSTION TURBINE INTERCONNECTION LEAD LINE

As discussed in the Generation section of the Supply Plan, the Companies are seeking approval of two new combustion turbines totaling 411 MW at Valmy, which are quick-start firm dispatchable resource. Interconnection of these turbines will require the addition of a shared 345 kV lead line terminal at the North Valmy Substation 345 kV bus. This new position will require the bus and substation yard to be expanded with new breakers and disconnects. After the addition of the two combustion turbines, with fast-start capabilities, the existing Valmy units must-run procedures can be retired. Without the quick-start units, it is required that the must-run remain in place in perpetuity. It was earlier planned that, after the Greenlink project was completed, the Valmy must-run could end, until load growth occurred such as to require it again. The latest load forecasts and Peak RC procedures indicate the must-run will remain in place in perpetuity unless significant new transmission (in addition to Greenlink) is constructed or the Valmy combustion turbines (2xCTs) with quick-start capabilities are constructed. The Companies request approval to construct the new Valmy 345 kV line terminal.

Construction Scope: Construct new 345 kV line position to interconnect new Valmy CTs generation resources. Including associated line disconnects, breakers, bus work, control house protection panels, line protection, communications, and control equipment. An interconnection map of the substation is included in Figure TP-68.

FIGURE TP-68
NORTH VALMY 345 KV SUBSTATION CT INTERCONNECTION AREA MAP

Budget and Cost Responsibility: The Companies will be responsible for the cost of the 345 kV line's terminal position. The cost estimate for the project is included in Figure TP-69.

FIGURE TP-69
PROJECTED CASH FLOWS FOR VALMY 345 KV SUBSTATION

Cash Flow ($MM)						
Project Total[19]	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
5.22	0.00	.22	.50	4.50	5.22	0.00

HARRY ALLEN 230 KV BUS POSITION FOR 200 MW SOLAR AND BATTERY INTERCONNECTION LEAD LINE – DRY LAKE EAST II

The interconnection of the Dry Lake East II PV/BESS 200/200 MW at Harry Allen 230 kV bus requires a new position and lead line. The new position will require new breakers and disconnects.

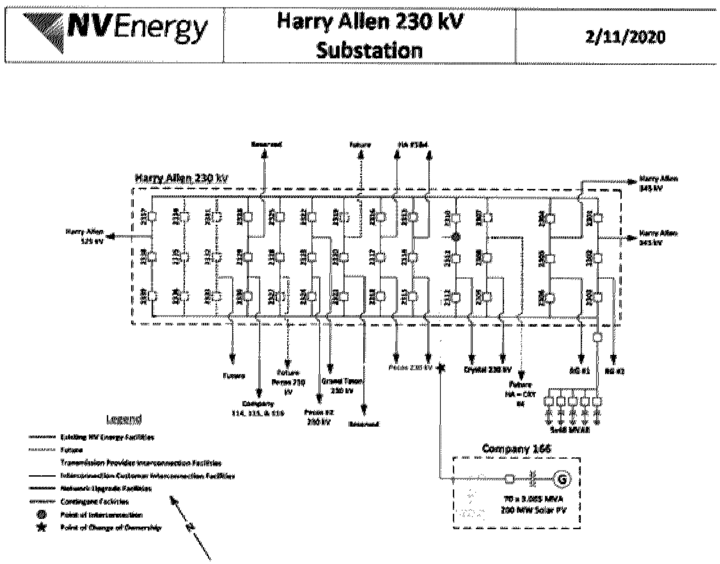
[19] The financial analysis conducted for the integrated resource plan used a preliminary estimated cost ($23.50 MM). Since that time the generator interconnection and designated resource system impacts studies were completed. The corrected costs are reflected in Figure TP-59.

The Pecos transformer 230/138 kV transformer #5 identified in the interconnection system impact study has already been constructed. The Companies request approval to construct the new Harry Allen 230 kV line terminal.

<u>Construction Scope</u>: Construct new 230 kV line position to interconnect new generation resources. Including associated line disconnects, a breaker, control house protection panels, change line protection, communications, and control equipment. A one-line diagram of the project is included in Figure TP-70.

FIGURE TP-70

Harry Allen 230 kV Substation interconnection one line



<u>Budget and Cost Responsibility</u>: The Companies will be responsible for the cost of the 230 kV line's terminal position. Figure TP-71 provides the cost estimates for the project.

FIGURE TP-71
PROJECTED CASH FLOWS FOR HARRY ALLEN 525/230 KV SUBSTATION

Cash Flow ($MM)						
Project Total	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
4.00	0.00	1.20	2.80	0.00	4.00	0.00

NEVADA SOLAR ONE SUBSTATION - SHARED LEAD LINE FOR INTERCONNECTION – BOULDER SOLAR III AND IV

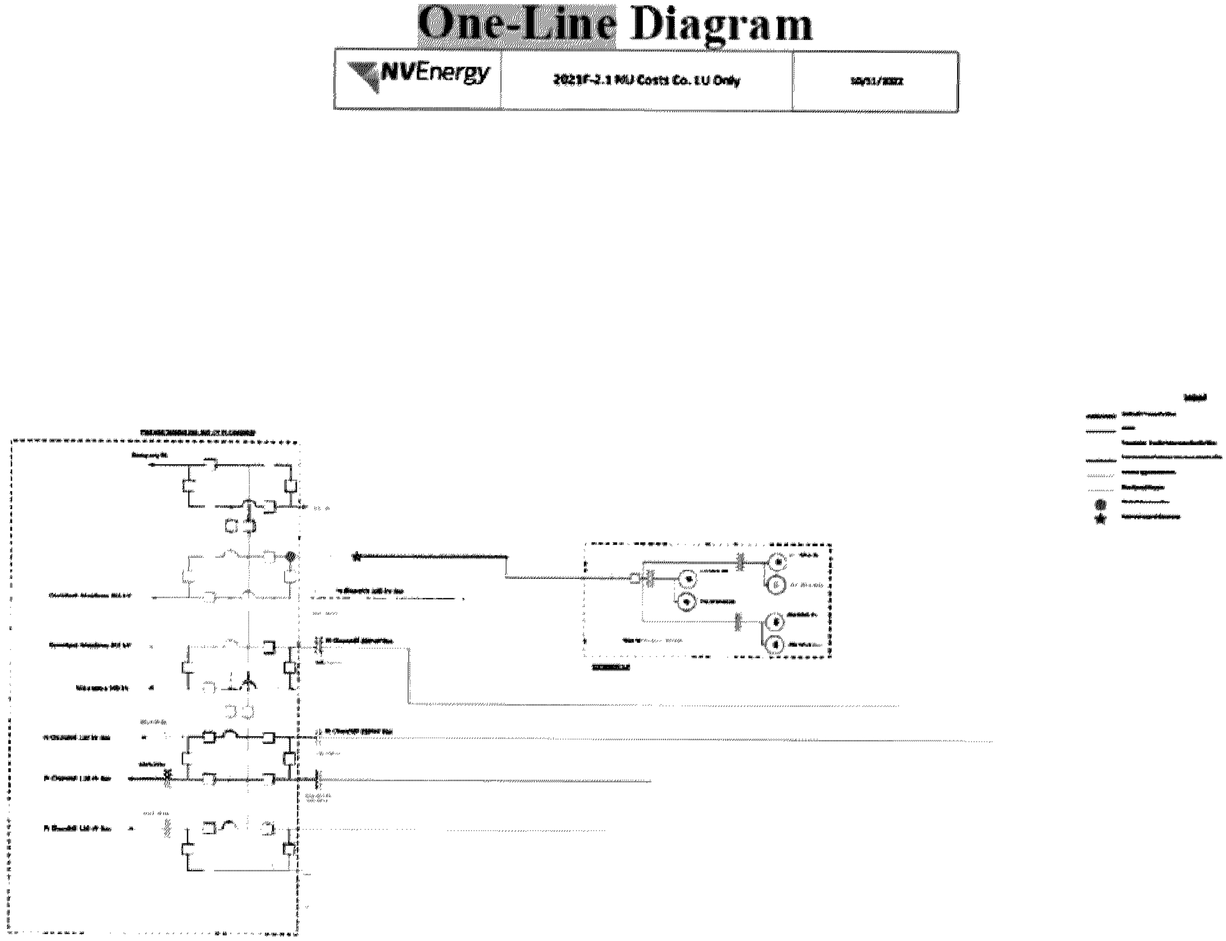
Boulder Solar III and IV solar and storage project interconnection will be utilizing an existing shared lead line. The costs to interconnect projects on a shared lead line have minimal costs. These minimal costs would include metering, communications, and protection changes. No new substation or transmission line, structures and equipment are required.

FT CHURCHILL 345 KV BUS POSITION FOR 700/700 MW SOLAR AND BATTERY INTERCONNECTION LEAD LINE - LIBRA

The interconnection of the Libra PV/BESS 700/700 MW at Ft Churchill 345 kV requires a new bus. This bus is contingent on the Greenlink West project. The ability to move Libra's 700 MW to the load pocket is dependent on construction of the 345 kV common tie lines. If these common tie lines are not completed, the new Libra resource will overload the 120 kV and 60 kV lines around Ft Churchill. It has also been assumed that large loads develop around the TRIC area, which will sink the Libra generation. The Companies request approval to construct the 345 kV lead line terminal.

Construction Scope: Construct new 345 kV line position to interconnect new generation resources, including associated line disconnects, a breaker, control house protection panels, change line protection, communications, and control equipment. The one line diagram of the upgrade is provided in Figure TP-72.

FIGURE TP-72
FT CHURCHILL 345 KV SUBSTATION INTERCONNECTION ONE LINE



Budget and Cost Responsibility: The Companies will be responsible for the cost of the 345 kV line's terminal position. Figure TP-73 provides the cost estimate for the project.

FIGURE TP-73
PROJECTED CASH FLOWS FOR FT CHURCHILL 345 KV INTERCONNECTION

Cash Flow ($MM)						
Project Total[20]	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
3.90	0.00	0.00	1.00	3.80	3.90	0.00

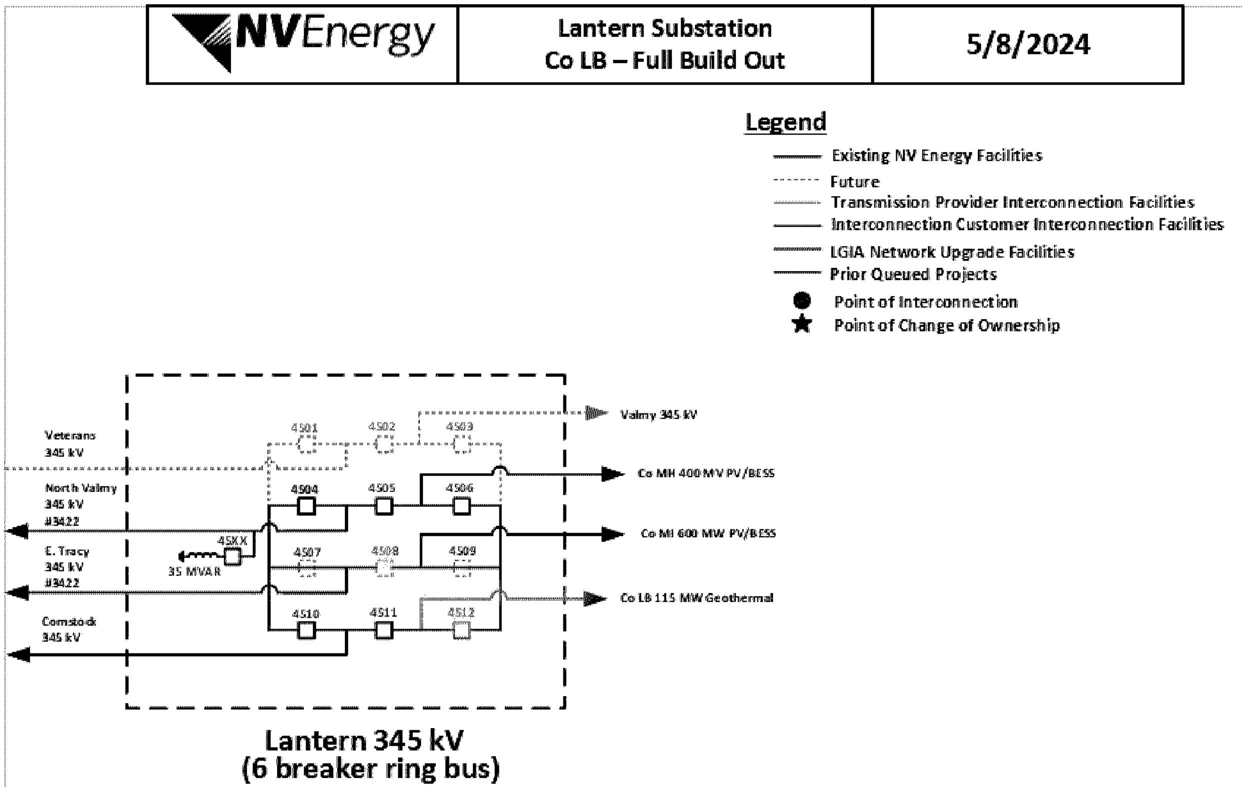
[20] The financial analysis for this resource plan had used a preliminary estimate $2.00 MM, the table contains a correct interconnection cost of $3.90 MM per the LGIA.

LANTERN 345 KV BUS POSITION FOR 115 MW GEOTHERMAL INTERCONNECTION LEAD LINE – CORSAC GEOTHERMAL

This project is designed to interconnect the Corsac Geothermal 115 MW facility at Lantern 345 kV bus. This project will be dependent on the Lantern – Comstock Meadows 345 kV line for transmission rights. The 345 kV bus rung, on which the Corsac Geothermal will be interconnected, will be constructed for the new Lantern – Comstock Meadows 345 kV line. The Lantern – Comstock 345 kV line is also required to move the large amount of power to the specific customer's load for which it is contracted to serve in 2030. The bus will be opened at breaker 4508 to create a six-breaker ring bus. It is also assumed that large loads developing around the TRIC area will also help sink the power from this new generation resource. This new line position will require a new breaker and disconnects. The Companies request approval to construct the 345 kV lead line terminal.

Construction Scope: Construct new 345 kV line position to interconnect new generation resources. Including associated line disconnects, a breaker, control house protection panels, communications, and control equipment. A one line diagram of the project is included in Figure TP-74.

FIGURE TP-74
LANTERN 345 KV SUBSTATION INTERCONNECTION ONE LINE



Budget and Cost Responsibility: The Companies will be responsible for the cost of the 345 kV line terminal position. Figure TP-75 includes a cost estimate for the project.

FIGURE TP-75
PROJECTED CASH FLOWS FOR LANTERN 345 KV INTERCONNECTION

Cash Flow ($MM)						
Project Total[21]	**Pre-2025**	**2025**	**2026**	**2027**	**3 Year Total** (2025-2027)	**Post 2027**
2.00	0.00	0.00	0.00	0.00	0.00	2.00

Transmission Projects' Jobs and Economic Benefits

The new transmission projects being requested for approval produce substantial jobs and economic benefits as Figure TP-76 below shows. The below listed transmission projects exclude Greenlink,

[21] The financial analysis for this resource plan had used a preliminary estimate $2.00 MM, the table contains a correct interconnection cost of $3.90 MM per the LGIA.

including its Common Ties component requested for construction approval in this filing - Ft. Churchill-Comstock Meadows #2 line. Due to the numerosity of the transmission projects and relatively limited investments associated with a number of those projects, the Companies estimated the jobs and economic benefits using the allocators derived for the Greenlink project.

FIGURE TP-76
NEW TRANSMISSION PROJECTS JOBS AND ECONOMIC BENEFITS

	Employment (Person Years)				Wages ($M)				Total Economic Impact ($M)			
	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total
Tolson Substation Transformer #2	4.8	1.3	3.6	9.7	$ 0.69	$ 0.08	$ 0.17	$ 0.94	$ 0.97	$ 0.25	$ 0.59	$ 1.81
Reid Gardner – Harry Allen 230 kV Line #3	12.0	3.2	9.1	24.3	$ 1.73	$ 0.20	$ 0.44	$ 2.37	$ 2.44	$ 0.62	$ 1.49	$ 4.55
Lantern-Comstock Meadows 345 kV Line	52.2	13.9	39.5	105.6	$ 7.52	$ 0.85	$ 1.89	$ 10.26	$ 10.61	$ 2.69	$ 6.47	$ 19.76
Comstock Meadows Transformer #2	6.5	1.7	4.9	13.1	$ 0.93	$ 0.11	$ 0.23	$ 1.27	$ 1.31	$ 0.33	$ 0.80	$ 2.45
West Tracy Transformer #1	6.5	1.7	4.9	13.1	$ 0.93	$ 0.11	$ 0.23	$ 1.27	$ 1.31	$ 0.33	$ 0.80	$ 2.45
Machacek Two 230 kV Line Breakers	7.4	2.0	5.6	14.9	$ 1.06	$ 0.12	$ 0.27	$ 1.45	$ 1.50	$ 0.38	$ 0.91	$ 2.79
Darling Substation Two 37 MVA 230/12 kV	21.6	5.7	16.3	43.7	$ 3.12	$ 0.35	$ 0.78	$ 4.25	$ 4.39	$ 1.11	$ 2.68	$ 8.19
Log Cabin 37 MVA 230/12 kV	16.8	4.5	12.7	33.9	$ 2.42	$ 0.27	$ 0.61	$ 3.30	$ 3.41	$ 0.86	$ 2.08	$ 6.35
Spring Canyon	24.7	6.6	18.6	49.9	$ 3.55	$ 0.40	$ 0.89	$ 4.85	$ 5.01	$ 1.27	$ 3.06	$ 9.33
Ft. Churchill #3 and #4 600 MVA 525/345 kV	11.9	3.2	9.0	24.1	$ 1.72	$ 0.19	$ 0.43	$ 2.35	$ 2.42	$ 0.61	$ 1.48	$ 4.52
Mackay 345 kV Switching Station	13.9	3.7	10.5	28.1	$ 2.01	$ 0.23	$ 0.50	$ 2.74	$ 2.83	$ 0.72	$ 1.72	$ 5.27
Gosling 345 kV Switching Station	2.5	0.7	1.9	5.0	$ 0.36	$ 0.04	$ 0.09	$ 0.49	$ 0.51	$ 0.13	$ 0.31	$ 0.94
Ft. Churchill-Veterans 525kV Line Permitting	7.0	1.8	5.3	14.1	$ 1.00	$ 0.11	$ 0.25	$ 1.37	$ 1.41	$ 0.36	$ 0.86	$ 2.63
Naniwa 345 kV Switching Station	12.9	3.4	9.8	26.1	$ 1.86	$ 0.21	$ 0.47	$ 2.54	$ 2.63	$ 0.66	$ 1.60	$ 4.89
Nighthawk 345/120 kV Substation	33.3	8.9	25.2	67.4	$ 4.80	$ 0.54	$ 1.21	$ 6.55	$ 6.77	$ 1.71	$ 4.13	$ 12.61
Vaquero 345/120 kV Substation	14.9	4.0	11.3	30.2	$ 2.15	$ 0.24	$ 0.54	$ 2.93	$ 3.03	$ 0.77	$ 1.85	$ 5.65
Viking 345 kV Switching Station	27.4	7.3	20.7	55.3	$ 3.94	$ 0.45	$ 0.99	$ 5.38	$ 5.56	$ 1.41	$ 3.39	$ 10.35
Veterans 345/120 kV Substation	19.9	5.3	15.0	40.2	$ 2.87	$ 0.32	$ 0.72	$ 3.91	$ 4.04	$ 1.02	$ 2.46	$ 7.53
Prospector 230 kV Line Terminal	1.1	0.3	0.8	2.2	$ 0.16	$ 0.02	$ 0.04	$ 0.22	$ 0.22	$ 0.06	$ 0.14	$ 0.41
Valmy CTs Line Terminal	2.6	0.7	2.0	5.2	$ 0.37	$ 0.04	$ 0.09	$ 0.51	$ 0.53	$ 0.13	$ 0.32	$ 0.98
Dry Lake East II PV/BESS Line Terminal	2.0	0.5	1.5	4.0	$ 0.29	$ 0.03	$ 0.07	$ 0.39	$ 0.40	$ 0.10	$ 0.25	$ 0.75
Libra PV/BESS Line Terminal	1.9	0.5	1.5	3.9	$ 0.28	$ 0.03	$ 0.07	$ 0.38	$ 0.39	$ 0.10	$ 0.24	$ 0.73
Corsac Geothermal	-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL TRANSMISSION	303.8	80.7	229.5	614.0	$ 43.75	$ 4.96	$ 10.99	$ 59.70	$ 61.70	$ 15.62	$ 37.62	$ 114.95

4. INFORMATIONAL

CAPTAIN JACK – FT CHURCHILL 525 KV LINE

The Companies are continuing to evaluate the feasibility of the Captain Jack – Ft Churchill 525 kV transmission line or a comparable alternative to increase transmission import capacity into the Companies' northern Nevada region and to access the Pacific Northwest region for diverse renewable energy resources. Several load serving, marketing, and transmission entities have expressed interest in this transmission line to diversify their regions' energy portfolios, access renewable energy resources outside their native regions, and to improve transmission system reliability. The Companies have submitted a transmission-to-transmission interconnection request with Bonneville Power Administration at Captain Jack Substation. A preliminary routing and siting study for the line has been completed.

ON LINE 2 – ROBINSON SUMMIT – HARRY ALLEN 525 KV LINE

The Companies were granted an offer for the right of way N-82076 to construct and operate a 235-mile 525 kV transmission line and fiber optic line called ON Line 2 in 2011 by the Bureau of Land Management. The Bureau of Land Management later extended the grant offer in abeyance until 2024. The Companies have requested an extension of the abeyance until 2029. The need for ON Line 2 is being evaluated and is dependent on the transmission requests that could be received. A 2028 in-service date would align with the planned in-service date of the Greenlink North and the Crosstie transmission project. The Crosstie project represents a transmission line between the Companies' Robinson Summit Substation and PacifiCorp's Clover Substation in central Utah. If SWIP-N and Crosstie are constructed as planned, then it may become necessary to construct ON Line 2. Additionally, if large resources are added on Greenlink or at Robinson Summit, ON Line 2 could become a required network upgrade. There is the potential to construct a collector substation, that is not currently permitted, to interconnect large renewable resources in the designated renewable energy zone that is located along the ON Line 2 route.

CLARK MUST-RUN MITIGATIONS

Preliminary transmission system analysis showed that to retire Clark thermal generation units and end the year-by-year power purchases with Saguaro and NCA2, the Clark Substation will require transformer E1 138/69 kV be replaced with a 167 MVA unit. Similarly, the Clark transformer #6 would need to be replaced with a 336 MVA 230/138 kV transformer, and Falkner Substation would require a second 336 MVA 230/138 kV transformer be installed. These transformers were included in all the alternative resource plans and are, therefore, not material to the preferred plan selection. As Clark is planned to retire in 2049, a periodic must-run at Clark is the least cost mitigation. The need for the must-run will increase as more and more solar generation is added to the resource plan.

NORTHWEST TRANSFORMERS #7

The Northwest 1500 MVA 525/230 kV transformer #7 is required to allow White Pine Pumped Hydro and Amargosa Solar generators to be designated network resources. Both generators are named placeholders in the current resource plan. This transformer's cost was included in all the alternative resource plans and is, therefore, not material to the section of the preferred plan. When either of these two resources are selected in a resource plan, this transformer will be requested for construction approval at that time.

THERMAL RESOURCES EVALUATED BUT NOT REQUESTED IN THIS IRP

Two new Ft Churchill CTs totaling 411 MW require a 345 kV line terminal at Ft Churchill Substation for generator lead line interconnection. The interconnection and transmission capacity are contingent on: Greenlink West's construction of Ft Churchill 345 kV bus, Ft Churchill – Mira Loma 345 kV line and the Ft Churchill – Comstock Meadows 345 kV line #2. The line terminal is estimated to cost $5.00 million. The initial estimate used in the selection of preferred plan was 2.00 million.

Two new Higgins CTs totaling 411MW require that a new 230 kV line terminal at Big Horn Substation be constructed. It also requires a new Big Horn – Arden 230 kV line #3 be constructed for N-1 contingency loss of any of the existing Big Horn – Arden lines. Estimated costs of these two network upgrades are $84.00 million.

Two new Harry Allen CTs 411 MW require a 230 kV line terminal at Harry Allen Substation for the generator interconnection. This new line terminal is estimated to cost $5.00 million.

NAMED PLACEHOLDER RESOURCES IN THIS IRP

Idaho Wind totaling 952 MW in 2029 will be contingent on SWIP-N which is not a NV Energy project. The SWIP-N in-service date is as early as 2028. The SWIP-N project includes series compensation of ON Line.

Sierra Solar II PV/BESS 600 MW will require series compensation of ON Line. It also requires Lantern – Comstock Meadow 345 kV line be constructed.

Amargosa phase I, II and III PV/BESS totaling up to 1,200 MW will require series compensation of ON Line. It also requires the construction of Northwest #7 transformer 1,500 MVA 525/230 kV.

White Pine PV/Pumped Hydro totaling up to 1,000 MW will require series compensation of ON Line, and the Northwest #7 transformer 1,500 MVA 525/230 kV be constructed.

RENEWABLE/STORAGE RESOURCES EVALUATED BUT NOT REQUESTED IN THIS IRP

NCA 2 PV/BESS 57 MW requires the rebuilding of Cary – Pabco 69 kV line and a new lead line, which is estimated to cost $12.0 million.

Gold Stike 80 MW required no new network upgrades.

Red Valley PV/BESS 200 MW required a new 230 kV line, estimated to cost $41.0 million.

Stagecoach Wind 500 MW requires a new collector Substation near Robinson Summit estimated to cost $32.7 million.

5. UPDATES ON PREVIOUSLY APPROVED TRANSMISSION PROJECTS

The following projects have been approved by the Commission and are not complete or completed after the most recent Triennial Filing. These updates are provided for information only.

Docket	Project Name	ISD	Status	Cost ($MM) - as of February 2024
19-05003	Dodge Flat Solar - 200 MW at Olinghouse 345 kV	12/31/2021	Complete	NA
18-06003	Fish Springs Ranch - 100 MW at Ft Sage 345 kV	6/30/2021	Complete	NA
18-06003	Eagle Shadow Mountain - 300 MW at Reid Gardner 230 kV	12/31/2021	Complete	3.9
19-05003	Harry Allen Solar - 100 MW at HA 230 kV	2/24/2021	Active	1.9
19-05003	Aiya Solar - 100 MW at RG 230 kV - NO DNR	6/30/2023	Withdrawn	NA
19-06003	Moapa Solar - 200 MW at HA 230 kV	6/1/2022	Complete	1.7
19-06003	Eagle Shadow Mountain 2 - 300 MW at Reid Gardner 230 kV	6/1/2023	Active	0.0
19-06003	Gemini Solar - 690 MW at Crystal 230 kV	11/1/2023	Active	9.7
19-06003	Gemini Solar - 250 MW at 525 kV	12/1/2023	Suspended	0.0
20-07023	Dry Lake Solar - 150 MW at HA 230 kV	5/29/2023	Active	1.9
20-07023	Chuckwalla Solar - 200 MW at HA 230 kV	6/1/2023	Active	0.0
20-07023	Boulder Solar 3 - 128 MW at NSO 230 kV	n/a	Suspended	0.0
Update 19-05003	McDonald 230/138 kV Substation Upgrade	5/30/2019	Complete	6.2
Update 19-05003	Bordertown to California 120 kV Project	11/21/2024	Active	12.8

19-05003	Comstock Meadows 345 /120 kV Substation	11/1/2025	Suspended	5.4
19-05003	Reid Gardner to Tortoise #2 230 kV line	1/6/2023	Active	7.0
19-05003	Shaffer 345 kV Substation	12/1/2023	Active	3.1
19-05003	Magnolia 230/138 Transformer #2	5/4/2020	Complete	6.8
19-05003	Bighorn 230/69 kV Transformer and Oasis 69 kV Line	6/29/2028	Active	1.7
19-05003	West Henderson routing and siting	6/2/2022	Active	23.5
19-05003	Carson Lake - 20 MW at 230 kV Substation	9/16/2022	Suspended	NA
19-05003	Pershing Solar - 240 MW on #3421	n/a	Suspended	0.8
19-05003	Apex 230 kV Switchyard	6/1/2021	Active	11.0
20-07023	Greenlink North	12/1/2026	Active	See narrative
20-07023	Greenlink West	12/1/2029	Active	See narrative
20-07023	Mercury to Northwest 138 kV Line Relocation	9/15/2023	Active	0.4
20-07023	Arden to Avera 230 kV Substation (now Beltway Complex)	5/31/2022	Active	4.5
20-07023	Round Mountain 230/24.9 kV Transformer Addition	11/12/2021	Completed	NA

6. TRANSMISSION LOSSES

NAC § 704.9385(3)(h) requires the Companies include in its Transmission Plan a description of efforts to reduce the impact of line losses on future resource requirements. The Companies' efforts to evaluate and mitigate line losses are ongoing. Line losses are calculated into the overall plan of service for load growth, selection of company-owned generation, independent power producer development, and renewable energy evaluations in order to develop the most cost effective facilities (*i.e.*, the impact of losses is evaluated in those cases where the Companies have the ability to select from various options).

7. RENEWABLE ENERGY ZONE TRANSMISSION PLAN

In response to the requirements provided for in NAC § 704.9385(6) and NAC § 704.9489(5), regarding the development of transmission facilities to serve renewable energy zones within the State of Nevada, the Companies have prepared a Conceptual Renewable Energy Zone Transmission Plan ("REZTP" or "Plan").

The REZTP is a conceptual plan for transmission facilities that shows possible transmission access to areas of Nevada that have been designated as renewable energy zones. The REZTP does not request any funds construction nor does it request Commission approval of any facilities associated with the REZTP.

The Companies did not produce new studies for the REZTP for this filing. Upon a new identification of renewable energy zones by the Commission, the Companies will revisit the REZTP and update accordingly.

8. NORTHERNGRID MEMBERSHIP

Per NAC § 704.9385(3)(f), the Companies are required to describe their participation in regional planning organizations, as well as the role of these organizations in the Companies' transmission planning activities. In Docket No. 21-06001, the Companies requested permission to discontinue participation in WestConnect and begin participation in NorthernGrid effective January 1, 2022. Since January 1, 2022, the Companies have participated in the NorthernGrid regional transmission planning process. The Companies are mandated to participate in a regional planning group in compliance with FERC Order 1000 and Attachment K of the Companies OATT. NorthernGrid has a FERC-approved Planning Participation Agreement setting forth the rights and obligations of members who pay dues and participate. The Companies participated in the 2022-2023 regional transmission planning cycle activities and are currently participating in the 2024-2025 planning cycle. The Companies are requesting permission to continue participation in NorthernGrid with funding of approximately $396,000 distributed equally over the three-year Action Plan period, as shown in Figure TP-77 below. With the FERC approval of Order No. 1920, it will be necessary to revise the NorthernGrid regional transmission planning process. This could result in additional costs beyond this budget.

FIGURE TP-77
NORTHERNGRID MEMBERSHIP DUES (IN THOUSANDS)

	2025	2026	2027	2025-2027
NV Energy	$132	$132	$132	$396

9. FEDERAL REGULATORY FILINGS

NAC § 704.9385(3)(g) requires the Companies include in the Transmission Plan a summary of the impacts of relevant orders issued by FERC since the last IRP, Docket No. 16-07001. The following information is provided in compliance with that requirement.

Since May 2018, Nevada Power Company, Sierra Pacific and/or NV Energy was a party to or was affected by the following Federal Energy Regulatory Commission (FERC) orders categorized chronologically (the most recent first) and by the following subject matters:

a. Rulemaking Orders
b. Transmission Tariff Orders
c. Rate Orders
d. Agreement Orders
e. California Independent System Operator Corporation Energy Imbalance Market Orders
f. Merger, Acquisitions & Asset Transfer Orders
g. Gas Pipeline Suppliers' Orders

a. Rulemaking Orders

May 13, 2024
Docket No. RM21-17-000
Order 1920 "Building for the Future through Electric Regional Transmission Planning and Cost Allocation"
FERC issued Order 1920, which implements many new regional transmission planning requirements. The final rule will be effective 60 days after publication in the Federal Register (tbd), and compliance filings will be due 10 months after the effective date. The interregional components of compliance will be due 12 months after the effective date (tbd). Requests for re-hearings and clarifications are due by June 12, 2024.

October 26, 2023
Docket No. RM19-17 (185 FERC ¶ 61,064)
Order 902 "*Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards Under the NERC Standards Efficiency Review*"
FERC approved request to retire six Reliability Standards with a combined total of 56 requirements. For the reasons discussed below, we determine that the retirement of six Reliability Standards (the MOD A Reliability Standards)[22] in their entirety is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

[22] Reliability Standards MOD-001-1a (Available Transmission System Capability), MOD-004-1 (Capacity Benefit Margin), MOD-008-1 (Transmission Reliability Margin Calculation Methodology), MOD-028-2 (Area Interchange Methodology), MOD-029-2a (Rated System Path Methodology), and MOD-030-3 (Flowgate Methodology).

October 19, 2023
Docket No. RM22-12 (185 FERC ¶ 61,042)
Order 901 *"Reliability Standards to Address Inverter-Based Resources"*
FERC directed NERC to develop new or modified Reliability Standards that address reliability gaps related to inverter-based resources in the following areas: data sharing; model validation; planning and operational studies; and performance requirements. FERC is also directing NERC to submit to the Commission an informational filing within 90 days of the issuance of this final rule that includes a detailed, comprehensive standards development plan providing that all new or modified Reliability Standards necessary to address the inverter-based resource-related reliability gaps identified in this final rule be submitted to the Commission by November 4, 2026.

July 28, 2023
Docket No. RM22-14 (184 FERC ¶ 61,054)
Order 2023, *"Improvements to Generator Interconnection Procedures & Agreements"*
FERC required all public utilities to submit tariff compliance filings by April 3, 2024, in order to provide one cluster study per year for interconnection projects. Additionally, the tariff will provide a first-ready, first-served study process; there are new penalties for delayed studies and project withdraws, automatic project withdraws for failures to meet deadlines; new commercial readiness deposit, new heatmap posted on OASIS to see available transmission capacity; new affected systems procedures and agreements, no deposits in lieu of site controls except for regulatory limitations; as well as requirements to include new alternative transmission technologies in the studies. Order 2023 was 1482 pages with over 200 pages of tariff changes.

July 27, 2023
Docket No. RM22-19 (183 FERC ¶ 61,033)
Order 893 *"Incentives for Advanced Cybersecurity Investment"*
FERC revised its regulations to provide incentive-based rate treatment for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by utilities for the purpose of benefitting consumers by encouraging investments by utilities in Advanced Cybersecurity Technology and participation by utilities in cybersecurity threat information sharing programs, as directed by the Infrastructure Investment and Jobs Act of 2021.

June 15, 2023
Docket No. RM22-16 (183 FERC ¶ 61,191)
Order 896 *"Transmission System Planning Performance Requirements for Extreme Weather"*
FERC ordered NERC to develop a new or modified Reliability Standard no later than 18 months of the date of publication of this final rule in the Federal Register to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System. Specifically, NERC must develop a new or modified Reliability Standard that requires the following: development of benchmark planning cases based on prior extreme heat and cold weather events and/or future meteorological

projections; planning for extreme heat and cold events using steady state and transient stability analyses that cover a range of extreme weather scenarios, including the expected resource mix's availability during extreme weather conditions and the broad area impacts of extreme weather; and corrective action plans including mitigation activities for specified instances where performance requirements during extreme heat and cold events are not met.

June 15, 2023
Docket No. RM22-16 (183 FERC ¶ 61,192
Order 897 *"One Time Informational Reports on Extreme Weather Vulnerability Assessments, Climate Change, Extreme Weather & Electric System Reliability"*
FERC required all transmission providers to submit one-time reports describing their policies and processes for conducting extreme weather vulnerability assessments and identifying mitigation strategies. NV Energy's report was submitted on October 23, 2023.

January 19, 2023
Docket No. RM22-3 (182 FERC ¶ 61,021)
Order 887, *"Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems"*
FERC directed NERC to develop and submit for Commission approval new or modified Critical Infrastructure Protection (CIP) Reliability Standards that require internal network security monitoring for high and medium impact Bulk Electric System (BES) cyber systems. The new or modified CIP Reliability Standards would require that applicable responsible entities implement internal network security monitoring for their high and medium impact BES cyber systems.

December 16, 2021
Docket No. RM20-16 (177 FERC ¶ 61,179)
Order 881, *"Managing Transmission Line Ratings ("TLRs")"*
FERC required all transmission providers to make tariff compliance filings by July 10, 2022, and by July 12, 2025 to provide hourly ambient adjusted ratings (AARs) for transmission lines; calculate seasonal and emergency ratings; to share AARs and methodologies with their respective transmission provider(s), market monitors in RTOs/ISOs & reliability coordinator; to use AARs to evaluate near term transmission services (10 days); and to maintain a database of its TLRs and methodologies on its OASIS website.

December 17, 2020
Docket No. RM20-8 (173 FERC ¶ 61,243)
Virtualization and Cloud Computing Services "Order Directing Informational Filing"
FERC issued an order directing NERC to make an informational filing that considers the feasibility of modifying the CIP Reliability Standards to facilitate the voluntary use of virtualization and cloud computing for purposes beyond data storage (i.e., to perform BES reliability operating services), as well as the status and schedule for any plans to modify the standards by NERC. NERC's informational filing is by January 1, 2022.

b. Transmission Tariff Orders

October 3, 2023
Docket No. ER23-2143 Tariff Attachment P *"Energy Imbalance Market Charges"*
FERC accepted amended tariff Attachment P, which will sub-allocate any revenue or charges associated with Western Energy Imbalance Market assistance energy transfers. The tariff change is effective July 1, 2023.

July 27, 2023
Docket No.22-2304 (184 FERC ¶ 61,048)
FERC Tariff Attachment Q, *"Transmission Line Ratings and Ambient Air Ratings ("AARs")"*
FERC issued an order accepting the compliance filing. However, the Company needs to file its timeline for calculating its AARs by November 12, 2024.

May 15, 2023
Docket No. ER23-2933, Tariff Attachment N "*Interconnection Procedures and Agreement"*.
FERC accepted tariff revisions to the Large Generator Interconnection Procedures, which removed the tariff language not approved by FERC's initial order issued Feb. 3, 2023. This tariff change is effective 12/1/2022. FERC also accepted the revised tariff filing that changed the method for allocating the cost of identified interconnection-related facilities among interconnection customers being studied in a cluster. This tariff change is effective 5/16/2023.

May 15, 2023
Docket No. EL23-27, "*Dismissal of Show Cause Order* "
FERC terminated the section 206 show cause proceeding initiated to investigate the Companies' initial tariff filing that proposed changes to the cost allocation of interconnection projects and penalty provisions for withdrawn projects because the tariff change was withdrawn.

March 22, 2023
Docket No. EL22-73, *"Order Granting Petition for Declaratory Order"*
FERC granted NV Energy's request for transmission rate incentives for the Greenlink Nevada Transmission Project. Specifically, FERC authorized NV Energy to recover: 1) 100 percent of its prudently-incurred costs if the Project is cancelled or abandoned, in whole or in part, for reasons beyond NV Energy's control (Abandoned Plant Incentive); 2) the deferral of 100 percent of the Project's prudently incurred pre-commercial costs through the creation of a regulatory asset (Regulatory Asset Incentive); and 3) the opportunity to include 100 percent of Construction Work in Progress (CWIP) in rate base.

February 10, 2023
Docket No. ER22-2762 (182 FERC ¶ 61,063) "*Order Accepting Proposed Tariff re Northwest Power Pool ("WPP")"* FERC accepted WPP's the proposed Western Resource Adequacy

Program (WRAP) Tariff effective January 1, 2023. The proposed WRAP Tariff sets forth the framework for a new voluntary resource adequacy planning and compliance program in the Western Interconnection.

February 3, 2023
Docket No. ER23-2933 (182 FERC ¶ 61,048) "*Order on Tariff Revisions*"
Tariff Attachment N "*Interconnection Procedures and Agreement*". FERC accepted in part and rejected in part, proposed tariff revisions to (i) clarify or clean up various tariff provisions, (ii) modify its Large Generator Interconnection Procedures (LGIP) and Small Generator Interconnection Procedures (SGIP) and (iii) add a new Schedule 12 to recover from retail access transmission service customers the applicable portion of franchise or licensing fees assessed by Nevada local authorities. FERC accepted the proposed pass-through of license and franchise fees as just and reasonable because these fees are akin to a tax and are therefore legitimate costs of providing unbundled retail transmission service to customers in these retail jurisdictions. The Commission also accepted the proposed modification to the LGIP and SGIP; except for the withdrawal penalties and cure period.

February 2, 2023
Docket No. EL23-27 (182 FERC ¶ 61,051) "Order Establishing a *Show Cause Proceeding* "
FERC initiated a Section 206 Show Cause Order for the Company to explain the methodology for allocating network upgrade costs among an interconnection queue cluster. This order is a result of a tariff clean-up order issued the same day. NVE had 60 days [by 4/4/2023] from the date of the order, to either (1) show cause as to why its tariff language remains just and reasonable and not unduly discriminatory or preferential, or (2) explain what changes to its tariff it believes would remedy the identified concerns.

September 27, 2022
Docket No. ER22-2570 "*Letter Order Accepting Sierra Pacific Power Company's 08/01/2022 filing of revisions to its Reserve Energy Service Rate Schedule*" The Company revised the index settlement price for reserve energy to the average of the Mid-Columbia. FERC accepted Sierra Pacific Power Company's Rate Schedule 42, which revised the index settlement price for reserve energy to the average of the Mid-Columbia and Palo Verde Day-Ahead peak or Off-peak Price, as published by Intercontinental Exchange, Inc., and eliminated the option to return in-kind energy. This order was effective October 1, 2022.

May 9, 2022
Docket No. ER22-1242 (179 FERC ¶ 61,103) *"Order on Tariff Revisions"*
FERC issued an order accepting proposed revisions to the FERC Tariff Schedule 2, *Reactive Supply and Voltage Control from Generation or Other Sources Service*, to eliminate all charges for Schedule 2 service from the Company's own and affiliated resources effective March 11, 2022.

March 7, 2022
Docket No. ER21-2481 *"Letter Order Accepting Nevada Power Company's 07/22/2022 Filing Stating That Their Currently Effective Joint Open Access Transmission Tariff complies with Order No. 676-I."*

December 21, 2021
Docket No. ER22-236 *"Letter Order Accepting Certificate of Concurrence to the NorthernGrid Funding Agreement*". FERC accepted Nevada Power Company's Certificate of Concurrence to the NorthernGrid Funding Agreement that was submitted to FERC by MATL LLP in Docket No. ER22-222.

December 21, 2021
Docket No. ER22-262 *"Letter Order Accepting Notice of Cancellation of Certificate of Concurrence to the WestConnect Planning Participation Agreement*".

October 22, 2021
Docket No. ER21-2768 *"Letter Order Accepting Revisions to Attachment K of the open access transmission tariff"*. FERC accepted revisions to Attachment K of the FERC tariff in order to reflect transition from the WestConnect regional transmission planning process to the NorthernGrid regional transmission planning process to be effective January 1, 2022.

August 6, 2021
Docket No. ER21-2111 *"Order Accepting Large Generator Interconnection Agreement between Nevada Power Company and FS Saguaro, LLC*".

October 15, 2020
Docket No. ER19-1904 (173 FERC ¶ 61,059) *"Order on Compliance"*
FERC accepted in part and rejected in part proposed revisions to the FERC tariff in compliance with the requirements of Order Nos. 845 and 845-A and the order on compliance issued on October 15, 2020.

c. Rate Orders

November 21, 2022
Docket No.ER22-839, Spring Valley Wind, (181 FERC ¶ 61,153)
Docket No.ER22-840, Battle Mountain (181 FERC ¶ 61,152)
Docket No.ER22-841 Copper Mountain (181 FERC ¶ 61,151)
"Letter Order Approving Joint Offer of Settlement & Settlement Agreement Addressing the Annual Revenue Requirement for Reactive Supply & Voltage"
FERC accepted three NV Energy settlements in three separate orders with the following generators: Battle Mountain, Copper Mountain and Spring Valley Wind to resolve SPPC and

Nevada Power Company *d/b/a* NV Energy payments for Reactive Supply and Voltage Control from Generation Sources Service as defined its FERC Tariff Schedule 2. The settlement provides for a black-box annual revenue requirement for services provided between January 20, 2022, Schedule 2 effective date and March 11, 2022 ("Recovery Period"), when FERC made effective NV Energy's revisions to Schedule 2, which eliminated reactive service compensation for generation resources within the standard power factor range. The generators were paid for their services during the Recovery Period: Battle Mountain – $83,013.70; Copper Mountain – $150,000 and Spring Valley Wind - $82,191.78.

June 8, 2022
Docket No. ER21-434 "*Order on Justification Filings and Directing Refunds re: Nevada Power Company Real Time Sale above the $1000 WECC Soft Cap.* Nevada Power sold 50 MW to Salt River Project for $1,700/MWh on August 19, 2020, and was ordered to refund price above the Palo Verde Index price for that hour.

May 9, 2022
Docket No. ER22-1242 *"Order on Tariff Revisions*". FERC accepted Nevada Power's proposed revisions to Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service) of the tariff to eliminate all charges for Schedule 2 service from Nevada Power's own and affiliated resources.

d. Agreement Orders

November 2, 2023
Docket No. ER23-2805 *"Letter Order accepting September 11, 2023, filing of an amended Network Integration Transmission Service Agreement with Lassen Municipal Utility District as Network Customer"*

April 19, 2023
Docket Nos. ER23-1180; ER23-1181, ER23-1182 and ER23-1196
Letter order accepting NV Energy's notices of termination for sixteen rate schedules or service agreements, some were prior to the existence of FERC e-tariff. These terminations were part of the inter-company re-organization merger. The terminations were effective February 27, 2023.

January 17, 2023
Docket No. ER23-482 *"Letter order accepting a Service Agreement for the Resale, Reassignment, or Transfer of Point-to-Point Transmission Service with Star Peak Geothermal LLC effective December 1, 2022."*

December 13, 2022
Docket No. ER23-164 "*Letter Order Accepting Nevada Power Company's October 21, 2022, Filing of Revisions to Amended and Restated Navajo Western Transmission System Operating Agreement.* The Amendment (1) updates responsibility for the operation and maintenance costs for the period of January 1, 2020, through December 31, 2029; (2) reflects the current participants ownership shares, cost responsibility and facilities; and (3) makes the agreement consistent with changes being made to the Navajo Co-Tenancy Agreement and the Navajo Southern Transmission System Operating Agreement.

October 31, 2022
Docket No. ER22-2848 "*Letter Order Accepting Nevada Power Company's September 14, 2022, Filing of an Amended Engineering, Procurement and Construction Agreement with 302PN 8me LLC.*" FERC accepted the amended EPC Agreement between with 302PN 8me LLC, effective November 14, 2022.

July 8, 2022
Docket No. ER22-1871 "*Letter Order Accepting Arizona Public Service Company's 05/13/2022 Filing of a Non-Conforming Large Generator Interconnection Agreement Among APS, The Department of Water and Power of City of Los Angeles, and Nevada Power Company*".

March 8, 2022
Docket No. ER22-796 "*Letter Order Accepting Nevada Power Company's January 10, 2022, Filing of Amended Facilities Agreement with PacifiCorp*".

June 23, 2021
Docket No. ER21-18868 "*Letter Order Accepting Nevada Power Company's 05/07/2021 Filing of an Engineering, Procurement, and Construction Agreement with 302PN 8me LLC.*"

May 10, 2021
Docket No. ER21-1476 "*Letter Order Accepting Sierra Pacific Power Company's 03/19/2021 filing of an engineering and construction agreement with Liberty Utilities LLC*" The EC Agreement provides the engineering, design and construction terms and conditions under which Sierra Pacific will modify its transmission facilities to accommodate the distribution improvements proposed by Liberty Utilities. The EC Agreement is accepted for filing effective May 19, 2021.

February 17, 2021
Docket No. ER21-770 "*Letter Order Accepting Sierra Pacific Power Company's 12/30/2020 filing of a firm point-to-point transmission service agreement with AMOR IX, LLC*" Sierra Pacific's firm point-to-point Transmission Service Agreement with AMOR IX, LLC (AMOR IX) under the FERC tariff. The Service Agreement sets forth Sierra Pacific's agreement to provide firm point-to-point Transmission Service for up to 13 MW of capacity to AMOR IX, from the Ragtown 63

kV Substation Point of Receipt in North System to the Gonder-Pavant 230 kV Bus Point of Delivery. The Service Agreement includes a $0.33/kW-month distribution service charge for using Sierra Pacific's 63 kV high-voltage distribution system, which is a non-conforming addition to the *pro forma* Service Agreement. The Service Agreement is accepted for filing effective March 1, 2021.

February 17, 2021
Docket No. ER21-771 "*Letter Order Accepting Sierra Pacific Power Company's 12/30/2020 filing of a firm point-to-point transmission service agreement with AMOR IX, LLC*" Sierra Pacific's firm point-to-point Transmission Service Agreement with AMOR IX, LLC (AMOR IX) under the FERC tariff. The Service Agreement sets forth Sierra Pacific's agreement to provide firm point-to-point Transmission Service for up to 7 MW of capacity to AMOR IX, from the Ragtown 63 kV Substation Point of Receipt in North System to the Gonder-Pavant 230 kV Bus Point of Delivery. The Service Agreement includes a $0.33/kW-month distribution service charge for using Sierra Pacific's 63 kV high-voltage distribution system, which is a non-conforming addition to the *pro forma* Service Agreement. The Service Agreement is accepted for filing effective March 1, 2021.

December 9, 2020
Docket No. ER20-3017 "*Letter Order Accepting Sierra Pacific Power Company's 09/29/2020 filing of a revised power purchase agreement with Liberty Utilities (CalPeco Electric) LLC*"

July 17, 2020
Docket No. ER20-1963 "*Letter Order Accepting Nevada Power Company's 06/02/2020 Filing of a Firm Point-To-Point Transmission Service Agreement with Open Mountain Energy, LLC.*"

e. California Independent System Operator Corporation (CAISO) Energy Imbalance Market (EIM) Related Orders

April 15, 2021
Docket No. ER21-395 (175 FERC ¶ 61,043)
California Independent System Operator "*Order Granting Waiver Request*"
FERC waived a $685,000 CAISO penalty owed by Sierra Pacific and Nevada Power d/b/a NV Energy for incorrect meter data submittals over a period of five years for Kings Beach generation facility. The market participant inadvertently had been reporting station power values as the plant's generating output. The error was due to these meters reporting output on channel one of the meter and station power on channel three, whereas all other generator meters for which the market participant has responsibility have the opposite configuration FERC accepted CAISO's $69,000 penalty & $35,668 market adjustment that NV Energy paid in 2020 for the meter error.

f. Merger, Acquisitions & Asset Transfer Orders

July 1, 2022
Docket No. EC22-55 (180 FERC ¶ 62,000) *"Order Authorizing Merger"*
FERC approved the NPC and SPPC intercompany reorganization merger pursuant to Federal Power Act (FPA) section 203. FERC authorized the internal reorganization of NV Energy whereby SPPC will merge with and into Nevada Power Company. The jurisdictional facilities involved include transmission assets and various agreements. FERC accepted NPC's pledge to hold harmless all transmission customers from any transaction-related costs for a period of five years in accordance with Commission policy and precedent. NPC is required to submit the Companies' final proposed accounting entries as they relate to transfers of plant assets within six months after the merger is consummated and after the company receives FERC's FPA section 205 and PUCN's authorizations.

June 8, 2022
Docket No. ER21-434 (175 FERC ¶ 61,226) *"Order on Justification Filings and Directing Refunds"*
The Western Electric Coordinating Council (WECC) soft price cap is $1000/MWh for wholesale energy sales outside of the California ISO in the U.S. West. In November 2020, NV Energy filed a WECC Soft Cap report for a 50 MW sale to the Salt River Project at $1,700/MWh. The report was supplemented in July 2021 at the direction of FERC data requests. In June 2022, FERC ordered NV Energy to refund Salt River $16,000 plus interest. FERC held that the sale should be limited to the average Mead Hub Index price which was $1,380/MWh**.**

March 26, 2022
Docket No. AC21-51 *Account 102*
March 1, 2021, Nevada Power Company (NPC) and Sierra Pacific Power Company (SPPC) filed a letter proposing accounting entries to clear Account 102, Electric Plant Purchased or Sold, relating to the partial transfer of plant assets related to the One Nevada Transmission Line project from NPC to SPPC. Applicants represent that the assets were transferred at an amount equal to the original cost less accumulated depreciation, i.e., net book value. The Commission approved both accounting entries.

November 12, 2021
Docket No. EC21-131 (177 FERC ¶ 62,081)
"*Order Authorizing Disposition of Jurisdictional Facilities and Acquisition of Existing Generating Facility re Sierra Pacific Power Company"* Sierra Pacific and Apple Inc. (Apple) jointly filed an application requesting authorization for the disposition of jurisdictional facilities and acquisition of a generation facility associated with a transaction whereby Sierra Pacific will purchase the Fort Churchill Solar Array from Apple.

March 26, 2021

Docket No. AC21-51 "*Letter Order Approving Nevada Power Company's et al 3/1/21, as supplemented on 3/17/21, filing of proposed accounting entries to clear Account 102, relating to the partial transfer of plant assets related to the One Nevada Transmission Line*" FERC authorized clearing Account 102, Electric Plant Purchased or Sold, relating to the partial transfer of plant assets related to the One Nevada Transmission Line project from Nevada Power Company to Sierra Pacific Power Company.

February 2, 2020

Docket No. AC20-43 "*Letter Order Approving Desertlink, LLC's 12/23/2019 Request for Approval of Proposed Accounting Entries to Clear Account 102, Relating to the Acquisition of Certain Electric Plant from Nevada Power Company.*"

g. Gas Pipeline Suppliers Orders

Gas Transmission Northwest LLC ("GTN")

November 16, 2023

Docket No. RP23-1099 "*Order Scheduling Prehearing Conference and Adopting Hearing Rules.*"

November 8, 2023

Docket No. RP23-1099 "*Order of Chief Judge Designating Settlement Judge.*"

October 31, 2023

Docket No. RP23-1099 185 FERC ¶ 61,086

"*Order Accepting and Suspending Tariff Records, Subject to Refund, and Establishing Hearing Procedures*" GTN proposes a primary rate case reflecting a general system-wide rate increase and several changes to its tariff, including proposals for environmental cost recovery, an electric power cost tracker, and enhanced parking and lending service, effective November 1, 2023. Additionally, GTN submitted *pro forma* tariff records presenting its preferred case, a proposal to prospectively change its rate structure from the existing dekatherm-mile (Dth-mile) rate design to a two-zone rate design, following Commission approval.

December 21, 2022

Docket No. RP23-252 "*Letter order accepting Gas Transmission Northwest's 12/1/22 filing of its annual fuel charge adjustment*"

November 18, 2021

Docket No. RP15-904 177 FERC ¶ 61,110

Letter order approving Gas Transmission Northwest's 09/29/21 filing of a stipulation and agreement. The Settlement is submitted in lieu of a Natural Gas Act section 4 general rate case filing and fulfills GTN's obligation, established in earlier proceedings, to submit rates to be effective no later than April 1, 2022. GTN believes that the Settlement is supported or unopposed by all of its shippers and other interested parties.

June 28, 2021
Docket No. RP15-904 175 FERC ¶ 61,250 "*Order Granting Petition to Amend Settlement*"
The amendment postpones the date by which GTN must file a new rate case in order to provide time for additional settlement negotiations.

Kern River Gas Transmission Company

March 20, 2023
Docket No. RP23-477
Letter order accepting Kern River Gas Transmission Company's 02/28/2023 filing of tariff records to reflect new electric compressor fuel surcharges applicable to gas scheduled for delivery downstream of its Daggett compressor station.

August 17, 2022
Docket No. RP22-1083
Letter order accepting Kern River filing of tariff records to make minor housekeeping changes in Kern River's Tariff, including to reflect a name change for a shipper.

March 16, 2022
Docket No. RP22-614
Letter order accepting Kern River filing of tariff records to reflect revised electric compressor fuel surcharges applicable to gas scheduled for delivery.

September 20, 2021
Docket No. RP21-1051
Letter order accepting Kern River's August 26, 2021, filing of a revised tariff record to reflect the addition of its new Desert Peak delivery meter. Kern River filed a revised tariff record to reflect the addition of its new Desert Peak delivery meter to the list of delivery points for the Nevada Firm Pool and Nevada AOS/Interruptible Pool. The referenced tariff record was effective October 1, 2021.

Northwest Pipeline LLC ("Northwest")

September 18, 2023
Docket No. RP23-986
Letter order accepting Northwest Pipeline LLC's 08/30/2023 filing of a tariff record to reflect the semi-annual fuel reimbursement factor for its transportation schedules.

March 23, 2023
Docket No. RP23-479
Letter order accepting Northwest Pipeline LLC's 02/28/2023 filing of a tariff record to reflect its revised fuel reimbursement factors.

February 24, 2023
Docket No. RP22-1155 Letter order accepting Northwest Pipeline LLC's 01/31/2023 filing of a refund report reflecting the details of the refunds made in accordance with Article VI of the Stipulation and Agreement.

December 21, 2022
Docket No. RP22-1155 Letter order accepting Northwest Pipeline LLC's 11/30/22 filing of tariff records to implement the rates provided in the Stipulation and Agreement.

November 15, 2022
Docket No. RP22-1155 (181 FERC ¶ 61,118)
Order approving Northwest Pipeline LLC's 08/26/2022 filing of a stipulation and settlement agreement. Northwest filed a stipulation and settlement agreement (Settlement) in lieu of a general, system-wide rate case under section 4 of the Natural Gas Act. The uncontested Settlement incorporates *pro forma* tariff records to establish reduced system-wide rates.

September 19, 2022
Docket No. RP22-1160
Letter order accepting Northwest Pipeline LLC's 08/30/22 filing of a tariff record to reflect the fuel reimbursement factor for its transportation schedules.

July 29, 2022
Docket No. RP17-346 (80 FERC ¶ 61,068) *"Order Granting Petition to Amend Settlement"*
The parties are seeking approval of an agreement between Northwest and the Settling Parties to extend by two months Northwest's rate filing requirement approved by the Commission on August 18, 2017 (2017 Settlement) in the above-captioned docket. The petition confirms the agreement in principle between Northwest and the Settling Parties to enter into a pre-filing settlement in lieu of Northwest submitting a general rate case under section 4 of the Natural Gas Act and requests an extension of time to document the settlement in principle so that it may be submitted to the Commission.

June 1, 2022
Docket No. RP21-543
"Letter order accepting Northwest Pipeline LLC's 5/13/22 filing of an activity report for the first year of Rate Schedule TPAL in compliance with the Commission Order"

March 17, 2022

Docket No. RP22-597.
"Letter order accepting Northwest Pipeline LLC's 02/25/2022 filing of a tariff record to update its fuel reimbursement factors"

September 15, 2021
Docket No. RP21-1059
"Letter order accepting Northwest Pipeline LLC's 8/30/212021 filing of a tariff record to reflect its updated semi-annual fuel reimbursement factor for Rate Schedules TF-1, TF-2, TI-1, and DEX-1"

March 31, 2021

Docket No. RP21-311 (174 FERC ¶ 61,255) *"Order on Tariff Records"*
Northwest filed revised tariff records proposing to establish a new interruptible term park and loan (TPAL) service and to modify its existing Rate Schedule PAL (PAL) park and loan service.

March 17, 2021
Docket No. RP21-520
"Letter order accepting Northwest Pipeline LLC's 02/25/2021 filing of a revised tariff record to update its fuel reimbursement factors of its tariff"

Great Basin Gas Transmission Company (*previously* Paiute Pipeline Company ("Paiute"))

May 15, 2023
Docket No. CP23-466 *"Notice of Application and Establishing Intervention Deadline"*
Great Basin filed an application under sections 7b and 7c of the Natural Gas Act requesting authorization for its 2024 Expansion Project (Project). Great Basin proposes to: (1) construct approximately 0.25 miles of 20-inch-diameter pipeline loop along its Carson Lateral in Storey County, Nevada; (2) replace approximately 2.88 miles of existing 10-inch-diameter pipeline with new 20-inch-diameter pipeline along the Carson Lateral in Lyon County, Nevada; and (3) construct approximately 0.28 miles of 12-inch-diameter pipeline loop on its South Tahoe Lateral in Douglas County, Nevada. The Project will provide 5,674 dekatherms per day of incremental firm transportation service to meet the growth requirements of two existing firm transportation shippers. Great Basin estimates the total cost of the Project to be $14,939,850 and proposes a new incremental recourse rate to apply to the Project capacity.

February 24, 2023
Docket No. RP23-421
Letter order accepting Great Basin's 02/03/2023 filing of a tariff record reflecting its Preliminary Statement for its new section-based baseline tariff. Great Basin states that it has filed a new Tariff, denoted as FERC Gas Tariff, Revised Volume No. 1 effective January 23, 2023, as requested.

January 13, 2023
Docket No. RP23-305
Letter order accepting Great Basin's 12/22/22 filing of a tariff record to cancel its Tariff ID No. 5000, FERC Gas Tariff, Original Volume No. 1.

April 13, 2022
Docket No. CP22-141 "*Notice of Application and Establishing Intervention Deadline*"
March 30, 2022, Great Basin filed an application under sections 7(b) and 7(c) of the Natural Gas Act requesting that the Commission authorize the 2023 Mainline Replacement Project (project), which consists in the abandonment and replacement of approximately 20.36 miles of 16-inch-diameter steel pipe and associated auxiliary or appurtenant facilities located in Humboldt County, Nevada, all as more fully set forth in the application which is on file with the Commission and open for public inspection. The estimated cost of the project is $47,119,897.

September 28, 2021
Docket No. RP21-1113
Letter order accepting Great Basin's 09/14/2021 filing of tariff records to establish a new baseline FERC Gas Tariff, Original Volume No. 1 as a result of a change in corporate name from Paiute Pipeline Company to Great Basin Gas Transmission Company.

August 27, 2021
Docket No. RP21-987 (176 FERC ¶ 61,134) *Order Rejecting Tariff Records*
July 29, 2021, Paiute filed revised tariff records to its FERC Gas Tariff to define and allow for the receipt and transport of renewable natural gas (RNG) on its pipeline system. Paiute states that the proposed changes will enable the development of RNG in Paiute's market area while protecting Paiute's system, its customers' gas-burning equipment.

July 16, 2021
Docket No. RP21-912
Letter order accepting Paiute's 06/25/2021 filing of a revised tariff record updating its tariff cover page to reflect a new address and fax number.

Tuscarora Gas Transmission Company ("Tuscarora")

October 29, 2020
RP20-1230

Letter order accepting Tuscarora Gas Transmission Company's 09/29/2020 filing of a report with workpapers supporting the derivation of the fuel and line loss percentages during the period of 12/01/2019 through 08/31/2020 of its tariff.

10. TRANSMISSION TECHNICAL APPENDICES

The following transmission-related information is set forth in the Technical Appendix volume as:

Technical Appendix TRAN-1: Greenlink Nevada May 2024 Revision 1
Technical Appendix TRAN-2: Apex Master Plan May 2024 Non-confidential
Technical Appendix TRAN-3: Western Nevada Load Pocket April 2024 Non-confidential
Technical Appendix TRAN-4: Agreements List

SECTION 3. ECONOMIC ANALYSIS

A. Overview

Supply and demand fundamentals of the wholesale electric energy market have changed significantly in recent years, resulting in tightened supplies, uncertain market capacity, and greater price volatility. With reliance on the Western Interconnection market an increasingly risky strategy, this 2024 Joint IRP prioritizes resource adequacy to reduce the Companies' open capacity position ("open position"), which is the portion of the utility's capacity needs that are not met by resources under utility ownership or long-term contract. By adding new resources within their balancing authority area ("BAA"), the Companies limit their dependence on the external market and simultaneously respond to the increased capacity requirements associated with the new load forecast included in this filing.

In addition to the Companies' resource adequacy and greater capacity needs, the Companies are statutorily mandated to comply with the state's Renewable Portfolio Standard ("RPS"), which requires for calendar year 2030 and each following calendar year, 50 percent of the total amount of electricity sold by the utility to its retail customers to be from renewable energy sources. The Companies, however, are planning beyond compliance with Nevada's RPS. While the Companies do not request resources in this filing for this added purpose, all plans in this 2024 Joint IRP target the state's 2050 clean energy goal signed into law in 2019 in Senate Bill 358. This goal aspires for an amount of energy production from zero carbon dioxide emission resources that is equal to the total amount of electricity sales in 2050. Moreover, the Companies are acting to meet expected customer participation in future NV GreenEnergy Rider ("NGR") programs as described in the Renewables Section of the narrative. Combined, achievement of these renewable requirements and ambitions are especially challenging given the Companies' recent experience with previously approved renewable resource projects failing to achieve commercial operation amid supply chain disruptions and other production obstacles. This 2024 Joint IRP presents a diverse energy portfolio that targets these important renewable energy goals and aspirations.

Economic analyses of diverse capacity and energy supply plans were conducted which incorporated revenue requirements needed to recover the costs of utility-owned resources, such as future generators and transmission infrastructure, as well as power purchase agreements. Sets of cases were developed and analyzed which led to the selection of four alternative plans and, ultimately, identification of a Preferred Plan and an Alternate Plan. In this section, the following economic analysis topics are covered:

- Economic Analysis Methodology;
- Key Modeling Assumptions;
- Assessment of Need;

- Plan Development;
- Economic Analysis Results;
- Environmental Externalities and Economic Benefits to the State;
- Selection of the Preferred Plan;
- Loads and Resources Tables;
- Additional Studies; and
- Long-Term Avoided Costs.

The Commission's regulations for integrated resource planning serve as the framework for the analysis of the alternative plans set forth in this filing. These include:

- NAC § 704.937: Inclusion in supply plan of alternative plans.
  - Provide a list of options for supply, including existing and planned options;
  - Identify the criteria used for the selection of supply options;
  - Calculate the present worth revenue requirement ("PWRR") for each case alternative;
  - Calculate the present worth of societal cost ("PWSC") for each case alternative;
  - Consider each case alternative for the mitigation of risk;
  - Consider each case alternative for reliability;
  - Ensure each case alternative meets or exceeds the RPS; and
  - List the assumptions used to evaluate the case alternatives.
- NAC § 704.9357: Analysis of the net economic benefit to the state.
- NAC § 704.9359: Determination of environmental costs to the state.
- NAC § 704.9465: Integrated analysis to establish priorities among options.
- NAC § 704.9475: Analysis of sensitivity for major assumptions and estimates used.
- NAC § 704.948: Analysis of decisions with respect to mitigating risk, minimizing cost and volatility, and maximizing reliability.

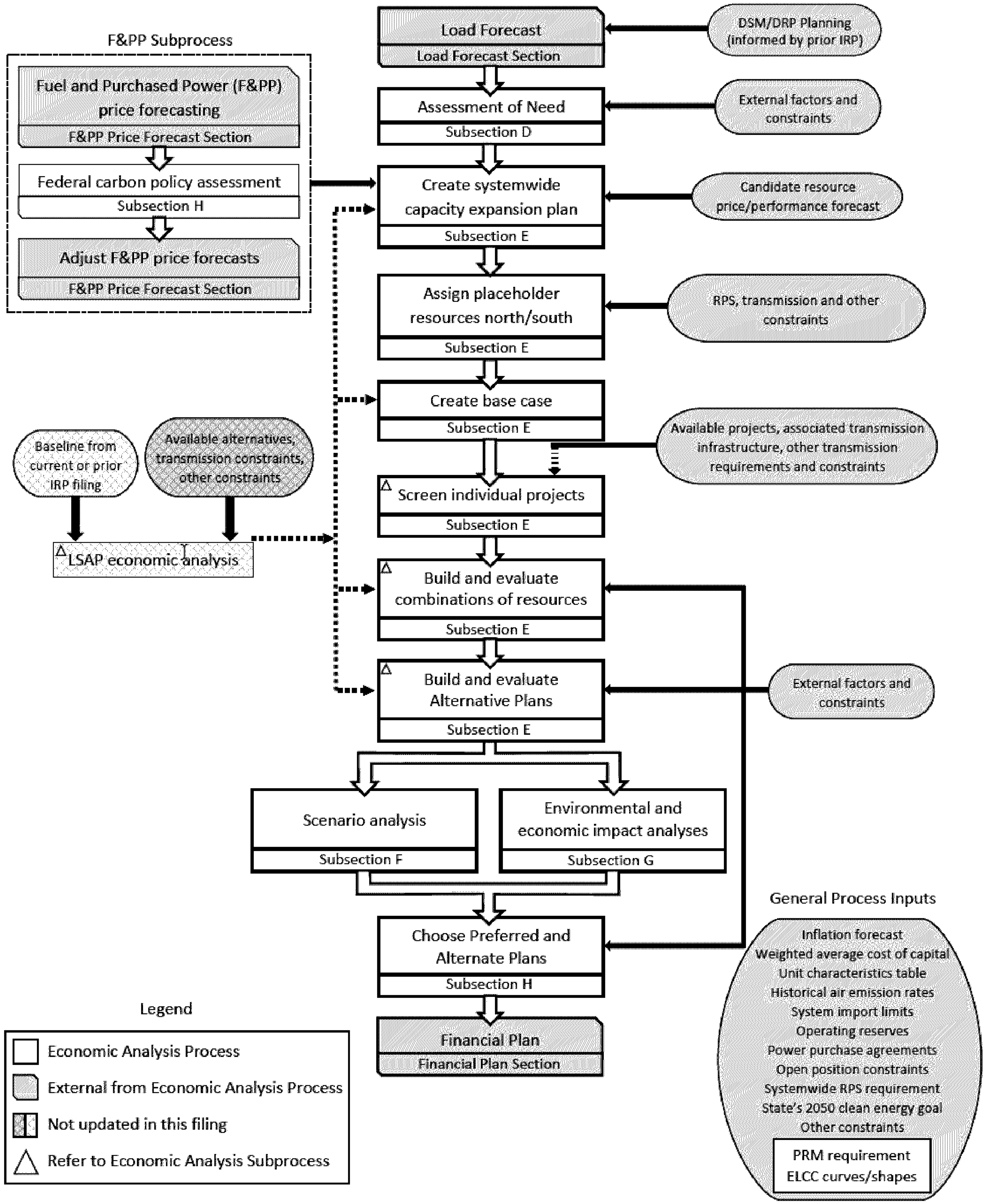
Additionally, pursuant to NAC § 704.952(5), a stakeholder briefing was conducted to inform the Commission's Regulatory Operations Staff ("Staff"), personnel from the Bureau of Consumer Protection ("BCP") and interested parties of preliminary key modeling assumptions and to provide an overview of the 2024 Joint IRP. The meeting took place via Microsoft Teams on January 31, 2024. A second stakeholder briefing was conducted via Microsoft Teams on May 22, 2024, prior to filing. Notice of these meetings and any presentations given are provided in Technical Appendix ECON-1.

With the passage of Assembly Bill No. 524 ("AB524") during the 2023 Legislative Session, new requirements were enacted governing the scenarios considered in IRPs and the information to be included regarding each requested project and presented scenario. While these requirements are not yet incorporated into the Nevada Administrative Code, the Companies address these new statutory requirements in the 2024 Joint IRP. For instance, Section 5 of AB524 amends NRS § 704.744 to require an electric utility to schedule a consumer session before filing an IRP or an amendment to an IRP. The Companies held a consumer session for interested persons on January 10, 2024, at the Commission's offices in Las Vegas and Carson City. Pursuant to NRS § 704.744(3), a summary of the consumer session is included in the testimony of the Companies' witness Kimberly Williams in support of the 2024 Joint IRP.

B. Economic Analysis Methodology

To aid in understanding the economic analysis performed for this 2024 Joint IRP, an overall flowchart of the methodology is provided here for reference. This flowchart, Figure EA-1, is intended to supplement the narrative. It is generic and generally applicable to all IRP filings, but some details may vary from filing to filing as dictated by different circumstances. The steps in the flowchart include references to locations in this narrative as a guide to the reader.

FIGURE EA-1
OVERALL WORKFLOW DIAGRAM OF ECONOMIC ANALYSIS METHODOLOGY



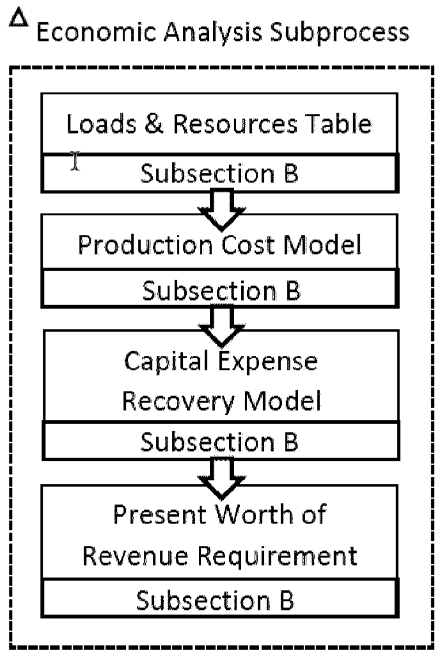
As shown in the workflow, the Companies first assess their need for future resources given forecasted customer load growth, required and anticipated interest in renewable generation, reliability requirements, and any system obligations. The Companies then consider diverse, potential options for meeting their needs by evaluating new resources that may be available to supply capacity and energy, options to decrease a portion of the anticipated energy demand, and access to and availability of market purchases. Based on the needs and the available options to fulfill these needs, the Companies build a generic or base case that meets the requirements for capacity and energy.

The Companies use Energy Exemplar's PLEXOS Energy Modeling Software for the economic analysis of this 2024 Joint IRP. The software tool PLEXOS LT is used for capacity planning, and PLEXOS ST ("PLEXOS") is used for production cost modeling. More information on Energy Exemplar's modeling software is provided in Technical Appendix ECON-2.

PLEXOS LT is used to develop a base case – a long-term portfolio that includes existing and approved projects and future placeholder resources to fill the anticipated need. Plans are created from the base case with varying available resources in lieu of placeholder resources. For scenarios with dramatically different long-term goals, such as those required by NRS § 704.741(3)(c)(1) and (2), which are discussed more in the Plan Development Subsection, distinct expansion plans may be created in PLEXOS LT.

Note that some steps in the process flow diagram include a small triangle in the box. The triangle indicates this step requires a more detailed subprocess consisting of the development of one or more Loads and Resources ("L&R") tables, production cost model runs, capital expense recovery ("CER") models, and PWRR calculations. A diagram of this subprocess follows in Figure EA-2.

FIGURE EA-2
WORKFLOW DIAGRAM OF ECONOMIC ANALYSIS SUBPROCESS – SPECIFIC PLAN ANALYSES



This subprocess is performed for every case analyzed. More detailed descriptions of each of these specific analysis steps are provided in the remainder of this subsection.

L&R Tables. The Companies' analysis for each case evaluated begins with the development of the L&R table. A long-term forecast of annual coincident peak loads, planning reserve requirements, and a forecast of planning capacity for all supply-side and demand-side resources are used to determine the Companies' annual open capacity position. The open position is the portion of the utility's capacity needs that are not met by resources under utility ownership or long-term contract. More specifically, in the L&R tables, the open position is defined as the difference between the forecasted system coincident net peak demand (accounting for the planning reserve margin and any capacity reductions associated with net energy metering, demand response ("DR") programs, demand side management ("DSM") programs, and any other program used to shift or reduce peak demand) and the planning capacity of available resources, either owned or under contract, at the time of the forecasted system net peak demand less reserves held for unbundled open access transmission tariff ("OATT") customers. Alternatively, DR programs, DSM programs, and/or any other program used to shift or reduce peak demand may be accounted for as supply resources and reflected in the planning capacity of available resources. In accordance with the Stipulation accepted in Phase 2 of the 2021 Joint IRP in Docket No. 21-06001, the annual planning capacity for supply-side resources is reduced by 90 MW to account for reserves held for unbundled OATT customers.

For the forecast annual capacity for supply side resources in this 2024 Joint IRP, the Companies use the software tool PLEXOS LT in development of long-term plans with existing/approved projects and future placeholder resources to fill the open position. Multiple plans are created using multiple L&R tables with varying potential resources. An evaluation of the cost of energy production and the cost to acquire the resources is conducted for each plan.

The Companies may leave some of the open position to be filled with market purchases of energy and capacity. In any year in which an open position is present, the Companies will secure the needed capacity from the electric wholesale market, modeled at the forecasted capacity cost for that year. The cost of this capacity is included in the total costs for each plan. A more detailed discussion regarding the creation and use of the L&R tables is included in the Loads and Resources Subsection of this Economic Analysis Section.

For this 2024 Joint IRP, the Companies updated modeling assumptions in the L&R tables. These assumptions are described in the Key Modeling Assumptions and L&R Table Subsections.

Production Cost Model. After developing the L&R tables, the Companies utilize additional software tools to evaluate each plan over the study period. The first is a production cost model known as PLEXOS. PLEXOS computes overall production cost by performing hourly, chronological economic unit commitment and dispatch of the Companies' electric production resources and market purchases to satisfy load requirements in a least-cost solution over the planning period. A more detailed description of PLEXOS can be found in Technical Appendix ECON-2. There are several key modeling assumptions made in performing PLEXOS analyses. These are discussed in more detail in the next subsection, and include, but are not limited to:

a) Study period
b) Joint system modeling
c) Area configuration
d) Hourly load forecast
e) Market fundamentals, including fuel and purchased power forecasts of costs
f) Existing thermal generation operating characteristics and costs
g) Operating reserves
h) Planning reserve margin ("PRM")
i) Effective Load Carrying Capability ("ELCC")
j) L&R Tables
k) Open Capacity Position Target
l) Power purchase agreements ("PPAs")

m) Existing renewable resources
n) Battery modeling
o) Certain demand response and distributed resources modeling
p) Carbon dioxide emissions impact modeling
q) Transmission limits
r) Placeholder resources

Capital Expense Recovery Model. The second model used to evaluate each plan is a spreadsheet workbook called the CER. The CER calculates the annual revenue requirements to recover expenses associated with the capital costs of utility-owned resources, such as future generators or transmission infrastructure. Note that transmission infrastructure included in the CER may be associated with a generating or storage resource or may be unrelated to any identified resource in a plan. Only native load allocations of transmission-related costs are included in the CER. Several key modeling assumptions made in the CER include, but are not limited to:

a) Capital costs of new generating resources;
b) Capital costs of resource acquisitions;
c) Capital costs of transmission projects;
d) Construction cost escalation rates;
e) Cash flow schedules;
f) Allowance for Funds Used During Construction ("AFUDC") estimates;
g) Construction start dates;
h) Project in-service dates;
i) Project book lives; and
j) Project tax lives.

Present Worth of Revenue Requirements. The sum of the annual production costs from PLEXOS and the annual capital revenue requirements from the CER over the study period, discounted by each company's weighted average cost of capital, provides the PWRR for each plan. A comparison of the PWRRs from each plan provides a ranking of the plans from least cost to greatest cost. This ranking is only one factor used to determine the selection of alternative plans and ultimately, selection of the Preferred and Alternate Plans. Other important factors that affect the selection of these plans include resource adequacy, reliability, risk mitigation, resource and fuel diversity, RPS performance, consistency with Nevada's energy policies, carbon emissions, and the needs of individual customers.

Scenario Analysis. NAC § 704.9475 requires the utility to conduct an analysis of sensitivity for all major assumptions and estimates used in the resource plan in addition to base assumptions. To satisfy this requirement, the Companies evaluate each alternative plan with sensitivities of a) load forecasts, b) fuel and purchase power price forecasts, and c) carbon policy scenarios.

The base assumptions for this filing are a base (or mid-level) load forecast, base (or mid-level) fuel and purchase power price forecasts, and a mid-level carbon policy scenario. For this 2024 Joint IRP, the Companies have conducted sensitivities of the load forecast with a high economic growth case and a low economic growth case. The base fuel and purchase power price forecasts have been supplemented with additional fuel and purchase power price forecasts: high and low fuel and purchase power price forecasts used in sensitivity analysis. The mid-level carbon policy assumption has been tested with three additional forecasts: high, low, and no carbon policy sensitivities. Further details on these forecasts are provided in the Load Forecast and Fuel and Purchased Power Price Forecast Sections.

The sensitivity analysis demonstrates how the PWRR results change when subjected to distinct key assumptions. Figure EA-3 below details the scenarios performed on each plan.

FIGURE EA-3
SENSITIVITIES OF KEY ASSUMPTIONS
CONDUCTED FOR ECONOMIC ANALYSIS

Scenario	Load	Market Fundamentals	Carbon
1*	Base	Base	Mid C
2	Base	Base	High C
3	Base	Base	Low C
4	Base	Base	No C
5	Base	High	Mid C
6	Base	Low	Mid C
7	High	Base	Mid C
8	Low	Base	Mid C

* Base Assumptions

In this 2024 Joint IRP, the Companies have conducted unique studies in addition to those shown in Figure EA-3. Detailed descriptions of these additional studies are contained in Subsection J, Additional Studies. In addition to the sensitivities shown in Figure EA-3, the Preferred Plan was subjected to a base load, base fuel, and mid-carbon scenario with the added ability to make off-system sales. A technical appendix is also provided for each additional study conducted. At a minimum, these appendices contain the relevant L&R tables, production cost summaries, CER, and PWRR comparisons associated with each study.

C. Key Modeling Assumptions

Study Period. The resource planning regulations specify the calculation of a 20-year PWRR for each plan. The Companies have extended the economic analysis to include the year 2050. That is, for this 2024 Joint IRP, the Companies have conducted economic analyses covering the period from 2025 to 2050. A 20-year and a 26-year PWRR for all plans has been calculated and included to provide additional context of the benefits of the plans.

Joint System Modeling. The Sierra and Nevada Power loads and resources are modeled as a system to take full advantage of the joint dispatch. All reported PWRR results include the total production costs and capital revenue requirements for both the Sierra and Nevada Power systems. The production cost summary data in Technical Appendix ECON-4 lists the production costs for each plan for the joint system, Nevada Power, and Sierra.

Area Configuration. The area configuration refers to how the joint system and external markets are represented in PLEXOS. A zonal model is used, and its purpose is to simulate transmission between areas. The areas may contain both resources and load, or resources only, and are connected to each other to simulate transmission between areas. PLEXOS allows for the modeling of transmission to ensure that transmission capacities are not violated. However, PLEXOS is not an AC power-flow transmission model, and the transmission flows determined by PLEXOS are based on economics. PLEXOS zonal tie flow outputs do not represent actual transmission line flows. A graphical depiction of the area configuration used in this filing, along with the annual maximum transfer between areas, is provided in Technical Appendix ECON-8.

Hourly Load Forecast. The Companies' load forecast has been updated for this 2024 Joint IRP. This update is described in the Load Forecast Section.

Market Fundamentals. The Companies' fuel and purchased power price forecasts have been updated for this 2024 Joint IRP. Details on market fundamentals and price forecasts can be found in the Market Fundamentals and Fuel and Purchased Power Price Forecast Sections. For all economic analyses, the forecast market capacity price is applied to the months June through September, consistent with Western Resource Adequacy Program ("WRAP") assumptions.

Existing Thermal Generation Operating Characteristics and Costs. PLEXOS uses the operating characteristics for each existing thermal generator to determine the most economic unit commitment and dispatch of the Companies' thermal generation resources. These characteristics include maximum and minimum capacities, heat rate curves, fixed and variable operation and maintenance costs, start costs, minimum up and down times, and forced outage rates. A summary of the Companies' operating characteristics is shown in confidential Technical Appendix GEN-1.

The Companies made additional assumptions concerning the operation of their fleet of combustion turbines. For this filing, it was assumed combustion turbines would have a minimum capacity factor of one percent. This assumption was included to reflect expected minimum operation and is a reasonable approximation of the runtime needed to confirm capacity accreditation and to allow for annual testing.

Operating Reserves. As one BAA, the Companies are a member of the Northwest Power Pool Reserve Sharing Group and must plan operating reserves sufficient to recover from a supply contingency. The Companies' operating reserve requirements comply with Western Electricity Coordinating Council ("WECC") and North American Electric Reliability Corporation ("NERC") standards. Operating reserves include a contingency reserve requirement, a portion of which is spinning reserve (spare online capacity).

The contingency reserve is modeled as approximately six percent of the combined system load. The spinning reserve requirement is such that at least 50 percent of the contingency reserve must be met with spare capacity from operating (spinning) resources or from stand-alone batteries that have not been fully discharged. To account for uncertainties in the load and renewable energy day-ahead forecasts, the Companies also model uncertainty reserves. The uncertainty reserve is modeled as an additional requirement for online resources to balance the forecast error and variability of load, solar resources, and wind resources and was updated for the 2024 Joint IRP with a dynamic calculation that captures the hour-by-hour conditions and operating needs of the system. Additional information pertaining to the uncertainty reserve update is provided in Technical Appendix ECON-13.

PRM. In this 2024 Joint IRP, the Companies update the methodology and several key data inputs to determine the PRM to be used for capacity planning purposes. As before, the Companies employ a "1-day-in-10-years" loss of load planning standard to ensure the joint system has an adequate supply of resources. For this update, the PRM was calculated for the joint system utilizing an unforced capacity ("UCAP") accounting method, which reduces the peak summer capacity of thermal generation resources by each resource's forced outage rate. In past filings, the Companies used the installed capacity ("ICAP") method for determining the PRM, in which the impact of thermal forced outage rates was captured in the PRM itself rather than in the capacity accreditation. The updated analysis indicates a joint system UCAP PRM requirement of 12.5 percent for this 2024 Joint IRP, equivalent to an ICAP PRM of 16.3 percent. A detailed description of the methodology and data used for the PRM calculation, as well as further explanation of the change from the ICAP to the UCAP accounting method, is provided in the 2024 Resource Adequacy Study in Technical Appendix ECON-12.

ELCC. The Companies use ELCC to assign the planning capacity associated with renewable resources. The ELCC values were updated for this 2024 Joint IRP. A detailed report of the updated

ELCC values is provided in Technical Appendix ECON-12. Additional information on the allocation of ELCC by renewable resource type is provided in the Loads and Resources Table Subsection of this Economic Analysis Section.

The Companies updated the ELCC curves and surface used for this economic analysis. The updated ELCC curves quantify the effective capacity value of the Companies' resource portfolio for different types of dispatch-limited resources and captures how their effective capacity changes as a function of their penetration. These curves are contained in the L&R workbooks and differ slightly from the ELCC "surface" used in PLEXOS LT. An ELCC surface was created for solar and storage to allow the Companies to dynamically account for the interactive effects between solar and storage for the creation of the potential buildouts generated by PLEXOS LT. The updated ELCC study – and updated PRM study – were designed to allow the outputs to remain useful over time *even as the portfolio and load forecast change*. The use of ELCC curves and surfaces, which relate the effective capacity value of each resource type to its penetration within NV Energy's system rather than point estimates, allows the Companies to capture both saturation effects and diversity benefits that occur as the penetration of individual variable resource types increases over time.

L&R Tables. The Companies updated the L&R tables to utilize NV Energy's coincident peak loads rather than the non-coincident peaks that were used in previous filings. This change is consistent with the analysis used to create the PRM. Additionally, the capacity contributions of the Companies' thermal generating fleet were adjusted to account for historic outage rates in accordance with the UCAP accounting convention. This update creates an effective capacity for thermal units similar to the ELCC used for renewable resources.

Open Capacity Position Target. The Companies set an open capacity position target of no more than 750 MW in 2028 and every year thereafter. Achieving this open capacity position target is vital to limit reliance on uncertain market availability and deliverability, which poses significant reliability risk to the Companies. This target aligns with NV Energy's intent to become financially binding in WRAP in winter 2027-2028. The open capacity position target as well as WRAP requirements for resource sufficiency and potential penalties for resource insufficiency are further described in the Day Ahead Markets and Regional Transmission Organization Section.

PPAs. Existing PPAs are modeled in accordance with the terms of each contract and can be found in Figures CON-1 and CON-2 in Section 2.B.

Existing Renewable Resources. Energy and pricing of existing renewable energy PPAs are modeled in accordance with the terms of the approved PPAs as described in the Renewables Section and are the same in all cases. Existing renewable PPAs and PPA-style (e.g., Dry Lake) resources are modeled as must-take resources. Sierra Solar is a yet-to-be commissioned company-owned resource that is modeled as must-take for its first 10 years of operation and modeled as a dispatchable resource for the remainder of the project's life. The Companies continue to use ELCC to assign the planning capacity values associated with renewable resources.

Battery Modeling. Battery energy storage systems ("BESS") are directly modeled in PLEXOS, allowing for dispatch of battery resources based on economics and allowable cycles per year. The forced outage rate of stand-alone battery systems was estimated to be five percent.

Paired solar photovoltaic ("PV") and BESS facilities are modeled with the PV resource separate from the battery resource. A modeling constraint requires the battery to be charged solely by the associated PV resource, and a second constraint limits the total paired facility output so that it does not exceed applicable inverter or transmission interconnection limits. This modeling method ensures a reasonable dispatch of battery resources based on economics and allowable cycles per year.

Certain Demand Side Management ("DSM") and Distributed Resource Plan ("DRP") Program Modeling. The existing DSM air conditioning load management program, previously modeled as a reduction to the load forecast, is modeled as a fixed supply resource in this 2024 Joint IRP. In addition, certain future DSM and DRP programs are modeled as supply resources in this IRP. As such, these resources are shown in the L&R tables and are modeled in PLEXOS. More information about these programs is provided in the DSM and DRP Volumes of this 2024 Joint IRP.

Carbon Dioxide Emissions Impact Modeling. The production cost model in this 2024 Joint IRP does not include allowance prices for carbon dioxide emissions. The social costs of carbon due to carbon dioxide emissions are included in the societal cost analyses. Information on the modeling of climate policy's impacts on fuel prices is provided in the Fuel and Purchased Power Price Forecast Section. Information on the social cost of carbon is included in Subsection G, Externalities and Net Economic Benefits, of this Economic Analysis Section.

Transmission Limits. Transmission limits, including access to external markets as well as limits between the Companies (over ON Line and/or Greenlink Nevada) were modeled in accordance with Technical Appendix ECON-8. It is noteworthy that LS Power appears to be moving forward with construction of the Southwest Intertie Project-North ("SWIP-N") as discussed in the Transmission Section of the narrative. While the Companies have included an expectation that SWIP-N would allow access to Idaho Wind placeholder resources, they do not rely on SWIP-N for market access at this time as construction of this line is not under the Companies' control. PLEXOS is not an AC power-flow transmission model, but all transmission capacity constraints are included in the model. Any projected flows are based on economics and are not allowed to exceed the transmission capacities.

Placeholder Resources. In creating a long-term resource portfolio in PLEXOS LT, diverse candidate resource types are available to be selected as future resource “placeholders.” No specific future projects are modeled in PLEXOS LT, only generic candidates. Accordingly, the resulting base case includes no specific future projects, only placeholder resources. Candidate resources available for this 2024 Joint IRP include firm dispatchable resources, renewable resources, including wind, geothermal, and solar PV, and energy storage resources, such as BESS and pumped storage hydro (“PSH”). The Companies are not requesting approval to acquire or build any placeholder resources. Moreover, placeholder resources are subject to change in future filings as the Companies' needs change. Additional information regarding candidate resources is provided in the Candidate Resource discussion below and in Technical Appendix ECON-10.

Firm dispatchable placeholder resources are intended to represent technologies that can supply electricity reliably on demand for hours, days, or weeks at a time, and are discussed more in Subsection E of this Economic Analysis Section.

Future renewable resource additions (also referred to as “renewable placeholders”) are included as needed to serve new load and to ensure compliance with the requirements of Nevada’s RPS, as well as to serve the NGR and to target the state’s 2050 clean energy goal. Renewable placeholders are assumed to be solar PV systems, wind, or geothermal resources. The Companies are not suggesting these types of renewable resources are the only renewable resources that will be considered to fulfill future needs.

Storage placeholder resources, such as BESS and PSH, provide capacity and generally decrease excess energy. The Companies are not suggesting these types of storage resources are the only such resources that will be considered to fulfill future needs.

For the alternative plans, the Companies have included “named placeholders.” These placeholders are known, likely future projects that the Companies may contract or acquire. These projects are not being requested in this filing but are included based on currently available information. Inclusion of these named placeholders addresses a directive within ordering paragraph 6 in the Commission’s March 1, 2024, Order in the Fifth Amendment to the 2021 Joint IRP[1] (“Fifth Amendment"). Anticipated company-owned projects are modeled as company-owned, rate-based assets in the CER, and anticipated PPAs are modeled in the production cost model with the anticipated PPA pricing. Named placeholders include the appropriate estimated project-specific transmission infrastructure costs based on location as currently known.

CER Inputs. The CER calculates the revenue requirements needed to recover capital expenditures of utility-owned resources, such as future generators or transmission infrastructure. Only native load allocations of transmission-related costs are included in the CER. The project's timing, cash

[1] Docket No. 23-08015

flows during the construction period, AFUDC, tax credit impacts, and project book lives and tax lives are all factors in the final annual revenue requirement included in the PWRR calculation. CER analyses are provided in Technical Appendices ECON-6 and ECON-7.

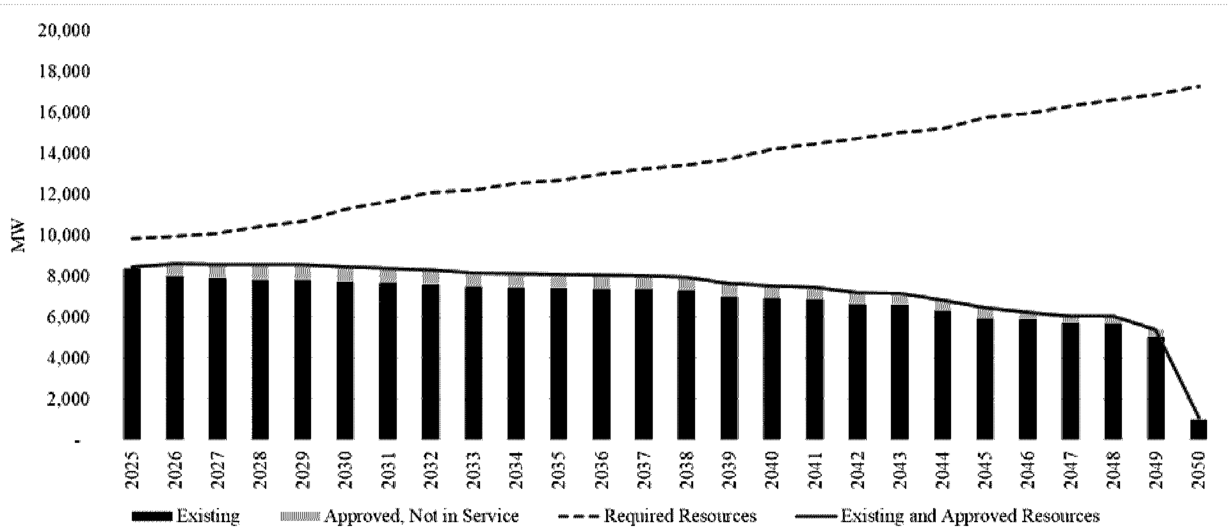
Cost estimates for approved projects are generally not included in the CER. Such costs are the same in all cases and have no impact on the economic analysis of the alternative cases. For this 2024 Joint IRP, however, cost estimates for Greenlink Nevada are included in the CER due to the change in the overall project costs and the request for incremental project cost approval included in this filing. Revenue requirements are shown for the 26-year study period, 2025 to 2050, and capital costs are designed to match the costs shown in the financial analysis. Greenlink Nevada costs are included in all plans and do not affect PWRR rankings.

D. Assessment of Need

The Companies take into account many factors when assessing resource requirements over the IRP study period. In this 2024 Joint IRP, the Companies consider capacity needs related to changes in forecast load growth, recent cancellations of previously approved renewable/storage resource projects as noted in the Renewables Section, and the continuing desire to minimize dependance on the uncertain availability and deliverability of market capacity. The Companies also consider the energy required to serve the growing load, as well as the proportion of this energy that would need to be supplied by renewable resources to meet Nevada's RPS requirement. Moreover, the Companies address expected customer participation in the NGR program. While the Companies do not request resources in this filing for this purpose, all plans in this filing target the Companies' proportionate share of the state's 2050 clean energy goal.

Figure EA-4 illustrates the Companies' capacity position given the assumptions described above. The figure shows the system capacity requirements (loads plus PRM and reserves for OATT customers) as updated in this 2024 Joint IRP, existing resources (owned resources and those under contract and in service), and resources approved but not yet in service. Thermal units are shown at their peak capacities derated for their historic average forced outage rate, while renewable units have been adjusted for their ELCC. This is consistent with the use of a UCAP PRM as described previously.

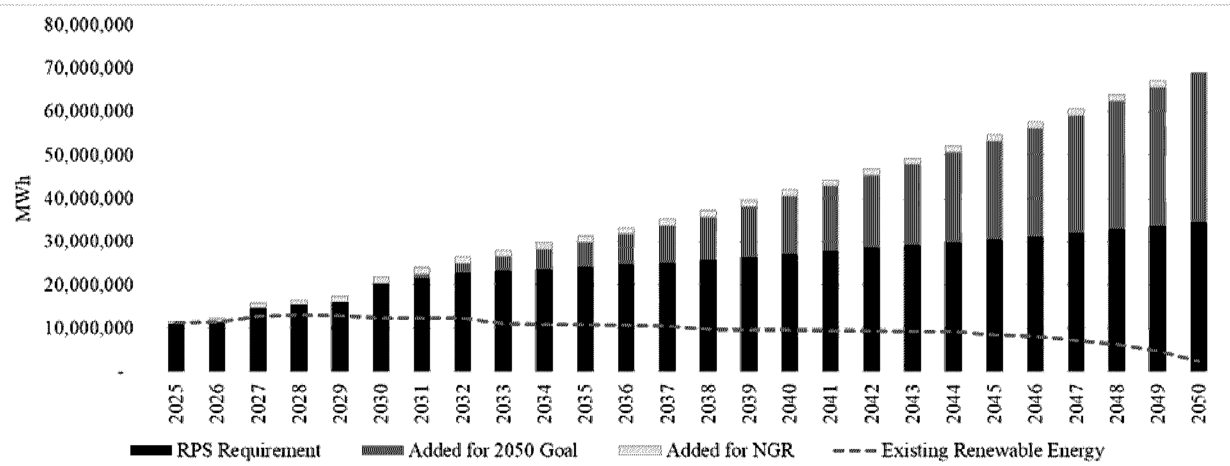
FIGURE EA-4
NV ENERGY CAPACITY POSITION



The difference between the 2024 IRP required resources line (top line) and the existing and approved resources (lower line) represents the total capacity need for NV Energy. It is noteworthy that this capacity need grows to nearly 1,900 MW by 2028. This need will be satisfied with combinations of specific projects, placeholders, and open positions that will be filled by the market. Due to concerns regarding the availability of market capacity and energy, additional near-term resources should be secured now to limit reliance on market capacity. As discussed in the Day Ahead and Regional Transmission Organization Section, reducing the open position with specific resources is consistent with resource sufficiency requirements in WRAP and the expected requirements of a potential future market or regional transmission organization ("RTO").

In addition to meeting the energy and capacity requirements resulting from the updated load forecast, the Companies must comply with the state's RPS. Rather than simply meeting this requirement, the Companies are striving to increase the amount of energy generated by renewable resources to meet anticipated customer participation in future NGR offerings. In later years, the Companies target their proportionate share of the state's 2050 clean energy goal. Figure EA-5 offers an approximation of the net renewable energy that the Companies may need in future years and is not as refined as the detailed calculations provided in the Renewables Section.

FIGURE EA-5
NV ENERGY NEED FOR ADDITIONAL RENEWABLE ENERGY



In summary, to continue to reliably serve load in Nevada and to meet customer needs as well as state mandates, the Companies need additional resources to:

- Respond to the forecasted growth in customer demand;
- Reduce reliance on uncertain market availability and deliverability;
- Ensure adequate renewable resources to maintain compliance with the RPS; and
- Ensure adequate renewable resources to meet anticipated customer interest in NGR offerings.

E. Plan Development

NAC § 704.937(1) requires a supply plan contain a "diverse set of alternative plans, which include a list of options for the supply of capacity and electric energy" and that the supply plan "includes a description of all existing and planned facilities for generation and transmission, existing and planned power purchases, and other resources available as options to the utility for the future supply of electric energy." The description must include the expected capacity of the facilities and resources for each year of the supply plan.

NAC § 704.937(1) contains a requirement for a scenario of low carbon dioxide emissions in triennial IRPs submitted on or before June 1, 2027, that "uses sources of supply that result in, by the year 2030, an 80 percent reduction in carbon dioxide emissions from the generation of electricity to meet the demands of customers of the utility as compared to the amount of such emissions in the year 2005," while also meeting the state's 2050 clean energy goal and including the deployment of distributed generation.

NRS § 704.741(3)(c)(2), while not yet detailed in the Nevada Administrative Code, directs the Commission to require utilities to include at least one scenario in a supply plan that "provides for the construction or acquisition of energy resources through contract or ownership to be placed into service to close an open position utilizing dedicated energy resources in this State and dedicated energy resources delivered through firm transmission." Moreover, a "significant share of the renewable energy facilities and energy storage systems included in the scenario must be owned by the utility."

To facilitate the development of these diverse supply plans to address the needs identified in the previous subsection, the Companies used PLEXOS LT to develop the initial placeholder resource buildout or base case. PLEXOS LT builds a least-cost capacity expansion plan that adheres to the PRM requirement, RPS constraints, and NGR goals; targets the Companies' proportionate share of the state's 2050 clean energy goal; and continually factors in the codependency and diminishing ELCC of additional renewable resources. Separate runs of PLEXOS LT are utilized to develop plans with dramatically different goals, such as those required by NRS § 704.741(3)(c)(1) and (2). Additional information on the PLEXOS LT model is provided in Technical Appendix ECON-2.

Descriptions of the candidate resources available for selection in PLEXOS LT for the base case expansion follow. For each distinct run of PLEXOS LT employed to develop plans to reach dramatically different goals, any constraints applied to candidate resources, including their build limits, are described in subsequent portions of this section along with the descriptions of the distinct plan developments.

Candidate Resources:

New firm dispatchable generation. The Companies continue to pursue options for firm *low-carbon* dispatchable resources as technology evolves. However, for the purpose of this 2024 Joint IRP, the firm dispatchable resources are modeled with the characteristics of gas turbines due to the lack of sound data on proven, appropriate low-carbon alternatives. New firm dispatchable resources could include the use of hydrogen as a fuel, fuel cells, or biofuel combustion units.

Firm dispatchable resources are available for the model to select beginning in 2040. Two technologies representative of firm dispatchable generation are modeled as candidate choices for PLEXOS LT to select:

- 2x1 Combined Cycle Unit
- Combustion Turbine Peaking Unit

Detailed information about these candidate units is provided in Technical Appendix ECON-10.

New combustion turbine peaking units. The combustion turbine peaking unit candidate is modeled in 440 MW unit sizing (a set of two individual combustion turbine peaking units) and is available to be in-service beginning in 2027. A total build limit of 880 MW is in place. More details are provided in the Generation Section and in Technical Appendix ECON-10.

New Paired PV/BESS facilities. Paired solar PV with 4-hour BESS are modeled with linear expansion in increments of 1 MW to allow the PLEXOS LT program to select the optimal size of both the PV and BESS. The buildout is limited in the first few years for practicality purposes due to the time required to develop projects. Moreover, for 2026 and 2027, the PV and BESS are required to be built in a 1-to-1 ratio and annual build limits were applied based on known, potential projects at the time of the study. The 2026 and 2027 build limits are 157 MW PV/BESS and 682 MW PV/BESS, respectively. Beginning in 2028, the constraint is eased to allow incremental paired BESS to be sized between 50 and 100 percent of the associated PV system's size and the build limits are relaxed to have no upper limit. Pricing is based upon National Renewable Energy Laboratory ("NREL") data and adjusted based upon the results of recent requests for proposals ("RFPs"), as described in the Renewables Section. More detailed information regarding the paired PV/BESS candidate units is provided in Technical Appendix ECON-10.

New stand-alone PV facilities. Like the paired facilities, stand-alone PV facilities are modeled with 1 MW linear expansion. The build limit for 2027, which is the first year of availability, is based on potential projects and set at 30 MW. Starting in 2028, there is no upper build limit. Pricing is based upon NREL data and adjusted based upon the results of recent RFPs, as described in the Renewables Section. More information on the stand-alone PV facilities is provided in Technical Appendix ECON-10.

New geothermal PPA. The new geothermal candidate is modeled as a north region candidate. It is also modeled with 1 MW linear expansion beginning in 2029 with no upper build limit. The geothermal candidate utilizes PPA pricing based upon NREL data and is adjusted based upon the results of recent RFPs, as described in the Renewables Section. Additional information can be found in Technical Appendix ECON-10.

New stand-alone BESS. As with the paired 4-hour BESS candidates, stand-alone 4-hour BESS candidates are modeled with 1 MW linear expansion. The buildout for the first few years is based on potential projects, with a build limit in 2026 and 2027 of 139 MW and 117 MW, respectively. Starting in 2028, there is no upper build limit. The stand-alone

BESS candidate pricing is based upon NREL data and is adjusted based upon results of recent RFPs, as described in the Renewables Section. More details can be found in Technical Appendix ECON-10.

New Idaho wind PPA. The Idaho wind candidate is modeled with 1 MW linear expansion starting in 2029 with a total build limit of 952 MW. This threshold aligns with the Companies' expected allocation of SWIP-North transmission capacity and SWIP-North's assumed in-service date. The Idaho wind candidate utilizes PPA pricing based upon NREL data and is adjusted based upon results of recent RFPs, as described in the Renewables Section. More information is provided in Technical Appendix ECON-10.

New Nevada wind PPA. The Nevada wind candidate uses one MW linear expansion with an upper build limit of 4,000 MW starting in 2030. The Nevada wind candidate utilizes PPA pricing based upon NREL data and is adjusted based upon results of recent RFPs, as described in the Renewables Section. More details can be found in Technical Appendix ECON-10.

New Pumped Storage Hydro. The pumped storage hydro candidate is modeled as a north region candidate. Available to be placed in service beginning in 2032, the pumped storage hydro candidate is modeled as an 8-hour, 1,000 MW unit. More details can be found in Technical Appendix ECON-10.

The capacity expansion plans developed by PLEXOS LT are designed to meet the joint system needs of NV Energy. The expansion plans generated by PLEXOS LT were reviewed and adjustments were made to assign resources to Nevada Power and Sierra, ensuring each company meets a share of the PRM and RPS requirements.

RPS compliance and NGR contribution are targeted at a system level. Likewise, all cases are designed to reach NV Energy's proportionate share of the state's 2050 clean energy goal at a system level, as well. In this analysis, only generation owned or controlled by the Companies contributed to the 2050 goal. An example of the calculation of zero carbon generation in this analysis is presented later in this subsection under the heading "Calculation of Zero Carbon Generation."

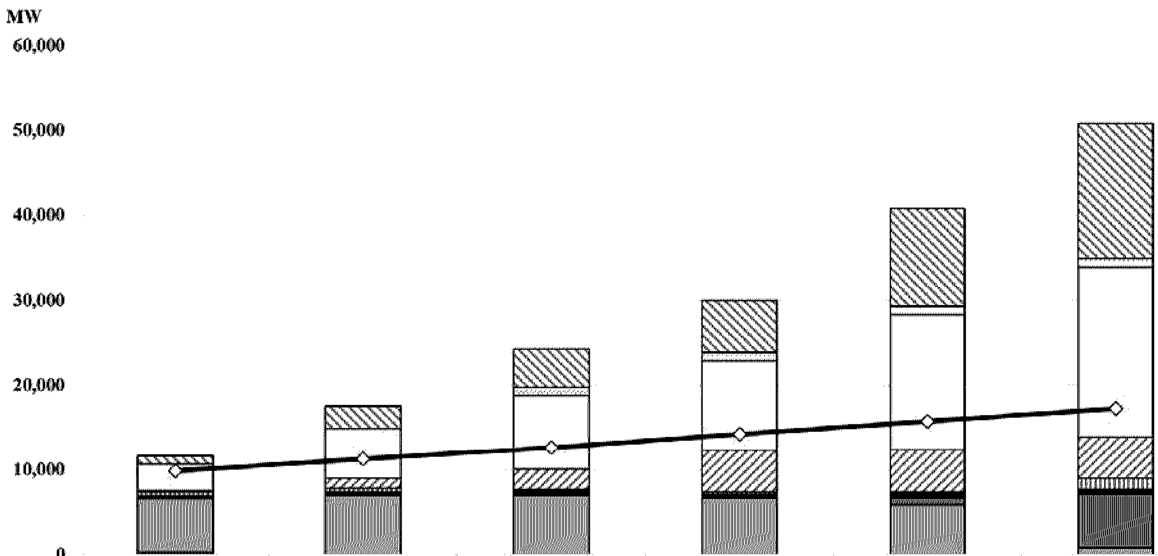
The resulting Base Case buildout is shown in Figure EA-6. A graphic representation of installed capacity over the study period is shown in Figure EA-7.

FIGURE EA-6
BUILDOUT FOR 2024 JOINT IRP BASE CASE

	BASE CASE	
	Sierra	Nevada Power
2025	Storage DR - SPPC_25	Storage DR - NPC_25
2026		146 MW *BESS Paired - NPC_26 146 MW *PV Paired - NPC_26
2027	4 MW Community Solar - SPPC_27 4 MW Community Storage - SPPC_27 10 MW **Solar For All - SPPC_27 57 MW *BESS Paired - SPPC_27 57 MW *PV Paired - SPPC_27 420 MW CT - SPPC_27	14 MW Community Solar - NPC_27 14 MW Community Storage - NPC_27 20 MW **Solar For All - NPC_27 509 MW *BESS Paired - NPC_27 509 MW *PV Paired - NPC_27
2028		11 MW Community Solar - NPC_28 11 MW Community Storage - NPC_28 587 MW *PV Alone - NPC_28
2029	762 MW *WIND(ID) - SPPC_29	190 MW *WIND(ID) - NPC_29
2030	331 MW *BESS Alone - SPPC_30	110 MW *BESS Alone - NPC_30 1170 MW *PV Alone - NPC_30
2031	163 MW *BESS Alone - SPPC_31 951 MW *PV Alone - SPPC_31	245 MW *BESS Alone - NPC_31
2032	524 MW *BESS Alone - SPPC_32	817 MW *WIND(NV) - NPC_32
2033		219 MW *BESS Alone - NPC_33 1053 MW *PV Alone - NPC_33 326 MW *WIND(NV) - NPC_33

2034	201 MW *BESS Alone - SPPC_34 475 MW *PV Alone - SPPC_34 277 MW *WIND(NV) - SPPC_34	246 MW *BESS Alone - NPC_34
2035	500 MW *PSH - SPPC_35	500 MW *PSH - NPC_35 385 MW *PV Alone - NPC_35
2036		728 MW *PV Alone - NPC_36 224 MW *WIND(NV) - NPC_36
2037	215 MW *WIND(NV) - SPPC_37	501 MW *WIND(NV) - NPC_37
2038	1121 MW *WIND(NV) - SPPC_38	
2039	260 MW *WIND(NV) - SPPC_39	260 MW *WIND(NV) - NPC_39 305 MW *BESS Alone - NPC_39 934 MW *PV Alone - NPC_39
2040	631 MW *BESS Alone - SPPC_40 594 MW *PV Alone - SPPC_40	631 MW *BESS Alone - NPC_40
2041	380 MW *BESS Alone - SPPC_41	380 MW *BESS Alone - NPC_41 1367 MW *PV Alone - NPC_41
2042	726 MW *BESS Alone - SPPC_42	726 MW *BESS Alone - NPC_42 936 MW *PV Alone - NPC_42
2043	254 MW *BESS Alone - SPPC_43 503 MW *PV Alone - SPPC_43	763 MW *BESS Alone - NPC_43
2044	674 MW *BESS Alone - SPPC_44 818 MW *PV Alone - SPPC_44	674 MW *BESS Alone - NPC_44 350 MW *PV Alone - NPC_44
2045	440 MW *BESS Alone - SPPC_45 1779 MW *PV Alone - SPPC_45	440 MW *BESS Alone - NPC_45 840 MW Firm Dispatchable - NPC_45
2046	1154 MW *BESS Alone - SPPC_46 989 MW *PV Alone - SPPC_46	660 MW *PV Alone - NPC_46
2047	128 MW *BESS Alone - SPPC_47 1446 MW *PV Alone - SPPC_47	1148 MW *BESS Alone - NPC_47 420 MW Firm Dispatchable - NPC_47
2048	334 MW *Geo - SPPC_48 549 MW *BESS Alone - SPPC_48	934 MW *PV Alone - NPC_48 137 MW *BESS Alone - NPC_48
2049	523 MW *BESS Alone - SPPC_49 420 MW Firm Dispatchable - SPPC_49 764 MW *Geo - SPPC_49	
2050	899 MW *BESS Alone - SPPC_50	899 MW *BESS Alone - NPC_50 4596 MW Firm Dispatchable - NPC_50 2199 MW *PV Alone - NPC_50

FIGURE EA-7
BASE CASE INSTALLED CAPACITY



	2025	2030	2035	2040	2045	2050
BESS	946	2,756	4,532	6,150	11,430	15,923
PSH	-	-	1,000	1,000	1,000	1,000
Solar	3,146	5,873	8,719	10,524	15,942	19,970
Wind	152	1,104	2,372	4,953	4,953	4,953
Geo	422	415	264	252	252	1,325
Hydro	148	136	136	136	135	135
Other	256	315	319	347	369	397
Firm	-	-	-	-	840	6,276
Gas	6,318	6,999	6,999	6,657	5,854	864
Coal	261	-	-	-	-	-
PRMR	9,866	11,281	12,695	14,224	15,766	17,315

Certain DSM and DRP programs are included in the Base Case and in all subsequent cases. These programs are provided in Figure EA-8. Additional information is provided in the DSM and DRP Volumes.

FIGURE EA-8
DSM/DRP PROGRAMS INCLUDED IN ALL CASES AND PLANS

Project Description	Technology	Company	Capacity (MW)[1]	Commercial Operation[2]	Term (years)
Air Conditioning Load Management (ACLM)	Demand Response	Nevada Power / Sierra	Annual Growth	In Operation	Ongoing
Behind the Meter (BTM) Storage	Demand Response	Nevada Power / Sierra	Annual Growth	Beginning 2025	Ongoing
Utility Owned Community Solar	Solar PV/BESS	Nevada Power	14	6/1/2027	20
Utility Owned Community Solar		Sierra	4	6/1/2027	20
Utility Owned Community Solar		Nevada Power	11	6/1/2028	20
Solar for All	Solar PV	Nevada Power	20	6/1/2027	20
Solar for All	Solar PV	Sierra	10	6/1/2027	20

[1]Each PV/BESS resource proposed a 1:1 PV/BESS Ratio.

[2]COD as proposed.

These programs contribute to the capacity need and to the renewable energy requirements, as appropriate, and are the same in all modeled cases and plans. Due to timing of the DSM and DRP program development, the programs proposed in this 2024 Joint IRP differ from those modeled. These differences are explained further in the DSM and DRP Volumes.

Individual Project Screening:

NV Energy compiled a diverse set of potential projects that could fill a portion of the Companies' near-term need for additional capacity and renewable credits. These resource options were developed from a combination of self-development efforts, request for proposal bid responses, and bilateral negotiations as described in the Renewables and Generation Sections. The projects are briefly described in the list of screening cases below but are more fully described in the Renewables and Generation Sections.

Screening cases listed below were developed by adding these projects individually to the Base Case, then adjusting placeholder resources to achieve similar open positions and similar amounts of renewable energy in each screening case.

- ***Two CTs at Valmy***. Replaces Base Case placeholder resources with approximately 411 MW of summer peak capacity. This project will be in service by June 2028. These units will be located at the existing North Valmy Generating Station in Humboldt County, Nevada, and will be owned and operated by Sierra. Further details, including construction costs and operation and maintenance expenses, can be found in the Generation Section.

- ***Two CTs at Ft. Churchill***. Replaces Base Case placeholder resources with approximately 411 MW of summer peak capacity. The in-service date for this project is June 2029. These units will be located at the existing Ft. Churchill Generating Station in Yerington, Nevada, and will be owned and operated by Sierra. Further details, including construction costs and operation and maintenance expenses, can be found in the Generation Section.

- ***Two CTs at Harry Allen***. Replaces Base Case placeholder resources with approximately 445 MW of summer peak capacity. The in-service date for this project is June 2030. These units will be located 30 miles north of Las Vegas at the existing Harry Allen Generating Station and will be owned and operated by Nevada Power. Further details, including construction costs and operation and maintenance expenses, can be found in the Generation Section.

- ***Two CTs at Higgins***. Replaces Base Case placeholder resources with approximately 440 MW of summer peak capacity. The in-service date for this project is June 2029. These units will be located at the existing Walter M. Higgins Generating Station in Primm, Nevada, and will be owned and operated by Nevada Power. Further details, including construction costs and operation and maintenance expenses, can be found in the Generation Section.

- ***Dry Lake East PV/BESS.*** Replaces Base Case placeholder resources with a PPA consisting of 200 MW of PV paired with 200 MW of 4-hour BESS. The in-service date for both the PV and BESS is December 2026. Located in Clark County, Nevada, this project will contribute to NV Energy's RPS and capacity needs. Contracted capacity is allocated solely to Nevada Power. Further details, including contract price and term, can be found in the Renewables Section.

- ***Boulder Solar III PV/BESS***. This project is a new version of the cancelled Boulder Solar III PV/BESS PPA approved in Docket 20-07023 and includes a longer term and updated pricing. The project replaces Base Case placeholder resources with 128 MW of PV paired with 128 MW of 4-hour BESS. With an in-service date of June 2027 for both the PV and BESS, this project will contribute to NV Energy's RPS and capacity requirements. Contracted capacity is allocated solely to Nevada Power. Further details, including contract price and term, can be found in the Renewables Section.

- ***Libra PV/BESS***. Replaces Base Case placeholder resources with a PPA consisting of 700 MW of PV paired with 700 MW of 4-hour BESS. This project is located in Mineral County, Nevada and has an in-service date of December 2027 for both the PV and BESS. The project will contribute to the Companies' RPS and capacity needs. For the individual project screening, the Libra PV/BESS was allocated solely to Nevada Power due to its large size. In subsequent analyses, multiple scenarios with various allocations between Nevada Power and Sierra were evaluated and are further described in the Combination

Case Analysis below. Further details, including contract price and term, can be found in the Renewables Section.

- ***Geo-1***. Replaces Base Case placeholder resources with a PPA consisting of a portfolio of geothermal projects totaling 152 MW. Located in northern Nevada, the geothermal portfolio project's in-service dates range from 2027 to 2033. The project will contribute to NV Energy's capacity and RPS requirements, and contracted energy and capacity will be wholly allocated to Sierra. Further details, including contract price and term, can be found in the Renewables Section.

- ***Solar-1***. Replaces Base Case placeholder resources with a PPA consisting of 57 MW PV paired with 57 MW of 4-hour BESS. Located in southern Nevada, this project has an in-service date of April 2026 and will contribute to the capacity and RPS needs of the Companies. Contracted capacity is allocated exclusively to Nevada Power. Further details, including contract price and term, can be found in the Renewables Section.

- ***Battery-1***. Replaces Base Case placeholder resources with an 80 MW 4-hour BESS PPA. Located in southern Nevada, with an in-service date of May 2026, this project will contribute to the Companies' capacity requirements. Contracted capacity is allocated solely to Nevada Power. Further details, including contract price and term, can be found in the Renewables Section.

- ***Solar-2***. Replaces Base Case placeholder resources with a PPA consisting of 200 MW PV paired with 200 MW of 4-hour BESS. Located near southern Nevada, the project has an in-service date of March 2028. The project contributes to the capacity and RPS requirements of the Companies, and contracted energy and capacity is allocated entirely to Nevada Power. Further details, including contract price and term, can be found in the Renewables Section.

- ***Wind-1***. Replaces Base Case placeholder resources with a PPA consisting of 500 MW of wind. Located in northern Nevada, the project has an in-service date of December 2028 and will contribute to the RPS and capacity needs of the Companies. Contracted capacity is allocated exclusively to Sierra. Further details, including contract price and term, can be found in the Renewables Section.

More specific information on the final resource buildouts for each of the project screenings can be found in the L&R Tables in Technical Appendix ECON–5. Redacted cost summaries and load balances from the production cost model runs are included in Technical Appendix ECON-4. The CER analysis for each case is part of Technical Appendices ECON-6 and ECON-7.

Note that the CER for each individual project screening includes the required transmission infrastructure capital associated with the project as described in the Transmission Plan. Moreover, the Base Case, all project screenings, and all subsequent cases and plans include any additional transmission infrastructure required to address customer loads and other needs independent of the generating resources and is detailed in the Transmission Plan. All cases and plans also include the updated cost of the Greenlink Nevada transmission project as specified in the Transmission Plan. All transmission infrastructure capital costs are included in Technical Appendices ECON-6 and ECON-7.

The PWRR of the individual project screening analyses are shown in Figure EA-9 below. The cases are listed in rank order based on the 20-year PWRR.

FIGURE EA-9
RESULTS OF INDIVIDUAL PROJECT SCREENINGS

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Least Cost Case (million $)	26 Year PWRR Change from Least Cost Case (million $)	20 Year PWRR Rank Order	26 Year PWRR Rank Order
Libra NPC	$ 32,159	$ 40,231	$ -	$ -	**1**	**1**
Harry Allen CTs	$ 32,205	$ 40,343	$ 47	$ 111	**2**	**2**
Valmy CTs	$ 32,297	$ 40,396	$ 138	$ 164	**3**	**3**
Battery-1	$ 32,309	$ 40,397	$ 151	$ 165	**4**	**4**
Higgins CTs	$ 32,312	$ 40,455	$ 154	$ 224	**5**	**9**
Base	$ 32,314	$ 40,410	$ 156	$ 179	**6**	**5**
Solar-1	$ 32,334	$ 40,425	$ 175	$ 193	**7**	**6**
Boulder Solar III	$ 32,345	$ 40,426	$ 186	$ 194	**8**	**7**
Dry Lake East	$ 32,354	$ 40,433	$ 195	$ 202	**9**	**8**
Solar-2	$ 32,359	$ 40,463	$ 200	$ 232	**10**	**10**
Geo-1	$ 32,519	$ 40,592	$ 360	$ 361	**11**	**11**
Wind-1	$ 32,521	$ 40,665	$ 363	$ 434	**12**	**12**
FTC CTs	$ 32,904	$ 41,118	$ 746	$ 886	**13**	**13**

Further evaluation of the individual project screenings was performed, comparing cases to the Base Case in a stepwise process in which similar resource types were grouped: CT and standalone BESS, paired PV and BESS, Wind, and Geothermal. This evaluation process led to the selection of projects which advanced to the next phase of the economic evaluation, the Combination Cases.

The first step of this expanded evaluation compared capacity-only projects (CTs and standalone BESS) to the Base Case. Note that the Base Case includes BESS as early as 2026 and two CTs in 2027 as part of a least cost placeholder-only buildout from the expansion model. Figure EA-10 provides a comparison table.

FIGURE EA-10
RESULTS OF INDIVIDUAL PROJECT SCREENING –
CT AND STANDALONE BESS COMPARISON

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Base Case (million $)	26 Year PWRR Change from Base Case (million $)
Harry Allen CTs	$ 32,205	$ 40,343	$ (109)	$ (68)
Valmy CTs	$ 32,297	$ 40,396	$ (18)	$ (14)
Battery-1	$ 32,309	$ 40,397	$ (5)	$ (13)
Higgins CTs	$ 32,312	$ 40,455	$ (2)	$ 45
Base	$ 32,314	$ 40,410	$ -	$ -
FTC CTs	$ 32,904	$ 41,118	$ 590	$ 707

Key findings from the individual project screening of CT and standalone BESS resources include:

- The Harry Allen CTs, Valmy CTs, and Higgins CTs screenings have lower 20-year PWRRs than the Base Case, suggesting they are economic resource options that warrant further consideration.
- As detailed in the Generation Section, the equipment costs for all CT projects were similar, but the site-specific costs were not. These costs, together with the estimates for site-specific transmission and gas infrastructure, resulted in the cost differentials in the cases that included CTs.
- The Harry Allen CTs screening has the lowest 20-year PWRR due, in part, to the later in-service date for the units at this location.
- The Fort Churchill CTs screening has a higher 20-year PWRR than the Base Case, indicating it is not as economic as the other CT options. Fort Churchill CTs were removed from further consideration at this time.
- The Battery-1 screening has a 20-year PWRR that closely approximates the PWRR of the Base Case. However, the due diligence evaluations of the project were in progress concurrent with this screening analysis and ultimately, Battery-1 was removed from consideration for this filing. Additional information regarding the removal of this project from the current filing is available in the Renewables Section.

The Base Case includes 712 MW of Paired PV and BESS and 587 MW of Standalone PV placeholder resources by the summer of 2028. An evaluation of similar projects was conducted to evaluate options to acquire the PV and BESS selected in the Base Case. Figure EA-11 provides a paired PV and BESS comparison table.

FIGURE EA-11
RESULTS OF INDIVIDUAL PROJECT SCREENING –
PAIRED PV AND BESS COMPARISON

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Base Case (million $)	26 Year PWRR Change from Base Case (million $)
Libra NPC	$ 32,159	$ 40,231	$ (156)	$ (179)
Base	$ 32,314	$ 40,410	$ -	$ -
Solar-1	$ 32,334	$ 40,425	$ 20	$ 15
Boulder Solar III	$ 32,345	$ 40,426	$ 30	$ 16
Dry Lake East	$ 32,354	$ 40,433	$ 40	$ 23
Solar-2	$ 32,359	$ 40,463	$ 45	$ 53

Key findings from the individual project screening of PV and BESS resources include:

- The Libra NPC screening, with output allocated solely to Nevada Power, has a lower 20- and 26-year PWRR compared to the Base Case, suggesting this project is an economic resource that warrants further consideration.
- The Boulder Solar III and Dry Lake East screenings each have slightly higher 20-year PWRRs compared to the Base Case. Combined, however, these projects provide 328 MW of Paired PV and BESS to potentially fill a portion of the amount indicated in the Base Case. Therefore, these projects were included for further consideration.
- The Solar-1 and Solar-2 projects' due diligence evaluations were in progress concurrent with this analysis and ultimately, both projects were removed from consideration for this filing. Additional information regarding the removal of these projects from the current filing is available in the Renewables Section.

In the Base Case, 952 MW of Idaho Wind was selected in 2029. Unfortunately, there were no specific Idaho Wind projects available at this time for the screening analysis. Nevada Wind was selected, as well, beginning in 2032. An evaluation of project options was conducted to explore the potential benefit of an earlier in-service date for Nevada Wind. Figure EA-12 provides a wind comparison table.

FIGURE EA-12
RESULTS OF INDIVIDUAL PROJECT SCREENING –
WIND COMPARISON

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Base Case (million $)	26 Year PWRR Change from Base Case (million $)
Base	$ 32,314	$ 40,410	$ -	$ -
Wind-1	$ 32,521	$ 40,665	$ 207	$ 255

The Wind-1 screening has a higher 20- and 26-year PWRR than the Base Case. The Base Case did not call for Nevada Wind until 2032, whereas the Wind-1 project has an in-service date of 2028. Regardless, the project due diligence evaluation was in progress concurrent with this analysis and ultimately, the project was removed from consideration for this filing. Additional information regarding the removal of this project from the current filing is available in the Renewables Section.

Geothermal generation was not selected in the Base Case until 2048. However, an evaluation of geothermal project options was conducted to assess the economic value of an earlier in-service date and to ensure a diverse mix of resource options was evaluated. Figure EA-13 provides a geothermal comparison table.

FIGURE EA-13
RESULTS OF INDIVIDUAL PROJECT SCREENING
GEOTHERMAL COMPARISON

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Base Case (million $)	26 Year PWRR Change from Base Case (million $)
Base	$ 32,314	$ 40,410	$ -	$ -
Geo-1	$ 32,519	$ 40,592	$ 205	$ 182

The Geo-1 screening has higher 20-year and 26-year PWRRs compared to the Base Case. This is consistent with the exclusion of geothermal from the Base Case until 2048, which is significantly later than the Geo-1's in-service dates of 2027 to 2033. Regardless, the project due diligence evaluation was in progress concurrent with this analysis and ultimately, the project was removed from consideration for this filing. Additional information regarding the removal of this project from the current filing is available in the Renewables Section.

At the conclusion of the individual project screening, the projects listed below are subject to further examination in the next step of the analysis.

- Harry Allen CTs
- Valmy CTs
- Higgins CTs
- Libra PV/BESS
- Boulder Solar III PV/BESS
- Dry Lake East PV/BESS

Combination Cases:

The Companies continue their analysis by developing a set of cases in which combinations of available projects are added to the Base Case, with adjustment of placeholder resources such that the open positions and systemwide RPS and NGR attainment of each combination case are as similar as possible. Additionally, the Combination Cases are developed subject to the following conditions:

- No placeholders in the Action Plan period (2025-2027);
- Placeholder resources in 2028 are also eliminated;
- To the extent possible, open positions remain at or below 750 MW starting in 2028;
- When possible, renewable energy requirements are met without the need to use previously banked portfolio credits ("PCs"); and,
- Near-term CTs are limited to include only one set of CTs, or approximately 420 MW, consistent with the selection of one set of near-term CTs in the Base Case.

The Companies devised a project naming convention for the creation of concise case names as shown in Figure EA-14. The combination cases produced are shown in Figure EA-15.

FIGURE EA-14
PROJECT NAMING CONVENTION FOR COMBINATION CASE NAMES

PROJECT NAME	NAMING CONVENTION
Valmy CTs	V
Higgins CTs	I
Harry Allen CTs	A
Boulder Solar III PV/BESS	B
Dry Lake East PV/BESS	D
Libra PV/BESS – 100% NPC	L1
Libra PV/BESS – 60% Nevada Power, 40% Sierra	L2
Libra PV/BESS – 50% Nevada Power, 50% Sierra	L3

FIGURE EA-15
COMBINATION CASES

COMBINATION THEME	RESOURCES INCLUDED	CASE NAME
North CT + B + D + L1	Valmy CTs, Boulder Solar III, Dry Lake East, and Libra	VBDL1
South CT + B + D + L3	Higgins CTs, Boulder Solar III, Dry Lake East, and Libra Split	IBDL3
South CT + B + D + L3	Harry Allen CTs, Boulder Solar III, Dry Lake East, and Libra Split	ABDL3
B + D + L2	Boulder Solar III, Dry Lake East, and Libra Split	BDL2

It is noteworthy that all the combination cases include the Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS projects, as they are all needed to satisfy the RPS requirement. Libra PV/BESS is also needed in all cases to satisfy the Companies' open position goals. Even with the addition of these PV/BESS projects, the Companies will have to use banked PCs to meet the state's RPS mandates and company credit commitments (NGR, ESA, and 704B obligations) in the early years of the study period, which is further explained in the Renewables Section.

Of all the siting options studied for the addition of two CTs, only the Valmy location has the benefit of eliminating the existing Valmy steamer must-run requirement as described in the Transmission Section of the narrative. Without the two fast start peaking units at the Valmy location, the Valmy steamer must-run requirement continues in perpetuity due to the load growth in the region. It is also significant to note that CTs at this location do not compete for natural gas availability with Sierra's local gas distribution company in Reno/Sparks.

As mentioned previously, placeholder resources in the combination cases are adjusted to ensure similar open positions are present in each case to the extent possible. This adjustment ensures that the cases are similarly reliable. The open positions for the combination cases are shown in Figure EA-16.

FIGURE EA-16
OPEN POSITIONS FOR EACH COMBINATION CASE

While placeholder resources were eliminated in the action plan period as previously described, placeholder resources in later years were adjusted to ensure each case similarly satisfies the systemwide RPS requirement, the expected level of NGR participation, and the targeting of the state's 2050 clean energy goal. The placeholder resources in each of these cases are reflected in the respective L&R tables. The redacted cost summaries and load balances from the production cost model runs are included in Technical Appendix ECON-4. The CER analysis for each case is part of Technical Appendices ECON-6 and ECON-7.

The PWRR results of the combination case screening are shown in Figure EA-17, in rank order relative to the least cost case.

FIGURE EA-17
RESULTS OF COMBINATION CASE ANALYSIS

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Least Cost Case (million $)	26 Year PWRR Change from Least Cost Case (million $)	20 Year PWRR Rank Order	26 Year PWRR Rank Order
VBDL1	$ 32,291	$ 40,399	$ -	$ -	**1**	**1**
ABDL3	$ 32,397	$ 40,551	$ 107	$ 152	**2**	**2**
IBDL3	$ 32,505	$ 40,664	$ 214	$ 265	**3**	**3**
BDL2	$ 32,617	$ 41,454	$ 327	$ 1,054	**4**	**4**

Key findings and observations of the combination case comparisons include:

- All combination cases add the Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS projects for RPS compliance.
- Libra PV/BESS is required in all cases to meet the Companies' open position goals, as well.
- VBDL1, which includes CTs at Valmy, has the lowest 20- and 26-year PWRR amongst all the cases. The Valmy CTs, moreover, have an in-service date in 2028, which is the earliest in-service date of all CT options. This early in-service date reduces market reliance – and decreases reliability risk – earlier than other cases.
- ABDL3, which includes CTs at Harry Allen, has the second lowest 20-year and 26-year PWRR when compared to the other cases. The Harry Allen CTs have an in-service date in 2030, resulting in greater market reliance and therefore, increased reliability risk in 2028 and 2029 relative to the other CT options. All else being equal, the later in-service date also has the effect of reducing the PWRR relative to the earlier CT options.
- IBDL3, which includes CTs at Higgins, has the third lowest 20-year and 26-year PWRR when compared to the other cases studied here. The Higgins CTs have an in-service date of 2029.
- BDL2, which adds only renewable projects and does not include new CTs, has the highest 20-year and 26-year PWRR. Without a CT project in this case, there is a greater need for BESS over the planning period to account for annual effective capacity degradation, which is the primary driver of the higher PWRRs in this case. This outcome is consistent with the selection of two near-term CTs in the least cost buildout from PLEXOS LT.
- The difference between the 26-year PWRR of the Valmy CT case and the 26-year PWRR of the south CT cases ranges from approximately $150 million to nearly $270 million.
- The difference between the 26-year PWRR of the Valmy CT case and the 26-year PWRR of the BDL2 case is approximately $1.05 billion.

- As described previously, only the case that adds CTs at Valmy has the benefit of eliminating the existing Valmy steamer must-run requirement as detailed in the Transmission Section. Without two fast start peaking units at the Valmy location, the Valmy steamer must-run requirement continues in perpetuity due to load growth in the region.
- Also described previously, it is noteworthy that CTs at the Valmy location do not compete for natural gas availability with Sierra's local gas distribution company in Reno/Sparks.

Alternative Plans:

Informed by the analysis of the combination cases, as well as statutory requirements, a diverse set of alternative plans are created. Two of the plans are updated versions of combination cases. Two additional plans address statutory requirements described previously and are referred to as the Low Carbon Plan and No Open Position Plan.

All alternative plans include "named placeholders" that address a directive within ordering paragraph 6 of the Commission's April 9, 2024, Modified Final Order in the Fifth Amendment. Named placeholders are provided to represent reasonably known projects in progress or requested and to reflect anticipated Company-owned projects. These are presented with estimated cost/pricing data, including anticipated associated transmission infrastructure costs, and are described further in the Renewables Section. The Companies are not requesting approval of any of the named placeholders, and all placeholders are subject to change as needs and circumstances change in future filings.

The two alternative plans developed from combination cases were purposefully created to differ from the combination cases only in that named placeholders are included to facilitate comparison. The alternative plans are described in greater detail below. The L&R Tables are provided in Technical Appendix ECON-5.

Balanced Plan. The least cost case from the combination case evaluation, **VBDL1**, was chosen to move forward in the alternative plan analysis as it represents a balanced approach to meeting the capacity needs in this filing, as well as the state's, Companies', and customers' renewable energy needs, while minimizing cost impact on customers. This plan was named the Balanced Plan and combines new CTs at Valmy, Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS projects. Libra's capacity is allocated entirely to Nevada Power in this plan. The projects add near-term capacity in 2027 and 2028, reduce the Companies' dependence on uncertain market capacity purchases, contribute to RPS and NGR needs, and supply energy after solar resource output declines in the evening hours. The Valmy CTs enable the removal of the existing Valmy steamer must-run requirement as described in the Transmission Section of the narrative and do not compete for natural gas availability with Sierra's local gas distribution company in Reno/Sparks. The named placeholders in this plan are detailed in Figure EA-18.

FIGURE EA-18
BALANCED PLAN NAMED PLACEHOLDERS

Named Placeholder	In-Service Date	Type	Company	Location	Rating
Idaho Wind 2029 - Wind(ID)	6/1/2029	PPA	Sierra	Idaho	952 MW
Sierra Solar II BESS	4/1/2030	PPA	Sierra	Northern NV	100 MW
Sierra Solar II PV	4/1/2030	PPA	Sierra	Northern NV	600 MW
Amargosa I BESS	4/1/2031	Owned	Nevada Power	Southern NV	200 MW
Amargosa I PV	4/1/2031	Owned	Nevada Power	Southern NV	200 MW
Sierra Solar III BESS	4/1/2032	Owned	Sierra	Northern NV	500 MW
Amargosa II BESS	4/1/2033	Owned	Nevada Power	Southern NV	200 MW
Amargosa II PV	4/1/2033	Owned	Nevada Power	Southern NV	400 MW
Amargosa III BESS	4/1/2034	Owned	Nevada Power	Southern NV	200 MW
Amargosa III PV	4/1/2034	Owned	Nevada Power	Southern NV	200 MW
White Pine Pumped Storage	4/1/2035	PPA	Sierra	Northern NV	500 MW
White Pine Pumped Storage	4/1/2035	PPA	Nevada Power	Northern NV	500 MW

Renewable Plan. The combination case that adds only renewable and storage projects, **BDL2**, was chosen to move forward in the alternative plan analysis as an option that adds no near-term thermal projects. This plan was named the Renewable Plan and combines Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. In this plan, Libra's capacity is allocated 60 percent to Nevada Power and 40 percent to Sierra. The named placeholders in this plan are identical to those in the previous plan. While the projects add near-term capacity in the same early years as the Balanced Plan, less capacity is added in 2028. The lack of near term CTs results primarily in incremental BESS placeholders in 2030 in order to ensure similar open positions to the Balanced Plan. Without the two fast start peaking units at the Valmy location, the Valmy steamer must-run requirement continues in perpetuity in this plan due to the load growth in the region.

Low Carbon Plan. As previously described, a low carbon plan which uses supply resources that result in, by the year 2030, an 80 percent reduction in carbon dioxide emissions compared to such emissions from 2005, is a required alternative plan. Using the 2005 carbon dioxide emissions baseline of 20.0 million short tons established in the Fourth Amendment to the 2021 Joint IRP,[2] the Companies created a new PLEXOS LT expansion plan to develop this plan. This PLEXOS LT run utilized the same load, PRM requirement, and candidate resources as the base case expansion; however, new build constraints for a greater renewable energy requirement, beginning in 2027, were added to meet the 2030 carbon dioxide emissions goal.

The presumed retirement dates of existing resources were not changed in the creation of this plan. Notably, the least cost reliable buildout from PLEXOS LT that meets the requirements for this low carbon scenario includes, in 2050, the same amount of gas-fired and firm dispatchable resources – resources modeled as gas turbines – as the Base Case. In other words, the least cost reliable buildout adds incremental firm dispatchable resources in this scenario just as it did for the Base Case, regardless of the aggressive, early renewable/storage buildout to meet the particular goals of this scenario. As this scenario has the same capacity need as the base case and other plans, if any existing thermal units were retired earlier in this plan, indications are that incremental new firm dispatchable resources would likely be added in subsequent years to achieve the needed capacity. Due to the early renewable/storage buildout, the BESS ELCC saturates earlier in this plan than the others, which devalues BESS relative to firm dispatchable resources in subsequent years. While early retirement of existing thermal resources would remove fixed costs, the subsequent replacement with new firm dispatchable resources would require substantial incremental capital costs.

The Low Carbon Plan adds no near-term thermal generation and combines Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra's capacity is allocated 100 percent to Nevada Power in this plan. Without the two fast start peaking units at the Valmy location, the Valmy steamer must-run requirement continues in perpetuity in this plan due to the load growth in the region. A significant increase in near-term renewable placeholders is needed in this plan to comply with carbon dioxide reduction requirements. Additionally, the number, size, and timing of the named placeholders are adjusted relative to the prior plans to accommodate the increased level of renewable placeholders. The named placeholders in this plan are shown in Figure EA-19.

[2] Docket No. 22-11032, Technical Appendix ECON-10.

FIGURE EA-19
LOW CARBON PLAN NAMED PLACEHOLDERS

Named Placeholder	In-Service Date	Type	Company	Location	Rating
Idaho Wind 2029 - Wind(ID)	6/1/2029	PPA	Sierra	Idaho	952 MW
Sierra Solar II BESS	4/1/2029	PPA	Sierra	Northern NV	357 MW
Sierra Solar II PV	4/1/2029	PPA	Sierra	Northern NV	357 MW
Sierra Solar III BESS	4/1/2030	Owned	Sierra	Northern NV	200 MW
Sierra Solar III PV	4/1/2030	Owned	Sierra	Northern NV	200 MW
Amargosa I PV	4/1/2033	Owned	Nevada Power	Southern NV	400 MW
White Pine Pumped Storage	4/1/2033	PPA	Sierra	Northern NV	500 MW
White Pine Pumped Storage	4/1/2033	PPA	Nevada Power	Northern NV	500 MW

No Open Position Plan. The Companies also prepared a plan that provides for the acquisition of energy resources to close the open position utilizing dedicated energy resources in Nevada or delivered through firm transmission as described in NRS § 704.741(3)(c)(2). The Companies created a new PLEXOS LT expansion plan to develop this plan. This PLEXOS LT run used the same load, PRM requirement, and candidate resources as the base case expansion but permitted no market capacity purchases beginning in 2028. Notably, two sets of CTs were selected in the early years in this expansion buildout. This plan includes two CTs at each of the Valmy and Harry Allen Generating Stations, as well as Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra's capacity is allocated solely to Nevada Power in this plan. As with the Balanced Plan, the Valmy CTs enable the retirement of the existing Valmy steamer must-run requirement as described in the Transmission Section of the narrative and do not compete for natural gas availability with Sierra's local gas distribution company in Reno/Sparks. The named placeholders for this plan are shown in Figure EA-20.

FIGURE EA-20
NO OPEN POSITION PLAN NAMED PLACEHOLDERS

Named Placeholder	In-Service Date	Type	Company	Location	Rating
Idaho Wind 2029 - Wind(ID)	6/1/2029	PPA	Sierra	Idaho	952 MW
Sierra Solar II PV	4/1/2030	PPA	Sierra	Northern NV	600 MW
Amargosa I BESS	4/1/2031	Owned	Nevada Power	Southern NV	100 MW
Amargosa I PV	4/1/2031	Owned	Nevada Power	Southern NV	400 MW
Sierra Solar III BESS	4/1/2032	Owned	Sierra	Northern NV	500 MW
Amargosa II BESS	4/1/2033	Owned	Nevada Power	Southern NV	400 MW
Amargosa II PV	4/1/2033	Owned	Nevada Power	Southern NV	400 MW
White Pine Pumped Storage	4/1/2034	PPA	Sierra	Northern NV	500 MW
White Pine Pumped Storage	4/1/2034	PPA	Nevada Power	Northern NV	500 MW

All four alternative plans address the need for RPS-contributing projects and provide capacity by replacing placeholder resources with proposed projects that reduce the Companies' open position. The plans are responsive to the continued uncertain availability and deliverability of market capacity, consistent with advancing resource sufficiency as required for participation in the WRAP. All plans meet the PRM requirement, the state's RPS requirements, and the expected level of NGR participation, and target the Companies' proportionate contribution to the state's 2050 clean energy goal.

Figures EA-21 and EA-22 present the detailed buildouts for the alternative plans. Proposed resources and named placeholders are highlighted.

FIGURE EA-21
BUILDOUT FOR BALANCED PLAN AND RENEWABLE PLAN

	Balanced Plan		Renewable Plan	
	Sierra	Nevada Power	Sierra	Nevada Power
2025	Storage DR - SPPC_25	Storage DR - NPC_25		
2026		200 MW **Dry Lake East PV - NPC_26 200 MW **Dry Lake East BESS - NPC_26		200 MW **Dry Lake East PV - NPC_26 200 MW **Dry Lake East BESS - NPC_26
2027	4 MW Community Solar - SPPC_27 4 MW Community Storage - SPPC_27 10 MW **Solar For All - SPPC_27	14 MW Community Solar - NPC_27 14 MW Community Storage - NPC_27 20 MW **Solar For All - NPC_27 700 MW **Libra PV - NPC_27 700 MW **Libra BESS - NPC_27 128 MW **Boulder Solar III PV - NPC_27 128 MW **Boulder Solar III BESS - NPC_27	4 MW Community Solar - SPPC_27 4 MW Community Storage - SPPC_27 10 MW **Solar For All - SPPC_27 280 MW **Libra PV - SPPC_27 280 MW **Libra BESS - SPPC_27	14 MW Community Solar - NPC_27 14 MW Community Storage - NPC_27 20 MW **Solar For All - NPC_27 420 MW **Libra PV - NPC_27 420 MW **Libra BESS - NPC_27 128 MW **Boulder Solar III PV - NPC_27 128 MW **Boulder Solar III BESS - NPC_2
2028	411 MW Valmy CTs - SPPC_28	11 MW Community Solar - NPC_28 11 MW Community Storage - NPC_28		11 MW Community Solar - NPC_28 11 MW Community Storage - NPC_28
2029	952 MW *Idaho Wind 2029 - WIND(ID) - SPPC_29		952 MW *Idaho Wind 2029 - WIND(ID) - SPPC_29	
2030	2 MW *BESS Alone - SPPC_30 840 MW *PV Alone - SPPC_30 100 MW Sierra Solar II BESS - SPPC_30 600 MW Sierra Solar II PV - SPPC_30		232 MW *BESS Alone - SPPC_30 192 MW *PV Alone - SPPC_30 100 MW Sierra Solar II BESS - SPPC_30 600 MW Sierra Solar II PV - SPPC_30	272 MW *BESS Alone - NPC_30 648 MW *PV Alone - NPC_30
2031	204 MW *BESS Alone - SPPC_31 751 MW *PV Alone - SPPC_31	4 MW *BESS Alone - NPC_31 200 MW Amargosa I BESS - NPC_31 200 MW Amargosa I PV - NPC_31	308 MW *BESS Alone - SPPC_31 666 MW *PV Alone - SPPC_31	108 MW *BESS Alone - NPC_31 85 MW *PV Alone - NPC_31 200 MW Amargosa I BESS - NPC_31 200 MW Amargosa I PV - NPC_31
2032	500 MW Sierra Solar III BESS - SPPC_32	24 MW *BESS Alone - NPC_32 817 MW *WIND(NV) - NPC_32	209 MW *BESS Alone - SPPC_32 500 MW Sierra Solar III BESS - SPPC_32	125 MW *BESS Alone - NPC_32 817 MW *WIND(NV) - NPC_32
2033	11 MW *BESS Alone - SPPC_33	8 MW *BESS Alone - NPC_33 653 MW *PV Alone - NPC_33 326 MW *WIND(NV) - NPC_33 200 MW Amargosa II BESS - NPC_33 400 MW Amargosa II PV - NPC_33		19 MW *BESS Alone - NPC_33 653 MW *PV Alone - NPC_33 326 MW *WIND(NV) - NPC_33 200 MW Amargosa II BESS - NPC_33 400 MW Amargosa II PV - NPC_33
2034	246 MW *BESS Alone - SPPC_34 238 MW *PV Alone - SPPC_34 277 MW *WIND(NV) - SPPC_34	1 MW *BESS Alone - NPC_34 38 MW *PV Alone - NPC_34 200 MW Amargosa III BESS - NPC_34 200 MW Amargosa III PV - NPC_34	309 MW *BESS Alone - SPPC_34 238 MW *PV Alone - SPPC_34 277 MW *WIND(NV) - SPPC_34	86 MW *BESS Alone - NPC_34 38 MW *PV Alone - NPC_34 200 MW Amargosa III BESS - NPC_34 200 MW Amargosa III PV - NPC_34
2035	500 MW *White Pine PSH - SPPC_35	500 MW *White Pine PSH - NPC_35 385 MW *PV Alone - NPC_35	500 MW *White Pine PSH - SPPC_35	500 MW *White Pine PSH - NPC_35 385 MW *PV Alone - NPC_35

2036		728 MW *PV Alone - NPC_36 224 MW *WIND(NV) - NPC_36		728 MW *PV Alone - NPC_36 224 MW *WIND(NV) - NPC_36
2037	229 MW *WIND(NV) - SPPC_37	487 MW *WIND(NV) - NPC_37	229 MW *WIND(NV) - SPPC_37	487 MW *WIND(NV) - NPC_37
2038	1121 MW *WIND(NV) - SPPC_38		1121 MW *WIND(NV) - SPPC_38	
2039	260 MW *WIND(NV) - SPPC_39	260 MW *WIND(NV) - NPC_39 305 MW *BESS Alone - NPC_39 934 MW *PV Alone - NPC_39	415 MW *WIND(NV) - SPPC_39	104 MW *WIND(NV) - NPC_39 413 MW *BESS Alone - NPC_39 934 MW *PV Alone - NPC_39
2040	593 MW *BESS Alone - SPPC_40 594 MW *PV Alone - SPPC_40	669 MW *BESS Alone - NPC_40	752 MW *BESS Alone - SPPC_40 594 MW *PV Alone - SPPC_40	694 MW *BESS Alone - NPC_40
2041	380 MW *BESS Alone - SPPC_41	380 MW *BESS Alone - NPC_41 1367 MW *PV Alone - NPC_41	418 MW *BESS Alone - SPPC_41	342 MW *BESS Alone - NPC_41 1367 MW *PV Alone - NPC_41
2042	697 MW *BESS Alone - SPPC_42	755 MW *BESS Alone - NPC_42 936 MW *PV Alone - NPC_42	726 MW *BESS Alone - SPPC_42	726 MW *BESS Alone - NPC_42 936 MW *PV Alone - NPC_42
2043	295 MW *BESS Alone - SPPC_43 252 MW *PV Alone - SPPC_43	722 MW *BESS Alone - NPC_43 252 MW *PV Alone - NPC_43	305 MW *BESS Alone - SPPC_43 252 MW *PV Alone - SPPC_43	712 MW *BESS Alone - NPC_43 252 MW *PV Alone - NPC_43
2044	661 MW *BESS Alone - SPPC_44 818 MW *PV Alone - SPPC_44	687 MW *BESS Alone - NPC_44 350 MW *PV Alone - NPC_44	1333 MW *BESS Alone - SPPC_44 818 MW *PV Alone - SPPC_44	1333 MW *BESS Alone - NPC_44 350 MW *PV Alone - NPC_44
2045	440 MW *BESS Alone - SPPC_45 1779 MW *PV Alone - SPPC_45	440 MW *BESS Alone - NPC_45 840 MW Firm Dispatchable - NPC_45	1542 MW *BESS Alone - SPPC_45 1779 MW *PV Alone - SPPC_45	1670 MW *BESS Alone - NPC_45 840 MW Firm Dispatchable - NPC_45
2046	1154 MW *BESS Alone - SPPC_46 989 MW *PV Alone - SPPC_46	660 MW *PV Alone - NPC_46	1488 MW *BESS Alone - SPPC_46 989 MW *PV Alone - SPPC_46	660 MW *PV Alone - NPC_46
2047	112 MW *BESS Alone - SPPC_47 1751 MW *PV Alone - SPPC_47	1492 MW *BESS Alone - NPC_47 420 MW Firm Dispatchable - NPC_47 195 MW *PV Alone - NPC_47	140 MW *BESS Alone - SPPC_47 1446 MW *PV Alone - SPPC_47	1858 MW *BESS Alone - NPC_47 420 MW Firm Dispatchable - NPC_47
2048	225 MW *BESS Alone - SPPC_48 334 MW *Geo - SPPC_48 717 MW *PV Alone - SPPC_48	675 MW *BESS Alone - NPC_48 717 MW *PV Alone - NPC_48	677 MW *BESS Alone - SPPC_48 334 MW *Geo - SPPC_48 841 MW *PV Alone - SPPC_48	554 MW *BESS Alone - NPC_48 93 MW *PV Alone - NPC_48
2049	497 MW *BESS Alone - SPPC_49 420 MW Firm Dispatchable - SPPC_49 764 MW *Geo - SPPC_49	26 MW *BESS Alone - NPC_49	523 MW *BESS Alone - SPPC_49 420 MW Firm Dispatchable - SPPC_49 764 MW *Geo - SPPC_49	
2050	863 MW *BESS Alone - SPPC_50	934 MW *BESS Alone - NPC_50 4596 MW Firm Dispatchable - NPC_50 2199 MW *PV Alone - NPC_50	988 MW *BESS Alone - SPPC_50	809 MW *BESS Alone - NPC_50 4596 MW Firm Dispatchable - NPC_50 2199 MW *PV Alone - NPC_50

FIGURE EA-22
BUILDOUT FOR LOW CARBON AND NO OPEN POSITION

	Low Carbon Plan		No Open Position Plan	
	Sierra	Nevada Power	Sierra	Nevada Power
2025	Storage DR - SPPC_25	Storage DR - NPC_25	Storage DR - SPPC_25	Storage DR - NPC_25
2026		200 MW **Dry Lake East PV - NPC_26 200 MW **Dry Lake East BESS - NPC_26		200 MW **Dry Lake East PV - NPC_26 200 MW **Dry Lake East BESS - NPC_26
2027	4 MW Community Solar - SPPC_27 4 MW Community Storage - SPPC_27 10 MW **Solar For All - SPPC_27	14 MW Community Solar - NPC_27 14 MW Community Storage - NPC_27 20 MW **Solar For All - NPC_27 700 MW **Libra PV - NPC_27 700 MW **Libra BESS - NPC_27 128 MW **Boulder Solar III PV - NPC_27 128 MW **Boulder Solar III BESS - NPC_27	4 MW Community Solar - SPPC_27 4 MW Community Storage - SPPC_27 10 MW **Solar For All - SPPC_27	14 MW Community Solar - NPC_27 14 MW Community Storage - NPC_27 20 MW **Solar For All - NPC_27 700 MW **Libra PV - NPC_27 700 MW **Libra BESS - NPC_27 128 MW **Boulder Solar III PV - NPC_27 128 MW **Boulder Solar III BESS - NPC_2
2028	620 MW *PV Alone - SPPC_28 1500 MW *WIND(NV) - SPPC_28	11 MW Community Solar - NPC_28 11 MW Community Storage - NPC_28 620 MW *PV Alone - NPC_28	411 MW Valmy CTs - SPPC_28 358 MW *BESS Alone - SPPC_28	11 MW Community Solar - NPC_28 11 MW Community Storage - NPC_28 225 MW *PV Alone - NPC_28
2029	35 MW *BESS Alone - SPPC_29 525 MW *WIND(NV) - SPPC_29 357 MW Sierra Solar II BESS - SPPC_29 357 MW Sierra Solar II PV - SPPC_29 952 MW *Idaho Wind 2029 - WIND(ID) - SPPC_29	975 MW *WIND(NV) - NPC_29	952 MW *Idaho Wind 2029 - WIND(ID) - SPPC_29	
2030	1433 MW *BESS Alone - SPPC_30 689 MW *PV Alone - SPPC_30 500 MW *WIND(NV) - SPPC_30 200 MW Sierra Solar III BESS - SPPC_30 200 MW Sierra Solar III PV - SPPC_30	1841 MW *BESS Alone - NPC_30 500 MW *WIND(NV) - NPC_30	520 MW *PV Alone - SPPC_30 600 MW Sierra Solar II PV - SPPC_30	445 MW Harry Allen CTs - NPC_30
2031	384 MW *BESS Alone - SPPC_31 928 MW *PV Alone - SPPC_31	469 MW *BESS Alone - NPC_31	319 MW *BESS Alone - SPPC_31 450 MW *PV Alone - SPPC_31	50 MW *PV Alone - NPC_31 100 MW Amargosa I BESS - NPC_31 400 MW Amargosa I PV - NPC_31
2032	1415 MW *PV Alone - SPPC_32	56 MW *BESS Alone - NPC_32	110 MW *BESS Alone - SPPC_32 443 MW *PV Alone - SPPC_32 500 MW Sierra Solar III BESS - SPPC_32	43 MW *PV Alone - NPC_32 400 MW Amargosa II BESS - NPC_32 400 MW Amargosa II PV - NPC_32
2033	500 MW *White Pine PSH - SPPC_33 222 MW *PV Alone - SPPC_33	500 MW *White Pine PSH - NPC_33 188 MW *PV Alone - NPC_33 400 MW Amargosa I PV - NPC_33		68 MW BESS Alone - NPC_33 883 MW PV Alone - NPC_33 422 MW *WIND(NV) - NPC_33
2034	452 MW *PV Alone - SPPC_34		500 MW *White Pine PSH - SPPC_34 456 MW PV Alone - SPPC_34	500 MW *White Pine PSH - NPC_34
2035	207 MW *BESS Alone - SPPC_35 686 MW *PV Alone - SPPC_35		889 MW PV Alone - SPPC_35	

2036		617 MW *BESS Alone - NPC_36 617 MW *PV Alone - NPC_36	191 MW *WIND(NV) - SPPC_36	423 MW PV Alone - NPC_36 286 MW *WIND(NV) - NPC_36
2037		61 MW *BESS Alone - NPC_37 631 MW *PV Alone - NPC_37	150 MW *WIND(NV) - SPPC_37	602 MW *WIND(NV) - NPC_37
2038	605 MW *BESS Alone - SPPC_38 559 MW *PV Alone - SPPC_38	839 MW *PV Alone - NPC_38	1131 MW *WIND(NV) - SPPC_38	
2039		757 MW *BESS Alone - NPC_39 1130 MW *PV Alone - NPC_39		850 MW BESS Alone - NPC_39 178 MW PV Alone - NPC_39 939 MW *WIND(NV) - NPC_39
2040	124 MW *BESS Alone - SPPC_40	373 MW *BESS Alone - NPC_40 367 MW *PV Alone - NPC_40	766 MW Firm Dispatchable - SPPC_40	690 MW PV Alone - NPC_40 279 MW *WIND(NV) - NPC_40
2041	419 MW *BESS Alone - SPPC_41 173 MW *PV Alone - SPPC_41	419 MW *BESS Alone - NPC_41 691 MW *PV Alone - NPC_41		566 MW BESS Alone - NPC_41 1552 MW PV Alone - NPC_41
2042	276 MW *BESS Alone - SPPC_42	397 MW *BESS Alone - NPC_42 825 MW *PV Alone - NPC_42	738 MW BESS Alone - SPPC_42	397 MW BESS Alone - NPC_42 1149 MW PV Alone - NPC_42
2043	110 MW *BESS Alone - SPPC_43	74 MW *BESS Alone - NPC_43 187 MW *PV Alone - NPC_43 210 MW Firm Dispatchable - NPC_43	174 MW *BESS Alone - SPPC_43	695 MW *BESS Alone - NPC_43 475 MW *PV Alone - NPC_43
2044	391 MW *BESS Alone - SPPC_44 210 MW Firm Dispatchable - SPPC_44	260 MW *BESS Alone - NPC_44 902 MW *PV Alone - NPC_44	473 MW BESS Alone - SPPC_44 1278 MW PV Alone - SPPC_44	710 MW BESS Alone - NPC_44
2045	647 MW *BESS Alone - SPPC_45	105 MW *BESS Alone - NPC_45 840 MW Firm Dispatchable - NPC_45 1230 MW *PV Alone - NPC_45	503 MW BESS Alone - SPPC_45	933 MW BESS Alone - NPC_45 420 MW Firm Dispatchable - NPC_45 1561 MW PV Alone - NPC_45
2046	1184 MW *BESS Alone - SPPC_46 786 MW *PV Alone - SPPC_46		210 MW Firm Dispatchable - SPPC_46 1124 MW *BESS Alone - SPPC_46 669 MW *PV Alone - SPPC_46	482 MW *BESS Alone - NPC_46 669 MW *PV Alone - NPC_46
2047	154 MW *BESS Alone - SPPC_47 73 MW *Geo - SPPC_47	616 MW *BESS Alone - NPC_47 420 MW Firm Dispatchable - NPC_47 1028 MW *PV Alone - NPC_47	160 MW BESS Alone - SPPC_47	1440 MW BESS Alone - NPC_47 210 MW Firm Dispatchable - NPC_47 1749 MW PV Alone - NPC_47
2048	475 MW *Geo - SPPC_48	210 MW Firm Dispatchable - NPC_48	475 MW *BESS Alone - SPPC_48 379 MW *Geo - SPPC_48 544 MW *PV Alone - SPPC_48	204 MW *BESS Alone - NPC_48 233 MW *PV Alone - NPC_48 210 MW Firm Dispatchable - NPC_48
2049	210 MW Firm Dispatchable - SPPC_49 126 MW *BESS Alone - SPPC_49 551 MW *Geo - SPPC_49		210 MW Firm Dispatchable - SPPC_49 566 MW *BESS Alone - SPPC_49 818 MW *Geo - SPPC_49	
2050	1435 MW *BESS Alone - SPPC_50	359 MW *BESS Alone - NPC_50 4596 MW Firm Dispatchable - NPC_50 2206 MW *PV Alone - NPC_50	646 MW BESS Alone - SPPC_50 419 MW PV Alone - SPPC_50	1201 MW BESS Alone - NPC_50 4596 MW Firm Dispatchable - NPC_50 1675 MW PV Alone - NPC_50

Discussion of Alternative Plans:

As previously stated, the specific supply options included in each alternative plan can be found in the L&R Tables in Technical Appendix ECON-5. The open positions, also shown in each L&R Table, demonstrate one measure of the reliance of each plan on the availability of market capacity. The greater the open position, the greater the Companies' dependance on the market and the availability of market capacity, which increases the associated reliability risk. Importantly, the planning and analysis that led to the development of these alternative plans is consistent with the resource adequacy requirements for participation in WRAP and potential future markets or RTOs the Companies may seek to join in the future.

A graphical comparison of the capacity positions for each plan is shown in Figure EA-23. The capacity position values represent NV Energy's forecasted open/(long) capacity position for each plan using the ELCC and PRM requirement for its joint system and are not a regional assessment.

Note that when a plan's representative line falls below the graph's zero mark, it indicates that the Companies have acquired more resources than are needed to meet load plus reserve requirements. This excess, or long position, may occur when resources are added to meet goals beyond capacity needs or when an added resource size is large relative to the open position.

FIGURE EA-23
OPEN/(LONG) CAPACITY POSITIONS FOR ALTERNATIVE PLANS

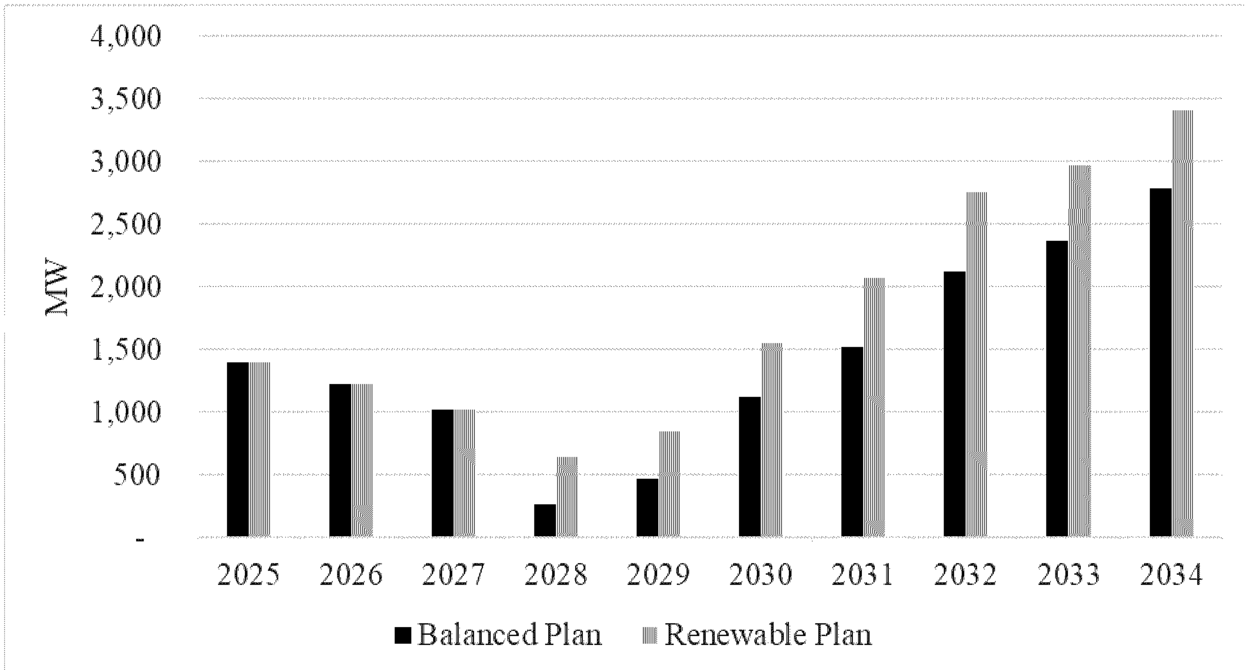
As shown in Figure EA-23, the No Open Position Plan closes the open position by 2028 and the Low Carbon Plan does so by 2029. While the Low Carbon Plan has no requirement to close the open position, the aggressive buildout required to meet the 2030 Low Carbon goal results in an excessively long position from 2029 to 2041. The Balanced Plan and Renewable Plan achieve the 750 MW Open Position Target by 2028 and maintain it through the study period.

Another assessment of the Companies' reliance on market capacity is found in evaluating the open position without future placeholders, including the removal of all named placeholders. Actual future resources might not be equal in size or available at the same time as the placeholders in each alternative plan's buildout. This poses potential risk of a greater market reliance in the future if these placeholders do not come to fruition.

Figure EA-24 shows the open position of the Balanced Plan and Renewable Plan without placeholders to highlight the potential risk of market reliance. The Low Carbon Plan and No Open

Position Plan are not included in the figure below due to their unique buildouts, which are a factor of these plans' specific goals and are highly dependent on placeholders.

FIGURE EA-24
OPEN POSITION OF BALANCED PLAN AND RENEWABLE PLAN WITHOUT PLACEHOLDERS

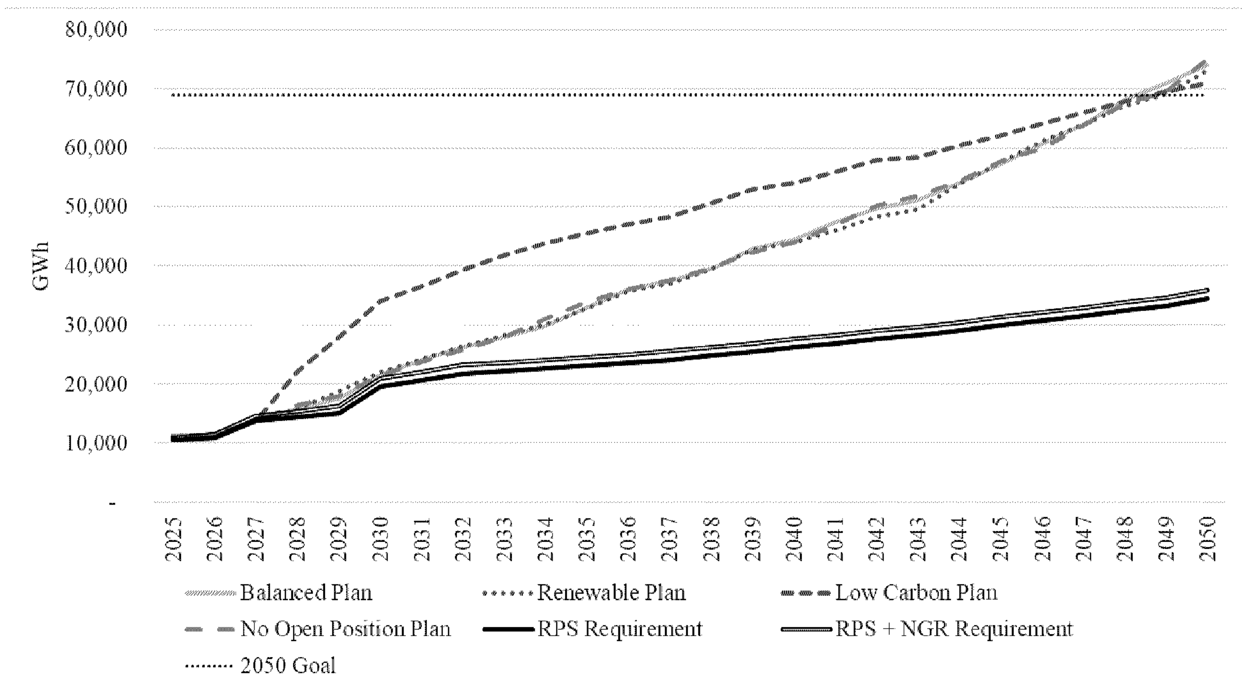


Both the Balanced Plan and Renewable Plan lower the open position below 750 MW in 2028, but by 2029, in this view, the Renewable Plan open position again exceeds the 750 MW target. By 2030 and each subsequent year, the open position for both plans surpass 1,000 MW and quickly grow to over 2,000 MW by 2032. The reliance on future placeholders is demonstrated in the figure and if the replacement of those placeholders with future real projects is not realized, the Companies would be forced to rely on the market. Also demonstrated in this figure is the impact of the firm capacity added in 2028 in the Balanced Plan, which is not subject to the declining ELCC of renewable/storage resources and causes the Balanced Plan's open position to grow more slowly than that of the Renewable Plan.

Pursuant to NRS § 704.741(4)(b)(4), all alternative plans present a balanced portfolio of energy supply and demand-side resources that increase the Companies' access to carbon-free energy, support compliance with the RPS, and advance goals for the reduction of greenhouse gas emissions as set forth in NRS § 445B.380 and NRS § 704.7820. NRS § 445B.380 prescribes an annual greenhouse gas report prepared by the Nevada Division of Environmental Protection which must quantify reductions required to achieve a statewide decrease in net greenhouse gas emissions of 28 percent by the year 2025, as compared to the state's level of greenhouse gas emissions in 2005, as well as a 45 percent statewide reduction in net greenhouse gas emissions by the year 2030, as compared to the same baseline year of 2005. NRS § 704.7820 is the state's 2050 clean energy goal – "a goal of achieving by 2050 an amount of energy production from zero carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State.

A graphical comparison of the net renewable energy of each plan is shown in Figure EA-25.

FIGURE EA-25
NET RENEWABLE ENERGY FOR ALTERNATIVE PLANS



The RPS compliance status of all four alternative plans is presented in the Renewables Section of the narrative.

The carbon dioxide emissions associated with each of the Alternative Plans is presented in Figure EA-26, which includes a view of the Companies' proportionate share of the 2025 and 2030 greenhouse gas reduction aspirational goals defined in NRS § 445B.380 and the Low Carbon Plan's 2030 target as indicated in NAC § 704.937(1). Figure EA-26 assigns an emission rate for market purchases as derived by NERA for this 2024 Joint IRP and provides total carbon dioxide emissions for each plan.

FIGURE EA-26
CARBON DIOXIDE EMISSIONS BY ALTERNATIVE PLAN

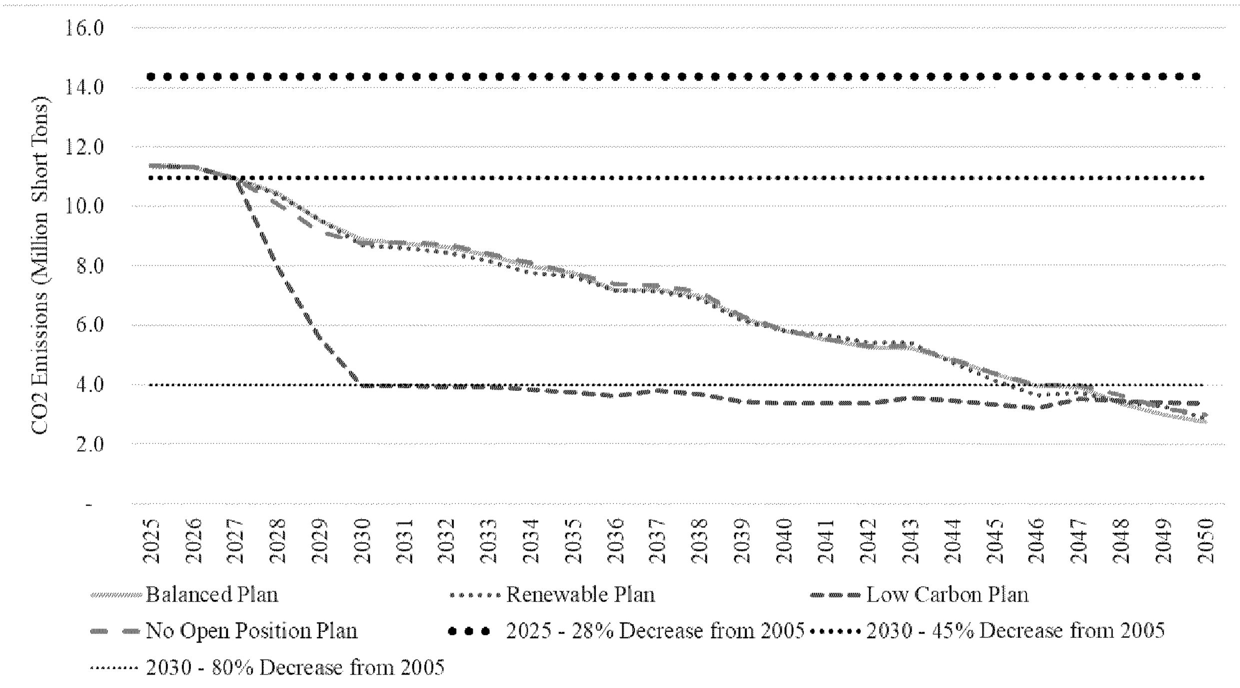
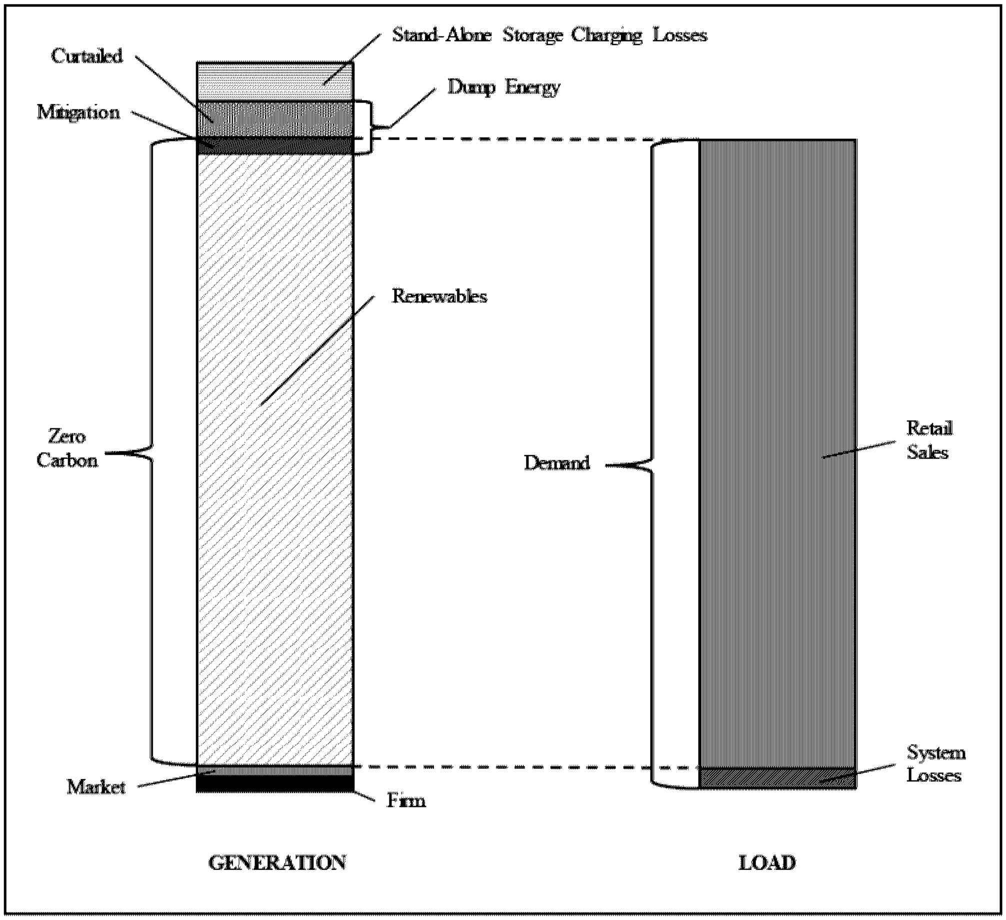


Figure EA-26 clearly demonstrates that the Low Carbon Plan achieves dramatically lower carbon dioxide emission levels much earlier than the other plans and accomplishes the stated aim of that plan. It is noteworthy that the year-by-year carbon dioxide emissions of the Balanced Plan and No Open Position Plan do not differ significantly from those of the Renewable Plan, despite the incremental near-term CTs in the Balanced and No Open Position Plans.

The alternative plans' targeting of the Companies' proportionate share of the state's 2050 clean energy goal as defined in NRS § 704.7820 is illustrated next in the Calculation of Zero-Carbon Generation.

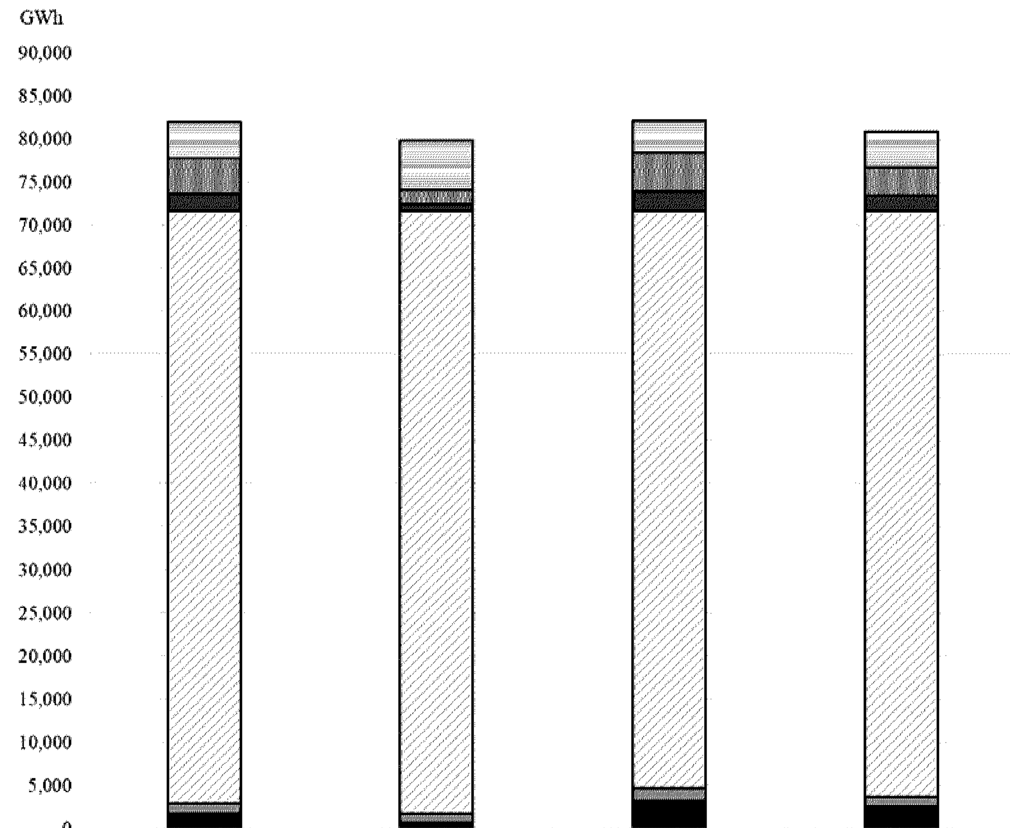
<u>Calculation of Zero-Carbon Generation</u>. The state's 2050 clean energy goal requires an amount of generation from zero-carbon dioxide emission resources that is equal to electricity sales in 2050. The analysis in this 2024 Joint IRP is performed in the same manner as in recent filings in that only generation owned or under contract to the Companies is considered in meeting the 2050 goal. Figure EA-27 illustrates the calculation of zero-carbon generation. The PLEXOS analysis determines the generation to serve customer demand. Demand is the sum of retail sales plus system losses. Generation consists of energy produced by renewable and non-renewable resources and a portion of the overgeneration (or dump) energy. As indicated in previous filings, the Companies believe a portion of overgeneration will be mitigated. That is, a portion of over-generated energy may be used by the system through more optimal utilization of the batteries or through off-system sales. As in recent filings, for purposes of calculating zero-carbon generation, the Companies have assumed approximately one-third of the overgeneration would be mitigated. The remaining excess energy would be curtailed.

FIGURE EA-27
ILLUSTRATION OF ANNUAL ENERGY PRODUCTION
FOR CALCULATION OF ZERO-CARBON GENERATION



Using the explanation above, the Companies calculated the zero-carbon generation for each plan in 2050. The results of the calculation, shown both in MWh and as a percentage of retail load, are presented in Figure EA-28.

FIGURE EA-28
CALCULATION OF 2050 GENERATION BY PLAN

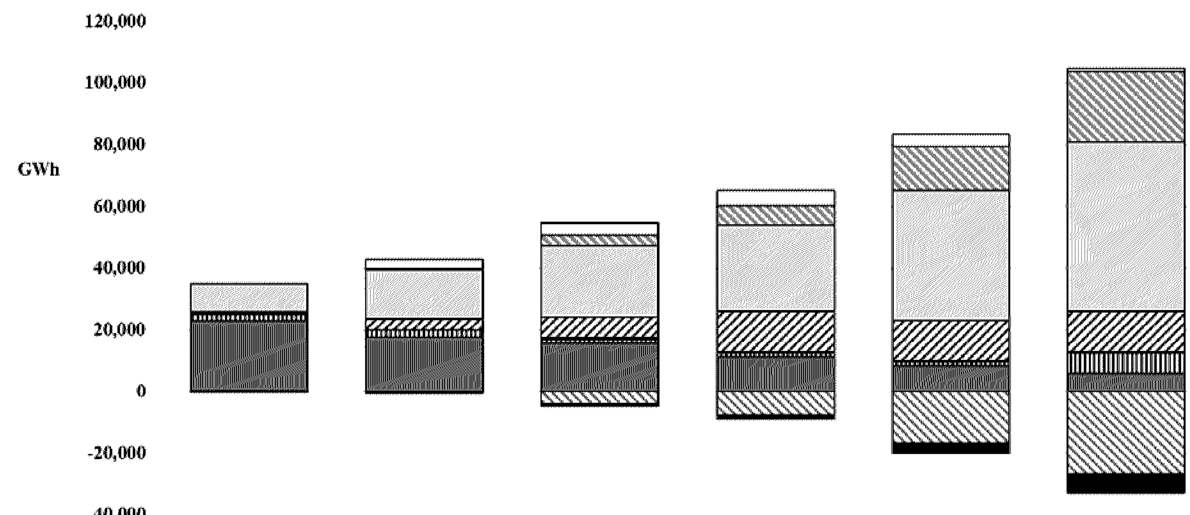


	Balanced Plan	Renewable Plan	Low Carbon Plan	No Open Position Plan
Stand-Alone Storage Charging Losses	4,214	5,723	3,769	4,133
Curtailed	4,047	1,620	4,458	3,346
Mitigation	2,023	810	2,229	1,673
Renewables	68,760	69,951	67,022	68,019
Market	1,168	1,105	1,437	1,129
Firm Dispatchable	1,799	670	3,267	2,578
Zero Carbon Generation (Renewables+Mitigation)	**70,783**	**70,760**	**69,250**	**69,692**
Retail Sales	**69,034**	**69,034**	**69,034**	**69,034**
Percent Zero Carbon Generation	**103%**	**103%**	**100%**	**101%**

Figures EA-29 through EA-40 provide information on energy production, installed capacity, and firm capacity for the alternative plans. For each plan, the energy production by resource type and the installed capacity by resource type are provided in five-year intervals between 2025 and 2050. These figures illustrate the resource diversity of each plan. Each plan demonstrates a significant decrease in fossil fuel generation over the years, accompanied by a sizable increase in energy from solar and storage resources and, to a lesser extent, wind and geothermal resources. Note that the "Storage Charge" and "Excess" energy presented in these graphs are depicted as negative values as these represent BESS charging and excess (unneeded) energy, respectively, as opposed to energy production. Also, for each plan, the firm capacity in 2050 by resource type is provided to illustrate the effect that ELCC has on installed capacity. They are included here to illustrate how these characteristics are influenced by increasing renewable and storage resource penetration as well as how they vary with each plan.

Balanced Plan: The energy production by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-29. A more detailed, tabular version of the graphical data is available in Technical Appendix ECON-4.

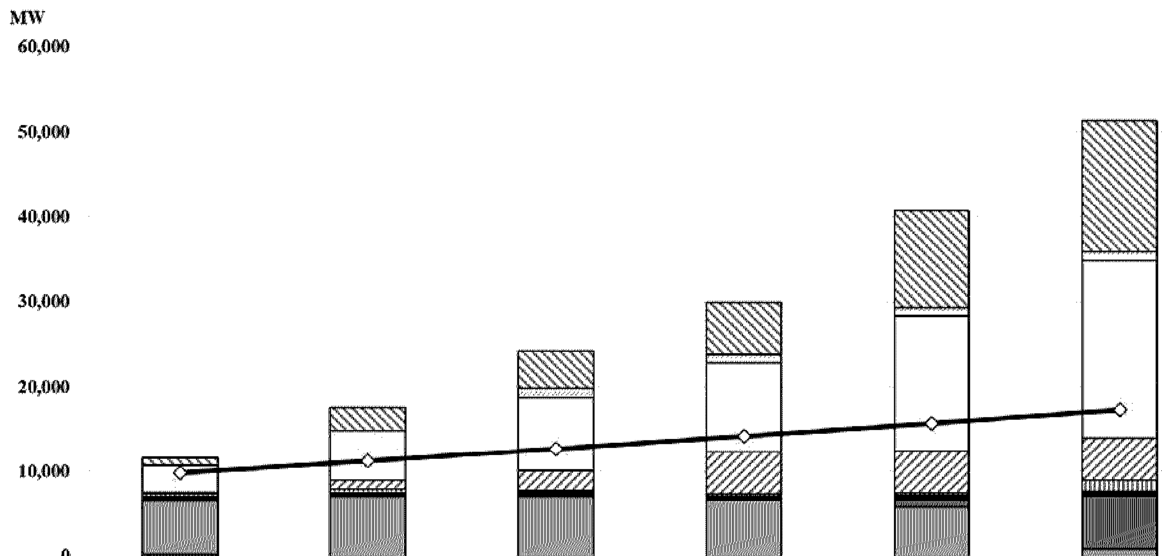
FIGURE EA-29
ENERGY PRODUCTION BY RESOURCE TYPE
BALANCED PLAN



	2025	2030	2035	2040	2045	2050
Market Energy	132	3,251	3,941	4,928	4,109	1,168
Battery Discharge	120	175	3,421	6,351	14,180	22,674
Solar	9,109	15,931	23,403	27,823	41,961	54,793
Wind	315	3,396	6,658	13,264	13,212	13,212
Hydro	381	349	341	339	336	262
Geo	1,966	2,141	1,300	1,217	1,208	6,562
Other	80	112	29	29	0	0
Gas & Firm	22,502	17,642	15,698	11,285	8,377	6,012
Coal	446	0	0	0	0	0
Excess Energy	-26	-399	-767	-1,356	-3,191	-6,070
Battery Charging	-136	-200	-4,154	-7,655	-16,884	-26,882

The installed capacity by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-30.

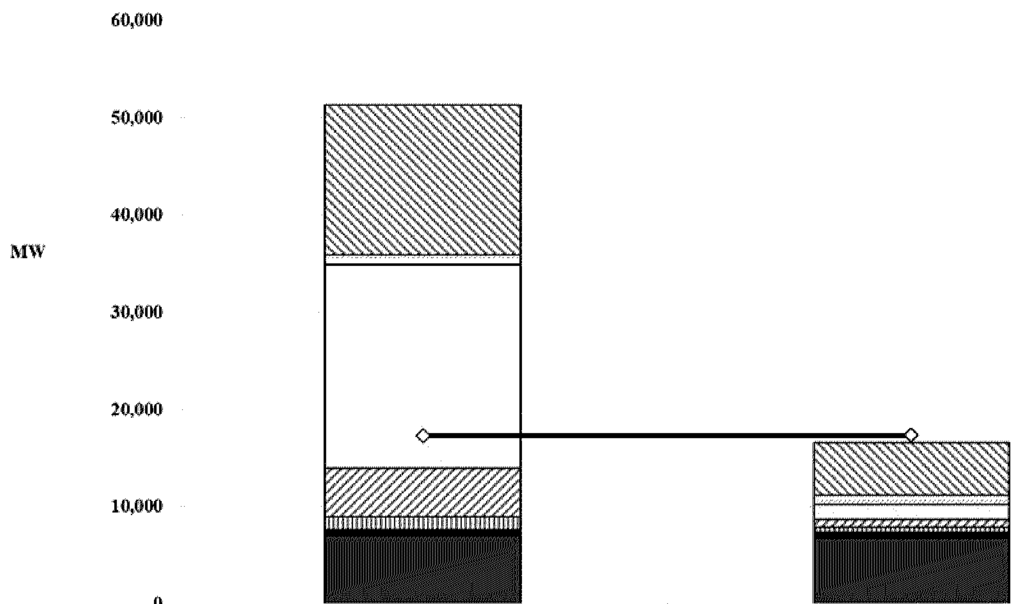
FIGURE EA-30
INSTALLED CAPACITY
BALANCED PLAN



	2025	2030	2035	2040	2045	2050
BESS	946	2,733	4,509	6,127	11,407	15,413
PSH	-	-	1,000	1,000	1,000	1,000
Solar	3,146	5,872	8,719	10,524	15,943	20,971
Wind	152	1,104	2,372	4,953	4,953	4,953
Geo	422	415	264	252	252	1,325
Hydro	148	136	136	136	135	135
Other	256	315	319	347	369	397
Firm	-	-	-	-	840	6,276
Gas	6,318	6,990	6,990	6,648	5,845	855
Coal	261	-	-	-	-	-
PRMR	9,866	11,281	12,695	14,224	15,766	17,315

The firm capacity by resource type for the year 2050 is provided in Figure EA-31.

FIGURE EA-31
2050 INSTALLED CAPACITY VERSUS FIRM CAPACITY
BALANCED PLAN

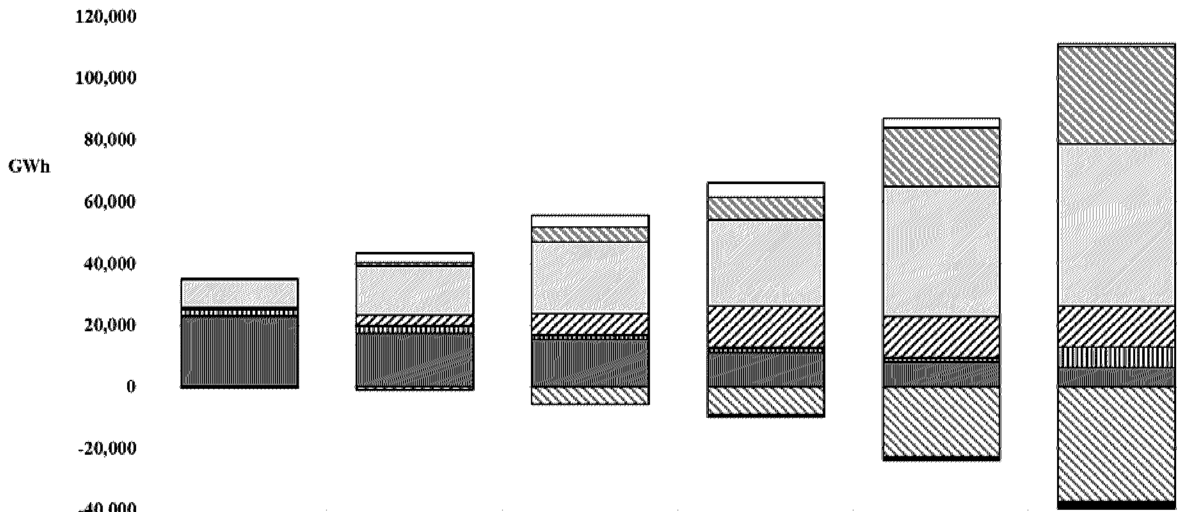


	Installed Capacity	Firm Capacity (ELCC)
BESS	15,413	5,425
PSH	1,000	980
Solar	20,971	1,539
Wind	4,953	800
Geo	1,325	546
Hydro	135	135
Other	397	397
Gas & Firm Dispatchable	7,131	6,777
PRMR	17,315	17,315

Renewable Plan: This plan does not add near-term thermal generation. The plan combines Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. In this plan, Libra's capacity is allocated 60 percent to Nevada Power and 40 percent to Sierra.

The energy production by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-32. A more detailed tabular version of the graphical data is available in Technical Appendix ECON-4.

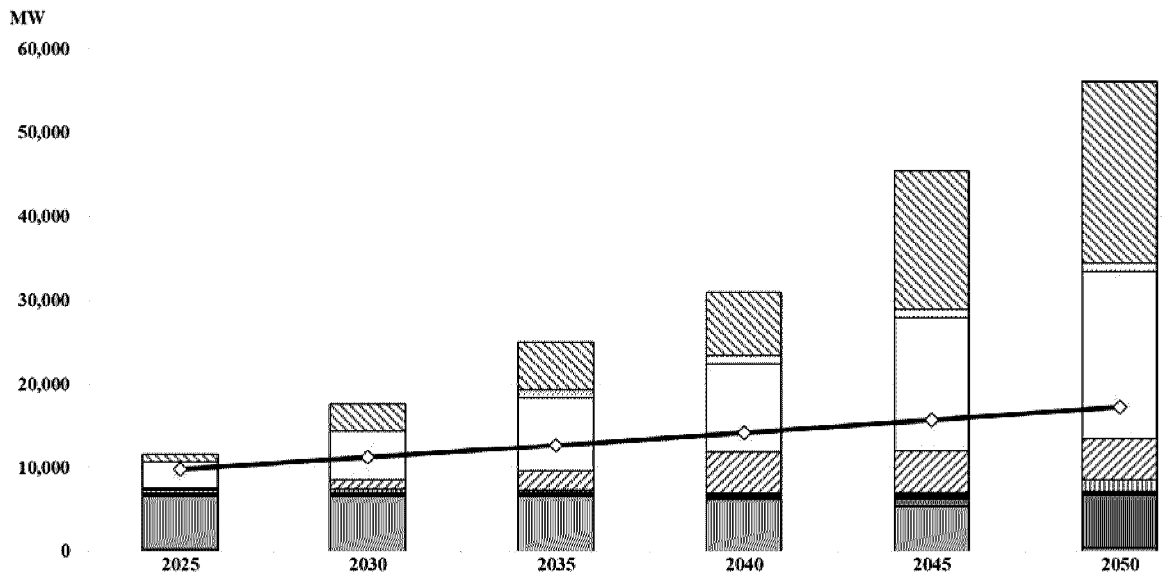
FIGURE EA-32
ENERGY PRODUCTION BY RESOURCE TYPE
RENEWABLE PLAN



	2025	2030	2035	2040	2045	2050
Market Energy	131	3,345	3,985	4,511	2,935	1,105
Battery Discharge	120	827	4,550	7,445	19,199	31,468
Solar	9,109	15,937	23,423	27,862	42,058	52,380
Wind	315	3,396	6,658	13,264	13,212	13,212
Hydro	381	349	337	345	254	226
Geo	1,966	2,141	1,300	1,217	1,208	6,562
Other	80	112	29	29	0	0
Gas & Firm	22,502	17,435	15,416	11,415	8,227	6,393
Coal	447	0	0	0	0	0
Excess Energy	-26	-175	-364	-972	-1,084	-2,429
Battery Charging	-136	-969	-5,464	-8,892	-22,702	-37,185

The installed capacity by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-33.

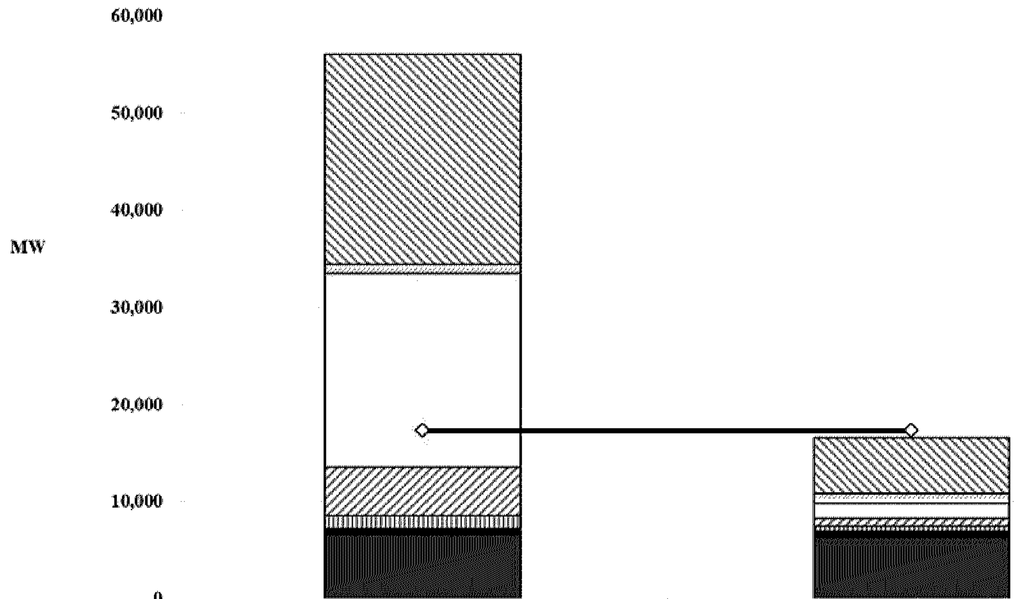
FIGURE EA-33
INSTALLED CAPACITY
RENEWABLE PLAN



	2025	2030	2035	2040	2045	2050
BESS	946	3,235	5,677	7,587	16,517	21,582
PSH	-	-	1,000	1,000	1,000	1,000
Solar	3,146	5,872	8,719	10,524	15,943	19,971
Wind	152	1,104	2,372	4,952	4,952	4,952
Geo	422	415	264	252	252	1,325
Hydro	148	136	136	136	135	135
Other	256	315	319	347	369	397
Firm	-	-	-	-	840	6,276
Gas	6,318	6,579	6,579	6,237	5,434	444
Coal	261	-	-	-	-	-
PRMR	9,866	11,281	12,695	14,224	15,766	17,315

The firm capacity by resource type for the year 2050 is provided in Figure EA-34.

FIGURE EA-34
2050 INSTALLED CAPACITY VERSUS FIRM CAPACITY
RENEWABLE PLAN

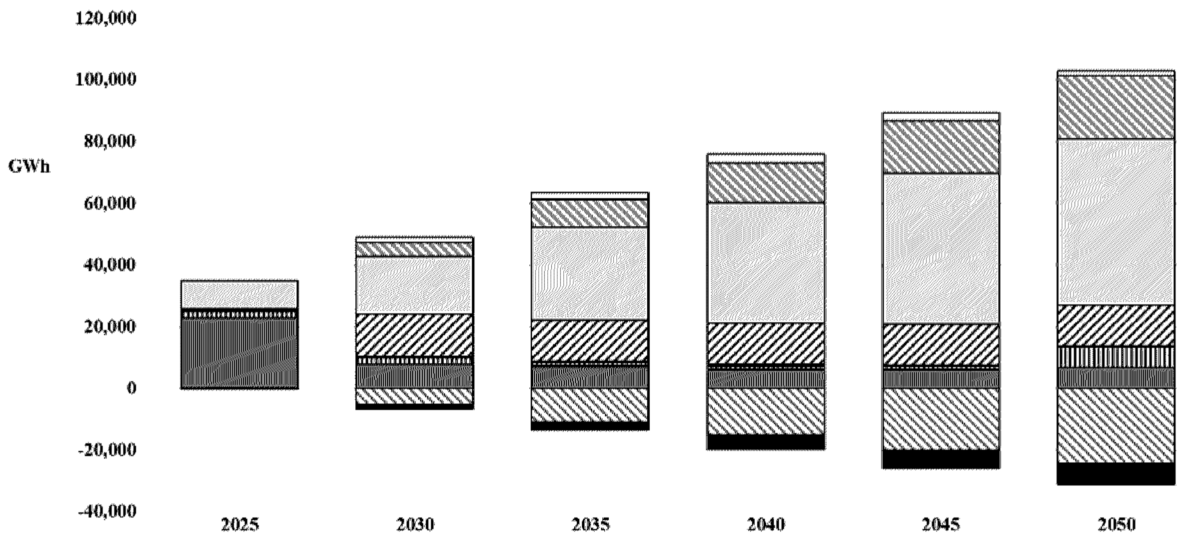


	Installed Capacity	Firm Capacity (ELCC)
BESS	21,582	5,763
PSH	1,000	980
Solar	19,971	1,558
Wind	4,952	799
Geo	1,325	546
Hydro	135	135
Other	397	397
Gas & Firm Dispatchable	6,720	6,398
PRMR	17,315	17,315

Low Carbon Plan: The Low Carbon Plan adds no near-term thermal generation and combines Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra's capacity is allocated 100 percent to Nevada Power in this plan. A significant increase in near-term renewable placeholders is needed in this plan to comply with carbon dioxide reduction requirements.

The energy production by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-35. A more detailed tabular version of the graphical data is available in Technical Appendix ECON-4.

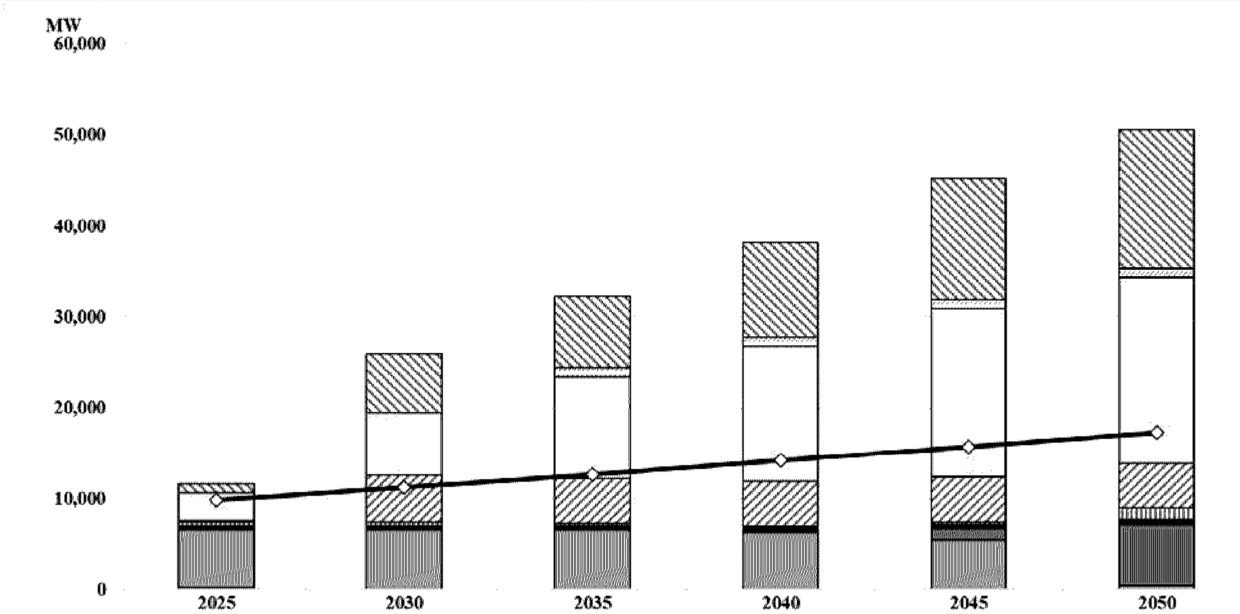
FIGURE EA-35
ENERGY PRODUCTION BY RESOURCE TYPE
LOW CARBON PLAN



	2025	2030	2035	2040	2045	2050
Market Energy	132	1,711	2,135	2,806	2,739	1,437
Battery Discharge	120	4,558	9,036	12,715	16,837	20,678
Solar	9,109	18,872	30,088	39,183	48,890	53,662
Wind	315	13,559	13,212	13,264	13,212	13,212
Hydro	381	333	311	335	319	267
Geo	1,966	2,141	1,300	1,217	1,208	6,567
Other	80	112	29	29	0	0
Gas & Firm	22,500	7,837	7,285	6,308	6,246	7,036
Coal	447	0	0	0	0	0
Excess Energy	-26	-1,368	-2,703	-4,474	-6,144	-6,687
Battery Charging	-136	-5,359	-10,825	-15,159	-19,999	-24,442

The installed capacity by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-36.

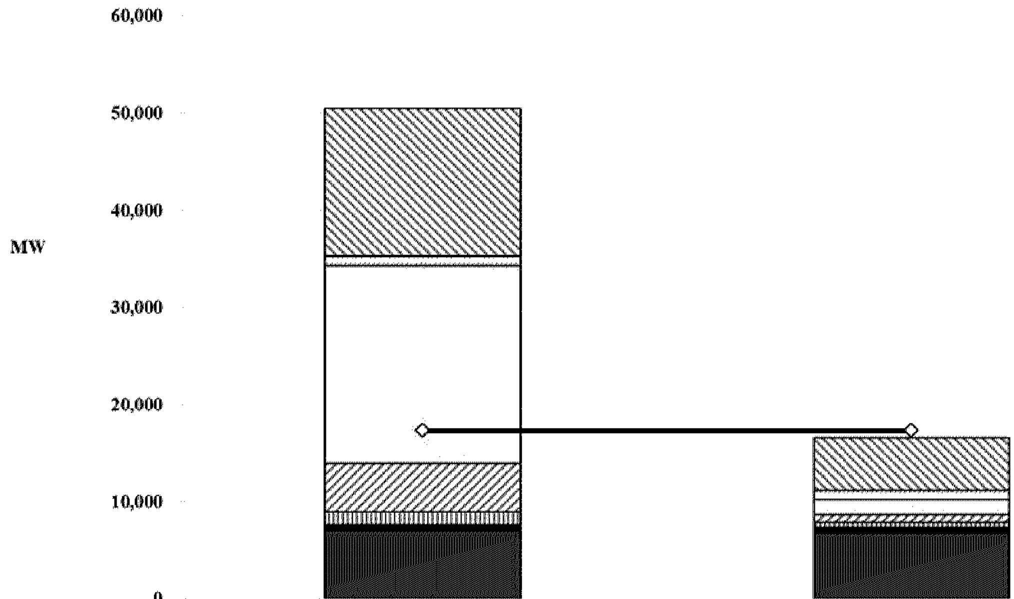
FIGURE EA-36
INSTALLED CAPACITY
LOW CARBON PLAN



	2025	2030	2035	2040	2045	2050
BESS	946	6,497	7,791	10,379	13,300	15,202
PSH	-	-	1,000	1,000	1,000	1,000
Solar	3,146	6,918	11,191	14,883	18,556	20,376
Wind	152	5,104	4,952	4,952	4,952	4,952
Geo	422	415	264	252	252	1,326
Hydro	148	136	136	136	135	135
Other	256	315	319	347	369	397
Firm	-	-	-	-	1,260	6,696
Gas	6,318	6,579	6,579	6,237	5,434	444
Coal	261	-	-	-	-	-
PRMR	9,866	11,281	12,695	14,224	15,766	17,315

The firm capacity by resource type for the year 2050 is provided in Figure EA-37.

FIGURE EA-37
2050 INSTALLED CAPACITY VERSUS FIRM CAPACITY
LOW CARBON PLAN

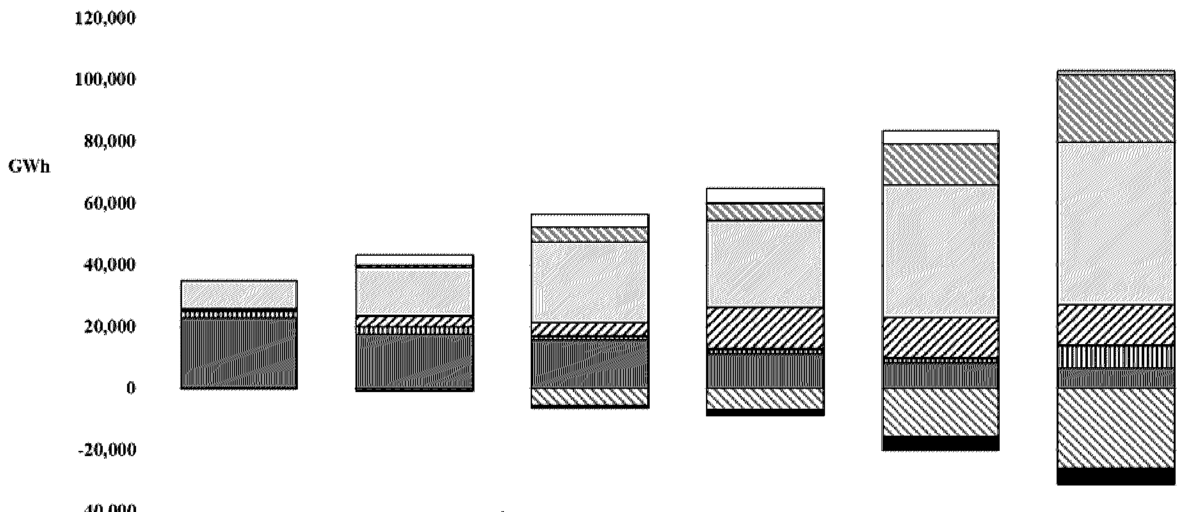


	Installed Capacity	Firm Capacity (ELCC)
BESS	15,202	5,401
PSH	1,000	980
Solar	20,376	1,533
Wind	4,952	800
Geo	1,326	546
Hydro	135	135
Other	397	397
Gas & Firm Dispatchable	7,140	6,799
PRMR	17,315	17,315

No Open Position Plan: This plan includes two CTs at both Valmy and Harry Allen locations, Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra's capacity is allocated solely to Nevada Power in this plan.

The energy production by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-38. A more detailed tabular version of the graphical data is available in Technical Appendix ECON-4.

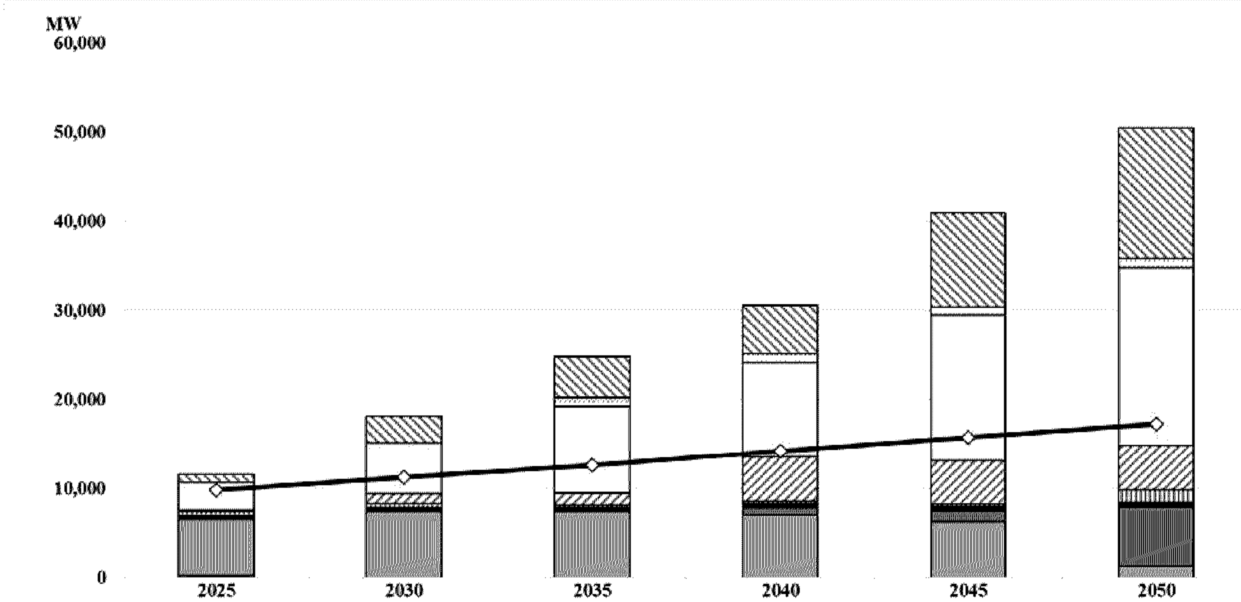
FIGURE EA-38
ENERGY PRODUCTION BY RESOURCE TYPE
NO OPEN POSITION PLAN



	2025	2030	2035	2040	2045	2050
Market Energy	131	3,354	4,029	4,802	4,283	1,187
Battery Discharge	120	634	4,552	5,842	13,314	21,896
Solar	9,109	15,705	26,263	28,067	42,857	52,486
Wind	315	3,396	4,122	13,264	13,212	13,212
Hydro	381	349	340	339	333	258
Geo	1,966	2,141	1,300	1,217	1,208	7,062
Other	80	112	29	29	0	0
Gas & Firm	22,503	17,640	15,638	11,406	8,309	6,766
Coal	445	0	0	0	0	0
Excess Energy	-26	-193	-865	-1,677	-4,329	-5,187
Battery Charging	-136	-741	-5,538	-7,064	-15,879	-25,950

The installed capacity by resource type in five-year intervals between 2025 and 2050 is provided in Figure EA-39.

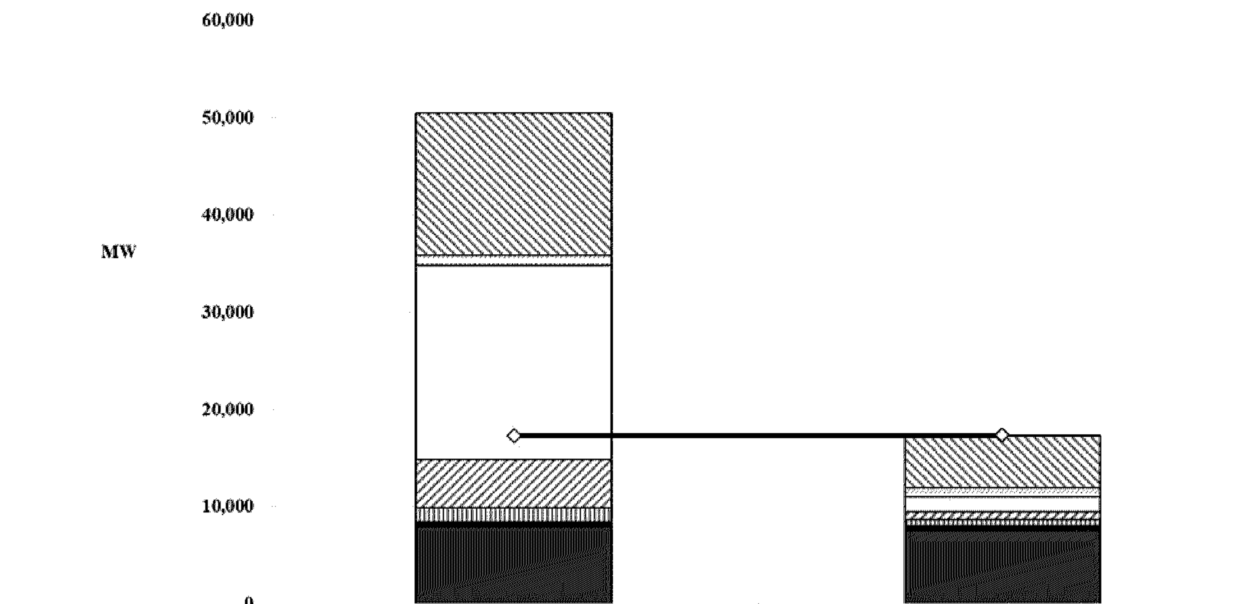
FIGURE EA-39
INSTALLED CAPACITY
NO OPEN POSITION PLAN



	2025	2030	2035	2040	2045	2050
BESS	946	2,989	4,590	5,491	10,503	14,629
PSH	-	-	1,000	1,000	1,000	1,000
Solar	3,146	5,777	9,773	10,613	16,293	20,051
Wind	152	1,104	1,374	4,952	4,952	4,952
Geo	422	415	264	252	252	1,424
Hydro	148	136	136	136	135	135
Other	256	315	319	347	369	397
Firm	-	-	-	766	1,186	6,622
Gas	6,318	7,435	7,435	7,093	6,290	1,300
Coal	261	-	-	-	-	-
PRMR	9,866	11,281	12,695	14,224	15,766	17,315

The firm capacity by resource type for the year 2050 is provided in Figure EA-40.

FIGURE EA-40
FIRM CAPACITY IN 2050
NO OPEN POSITION PLAN



	Installed Capacity	Firm Capacity (ELCC)
BESS	14,629	5,360
PSH	1,000	980
Solar	20,051	1,523
Wind	4,952	799
Geo	1,424	586
Hydro	135	135
Other	397	397
Gas & Firm Dispatchable	7,922	7,542
PRMR	17,315	17,315

Impacts of the Alternative Plans. Pursuant to NRS § 704.741(4)(b), the following information on the impacts of the plans is presented.

Pursuant to NRS § 704.741(4)(b)(1) regarding the impact of each plan on the ability of the Companies to reduce reliance on market purchases, all plans target a reduced open capacity position by 2028 to varying degrees due to ongoing concerns about the availability and deliverability of market capacity and energy. The open positions of each plan are presented in Figure EA-23, and the forecast of energy needs is provided in the Load Forecast Section.

Pursuant to NRS § 704.741(4)(b)(2) regarding the ability to reliably integrate into the Companies' supply portfolio larger amounts of electricity from variable energy resources, all plans add substantial amounts of renewable resources with similar diversity over the study period and all target the state's 2050 clean energy goal. As described previously, the use of ELCC methodology ensures the reliable integration of growing amounts of electricity from variable energy resources in each plan. The plans experience varying amounts of excess energy, largely based on the varying renewable and storage resources over the years in each plan. The Low Carbon Plan experiences substantially more excess energy over the 26-year study period than the other plans, due to its large early buildout of renewables to achieve the particular goals of this plan. The Renewable Plan experiences the least amount of excess energy over the study period, likely due to its higher proportion of BESS than the other plans which reduces excess energy but comes at a cost. BESS are a key resource addition to achieve a renewable energy future and to allow flexibility in system operation. However, as limited-duration storage resources, batteries cannot replace the value of firm dispatchable resources, such as fast-start combustion turbines, that economically provide energy at any time, not reliant on state of charge, for hours, days, or weeks as needed. To address capacity and energy needs most economically, a balance of renewable, storage, and firm dispatchable resources is a sound approach to a decarbonizing portfolio. The Balanced Plan offers this balanced approach with the request for two hydrogen-capable natural gas combustion turbines located at the North Valmy Generating Station in addition to over 1,000 MW of both PV and BESS projects.

Pursuant to NRS § 704.741(4)(b)(3), the alternative plans do not differ in the ability of the utility to access energy markets or geographic locations that have excess capacity. As described in Subsection C, Key Modeling Assumptions, and also shown in the Area Diagram in Technical Appendix ECON-8, all plans model identical access to external energy markets. No transmission projects are proposed in the plans that increase regional access. However, access to 952 MW of Idaho Wind placeholder resource is modeled in all four plans, reliant on the Companies' expected allocation of SWIP-North transmission capacity. The Transmission Section of the narrative includes further discussion of LS Power's intent to construct SWIP-North.

Pursuant to NRS § 704.741(4)(b)(4) regarding access to carbon-free energy, compliance with the RPS, and certain decarbonizing goals, the Renewables Section of the narrative provides information on the RPS performance of each of the alternative plans. In addition, Figure EA-26 presented previously, provides the performance of each plan relative to the reduction of greenhouse gas emissions set forth in NRS 445B.380 and 704.7820. The plans do not differ in their ability to access renewable resources as regional transmission lines modeled do not vary between the plans. In addition, the plans each model the same DSM and DRP resources.

Pursuant to NRS § 704.741(4)(b)(5) regarding the ability of the Companies to demonstrate resource adequacy to a regional entity, as presented in Subsection C, Key Modeling Assumptions, the Companies set an open capacity position target of no more than 750 MW in 2028 and every year thereafter, which aligns with NV Energy's intent to become financially binding in WRAP in winter 2027-2028. The open capacity position target as well as WRAP requirements for resource sufficiency and potential penalties for resource insufficiency are further described in the Day-

Ahead Markets and Regional Transmission Organization Section. The open positions of each of the alternative plans are presented in Figure EA-23.

Pursuant to NRS § 704.741(4)(b)(6) regarding the ability to advance cost-effective DSM in the alternative plans, it should be noted that all plans include the same amount of DSM, either incorporated within the load forecast or included as resources as shown in Figure EA-8. As mentioned previously, excess energy exists in all the plans due to must-take renewable energy PPAs. The plans experience different amounts of excess energy over the study period, with the Low Carbon Plan having the most. Within the proposed DSM programs in this 2024 Joint IRP, programs that have the effect of absorbing excess renewable energy such as new electrification load within the DRP or battery storage DR within the DSM Plan could be preferentially grown to target excess energy in a resource plan. Discussion of these programs is presented in the DSM and DRP Volumes.

Pursuant to NRS § 704.741(4)(b)(7), the rate impact of each of the alternative plans is presented in the Financial Plan.

Pursuant to NRS § 704.741(4)(b)(8), the projects in the Balanced Plan bring the following jobs benefits, as described in the Renewables, Generation, and Transmission Sections of the Supply Plan. Only available and/or requested projects are included here; job benefits are not estimated for theoretical future placeholder resources that exist in each plan.

- As discussed further in the Renewable Section, the Dry Lake East project is estimated to provide more than 250 construction jobs over a one-year construction period. After commercial operation in December 2026, the facility is expected to provide six permanent jobs with an average annual salary of $125,000, for an estimated annual payroll of $748,000 and a total payroll of approximately $18.7 million over the 25-year term of the PPA. Union worksite agreements are being pursued.
- As discussed further in the Renewable Section, the Boulder Solar III project is estimated to provide more than 350 construction jobs over the construction period. After commercial operation in June 2027, the facility is expected to provide two permanent jobs with an average annual salary of $66,650, for a total payroll of approximately $3.3 million over the 25-year term of the PPA. Union worksite agreements are being pursued.
- As discussed further in the Renewable Section, the Libra Solar project is estimated to provide more than 1,100 construction jobs over a two-year construction period. After commercial operation in December 2027, the facility is expected to provide 30 permanent jobs with an average annual salary of $138,314, for an estimated first year annual payroll of $4,149,420 and a total payroll of approximately $107.2 million over the 25-year term of the PPA. Union worksite agreements are being pursued.

- As described in the Generation Section, construction of the Valmy CTs is expected to utilize skilled labor with an estimated 400 skilled jobs during construction. Operation of the Valmy CTs will utilize existing plant staff.
- As described in the Transmission Section, transmission projects requested in the Preferred Plan to support proposed projects and meet customers' demands (excludes Greenlink Nevada) are expected to create 304 direct person years of employment during construction for an estimated $44 million in direct wages and salaries.
- The Greenlink Nevada transmission project is anticipated to created 2,108 direct person years of employment during construction, for an estimated $304 million in direct wages and salaries.[3] After commencing operation, the project is expected to require 9 full-time employees for operations and maintenance at an average annual wage of $125,000 for an annual payroll of $1.13 million for the life of the assets.

The Renewable and Low Carbon Plans will experience the same jobs benefits from proposed projects as the Balanced Plan, except they will forego the jobs created by the Valmy CT project. As stated previously, while all plans model future placeholder resources, jobs benefits are not estimated for these theoretical placeholder resources. The Low Carbon Plan models incremental *near-term* placeholder resources relative to the Balanced and Renewable Plans, therefore, incremental job benefits from projects that replace these near-term placeholder resources in future filings would be expected to occur if the Commission chose to approve the Low Carbon Plan. Job benefits are not estimated for these theoretical future placeholder resources.

The No Open Position Plan will experience the same job benefits as the Balanced Plan, except that it will experience twice the job benefits from CT projects due to the incremental set of two CTs built in that plan. Additionally, as this plan models incremental near-term placeholder resources relative to the Balanced and Renewable Plans, incremental job benefits from projects that replace these near term placeholder resources in future filings would be expected to occur in this plan similar to, but to a lesser degree than, the Low Carbon Plan if the Commission chose to approve this plan. Job benefits are not estimated for these theoretical future placeholder resources.

Additionally, NERA assesses the net economic impact on the state for each alternative plan in Subsection G. Employment (total jobs) is one of the four impact measures presented in Figure NERA-16, which provides estimates of the average annual economic impacts in Nevada over the 26-year study period for the other 2024 IRP plans relative to the Balanced Plan.

[3] Docket 20-07023, Fourth Amendment to the 2018 Joint IRP, Oct 7, 2020, Amended Application, Technical Appendix ECON-6A at 45, 47.

F. Economic Analysis Results

Alternative Plan Analysis Results. The PWRR comparison for the alternative plans - including the scenario with sales - is presented in Figure EA-41.

FIGURE EA-41
PWRR OF ALTERNATIVE PLANS

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Least Cost Case (million $)	26 Year PWRR Change from Least Cost Case (million $)	20 Year PWRR Rank Order	26 Year PWRR Rank Order
Balanced Plan	$ 32,931	$ 41,294	$ -	$ -	**1**	**1**
Renewable Plan	$ 33,252	$ 42,342	$ 321	$ 1,047	**2**	**2**
No Open Position	$ 35,614	$ 46,293	$ 2,683	$ 4,998	**3**	**3**
Low Carbon	$ 38,520	$ 47,115	$ 5,590	$ 5,821	**4**	**4**

Scenario Analysis. NAC § 704.9475 requires the utility to conduct an analysis of sensitivity for all major assumptions and estimates used in the resource plan in addition to the base assumptions. To satisfy this requirement, the Companies evaluate each plan with sensitivities of a) load forecasts, b) fuel and purchase power price forecasts, and c) carbon policy forecasts.

The base assumptions for this filing are a base (or mid-level) load forecast, base (or mid-level) fuel and purchase power price forecasts, and a mid-level carbon policy assumption. The alternative plans were tested using high and low economic growth scenarios, high and low fuel and purchased power price forecasts, and high, low, and no carbon policy sensitivities. In addition, the Preferred Plan was subjected to a base load, base fuel, and mid-carbon policy scenario with the added ability to make off-system sales. The results of the scenario analyses are presented in Figures EA-42 and EA-43. Further details regarding these load forecasts can be found in the Load Forecast and Fuel and Purchased Power Price Forecast Sections.

The production costs, capital costs, and total PWRR results of all the scenarios can be found in Technical Appendices ECON-6 through ECON-7.

FIGURE EA-42
20-YEAR PWRR FOR ALL PLANS AND SCENARIOS

2024 IRP 20-year PWRR ($ millions) by Scenario									
	Base Load							High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	BLBFMC Sales	HLBFMC	LLBFMC
Balanced Plan	$ 32,931	$ 33,105	$ 32,694	$ 33,098	$ 39,185	$ 29,118	$ 30,854	$ 35,071	$ 30,576
Renewable Plan	$ 33,252	$ 33,426	$ 33,020	$ 33,419	$ 39,466	$ 29,482	n/a	$ 35,443	$ 30,825
Low Carbon Plan	$ 35,614	$ 35,791	$ 35,378	$ 35,785	$ 41,915	$ 31,797	n/a	$ 37,583	$ 33,607
No Open Position Plam	$ 38,520	$ 38,622	$ 38,380	$ 38,618	$ 42,442	$ 36,115	n/a	$ 39,978	$ 36,853

2024 IRP 20-year PWRR Differential ($ millions) by Scenario									
	Base Load							High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	BLBFMC Sales	HLBFMC	LLBFMC
Balanced Plan	$ -	$ -	$ -	$ -	$ -	$ -	n/a	$ -	$ -
Renewable Plan	$ 321	$ 322	$ 326	$ 321	$ 281	$ 364	n/a	$ 371	$ 249
Low Carbon Plan	$ 2,683	$ 2,687	$ 2,684	$ 2,686	$ 2,730	$ 2,678	n/a	$ 2,511	$ 3,031
No Open Position Plam	$ 5,590	$ 5,518	$ 5,687	$ 5,520	$ 3,256	$ 6,997	n/a	$ 4,906	$ 6,277

2024 IRP 20-year PWRR Ranking by Scenario									
	Base Load							High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	BLBFMC Sales	HLBFMC	LLBFMC
Balanced Plan	1	1	1	1	1	1	n/a	1	1
Renewable Plan	2	2	2	2	2	2	n/a	2	2
Low Carbon Plan	3	3	3	3	3	3	n/a	3	3
No Open Position Plam	4	4	4	4	4	4	n/a	4	4

FIGURE EA-43
26-YEAR STUDY PERIOD PWRR FOR ALL PLANS AND SCENARIOS

2024 IRP 26-year PWRR ($ millions) by Scenario									
	Base Load							High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	BLBFMC Sales	HLBFMC	LLBFMC
Balanced Plan	$ 41,294	$ 41,468	$ 41,047	$ 41,467	$ 48,647	$ 36,937	$ 38,891	$ 44,287	$ 38,480
Renewable Plan	$ 42,342	$ 42,516	$ 42,100	$ 42,514	$ 49,599	$ 38,035	n/a	$ 45,388	$ 39,443
Low Carbon Plan	$ 46,293	$ 46,470	$ 46,046	$ 46,469	$ 53,750	$ 41,904	n/a	$ 49,098	$ 43,915
No Open Position Plan	$ 47,115	$ 47,216	$ 46,966	$ 47,217	$ 52,055	$ 44,194	n/a	$ 49,477	$ 45,019

2024 IRP 26-year PWRR Differential ($ millions) by Scenario									
	Base Load							High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	BLBFMC Sales	HLBFMC	LLBFMC
Balanced Plan	$ -	$ -	$ -	$ -	$ -	$ -	n/a	$ -	$ -
Renewable Plan	$ 1,047	$ 1,048	$ 1,053	$ 1,047	$ 953	$ 1,098	n/a	$ 1,100	$ 963
Low Carbon Plan	$ 4,998	$ 5,002	$ 4,999	$ 5,002	$ 5,104	$ 4,967	n/a	$ 4,811	$ 5,435
No Open Position Plan	$ 5,821	$ 5,748	$ 5,920	$ 5,750	$ 3,408	$ 7,257	n/a	$ 5,189	$ 6,539

2024 IRP 26-year PWRR Ranking by Scenario									
	Base Load							High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	BLBFMC Sales	HLBFMC	LLBFMC
Balanced Plan	1	1	1	1	1	1	n/a	1	1
Renewable Plan	2	2	2	2	2	2	n/a	2	2
Low Carbon Plan	3	3	3	3	4	3	n/a	3	3
No Open Position Plan	4	4	4	4	3	4	n/a	4	4

The buildouts for each plan were not modified for any of the scenarios analyzed.

The key findings of the 20-year and 26-year PWRR analysis are summarized below:

- The Balanced Plan is the least cost of all alternative plans in all scenarios.
- The Renewable Plan is the second least cost plan in all scenarios.
- The Low Carbon Plan and No Open Position Plan are the two highest cost plans in all scenarios due to the aggressive buildouts to achieve the Plans' respective goals.
- The No Open Position Plan is the highest cost of the alternative plans in all scenarios and time horizons except the 26-year view of the high fuel scenario, in which the Low Carbon Plan is higher.
- The BLHFMC (High Fuel) scenario results in the highest PWRR and the BLLFMC (Low Fuel) scenario results in the lowest PWRR for all plans.

G. Environmental Externalities and Net Economic Benefits

Nevada regulations require NV Energy to consider environmental costs and "net economic benefits" (which are generally termed "economic impacts") when analyzing alternative resource plans.

1. OVERVIEW OF RELEVANT REGULATIONS

The regulations require the Companies to rank power supply options based on the Present Worth of Revenue Requirement ("PWRR") and the Present Worth of Societal Costs ("PWSC"). The PWSC of a resource plan is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…."[4] Environmental costs are defined by the Commission as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[5] In addition, the August 2018 Order of the Commission in Docket No. 17-07020 ("August 2018 Order") requires that environmental costs include estimates of the "social cost of carbon" and prescribes a methodology for their calculation. The regulations state that "environmental costs to the State associated with operating and maintaining a supply plan or demand-side plan must be quantified for air emissions, water and land use and the social cost of carbon as calculated pursuant to subsection 5 of NAC § 704.937."[6]

The regulations also require the Companies to assess the "net economic benefits" of plans under certain circumstances, as noted below. "Economic benefits" are often referred to as "economic impacts," so that they are distinguished from other types of benefits. The net economic benefits include both the positive impacts on the Nevada economy of greater expenditures in Nevada and the negative impacts on the Nevada economy of higher electricity rates for consumers and businesses that generally accompany greater expenditures.

This section provides quantitative estimates and qualitative assessments that comply with the regulations discussed above.

The Companies retained the services of NERA Economic Consulting ("NERA") to provide analyses of the environmental costs and net economic benefits for the four alternative resource

[4] NAC § 704.937(4).

[5] NAC § 704.9359.

[6] *Id.*

plans for the 2024 IRP.[7] Details on NERA's analyses of the 2024 IRP plans are provided in the NERA Report (Technical Appendix Item ECON-9).

2. CARBON DIOXIDE POLICY USED IN THESE ANALYSES

NERA developed three carbon dioxide ("CO_2") policy scenarios for the 2024 IRP plans that reflect two 2022 federal policy changes, with the "Mid CO_2 Policy" scenario used for the results presented here. In analyses prior to the Fourth Amendment of the 2021 IRP, NERA had developed scenarios that assumed establishment of a national cap-and-trade program to regulate electric utility CO_2 emissions under Section 111(d) of the Clean Air Act, resulting in trajectories for CO_2 allowance prices. But on June 30, 2022, the Supreme Court ruled that Section 111(d) does not provide the U.S. Environmental Protection Agency ("EPA") with the authority to regulate CO_2 emissions based on "generation shifting" as would occur under a cap-and-trade program. Thus, the assumption of a future cap-and-trade program is no longer appropriate.

The second major recent federal climate policy development is passage of the Inflation Reduction Act ("IRA") in August 2022. The IRA includes federal tax credits for new renewable and clean energy electricity projects and for existing nuclear generation from merchant generators. NERA developed a full set of results for the Mid CO_2 Policy scenario based upon their modeling estimates of how these various IRA tax credit programs and other selected provisions will affect the trajectories of natural gas and coal prices. The Companies used these estimated effects on fuel prices in its PLEXOS modeling of the 2024 IRP plans. Results were also developed for the two other NERA CO_2 policy scenarios, the Low CO_2 Policy scenario, and the High CO_2 Policy scenario.

3. ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS

NERA uses a damage value approach to develop estimates of the environmental costs of conventional and toxic air emissions. This approach begins with the premise that the conceptually correct measure of the value of pollutant emissions is equal to the value of the damages caused by those emissions (assuming no binding cap-and-trade program or other price for emissions). Damages can include effects on health, visibility, and agriculture.[8] The empirical information used in this approach includes information developed by EPA based upon its summaries of research by environmental scientists and economists (although NERA has not validated this information).

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[7] NERA is a global firm of economic experts who apply economic, finance, and quantitative principles to complex business and legal challenges. NERA has earned wide recognition for its work in energy, environmental economics and regulation, antitrust, public utilities regulation, transportation, health care, and international trade, among other areas of expertise. References to NERA in this document relate to the principal authors of the NERA Report, Dr. David Harrison, Project Director, and Mr. Andrew Busey, Project Manager. The analyses and conclusions in the NERA Report represent those of the authors and do not necessarily represent those of NERA or any of its clients.

[8] Given data limitations, NERA did not quantify non-health welfare effects but indicated that they expect non-health costs to be small relative to the health damages.

Figure NERA-1 presents the estimated environmental costs of conventional and toxic air emissions for the 2024 IRP plans. The figure shows environmental costs for emissions controlled to meet National Ambient Air Quality Standards ("NAAQS") as well as emissions related to requirements of the Mercury and Air Toxics Standards ("MATS") issued by EPA in 2011. Based on the NAAQS, NERA included values for emissions of nitrogen oxides ("NO_X"), particulate matter ("PM"), volatile organic compounds ("VOC"), carbon monoxide ("CO"), and sulfur dioxide ("SO_2"). VOC environmental costs are estimated to be $0 because they do not contribute to ambient ozone concentrations in Nevada, as discussed in the NERA Report. CO is not monetized because the requisite air quality modeling data are unavailable; however, CO emissions projections are included in the NERA Report. As noted in the NERA Report, the national SO_2 cap is not expected to be binding and, thus, costs from SO_2 emissions are evaluated based on damage values like other air emissions (rather than modeled as covered by a cap-and-trade program as in some past IRPs). Based on their inclusion in the MATS regulation, emissions of mercury and hydrogen chloride ("HCl") are also included. The MATS regulation uses PM emissions as a proxy for non-mercury metallic air toxics, but this element of the MATS regulation does not lead to additional environmental costs because PM emissions are already included based upon the NAAQS. HCl is not monetized because EPA does not provide the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are included in the NERA Report. NERA does not expect that including costs for the other pollutants, if they could be estimated, would have any significant effects on the estimates of the environmental costs of conventional and toxic air emissions.

FIGURE NERA-1. PRESENT VALUES OF ENVIRONMENTAL COSTS FOR CONVENTIONAL AIR EMISSIONS AND AIR TOXICS, 2025-2050 (2025$ MILLIONS)

	Balanced	**Renewable**	**No Open Position**	**Low Carbon**
NOx	$2.60	$2.55	$2.49	$1.76
PM	$89.22	$86.55	$93.11	$57.09
VOC	$0.00	$0.00	$0.00	$0.00
CO	--	--	--	--
SO2	$6.05	$5.91	$6.31	$3.99
Mercury	$0.00	$0.00	$0.00	$0.00
HCl	--	--	--	--
Total	**$97.87**	**$95.01**	**$101.91**	**$62.85**

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Total may differ from the sum of the rows due to independent rounding. "-" denotes that the environmental costs of the air emission or air toxic are not monetized. The costs of VOC emissions are zero because of evidence that these emissions do not contribute to urban ozone, the relevant damage category. The costs of mercury emissions are non-zero but round to $0.00 in millions for all four plans.

Source: NERA calculations as explained in text.

Figure NERA-2 shows the differences in environmental costs for conventional and toxic air emissions for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Compared to the Balanced Plan (Preferred Plan), the Renewable Plan has lower costs (less than 3 percent), the No Open Position Plan has greater costs (about 4 percent) and the Low Carbon Plan has lower costs (about 36 percent).

FIGURE NERA-2. DIEFFERENCES IN PRESENT VALUES OF ENVIRONMENTAL COSTS OF CONVENTIONAL AND TOXIC AIR EMISSIONS RELATIVE TO THE BALANCED PLAN (PREFERRED PLAN), 2025-2050 (2025$ MILLIONS)

	Balanced	Renewable	No Open Position	Low Carbon
NOx	--	-$0.05	-$0.11	-$0.84
PM	--	-$2.68	$3.88	-$32.13
VOC	--	$0.00	$0.00	$0.00
CO	--	--	--	--
SO2	--	-$0.14	$0.26	-$2.05
Mercury	--	$0.00	$0.00	$0.00
HCl	--	--	--	--
Total	**--**	**-$2.87**	**$4.03**	**-$35.03**

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Total may differ from the sum of the rows due to independent rounding. "-" denotes that the environmental costs of the air emission or air toxic are not monetized. The costs of VOC emissions are zero because of evidence that these emissions do not contribute to urban ozone, the relevant damage category.

4. SOCIAL COST OF CARBON FOR CARBON DIOXIDE EMISSIONS

NERA developed estimates of the social cost of carbon for the four 2024 IRP plans using estimates of the CO_2 emissions for each of the plans and the valuation methodology required by the Commission in its August 2018 Order.

a. ESTIMATES OF CARBON DIOXIDE EMISSIONS

NERA developed estimates of CO_2 emissions over the period from 2025 to 2050 for the 2024 IRP plans using information from modeling done by the Companies and from other sources. Figure NERA-3 provides these estimates of CO_2 emissions for the 2024 IRP plans, with Figure NERA-4 showing percent differences for the three other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Note that CO_2 emissions are measured in metric tons to be consistent with the dollar estimates of the social cost of carbon. Compared to the Balanced Plan (Preferred Plan), the annual CO_2 emissions are slightly lower in the Renewable Plan and slightly larger in the No Open

Position Plan. The Low Carbon Plan has much lower CO_2 emissions than the other three 2024 IRP cases.

FIGURE NERA-3. CARBON DIOXIDE EMISSIONS, 2025-2050 (MILLIONS OF METRIC TONS)

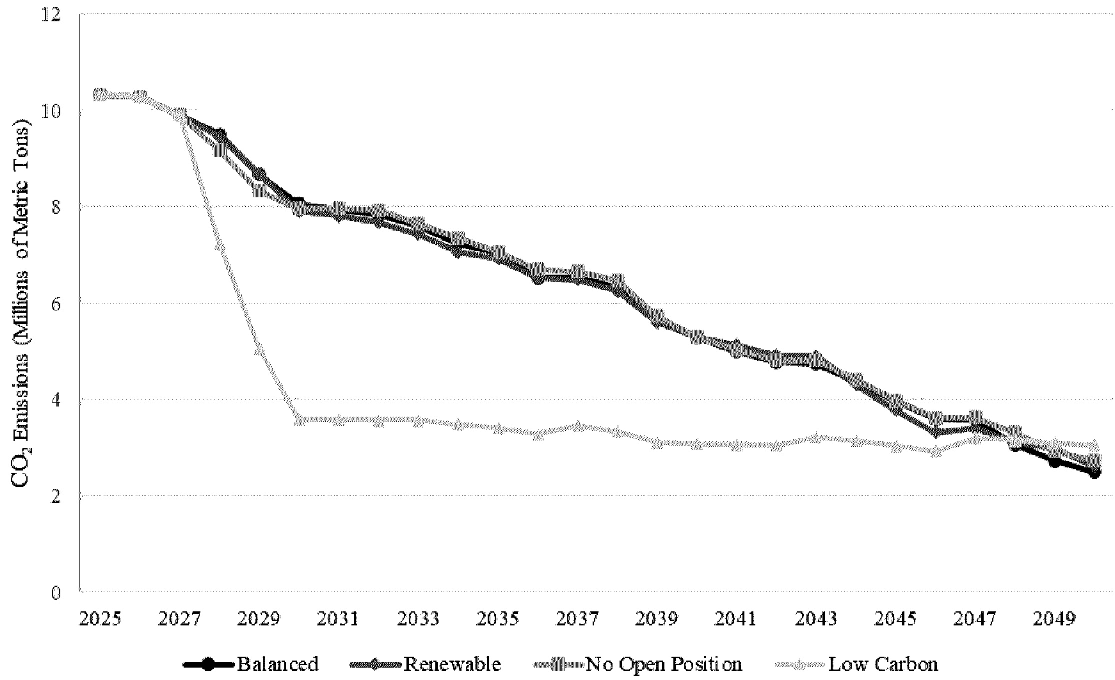
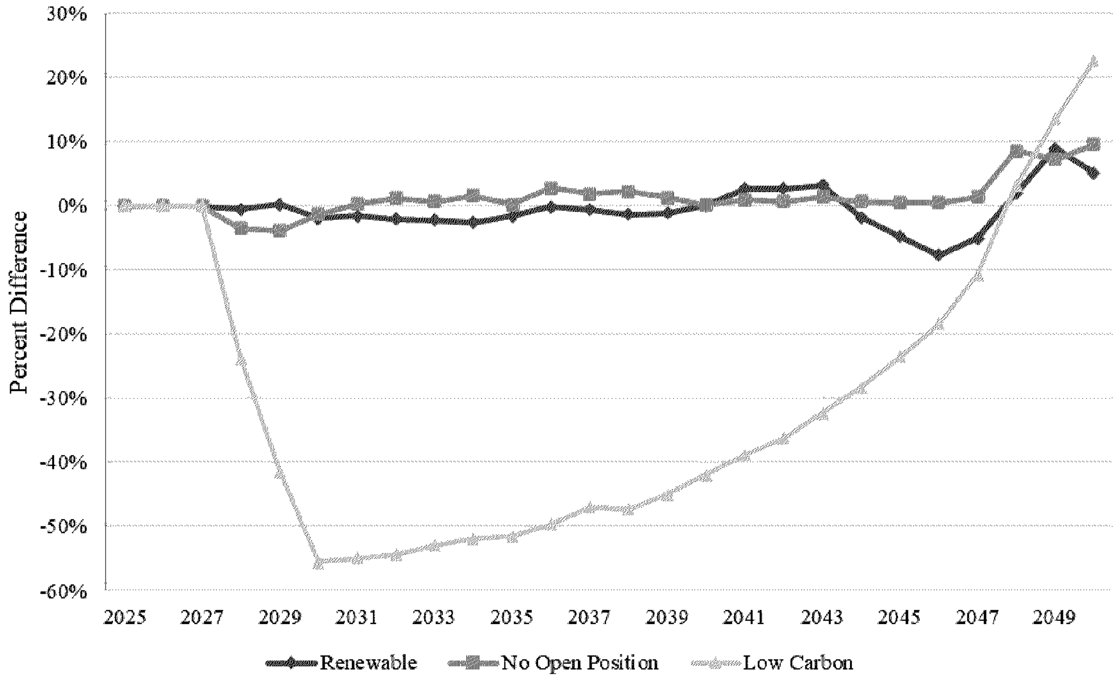


FIGURE NERA-4. PERCENTAGE DIFFERENCE IN CARBON DIOXIDE EMISSIONS RELATIVE TO THE BALANCED PLAN (PREFERRED PLAN), 2025-2050



b. Methodology Required by the Commission to Value Carbon Dioxide Emissions

Subsection 5 of the Commission's August 2018 Order requires the following determination of the social cost of carbon. "[T]he social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016."[9]

[9] There is some potential confusion in use of the term "social cost of carbon." The term is used by the Interagency Working Group (as well as many commentators) to refer to its estimates; but these estimates are referred to by the Commission in its August 2018 Order as the "future global economic costs." The Commission, in its August 2018 Order, refers to the social cost of carbon as the difference between future global economic costs and the costs internalized as private costs. NERA adopts the terminology of the August 2018 Order in its current report (although some previous reports have used "social cost of carbon" to refer to the values developed by the Interagency Working Group). The NERA Report provides information on the methodology used by the Interagency Working Group to develop its estimates and on the wide range of estimates that are provided in the February 2021 report, which updates the August 2016 report for inflation.

The Interagency Working Group provided estimates of the present value of future global economic costs from an additional annual ton of CO_2 for three discount rates—2.5 percent, 3 percent, and 5 percent—using the average of the damages distribution it calculated from modeling results. It also provided a fourth set of global economic costs based on the 3 percent discount rate and the 95th percentile of the damages distribution, which it noted are designed to represent impacts from temperature change further out in the tails of the global economic cost distribution. These four sets of values cover a very large range and, indeed, the full range of values reported by the Interagency Group was much greater than these four sets of estimates.

Because the carbon policy scenarios developed by NERA do not result in internalization of any environmental costs related to CO_2 emissions as private costs, NERA calculated the social cost of carbon based on the global environmental cost values in the most recent report of the Interagency Working Group (Interagency Working Group 2021), using the values based on a 3 percent discount rate and the average of the damages distribution.

c. SOCIAL COSTS OF CARBON

Figure NERA-5 shows the estimates of the present values of the social costs of carbon for the 2024 IRP plans, and Figure NERA-6 shows the difference in the social costs of carbon for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Compared to the Balanced Plan (Preferred Plan), the costs of CO_2 emissions are slightly lower in the Renewable Plan, slightly larger in the No Open Position Plan, and much lower in the Low Carbon Plan.

FIGURE NERA-5. PRESENT VALUES OF SOCIAL COSTS OF CARBON, 2025-2050 (2025$ MILLIONS)

Balanced	Renewable	No Open Position	Low Carbon
$9,997	$9,933	$10,047	$6,825

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using the social cost of carbon values from the Interagency Working Group based upon a 3 percent discount rate and the average damages distribution.
Source: NERA calculations as explained in text.

FIGURE NERA-6. DIFFERENCES IN PRESENT VALUES OF SOCIAL COSTS OF CARBON, RELATIVE TO THE BALANCED PLAN (PREFERRED PLAN), 2025-2050 (2025$ MILLIONS)

Balanced	Renewable	No Open Position	Low Carbon
-	-$64	$50	-$3,172

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using the social cost of carbon values from the Interagency Working Group based upon a 3 percent discount rate and the average damages distribution.
Source: NERA calculations as explained in text.

NERA has in prior IRPs noted that the global values developed by the Interagency Working Group are not comparable to the environmental costs calculated for conventional and toxic air emissions for several reasons: (a) the Interagency Working Group values are more uncertain partly because they are based upon impacts in the distant future; (b) the Interagency Working Group values are based on different discount rates than the private (NV Energy) discount rates used to calculate the present value of environmental costs; and (c) the Interagency Working Group values are based upon global damages rather than U.S. damages.

5. EXTERNAL ENVIRONMENTAL COSTS OF WATER CONSUMPTION

NERA estimated the value of water consumption by the Companies that is not included in the PWRR. These external environmental costs are based upon current information related to water use from wells owned by the Companies and do not include water that is leased or purchased, because the value of leased or purchased water is included in the PWRR. Moreover, no external environmental water costs are calculated for power purchased by the Companies through contracts, renewable power purchase agreements, or spot market transactions because NERA assumes that all water costs will be included in the product rate paid by the Companies, and thus, in the PWRR.

Figure NERA-7 shows the estimated external environmental costs of water consumption (i.e., the added costs beyond those already included in the PWRR) for the 2024 IRP plans, and Figure NERA-8 shows the differences between the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. All values are calculated as present values over the 26-year period from 2025 to 2050 as of 2025. Compared to the Balanced Plan (Preferred Plan), the external water costs are somewhat greater for the Renewable Plan, slightly smaller for the No Open Position Plan, and somewhat greater for the Low Carbon Plan.

FIGURE NERA-7. PRESENT VALUES OF EXTERNAL ENVIRONMENTAL WATER COSTS, 2024-2051 (2024$ MILLIONS)

Balanced	Renewable	No Open Position	Low Carbon
$12.88	$16.70	$12.75	$14.65

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra.
Source: NERA calculations as explained in text.

FIGURE NERA-8. DIFFERENCES IN PRESENT VALUES OF EXTERNAL ENVIRONMENTAL WATER COSTS RELATIVE TO THE BALANCED PLAN (PREFERRED PLAN), 2025-2050 (2025$ MILLIONS)

Balanced	Renewable	No Open Position	Low Carbon
-	$3.82	-$0.13	$1.77

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra.
Source: NERA calculations as explained in text.

6. OTHER ENVIRONMENTAL EFFECTS

NERA considered three other categories of potential environmental costs: (1) land use; (2) water quality; and (3) solid waste disposal, including sludge and ash disposal. For all three categories, NERA considered whether there might be significant differences in environmental costs among the 2024 IRP resource plans. NERA concluded than any cost differences were likely to be highly site-specific and were not likely to be significant relative to the estimated environmental costs.

7. PRESENT WORTH OF SOCIETAL COST

Figure NERA-9 provides estimates of the PWSC for the 2024 IRP plans. As noted above, PWSC is defined as the sum of the PWRR and the environmental costs. Figure NERA-9 shows the PWSC values for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Compared to the Balanced Plan (Preferred Plan), the Renewable Plan and Low Carbon Plan have slightly greater PWSC (about 2 percent and 5 percent, respectively), and the No Open Position Plan has a somewhat greater PWSC (about 10 percent).

FIGURE NERA-9. PRESENT WORTH OF SOCIETAL COSTS, 2025-2050 (2025$ MILLIONS)

	Balanced	Renewable	No Open Position	Low Carbon
PWRR	$41,294	$42,342	$46,293	$47,115
Conventional Air Emission Costs	$98	$95	$102	$63
External Water Costs	$13	$17	$13	$15
Social Costs of Carbon	$9,997	$9,933	$10,047	$6,825
PWSC	$51,402	$52,386	$56,454	$54,017

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050. Values other than the social costs of carbon are based on inflation information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the Interagency Working Group case based upon a 3 percent discount rate and the average damages distribution. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

FIGURE NERA-10. DIFFERENCES IN PRESENT WORTH OF SOCIETAL COSTS RELATIVE TO THE BALANCED PLAN (PREFERRED PLAN), 2025-2050 (2025$ MILLIONS)

	Balanced	Renewable	No Open Position	Low Carbon
PWRR	-	$1,047	$4,998	$5,821
Conventional Air Emission Costs	-	-$3	$4	-$35
External Water Costs	-	$4	$0	$2
Social Costs of Carbon	-	-$64	$50	-$3,172
PWSC	-	$985	$5,052	$2,615

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050. Values other than the social costs of carbon are based on inflation information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the Interagency Working Group case based upon a 3 percent discount rate and the average damages distribution. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

8. ECONOMIC IMPACTS

NERA used the economic model developed by Regional Economic Models, Inc. ("REMI") to develop comprehensive estimates of economic impacts for 2024 IRP plans. The Companies provided NERA with information on the 2024 IRP plans that, together with some other information, enabled NERA to estimate both the positive economic impacts of expenditures in Nevada for the 2024 IRP resource plans and the negative economic impacts of the electricity revenue requirements for the 2024 IRP resource plans. These analyses are based primarily on the costs and revenue requirements related to the Companies' bundled customers and do not include costs and revenues related to entities that purchase transmission capacity from the Companies ("transmission-only customers"), as the PWRR cost information generally is based on bundled customers. The only exception is that the costs and revenue requirements include those related to provision of 90 MW of additional reserve capacity for transmission-only customers, information that is included in the PWRR.

9. REMI MODEL

As explained in detail in the NERA Report, the REMI model provides a detailed representation of the Nevada economy. The core of the model is a set of input-output ("I/O") relationships among different industries that allow one to estimate how changes in demand or supply in each relevant industry will affect all other industries. The I/O formulation also includes "economic leakage," which is the extent to which expenditures in any industry lead to imported goods from outside the economy (and thus do not have "multiplier" effects in Nevada). REMI also provides estimates of the impacts on Nevada when feedback mechanisms in the economy are included (e.g., changes in wages that result from changes in economic activity and thus in the demand for labor).

Simulations of the economy in REMI require a "baseline" plan to which alternative plans can be compared. The Companies developed a Base Case that is assumed to reflect the REMI baseline or reference case. The economic impact analysis was conducted over the period from 2025 to 2050, which is the period over which the Companies forecast expenditures and revenues. NERA developed economic impact assessments for the 2024 IRP plans relative to the Base Case. Although the Base Case is assumed to be the baseline or reference case for purposes of the REMI modeling, results are presented for the other 2024 IRP plans relative to the Balanced Plan (the Preferred Plan), the same format as for the environmental cost comparisons.

a. EXPENDITURES, REVENUES AND ECONOMIC IMPACTS

Figure NERA-11 shows the average annual expenditures in Nevada under the 2024 IRP plans and the Base Case. The table includes construction expenditures, fuel expenditures and non-fuel operating and maintenance ("O&M") expenditures. Only expenditures in Nevada are included in these calculations because the objective is to estimate the economic impacts in Nevada, and expenditures outside Nevada are unlikely to contribute significantly to the Nevada economy. Note that these average annual values do not reflect differences over the 26-year period, differences that are included in the REMI modeling. As discussed in the NERA Report, the expenditures exclude certain categories of expenditures, such as market purchases by the Companies, because those expenditures are assumed to be from power producers outside Nevada (and thus the expenditures would not generate significant positive economic impacts in Nevada). The NERA analysis assumes that 50 percent of expenditures related to the open position would occur within the state and that 50 percent of these expenditures would occur outside Nevada.

FIGURE NERA-11. AVERAGE ANNUAL EXPENDITURES IN NEVADA, 2025-2050 (2025$ MILLIONS)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Construction	$3,235	$3,346	$3,616	$2,973	$3,283
Fuel	$495	$489	$478	$504	$357
O&M	$730	$720	$820	$619	$921
Total	**$4,460**	**$4,555**	**$4,913**	**$4,096**	**$4,561**

Note: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

Figure NERA-12 shows the differences in average annual expenditures in Nevada over the period from 2025 to 2050 for the 2024 IRP resource plans relative to the Base Case. The differences in each year relative to the Base Case are the values that are included in the REMI modeling, based upon detailed information to reflect the sectors directly affected by the expenditures in Nevada in each year.

FIGURE NERA-12. AVERAGE ANNUAL EXPENDITURES IN NEVADA RELATIVE TO THE BASE CASE, 2025-2050 (2025$ MILLIONS)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Construction	-	$111	$381	-$262	$49
Fuel	-	-$6	-$17	$9	-$138
O&M	-	-$10	$88	-$111	$191
Total	-	**$95**	**$452**	**-$363**	**$101**

Note: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

Figure NERA-13 shows the average annual electricity revenue requirements for 2025-2050, apportioned by customer class, for the 2024 IRP cases. The values by customer class are based on the methodology described in the NERA Report that includes information for Nevada Power and Sierra.

FIGURE NERA-13. AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS, 2025-2050 (2025$ MILLIONS)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Residential	-	$37	$97	$328	$215
Commercial	-	$24	$57	$156	$141
Industrial	-	$12	$27	$60	$73
Total	-	**$73**	**$180**	**$544**	**$429**

Note: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.
Source: NERA calculations as explained in text.

Figure NERA-14 shows differences in the average annual electricity revenue requirements for the four 2024 IRP plans relative to the Base Case, which is assumed to be consistent with the REMI baseline. The differences in each year are the values that are included in the REMI modeling, based on detailed information to reflect the direct impacts on the three sets of customers in each year.

FIGURE NERA-14. ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS RELATIVE TO THE BASE CASE, 2025-2050 (2025$ MILLIONS)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Residential	-	$37	$97	$328	$215
Commercial	-	$24	$57	$156	$141
Industrial	-	$12	$27	$60	$73
Total	-	**$73**	**$180**	**$544**	**$429**

Note: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.
Source: NERA calculations as explained in text.

REMI modeling takes as inputs the annual expenditures in Nevada and the annual electricity revenue requirements—both relative to the Base Case—and develops estimates of the economic impacts in Nevada for the 2024 IRP plans over time. The NERA Report describes the methodologies that are used to translate the expenditure and revenue requirement categories into the annual REMI inputs that NERA uses when it runs the REMI model over the 26-year period from 2025-2050. Expenditures and revenue requirements beyond 2050 are not included in the modeling. Because of the difference in timing between construction expenditures and the associated revenue requirements—with construction expenditures positively affecting the economy when they are expended but negative impacts on the economy from changes in revenue requirements allocated over multiple future years—this means that some of the negative impacts of the construction of new resources in the 2040s will extend beyond 2050 and thus will not be included in the REMI modeling.

Figure NERA-15 provides estimates of the differences in four economic outcome measures for selected years in Nevada for the 2024 IRP plans relative to the Base Case. The measures include gross state product, personal income, state and local tax revenues, and employment (total jobs). The economic impacts of the 2024 IRP plans vary over the selected years in the 26-year period from 2025-2050, reflecting the different timing of construction and other major initial changes in economic activity under the different 2024 IRP plans.

FIGURE NERA-15. ECONOMIC IMPACTS IN NEVADA FOR SELECTED YEARS RELATIVE TO THE BASE CASE, 2025-2050

	Nevada Economic Impact						
	2025	2026	2027	2028	2035	2045	2050
Base							
Gross State Product (millions of 2025 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2025 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2025 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
Balanced							
Gross State Product (millions of 2025 dollars)	6	-61	255	-144	-35	-48	-41
Personal Income (millions of 2025 dollars)	4	-35	166	-85	-32	-36	8
State & Local Tax Revenue (millions of 2025 dollars)	0	-3	16	-8	-3	-3	1
Employment (total jobs)	49	-499	2,101	-1,071	-298	-280	-107
Renewable							
Gross State Product (millions of 2025 dollars)	-29	-75	154	-233	-17	1,467	-3
Personal Income (millions of 2025 dollars)	-18	-46	102	-140	8	1,041	161
State & Local Tax Revenue (millions of 2025 dollars)	-2	-4	10	-13	1	98	15
Employment (total jobs)	-243	-642	1,250	-1,716	-125	9,153	498
No Open Position							
Gross State Product (millions of 2025 dollars)	21	-41	287	260	-2,051	-1,218	-2,366
Personal Income (millions of 2025 dollars)	13	-23	186	179	-1,153	-873	-1,649
State & Local Tax Revenue (millions of 2025 dollars)	1	-2	18	17	-108	-82	-155
Employment (total jobs)	173	-326	2,383	2,156	-14,337	-7,760	-13,762
Low Carbon							
Gross State Product (millions of 2025 dollars)	-35	-14	-27	1,060	-1,885	-386	-38
Personal Income (millions of 2025 dollars)	-21	-10	-17	660	-950	-188	-46
State & Local Tax Revenue (millions of 2025 dollars)	-2	-1	-2	62	-89	-18	-4
Employment (total jobs)	-292	-143	-238	8,018	-12,600	-1,391	639

Notes: The Base Case is assumed to be consistent with the REMI baseline, and thus results are reported relative to the Base Case.
Employment values include full-time and part-time jobs.
Sources: REMI; NERA calculations as explained in text.

Figure NERA-16 provides estimates of the average annual economic impacts in Nevada—based on the four impact measures—over the 26-year period from 2025-2050 for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Relative to the Balanced Plan, the economic impacts are positive for the Renewable Plan and negative for the No Open Position Plan for all four economic impact metrics. The Low Carbon Plan has greater economic impacts than the Balanced Plan for three of the metrics and smaller economic impacts for one of the metrics. These average annual values do not reflect differences in timing of expenditures and revenue requirements among the 2024 IRP cases. Thus, for example, the large average annual positive impacts of the Renewable Plan are due largely to the positive impacts of the 2040s (see Figure NERA-15). These positive impacts reflect the large positive impacts from construction expenditures in the 2040s that are not matched with all the negative impacts of the associated revenue requirements because these revenue requirements extend beyond 2050, the end of the study period.

FIGURE NERA-16. ANNUAL AVERAGE ECONOMIC IMPACTS IN NEVADA RELATIVE TO THE BALANCED PLAN (PREFERRED PLAN)

	Balanced	Renewable	No Open Position	Low Carbon
Gross State Product (millions of 2025 dollars)	-	185	-257	-28
Personal Income (millions of 2025 dollars)	-	164	-191	71
State & Local Tax Revenue (millions of 2025 dollars)	-	15	-18	7
Employment (total jobs)	-	1,350	-1,458	639

Notes: Employment values include full-time and part-time jobs.
Sources: REMI; NERA calculations as explained in text.

H. Selection of the Preferred Plan

The following criteria were used when selecting the Balanced Plan as the Preferred Plan and the Renewable Plan as the Alternate Plan.

Capacity and RPS needs due to load growth as well as cancellations of previously approved project

With the updated load forecast, the Companies have a growing need for resources for capacity, energy, and RPS contribution, which is also impacted by recent cancellations of Commission-approved projects. Substantial renewable and storage resource needs are addressed in all plans in the face of growing load and an aggressive RPS ramp up in the next several years. All alternative plans provide significant incremental capacity as well as RPS contribution with three PV/BESS projects. Two of the plans add near-term thermal resources as well. All plans address expected increased customer participation in the NGR program in addition to the state's RPS requirement.

Intent to reduce the risk of exposure to the uncertain availability of market capacity, simultaneously advancing resource sufficiency as required for participation in WRAP or a future market or RTO

As described in the introduction to this 2024 Joint IRP, as in prior filings, recent events and reports further advance the steadily diminishing confidence in the availability of market capacity in the West. This 2024 Joint IRP addresses these concerns regarding the availability of market capacity as it is impacted by changes in climate, weather, and resource variability across the region. As described in the introduction, these efforts to reduce reliance on market capacity simultaneously contribute to the resource sufficiency requirements of WRAP and expected requirements of a future regional market or RTO. While all four alternative plans reduce the near-term exposure to uncertain market capacity by adding new resources, the Balanced plan mitigates this concern the most without creating excessively long capacity positions. The Renewable plan has the highest open position in 2028 and 2029.

PWRR and PWSC results

The Balanced Plan has the lowest PWRR of the alternative plans in the 20-year and 26-year study periods in all scenarios due in large part to its balance of renewable, storage, and cost-effective firm dispatchable resources and the moderate level of open position maintained in this plan. The Renewable Plan has the second lowest PWRR in both study periods in all scenarios – averaging 1 percent higher than the Balanced Plan in the 20-year planning period and 2.5 percent higher in the 26-year study period. Without near term CTs, the Renewable Plan has a larger buildout of BESS over the 26-year study period which leads to a significant increase in cost. The BESS, unlike CTs, is subject to a declining ELCC, a shorter asset life, and is energy limited, all of which drive an increased BESS buildout through the study period in this plan. The No Open Position and Low Carbon Plans have substantially higher PWRRs than the other two plans due to the need for more resources to meet the specific goals of these two plans. The Low Carbon Plan has the highest PWRR due to this plan's need for a very large renewable and storage resource buildout in a very short span of time to meet the prescribed carbon dioxide target in 2030. As determined in NERA's analysis, the Balanced Plan has the lowest PWSC of the alternative plans over the 26-year study period. Compared to the Balanced Plan, the Renewable Plan and Low Carbon Plan have slightly greater PWSC (about 2 percent and 5 percent, respectively), and the No Open Position Plan has a somewhat greater PWSC (about 10 percent).

Decarbonization goals of customers, the Companies, and the state

> All plans presented in this 2024 Joint IRP add multiple PV/BESS projects to not only achieve RPS compliance but to serve anticipated customer participation in the NGR program. In addition, all plans target the Companies' proportionate contribution to the state's 2050 clean energy goal. Due to the cancellation of previously approved projects in this IRP and recent filings, all of the plans require use of the banked PCs to ensure RPS compliance while addressing expected customer participation in the NGR program in the early years. Despite varying additions of thermal resources in the early years among the plans, all plans have similar carbon dioxide emissions over the study period with the exception of the Low Carbon Plan, which decarbonizes much more rapidly.

The Low Carbon Plan, in adding renewable resources at a very accelerated pace to achieve a dramatic carbon dioxide emissions reduction by 2030, despite much higher forecasted load than the 2005 emissions baseline year, has many undesirable traits, namely:

- It has a very long capacity position in many years— acquiring resources before needed to meet demand is unnecessary and expensive;
- It has significantly more excess energy in the first two decades than the other alternative plans, which may cause significant operational and administrative problems;
- It cements existing technology into the portfolio instead of allowing the Companies and customers to take advantage of technology improvements that will undoubtedly occur in the ensuing years;
- Overbuilding existing technology into a portfolio may limit the Companies economic participation in regional markets; and,
- Most significantly, in connection with the other concerns identified here, the Low Carbon Plan is much more expensive than the Balanced and Renewable plans.

NV Energy fully supports the state's decarbonizing goals and maintains similar environmental goals of its own. While the Low Carbon Plan results in nearly one third fewer tons of carbon dioxide over the study period than the other plans, it puts undue burden on our customers and therefore is not optimal.

In order to ensure no purchase of market capacity in the No Open Position Plan, the buildout is essentially forced to hold excess capacity by varying amounts in all years after an initial period of reducing the open position to zero. Due to the inherent unevenness of load growth and certain resource sizes, maintaining an exact zero open position is not possible. The resulting long capacity position in many years increases the cost of this plan. While the No Open Position Plan would improve reliability by largely eliminating reliance on the market, the plan is not optimal because, as described, the absolute elimination of open capacity positions leads to long capacity positions and therefore, additional cost that places undue burden on our customers.

The Renewable Plan eliminates the 2028 Valmy CTs proposed in the Balanced Plan in favor ofplaceholder 4-hour BESS PPAs beginning in 2030. While the Renewable and Balanced Plans have similar amounts of capacity resources at the time of the system peak, the resources do not have the same availability throughout the day. BESS resources are, by design, limited in discharge duration, which limits their ability to produce power when needed. The CTs, by contrast, can generate energy as needed, 24/7, provided there is sufficient fuel to operate the units. Moreover, the gas pipeline and fuel supply agreements are already planned at the Valmy site.

The Balanced Plan employs a balanced approach to decarbonizing, adding multiple PV/BESS projects and a thermal project, resulting in the lowest PWRR of all plans across multiple time horizons. It reduces the open position dramatically but cost-effectively. In this plan, the addition of two fast start peaking units at the Valmy location eliminates the must-run requirement imposed on the Valmy steamers – a requirement that would continue in perpetuity in the absence of these peakers due to the forecasted northern load growth. It is also noteworthy that CTs at this location do not compete for natural gas with Sierra's local gas distribution company in Reno/Sparks. This plan adds the same renewable and storage projects as the other plans, as substantial renewable and storage resources are needed for RPS compliance in the face of growing load and an aggressive near-term RPS ramp up, as well as to address the expected NGR program demand.

Based on the criteria and discussion presented, the Companies selected the Balanced Plan as the Preferred Plan and the Renewable Plan as the Alternate Plan. The selected Preferred Plan balances incremental capacity and RPS contribution with overall cost, economic net benefits, social costs, and other decarbonizing goals of the state, customers, and the Companies.

The average cost of generation for the Preferred Plan is contained in Technical Appendix ECON-3.

I. Loads and Resources Tables

NAC § 704.945 requires a table of loads and resources for each alternative plan analyzed. For the Preferred Plan, the 20-year projection of coincident peak load, planning reserve requirements, total required resources, existing and future supply-side resources, existing and future demand-side resources, and reserves for OATT customers are provided in Figure EA-44. L&R tables for NV Energy, Nevada Power and Sierra for all alternative plans and for each scenario are provided in Technical Appendix ECON-5.

Overview. The L&R tables provide the forecast coincident peak load (in MW) for each year ("Peak Load"), plus a planning reserve requirement (together with Peak Load, "Required Resources"), and the forecast capacities of the existing and future supply-side and demand-side DR program resources (in MW) available to meet the Required Resources reduced by the OATT reserve.

The Peak Load includes wholesale firm sales and is net of certain demand-side resources including demand-side energy efficiency programs and net metering programs. Loads within the BAA for customers that supply their own supply-side, such as those authorized to procure their own energy supply under NRS Chapter 704B, are not included in the load that the Companies plan to serve.

A 12.5 percent PRM is added to the Peak Load to determine the Required Resources for the joint system. Designed to achieve a loss of load probability of no more than one day in 10 years, the PRM helps ensure that the Companies plan for sufficient supply-side resources and demand-side resources to meet the total requirements of bundled customers.

Supply-side resources include a combination of existing, proposed, and placeholder generation and PPAs, both conventional and renewable. The capacity value assigned to supply-side resources represents the planning or effective capacity of each resource during the Peak Load.

Per the Phase 2 Stipulation in the 2021 Joint IRP in Docket No. 21-06001, a reduction of 90 MW is taken from the total available resources to account for the reserves to be held for OATT customers. The 90 MW of reserves are split between the Companies based on a ratio of load in each region.

Overall, the L&R tables represent the diverse set of resource options maintained by the Companies to meet the expected Required Resources.

Methodology for Assigning L&R Capacity Values for Existing and Future Resources.

The peak summer capacity for existing conventional generation is listed in confidential Technical Appendix GEN-1. The capacity for thermal generators varies depending on the time of year and is categorized as winter capacity, summer capacity or peak capacity. As described in the Key Modeling Assumptions Subsection, unforced capacity ("UCAP") accounting was used for this update, which reduces the peak summer capacity of existing thermal generation resources by each resource's historic forced outage rate. For conventional generation PPAs, the contractually agreed upon capacity during the Peak Load hour is used.

The capacity value provided for renewable resources in the L&R table is adjusted by the ELCC for the particular resource type to reflect the overall renewable penetration. The L&R capacity value for all (existing and new) wind, solar PV, battery and PV/BESS resources vary inversely with the amount of intermittent renewable penetration on the system. That is, as the total aggregate amount of nameplate intermittent renewable capacity increases, the ELCC, as a percent of nameplate capacity, decreases. The L&R capacity values for geothermal resources, by constrast, do not vary significantly with the amount of resource on the system.

The L&R tables show existing contracts expiring pursuant to the contract term. Renewable placeholder contracts are added as needed to meet load growth, requirements for RPS compliance, and in some cases, for achievement of the Companies' renewable goals, which include a contribution to the state's 2050 clean energy goal.

Since the L&R tables provide a projection of capacity only, the capacity values cannot be extrapolated to forecast retail energy sales, total megawatt-hour output from conventional and renewable resources, or portfolio credit contributions to meet Nevada's RPS.

Combined L&R Table. Figure EA-44 provides the L&R table for the Preferred Plan under the Base Load scenario.

FIGURE EA-44
L&R TABLE
PREFERRED PLAN
(2025-2044)

1										**NV Energy**											
2										**LOADS AND RESOURCES TABLE**											
3										*Balanced Plan*											
4		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
5	Gross Peak	8,840	8,993	9,173	9,522	9,833	10,409	10,797	11,275	11,383	11,701	11,847	12,291	12,563	12,691	12,988	13,397	13,762	13,867	14,294	14,436
6	DSM Energy Efficiency Savings	109	165	211	266	342	403	457	515	537	587	609	725	768	752	774	795	870	807	912	885
7	DR Energy Efficiency Savings	10	10	11	9	11	12	12	13	13	14	15	16	16	18	17	18	19	20	20	22
8	Private Generation	31	33	36	41	41	47	48	50	55	17	18	62	61	63	69	21	73	26	73	74
9	Forecast System Peak	8,690	8,785	8,916	9,206	9,439	9,948	10,278	10,698	10,778	11,084	11,205	11,488	11,718	11,858	12,128	12,563	12,800	13,015	13,290	13,454
10	Sales Obligations																				
11	**NET System Peak**	8,690	8,785	8,916	9,206	9,439	9,948	10,278	10,698	10,778	11,084	11,205	11,488	11,718	11,858	12,128	12,563	12,800	13,015	13,290	13,454
12	Planning Reserves (12.5%)	1,086	1,098	1,115	1,151	1,180	1,243	1,285	1,337	1,347	1,385	1,401	1,436	1,465	1,482	1,516	1,570	1,600	1,627	1,661	1,682
13	**REQUIRED RESOURCES**	9,776	9,883	10,031	10,357	10,619	11,191	11,563	12,035	12,125	12,469	12,605	12,924	13,183	13,340	13,644	14,134	14,400	14,642	14,951	15,136
14	OATT Reserves	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
15	**AVAILABLE RESOURCES**	8,380	8,657	9,007	10,092	10,365	10,576	10,998	11,491	11,657	11,953	12,961	12,982	13,089	13,174	13,082	13,499	13,757	13,983	14,287	14,433
16	OPEN Position	1,396	1,226	1,024	265	254	615	565	544	468	516	-	-	94	166	562	635	643	659	664	703
17	OPEN/(LONG) Position	1,396	1,226	1,024	265	254	615	565	544	468	516	(356)	(58)	94	166	562	635	643	659	664	703
19	Company	(All)																			
21	Sum of L&R MW																				
22		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
23	Owned																				
24	NVE.Owned.Coal.Steamer	242	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	NVE.Owned.Diesel.Gen	5	5	5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	NVE.Owned.Gas.CC	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457	3,457
27	NVE.Owned.Gas.CC-int	735	735	735	735	735	735	735	735	735	735	735	735	735	735	735	735	735	735	735	542
28	NVE.Owned.Gas.CT	1,548	1,548	1,548	1,548	1,548	1,548	1,548	1,548	1,548	1,548	1,548	1,502	1,502	1,502	1,502	1,502	1,502	1,298	1,298	1,298
29	NVE.Owned.Gas.Steamer	261	503	503	503	503	503	503	503	503	503	503	503	503	503	242	242	242	242	242	242
30	NVE.Owned.Renewable.PV	40	42	98	93	94	80	75	78	70	70	67	63	63	65	62	62	57	55	55	53
31	NVE.Owned.Storage.BESS-4	110	450	433	434	433	442	434	408	398	378	378	377	377	378	364	314	292	260	244	229
32	NVE.Owned.Storage.BESS-2	220	194	192	190	190	191	187	176	172	163	163	163	162	163	157	136	127	114	107	-
33	NVE.Owned.Renewable.WH	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-
34	NVE.Owned.DR/DSM.ACLM	219	234	249	262	274	283	292	298	303	309	314	320	325	331	336	342	347	353	358	364
35	NVE.Owned.DR/DSM.PV	-	-	4	5	5	4	4	4	3	3	3	3	3	3	3	3	2	2	2	2
36	NVE.Owned.DR/DSM.BESS-2	-	52	117	175	226	278	322	333	353	364	386	407	428	448	447	401	387	352	334	318
37	Owned Total	6,842	7,225	7,346	7,412	7,470	7,526	7,562	7,545	7,547	7,535	7,559	7,535	7,560	7,590	7,310	7,199	7,148	6,868	6,832	6,505
38	Contracted																				
39	PPA.Contracted.Diesel.Gen	11	11	11	11	11	11	11	-	-	-	-	-	-	-	-	-	-	-	-	-
40	PPA.Contracted.Renewable.CSP	15	16	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	PPA.Contracted.Renewable.Geo	176	200	213	223	224	173	173	163	110	110	110	110	110	105	105	105	105	105	105	105
42	PPA.Contracted.Renewable.Hydro	148	142	142	138	136	136	136	136	136	136	136	136	136	136	136	136	135	135	135	135
43	PPA.Contracted.Renewable.LFG	15	15	15	15	15	15	15	15	-	-	-	-	-	-	-	-	-	-	-	-
44	PPA.Contracted.Renewable.PV	630	632	523	475	475	388	356	364	331	329	313	293	288	261	241	243	227	227	228	220
45	PPA.Contracted.Renewable.Wind	17	17	17	17	17	17	17	17	-	-	-	-	-	-	-	-	-	-	-	-
46	PPA.Contracted.Storage.BESS-4	616	489	483	479	477	479	469	424	413	394	393	392	391	338	325	282	263	235	222	209
47	PPA.Contracted.DR/DSM.PV	-	-	6	5	5	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3
48	Contracted Total	1,628	1,522	1,423	1,363	1,360	1,223	1,181	1,123	993	972	955	934	928	843	810	769	733	705	693	672
49	Proposed																				
50	NVE.Proposed.GAS.CT																				
51	2058 - Valmy CTs - North - SPPC	-	-	-	379	379	379	379	379	379	379	379	379	379	379	379	379	379	379	379	379
52	PPA.Proposed.Renewable.PV																				
53	2051 - *Dry Lake East PV Paired - South - NPC	-	-	31	31	31	27	26	26	24	24	23	21	22	22	21	21	20	20	20	19
54	2052 - *Boulder Solar III PV Paired - South - NPC	-	-	20	20	20	17	16	17	15	15	15	14	14	14	13	14	13	13	13	12
55	2052 - *Libra PV Paired - North - NPC	-	-	-	107	108	95	90	93	84	83	80	75	76	78	73	74	69	69	70	67
56	PPA.Proposed.Storage.BESS-4																				
57	2046 - *Dry Lake East BESS Paired - South - NPC	-	-	169	169	169	173	170	160	156	148	148	148	148	149	143	124	115	103	97	92
58	2047 - *Boulder Solar III BESS Paired - South - NPC	-	-	108	108	108	111	109	102	100	95	95	95	94	95	91	79	74	66	62	59
59	2047 - *Libra BESS Paired - North - NPC	-	-	-	593	592	605	596	559	546	519	519	518	516	520	499	433	404	362	340	321
60	Proposed Total	-	-	328	1,407	1,407	1,407	1,386	1,336	1,304	1,263	1,259	1,250	1,249	1,257	1,219	1,124	1,074	1,012	981	949
61	Placeholders																				
62	NVE.Placeholders.Other.TBD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	NVE.Placeholders.Renewable.PV	-	-	-	-	-	-	26	26	72	96	92	85	87	88	84	84	80	80	80	77
64	PPA.Placeholders.Renewable.GEO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	PPA.Placeholders.Renewable.PV	-	-	-	-	-	203	281	289	343	371	401	454	460	471	540	611	709	798	854	938
66	PPA.Placeholders.Renewable.WIND	-	-	-	-	218	218	218	435	510	547	547	576	660	771	800	800	800	800	800	800
67	PPA.Placeholders.Storage.PSH	-	-	-	-	-	-	-	-	-	-	980	980	980	980	980	980	980	980	980	980
68	PPA.Placeholders.Storage.BESS-4	-	-	-	-	-	89	264	267	276	444	444	444	442	446	644	1,341	1,689	2,263	2,623	3,096
69	NVE.Placeholders.Storage.BESS-4	-	-	-	-	-	-	170	560	702	815	814	814	813	818	785	681	634	567	534	506
70	Placeholders Total	-	-	-	-	218	510	959	1,577	1,903	2,273	3,278	3,353	3,442	3,574	3,833	4,497	4,892	5,488	5,871	6,397

J. Additional Studies

VARIOUS LEVELS OF DSM PROGRAMS.

The Companies conducted additional economic analyses to assist in the determination of the rate impacts associated with differing levels of DSM programs. To this end, the Companies performed additional economic analyses on the Preferred Plan. One case assumed the Proposed DSM implementation, another case adopted an Enhanced DSM implementation, and the third case includes no DSM programs. Each of these cases assumed DSM implementation levels different from that assumed in the Preferred Plan. For the case with no DSM, the Companies created a new expansion plan in PLEXOS LT using a load forecast that excluded DSM programs entirely.

In addition, the Companies conducted additional economic analysis to assist in the determination of the impact of achieving less than the planned levels of Demand Side Management pursuant to Directive 5 in Docket No. 23-06044.

In each of these additional cases, the DSM programs incorporated in the load forecast are adjusted. As such, each case required an updated load forecast. Only in the no DSM case were changes made to the DSM/DR programs modeled as supply resources. In this case, these programs were removed.

Figure EA-45 provides the additional studies' names, brief descriptions of the DSM level incorporated in the load forecast for each study, and a reference to further information on the load forecast located in the Load Forecast Section.

FIGURE EA-45
ADDITIONAL STUDIES OF DSM LEVELS

Case	DSM Level	Load Forecast Reference
IRP Preferred Plan	1.1 percent of retail sales	1.1 percent of weather-normalized sales
Proposed DSM case	0.7 percent of retail sales	Preferred DSM
Enhanced DSM case	Proposed DSM + 20 percent	Preferred DSM Plus 20
No DSM case	0 percent of retail sales	Before DSM Reductions
DSM Directive-5 case	less than Proposed DSM case	Lower DSM (Directive 5)

The Companies adjusted the L&R Table of the Preferred Plan to create the Proposed DSM, Enhanced DSM, and DSM Directive-5 cases because these cases required relatively minor adjustments to peak loads from the Preferred Plan. As mentioned previously, for the No DSM case, the Companies created a new expansion plan in PLEXOS LT using the appropriate load forecast and all the same assumptions from the Base Case.

The load forecasts for these cases are described in the Load Forecast Section. The L&R tables and production cost summaries for the DSM studies are provided in Technical Appendix ECON-15. The CER analyses for the DSM studies are provided in Technical Appendices ECON-6 and ECON-15. The PWRR of these scenarios are provided in Figure EA-46.

FIGURE EA-46
PWRR OF DSM SCENARIOS

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Least Cost Case (million $)	26 Year PWRR Change from Least Cost Case (million $)	20 Year PWRR Rank Order	26 Year PWRR Rank Order
Preferred Plan	$ 32,931	$ 41,294	$ -	$ -	**1**	**1**
Proposed DSM	$ 33,632	$ 42,224	$ 701	$ 930	**3**	**3**
Enhanced DSM	$ 33,458	$ 41,994	$ 527	$ 700	**2**	**2**
DSM Directive 5	$ 33,784	$ 42,432	$ 853	$ 1,138	**4**	**4**
No DSM	$ 37,014	$ 46,457	$ 4,083	$ 5,163	**5**	**5**

An interpretation of the results, including the rate impact or revenue requirement impact, as applicable, can be found in the DSM Plan.

VALUE ASSOCIATED WITH GREENLINK NEVADA PROJECTS FOR BUNDLED RETAIL CUSTOMERS.

As detailed in the Transmission Section, there have been increases in the estimated total cost of the Greenlink Nevada ("Greenlink") transmission projects. The Companies maintain that, in the face of Sierra's growing loads, the Greenlink projects are necessary for continued joint system resource planning. The projects facilitate a reduced overall PRM requirement for NV Energy, systemwide access to the diverse renewable resources abundant in Nevada, and systemwide access to the benefits of WRAP and a future market or RTO.

The Companies created an illustrative case assuming Greenlink was not constructed. Together with the Preferred Plan, this illustrative case is intended to demonstrate a portion of the value associated with the Greenlink projects for bundled retail customers.

Without Greenlink, Sierra will have very limited access to market purchases, including market capacity. Nevada Power will not have the same limitation. That is, the removal of the Greenlink projects will have a more significant impact on planned resources for Sierra than for Nevada Power. As Sierra will become increasingly transmission constrained over time if Greenlink is not built, the analysis of this scenario focuses largely on changes that impact Sierra.

An illustrative case was developed to provide an approximation, using simplifying assumptions, of the Companies' PWRR in a scenario that serves the forecasted demand in this 2024 Joint IRP in the absence of Greenlink. This illustrative case is a simplification, as a complete analysis would require many months to perform and would necessitate additional consultant engagement.

The general process of the Greenlink illustrative evaluation, dubbed No Greenlink, follows.

1. NV Energy engaged E3 to perform a Loss of Load Probability ("LOLP") analysis specific to Sierra without Greenlink, identifying the extent to which the Greenlink projects impact the Companies' ability to deliver resources from throughout the joint system to loads in Sierra in the future as well as the appropriate PRM for Sierra in 2028 in a scenario in which resource planning is bifurcated between Sierra and Nevada Power due to Sierra's growing transmission-constrained loads. This PRM-only analysis is performed in a similar manner to the study performed systemwide to refresh the ELCC and PRM requirement for this 2024 Joint IRP (with Greenlink Nevada) using the same data inputs but with a specific geographic focus on Sierra, including the altered import constraints. The reserve requirement applied to Sierra included 50 percent of the largest single generating unit contingency in the northern system – the failure of a single GT at Tracy CC. Note that, if resource planning without Greenlink were required, further study would be needed to determine whether a larger portion of this largest single contingency should be applied. See Technical Appendix ECON-14 for discussion of the Sierra Subsystem Resource Adequacy Analysis ("Sierra Subsystem Analysis") including discussion of the limitations of the simplified application of this study. Results of the study indicate:

   > "Without the Greenlink Nevada projects, the simulation shows a risk of loss of load events of 2.6 days per year, a value much higher than NV Energy's planning standard for the system of 0.1 days per year. This implies that without the transmission upgrades, the south-to-north transmission limit could result in LOLE risk specific to Sierra even if the joint system is adequately planned to the 0.1 days per year standard."[10]

   And further estimates that

[10] Technical Appendix ECON-14, *Sierra Subsystem Resource Adequacy Analysis at* 6.

"[A]n 18% UCAP PRM requirement would be needed to meet a 0.1 days/yr standard in Sierra."[11]

2. The Companies performed an assessment of need, identifying capacity needs of a system in which Sierra becomes increasingly transmission constrained as its load grows. The Companies applied the PRM from the Sierra Subsystem Analysis to Sierra and retained the 2024 Joint IRP PRM for Nevada Power. As noted in the Sierra Subsystem Analysis, this likely understates the PRM requirement for Nevada Power in a scenario in which planning for the two systems is bifurcated, and thus understates the overall need. The ELCC values developed for the 2024 Joint IRP were used for both Companies in the absence of a full systemwide LOLP Study without Greenlink. It is noteworthy that the Sierra Subsystem Analysis identifies the risk that assessment of ELCC values for Sierra alone would tend to result in less value for the capacity contribution of BESS to Sierra compared to the joint system due to characteristics of Sierra's system. The Companies conservatively allowed the open positions for Sierra to be substantially similar to the Preferred Plan in this illustrative case. If resource planning without Greenlink were required, further study would be needed to determine whether Sierra's open positions should be reduced. Note that the renewable energy need is unaffected.

3. The Companies created a new PLEXOS LT analysis for the No Greenlink illustrative case using the base load forecast and the updated Sierra PRM. Most candidate resources were the same as those used in the 2024 Joint IRP economic analysis. Nevada wind was removed as a candidate resource under the assumption that Nevada wind resources would largely be located in eastern Nevada, which would require Greenlink for connection to load pockets in the state. Build limits on near term thermal units were relaxed to address the increased PRM for Sierra.

4. The PLEXOS LT expansion plan was created in a manner similar to that for the 2024 Joint IRP Base Case. More PV, BESS, and firm dispatchable placeholders were chosen to address Sierra's increased PRM and to replace the Nevada wind in the later years of the study period.

5. Proposed resources from the Preferred Plan were inserted to replace near-term expansion plan placeholders. The Libra PV/BESS project, planned to interconnect at the junction of Greenlink North and Greenlink West, was omitted as its size and timing could not be accommodated by Sierra customers, and the limited transmission between northern and southern Nevada in this scenario made delivery of energy to Nevada Power questionable. Adjustments were made to the remaining placeholders to allocate resources between Nevada Power and Sierra. These adjustments considered the capacity needs and RPS goals of the Companies while respecting the very limited transmission capability between them. Note that the Companies do not distinguish the performance of placeholder PV in northern Nevada versus southern Nevada in its resource planning.

[11] Ibid.

6. Named placeholders from the Preferred Plan were also inserted to replace No Greenlink expansion plan placeholders. Without the Greenlink North project, the 952 MW Idaho Wind cannot be delivered entirely to Sierra. This resource was split by allocating approximately 110 MW to Sierra and the remainder to Nevada Power. Without the Greenlink North project, the PSH resource allocation was also adjusted, with 380 MW to Sierra and the remainder to Nevada Power. The L&R table for the No Greenlink case is included in Technical Appendix ECON-16.

7. Sierra's import capability modeled in this No Greenlink case was modified to reflect no increase associated with Greenlink. An updated area diagram for this case is provided in Technical Appendix ECON-16. The production cost summaries from the PLEXOS analysis are also provided in Technical Appendix ECON-16. The CER analysis for this illustrative case is provided in Technical Appendices ECON-6 and ECON-16.

8. In the IRP Preferred Plan, it is assumed that Greenlink will be available to interconnect some amount of placeholder resources to the load centers. Greenlink offers approximately 2,269 MW of available interconnections for renewables. Placeholders in excess of this amount will be built elsewhere in the state, likely requiring incremental transmission not yet studied (approximately the same in all plans). As described in the Transmission Section, if Greenlink is not constructed, assuming the same quantity of resources would be interconnected in the identified Renewable Resource Zones along Greenlink, the construction of three alternate transmission lines would be required. It was generously assumed the construction of these three alternate transmission lines could be completed in the same timeframes as the Greenlink projects to ensure the timely interconnection of future resources. One of the required lines would run from Amargosa to Nevada Power, connecting approximately 1,200 MW of renewable/storage resources. Another line would run from Esmeralda to Sierra to connect approximately 600 MW of resources, while a third line would run from Lander to Sierra, also connecting approximately 600 MW of resources. Radial lines to connect resources to Sierra's load must each be limited to 600 MW of resources to maintain the largest single source of transmission contingency at 600 MW for the northern system. Additional information on this reliability requirement is provided in the Transmission Section. While the No Greenlink case includes substantial incremental nameplate capacity relative to the Preferred Plan, no incremental transmission costs were applied to access these resources. Instead, the conservative assumption was made that incremental resources could be strategically located to minimize incremental transmission requirements.

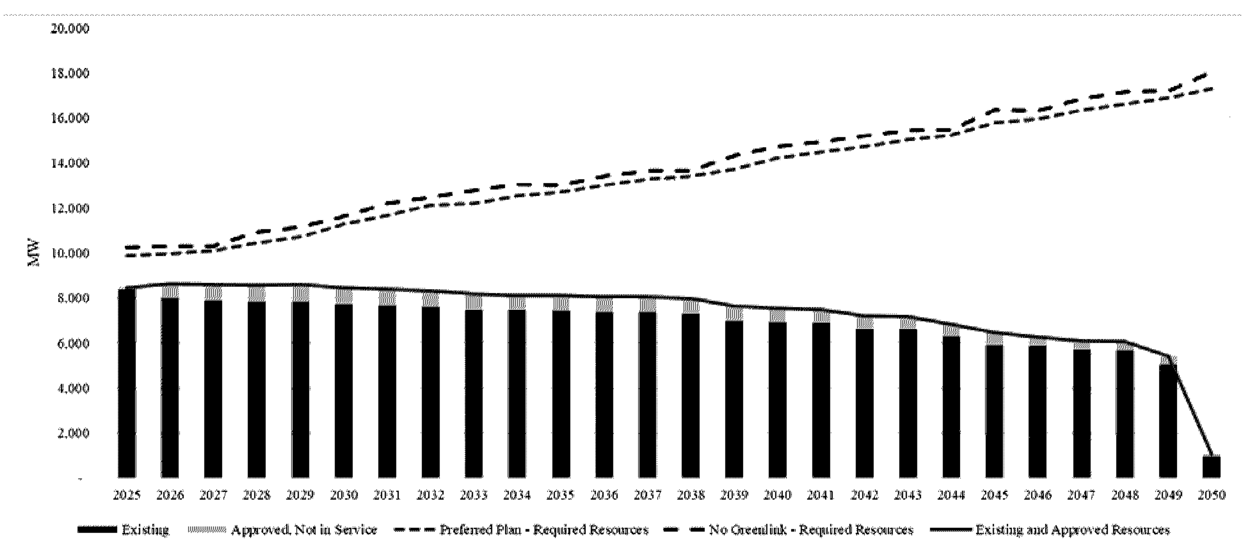
9. The No Greenlink CER excludes the cost of Greenlink West and Greenlink North but includes costs for the following three transmission segments to connect the same amount of resources to the load centers in the absence of Greenlink: Amargosa to NPC ($683.2M), Esmeralda to

SPPC ($674.4M), and Lander to SPPC ($900.4M). The Greenlink Common Ties ($731.2M) connecting Fort Churchill/Walker River to the northern load center exist in both the Preferred Plan and the No Greenlink Case CERs as these common ties are required in both scenarios. Information on these transmission segments can be found in the Transmission Section of the narrative.

No Greenlink Case Discussion:

Figure EA-47 illustrates the Companies' capacity position in the No Greenlink illustrative case given the assumptions described previously. As in Figure EA-4 in the Assessment of Need Subsection, Figure EA-47 shows the system capacity requirements (loads plus *adjusted* PRM and reserves for OATT customers), existing resources (owned resources and those under contract and in service), and resources approved but not yet in service. Thermal units are shown at their peak capacities derated for their annual average forced outage rate, while renewable units have been adjusted for their ELCC in the No Greenlink case. This is consistent with the conventions used to develop the Preferred Plan as described previously. The required resources for the Preferred Plan are included in the figure for comparison to the increased No Greenlink required resources.

FIGURE EA-47
NV ENERGY CAPACITY POSITION – NO GREENLINK



Figures EA-48 through EA-50 provide the Companies' open positions in the No Greenlink illustrative case, as well as a comparison with the Preferred Plan open positions. The open positions of Nevada Power and Sierra were built to match the open positions of the Preferred Plan as closely as reasonably possible for a consistent comparison. It is possible that, if the Companies were performing full planning for a future without Greenlink, rather than creating a simplification in the form of an illustrative case, that additional resources would be added to Sierra that would reduce the open position in light of the rapid load growth forecasted against the backdrop of the 600 MW import constraint.

FIGURE EA-48
NV ENERGY OPEN POSITION – NO GREENLINK

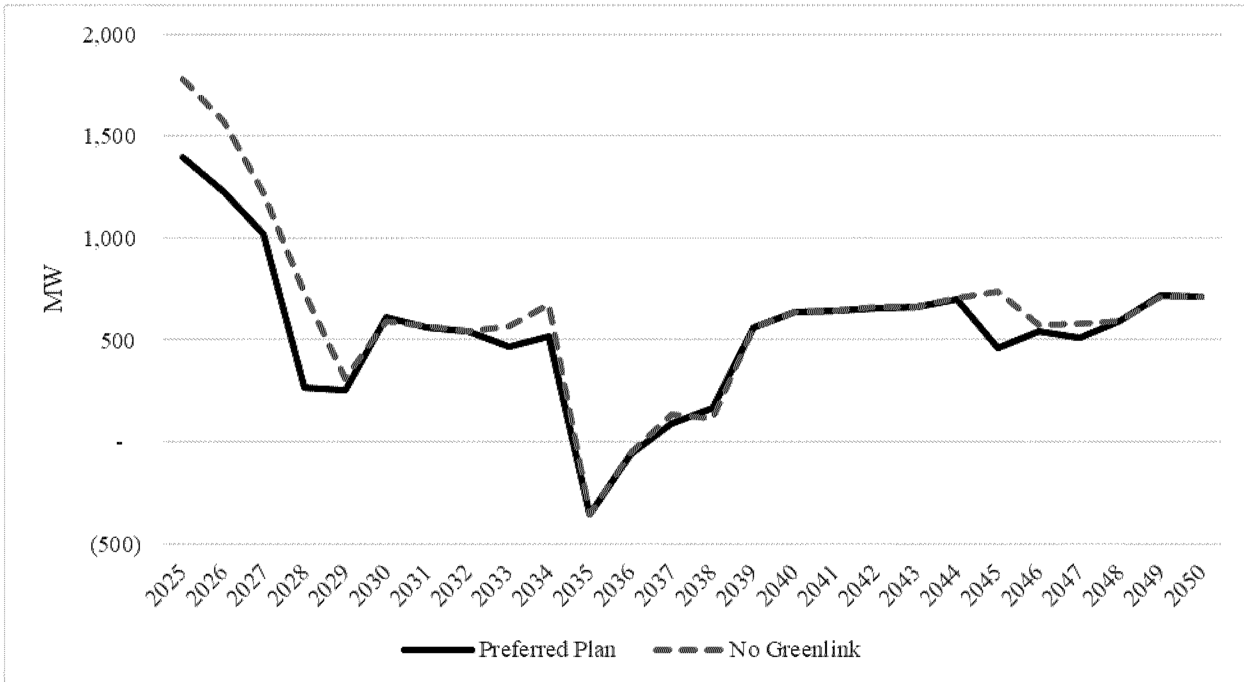


FIGURE EA-49
NEVADA POWER OPEN POSITION – NO GREENLINK

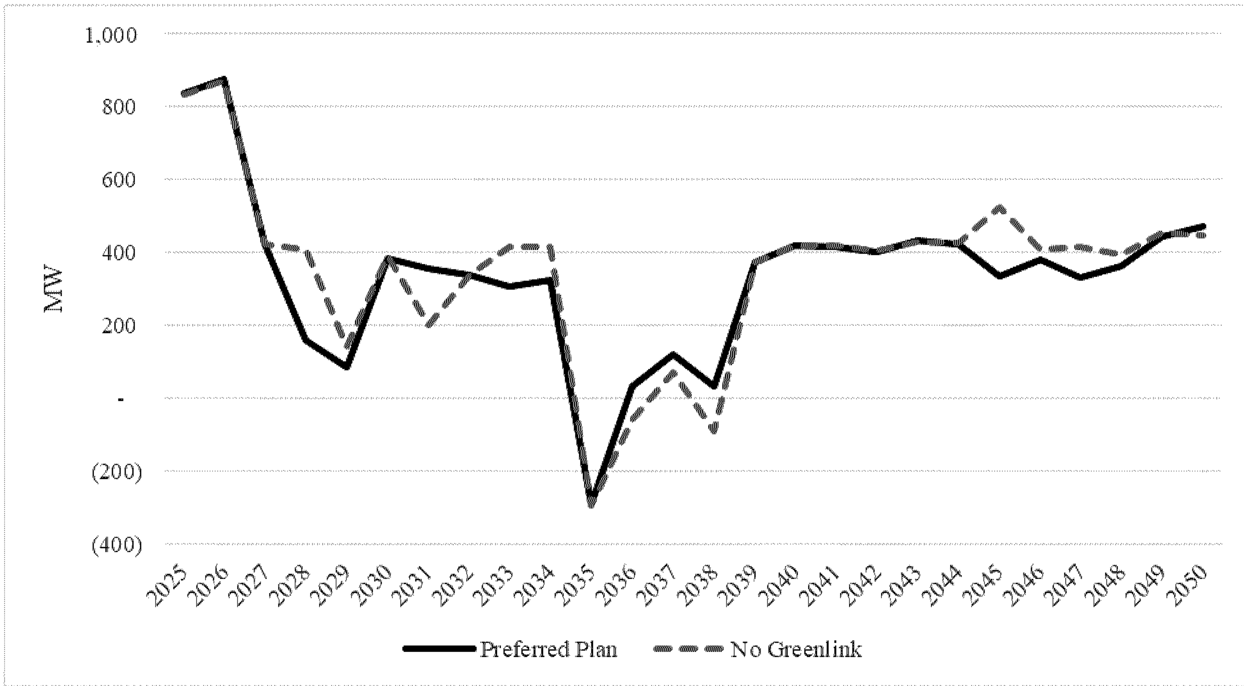


FIGURE EA-50
SIERRA OPEN POSITION – NO GREENLINK

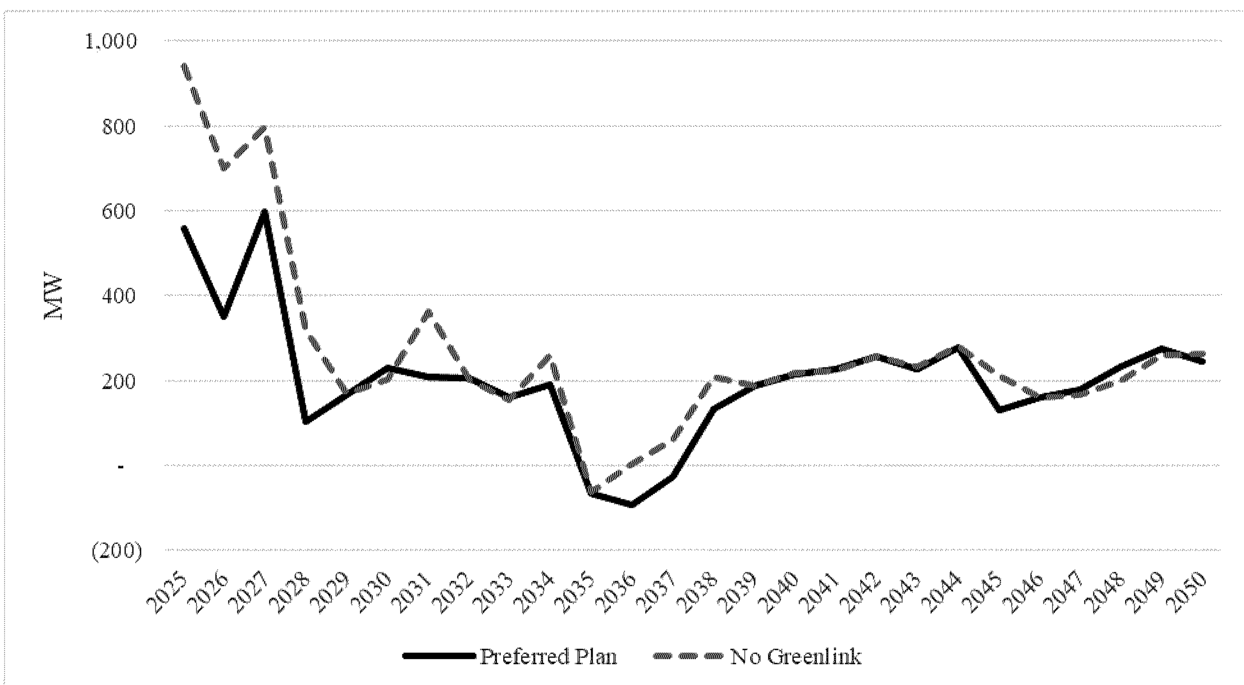


Figure EA-51 provides the difference in installed capacity by resource type between the No Greenlink case and the Preferred Plan.

FIGURE EA-51
INSTALLED CAPACITY DIFFERENCE
NO GREENLINK MINUS PREFERRED PLAN

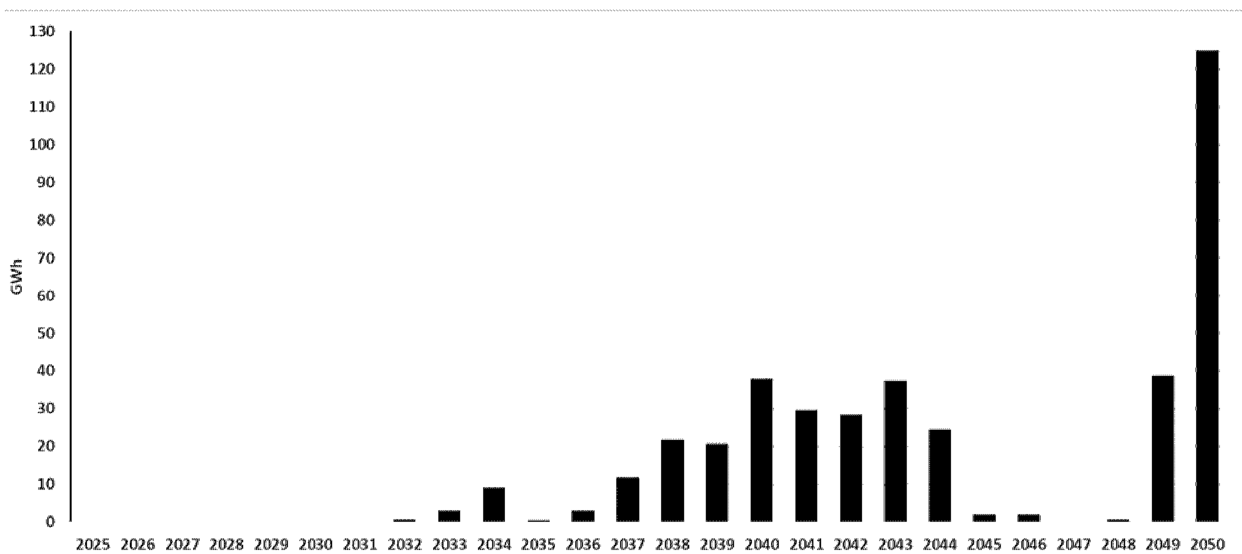
	PV	BESS	WIND(ID)	WIND(NV)	PSH	FIRM	GEO
2025	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	-	-	-	-	411	-
2030	(5)	(2)	-	-	-	-	-
2031	(20)	257	-	-	-	-	-
2032	964	96	-	(817)	-	-	-
2033	196	421	-	(326)	-	-	-
2034	471	(37)	-	(277)	-	-	-
2035	(143)	-	-	-	-	-	-
2036	269	350	-	(224)	-	-	-
2037	798	-	-	(716)	-	-	-
2038	1,464	-	-	(1,121)	-	-	-
2039	(238)	1,275	-	(519)	-	-	-
2040	389	(212)	-	-	-	-	-
2041	(395)	(210)	-	-	-	-	-
2042	159	8	-	-	-	-	-
2043	548	(232)	-	-	-	-	-
2044	(496)	(733)	-	-	-	-	145
2045	(1,779)	3,121	-	-	-	(210)	709
2046	(509)	1,001	-	-	-	-	-
2047	(114)	1,871	-	-	-	-	-
2048	730	(900)	-	-	-	210	(334)
2049	2,118	277	-	-	-	-	(764)
2050	(158)	703	-	-	-	420	-
Total	4,249	7,054	-	(4,000)	-	831	(244)

The No Greenlink illustrative case results in approximately 7,900 MW more installed capacity over the study period than the Preferred Plan. This increase in installed capacity is driven by the increased PRM in Sierra and the limited ability to transfer energy from system to system. In such a scenario, resources would need to be located closer to their respective load pocket due to the limited ability to share resource output between Sierra and Nevada Power.

In addition, due to the larger PRM for Sierra in this case and the fact that the Libra PV/BESS project is an inappropriate fit for the system without Greenlink, this illustrative case is reliant on substantial amounts of near-term placeholder resources as early as 2028. In the very near term, this plan replaces Libra PV/BESS, a known and viable project, with two regional placeholder resources with the same 2028 in-service year as Libra: 250 MW PV paired with 250 MW BESS in Sierra's territory and 450 MW PV paired with 450 MW BESS in Nevada Power's territory. In addition, an incremental set of northern CTs are needed in 2029 that are not in the Preferred Plan. Without Greenlink, the need for more resources located closer to each respective load pocket is clear.

The No Greenlink Illustrative case is observed to have significant unserved energy beginning in the early 2030s and generally growing over the years, as shown in Figure EA-52. This is likely due to the use of ELCC values developed for the 2024 Joint IRP in the absence of a full systemwide LOLP Study without Greenlink, as described previously. These ELCC values credit too much capacity to northern resources, especially BESS, in Sierra's smaller system, as discussed in the Sierra Subsystem Analysis. The unserved energy can be observed to diminish somewhat when large amounts of diverse renewable resources (geothermal) are added in 2045.

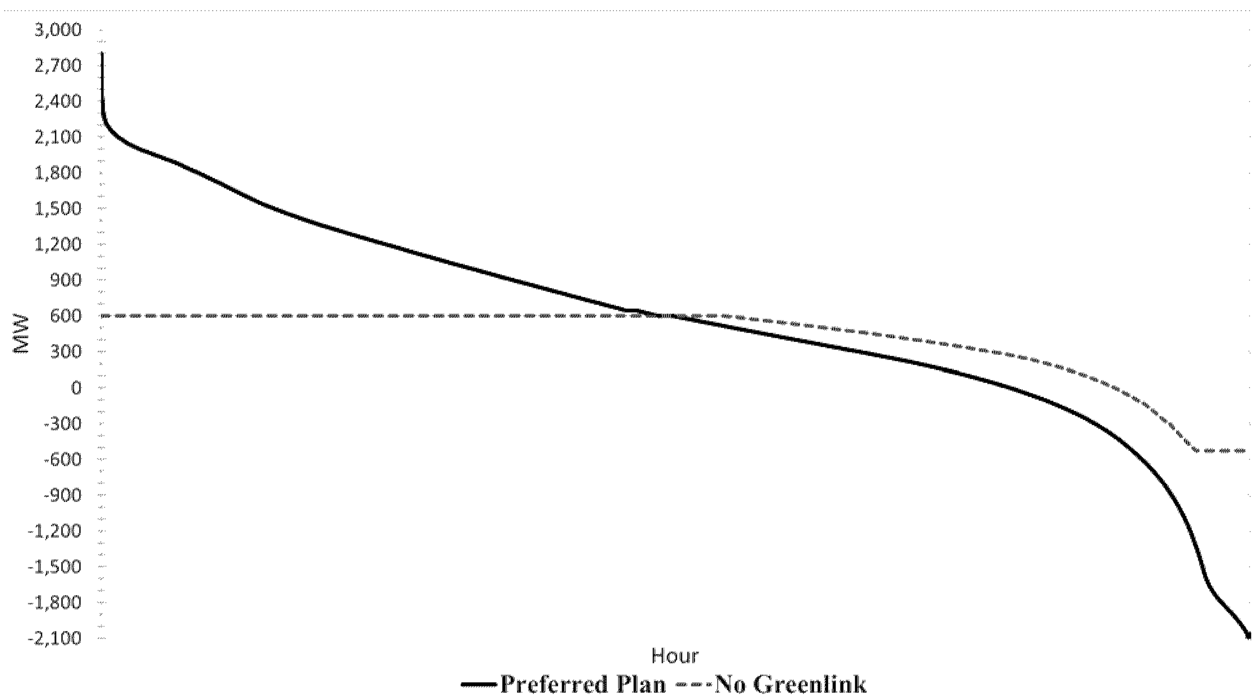
FIGURE EA-52
NO GREENLINK CASE UNSERVED ENERGY BY YEAR (GWH)



As evidenced by the unserved energy in this illustrative case, the simplifications applied in this case result in understatement of Sierra's reliability needs. As stated previously, this case was developed to provide an *approximation* of PWRR without Greenlink, as a complete analysis would require many months to perform and would necessitate additional consultant engagement. Such an analysis would be expected to result in identification of a requirement for significant additional capacity resources for Sierra relative to the No Greenlink illustrative case presented here.

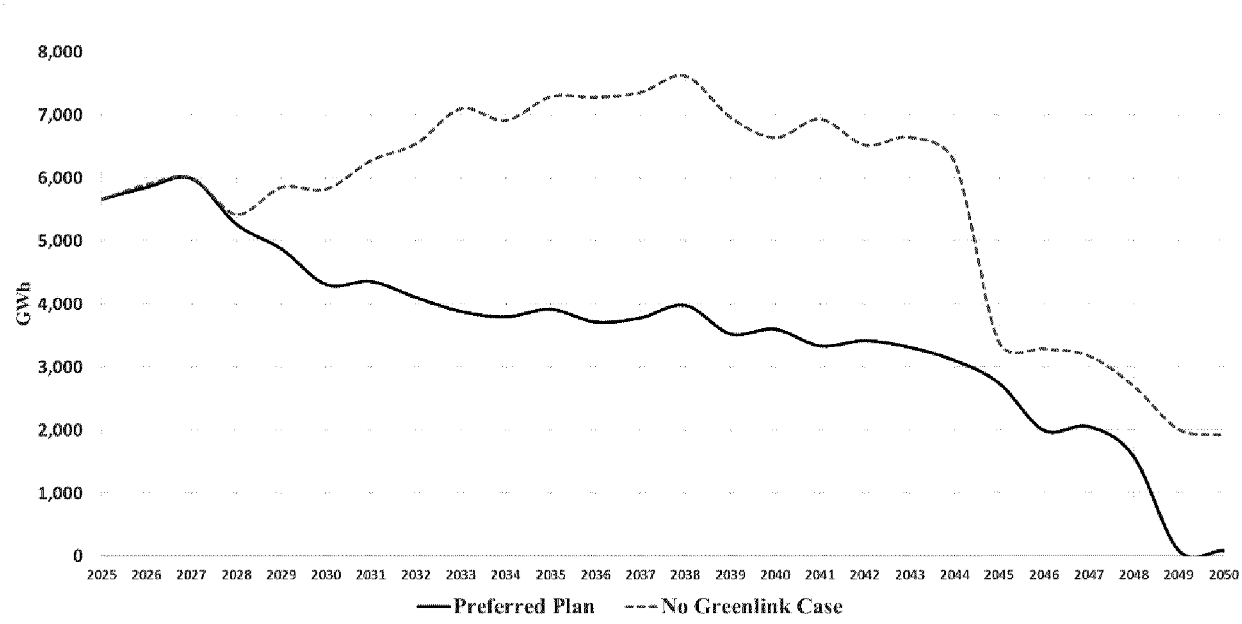
Figure EA-53 presents a flow duration curve of Sierra's imports in which the horizontal axis indicates all hours in the 26-year study period and the vertical axis indicates Sierra's hourly import flow. The hourly import data presented in this figure are sorted from maximum to minimum, left-to-right. As can be seen, without Greenlink, energy flows into Sierra are constrained (i.e., at their maximum) in substantially more hours over the study period, more than half of all hours, than in the Preferred Plan which only has one hour at maximum import. Also evident in Figure EA-53, Sierra has a wider range of import/export capability in the Preferred Plan, extending from 2,800 MW import and 2,119 MW export, while without Greenlink the range is only 600 MW import and 526 MW export.

FIGURE EA-53
SIERRA IMPORT HOURLY FLOW DURATION, 2025-2050



Due to Sierra's limited import capability in the face of growing loads, the No Greenlink case has substantially more thermal generation within Sierra than in the 2024 Joint IRP Preferred Plan, as evidenced in Figure EA-54.

FIGURE EA-54
SIERRA THERMAL GENERATION



Carbon dioxide emissions are higher overall in the No Greenlink case relative to the Preferred Plan. Figure EA-55 indicates that the increase in Sierra's emissions from the higher thermal unit operation more than offsets decreases in Nevada Power's emissions in the No Greenlink case, resulting in increased systemwide carbon dioxide emissions. Emissions from market purchases, included in the systemwide total and also presented separately, are largely unchanged between these cases. Figure EA-56 illustrates the increased emissions from Sierra and the decreased emissions from Nevada Power in the No Greenlink case. Sierra's thermal resources emit 32.6 million short tons more in the No Greenlink case, while Nevada Power's thermal resources emit 12.6 million fewer short tons in this case. This is consistent with Sierra's need to serve a growing load in the face of unchanging import constraints. Overall, the No Greenlink case has 18.5 million short tons more carbon dioxide emissions than the Preferred Plan over the study period.

FIGURE EA-55
NV ENERGY CARBON DIOXIDE EMISSIONS COMPARISON
NO GREENLINK CASE VERSUS PREFERRED PLAN

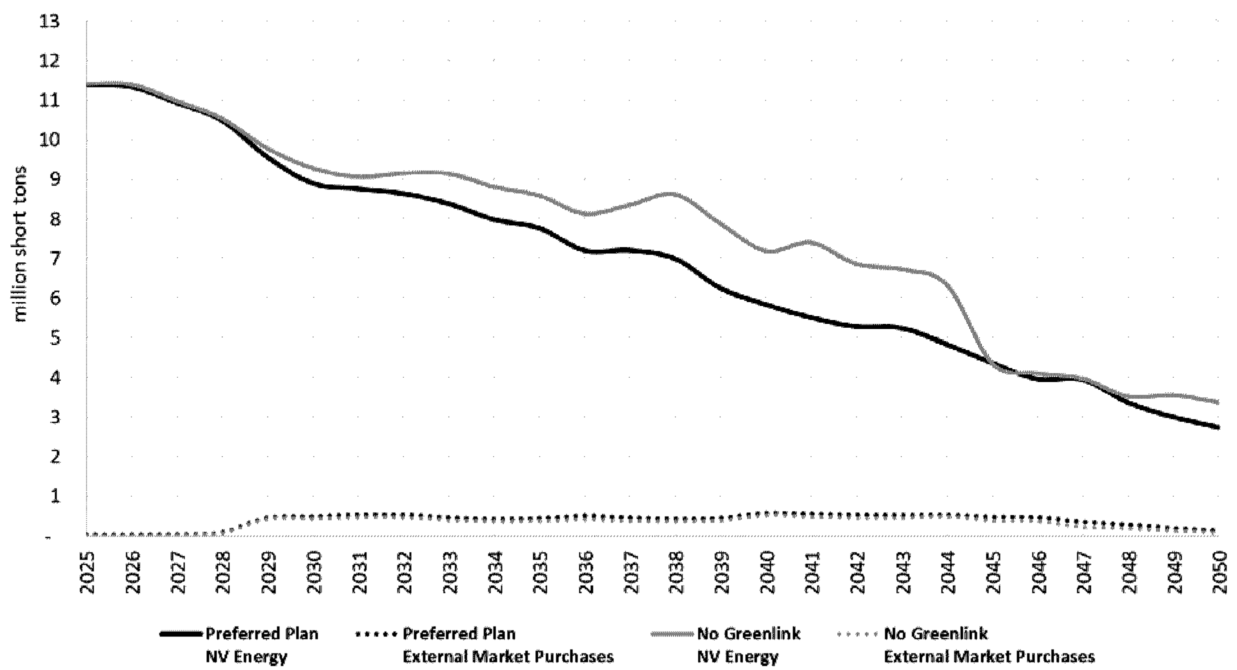
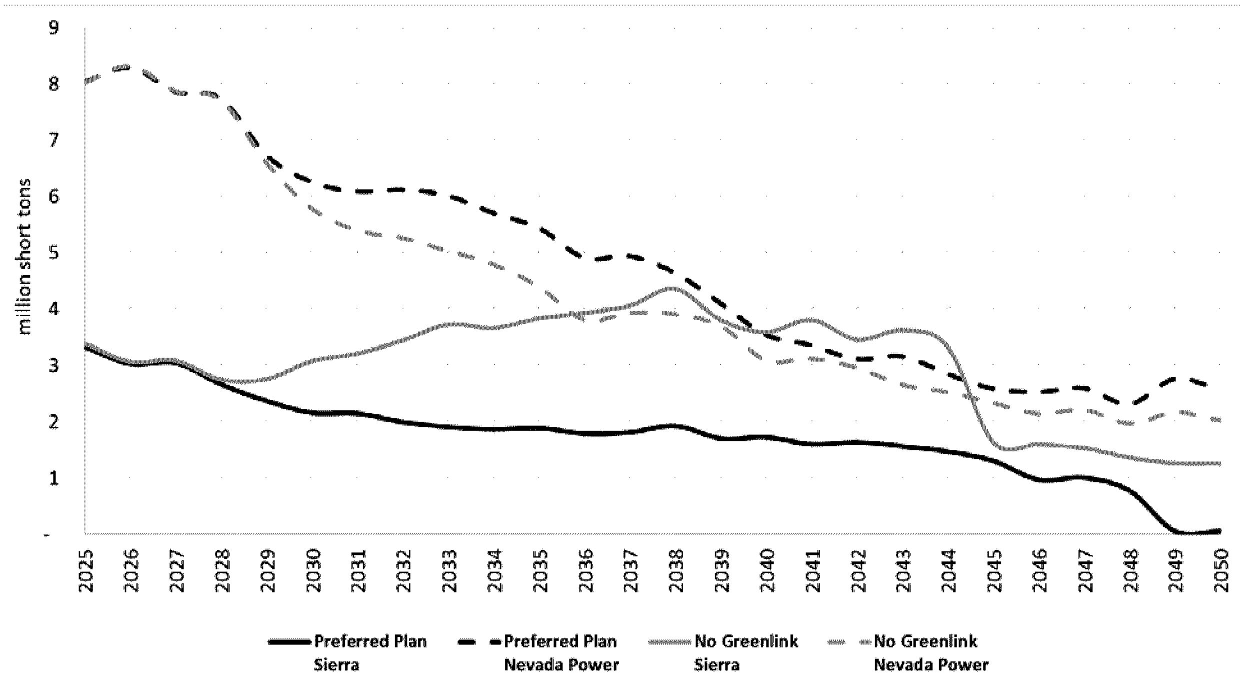


FIGURE EA-56
SIERRA AND NEVADA POWER CARBON DIOXIDE EMISSIONS COMPARISON
NO GREENLINK CASE VERSUS PREFERRED PLAN



A summary of the production cost of the No Greenlink illustrative case, as well as the CER, are included in Technical Appendix ECON-16. Figure EA-57 presents a comparison of the PWRR of the No Greenlink illustrative case to the Preferred Plan.

FIGURE EA-57
NV ENERGY PWRR COMPARISON
PREFERRED PLAN VERSUS NO GREENLINK CASE

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Least Cost Case (million $)	26 Year PWRR Change from Least Cost Case (million $)	20 Year PWRR Rank Order	26 Year PWRR Rank Order
Preferred Plan	$ 32,931	$ 41,294	$ -	$ -	**1**	**1**
No Greenlink	$ 33,042	$ 42,126	$ 111	$ 831	**2**	**2**

Overall, the No Greenlink illustrative case has increased production costs and decreased capital costs compared to the Preferred Plan, resulting in nearly equal (slightly higher) costs over the 20-year horizon. The No Greenlink illustrative case's 26-year PWRR, however, is approximately $830 million higher than the 26-year PWRR of the Preferred Plan.

From this analysis, it can be observed that the scenario without Greenlink, while resulting in a similar PWRR in the 20-year view, understates the reliability needs for Sierra. For Sierra's customers to experience the same reliability to which they are accustomed, still more resources would be required within Sierra's system than those added in this illustrative case.

Irrespective of the underbuilt Sierra subsystem in this case, the cost benefit of Greenlink to bundled retail customers appears over the long term. In the 26-year view, the beneficial impact of improved integration between the northern and southern systems on joint dispatch is evident in the lower PWRR of the Preferred Plan, driven by lower production costs. It is important to note that, as a long-lived transmission project, Greenlink will continue to provide benefits well past the 26-year study period at minimal cost.

The Sierra Subsystem Analysis discusses the reliability benefits of a more integrated joint system as created by Greenlink. Further observations about the benefits of improved transmission interconnection, such as those provided by Greenlink, that are not fully captured in the illustrative economic analysis presented previously follow.

- *Uncertainty and Extreme Events*. Without Greenlink, the Sierra system is significantly more import-constrained, which limits its ability to adapt when extreme weather events or other system disturbances occur. One benefit of regional interconnections is the potential to receive support from neighboring systems that are not experiencing the same events. For example, if a northern Nevada winter storm severely limits the output or results in the outage of multiple northern resources, Sierra's ability to access southern Nevada resources via transmission can mitigate the effects of forced outages and derates associated with such weather events.

- *System Diversity.* Some of the greatest benefits of a well-connected transmission system result from system diversity. Customer demand in different regions materializes at different times, as illustrated in the differences between coincident and non-coincident peak loads between Sierra and Nevada Power. Also, renewable resources can perform differently in different regions. For example, solar resource performance is generally better in southern Nevada while traditional geothermal resources are much more plentiful in northern Nevada. Similarly, higher performing wind resources exist in Idaho and Wyoming. Improved interconnection allows full access to a more diverse fleet of resources while allowing the resources to be located where they perform best.

- *Access to External Markets and Resource Adequacy Programs.* Improved interconnection to external markets unlocks more of the benefits associated with those markets. If a system is import-constrained, such as Sierra without Greenlink, it has limited ability to buy energy when needed. Significant import constraints limit the benefits of a resource adequacy program which allows for the pooling of resources for reliability. If a system cannot access outside resources during its time of need, it is not experiencing the full benefit of being part of a larger insurance pool of resources.

Significantly, at slightly *higher* cost over the next 20 years than the Preferred Plan, the No Greenlink illustrative case *underperforms* on Sierra's reliability needs and also forgoes the opportunities and benefits Greenlink provides beyond the direct benefits to bundled retail customers estimated here. Opportunities and benefits of the improved transmission interconnection provided by Greenlink are presented in the Transmission Section.

K. Long-Term Avoided Costs

Per NAC § 704.9492, the Companies have computed long-term avoided costs ("LTAC") based on the Preferred Plan for purposes of determining LTAC rates. Under Nevada's implementation of the Public Utility Regulatory Policies Act ("PURPA"), the Companies' LTACs are calculated based on the mix of resources approved by the Commission through the integrated resource planning process. LTAC rates calculated based on the Companies approved IRP are to be offered to qualifying facilities ("QFs") for blocks of capacity approved in the IRP. Estimates of LTACs are first filed in the utility's IRP, based on the utility's Preferred Plan. Here, the Companies have calculated estimated LTAC using the method outlined below.

Uncapped Long-Term Avoided Costs:

1. Determine the hourly marginal energy costs from the Preferred Plan.
2. Using the forecasted capacity cost described in the Fuel and Purchased Power Price Forecast Section, convert the forecasted capacity cost from $/kW-yr. to $/MWh based on a 7x16 hours on-peak period for the months of June, July, August, and September.
3. Add the converted capacity costs in $/MWh to the marginal energy costs for the 16 peak hours for every day of appropriate months.
4. Average all of the hours in the month to determine the average monthly Long-Term Avoided Cost for each month of each year.

Figures EA-57 and EA-58 show the average monthly uncapped long-term avoided costs for each company.

FIGURE EA-57
SIERRA LONG-TERM AVOIDED COSTS
($/MWH)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2025	$ 69.61	$ 48.25	$ 28.68	$ 21.23	$ 22.50	$ 55.82	$ 84.69	$ 79.35	$ 68.83	$ 28.79	$ 37.25	$ 53.71
2026	$ 52.31	$ 47.00	$ 31.18	$ 26.27	$ 25.65	$ 56.92	$ 125.25	$ 82.67	$ 66.47	$ 40.43	$ 40.36	$ 53.55
2027	$ 49.42	$ 47.89	$ 41.48	$ 25.52	$ 25.84	$ 53.26	$ 71.00	$ 72.99	$ 61.80	$ 30.98	$ 37.95	$ 42.24
2028	$ 41.40	$ 39.30	$ 33.68	$ 25.26	$ 29.45	$ 53.78	$ 61.95	$ 62.83	$ 58.57	$ 29.60	$ 35.51	$ 37.46
2029	$ 36.94	$ 33.72	$ 27.94	$ 24.15	$ 26.46	$ 56.22	$ 60.63	$ 60.78	$ 56.76	$ 29.26	$ 33.99	$ 35.22
2030	$ 35.40	$ 32.39	$ 24.48	$ 19.25	$ 19.99	$ 56.25	$ 63.74	$ 62.90	$ 60.15	$ 28.38	$ 33.50	$ 35.94
2031	$ 33.52	$ 29.79	$ 22.06	$ 18.38	$ 27.61	$ 56.36	$ 65.54	$ 63.12	$ 60.40	$ 27.61	$ 33.76	$ 36.47
2032	$ 35.02	$ 28.76	$ 22.09	$ 19.20	$ 20.30	$ 60.05	$ 67.67	$ 66.73	$ 64.37	$ 28.97	$ 34.44	$ 36.70
2033	$ 35.55	$ 31.25	$ 22.39	$ 20.07	$ 35.38	$ 57.83	$ 67.31	$ 68.39	$ 65.81	$ 29.40	$ 35.17	$ 38.63
2034	$ 35.08	$ 30.40	$ 21.39	$ 18.79	$ 19.28	$ 59.49	$ 68.21	$ 68.92	$ 65.65	$ 28.14	$ 34.96	$ 39.58
2035	$ 36.85	$ 32.40	$ 21.67	$ 27.37	$ 20.67	$ 68.04	$ 74.30	$ 69.36	$ 67.66	$ 30.95	$ 36.70	$ 40.21
2036	$ 42.12	$ 35.00	$ 23.25	$ 20.43	$ 21.05	$ 61.41	$ 75.69	$ 69.89	$ 67.53	$ 31.67	$ 37.48	$ 42.96
2037	$ 44.54	$ 35.66	$ 24.28	$ 19.51	$ 21.57	$ 62.26	$ 83.55	$ 71.87	$ 71.11	$ 33.35	$ 39.74	$ 43.83
2038	$ 46.22	$ 37.59	$ 24.93	$ 17.13	$ 21.99	$ 72.11	$ 79.12	$ 74.17	$ 72.73	$ 34.40	$ 41.58	$ 45.74
2039	$ 47.69	$ 37.73	$ 21.94	$ 13.24	$ 16.78	$ 64.23	$ 74.00	$ 75.10	$ 72.80	$ 35.36	$ 42.26	$ 47.79
2040	$ 50.25	$ 41.31	$ 21.32	$ 9.83	$ 13.66	$ 65.84	$ 75.47	$ 76.32	$ 74.90	$ 38.41	$ 44.82	$ 50.26
2041	$ 52.93	$ 42.96	$ 22.32	$ 9.27	$ 12.23	$ 65.28	$ 76.84	$ 79.04	$ 75.51	$ 37.59	$ 48.27	$ 55.36
2042	$ 55.56	$ 44.30	$ 19.48	$ 8.67	$ 13.26	$ 64.52	$ 77.39	$ 79.00	$ 77.05	$ 39.04	$ 48.58	$ 56.07
2043	$ 59.45	$ 46.77	$ 19.36	$ 8.26	$ 9.93	$ 67.61	$ 88.87	$ 82.01	$ 82.47	$ 42.75	$ 53.24	$ 61.31
2044	$ 63.21	$ 46.85	$ 22.51	$ 8.92	$ 9.85	$ 65.67	$ 83.65	$ 84.50	$ 82.79	$ 43.95	$ 56.50	$ 65.37
2045	$ 66.91	$ 51.21	$ 21.09	$ 6.97	$ 9.66	$ 66.59	$ 85.82	$ 84.35	$ 84.09	$ 46.05	$ 58.61	$ 67.61
2046	$ 68.31	$ 51.90	$ 19.41	$ 6.87	$ 7.94	$ 64.69	$ 83.33	$ 82.53	$ 84.69	$ 43.86	$ 59.43	$ 70.96
2047	$ 71.98	$ 52.07	$ 25.40	$ 8.39	$ 9.72	$ 64.64	$ 94.98	$ 82.16	$ 83.90	$ 45.81	$ 61.26	$ 74.16
2048	$ 70.98	$ 48.99	$ 18.78	$ 8.91	$ 7.89	$ 59.78	$ 79.83	$ 83.66	$ 84.18	$ 45.23	$ 62.96	$ 74.21
2049	$ 75.76	$ 46.56	$ 3.29	$ 2.30	$ 5.25	$ 60.28	$ 84.74	$ 90.47	$ 89.90	$ 48.69	$ 67.36	$ 80.33
2050	$ 73.09	$ 42.00	$ 4.83	$ 0.89	$ 2.78	$ 58.43	$ 87.39	$ 91.42	$ 89.82	$ 47.64	$ 65.40	$ 86.42

FIGURE EA-58
NEVADA POWER LONG-TERM AVOIDED COSTS
($/MWH)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2025	$ 50.94	$ 47.39	$ 26.62	$ 20.91	$ 22.22	$ 55.92	$ 84.79	$ 77.75	$ 68.55	$ 28.33	$ 36.37	$ 52.25
2026	$ 50.24	$ 46.42	$ 30.30	$ 25.74	$ 25.23	$ 56.30	$ 84.94	$ 83.11	$ 66.78	$ 30.71	$ 38.27	$ 50.50
2027	$ 48.22	$ 46.09	$ 39.07	$ 25.10	$ 25.60	$ 53.45	$ 71.29	$ 73.24	$ 61.65	$ 28.64	$ 37.19	$ 39.72
2028	$ 40.00	$ 38.05	$ 30.56	$ 23.03	$ 24.71	$ 53.26	$ 61.35	$ 61.94	$ 57.39	$ 27.54	$ 32.20	$ 35.53
2029	$ 36.35	$ 32.05	$ 26.75	$ 23.31	$ 25.61	$ 55.63	$ 60.07	$ 60.17	$ 55.80	$ 27.96	$ 32.17	$ 33.58
2030	$ 35.26	$ 31.27	$ 24.04	$ 19.21	$ 19.86	$ 55.97	$ 63.30	$ 62.44	$ 59.52	$ 27.66	$ 31.98	$ 34.60
2031	$ 33.30	$ 29.39	$ 22.06	$ 18.37	$ 27.53	$ 56.16	$ 65.16	$ 62.71	$ 59.87	$ 26.86	$ 32.38	$ 35.20
2032	$ 34.65	$ 27.83	$ 22.09	$ 19.17	$ 20.24	$ 60.10	$ 67.71	$ 66.70	$ 63.98	$ 28.21	$ 33.33	$ 35.96
2033	$ 35.31	$ 30.93	$ 22.39	$ 20.07	$ 35.37	$ 57.84	$ 67.20	$ 68.23	$ 65.47	$ 28.84	$ 33.86	$ 37.20
2034	$ 34.96	$ 30.15	$ 21.40	$ 18.79	$ 19.28	$ 59.51	$ 68.20	$ 68.87	$ 65.42	$ 27.69	$ 33.72	$ 37.88
2035	$ 36.62	$ 31.65	$ 21.67	$ 27.35	$ 20.62	$ 68.23	$ 74.55	$ 69.54	$ 67.46	$ 30.06	$ 35.18	$ 39.05
2036	$ 41.44	$ 34.03	$ 23.23	$ 20.42	$ 21.05	$ 61.55	$ 75.91	$ 70.07	$ 67.42	$ 30.82	$ 35.38	$ 41.59
2037	$ 43.64	$ 34.57	$ 24.14	$ 19.51	$ 21.57	$ 62.46	$ 83.78	$ 72.01	$ 70.91	$ 32.14	$ 37.55	$ 42.63
2038	$ 45.51	$ 36.52	$ 24.88	$ 17.12	$ 21.98	$ 72.25	$ 79.26	$ 74.24	$ 72.42	$ 33.41	$ 39.85	$ 44.34
2039	$ 46.65	$ 36.56	$ 21.93	$ 13.24	$ 16.77	$ 64.27	$ 74.01	$ 75.02	$ 72.50	$ 34.18	$ 40.15	$ 45.89
2040	$ 49.19	$ 40.04	$ 21.32	$ 9.82	$ 13.66	$ 66.09	$ 75.55	$ 76.30	$ 74.53	$ 37.11	$ 42.67	$ 47.95
2041	$ 51.87	$ 41.49	$ 22.32	$ 9.27	$ 12.23	$ 65.37	$ 76.89	$ 79.08	$ 75.27	$ 36.13	$ 45.85	$ 53.08
2042	$ 54.40	$ 42.96	$ 19.45	$ 8.67	$ 13.26	$ 64.65	$ 77.52	$ 79.09	$ 76.80	$ 37.62	$ 46.34	$ 53.88
2043	$ 57.81	$ 45.14	$ 19.35	$ 8.26	$ 9.93	$ 67.68	$ 88.85	$ 81.77	$ 81.81	$ 40.36	$ 50.42	$ 58.48
2044	$ 61.61	$ 45.20	$ 22.52	$ 8.92	$ 9.85	$ 65.77	$ 83.86	$ 84.54	$ 82.46	$ 42.24	$ 53.71	$ 62.93
2045	$ 65.38	$ 49.62	$ 21.09	$ 6.97	$ 9.66	$ 66.66	$ 86.05	$ 84.46	$ 83.92	$ 44.52	$ 55.77	$ 65.18
2046	$ 67.33	$ 50.93	$ 19.41	$ 6.87	$ 7.94	$ 64.71	$ 83.76	$ 82.87	$ 84.87	$ 43.11	$ 57.46	$ 69.05
2047	$ 70.33	$ 50.66	$ 25.40	$ 8.39	$ 9.72	$ 65.45	$ 91.89	$ 85.43	$ 84.70	$ 44.82	$ 58.26	$ 72.03
2048	$ 69.07	$ 47.74	$ 18.78	$ 8.91	$ 7.89	$ 59.99	$ 81.61	$ 84.21	$ 84.76	$ 44.69	$ 59.59	$ 70.82
2049	$ 74.24	$ 45.48	$ 3.29	$ 2.30	$ 5.25	$ 61.30	$ 87.34	$ 91.40	$ 89.74	$ 47.53	$ 64.04	$ 76.65
2050	$ 71.75	$ 40.83	$ 4.83	$ 0.89	$ 2.78	$ 58.43	$ 87.51	$ 92.20	$ 89.75	$ 46.61	$ 62.55	$ 79.47

The average monthly marginal costs for the Preferred Plan are provided in Technical Appendix ECON-11. During the June-September period, the capacity charge included in the market price forecast was added to the on peak hourly marginal energy cost to determine the LTAC.

Limits on Availability of Long-Term Avoided Cost Rate. The Companies propose that the LTAC rates be limited to a maximum of 76 MW at Nevada Power and 100 MW at Sierra of QF contracts and no more than a 25-year term.

Nevada Power's average peak load growth in the Action Plan period of 2025 through 2027, is estimated to be 76 MW per year. It is proposed that the qualifying facility tranche size for Nevada Power be set at this average annual Action Plan peak load growth rate of 76 MW.

Sierra's average peak load growth in the Action Plan period of 2025 through 2027, is projected to be 100 MW per year. Note that Sierra's forecasted peak load growth from 2025 to 2026 — approximately 20 MW – is impacted by the scheduled termination of the energy supply agreement with Liberty Utilities (CalPeco Electric) LLC ("Liberty"). Notwithstanding the loss of Liberty's load and resources in 2025, Sierra's proposed QF tranche size is proposed to be set at the average annual Action Plan peak load growth rate of 100 MW.

Methodology to Derive Avoided Cost Payments. NAC § 704.9492 requires that in its triennial IRP filing, the utility must propose a methodology and calculate and file LTAC and preliminary LTAC rates that reflect the utility's Preferred Plan. These calculations are set forth above and form the basis of a preliminary administratively determined LTAC and LTAC rates.

Under NAC § 704.9496, the Commission must specifically address in its IRP order the utility's proposed estimated rates for LTAC, including the methodology and limits to be used going forward. Next, the regulation requires that within 60 days of the final determination in the utility's IRP, the utility must recalculate and refile LTAC that reflect the plan of action ultimately adopted by the Commission.[12] Unless otherwise ordered by the Commission in its final determination regarding the utility's IRP, the recalculated rates reflecting LTAC also will reflect the same terms and be in the same format as the estimated rates originally filed by the utility in its IRP.[13]

The process contemplates that the recalculated, administratively determined estimate of LTAC and LTAC rates, along with the limits proposed by the utility, may be disputed. NAC § 704.9496(4) provides that "if required," within 90 days of the filing of the recalculated estimated LTAC and LTAC rates, the Commission will hold a hearing to approve the administratively determined LTAC rates and the limits of capacity or energy or both that should be made available to be filled by QFs at the utility's LTAC. The Commission has 45 days after the hearing on the administratively determined estimate of LTAC and LTAC rates to issue an order on the matter. To distinguish this order from the order in the IRP, this order will be referred to below as the "Subsection 4" order.

Within 30 days of the issuance of the Subsection 4 order, the utility must solicit proposals to provide the utility capacity or energy or both, consistent with the Commission-approved methodology for estimating long-term avoided costs.[14] Within 90 days of issuing this solicitation, the utility must file a report with the Commission summarizing the results of the solicitation.[15]

Finally, NAC § 704.9496(7) provides that the utility's LTAC rate for each block of capacity authorized to be filled by QFs is the lower of the administratively determined estimate of the utility's LTAC and LTAC rate, or the competitive rate solicited.

[12] NAC § 704.9496(2)
[13] NAC §704.9496(3)
[14] NAC § 704.9496(5)
[15] NAC § 704.9496(6)

SECTION 4. FINANCIAL PLAN

A. Introduction

The following section summarizes the results of the analysis of financial impacts of the Preferred and Alternate Plans presented in this IRP. The Financial Plan for both Nevada Power and Sierra spans a 20-year period (2025-2044) and analyzes these scenarios from the perspective of customers and the Companies using several financial metrics as mandated by NAC § 704.9401(1). Also included in the Financial Plan, for both utilities, are descriptions of the financial forecasting assumptions and common methodologies used to prepare the Financial Plan. Further, pursuant to NRS 704.741 (as amended by Assembly Bill 524 (2023)), the Companies are providing the customer rate impact of the Preferred Plan, Alternate Plan, and the two other alternative plans as part of this Financial Plan. The Companies have taken a fresh review of the customer rate impact analysis by utilizing the capital expense recovery ("CER") model to calculate the incremental customer rate impact analysis for more than the just the base tariff general rates ("BTGR"); the model also brings in the impact of the base tariff energy rates ("BTER") to have a more holistic view of the rates on our customers.

B. Capital Expenditures

The capital expenditures and cash flow analysis prepared for the Financial Plan utilize the CER model (described in the Economic Analysis section above) for the Preferred and Alternate Plans. Figure FP-1 below compares Nevada Power's total capital expenditures (including AFUDC) for the two Plans on a yearly basis over the planning period. Capital expenditures for the 20-year period, 2025-2044, are estimated to total $26.7 billion for the Preferred Plan and $27.0 billion for the Alternate Plan at Nevada Power. For Sierra, capital requirements shown in Figure FP-2 are estimated to total $18.5 billion for the Preferred Plan and $18.0 billion for the Alternate Plan. Additional project details can be found in the Economic Analysis section.

For Nevada Power, the total incremental capital expenditures requested in this filing occur in years 2025 through 2028 and are estimated to be $1.1 billion, in the Preferred and Alternate Plans. For Sierra, the total incremental capital expenditures requested in this filing occur in years 2025 through 2031 and are estimated to be $1.8 billion and $1.3 billion for the Preferred and Alternate Plans, respectively.

FIGURE FP-1
NEVADA POWER
CAPITAL EXPENDITURES ($ - MILLIONS)
(Including AFUDC)

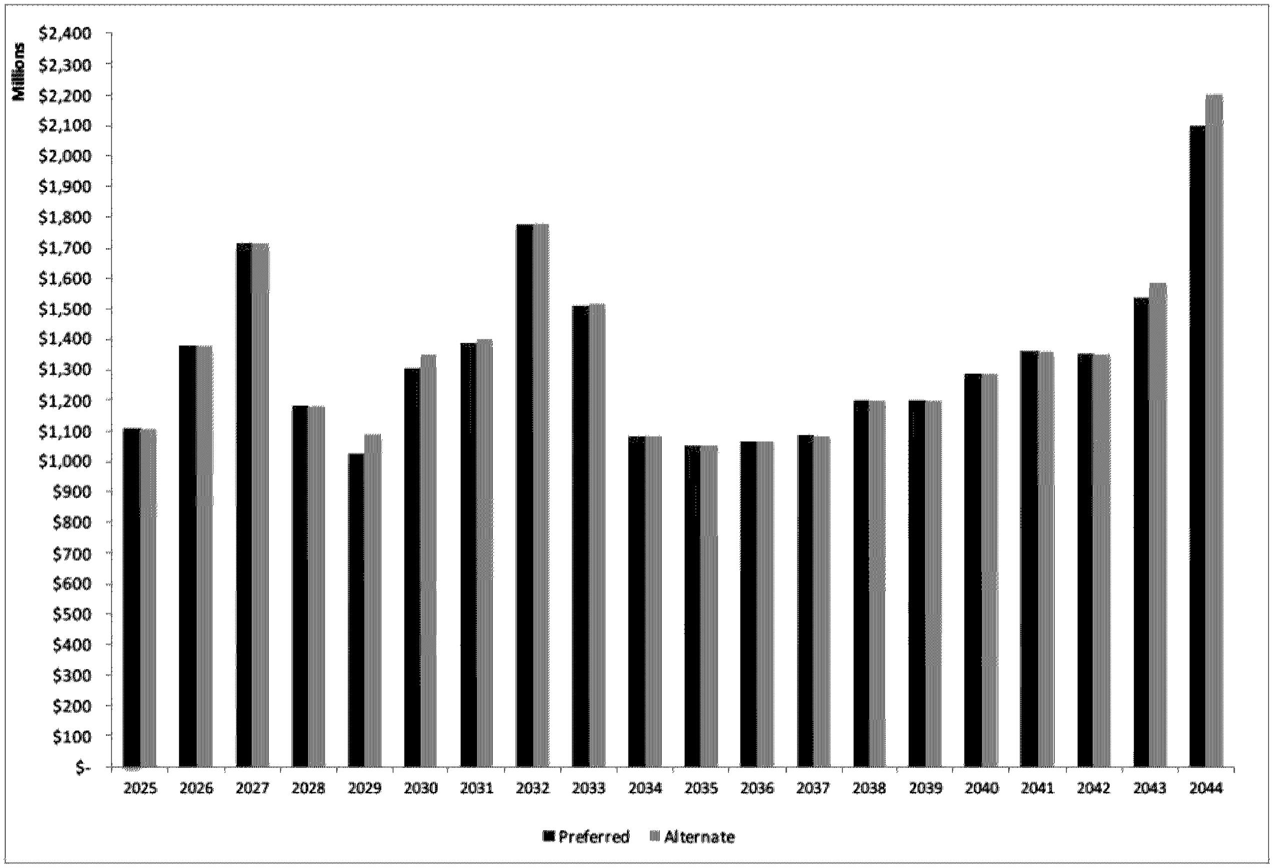
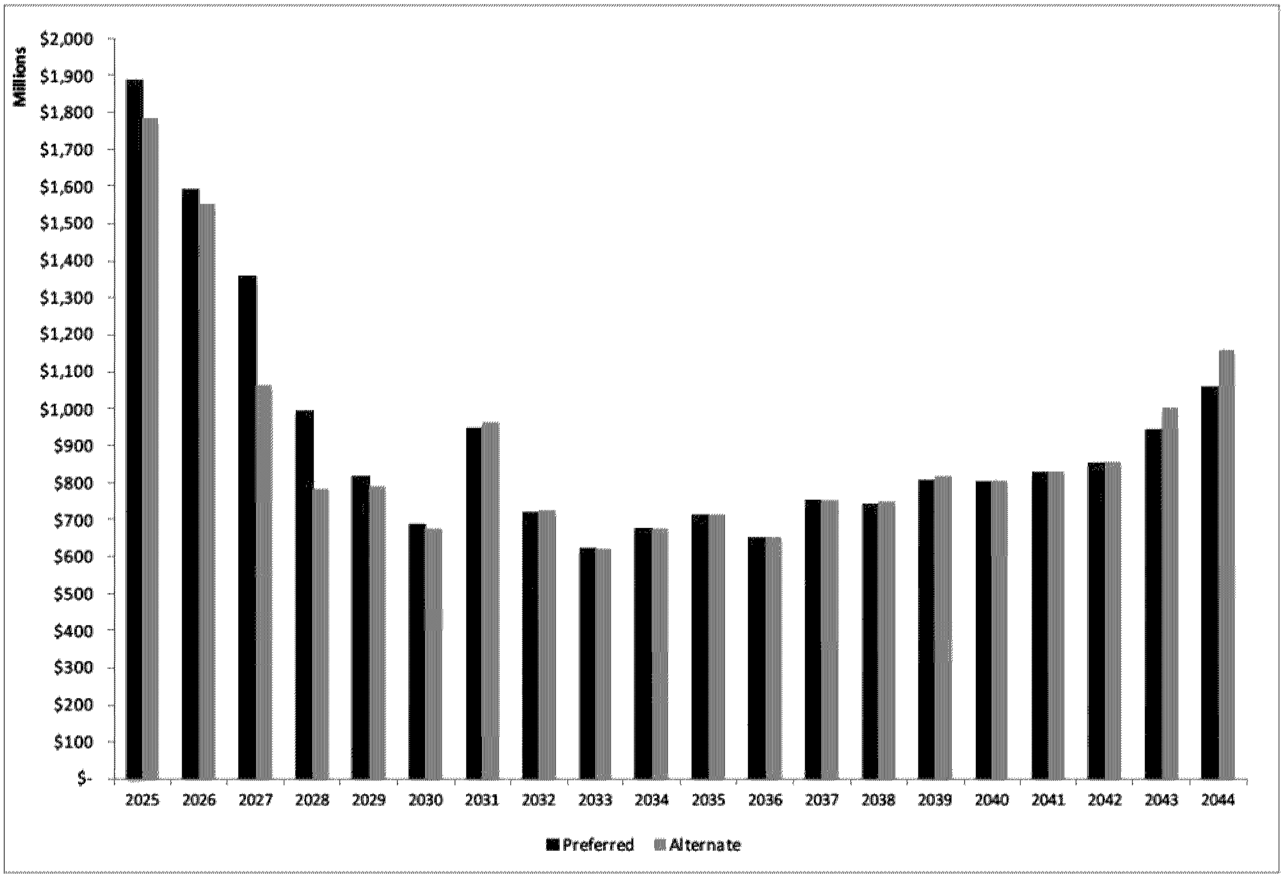


FIGURE FP-2
SIERRA
CAPITAL EXPENDITURES ($ - MILLIONS)
(Including AFUDC)



C. External Financing Requirements (REDACTED)

For the majority of the years during the 2025-2044 period, cash generated from operations at both utilities will be used to fund the capital project costs set forth in the CERs for each of the Preferred and Alternate Plans. Nevertheless, the Companies will have a continued need to access external short- and long-term financing to finance capital projects, working capital, refinance maturing debt, and maintain capital structures that are appropriate for their investment grade credit ratings. For Nevada Power, Figure FP-3 depicts annual total external debt requirements over the forecast horizon for the Preferred and Alternate Plans. External financing requirements for NPC, for the 20-year period are estimated to total [redacted] for the Preferred Plan and [redacted] for the Alternate Plans. For Sierra, external debt financing projections are shown in Figure FP-4 and are estimated to total [redacted] for the Preferred Plan and [redacted] for the Alternate Plan.

FIGURE FP-3
NEVADA POWER
SUMMARY OF EXTERNAL DEBT FINANCING ($ - MILLIONS)

[redacted]

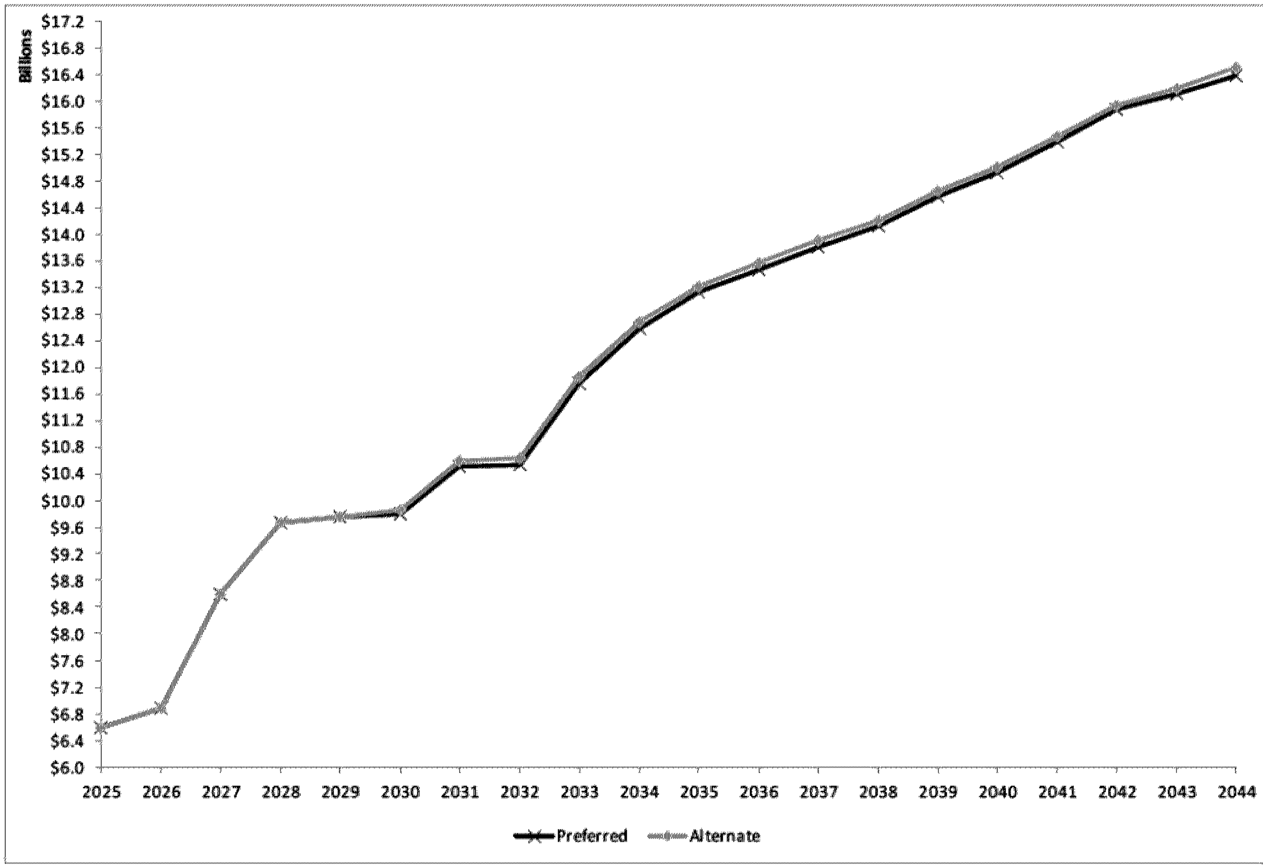
FIGURE FP-4
SIERRA – (REDACTED) SUMMARY OF EXTERNAL DEBT FINANCING
($ - MILLIONS)

[redacted]

D. Total Rate Base

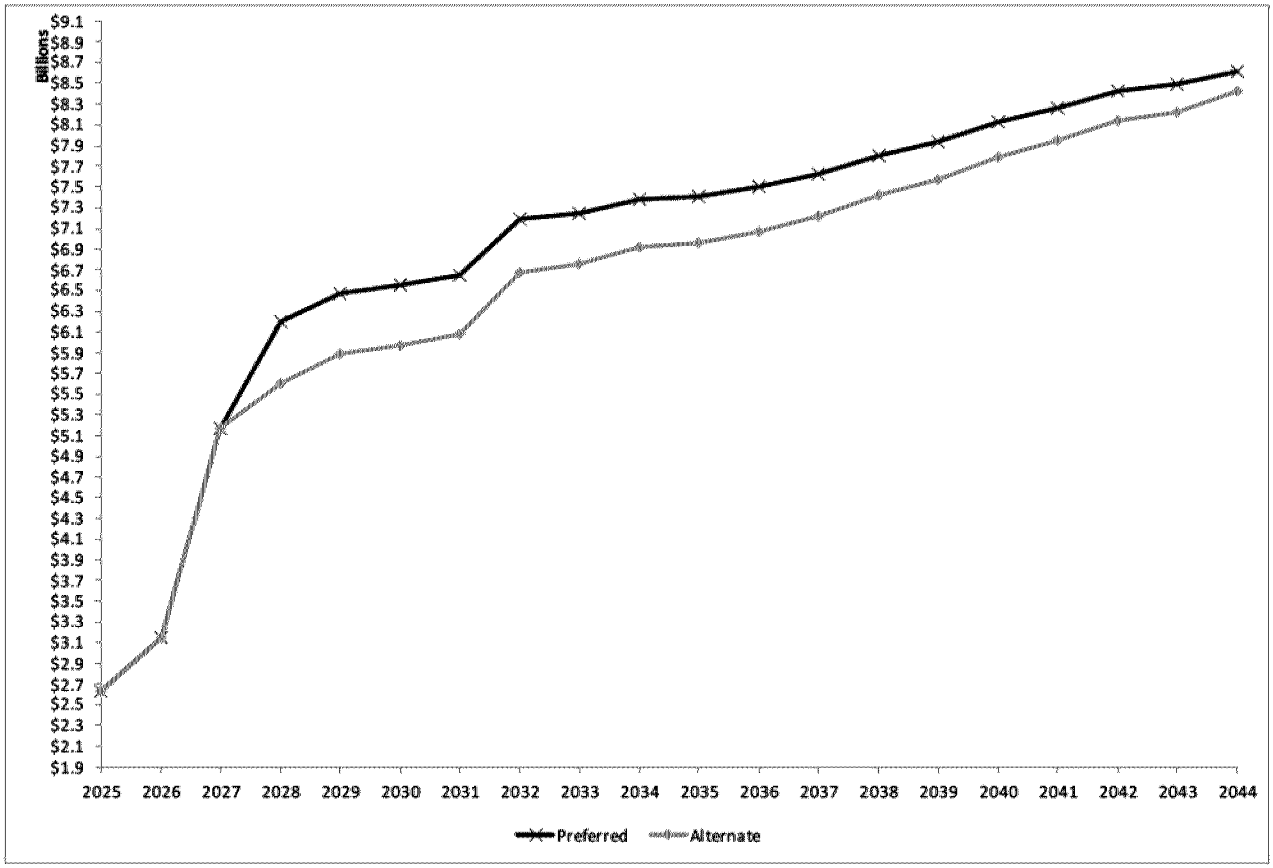
For Nevada Power, Figure FP-5 below compares total rate base per year over the planning period. Compound annual growth rates for rate base over the planning period total 4.9 percent for the Preferred and 5.0 percent for the Alternate Plan.

FIGURE FP-5
NEVADA POWER
ELECTRIC RATE BASE
($ - BILLIONS)



For Sierra, Figure FP-6 below compares total electric rate base per year over the 20-year planning period. Compound annual growth rates for rate base over the planning period total 6.4 percent for the Preferred Plan and 6.3 percent for the Alternate Plan.

FIGURE FP-6
SIERRA
ELECTRIC RATE BASE
($ - BILLIONS)

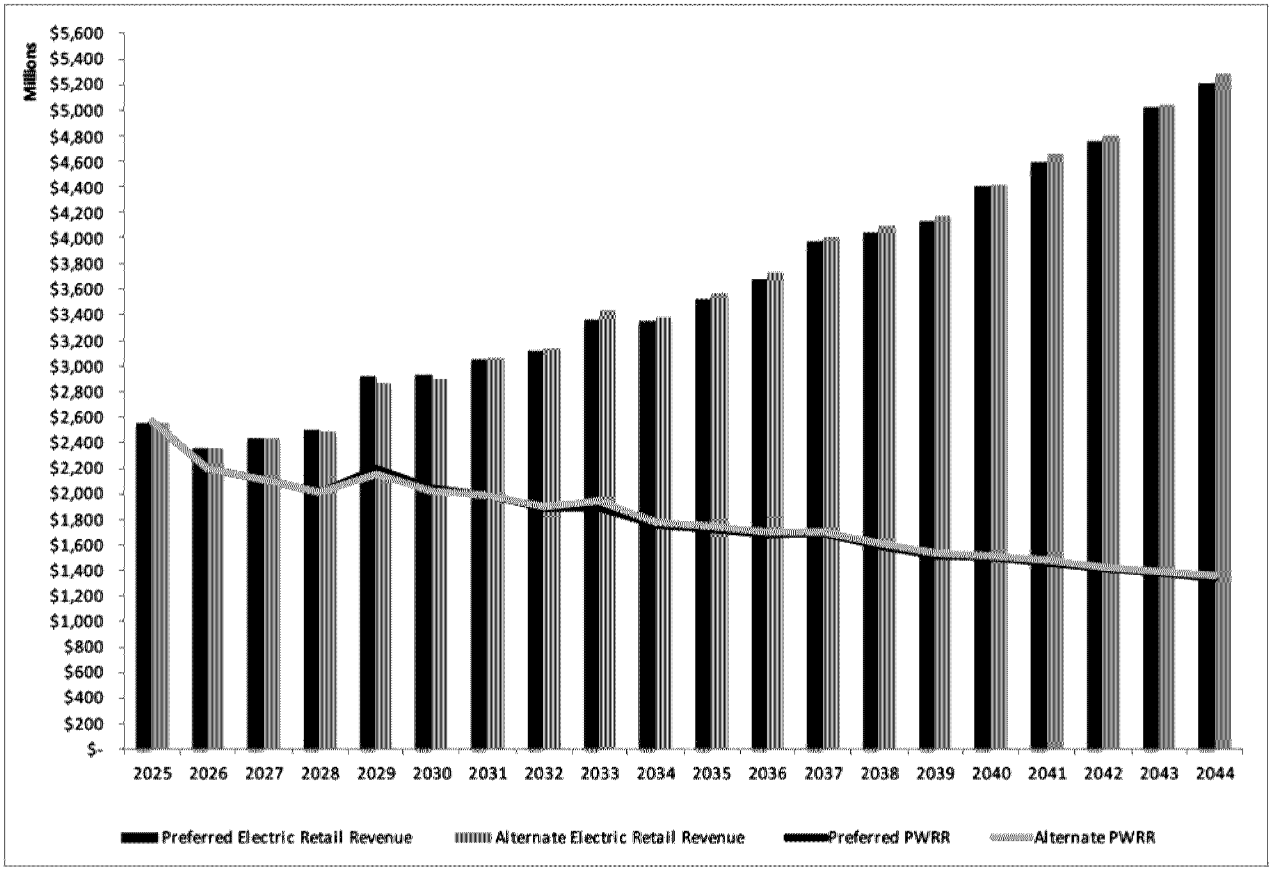


E. Electric Revenue

During the 20-year planning period, the Preferred and Alternate Plans for Nevada Power result in a compound annual growth rate in electric retail revenue (including fuel costs) of 3.8 percent (from approximately $2.6 billion to $5.2 billion). Figure FP-7 shows estimated annual total electric revenue (in nominal dollars) for Nevada Power for the planning period as well as its present worth.

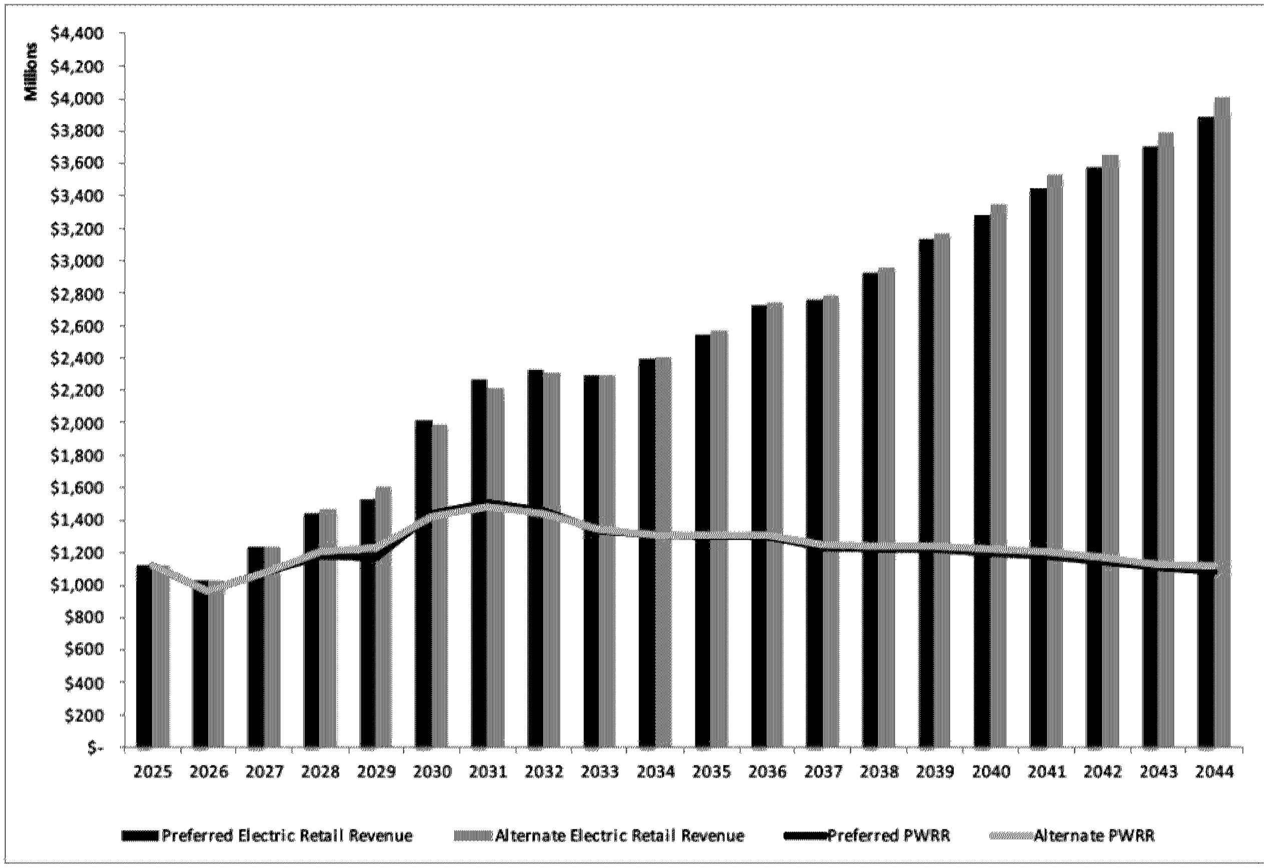
FIGURE FP-7

NEVADA POWER
TOTAL RETAIL ELECTRIC REVENUES AND PRESENT WORTH
($ - MILLIONS)



For Sierra, the Preferred and Alternate Plans result in a compound annual growth rate in electric retail revenue (including fuel costs) of 6.8 percent (from approximately $1.1 billion to $3.9 billion). Figure FP-8 shows estimated annual total electric revenue (in nominal dollars) for Sierra for the planning period as well as its present worth.

FIGURE FP-8
SIERRA
TOTAL RETAIL ELECTRIC REVENUES AND PRESENT WORTH
($ - MILLIONS)



F. Common Methodologies and Assumptions

The following section discusses the common methodologies and assumptions used in forecasting and evaluating the financial impact of the filing.

1. Common Methodologies

The financial analysis was performed using the Companies' financial forecasting model based on the Utilities International, Inc. ("UI") platform. The model uses many of the same inputs (e.g., capital expenditures or "CAPEX," AFUDC rate based at the Companies' current authorized rates of returns, production costs, depreciation rates and load forecast) from the CERs that are utilized in the Economic Analysis section described earlier. Additional inputs include pro-forma capital structures and capital costs. The UI platform simulates general rate review proceedings based on rate case timings that support major capital investments. The rate case timings used are summarized in the assumption section below.

2. Assumptions

Major financial modeling assumptions for Nevada Power and Sierra are described below. Unless noted, assumptions are the same for the entire planning period.

- Due to current system modeling limitations, Sierra's next general rate increase/decrease was modeled to go into effect January 1, 2025, even though the new rates are projected to be effective October 1, 2024.
- Nevada Power's next general rate increase/decrease will go into effect January 1, 2026.
- Rate case cycles occur at various frequencies scheduled to support major capital investments. The certification years for Nevada Power are 2025, 2028, 2030, 2032, 2034, 2036, 2038 2040, 2042 and 2044. The certification years for Sierra are 2024, 2026, 2027, 2029, 2031, 2033, 2035, 2037, 2039,2041and 2043.
- Inflation rate assumed over the forecast horizon was 2.3 percent.
- The AFUDC rate for new projects is set at the current approved marginal cost of capital 7.43 percent for Nevada Power and 6.95 percent for Sierra.
- For Nevada Power, the weighted average cost of capital of 7.43 percent was used as the discount rate and was based on the currently authorized 9.50 percent return on equity ("ROE"). For Sierra, the weighted average cost of capital of 6.95 percent was used as the discount rate and was based on the currently authorized 9.50 percent ROE.[1]
- The assumed marginal cost of new long-term debt ranges between 4.80 percent and 6.22 percent based on current pricing information.
- A 21 percent statutory federal income tax rate.
- Full recovery of all above-the-line costs incurred (including energy, operating and capital).

G. Financial Risks

This section discusses in more detail several financial matters which are important in assessing the Companies' Preferred and Alternate Plans.

1. External Financing Costs

Due to the ongoing need to access external capital, the Companies must continue to rely on access

[1] In general, we assumed a non-imputed equity ratio that would reset at each rate case with the exception that for Sierra, the financial modeling used approximately 55 percent equity ratio for 2024-2027.

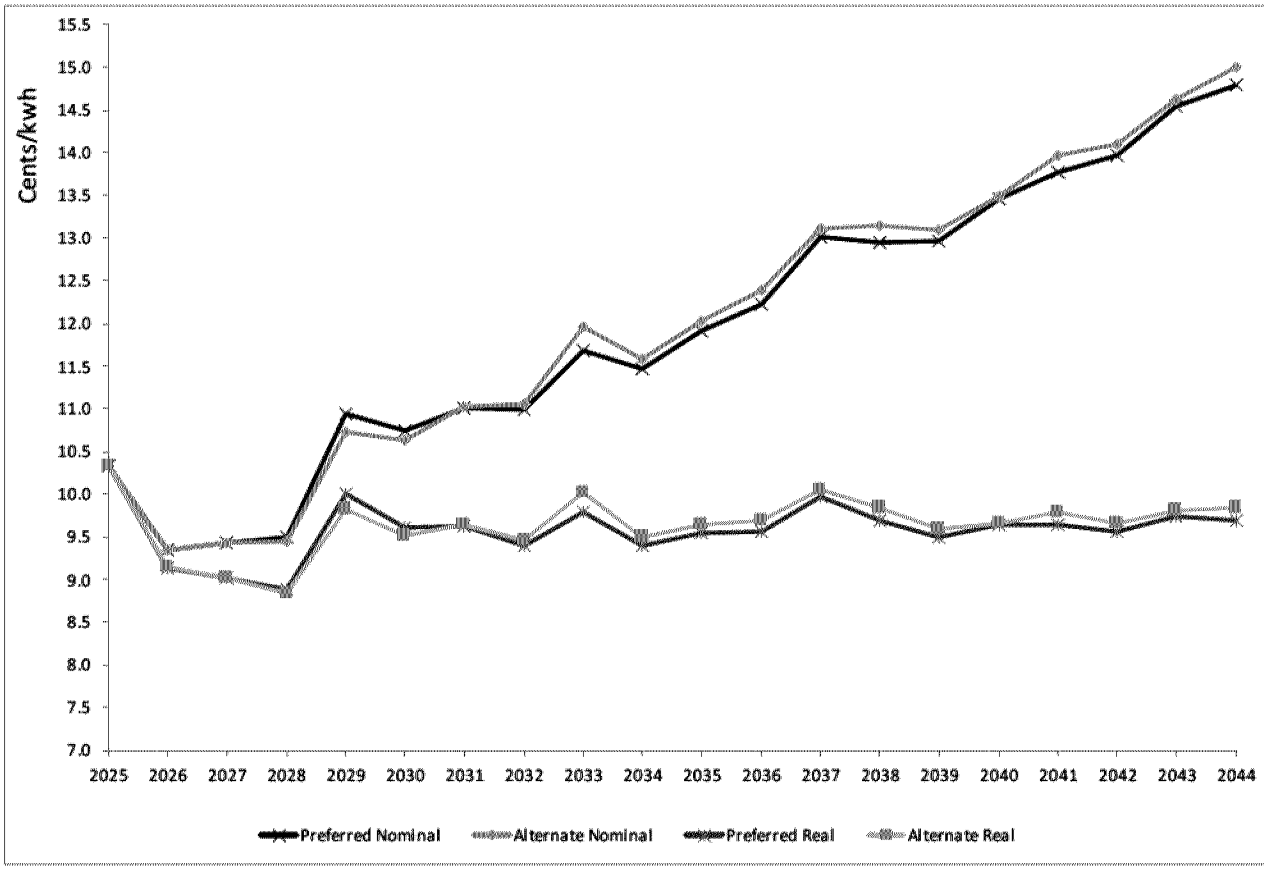
to the financial markets. Increasing volatility in, and over-reliance on, financial markets could lead to excessive financing costs for customers to fund future investments on their behalf.

2. Impact on Average System Cost

As shown in the Figure FP-9, the nominal average system cost per kWh for Nevada Power under the Preferred Plan increases from 10.33 cents in 2025 to 14.79 cents in 2044 and increases from 10.33 cents in 2025 to 15.01 cents in 2044 under the Alternate Plan. The compound annual growth rate for the nominal average system cost over the forecast period is 1.9 percent for the Preferred Plan and 2.0 percent for the Alternate Plan. Average system costs are projected to increase over the 20 years on a nominal basis, but, when inflation is reflected, then the average system costs are forecasted to stay fairly steady or slightly decrease on a real basis. The compound annual growth rate for real average system costs is (0.3) percent for the Preferred and Alternate Plans.

FIGURE FP-9

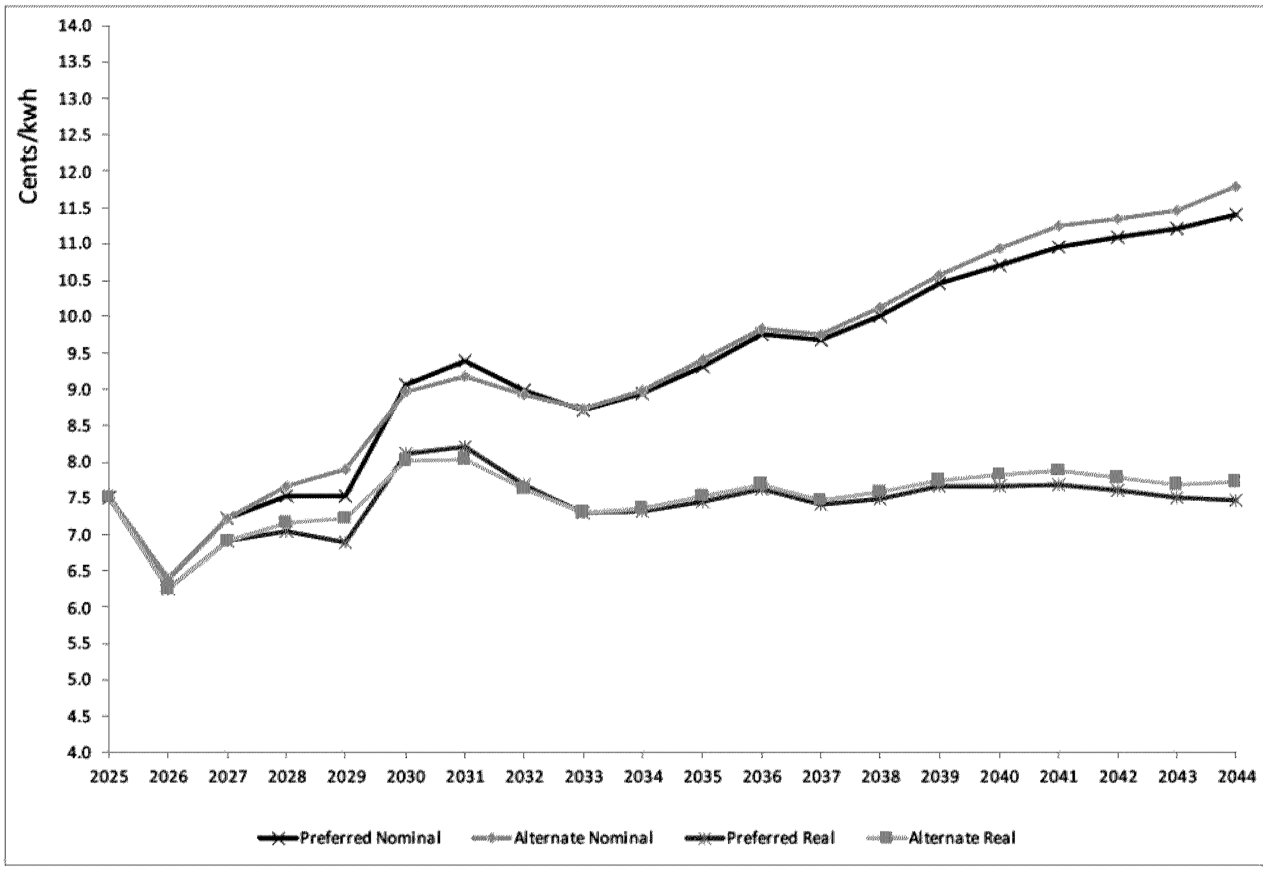
NEVADA POWER
NOMINAL & REAL AVERAGE SYSTEM COST (CENTS/KWH)



For Sierra, Figure FP-10 illustrates that the nominal average system cost per kWh is projected to increase over the 20 years from 7.51 cents in 2025 to 11.41 cents in 2044 under the Preferred Plan and from 7.51 cents in 2025 to 11.78 cents in 2044 under the Alternate Plan. The compound annual growth rate for the nominal average system cost over the forecast period is 2.2 percent for the Preferred Plan and 2.4 percent for the Alternate Plan. The real average system costs for Sierra have a compound annual growth rate of 0.0 percent for the Preferred Plan and 0.1 percent for the Alternate Plan.

FIGURE FP-10

SIERRA
NOMINAL & REAL AVERAGE SYSTEM COST (CENTS/KWH)



3. Credit Quality

The Companies' secured debt is rated investment grade by Moody's Investor Service and Standard & Poor's Global Ratings. The Companies have maintained adequate liquidity and demonstrated the ability to successfully access the debt markets at rates comparable to those experienced by similarly rated utilities. Annual projected credit metrics for Nevada Power are shown in Figures FP-11 through FP-14 and Sierra's are illustrated in Figures FP-15 through FP-18. The Companies' have primarily focused on credit metric calculations which align with the Moody's Investor Service calculation. The primary metric is Funds from Operations to Debt. To conform with Moody's calculations, adjustments are necessary to calculate the FFO/Debt metric accurately. Specifically, Funds from Operations is adjusted for items such as changes in working capital, capitalized interest, and changes in deferred energy balances. The denominator of the ratio is total debt, including balances on revolving lines of credit and operating and finance lease obligations.

Figures FP-14 and FP-18 summarize the cash generated from operations relative to capital expenditures for Nevada Power and Sierra, respectively. For Nevada Power, cash generated from operations exceeds capital expenditures for half of the annual periods in the Preferred and Alternate Plans. For Sierra, cash generated from operational funds exceeds capital expenditures for most of the annual periods in the Preferred and Alternate Plans. Over the 20-year period, both Companies operate at a level that is close and the Companies believe they will be able to maintain current credit quality. Despite the ability to fund a large portion of capital expenditures with internally generated cash, Figures FP-3 and FP-4 clearly illustrate the Companies' ongoing need to access external debt capital as the Companies maintain a balanced debt and equity level. There was some pressure on Sierra credit metrics before the downgrade was issued in May of 2024 from BAA1 to BAA2, but it is Sierra's goal to develop a strategy to get upgraded as soon as reasonably possible. A dip in Sierra's credit metrics can be observed during the heightened level of capital expenditures and heightened level of debt issuances. The debt issuances are the result of Sierra working to lower equity in the long run to approach the approved equity levels in recent general rate cases. Maintaining investment grade credit metrics nevertheless remains paramount. The Companies will continually manage their capital structures to minimize any potential negative pressure on credit quality, but regulatory support remains an important factor in the credit ratings process.

FIGURE FP-11
NEVADA POWER
(REDACTED) FUNDS FROM OPERATIONS TO TOTAL DEBT (%)

FIGURE FP-12
NEVADA POWER
(REDACTED) EBITDA[2] INTEREST COVERAGE

[2] EBITDA stands for earnings before interest, taxes, depreciation and amortization.

FIGURE FP-13
NEVADA POWER
(REDACTED) TOTAL DEBT TO TOTAL CAPITAL (%)

FIGURE FP-14
NEVADA POWER
(REDACTED) CASH FROM OPERATIONS TO CAPEX
($ - MILLIONS)

[redacted]

FIGURE FP-15
SIERRA
(REDACTED) FUNDS FROM OPERATIONS TO TOTAL DEBT (%)

[redacted]

FIGURE FP-16
SIERRA
(REDACTED) EBITDA INTEREST COVERAGE

FIGURE FP-17
SIERRA
(REDACTED) TOTAL DEBT TO TOTAL CAPITAL (%)

FIGURE FP-18
SIERRA
(REDACTED) CASH FROM OPERATIONS TO CAPEX
($ - MILLIONS)

[redacted]

H. Customer Rate Impact

The Companies took a fresh look at the customer rate impact analysis to not only look at the BTGR impacts but also factor in the BTER impacts to present a more holistic rate impact analysis. Each of the four alternative plans contains projects meant to address resource adequacy, reliability and reduce the Companies' reliance on market purchases. To provide a rate impact analysis of the projects proposed in this IRP pursuant to NRS 704.741 (as amended by Assembly Bill 524 (2023)), the costs of the four plans (Preferred, Alternate, Low Carbon, No Open Position) were compared to the cost of the "Base Case" plan. These costs were determined by utilizing the CER model (described in the Economic Analysis section) to project revenue requirements from capital projects to determine the BTGR impact on rates. In addition, each plan and the base case have had unique production costs modeled to project revenue requirements from costs related to fuel and purchased power to determine the BTER impact on rates. Total incremental costs (from both capital and production) were then allocated to the various rate classes based on an approximation of the current rate design. These rate class costs were then divided by the load forecast (also broken out by customer class), resulting in a per customer class rate impact in dollars per kilowatt hour ("kWh"). The rate classes considered for this rate impact analysis incorporate the grouping of several rate classes, into general rate class descriptions, as opposed to the more detailed rate classes that would result from the rate design process of a general rate case. As such, for the purposes of this analysis, the rate amounts shown can only provide an estimate of a particular rate impact for any particular customer type and are not a representation of a future rate design.

The Preferred Plan rate impact analysis is shown in Table FP-I. The rate impact analysis of the Preferred Plan shows maximum annual nominal rate impact of approximately $0.0024 per kWh at Nevada Power in 2034 ($0.0019 per kWh when adjusted for inflation) and $0.0071 per kWh at Sierra in 2033 ($0.0060 per kWh when adjusted for inflation) for residential customers of both utilities and smaller impacts for all but one other customer class. The rate impact analysis also shows a notable and sizeable decline in rates in multiple years of the analysis, particularly for Nevada Power.

TABLE FP-1
INCREMENTAL CUSTOMER RATE IMPACT OF THE PREFERRED PLAN

Average System Cost by Customer Class										
Dollars per kWh (Nominal)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Nevada Power Company										
Average Rate	-	(0.0006)	(0.0010)	0.0013	0.0005	(0.0025)	(0.0014)	(0.0008)	0.0004	0.0019
Residential	-	(0.0007)	(0.0012)	0.0016	0.0006	(0.0030)	(0.0018)	(0.0010)	0.0005	0.0024
Small Commercial	-	(0.0005)	(0.0009)	0.0012	0.0004	(0.0021)	(0.0012)	(0.0007)	0.0003	0.0016
Industrial	-	(0.0004)	(0.0007)	0.0009	0.0003	(0.0016)	(0.0009)	(0.0005)	0.0003	0.0012
Public Streets & Highway Lighting	-	(0.0003)	(0.0005)	0.0006	0.0002	(0.0011)	(0.0006)	(0.0003)	0.0002	0.0008
Sales to Public Authority	-	(0.0003)	(0.0006)	0.0008	0.0003	(0.0014)	(0.0008)	(0.0005)	0.0002	0.0010
Distribution Only	-	-	-	0.0001	-	(0.0001)	(0.0001)	-	-	0.0001
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0033)	(0.0021)	(0.0024)	0.0045	0.0039	0.0036	0.0045	0.0040
Residential	-	0.0002	(0.0052)	(0.0033)	(0.0038)	0.0070	0.0061	0.0056	0.0071	0.0062
Small Commercial	-	0.0001	(0.0032)	(0.0021)	(0.0025)	0.0046	0.0041	0.0038	0.0048	0.0043
Industrial	-	0.0001	(0.0025)	(0.0016)	(0.0019)	0.0036	0.0033	0.0030	0.0038	0.0033
Public Streets & Highway Lighting	-	0.0007	(0.0198)	(0.0142)	(0.0163)	0.0295	0.0251	0.0234	0.0298	0.0262
Distribution Only	-	-	-	-	-	-	-	-	-	-

Average System Cost by Customer Class										
Dollars per kWh (Real)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Nevada Power Company										
Average Rate	-	(0.0005)	(0.0010)	0.0013	0.0005	(0.0022)	(0.0012)	(0.0007)	0.0003	0.0016
Residential	-	(0.0006)	(0.0012)	0.0015	0.0006	(0.0027)	(0.0015)	(0.0009)	0.0004	0.0019
Small Commercial	-	(0.0005)	(0.0009)	0.0011	0.0004	(0.0019)	(0.0011)	(0.0006)	0.0003	0.0013
Industrial	-	(0.0004)	(0.0007)	0.0008	0.0003	(0.0014)	(0.0008)	(0.0004)	0.0002	0.0010
Public Streets & Highway Lighting	-	(0.0003)	(0.0005)	0.0006	0.0002	(0.0010)	(0.0005)	(0.0003)	0.0001	0.0006
Sales to Public Authority	-	(0.0003)	(0.0006)	0.0007	0.0003	(0.0012)	(0.0007)	(0.0004)	0.0002	0.0008
Distribution Only	-	-	-	0.0001	-	(0.0001)	(0.0001)	-	-	0.0001
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0032)	(0.0020)	(0.0022)	0.0040	0.0034	0.0031	0.0038	0.0033
Residential	-	0.0002	(0.0050)	(0.0031)	(0.0034)	0.0062	0.0053	0.0048	0.0060	0.0051
Small Commercial	-	0.0001	(0.0031)	(0.0020)	(0.0023)	0.0041	0.0036	0.0033	0.0041	0.0035
Industrial	-	0.0001	(0.0024)	(0.0015)	(0.0017)	0.0032	0.0028	0.0026	0.0032	0.0027
Public Streets & Highway Lighting	-	0.0007	(0.0189)	(0.0132)	(0.0149)	0.0264	0.0219	0.0201	0.0249	0.0214
Distribution Only	-	-	-	-	-	-	-	-	-	-

The Alternate Plan rate impact analysis is shown in Table FP-2. The analysis of the Alternate Plan shows maximum annual nominal rate impact of approximately $0.0040 at Nevada Power per kWh in 2034 ($0.0033 per kWh when adjusted for inflation) and $0.0074 per kWh at Sierra in 2034 ($0.0061 per kWh when adjusted for inflation) for residential customers of both utilities and smaller impacts for all but one other customer class. The rate impact analysis also shows a notable and sizeable decline in rates in multiple years of the analysis, particularly for Nevada Power.

TABLE FP-2
INCREMENTAL CUSTOMER RATE IMPACT OF THE ALTERNATE 2024 INTEGRATED RESOURCE PLAN

Average System Cost by Customer Class Dollars per kWh (Nominal)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nevada Power Company										
Average Rate	-	(0.0006)	(0.0012)	(0.0002)	(0.0011)	(0.0024)	(0.0006)	0.0003	0.0015	0.0032
Residential	-	(0.0007)	(0.0014)	(0.0003)	(0.0013)	(0.0029)	(0.0007)	0.0004	0.0019	0.0040
Small Commercial	-	(0.0005)	(0.0011)	(0.0002)	(0.0009)	(0.0020)	(0.0005)	0.0003	0.0013	0.0027
Industrial	-	(0.0004)	(0.0008)	(0.0001)	(0.0007)	(0.0015)	(0.0004)	0.0002	0.0009	0.0020
Public Streets & Highway Lighting	-	(0.0003)	(0.0006)	(0.0001)	(0.0005)	(0.0010)	(0.0002)	0.0001	0.0006	0.0013
Sales to Public Authority	-	(0.0003)	(0.0007)	(0.0001)	(0.0006)	(0.0013)	(0.0003)	0.0002	0.0008	0.0017
Distribution Only	-	-	(0.0001)	-	-	(0.0001)	-	-	0.0001	0.0001
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0030)	(0.0024)	(0.0041)	0.0020	0.0025	0.0039	0.0046	0.0048
Residential	-	0.0002	(0.0048)	(0.0037)	(0.0063)	0.0031	0.0039	0.0060	0.0072	0.0074
Small Commercial	-	0.0001	(0.0029)	(0.0024)	(0.0042)	0.0021	0.0026	0.0041	0.0049	0.0051
Industrial	-	0.0001	(0.0022)	(0.0018)	(0.0031)	0.0016	0.0021	0.0032	0.0039	0.0040
Public Streets & Highway Lighting	-	0.0007	(0.0180)	(0.0161)	(0.0275)	0.0132	0.0161	0.0252	0.0303	0.0312
Distribution Only	-	-	-	-	-	-	-	-	-	-

Average System Cost by Customer Class Dollars per kWh (Real)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nevada Power Company										
Average Rate	-	(0.0005)	(0.0011)	(0.0002)	(0.0010)	(0.0021)	(0.0005)	0.0003	0.0013	0.0027
Residential	-	(0.0006)	(0.0014)	(0.0002)	(0.0012)	(0.0026)	(0.0006)	0.0003	0.0016	0.0033
Small Commercial	-	(0.0005)	(0.0010)	(0.0002)	(0.0009)	(0.0018)	(0.0004)	0.0002	0.0011	0.0022
Industrial	-	(0.0004)	(0.0008)	(0.0001)	(0.0006)	(0.0014)	(0.0003)	0.0002	0.0008	0.0016
Public Streets & Highway Lighting	-	(0.0003)	(0.0005)	(0.0001)	(0.0004)	(0.0009)	(0.0002)	0.0001	0.0005	0.0011
Sales to Public Authority	-	(0.0003)	(0.0007)	(0.0001)	(0.0006)	(0.0012)	(0.0003)	0.0001	0.0007	0.0014
Distribution Only	-	-	(0.0001)	-	-	(0.0001)	-	-	0.0001	0.0001
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0029)	(0.0022)	(0.0037)	0.0018	0.0022	0.0033	0.0039	0.0039
Residential	-	0.0002	(0.0045)	(0.0035)	(0.0058)	0.0028	0.0034	0.0052	0.0061	0.0061
Small Commercial	-	0.0001	(0.0028)	(0.0023)	(0.0038)	0.0018	0.0023	0.0035	0.0041	0.0042
Industrial	-	0.0001	(0.0021)	(0.0017)	(0.0029)	0.0014	0.0018	0.0027	0.0032	0.0032
Public Streets & Highway Lighting	-	0.0007	(0.0172)	(0.0151)	(0.0251)	0.0118	0.0141	0.0216	0.0254	0.0256
Distribution Only	-	-	-	-	-	-	-	-	-	-

The Low Carbon Plan rate impact analysis is shown in Table FP-3. The analysis of the Low Carbon (LC) plan shows maximum annual nominal rate impact of approximately $0.0131 at Nevada Power per kWh in 2031 ($0.0114 per kWh when adjusted for inflation) and $0.0653 per kWh at Sierra in 2033 ($0.0547 per kWh when adjusted for inflation) for residential customers of both utilities and smaller impacts for all but one other customer class.

TABLE FP-3
INCREMENTAL CUSTOMER RATE IMPACT OF THE LOW CARBON (LC) 2024 INTEGRATED RESOURCE PLAN

Average System Cost by Customer Class Dollars per kWh (Nominal)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nevada Power Company										
Average Rate	-	(0.0006)	(0.0010)	0.0014	0.0044	0.0101	0.0106	0.0059	0.0065	0.0065
Residential	-	(0.0007)	(0.0012)	0.0017	0.0054	0.0125	0.0131	0.0073	0.0080	0.0081
Small Commercial	-	(0.0005)	(0.0009)	0.0012	0.0038	0.0087	0.0090	0.0050	0.0055	0.0055
Industrial	-	(0.0004)	(0.0007)	0.0009	0.0029	0.0065	0.0066	0.0037	0.0040	0.0041
Public Streets & Highway Lighting	-	(0.0003)	(0.0005)	0.0006	0.0019	0.0044	0.0044	0.0025	0.0026	0.0027
Sales to Public Authority	-	(0.0003)	(0.0006)	0.0008	0.0025	0.0056	0.0057	0.0032	0.0035	0.0035
Distribution Only	-	-	-	0.0001	0.0002	0.0004	0.0004	0.0002	0.0003	0.0003
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0034)	0.0113	0.0178	0.0403	0.0392	0.0374	0.0417	0.0393
Residential	-	0.0002	(0.0053)	0.0176	0.0278	0.0626	0.0605	0.0585	0.0653	0.0615
Small Commercial	-	0.0001	(0.0032)	0.0114	0.0182	0.0417	0.0411	0.0398	0.0445	0.0420
Industrial	-	0.0001	(0.0025)	0.0086	0.0138	0.0324	0.0324	0.0311	0.0348	0.0328
Public Streets & Highway Lighting	-	0.0007	(0.0200)	0.0763	0.1205	0.2656	0.2499	0.2442	0.2737	0.2586
Distribution Only	-	-	-	0.0001	0.0002	0.0004	0.0004	0.0004	0.0004	0.0004

Average System Cost by Customer Class Dollars per kWh (Real)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nevada Power Company										
Average Rate	-	(0.0005)	(0.0010)	0.0013	0.0041	0.0091	0.0092	0.0051	0.0054	0.0053
Residential	-	(0.0006)	(0.0012)	0.0016	0.0050	0.0112	0.0114	0.0063	0.0067	0.0066
Small Commercial	-	(0.0005)	(0.0008)	0.0011	0.0035	0.0077	0.0078	0.0043	0.0046	0.0045
Industrial	-	(0.0004)	(0.0007)	0.0009	0.0026	0.0058	0.0058	0.0032	0.0034	0.0033
Public Streets & Highway Lighting	-	(0.0003)	(0.0005)	0.0006	0.0018	0.0039	0.0039	0.0021	0.0022	0.0022
Sales to Public Authority	-	(0.0003)	(0.0006)	0.0008	0.0023	0.0050	0.0050	0.0028	0.0029	0.0029
Distribution Only	-	-	-	0.0001	0.0002	0.0004	0.0004	0.0002	0.0002	0.0002
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0032)	0.0106	0.0163	0.0361	0.0343	0.0320	0.0349	0.0322
Residential	-	0.0002	(0.0051)	0.0164	0.0254	0.0560	0.0529	0.0500	0.0547	0.0503
Small Commercial	-	0.0001	(0.0031)	0.0107	0.0167	0.0373	0.0359	0.0340	0.0373	0.0344
Industrial	-	0.0001	(0.0024)	0.0080	0.0126	0.0290	0.0283	0.0266	0.0291	0.0268
Public Streets & Highway Lighting	-	0.0006	(0.0192)	0.0714	0.1102	0.2376	0.2187	0.2089	0.2290	0.2117
Distribution Only	-	-	-	0.0001	0.0002	0.0003	0.0003	0.0003	0.0003	0.0003

The No Open Position Plan rate impact analysis is shown in Table FP-4. The analysis of the No Open Position (NOP) plan shows maximum annual nominal rate impact of approximately $0.0112 at Nevada Power per kWh in 2034 ($0.0091 per kWh when adjusted for inflation) and $0.0158 per kWh at Sierra in 2034 ($0.0129 per kWh when adjusted for inflation) for residential customers of both utilities and smaller impacts for all but one other customer class.

TABLE FP-4
INCREMENTAL CUSTOMER RATE IMPACT OF THE NO OPEN POSITION (NOP)
2024 INTEGRATED RESOURCE PLAN

Average System Cost by Customer Class Dollars per kWh (Nominal)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nevada Power Company										
Average Rate	-	(0.0006)	(0.0010)	0.0010	0.0005	(0.0001)	0.0032	0.0035	0.0085	0.0090
Residential	-	(0.0007)	(0.0012)	0.0012	0.0006	(0.0001)	0.0040	0.0043	0.0105	0.0112
Small Commercial	-	(0.0005)	(0.0009)	0.0008	0.0004	(0.0000)	0.0027	0.0030	0.0072	0.0076
Industrial	-	(0.0004)	(0.0007)	0.0006	0.0003	(0.0000)	0.0020	0.0022	0.0053	0.0056
Public Streets & Highway Lighting	-	(0.0003)	(0.0005)	0.0004	0.0002	(0.0000)	0.0014	0.0015	0.0034	0.0037
Sales to Public Authority	-	(0.0003)	(0.0006)	0.0006	0.0003	(0.0000)	0.0018	0.0019	0.0045	0.0048
Distribution Only	-	-	-	-	-	-	0.0001	0.0001	0.0003	0.0004
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0033)	0.0004	(0.0004)	0.0041	0.0036	0.0055	0.0066	0.0101
Residential	-	0.0002	(0.0053)	0.0007	(0.0006)	0.0064	0.0056	0.0087	0.0103	0.0158
Small Commercial	-	0.0001	(0.0032)	0.0004	(0.0004)	0.0043	0.0038	0.0059	0.0070	0.0108
Industrial	-	0.0001	(0.0025)	0.0003	(0.0003)	0.0033	0.0030	0.0046	0.0055	0.0084
Public Streets & Highway Lighting	-	0.0007	(0.0199)	0.0030	(0.0027)	0.0272	0.0230	0.0362	0.0433	0.0663
Distribution Only	-	-	-	-	-	-	-	0.0001	0.0001	0.0001

Average System Cost by Customer Class Dollars per kWh (Real)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nevada Power Company										
Average Rate	-	(0.0005)	(0.0010)	0.0009	0.0004	(0.0000)	0.0028	0.0030	0.0071	0.0074
Residential	-	(0.0006)	(0.0012)	0.0011	0.0005	(0.0001)	0.0035	0.0037	0.0088	0.0091
Small Commercial	-	(0.0005)	(0.0008)	0.0008	0.0004	(0.0000)	0.0024	0.0026	0.0060	0.0062
Industrial	-	(0.0004)	(0.0007)	0.0006	0.0003	(0.0000)	0.0018	0.0019	0.0044	0.0046
Public Streets & Highway Lighting	-	(0.0003)	(0.0005)	0.0004	0.0002	(0.0000)	0.0012	0.0013	0.0029	0.0030
Sales to Public Authority	-	(0.0003)	(0.0006)	0.0005	0.0003	(0.0000)	0.0015	0.0016	0.0038	0.0039
Distribution Only	-	-	-	-	-	-	0.0001	0.0001	0.0003	0.0003
Sierra Pacific Power Company										
Average Rate	-	0.0001	(0.0032)	0.0004	(0.0004)	0.0037	0.0032	0.0047	0.0055	0.0083
Residential	-	0.0002	(0.0050)	0.0006	(0.0006)	0.0057	0.0049	0.0074	0.0086	0.0129
Small Commercial	-	0.0001	(0.0031)	0.0004	(0.0004)	0.0038	0.0033	0.0050	0.0059	0.0088
Industrial	-	0.0001	(0.0024)	0.0003	(0.0003)	0.0030	0.0026	0.0039	0.0046	0.0069
Public Streets & Highway Lighting	-	0.0006	(0.0191)	0.0028	(0.0025)	0.0244	0.0202	0.0309	0.0362	0.0542
Distribution Only	-	-	-	-	-	-	-	-	0.0001	0.0001

I. Conclusion

The primary driver of the capital deployment proposed in this filing is to address the resource adequacy needs, but it is important to understand the financial impacts. As we evaluate the financial results of the modeling for the Preferred and Alternate Plans, the Companies have the capacity to finance and can afford either of these Plans. The amount of capital needed for the Plans adds some pressure on credit metrics for a couple years during the active construction phases. The capital expenditures will improve the Companies' financial strength when the assets, both proposed and under construction, are in rates. That is done with the goal of maintaining rate stability. The Companies have the financial ability and capacity to fund the projects proposed in this filing; however, any regulatory support that can be provided will help ensure the Companies' financial strength.

SECTION 5. DAY-AHEAD MARKETS AND REGIONAL TRANSMISSION ORGANIZATION

A. INTRODUCTION

Cause continues to exist to doubt the availability and deliverability of regional market capacity and energy and, therefore, it remains prudent to limit the Companies' immediate reliance on the market on a going-forward basis. The Preferred Plan addresses this through additions of diverse resources which aligns with meeting sufficiency requirements for future participation in WRAP, a future day-ahead market, or an RTO, and better positions NV Energy for changing regional conditions due to climate change and increasing decarbonization in the West.

B. DAY-AHEAD MARKETS AND SB 448 COMPLIANCE

In the March 23, 2023, order in Docket No. 22-09006, the Commission approved the establishment of a regulatory asset for costs, "directly related to fees required to fund the two day-ahead markets (CAISO and SPP) being developed as incremental steps towards a full RTO" and limited "NV Energy to recovering market development costs through 2025."[1] As a further compliance requirement, the Commission determined that in the 2024 IRP, NV Energy was to provide "a comprehensive plan to meet SB 448's requirement to join an RTO by 2030, including another proposal for cost recovery for costs related to market development."[2]

In the following sections, NV Energy first describes the status of the CAISO and SPP day-ahead market proposals. NV Energy next explains that, based on the current state of organized market activities in the West, the Companies plan to continue to pursue SB 448 requirements and capture additional economic, reliability and environmental benefits for customers by moving incrementally – by expanding the existing real-time market participation to join a day-ahead market. NV Energy will continue to participate in efforts to promote additional market services and will evaluate any potential viable RTO option. Finally, the Companies will describe the current status of the RTO Regulatory Asset.

<u>Current Status of Western Market Activities</u>

EDAM

In 2014, FERC conditionally accepted the CAISO's tariff amendments to implement the Western Energy Imbalance Market (EIM").[3] In December 2015, NV Energy became the second entity to

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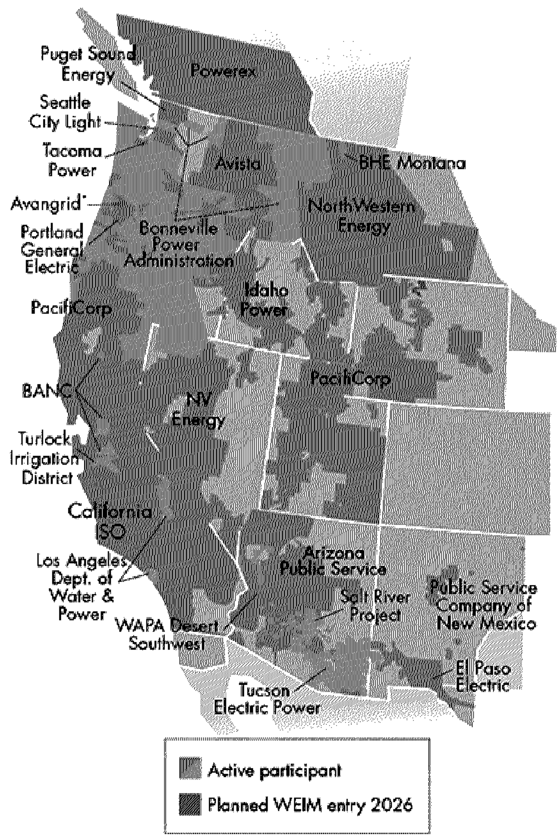
[1] Order at 391. The Commission rejected the inclusion of any staff or labor costs in the proposed Regulatory Asset.

[2] *Id.* at 394.

[3] *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,231 (accepting the CAISO tariff amendment to extend its real-time market to other balancing areas); *Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,058 (order denying requests for rehearing and granting in part and denying in part requests for clarification of the WEIM Authorization Order).

participate in the new market. As of the end of 2023, the CAISO had integrated twenty-two balancing areas into the EIM, as Figure DA-1 shows.

FIGURE DA-1
ACTIVE & PLANNED EIM PARTICIPANTS MAP



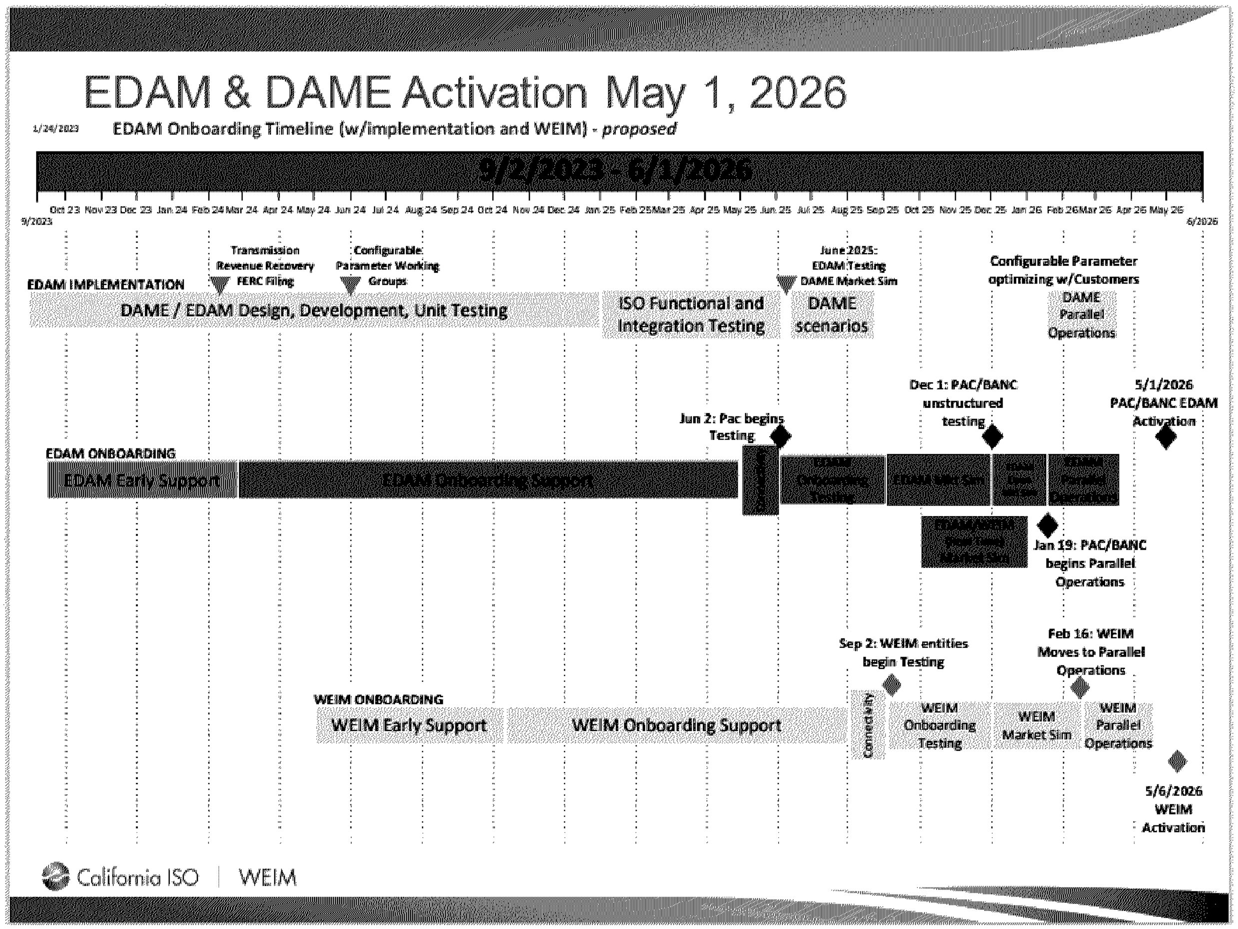
Based on the success of the EIM, the CAISO initiated a stakeholder process in November 2021 to expand its market services by extending day-ahead market participation to EIM entities ("EDAM"). Following an extensive stakeholder process, on August 22, 2023, the CAISO submitted its Day-Ahead Market Enhancement and EDAM tariff amendment to FERC. In its December 20, 2023, Order, FERC accepted in part, subject to condition, and rejected in part the tariff revisions.[4] The CAISO made the required compliance filing in Docket No. ER23-2686 on February 16, 2024. With respect to the transmission rate for EDAM, the part of the initial filing rejected by FERC without prejudice, the CAISO made a subsequent filing in Docket No. ER24-1746 on April 12, 2024, to update the proposed access charge provisions and provide additional support for the proposal. That filing is pending before FERC.

[4] *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210.

PacifiCorp, the Balancing Authority of Northern California ("BANC"), and the Los Angeles Department of Water and Power have announced their intention to participate in EDAM. In a letter dated March 21, 2024, Idaho Power stated they were "currently leaning towards EDAM." Portland General Electric has also expressed an intent to participate in EDAM. In accordance with the schedule presented by CAISO and the February 7, 2024, joint session of the EIM Governing Body and the CAISO Board of Governors (See Figure DA-2),[5] PacifiCorp and BANC, the "first movers" in EDAM, anticipate a go-live date in May 2026. The CAISO typically adds new participating balancing authority areas in the Spring. Given an approximately 18-month period for onboarding new participants, the earliest entry date for additional participants is expected to be Spring 2027.

[5] CAISO, *Extended Day Ahead Market Onboarding and Implementation Update*, Feb. 7, 2024, available at https://www.caiso.com/Documents/BriefingonExtendedDayAheadMarketOnboardingandImplementation-ISOPresentation-Feb2024.pdf.

FIGURE DA-2
EDAM & DAME[6] ACTIVATION SCHEDULE



On April 26, 2024, PacifiCorp executed its EDAM Implementation agreement. The agreement calls for a payment of $1.8 million for the costs the CAISO incurs to onboard PacifiCorp into EDAM. Any costs incurred by PacifiCorp for upgrades to its own system will be above and beyond that amount. By way of comparison, PacifiCorp paid CAISO $2.562 million under its EIM Implementation Agreement,[7] and NV Energy's EIM Implementation Agreement required a payment of $1.1 million.[8] The Los Angeles Department of Water and Power estimates its EDAM

[6] CAISO, Extended Day Ahead Market Onboarding and Implementation Update, Feb. 7, 2024, available at https://www.caiso.com/Documents/BriefingonExtendedDayAheadMarketOnboardingandImplementation-ISOPresentation-Feb2024.pdf.
[7] *See* CAISO's filing in FERC Docket No. ER14-1350.
[8] *See* CAISO's filing in FERC Docket No. ER14-1729.

implementation costs at approximately $14.7 million.[9] NV Energy expended approximately $11.2 million to perform the work necessary to participate in the EIM.

In addition to the activities listed in Figure DA-2, PacifiCorp and other EDAM participants will need to develop and file the amendments to their Open Access Transmission Tariffs ("OATT") to facilitate participation in the new market by their existing transmission customers. Thus, the training, testing, and market simulation involves not only the EDAM entity's staff, but also those of its transmission customers.

West-Wide Governance Pathways Initiative

Related to the development of EDAM has been the West-Wide Governance Pathways Initiative ("WWGPI"). Following the work of the Governance Review Committee, the CAISO's Board of Directors has voted to expand the existing joint authority model to EDAM. As noted in the September 29, 2023, WWGPI Phase One Straw proposal document, however, "[t]here was broad stakeholder agreement that joint authority was a sufficient approach for the governance of the Western EIM, and while many stakeholders felt that joint authority was also adequate for EDAM, the level of agreement was not as broad."[10]

To develop a form of governance that could attract additional participants, a set of Western regulators proposed an initiative to establish a separate non-profit entity governed by representation from across the West that could provide a full range of regional transmission operator services, utilizing a contract for services with the CAISO, including eventual assumption of the EDAM and the EIM.[11] The initial step in this effort was the formation of a sector-based, 26-person Launch Committee. NV Energy participated on this committee. On April 10, 2024, the Launch Committee released a Straw Proposal. The recommendation is to proceed in phases. The initial phase seeks to move toward more autonomous, independent oversight of the EDAM and EIM, within the confines of existing California public utility and corporate law. It aims to promote broader participation in EDAM and markets through three key changes, which would:

[9] Los Angeles Department of Water & Power, *Participation in the California Independent System Operator's Extended Day-Ahead Market*, Feb. 5, 2024, available at https://www.rtoinsider.com/wp-content/uploads/2024/02/BL-Participation-in-CAISO-EDAM-finalrev.pdf.
[10] Western Energy Board, *West-Wide Governance Pathway Initiative: Overview and Questions for Stakeholders*, Aug. 29, 2023, available at https://www.westernenergyboard.org/wp-content/uploads/West-Wide-Governance-Pathway-Initiative-Overview-8-29-23.pdf.
[11] *See* Western State Regulators and Energy Officials, *Letter RE: State regulators' call for viable path to electricity market inclusive of all western states, with independent governance*, Jul. 14, 2023, available at https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

- Give the WEIM Governing Body "primary authority" over certain market-related matters currently within the scope of its "joint authority" with the CAISO Board of Governors.[12]
- Modify the current process for resolving disputes between the EIM Governing Body and the CAISO Board of Governors to conclude, except in time-critical exigent circumstances, with the CAISO making a "dual filing" of both bodies' proposals for the FERC to render a decision.[13]
- Incorporate changes to the WEIM Governing Body charter responsibilities to account for customer and state interests in its decision-making process.[14]

If approved by the WEIM Governing Body and the CAISO Board of Governors, Phase 1 would be implemented when a set of geographically diverse EDAM entities accounting for at least 70 percent of CAISO BAA's annual load for 2022 (MWh) have executed implementation agreements.[15]

Phase 2 would require a change in California law. The objective would be to transition oversight of the EDAM and EDAM from the primary oversight of the EIM Governing Body to the sole authority of the board of a new regional organization.

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[12] Primary authority would be implemented by providing only the EIM Governing Body, rather than both bodies, the initial authority to approve or reject a proposed tariff rule. If the EIM Governing Body approved a proposed tariff rule, the rule would be placed on the CAISO Board of Governors consent agenda for approval after a full briefing and discussion. The CAISO Board of Governors, however, remove the matter from the consent agenda by majority vote, triggering the dispute resolution procedures. The scope of primary authority would be the same as those currently under joint authority.

[13] Step 1 would leave unchanged the procedure for submission of a Joint Authority tariff approved by both the EIM Governing Body and the CAISO Board of Governors and the general dispute resolution procedures delineated in Charter Section 2.2.2. The pivotal change would require the CAISO, in the event dispute resolution procedures do not resolve the dispute and either body votes in favor of a proposal that the other opposes, to make a "dual filing" with FERC pursuant to its Section 205 rights. The dual filing would present both the CAISO proposed tariff and the EIM Governing Body proposed tariff as "co-equal" proposals, with no preference for either proposal indicated in the filing. This requirement for co-equal filings would also apply in circumstances where either the CAISO Board of Governors or the EIM Governing Body believes a tariff change is necessary. One exception to the dual filing requirement remains. The CAISO Board of Governors may still authorize a filing with FERC, including a statement or opinion by the WEIM GB, when a change is a *time-critical* exigent circumstance to preserve reliability or market integrity. The CAISO BoG may take this time-critical action at any time, whether on its own initiative, following consideration of a WEIM GB proposal, or as an outcome of the dispute resolution process. The WEIM GB may, following a time-critical exigent circumstance filing and FERC resolution, still trigger the dispute resolution process to consider a durable solution.

[14] This step also contemplates a continued advisory role for a Body of State Regulators ("BOSR"), for WEIM GB and CAISO BoG decision making, and an active role in representing state interests, when necessary, in any "dual filing" before the FERC.

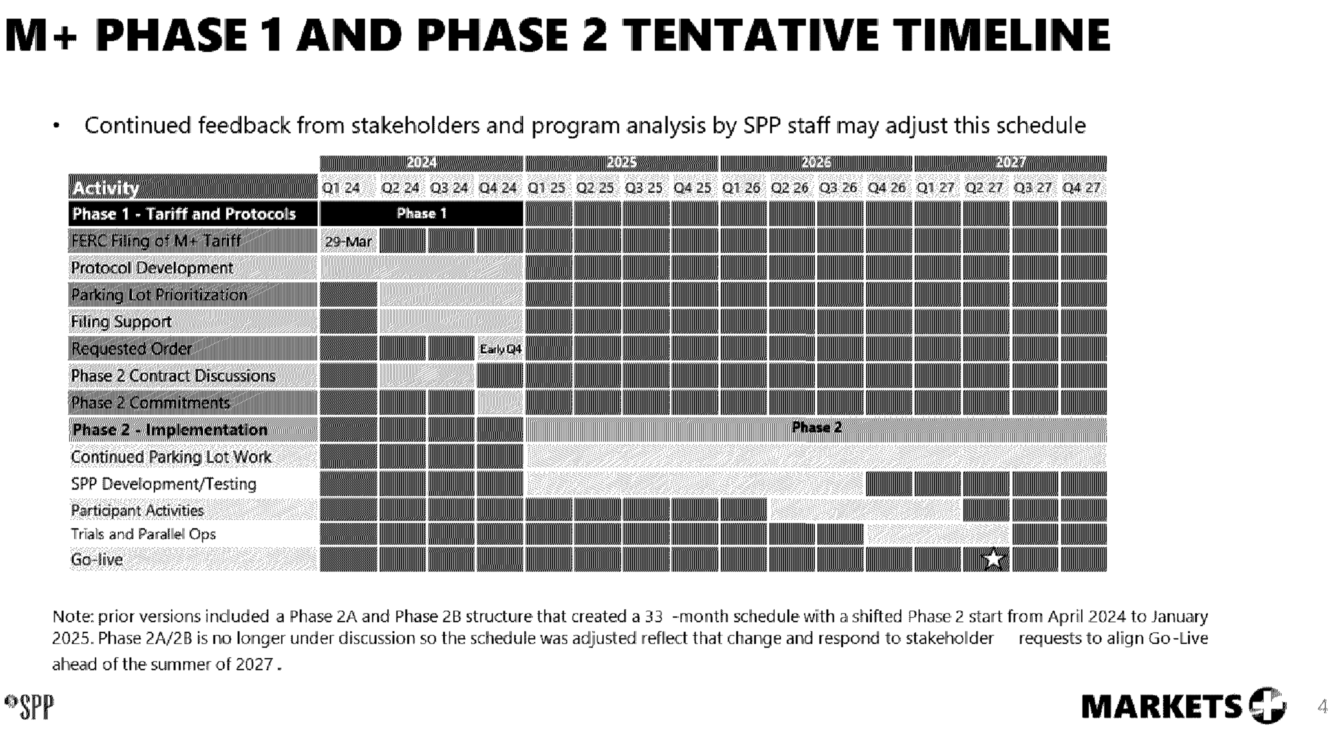
[15] This would be an additional commitment by balancing authorities such as NV Energy (Desert Southwest) and either Seattle City Light or Portland General Electric (Pacific Northwest) in addition to the previously announced participants (PacifiCorp, BANC, and LADWP).

Markets+

On March 29, 2024, in FERC Docket No. ER24-1658, the Southwest Power Pool ("SPP") filed the Markets+ Tariff with FERC. SPP requested FERC issue an order by July 31, 2024. SPP continues to work with participants on development of the market protocols that have many of the implementation details for the new market. Comments on SPP's submission were due April 29, 2024. The matter is pending before FERC. In addition, on April 12, 2024, twenty-six entities, including nine Balancing Authority Areas, released a letter stating they "look forward to participating in the ongoing development of the protocols and other market detail" though they "do not expect to make decisions about funding and joining a day-ahead market until the end of this calendar year."

At the Market Participants Executive Committee Meeting on February 20, 2024,[16] SPP provided the Schedule in Table 2 that supports a projected go-live date in the second quarter of 2027.

FIGURE DA-3
MARKETS+ TENTATIVE TIMELINE



[16] *See* Southwest Power Pool, Western Services Documents, *Markets+ Participant Executive Committee Meeting Minutes*, Feb. 20, 2024, available at https://www.spp.org/western-services-documents/.

Organized Market Options and SB 448 Compliance

As NV Energy explained in the February 16, 2024, response in Docket No. 23-10019 investigation, the Companies support participation in an organized day-ahead market to capture additional customer benefits, beyond those currently being realized through the Companies' participation in the EIM. How a potential day-ahead market may serve as a pathway to the Companies joining an RTO is an important factor, but one that should be considered wholistically with the other criteria in determining a best-interest, least-regrets approach to capture benefits for the Companies' retail and transmission customers.

Senate Bill 448 (2021)[17] recognizes the potential for RTO participation to bring benefits to Nevada, if such participation is: (1) viable and (2) in the best interests of the Companies and its customers. The Companies understand that, to be viable, the RTO must meet all of the identified statutory criteria,[18] including the requirement that governance be independent.[19] Viability also includes interconnectivity – the Companies must have sufficient transmission interchange with a footprint of sufficient size and resource diversity to secure the potential benefits of coordinated dispatch. "Best interests" includes reliability, economic, and environmental regulatory compliance components. ***Currently, the Companies do not have a viable RTO option***. The CAISO's Board of Governors, selected by the Governor of California, is not independent. While NV Energy has participated in the Governance Pathway's Initiative, it is uncertain that the end result will be an RTO with full independent governance that the Companies can "join." In addition, the Companies lack direct connectivity with the ***current*** SPP RTO and the expected footprint of SPP's anticipated RTO West.[20] While it is possible that the RTO West footprint could expand to include an entity such as WAPA's Desert Southwest Region with whom NV Energy does have a direct intertie, any such expansion is uncertain at this time. Direct interconnection would then trigger the second step of evaluating the SB 448 criteria and determining if participation would be in the best interests of the Companies and its customers.

Furthermore, NV Energy understands that Markets+ and RTO West will not be combined in a single optimization, at least, at the start of their operations. Thus, it is unclear if the Markets+ participants will choose to expand market services within the separate Markets+ governance and

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[17] Senate Bill 448 (2021) is codified at NRS 704.79881-704.7989.

[18] NRS 704.79882.

[19] "Has a structure of governance or control that is independent of the users of the transmission facilities, and no member of its board of directors has an affiliation with a user or with an affiliate of a user during the member's tenure on the board so as to unduly affect the regional transmission organization's performance." NRS 704.79882(7).

[20] At this time entities expected to participate in RTO West include Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Platte River Power Authority, Tri-State Generation and Transmission Association, Western Area Power Administration (Upper Great Plains-West region, Colorado River Storage Project, and Rocky Mountain region). RTO west is projected to commence operation in 2026. SPP RTO will expand with commitments from western utilities - Southwest Power Pool.

operating regime rather than combine with SPP's existing RTO operations, including RTO West. It is also undetermined what those expanded services might include and if they will meet the SB 448 criteria.

Given the realities of the situation in the West, NV Energy proposes to proceed along the following roadmap.

First, NV Energy will make a filing in accordance with the process developed as a result of the Workshops in Docket No. 23-10019 to propose participation in a day-ahead market. While NV Energy will provide the full evidentiary basis for its selection in that filing***, the Companies anticipate seeking permission for the Commission to expand its current EIM participation to EDAM.*** The positive experience with EIM that has generated significant economic, reliability, and environmental benefits for customers, the studies conducted by Brattle[21] and Energy and Environmental Economics,[22] the Companies' interconnectivity with announced EDAM participants, and comparison of the core market design elements are among the factors that will support the request.

Second, NV Energy will execute the required implementation agreement with CAISO and begin the systems upgrade and development work necessary for EDAM participation. The Companies also would proceed with the required modifications to their OATT. In all of these activities, NV Energy would seek to benefit from the experience of the first movers and other EDAM participants. An initial goal could be to complete the systems development work, training, customer integration, market simulations, and parallel operations activities to go live in the Spring of 2027.

Third, NV Energy will continue to explore Western market enhancements both to EDAM and to other Western initiatives. FERC-jurisdictional RTOs share a number of common characteristics including:

(1) Independent governance;
(2) Operate a real-time market;
(3) Operate a day-ahead market;
(4) Operate a market for co-optimized, ancillary services;
(5) Offer flow-based transmission with financial transmission rights;
(6) De-pancake transmission access charges for service within the RTO's footprint;
(7) Perform joint transmission planning and utilize a defined cost allocation methodology;
(8) Implement a common resource adequacy program; and

[21] Information on the Brattle study is available at https://www.oasis.oati.com/NEVP/index.html.
[22] Information on the Western Markets Exploratory Group study is available at https://www.oasis.oati.com/NEVP/index.html.

(9) Serve as the Reliability Coordinator.

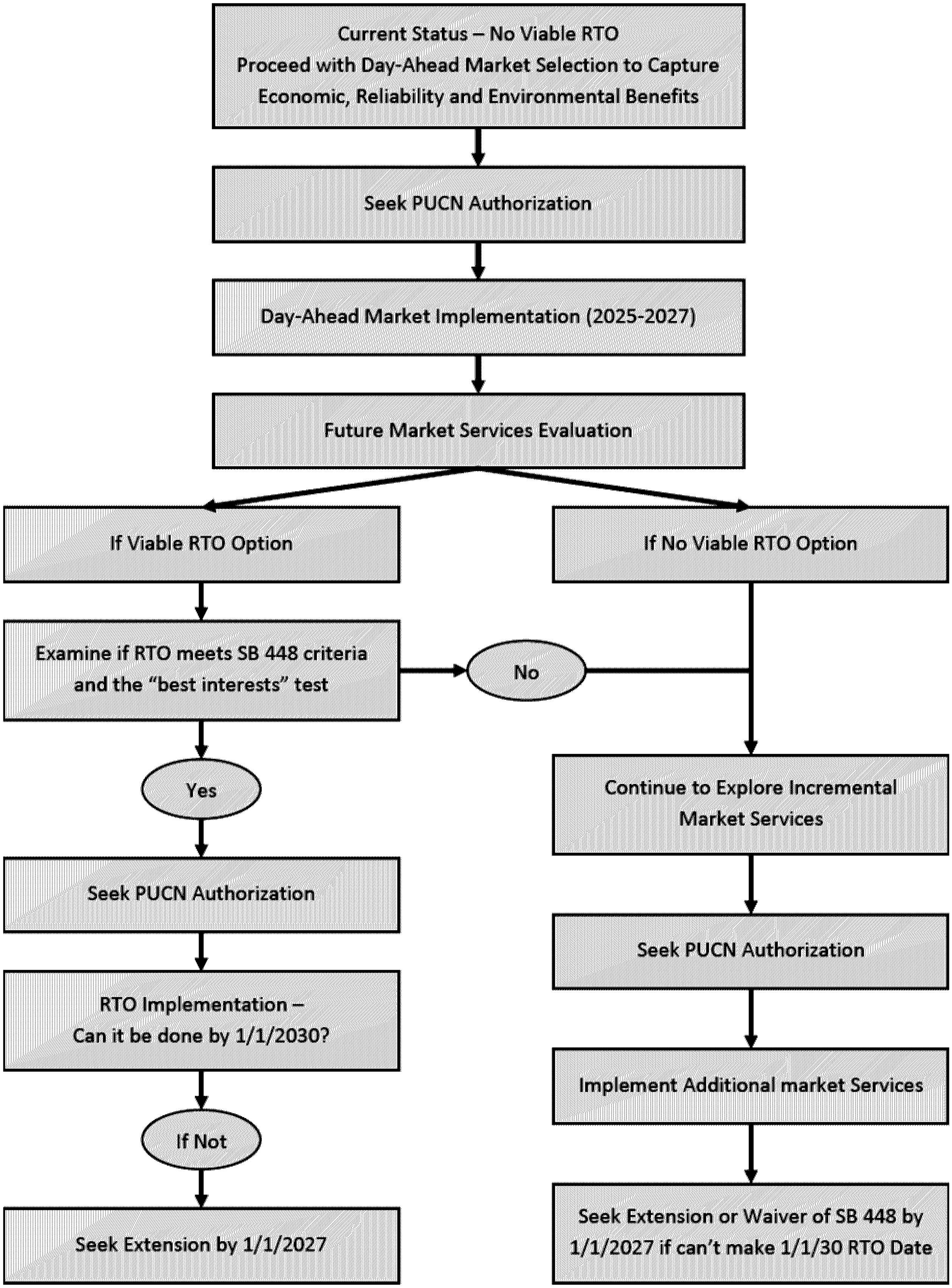
EIM and EDAM meet characteristics (2) and (3) and partially (5) and (6). The Western Power Pool's Resource Adequacy Program partially checks (8), and Northern Grid partially checks (7). More can and will be done. For example, it is likely that the day-ahead market operators will consider adding co-optimization of ancillary services as an enhancement. Given the potential savings from better utilization of the existing transmission structure as a means of achieving decarbonization objectives at the lowest reasonable cost, further regional market expansion is necessary.

Fourth, NV Energy will regularly inform the Commission, Staff, customers, and other stakeholders of ongoing Western Market Activities. In compliance with the March 23, 2023, order in Docket No. 22-09006, the Companies set up a webpage that displays NV Energy's Western Market Development and participation efforts.[23]

Fifth, as January 1, 2027, approaches, NV Energy will consider whether the Companies are in a position to join an RTO, which conforms with the eleven statutory criteria, or whether to seek a waiver or delay. Events in the West are too fluid, and the requirements dates still far enough out to make any judgments about the Companies' ability to meet the January 1, 2030, requirement. As it has with respect to the development of EDAM, Markets+, WRAP, the WWGPI and any other proposed expansion of organized Western wholesale electric market participation, NV Energy will continue to make "all reasonable efforts" to comply with the SB 448 mandate.

NV Energy's proposed roadmap is illustrated below.

[23] Available at https://www.oasis.oati.com/NEVP/index.html.


Current Status – No Viable RTO
Proceed with Day-Ahead Market Selection to Capture Economic, Reliability and Environmental Benefits
Seek PUCN Authorization
Day-Ahead Market Implementation (2025-2027)
Future Market Services Evaluation
If Viable RTO Option
If No Viable RTO Option
Examine if RTO meets SB 448 criteria and the "best interests" test
No
Yes
Continue to Explore Incremental Market Services
Seek PUCN Authorization
Seek PUCN Authorization
RTO Implementation – Can it be done by 1/1/2030?
Implement Additional market Services
If Not
Seek Extension by 1/1/2027
Seek Extension or Waiver of SB 448 by 1/1/2027 if can't make 1/1/30 RTO Date

Status of the Regulatory Asset and Plan for Recovery of Day-Ahead Market Development Costs

Through 2023, NV Energy has booked approximately $968,372 to the Regulatory Asset corresponding to payments to SPP to support the Companies' voting participation in the Phase 1 design of the SPP day-ahead market and preparation of the FERC tariff filing. NV Energy understands that this initial Phase 1 payment should support SPP's market protocol development for the first several months of 2024, but then SPP will incur additional costs of approximately $500,000 per month through the end of 2024 which will mark the projected end of Phase 1 and the start of the separate Phase 2 agreement. NV Energy's share of this additional assessment is approximately 10 percent. Consistent with the Companies' determination to seek authorization to join EDAM, NV Energy will be withdrawing from the Phase 1 funding agreement and not executing the Phase 2 agreement.

NV Energy understands that its current regulatory asset only extends to payments to market operators to "develop" the new market and not to "implement" the FERC-approved design. Thus, a new request will be made to cover the costs of the CAISO Implementation Agreement. With respect to cost incurred by NV Energy to participate in the day-ahead market, these will include IT system changes and certain additional personnel. A future project plan will cover activities including: (1) planning and workstream development, (2) procurement, (3) process changes, (4) identification of IT requirements as well as design, build, deployment and testing of systems, (5) CAISO testing and parallel operations, (6) training, and (6) customer outreach and assistance. While NV Energy has not estimated these costs yet, a full plan to put forth a new regulatory asset to cover these EDAM implementation costs will be presented in the future filing that will also seek approval for joining EDAM.

C. WESTERN RESOURCE ADEQUACY PROGRAM

As an additional step to improve resource adequacy for the state of Nevada in the future, the Companies have been actively participating in the development of WRAP. WRAP is the first regional reliability planning and compliance program in the West, with 22 entities currently participating in the program. Its purpose is to deliver a region-wide approach for assessing and addressing resource adequacy and improving reliability for the region. The importance for a regional reliability planning program cannot be overstated because it models the region as a whole to apply a common set of metrics that holds each participant accountable for bringing their fair share of capacity to meet their individual requirement within the footprint. The program has received support from state regulators across the West, and the Committee on Regional Electric Power Cooperation submitted a letter to FERC strongly supporting the WRAP program. Signatories on the letter included Chair Williamson, Commissioner Cordova, and former Commissioner Manthe.

As the program continues to be developed, the Companies have continued participating in the development of the program through a transitional period where participants may elect to go binding. In order to participate in the binding period of the program, the Companies will need to pass a forward-showing requirement. The forward showing is a participating load-serving entity's plan to be resource adequate during each month of the binding winter or summer season. The forward showing utilizes the entity's monthly 1 in 2 peak (P50) forecasted load with the region's monthly Planning Reserve Margin to calculate the entity's monthly requirement to become resource adequate. Each resource's capacity contribution is calculated by the program operator to apply only the capacity that would be available during the net load peak, also described as the capacity critical hours. The forward showing results apply the qualifying resource capacity towards the monthly requirement to determine whether the entity passes or fails the resource adequacy planning check. Any participant that fails the forward showing will be subject to penalties that utilize a cost of new entry charge, which is equal to the amount that it would cost to build new generation. It is important to note that market purchases may apply towards the forward showing, however, any contracts will need to satisfy strict requirements and limited market supply is available that meets the guidelines. Contracts must be in place ahead of the seven-month deadline to submit the forward showing for the binding season in order to count towards qualifying capacity for the forward showing. The contract must also include an identified source committed to the supply, provide assurance the capacity is not used for another entity's resource adequacy requirements, provide assurance the seller will not fail to deliver, and also commit that the energy will be delivered on firm transmission. Therefore, it may not always be possible for an entity to close forward showing shortfalls with contractual supply.

In response to the feedback received during the proceedings for the Fifth Amendment, the Companies worked closely with the Southwest Power Pool, the WRAP program operator, to provide the best estimate for the projected forward showing requirement for summer 2027 which was the first summer season NV Energy had selected to go financially binding. The results determined the largest deficiency occurred in July 2027 with a 1,670 MW resource shortfall. Following the conclusion of the Fifth Amendment, the Companies pushed the first selected binding season to the Winter 2027-2028 season which is the last season that a participant can elect to go binding. Therefore, the summer 2028 season will be the first financially binding summer season that the Companies will participate in the program. The Companies utilized the advisory Planning Reserve Margin for summer 2028 for the Southwest Region which varies monthly from 13.1 to 25.1 percent. This resulted in the largest monthly deficit of more than 2,100 MW for the month of September 2028 without the addition of any additional capacity (See Figure DA-4). The Companies performed one more additional scenario with the Preferred Plan to view the deficiency which shrank to a little over 540 MW for the month of September (See Figure DA-5).

FIGURE DA-4
EXISTING & APPROVED RESOURCES FORWARD-SHOWING ESTIMATE

Requirements Summary					
	Season	June-2028	July-2028	August-2028	September-2028
Program Monthly PRM	Summer	17.9%	14.0%	13.1%	25.1%
Peak Demand - DR Programs + PRM	Summer	10,272.6	10,196.2	10,068.2	10,367.0
Operating Reserves Adjustment	Summer	0.0	0.0	0.0	0.0
Forward Showing Obligation	Summer	10,272.6	10,196.2	10,068.2	10,367.0
Surplus/Deficient Capacity	Summer	-2,056.6	-1,980.2	-1,852.2	-2,151.0
Forward Showing Requirement Met	Summer	No	No	No	No

FIGURE DA-5
PREFERRED PLAN FORWARD-SHOWING ESTIMATE

Requirements Summary					
	Season	June-2028	July-2028	August-2028	September-2028
Program Monthly PRM	Summer	17.9%	14.0%	13.1%	25.1%
Peak Demand - DR Programs + PRM	Summer	10,272.6	10,196.2	10,068.2	10,367.0
Operating Reserves Adjustment	Summer	0.0	0.0	0.0	0.0
Forward Showing Obligation	Summer	10,272.6	10,196.2	10,068.2	10,367.0
Surplus/Deficient Capacity	Summer	-447.6	-371.2	-243.2	-542.0
Forward Showing Requirement Met	Summer	No	No	No	No

The assumptions used for the planning reserve margins in the forward-showing requirement are preliminary estimates and subject to change as the WRAP program continues to be developed. The WRAP program does not provide a load forecast for participants with the advisory modeled planning reserve margins that have been published (i.e. summer 2028) and has not published a draft business practice manual for load forecasting methodology, thus the Companies utilized its own load forecast for this forward-showing estimate. Additionally, the latest capacity contribution values from the WRAP program for each resource is for summer 2025 which would change by summer 2028 to an unknown amount since it is impossible to determine the amount of generation type additions to the region for that timeframe. This is due to the fact that the capacity contribution values for variable energy resources and batteries decline as more similar resource types are added to the region. Thus, the Companies used the refreshed effective load carrying capability ("ELCC") values used for this filing. Finally, the program has not entered into the binding stages which would provide more certainty of the footprint which may have an impact to the planning reserve margins and the capacity contributions. With so much uncertainty regarding the data inputs, the Companies made best efforts to estimate forward-showing requirements. However, these initial projections show the need for continued capacity additions to ensure the Companies are able to meet their forward-showing obligations for participation in the WRAP.

GEN-1

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

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NV Energy Generation Summary

Plant	I/S Date	Projected Retirement Date	Heat Rate at Max Load, No Duct Burners (BTU/kWh)	Winter/Summer Net Cap (MW)	Type
North					
Clark Mt. 1	1961	Retired		10 / 10	GTG/Diese
Clark Mt. 2	1963	Retired		10 / 10	GTG/Diese
Clark Mt. 3	1994	2044	12,242	72 / 66	GTG/Gas
Clark Mt. 4	1994	2044	11,932	72 / 66	GTG/Gas
Ft. Churchill 1	1968	2038	11,180	113 / 98	STG/Gas
Ft. Churchill 2	1971	2038	11,398	113 / 98	STG/Gas
Tracy 1	1963	Retired	12,477	53 / 53	STG/Gas
Tracy 2	1965	Retired	11,868	83 / 83	STG/Gas
Tracy 3	1974	2038	10,597	92 / 92	STG/Gas
Tracy 4&5 (Pinon	1996	2049	7,855	108 / 104	CC/Steam
Tracy 8, 9, 10	2008	2048	7,348	635 / 609	CC/Steam
Valmy 1	1981	2025	10,579	254 / 254	STG/Coal
Valmy 2	1985	2025	10,893	268 / 268	STG/Coal
Battle Mt	1960	Retired	15,695	8	Recip/Oil
Brunswick	1960	2028	15,695	5	Recip/Oil
Gabbs	1969	Retired	15,695	5.4	Recip/Oil
Kings Beach	2008	2058		12	Recip/Oil
Portola	1960	Retired		6	Recip/Oil
Valley Road	1960	Retired	15,695	6	Recip/Oil
Winemucca CT	1970	Retired	17,000	14/14	CT/Gas
South					
Clark 1	1955	Retired	12,081	42 / 42	STG/Gas
Clark 2	1957	Retired	10,928	59 / 66	STG/Gas
Clark 3	1961	Retired	11,629	70 / 67	STG/Gas
Clark 4	1973	2035	13,054	63 / 55	GTG/Gas
Clark 5	1979	2044	14,057	84 / 73	GTG/Gas
Clark 6	1979	2044	13,430	84 / 73	GTG/Gas
Clark 7	1980	2043	13,857	84 / 73	GTG/Gas
Clark 8	1982	2043	13,756	84 / 73	GTG/Gas
Clark 9	1993	2043	8,667	82 / 84	CC/Steam
Clark 10	1994	2044	8,588	82 / 84	CC/Steam
Clark 11 - 22	2008	2049	10,499	57 / 52	GTG/Gas
Harry Allen 3	1995	2046	11,426	84 / 76	GTG/Gas
Harry Allen 4	2006	2046	11,426	84 / 76	GTG/Gas
Harry Allen CC	2011	2049	6,983	568 / 556	CC/Gas
Lenzie CC 1	2006	2049	7,157	623 / 621	CC/Gas
Lenzie CC 2	2006	2049	7,088	623 / 621	CC/Gas

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

NV Energy Generation Summary

Plant	I/S Date	Projected Retirement Date	Heat Rate at Max Load, No Duct Burners (BTU/kWh)	Winter/Summer Net Cap (MW)	Type
~~RG 1~~	~~1965~~	*Retired*	~~10,882~~	~~100 / 100~~	~~STG/Coal~~
~~RG 2~~	~~1968~~	*Retired*	~~10,535~~	~~100 / 100~~	~~STG/Coal~~
~~RG 3~~	~~1976~~	*Retired*	~~11,006~~	~~100 / 100~~	~~STG/Coal~~
~~RG 4~~	~~1983~~	*Retired*	~~10,367~~	~~257 / 257~~	~~STG/Coal~~
Silverhawk CC	2004	*2049*	7,276	599 / 607	CC/Gas
Higgins CC	2004	*2049*	7,353	617 / 620	CC/Gas
~~Sunrise 1~~	~~1964~~	*Retired*	~~11,585~~		~~STG/Gas~~
~~Sunrise 2~~	~~1974~~	*Retired*	~~15,072~~		~~GTG/Gas~~
~~Navajo 1~~	~~1974~~	*Retired*	~~10,100~~	~~85 (NPC share)~~	~~STG/Coal~~
~~Navajo 2~~	~~1975~~	*Retired*	~~10,100~~	~~85 (NPC share)~~	~~STG/Coal~~
~~Navajo 3~~	~~1976~~	*Retired*	~~10,100~~	~~85 (NPC share)~~	~~STG/Coal~~
LVCogen 1	1994	*2049*	8,231	51 / 48	CC/Gas
LVCogen 2	2004	*2049*	7,695	115 / 112	CC/Gas
LVCogen 3	2004	*2049*	7,695	115 / 112	CC/Gas
Sunpeak 3	1991	*2041*	12,835	74 / 72	GTG/Gas
Sunpeak 4	1991	*2041*	12,767	74 / 72	GTG/Gas
Sunpeak 5	1991	*2041*	12,632	74 / 72	GTG/Gas

NEW

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

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Unit		Min. Net Capacity (MW)	Assumed Net Capability (MW) Winter	Summer	Peak
	North (°F)	45	45	73	102
	South (°F)	59	59	90	112
Fort Churchill Complex					
Ft. Churchill 1	ST	15	113	98	98
Ft. Churchill 2	ST	15	113	98	98
Tracy Complex					
Tracy 3	ST	28	92	92	92
Tracy 4	GT	30	68	65	65
Tracy 5	ST		25	24	24
Tracy 4 duct burners (total)			15	15	15
Tracy 4/5	CC	51.5	93	89	89
Tracy 4/5 + ducts	CC		108	104	104
Tracy 8	GT	80	167	162	152
Tracy 9	GT	80	167	162	152
Tracy 10	ST		161	151	140
Tracy CC duct burners (total)			140	134	123
Tracy CC (1X1)	CC	120	239	232	217
Tracy CC (1X1 + ducts)	CC		309	299	279
Tracy CC (2X1)	CC	250	495	475	444
Tracy CC (2X1 Peak Fire)				485	450
Tracy CC (2X1 + ducts)	CC		635	609	567
Tracy CC (2X1 Peak Fire + ducts)				619	573
Clark Mountain 3	GT	35	72	66	64
Clark Mountain 4	GT	35	72	66	64
Clark Mountain 3-4 (power augmentation - each)	GT	35			71
Valmy Complex					
Valmy 1 (full plant output)	ST	45	254	254	254
Valmy 2 (full plant output)	ST	40	268	268	268
Valmy 1 (SPPC portion only)	ST	22.5	127	127	127
Valmy 2 (SPPC portion only)	ST	20	134	134	134
Brunswick					
Brunswick	Diesel	1.5	5	4.75	4.75
Clark Complex					
Clark 4	GT	20	63	55	54
Clark 5	GT	35	84	73	72
Clark 6	GT	35	84	73	72
Clark 10	ST		82	84	71
Clark 10 CC - (5,6,10) 1x1	CC	52	125	115	107.5
Clark 10 CC - (5,6,10) 2x1	CC	115	250	230	215
Clark 7	GT	31	84	73	72
Clark 8	GT	31	84	73	72
Clark 9	ST		82	84	71
Clark 9 CC - (7,8,9) 1x1	CC	52	125	115	107.5
Clark 9 CC - (7,8,9) 2x1	CC	115	250	230	215
Clark 11-22 (each)	GT	35	45	42	41
Clark 11-22 (peak -each)	GT	35	57	52	51
Clark 11-22 (peak and wet compression - each)	GT	35			55
Clark 11-22 (total)			540	504	492
Clark 11-22 (peak - total)	GT		684	624	612
Clark 11-22 (peak and wet compression - total)	GT				660

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

Unit		Min. Net Capacity (MW)	Assumed Net Capability (MW)		
			Winter	Summer	Peak
	North (°F)	45	45	73	102
	South (°F)	59	59	90	112
Chuck Lenzie Complex					
LZ 1 CT1	GT	70	179	184	182
LZ 1 CT2	GT	70	179	184	182
Lenzie STG1	ST		165	158	153
Lenzie 1 duct burn			100	95	92
Lenzie CC 1 (1x1)	CC	110	250	256	252
Lenzie CC 1 (1x1 + ducts)	CC		300	303	298
Lenzie CC 1 (2x1)	CC	235	523	526	517
Lenzie CC 1 (2x1 + ducts)	CC		623	621	609
LZ 2 CT3	GT	70	179	184	182
LZ 2 CT4	GT	70	179	184	182
Lenzie STG2	ST		165	158	153
Lenzie 2 duct burners (total)			100	95	92
Lenzie CC 2 (1x1)	CC	110	250	256	252
Lenzie CC 2 (1x1 + ducts)	CC		300	303	298
Lenzie CC 2 (2x1)	CC	235	523	526	517
Lenzie CC 2 (2x1 + ducts)	CC		623	621	609
Silverhawk Station					
Silverhawk 3	GT	83	218	215	210
Silverhawk 4	GT	83	218	215	210
Silverhawk 3-4 (wet compression - each)	GT			224	222
SH CTA	GT	83	171	180	174
SH CTB	GT	83	171	180	174
SH STG	ST		168	165	159
SH duct burners (total)			100	95	90
Silverhawk CC (1x1)	CC	130	250	241	232
Silverhawk CC (1x1 + ducts)	CC		300	288	277
Silverhawk CC (2x1)	CC	262	480	465	447
Silverhawk CC (2x1 Peak Fire)	CC		510	495	477
Silverhawk (2x1 + ducts)	CC		580	560	537
Silverhawk CC (2x1 + ducts + Peak Fire)	CC		599	579	556
Silverhawk CC (2x1 + ducts + Peak Fire + Wet Compression)	CC			607	590
Harry Allen Station					
Harry Allen 3	GT	35	84	74	72
Harry Allen 4	GT	35	84	74	72
Harry Allen 3-4 (wet compression - each)	GT	35		76	74
Harry Allen 5	GT	78	175	171	163
Harry Allen 6	GT	78	175	171	163
Harry Allen 7	ST		173	169	161
Harry Allen duct burners (total)			45	45	45
Harry Allen CC (1x1)	CC	120	250	245	233
Harry Allen CC (1x1 + ducts)	CC		273	267	256
Harry Allen CC (2x1)	CC	267	523	511	487
Harry Allen CC (2x1 Peak Fire)			535	523	499
Harry Allen (2x1 + ducts)	CC		568	556	532
Harry Allen CC (2x1 Peak Fire + ducts)			580	568	544
Higgins Station					
CT1	GT	75	167	177	173
CT2	GT	75	167	177	173
STG	ST		179	168	160

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

Unit		Min. Net Capacity (MW)	Assumed Net Capability (MW) Winter	Summer	Peak
	North (°F)	45	45	73	102
	South (°F)	59	59	90	112
Higgins CC duct burners (total)			104	98	96
Higgins CC (1x1)	CC	118	245	238	231
Higgins CC (1x1 + ducts)	CC		297	287	279
Higgins CC (2x1)	CC	242	482	462	444
Higgins CC (2x1 Peak Fire)	CC		513	492	474
Higgins CC (2x1 + ducts)	CC		586	560	540
Higgins CC (2x1 + ducts + Peak Fire)	CC		617	590	570
Higgins CC (2x1 + ducts + Peak Fire + Wet Compression)	CC			620	602

Unit		Min. Net Capacity (MW)	Winter	Summer	Peak
Las Vegas Cogen					
GEN 1	GT	20	42	39	39
GEN 2	ST		9	9	9
LV Cogen 1 - 1x1	CC	25	51	48	48
GEN 3	GT	20	45	44	44
GEN 4	GT	20	45	44	44
GEN 7	ST		25	24	24
LV Cogen 2 - 1x1	CC	25	55	53	53
LV Cogen 2 - 2x1	CC	50	115	112	112
GEN 5	GT	20	45	44	44
GEN 6	GT	20	45	44	44
GEN 8	ST		25	24	24
LV Cogen 3 - 1x1	CC	25	55	53	53
LV Cogen 3 - 2x1	CC	50	115	112	112

Unit		Min. Net Capacity (MW)	Winter	Summer	Peak
SunPeak					
Sunpeak 3	GT	65	74	72	70
Sunpeak 4	GT	65	74	72	70
Sunpeak 5	GT	65	74	72	70
Sunpeak 3-5 (wet compression - each)	GT	65			77

RED indicates change from last version.

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	Minimum Run/Down Times				Start Times			AGC Minimum	
Unit	Minimum Run Time (minutes)	Minimum Down Time (minutes)	EIM Minimum Run Time (minutes)	EIM Minimum Down Time (minutes)	Minimum Time from Hot Start to On-Line - Normal (minutes)	Minimum Time from Cold Start to On-Line - Drained (minutes)	Minimum Time to On-Line - Fast Start (minutes)	AGC Minimum (MW) @ 59°F South and 45°F North	AGC Maximum (MW) @ 59°F South and 45°F North
FT Churchill Complex									
Ft. Churchill 1		60	45	60	135	720	-	15	113
Ft. Churchill 2		60	45	60	135	720	-	15	113
Tracy Complex									
Tracy 3		90	45	60	150	720	-	28	92
Tracy 4			-	-	-	-	-	38	67
Tracy 4&5			0	30	115	360	-	57	89
Tracy 4/5 duct burn			0	10	300	-	-	92	104
Tracy 8			0	35	60	-	-	80	167
Tracy 9			0	35	60	-	-	80	167
Tracy CC (1X1)			0	90	120	360	-	120	243
Tracy CC (1X1 + ducts)			0	30	300	-	-	263	308
Tracy CC (2X1)			60	30	180	420	-	250	482
Tracy CC (2X1 + ducts)			0	30	300	-	-	526	636
Clark Mountain 3		30	60	60	22	-	9	38	72
Clark Mountain 4		30	60	60	22	-	9	38	71
Clark Mountain 3-4 (power augmentation - each)									
Valmy Complex									
Valmy 1 (full plant output)		240	-	-	420	1440	-	NA	NA
Valmy 2 (full plant output)		240	-	-	420	1440	-	NA	NA
Valmy 1 (SPPC portion only)		240	-	-	420	1440	-	NA	NA
Valmy 2 (SPPC portion only)		240	-	-	420	1440	-	NA	NA
Clark Complex									
Clark 4	60	30	60	30	22	-	-	NA	NA
Clark 5	60	30	0	35	34	-	-	50	69
Clark 6	60	30	0	35	34	-	-	50	69
Clark 10 CC - (5,6,10) 1x1		60	0	195	90	300	-	84	108
Clark 10 CC - (5,6,10) 2x1	240	60	60	195	150	360	-	175	217
Clark 7	60	30	0	35	34	-	-	49	66
Clark 8	60	30	0	35	34	-	-	47	64
Clark 9 CC - (7,8,9) 1x1		60	0	195	90	300	-	78	106
Clark 9 CC - (7,8,9) 2x1	240	60	60	195	150	360	-	169	216
Clark 11-22		5	30	38	22	-	10	NA	NA
Chuck Lenzie Complex									
LZ 1 CT1			0	35	30	-	-	70	174
LZ 1 CT2			0	35	30	-	-	70	177
Lenzie CC 1 (1x1)			0	90	60	300	-	110	253
Lenzie CC 1 (1x1 + ducts)			0	30	300	-	-	230	308
Lenzie CC 1 (2x1)			60	30	120	300	-	235	529

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	Minimum Run/Down Times				Start Times			AGC Minimum	
Unit	Minimum Run Time (minutes)	Minimum Down Time (minutes)	EIM Minimum Run Time (minutes)	EIM Minimum Down Time (minutes)	Minimum Time from Hot Start to On-Line - Normal (minutes)	Minimum Time from Cold Start to On-Line - Drained (minutes)	Minimum Time to On-Line - Fast Start (minutes)	AGC Minimum (MW) @ 59°F South and 45°F North	AGC Maximum (MW) @ 59°F South and 45°F North
Lenzie CC 1 (2x1 + ducts)			0	30	300	-	-	537	627
LZ 2 CT3			0	35	30	-	-	70	178
LZ 2 CT4			0	35	30	-	-	70	178
Lenzie CC 2 (1x1)			0	90	60	300	-	110	255
Lenzie CC 2 (1x1 + ducts)			0	30	300	-	-	230	308
Lenzie CC 2 (2x1)			60	30	120	300	-	235	536
Lenzie CC 2 (2x1 + ducts)			0	30	300	-	-	528	634
Silverhawk Station									
Silverhawk 3	60	30	60	60	22	-	10	83	218
Silverhawk 4	60	30	60	60	22	-	10	83	218
SH CTA			0	35	30	-	-	86	170
SH CTB			0	35	30	-	-	86	165
Silverhawk CC (1x1)			0	90	120	300	-	138	240
Silverhawk CC (1x1 + ducts)			0	30	300	-	-	252	296
Silverhawk CC (2x1)			60	30	180	360	-	264	486
Silverhawk CC (2x1 Peak Fire)			0	30	300	-	-	294	516
Silverhawk (2x1 + ducts)			0	30	300	-	-	515	580
Silverhawk CC (2x1 + ducts + Peak Fire)			0	30	300	-	-	545	599
Silverhawk CC (2x1 + ducts + Peak Fire + Wet Compression)			15	30	300	-	-	555	
Harry Allen Station									
Harry Allen 3	60	30	60	60	22	-	10	NA	NA
Harry Allen 4	60	30	60	60	22	-	10	NA	NA
Harry Allen 5			0	35	30	-	-	80	186
Harry Allen 6			0	35	30	-	-	80	186
Harry Allen CC (1x1)			0	90	60	300	-	126	269
Harry Allen CC (1x1 + ducts)			0	30	300	-	-	290	310
Harry Allen CC (2x1)			60	30	120	300	-	270	553
Harry Allen (2x1 + ducts)			0	30	300	-	-	546	588
Higgins Station									
CT1			0	35	30	-	-	70	165
CT2			0	35	30	-	-	70	165
Higgins CC (1x1)			0	90	120	300	-	110	232
Higgins CC (1x1 + ducts)			0	30	300	-	-	256	291
Higgins CC (2x1)			60	30	120	300	-	250	485
Higgins CC (2x1 Peak Fire)			0	30	300	-	-	280	515
Higgins CC (2x1 + ducts)			0	30	300	-	-	474	595
Higgins CC (2x1 + ducts + Peak Fire)			0	30	300	-	-	504	625
Higgins CC (2x1 + ducts + Peak Fire + Wet Compression)			15	30	300	-	-	514	

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	Minimum Run/Down Times				Start Times			AGC Minimun	
Unit	Minimum Run Time (minutes)	Minimum Down Time (minutes)	EIM Minimum Run Time (minutes)	EIM Minimum Down Time (minutes)	Minimum Time from Hot Start to On-Line - Normal (minutes)	Minimum Time from Cold Start to On-Line - Drained (minutes)	Minimum Time to On-Line - Fast Start (minutes)	AGC Minimum (MW) @ 59°F South and 45°F North	AGC Maximum (MW) @ 59°F South and 45°F North
Las Vegas Cogen									
LV Cogen 1 - 1x0			-	-	-	-	-	20	42
LV Cogen 1 - 1x1	20	60	60	120	60	300	-	25	51
LV Cogen 2 - 1x0			-	-	-	-	-	20	45
LV Cogen 2 - 1x1			120	225	80	300	-	25	55
LV Cogen 2 - 2x1	120	60	120	225	80	300	-	50	115
LV Cogen 3 - 1x0			-	-	-	-	-	20	45
LV Cogen 3 - 1x1			120	225	80	300	-	25	55
LV Cogen 3 - 2x1	120	60	120	225	80	300	-	50	115
SunPeak									
Sunpeak 3	60	30	60	30	22	-	10	NA	NA
Sunpeak 4	60	30	60	30	22	-	10	NA	NA
Sunpeak 5	60	30	60	30	22	-	10	NA	NA

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	n and Maximum		Ramp Rates				Avg EFOR	MVAR Capabilities		Air Per
Unit	AGC Maximum (MW) @ 90°F South and 73°F North	AGC Maximum (MW) @ 112°F South and 102°F North	AGC Minimum Ramp Rate (MW/Min)	AGC Maximum Ramp Rate (MW/Min)	Control Operator Ramp Rate (MW/Min) Slow	Control Operator Ramp Rate (MW/Min) Fast	Average Unplanned Outage Rate, six year average (EFORd)	Gross MVAR Capability Leading	Gross MVAR Capability Lagging	Daily Hours of Operation (hrs/day)
FT Churchill Complex										
Ft. Churchill 1	98	98	0.01	3	3	4	7.0%	22	60	
Ft. Churchill 2	98	98	0.01	3	2	3	4.8%	22	60	
Tracy Complex										
Tracy 3	92	92	0.01	3	2	3	16.8%	35	55	
Tracy 4	66	63	-	-						
Tracy 4&5	87	83	0.01	2	3	4	7.9%	47	69	
Tracy 4/5 duct burn	102	98	0.01	2	3	4		44	57	
Tracy 8	162	155	0.01	12			1.4%			
Tracy 9	162	155	0.01	12			0.8%			
Tracy CC (1X1)	228	212	0.01	12	6	18				
Tracy CC (1X1 + ducts)	296	284	0.01	2						
Tracy CC (2X1)	460	438	0.01	24	6	36	1.4%	270	431	
Tracy CC (2X1 + ducts)	607	576	0.01	4						
Clark Mountain 3	69	65	0.01	6	3	6	14.4%	40	55	
Clark Mountain 4	68	64	0.01	6	3	6	6.3%	40	55	
Clark Mountain 3-4 (power augmentation - each)										
Valmy Complex										
Valmy 1 (full plant output)	NA	NA	NA	NA	0.5	1	2.8%	115	140	
Valmy 2 (full plant output)	NA	NA	NA	NA	0.5	1	11.2%	115	140	
Valmy 1 (SPPC portion only)	NA	NA	NA	NA	0.25	0.5				
Valmy 2 (SPPC portion only)	NA	NA	NA	NA	0.25	0.5				
Clark Complex										
Clark 4	NA	NA	NA	NA		3	14.3%	7	25	
Clark 5	68	65	0.01	3			9.3%	9	36	
Clark 6	68	65	0.01	3			8.1%	9	36	
Clark 10 CC - (5,6,10) 1x1	107	102	0.01	3						
Clark 10 CC - (5,6,10) 2x1	215	206	0.01	6	10	10	9.6%	58	123	
Clark 7	65	62	0.01	3			8.2%	9	36	
Clark 8	63	60	0.01	3			10.0%	9	36	
Clark 9 CC - (7,8,9) 1x1	104	99	0.01	3						
Clark 9 CC - (7,8,9) 2x1	214	205	0.01	6	10	10	10.3%	58	123	
Clark 11-22	NA	NA	NA	NA	6	13	7.2%	25	31	
Chuck Lenzie Complex										
LZ 1 CT1	179	179	0.01	14			1.4%			
LZ 1 CT2	181	181	0.01	14			0.8%			
Lenzie CC 1 (1x1)	255	252	0.01	14						
Lenzie CC 1 (1x1 + ducts)	303	298	0.01	3						
Lenzie CC 1 (2x1)	528	520	0.01	28	10	10	2.0%	220	550	

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	n and Maximum		Ramp Rates				Avg EFOR	MVAR Capabilities		Air Per
Unit	AGC Maximum (MW) @ 90°F South and 73°F North	AGC Maximum (MW) @ 112°F South and 102°F North	AGC Minimum Ramp Rate (MW/Min)	AGC Maximum Ramp Rate (MW/Min)	Control Operator Ramp Rate (MW/Min) Slow	Control Operator Ramp Rate (MW/Min) Fast	Average Unplanned Outage Rate, six year average (EFORd)	Gross MVAR Capability Leading	Gross MVAR Capability Lagging	Daily Hours of Operation (hrs/day)
Lenzie CC 1 (2x1 + ducts)	620	618	0.01	6						
LZ 2 CT3	183	183	0.01	14			1.5%			
LZ 2 CT4	183	183	0.01	14			0.8%			
Lenzie CC 2 (1x1)	255	252	0.01	14						
Lenzie CC 2 (1x1 + ducts)	303	298	0.01	3						
Lenzie CC 2 (2x1)	528	513	0.01	28	10	10	1.6%	220	550	
Lenzie CC 2 (2x1 + ducts)	630	625	0.01	6						
Silverhawk Station										
Silverhawk 3	215	210	0.01	18		48	2.0%	140	90	
Silverhawk 4	215	210	0.01	18		48	2.0%	140	90	
SH CTA	165	160	0.01	10			1.5%			
SH CTB	160	155	0.01	10			2.1%			
Silverhawk CC (1x1)	231	224	0.01	10						
Silverhawk CC (1x1 + ducts)	293	291	0.01	2						
Silverhawk CC (2x1)	465	451	0.01	20			1.9%	278	392	
Silverhawk CC (2x1 Peak Fire)	495	481	0.01	20						
Silverhawk (2x1 + ducts)	561	547	0.01	4						
Silverhawk CC (2x1 + ducts + Peak Fire)	579	556	0.01	4						
Silverhawk CC (2x1 + ducts + Peak Fire + Wet Compression)	607	590	0.01	4						
Harry Allen Station										
Harry Allen 3	NA	NA	NA	NA		6	20.9%	24	34	20
Harry Allen 4	NA	NA	NA	NA		6	14.3%	24	34	
Harry Allen 5	175	167	0.01	14			1.7%			
Harry Allen 6	172	163	0.01	14			1.2%			
Harry Allen CC (1x1)	257	237	0.01	14						
Harry Allen CC (1x1 + ducts)	277	252	0.01	2						
Harry Allen CC (2x1)	523	488	0.01	28			2.3%			
Harry Allen (2x1 + ducts)	550	522	0.01	4						
Higgins Station										
CT1	160	154	0.01	12			2.8%			
CT2	160	154	0.01	12			6.3%			
Higgins CC (1x1)	222	215	0.01	12						
Higgins CC (1x1 + ducts)	275	264	0.01	2						
Higgins CC (2x1)	462	446	0.01	24			5.6%	260	350	
Higgins CC (2x1 Peak Fire)	492	476	0.01	24						
Higgins CC (2x1 + ducts)	563	540	0.01	4						
Higgins CC (2x1 + ducts + Peak Fire)	593	570	0.01	4						
Higgins CC (2x1 + ducts + Peak Fire + Wet Compression)	623	600	0.01	4						

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	n and Maximum		Ramp Rates				Avg EFOR	MVAR Capabilities		Air Per
Unit	**AGC Maximum (MW) @ 90°F South and 73°F North**	**AGC Maximum (MW) @ 112°F South and 102°F North**	**AGC Minimum Ramp Rate (MW/Min)**	**AGC Maximum Ramp Rate (MW/Min)**	**Control Operator Ramp Rate (MW/Min) Slow**	**Control Operator Ramp Rate (MW/Min) Fast**	**Average Unplanned Outage Rate, six year average (EFORd)**	**Gross MVAR Capability Leading**	**Gross MVAR Capability Lagging**	**Daily Hours of Operation (hrs/day)**
Las Vegas Cogen										
LV Cogen 1 - 1x0	39	39	-	-						
LV Cogen 1 - 1x1	48	48	0.01	2.45	2.45	2.45	9.1%	4	24	
LV Cogen 2 - 1x0	44	44	-	-						
LV Cogen 2 - 1x1	53	53	0.01	2.5						
LV Cogen 2 - 2x1	112	112	0.01	5	5	10	8.2%			
LV Cogen 3 - 1x0	44	44	-	-						
LV Cogen 3 - 1x1	53	53	0.01	2.5						
LV Cogen 3 - 2x1	112	112	0.01	5	5	10	6.2%			
SunPeak										
Sunpeak 3	NA	NA	NA	NA		14.4	5.3%			12
Sunpeak 4	NA	NA	NA	NA		14.4	14.0%			12
Sunpeak 5	NA	NA	NA	NA		14.4	15.1%			12

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

Unit	'mit Operational Limitations Annual Hours of Operation (hrs/year)	Annual Number of Startups (#/year)	NPC Notes:
FT Churchill Complex			
Ft. Churchill 1			
Ft. Churchill 2			
Tracy Complex			
Tracy 3			
Tracy 4			
Tracy 4&5			
Tracy 4/5 duct burn			
Tracy 8			
Tracy 9			
Tracy CC (1X1)			
Tracy CC (1X1 + ducts)			
Tracy CC (2X1)			
Tracy CC (2X1 + ducts)			
Clark Mountain 3			
Clark Mountain 4			
Clark Mountain 3-4 (power augmentation - each)	72		
Valmy Complex			
Valmy 1 (full plant output)			Idaho Power ended participation of Valmy 1 on December 31, 2019
Valmy 2 (full plant output)			
Valmy 1 (SPPC portion only)			
Valmy 2 (SPPC portion only)			
Clark Complex			
Clark 4			
Clark 5			
Clark 6			
Clark 10 CC - (5,6,10) 1x1			
Clark 10 CC - (5,6,10) 2x1			
Clark 7			
Clark 8			
Clark 9 CC - (7,8,9) 1x1			
Clark 9 CC - (7,8,9) 2x1			
Clark 11-22	3500	350	
Chuck Lenzie Complex			
LZ 1 CT1			
LZ 1 CT2			
Lenzie CC 1 (1x1)			
Lenzie CC 1 (1x1 + ducts)			
Lenzie CC 1 (2x1)			

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

Unit	'mit Operational Limitations		NPC Notes:
	Annual Hours of Operation (hrs/year)	Annual Number of Startups (#/year)	
Lenzie CC 1 (2x1 + ducts)			
LZ 2 CT3			
LZ 2 CT4			
Lenzie CC 2 (1x1)			
Lenzie CC 2 (1x1 + ducts)			
Lenzie CC 2 (2x1)			
Lenzie CC 2 (2x1 + ducts)			
Silverhawk Station			
Silverhawk 3	1339	250	New unit. Estimated performance effective June 1, 2024
Silverhawk 4			New unit. Estimated performance effective June 1, 2024
SH CTA			
SH CTB			
Silverhawk CC (1x1)			
Silverhawk CC (1x1 + ducts)			
Silverhawk CC (2x1)			
Silverhawk CC (2x1 Peak Fire)			
Silverhawk (2x1 + ducts)	2000		
Silverhawk CC (2x1 + ducts + Peak Fire)			
Silverhawk CC (2x1 + ducts + Peak Fire + Wet Compression)			
Harry Allen Station			
Harry Allen 3	6135		
Harry Allen 4	3300		
Harry Allen 5			
Harry Allen 6			
Harry Allen CC (1x1)			
Harry Allen CC (1x1 + ducts)			
Harry Allen CC (2x1)			
Harry Allen (2x1 + ducts)	4000		
Higgins Station			
CT1			
CT2			
Higgins CC (1x1)			
Higgins CC (1x1 + ducts)			
Higgins CC (2x1)			
Higgins CC (2x1 Peak Fire)			
Higgins CC (2x1 + ducts)	3064		
Higgins CC (2x1 + ducts + Peak Fire)			
Higgins CC (2x1 + ducts + Peak Fire + Wet Compression)			

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Unit	'mit Operational Limitations Annual Hours of Operation (hrs/year)	Annual Number of Startups (#/year)	NPC Notes:
Las Vegas Cogen			
LV Cogen 1 - 1x0			
LV Cogen 1 - 1x1			
LV Cogen 2 - 1x0		396	
LV Cogen 2 - 1x1			
LV Cogen 2 - 2x1	30480		
LV Cogen 3 - 1x0		396	
LV Cogen 3 - 1x1			
LV Cogen 3 - 2x1			
SunPeak			
Sunpeak 3			
Sunpeak 4	3484		
Sunpeak 5			

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

CONFIDENTIAL - COMPANY USE ONLY

Unit	Prime Mover/ Primary Fuel	Start-Up Fuel	Secondary Fuel	Start-UP Energy (MMBTU Only) Normal	Start-UP Energy (MMBTU Only) Cold	No-Load Heat Input (MMBTU/hr) [Heat Input Coefficent C]	Min Load Net Heat Rate (BTU/KWh)	Max Load Net Heat Rate (BTU/KWh)	Average of Min and Max Net Heat Rate (BTU/KWh)	NPC Notes:
FT Churchill Complex										
Ft. Churchill 1	STG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Ft. Churchill 2	STG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy Complex										
Tracy 3	STG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy 4	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy 4&5	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy 4/5 duct burn	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy 8	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy 9	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy CC (1X1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy CC (1X1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy CC (2X1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tracy CC (2X1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark Mountain 3	GTG/Gas	Gas	Diesel #2 Oil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark Mountain 4	GTG/Gas	Gas	Diesel #2 Oil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Valmy Complex										
Valmy 1 (full plant output)	STG/Coal	Diesel #2 Oil	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Idaho Power ended participation of Valmy 1 on December 31, 2019
Valmy 2 (full plant output)	STG/Coal	Diesel #2 Oil	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Valmy 1 (SPPC portion only)	STG/Coal	Diesel #2 Oil	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Valmy 2 (SPPC portion only)	STG/Coal	Diesel #2 Oil	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark Complex										
Clark 4	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 5	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 6	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 10 CC - (5,6,10) 1x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 10 CC - (5,6,10) 2x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 7	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 8	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 9 CC - (7,8,9) 1x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 9 CC - (7,8,9) 2x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Clark 11-22	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Chuck Lenzie Complex										
LZ 1 CT1	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LZ 1 CT2	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 1 (1x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 1 (1x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 1 (2x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 1 (2x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LZ 2 CT3	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LZ 2 CT4	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 2 (1x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 2 (1x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 2 (2x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lenzie CC 2 (2x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Silverhawk Station										
Silverhawk 3	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	New unit. Estimated performance effective June 1, 2024
Silverhawk 4	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	New unit. Estimated performance effective June 1, 2024
SH CTA	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
SH CTB	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

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Unit	Prime Mover/ Primary Fuel	Start-Up Fuel	Secondary Fuel	Start-UP Energy (MMBTU Only) Normal	Start-UP Energy (MMBTU Only) Cold	No-Load Heat Input (MMBTU/hr) [Heat Input Coefficent C]	Min Load Net Heat Rate (BTU/KWh)	Max Load Net Heat Rate (BTU/KWh)	Average of Min and Max Net Heat Rate (BTU/KWh)	NPC Notes:
Silverhawk CC (1x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Silverhawk CC (1x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Silverhawk CC (2x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Silverhawk CC (2x1 Peak Fire)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Silverhawk (2x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Silverhawk CC (2x1 + ducts + Peak Fire)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Silverhawk CC (2x1 + ducts + Peak Fire + Wet Compression)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen Station										
Harry Allen 3	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen 4	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen 5	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen 6	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen CC (1x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen CC (1x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen CC (2x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Harry Allen (2x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins Station										
CT1	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
CT2	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins CC (1x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins CC (1x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins CC (2x1)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins CC (2x1 Peak Fire)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins CC (2x1 + ducts)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins CC (2x1 + ducts + Peak Fire)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Higgins CC (2x1 + ducts + Peak Fire + Wet Compression)	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Las Vegas Cogen										
LV Cogen 1 - 1x0	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LV Cogen 1 - 1x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LV Cogen 2 - 1x0	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LV Cogen 2 - 1x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LV Cogen 2 - 2x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LV Cogen 3 - 1x0	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LV Cogen 3 - 1x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LV Cogen 3 - 2x1	CC/Steam - Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
SunPeak										
Sunpeak 3	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Sunpeak 4	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Sunpeak 5	GTG/Gas	Gas	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

RED indicates change from last version.

REDACTED PUBLIC VERSION

CONFIDENTIAL - COMPANY USE ONLY		Consumables ($/MWh)	2024 Maint $ / Operating Hour (2024$)		
Units	EIM Configuration	O&M	O&M	Capital	O&M and Capital
Ft Churchill					
Ft. Churchill 1	FT CHUR_7_UNIT 1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Ft. Churchill 2	FT CHUR_7_UNIT 2	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Complex					
Tracy 3	TRACY_7_UNIT 3	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy 4&5	TRACY_7_UNITS 4-5_1X1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy 4&5	TRACY_7_UNITS 4-5_1X1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Combined Cycle 2x1	W TRACY_7_UNITS 8-10_2x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Combined Cycle 2x1 (Peak Fire)	W TRACY_7_UNITS 8-10_2x1_PEAK	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Combined Cycle 2x1 (with Duct Burners)	W TRACY_7_UNITS 8-10_2x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Combined Cycle 2x1 (Peak Fire with Duct Burners)	W TRACY_7_UNITS 8-10_2x1_DB_PEAK	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Combined Cycle 1x1	W TRACY_7_UNITS 8-10_1x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Combined Cycle 1x1 (with Duct Burners)	W TRACY_7_UNITS 8-10_1x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Tracy Combined Cycle 1x0	W TRACY_7_UNITS 8-10_1x0	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Mountain 3	E TRACY_7_UNIT CT3	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Mountain 3 (Fast Start)	Clark Mountain 3 - Fast Start	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Mountain 4	E TRACY_7_UNIT CT4	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Mountain 4 (Fast Start)	Clark Mountain 4 - Fast Start	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Mountain 3-4 (Power Augmentation)	Clark Mountain 3-4 - Power Augmentation	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Valmy Complex					
Valmy 1	Valmy 1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Valmy 2	Valmy 2	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Complex					
Clark 4	CLARK_7_UNIT 4	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark789 1x0	CLARK_7_UNITS 7-9_1X0	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark789 1x1	CLARK_7_UNITS 7-9_1X1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark789 2x1	CLARK_7_UNITS 7-9_2X1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark5610 1x0	CLARK_7_UNITS 5-6 10_1X0	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark5610 1x1	CLARK_7_UNITS 5-6 10_1X1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark5610 2x1	CLARK_7_UNITS 5-6 10_2X1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Peakers 11-22	CLARK_7_UNITS 11-14_1 PKR- DASH 1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	CLARK_7_UNITS 11-14_1 PKR - DASH 3	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	CLARK_7_UNITS 11-14_2 PKR - DASH 3	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	CLARK_7_UNITS 11-14_3 PKR - DASH 3	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	CLARK_7_UNITS 11-14_4 PKR - DASH 3	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Clark Peakers 11-22 (Peak + Wet Compression)	CLARK_7_UNITS 11-14_4 PKR_WC	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Arrow Canyon Complex					
Lenzie Combined Cycle 2x1	LENZIE_7_UNITS PB1_2x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 2x1 (with Duct Burners)	LENZIE_7_UNITS PB1_2x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 1x1	LENZIE_7_UNITS PB1_1x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 1x1 (with Duct Burners)	LENZIE_7_UNITS PB1_1x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 1x0	LENZIE_7_UNITS PB1_1x0	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 2x1	LENZIE_7_UNITS PB2_2x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 2x1 (with Duct Burners)	LENZIE_7_UNITS PB2_2x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 1x1	LENZIE_7_UNITS PB2_1x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 1x1 (with Duct Burners)	LENZIE_7_UNITS PB2_1x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Lenzie Combined Cycle 1x0	LENZIE_7_UNITS PB2_1x0	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1	SLVRHWK_7_UNITS_2x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (Peak Fire)	SLVRHWK_7_UNITS_2x1_PEAK	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (with Duct Burners)	SLVRHWK_7_UNITS_2X1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (Peak Fire with Duct Burners)	SLVRHWK_7_UNITS_2x1_DB_PEAK	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (Peak Fire + Wet Compression w	SLVRHWK_7_UNITS_2x1_DB_PEAK_WC	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 1x1	SLVRHWK_7_UNITS_1x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 1x1 (with Duct Burners)	SLVRHWK_7_UNITS_1x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk Combined Cycle 1x0	SLVRHWK_7_UNITS_1x0	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk 3	SLVRHWK_7_UNIT 3	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk 4	SLVRHWK_7_UNIT 4	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk 3-4 (Fast Start)	Silverhawk 3 - Fast Start	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Silverhawk 3-4 (Wet Compression)	SLVRHWK_7_UNIT 3_WC	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
		$ [redacted]			
Harry Allen Combined Cycle 2x1	HACC_7_UNITS 5-7_2x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen Combined Cycle 2x1 (Peak Fire)	HACC_7_UNITS 5-7_2x1_PEAK	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen Combined Cycle 2x1 (with Duct Burners)	HACC_7_UNITS 5-7_2x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen Combined Cycle 2x1 (Peak Fire with Duct Burners)	HACC_7_UNITS 5-7_2x1_DB_PEAK	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen Combined Cycle 1x1	HACC_7_UNITS 5-7_1x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen Combined Cycle 1x1 (with Duct Burners)	HACC_7_UNITS 5-7_1x1_DB	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen Combined Cycle 1x0	HACC_7_UNITS 5-7_1x0	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen 3	H ALLEN_7_UNIT 3-4_1PKR	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen 3 (Fast Start)	Harry Allen 3/4 - 1 Peaker - Fast Start	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen 3-4 (Wet Compression)	H ALLEN_7_UNIT 3-4_1PKR_WC	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen 3 and 4	H ALLEN_7_UNIT 3-4_2PKR	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen 3 and 4 (Fast Start)	Harry Allen 3/4 - 2 peakers - Fast Start	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
Harry Allen 3 and 4 (Wet Compression)	H ALLEN_7_UNIT 3-4_2PKR_WC	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]
		$ [redacted]			
		$ [redacted]			
Higgins Station		$ [redacted]			
Higgins Combined Cycle 2x1	HIGGINS_7_UNITS_2x1	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]

REDACTED PUBLIC VERSION

Units	EIM Configuration	Consumables ($/MWh) O&M	Maint $ / Operating Hour (2024$) O&M	Capital	O&M and Capital
Higgins Combined Cycle 2x1 (Peak Fire)	HIGGINS_7_UNITS_2x1_PEAK	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 2x1 (with Duct Burners)	HIGGINS_7_UNITS_2x1_DB	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 2x1 (Peak Fire with Duct Burners)	HIGGINS_7_UNITS_2x1_DB_PEAK	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 2x1 (Peak Fire + Wet Compression with	HIGGINS_7_UNITS_2x1_DB_PEAK_WC	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 1x1	HIGGINS_7_UNITS_1X1	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 1x1 (with Duct Burners)	HIGGINS_7_UNITS_1x1_DB	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 1x0	HIGGINS_7_UNITS_1X0	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
		$ [redacted]			
		$ [redacted]			
Las Vegas Station		$ [redacted]			
Las Vegas Block 1	LVCOGEN_7_UNITS 1	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Las Vegas Block 2 1x1	LVCOGEN_1_UNITS PB2-3_1 BLK 1x1	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Las Vegas Block 2 2x1	LVCOGEN_1_UNITS PB2-3_1 BLK 2x1	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Las Vegas Block 3 2x1	LVCOGEN_1_UNITS PB2-3_2 BLK 2x1	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
		0			
Sunpeak Station		$ [redacted]			
Sunpeak 3	SUNPEAK_7_UNIT 3	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Sunpeak 4	SUNPEAK_7_UNIT 4	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Sunpeak 5	SUNPEAK_7_UNIT 5	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Sunpeak 3-5 (Wet Compression)	SUNPEAK_7_UNIT 3_WC	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]

REDACTED PUBLIC VERSION

CONFIDENTI	2024		
	Maint$ / Start (2024$)		
Units	O&M	Capital	O&M and Capital
Ft Churchill			
Ft. Churchill 1	$ [redacted]	$ [redacted]	$ [redacted]
Ft. Churchill 2	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Complex			
Tracy 3	$ [redacted]	$ [redacted]	$ [redacted]
Tracy 4&5	$ [redacted]	$ [redacted]	$ [redacted]
Tracy 4&5	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Combined Cycle 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Combined Cycle 2x1 (Peak Fire)	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Combined Cycle 2x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Combined Cycle 2x1 (Peak Fire with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Combined Cycle 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Combined Cycle 1x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Tracy Combined Cycle 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Clark Mountain 3	$ [redacted]	$ [redacted]	$ [redacted]
Clark Mountain 3 (Fast Start)	$ [redacted]	$ [redacted]	$ [redacted]
Clark Mountain 4	$ [redacted]	$ [redacted]	$ [redacted]
Clark Mountain 4 (Fast Start)	$ [redacted]	$ [redacted]	$ [redacted]
Clark Mountain 3-4 (Power Augmentation)	$ [redacted]	$ [redacted]	$ [redacted]
Valmy Complex			
Valmy 1	$ [redacted]	$ [redacted]	$ [redacted]
Valmy 2	$ [redacted]	$ [redacted]	$ [redacted]
Clark Complex			
Clark 4	$ [redacted]	$ [redacted]	$ [redacted]
Clark789 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Clark789 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Clark789 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Clark5610 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Clark5610 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Clark5610 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Clark Peakers 11-22	$ [redacted]	$ [redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	$ [redacted]	$ [redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	$ [redacted]	$ [redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	$ [redacted]	$ [redacted]	$ [redacted]
Clark Peakers 11-22 (Peak)	$ [redacted]	$ [redacted]	$ [redacted]
Clark Peakers 11-22 (Peak + Wet Compression)	$ [redacted]	$ [redacted]	$ [redacted]
Arrow Canyon Complex			
Lenzie Combined Cycle 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 2x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 1x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 2x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 1x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Lenzie Combined Cycle 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (Peak Fire)	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (Peak Fire with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 2x1 (Peak Fire + Wet Compression v	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 1x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk Combined Cycle 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk 3	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk 4	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk 3-4 (Fast Start)	$ [redacted]	$ [redacted]	$ [redacted]
Silverhawk 3-4 (Wet Compression)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen Combined Cycle 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen Combined Cycle 2x1 (Peak Fire)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen Combined Cycle 2x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen Combined Cycle 2x1 (Peak Fire with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen Combined Cycle 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen Combined Cycle 1x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen Combined Cycle 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen 3	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen 3 (Fast Start)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen 3-4 (Wet Compression)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen 3 and 4	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen 3 and 4 (Fast Start)	$ [redacted]	$ [redacted]	$ [redacted]
Harry Allen 3 and 4 (Wet Compression)	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Station			
Higgins Combined Cycle 2x1	$ [redacted]	$ [redacted]	$ [redacted]

REDACTED PUBLIC VERSION

	Maint$ / Start (2024$)		
Units	O&M	Capital	**O&M and Capital**
Higgins Combined Cycle 2x1 (Peak Fire)	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 2x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 2x1 (Peak Fire with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 2x1 (Peak Fire + Wet Compression with	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 1x1 (with Duct Burners)	$ [redacted]	$ [redacted]	$ [redacted]
Higgins Combined Cycle 1x0	$ [redacted]	$ [redacted]	$ [redacted]
Las Vegas Station			
Las Vegas Block 1	$ [redacted]	$ [redacted]	$ [redacted]
Las Vegas Block 2 1x1	$ [redacted]	$ [redacted]	$ [redacted]
Las Vegas Block 2 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Las Vegas Block 3 2x1	$ [redacted]	$ [redacted]	$ [redacted]
Sunpeak Station			
Sunpeak 3	$ [redacted]	$ [redacted]	$ [redacted]
Sunpeak 4	$ [redacted]	$ [redacted]	$ [redacted]
Sunpeak 5	$ [redacted]	$ [redacted]	$ [redacted]
Sunpeak 3-5 (Wet Compression)	$ [redacted]	$ [redacted]	$ [redacted]

CONFIDENTIAL - COMPANY USE ONLY

HEAT INPUT = A(MW^2)+B(MW)+C

Unit	A	B	C	Incremental for Duct burners
FT Churchill Complex	[redacted]	[redacted]	[redacted]	
Ft. Churchill 1	[redacted]	[redacted]	[redacted]	
Ft. Churchill 2	[redacted]	[redacted]	[redacted]	
Tracy Complex	[redacted]	[redacted]	[redacted]	
Tracy 3	[redacted]	[redacted]	[redacted]	
Tracy 4	[redacted]	[redacted]	[redacted]	
Tracy 4&5	[redacted]	[redacted]	[redacted]	
Tracy 4/5 duct burn	[redacted]	[redacted]	[redacted]	[redacted]
Tracy 8	[redacted]	[redacted]	[redacted]	
Tracy 9	[redacted]	[redacted]	[redacted]	
Tracy CC (1X1)	[redacted]	[redacted]	[redacted]	
Tracy CC (1X1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Tracy CC (2X1)	[redacted]	[redacted]	[redacted]	
Tracy CC (2X1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Clark Mountain 3	[redacted]	[redacted]	[redacted]	
Clark Mountain 4	[redacted]	[redacted]	[redacted]	
Valmy Complex	[redacted]	[redacted]	[redacted]	
Valmy 1 (full plant output)	[redacted]	[redacted]	[redacted]	
Valmy 2 (full plant output)	[redacted]	[redacted]	[redacted]	
Valmy 2 (SPPC portion only)	[redacted]	[redacted]	[redacted]	
Clark Complex	[redacted]	[redacted]	[redacted]	
Clark 4	[redacted]	[redacted]	[redacted]	
Clark 5	[redacted]	[redacted]	[redacted]	
Clark 6	[redacted]	[redacted]	[redacted]	
Clark 10 CC - (5,6,10) 1x1	[redacted]	[redacted]	[redacted]	
Clark 10 CC - (5,6,10) 2x1	[redacted]	[redacted]	[redacted]	
Clark 7	[redacted]	[redacted]	[redacted]	
Clark 8	[redacted]	[redacted]	[redacted]	
Clark 9 CC - (7,8,9) 1x1	[redacted]	[redacted]	[redacted]	
Clark 9 CC - (7,8,9) 2x1	[redacted]	[redacted]	[redacted]	
Clark 11-22	[redacted]	[redacted]	[redacted]	
Chuck Lenzie Complex	[redacted]	[redacted]	[redacted]	
LZ 1 CT1	[redacted]	[redacted]	[redacted]	
LZ 1 CT2	[redacted]	[redacted]	[redacted]	
Lenzie CC 1 (1x1)	[redacted]	[redacted]	[redacted]	
Lenzie CC 1 (1x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Lenzie CC 1 (2x1)	[redacted]	[redacted]	[redacted]	
Lenzie CC 1 (2x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
LZ 2 CT3	[redacted]	[redacted]	[redacted]	
LZ 2 CT4	[redacted]	[redacted]	[redacted]	
Lenzie CC 2 (1x1)	[redacted]	[redacted]	[redacted]	
Lenzie CC 2 (1x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Lenzie CC 2 (2x1)	[redacted]	[redacted]	[redacted]	
Lenzie CC 2 (2x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Silverhawk Station	[redacted]	[redacted]	[redacted]	
Silverhawk 3	[redacted]	[redacted]	[redacted]	
Silverhawk 4	[redacted]	[redacted]	[redacted]	
SH CTA	[redacted]	[redacted]	[redacted]	
SH CTB	[redacted]	[redacted]	[redacted]	
Silverhawk CC (1x1)	[redacted]	[redacted]	[redacted]	
Silverhawk CC (1x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Silverhawk CC (2x1)	[redacted]	[redacted]	[redacted]	
Silverhawk CC (2x1 Peak Fire)	[redacted]	[redacted]	[redacted]	
Silverhawk (2x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Silverhawk CC (2x1 + ducts + Peak Fire)	[redacted]	[redacted]	[redacted]	[redacted]
Silverhawk CC (2x1 + ducts + Peak Fire + Wet Compression)	[redacted]	[redacted]	[redacted]	[redacted]
Harry Allen Station	[redacted]	[redacted]	[redacted]	
Harry Allen 3	[redacted]	[redacted]	[redacted]	
Harry Allen 4	[redacted]	[redacted]	[redacted]	
Harry Allen 5	[redacted]	[redacted]	[redacted]	
Harry Allen 6	[redacted]	[redacted]	[redacted]	
Harry Allen CC (1x1)	[redacted]	[redacted]	[redacted]	
Harry Allen CC (1x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Harry Allen CC (2x1)	[redacted]	[redacted]	[redacted]	
Harry Allen (2x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Higgins Station	[redacted]	[redacted]	[redacted]	
CT1	[redacted]	[redacted]	[redacted]	

HEAT INPUT = A(MW^2)+B(MW)+C

Unit	A	B	C	Incremental for Duct burners
CT2	[redacted]	[redacted]	[redacted]	
Higgins CC (1x1)	[redacted]	[redacted]	[redacted]	
Higgins CC (1x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Higgins CC (2x1)	[redacted]	[redacted]	[redacted]	
Higgins CC (2x1 Peak Fire)	[redacted]	[redacted]	[redacted]	
Higgins CC (2x1 + ducts)	[redacted]	[redacted]	[redacted]	[redacted]
Higgins CC (2x1 + ducts + Peak Fire)	[redacted]	[redacted]	[redacted]	[redacted]
Higgins CC (2x1 + ducts + Peak Fire + Wet Compression)	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Cogen				
LV Cogen 1 - 1x0	[redacted]	[redacted]	[redacted]	
LV Cogen 1 - 1x1	[redacted]	[redacted]	[redacted]	
LV Cogen 2 - 1x0	[redacted]	[redacted]	[redacted]	
LV Cogen 2 - 1x1	[redacted]	[redacted]	[redacted]	
LV Cogen 2 - 2x1	[redacted]	[redacted]	[redacted]	
LV Cogen 3 - 1x0	[redacted]	[redacted]	[redacted]	
LV Cogen 3 - 1x1	[redacted]	[redacted]	[redacted]	
LV Cogen 3 - 2x1	[redacted]	[redacted]	[redacted]	
SunPeak				
Sunpeak 3	[redacted]	[redacted]	[redacted]	
Sunpeak 4	[redacted]	[redacted]	[redacted]	
Sunpeak 5	[redacted]	[redacted]	[redacted]	

RED indicates change from last version.

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Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

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Unit	Type	Variable O&M (Consumables) per MWh Non-Fuel O&M Variable O&M - Costs associated with Dispach of the units Current 2024 $	Variable O&M (Consumables) per MWh Coal Handling These costs are included in column D Current 2024 $
Ft Churchill		[redacted]	[redacted]
Ft. Churchill 1	NG Boiler		
Ft. Churchill 2	NG Boiler		
Tracy Complex			
Tracy 3	NG Boiler		
Tracy 4&5	Small CC		
Tracy Combined Cycle 2x1	**Large CC**		
Tracy Combined Cycle 2x1 (Peak Fire)	Large CC		
Tracy Combined Cycle 2x1 (with Duct Burners)	Large CC		
Tracy Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC		
Tracy Combined Cycle 1x1	Large CC		
Tracy Combined Cycle 1x1 (with Duct Burners)	Large CC		
Tracy Combined Cycle 1x0	Large CC		
Clark Mountain 3	Peaker		
Clark Mountain 4	Peaker		
Clark Mountain 3-4 (Power Augmentation)	Peaker		
Valmy Complex			
Valmy 1	Coal Boiler		
Valmy 2	Coal Boiler		
Clark Complex			
Clark789 1x0	Small CC		
Clark789 1x1	Small CC		
Clark789 2x1	Small CC		
Clark5610 1x0	Small CC		
Clark5610 1x1	Small CC		
Clark5610 2x1	Small CC		
Clark 4	Peaker		
Clark Peakers 11-22	Peaker		
Clark Peakers 11-22 (Peak)	Peaker		
Clark Peakers 11-22 (Peak + Wet Compression)	Peaker		
Arrow Canyon Complex			
Lenzie Combined Cycle 2x1	**Large CC**		
Lenzie Combined Cycle 2x1 (with Duct Burners)	Large CC		
Lenzie Combined Cycle 1x1	Large CC		
Lenzie Combined Cycle 1x1 (with Duct Burners)	Large CC		
Lenzie Combined Cycle 1x0	Large CC		
Silverhawk Combined Cycle 2x1	**Large CC**		
Silverhawk Combined Cycle 2x1 (Peak Fire)	Large CC		
Silverhawk Combined Cycle 2x1 (with Duct Burners)	Large CC		
Silverhawk Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC		
Silverhawk Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)	Large CC		
Silverhawk Combined Cycle 1x1	Large CC		
Silverhawk Combined Cycle 1x1 (with Duct Burners)	Large CC		
Silverhawk Combined Cycle 1x0	Large CC		
Silverhawk 3	Peaker		
Silverhawk 4	Peaker		
Silverhawk 3-4 (Wet Compression)	Peaker		
Harry Allen Combined Cycle 2x1	**Large CC**		
Harry Allen Combined Cycle 2x1 (Peak Fire)	Large CC		
Harry Allen Combined Cycle 2x1 (with Duct Burners)	Large CC		
Harry Allen Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC		
Harry Allen Combined Cycle 1x1	Large CC		
Harry Allen Combined Cycle 1x1 (with Duct Burners)	Large CC		
Harry Allen Combined Cycle 1x0	Large CC		
Harry Allen 3	Peaker		
Harry Allen 4	Peaker		
Harry Allen 3-4 (Wet Compression)	Peaker		
Higgins Station			
Higgins Combined Cycle 2x1	**Large CC**		
Higgins Combined Cycle 2x1 (Peak Fire)	Large CC		
Higgins Combined Cycle 2x1 (with Duct Burners)	Large CC		
Higgins Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC		
Higgins Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)	Large CC		
Higgins Combined Cycle 1x1	Large CC		
Higgins Combined Cycle 1x1 (with Duct Burners)	Large CC		
Higgins Combined Cycle 1x0	Large CC		
Goodsprings			

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Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

		Variable O&M (Consumables) per MWh Non-Fuel O&M	Variable O&M (Consumables) per MWh Coal Handling
		Variable O&M - Costs associated with Dispach of the units	These costs are included in column D
Goodsprings	Renewable	[redacted]	[redacted]
Las Vegas Station		[redacted]	[redacted]
Las Vegas Block 1	Small CC	[redacted]	[redacted]
Las Vegas Block 2 1x0		[redacted]	[redacted]
Las Vegas Block 2 1x1	Small CC	[redacted]	[redacted]
Las Vegas Block 2 2x1	Small CC	[redacted]	[redacted]
Las Vegas Block 3 1x0		[redacted]	[redacted]
Las Vegas Block 3 1x1	Small CC	[redacted]	[redacted]
Las Vegas Block 3 2x1	Small CC	[redacted]	[redacted]
Sunpeak Station		[redacted]	[redacted]
Sunpeak 3	Peaker	[redacted]	[redacted]
Sunpeak 4	Peaker	[redacted]	[redacted]
Sunpeak 5	Peaker	[redacted]	[redacted]
Sunpeak 3-5 (Wet Compression)	Peaker	[redacted]	[redacted]

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Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

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	Maint $ / MWH Non-Fuel O&M	Maint $ / MWH Coal Handling	Maint $ / operating hr Non-Fuel O&M	Maint $ / operating hr Coal Handling
	Variable O&M - Costs associated with Dispach of the units	These costs are included in column F	Variable O&M - Costs associated with Dispach of the units	These costs are included in column H
	Current	Current	Current	Current
Unit	**2024 $**	**2024 $**	**2024 $**	**2024 $**
Ft Churchill	[redacted]	[redacted]	[redacted]	[redacted]
Ft. Churchill 1				
Ft. Churchill 2				
Tracy Complex				
Tracy 3				
Tracy 4&5				
Tracy Combined Cycle 2x1				
Tracy Combined Cycle 2x1 (Peak Fire)				
Tracy Combined Cycle 2x1 (with Duct Burners)				
Tracy Combined Cycle 2x1 (Peak Fire with Duct Burners)				
Tracy Combined Cycle 1x1				
Tracy Combined Cycle 1x1 (with Duct Burners)				
Tracy Combined Cycle 1x0				
Clark Mountain 3				
Clark Mountain 4				
Clark Mountain 3-4 (Power Augmentation)				
Valmy Complex				
Valmy 1				
Valmy 2				
Clark Complex				
Clark789 1x0				
Clark789 1x1				
Clark789 2x1				
Clark5610 1x0				
Clark5610 1x1				
Clark5610 2x1				
Clark 4				
Clark Peakers 11-22				
Clark Peakers 11-22 (Peak)				
Clark Peakers 11-22 (Peak + Wet Compression)				
Arrow Canyon Complex				
Lenzie Combined Cycle 2x1				
Lenzie Combined Cycle 2x1 (with Duct Burners)				
Lenzie Combined Cycle 1x1				
Lenzie Combined Cycle 1x1 (with Duct Burners)				
Lenzie Combined Cycle 1x0				
Silverhawk Combined Cycle 2x1				
Silverhawk Combined Cycle 2x1 (Peak Fire)				
Silverhawk Combined Cycle 2x1 (with Duct Burners)				
Silverhawk Combined Cycle 2x1 (Peak Fire with Duct Burners)				
Silverhawk Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)				
Silverhawk Combined Cycle 1x1				
Silverhawk Combined Cycle 1x1 (with Duct Burners)				
Silverhawk Combined Cycle 1x0				
Silverhawk 3				
Silverhawk 4				
Silverhawk 3-4 (Wet Compression)				
Harry Allen Combined Cycle 2x1				
Harry Allen Combined Cycle 2x1 (Peak Fire)				
Harry Allen Combined Cycle 2x1 (with Duct Burners)				
Harry Allen Combined Cycle 2x1 (Peak Fire with Duct Burners)				
Harry Allen Combined Cycle 1x1				
Harry Allen Combined Cycle 1x1 (with Duct Burners)				
Harry Allen Combined Cycle 1x0				
Harry Allen 3				
Harry Allen 4				
Harry Allen 3-4 (Wet Compression)				
Higgins Station				
Higgins Combined Cycle 2x1				
Higgins Combined Cycle 2x1 (Peak Fire)				
Higgins Combined Cycle 2x1 (with Duct Burners)				
Higgins Combined Cycle 2x1 (Peak Fire with Duct Burners)				
Higgins Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)				
Higgins Combined Cycle 1x1				
Higgins Combined Cycle 1x1 (with Duct Burners)				
Higgins Combined Cycle 1x0				
Goodsprings				

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Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	Maint $ / MWH Non-Fuel O&M	Maint $ / MWH Coal Handling	Maint $ / operating hr Non-Fuel O&M	Maint $ / operating hr Coal Handling
	Variable O&M - Costs associated with Dispach of the units	These costs are included in column F	Variable O&M - Costs associated with Dispach of the units	These costs are included in column H
Goodsprings	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Station	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Block 1	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Block 2 1x0	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Block 2 1x1	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Block 2 2x1	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Block 3 1x0	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Block 3 1x1	[redacted]	[redacted]	[redacted]	[redacted]
Las Vegas Block 3 2x1	[redacted]	[redacted]	[redacted]	[redacted]
Sunpeak Station	[redacted]	[redacted]	[redacted]	[redacted]
Sunpeak 3	[redacted]	[redacted]	[redacted]	[redacted]
Sunpeak 4	[redacted]	[redacted]	[redacted]	[redacted]
Sunpeak 5	[redacted]	[redacted]	[redacted]	[redacted]
Sunpeak 3-5 (Wet Compression)	[redacted]	[redacted]	[redacted]	[redacted]

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Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

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	Maint$ / Start$ (Normal Start)	Maint$ / Start$ (Fast Start)
	Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units
	Current	Current
Unit	**2024 $**	**2024 $**
Ft Churchill	[redacted]	
Ft. Churchill 1		
Ft. Churchill 2		
Tracy Complex		
Tracy 3		
Tracy 4&5		
Tracy Combined Cycle 2x1		
Tracy Combined Cycle 2x1 (Peak Fire)		
Tracy Combined Cycle 2x1 (with Duct Burners)		
Tracy Combined Cycle 2x1 (Peak Fire with Duct Burners)		
Tracy Combined Cycle 1x1		
Tracy Combined Cycle 1x1 (with Duct Burners)		
Tracy Combined Cycle 1x0		
Clark Mountain 3		
Clark Mountain 4		
Clark Mountain 3-4 (Power Augmentation)		
Valmy Complex		
Valmy 1		
Valmy 2		
Clark Complex		
Clark789 1x0		
Clark789 1x1		
Clark789 2x1		
Clark5610 1x0		
Clark5610 1x1		
Clark5610 2x1		
Clark 4		
Clark Peakers 11-22		
Clark Peakers 11-22 (Peak)		
Clark Peakers 11-22 (Peak + Wet Compression)		
Arrow Canyon Complex		
Lenzie Combined Cycle 2x1		
Lenzie Combined Cycle 2x1 (with Duct Burners)		
Lenzie Combined Cycle 1x1		
Lenzie Combined Cycle 1x1 (with Duct Burners)		
Lenzie Combined Cycle 1x0		
Silverhawk Combined Cycle 2x1		
Silverhawk Combined Cycle 2x1 (Peak Fire)		
Silverhawk Combined Cycle 2x1 (with Duct Burners)		
Silverhawk Combined Cycle 2x1 (Peak Fire with Duct Burners)		
Silverhawk Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)		
Silverhawk Combined Cycle 1x1		
Silverhawk Combined Cycle 1x1 (with Duct Burners)		
Silverhawk Combined Cycle 1x0		
Silverhawk 3		
Silverhawk 4		
Silverhawk 3-4 (Wet Compression)		
Harry Allen Combined Cycle 2x1		
Harry Allen Combined Cycle 2x1 (Peak Fire)		
Harry Allen Combined Cycle 2x1 (with Duct Burners)		
Harry Allen Combined Cycle 2x1 (Peak Fire with Duct Burners)		
Harry Allen Combined Cycle 1x1		
Harry Allen Combined Cycle 1x1 (with Duct Burners)		
Harry Allen Combined Cycle 1x0		
Harry Allen 3		
Harry Allen 4		
Harry Allen 3-4 (Wet Compression)		
Higgins Station		
Higgins Combined Cycle 2x1		
Higgins Combined Cycle 2x1 (Peak Fire)		
Higgins Combined Cycle 2x1 (with Duct Burners)		
Higgins Combined Cycle 2x1 (Peak Fire with Duct Burners)		
Higgins Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)		
Higgins Combined Cycle 1x1		
Higgins Combined Cycle 1x1 (with Duct Burners)		
Higgins Combined Cycle 1x0		
Goodsprings		

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	Maint$ / Start$ (Normal Start)	Maint$ / Start$ (Fast Start)
	Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units
Goodsprings	[redacted]	[redacted]
Las Vegas Station	[redacted]	[redacted]
Las Vegas Block 1	[redacted]	[redacted]
Las Vegas Block 2 1x0	[redacted]	[redacted]
Las Vegas Block 2 1x1	[redacted]	[redacted]
Las Vegas Block 2 2x1	[redacted]	[redacted]
Las Vegas Block 3 1x0	[redacted]	[redacted]
Las Vegas Block 3 1x1	[redacted]	[redacted]
Las Vegas Block 3 2x1	[redacted]	[redacted]
Sunpeak Station	[redacted]	[redacted]
Sunpeak 3	[redacted]	[redacted]
Sunpeak 4	[redacted]	[redacted]
Sunpeak 5	[redacted]	[redacted]
Sunpeak 3-5 (Wet Compression)	[redacted]	[redacted]

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Unit	Change Comments
Ft Churchill	
Ft. Churchill 1	Updated maintenance costs. Ratio change to 90% hours/10% starts
Ft. Churchill 2	Updated maintenance costs. Ratio change to 90% hours/10% starts
Tracy Complex	
Tracy 3	Updated maintenance costs. Ratio change to 90% hours/10% starts
Tracy 4&5	Updated maintenance costs. Ratio change to 90% hours/10% starts
Tracy Combined Cycle 2x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Tracy Combined Cycle 2x1 (Peak Fire)	New configuration
Tracy Combined Cycle 2x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Tracy Combined Cycle 2x1 (Peak Fire with Duct Burners)	New configuration
Tracy Combined Cycle 1x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Tracy Combined Cycle 1x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Tracy Combined Cycle 1x0	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Clark Mountain 3	Updated maintenance costs
Clark Mountain 4	Updated maintenance costs
Clark Mountain 3-4 (Power Augmentation)	New configuration
Valmy Complex	
Valmy 1	Updated maintenance costs
Valmy 2	Updated maintenance costs
Clark Complex	
Clark789 1x0	Updated maintenance costs. Ratio change to 90% hours/10% starts
Clark789 1x1	Updated maintenance costs. Ratio change to 90% hours/10% starts
Clark789 2x1	Updated maintenance costs. Ratio change to 90% hours/10% starts
Clark5610 1x0	Updated maintenance costs. Ratio change to 90% hours/10% starts
Clark5610 1x1	Updated maintenance costs. Ratio change to 90% hours/10% starts
Clark5610 2x1	Updated maintenance costs. Ratio change to 90% hours/10% starts
Clark 4	Updated maintenance costs
Clark Peakers 11-22	Updated maintenance costs. Increased ammonia price
Clark Peakers 11-22 (Peak)	Updated maintenance costs. Increased ammonia price
Clark Peakers 11-22 (Peak + Wet Compression)	Updated maintenance costs. Increased ammonia price
Arrow Canyon Complex	
Lenzie Combined Cycle 2x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Lenzie Combined Cycle 2x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Lenzie Combined Cycle 1x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Lenzie Combined Cycle 1x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Lenzie Combined Cycle 1x0	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Silverhawk Combined Cycle 2x1	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk Combined Cycle 2x1 (Peak Fire)	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk Combined Cycle 2x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk Combined Cycle 2x1 (Peak Fire with Duct Burners)	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk Combined Cycle 1x1	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk Combined Cycle 1x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk Combined Cycle 1x0	Updated maintenance costs. Ratio change to 80% hours/20% starts. Increased ammonia price
Silverhawk 3	New unit
Silverhawk 4	New unit
Silverhawk 3-4 (Wet Compression)	New unit
Harry Allen Combined Cycle 2x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Harry Allen Combined Cycle 2x1 (Peak Fire)	New configuration
Harry Allen Combined Cycle 2x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Harry Allen Combined Cycle 2x1 (Peak Fire with Duct Burners)	New configuration
Harry Allen Combined Cycle 1x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Harry Allen Combined Cycle 1x1 (with Duct Burners)	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Harry Allen Combined Cycle 1x0	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased ammonia price
Harry Allen 3	Updated maintenance costs. Stopped using biocide and scale inhibitor
Harry Allen 4	Updated maintenance costs. Stopped using biocide and scale inhibitor
Harry Allen 3-4 (Wet Compression)	Updated maintenance costs. Stopped using biocide and scale inhibitor
Higgins Station	
Higgins Combined Cycle 2x1	Updated maintenance costs. Increased ammonia price
Higgins Combined Cycle 2x1 (Peak Fire)	Updated maintenance costs. Increased ammonia price
Higgins Combined Cycle 2x1 (with Duct Burners)	Updated maintenance costs. Increased ammonia price
Higgins Combined Cycle 2x1 (Peak Fire with Duct Burners)	Updated maintenance costs. Increased ammonia price
Higgins Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)	Updated maintenance costs. Increased ammonia price
Higgins Combined Cycle 1x1	Updated maintenance costs. Increased ammonia price
Higgins Combined Cycle 1x1 (with Duct Burners)	Updated maintenance costs. Increased ammonia price
Higgins Combined Cycle 1x0	Updated maintenance costs. Increased ammonia price
Goodsprings	

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	Change Comments
Goodsprings	Updated maintenance costs
Las Vegas Station	
Las Vegas Block 1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased water, sewer, and ammonia prices
Las Vegas Block 2 1x0	
Las Vegas Block 2 1x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased water, sewer, and ammonia prices
Las Vegas Block 2 2x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased water, sewer, and ammonia prices
Las Vegas Block 3 1x0	
Las Vegas Block 3 1x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased water, sewer, and ammonia prices
Las Vegas Block 3 2x1	Updated maintenance costs. Ratio change to 90% hours/10% starts. Increased water, sewer, and ammonia prices
Sunpeak Station	
Sunpeak 3	Updated maintenance costs. Updated consumption rates.
Sunpeak 4	Updated maintenance costs. Updated consumption rates.
Sunpeak 5	Updated maintenance costs. Updated consumption rates.
Sunpeak 3-5 (Wet Compression)	New configuration

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

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Unit	Unit	Type	Summer KW Capacity	Fixed O&M per KW-Yr Includes Coal Yard DEAA — FIXED O&M - 24 hr reserve status 24x7x365 (Based on Summer KW Capacity) — Current — 2024 $	Fixed O&M Total (Including Coal Yard DEAA) — FIXED O&M - 24 hr reserve status 24x7x365 — Current — 2024 $	Fixed O&M Coal Yard (DEA $ - These $ included in Fixed O&M Total column) — FIXED O&M - 24 hr reserve status 24x7x366 — Current — 2024 $	Change Comments
Ft Churchill				[redacted]	[redacted]	[redacted]	
Ft. Churchill 1	Ft. Churchill 1	NG Boiler	98,000	[redacted]	[redacted]	[redacted]	
Ft. Churchill 2	Ft. Churchill 2	NG Boiler	98,000	[redacted]	[redacted]	[redacted]	
Tracy Complex				[redacted]	[redacted]	[redacted]	
Tracy 3	Tracy 3	NG Boiler	92,000	[redacted]	[redacted]	[redacted]	
Tracy 4&5	Tracy 4&5	Small CC	104,000	[redacted]	[redacted]	[redacted]	
Tracy Combined Cycle 2x1	Tracy Combined Cycle 2x1	Large CC	609,000	[redacted]	[redacted]	[redacted]	
Clark Mountain 3	Clark Mountain 3	Peaker	66,000	[redacted]	[redacted]	[redacted]	
Clark Mountain 4	Clark Mountain 4	Peaker	66,000	[redacted]	[redacted]	[redacted]	
Clark Mountain 4 (Fast Start)	Clark Mountain 4 (Fast Start)	Peaker		[redacted]	[redacted]	[redacted]	
Valmy Complex				[redacted]	[redacted]	[redacted]	
Valmy 1	Valmy 1	Coal Boiler	254,000	[redacted]	[redacted]	[redacted]	
Valmy 2	Valmy 2	Coal Boiler	268,000	[redacted]	[redacted]	[redacted]	
Clark Complex				[redacted]	[redacted]	[redacted]	
Clark789 2x1	Clark789 2x1	Small CC	230,000	[redacted]	[redacted]	[redacted]	
Clark5610 2x1	Clark5610 2x1	Small CC	230,000	[redacted]	[redacted]	[redacted]	
Clark 4	Clark 4	Peaker	55,000	[redacted]	[redacted]	[redacted]	
Clark Peakers 11-22	Clark Peakers 11-22	Peaker	624,000	[redacted]	[redacted]	[redacted]	
Arrow Canyon Complex				[redacted]	[redacted]	[redacted]	
Lenzie Combined Cycle 2x1	Lenzie Combined Cycle PB1 2x1	Large CC	621,000	[redacted]	[redacted]	[redacted]	
Lenzie Combined Cycle 2x1	Lenzie Combined Cycle PB2 2x1	Large CC	621,000	[redacted]	[redacted]	[redacted]	
Silverhawk Combined Cycle 2x1	Silverhawk Combined Cycle 2x1	Large CC	607,000	[redacted]	[redacted]	[redacted]	
Silverhawk 3	Silverhawk 3	Peaker	224,000	[redacted]	[redacted]	[redacted]	New unit. Estimated performance effective June 1, 2024
Silverhawk 4	Silverhawk 4	Peaker	224,000	[redacted]	[redacted]	[redacted]	New unit. Estimated performance effective June 1, 2024
Harry Allen Combined Cycle 2x1	Harry Allen Combined Cycle 2x1	Large CC	556,000	[redacted]	[redacted]	[redacted]	
Harry Allen 3	Harry Allen 3	Peaker	76,000	[redacted]	[redacted]	[redacted]	
Harry Allen 4	Harry Allen 4	Peaker	76,000	[redacted]	[redacted]	[redacted]	
Higgins Station				[redacted]	[redacted]	[redacted]	
Higgins Combined Cycle 2x1	Higgins Combined Cycle 2x1	Large CC	620,000	[redacted]	[redacted]	[redacted]	
Goodsprings				[redacted]	[redacted]	[redacted]	
Goodsprings	Goodsprings	Renewable	5,000	[redacted]	[redacted]	[redacted]	
Las Vegas Station				[redacted]	[redacted]	[redacted]	
Las Vegas Block 1	Las Vegas Block 1	Small CC	48,000	[redacted]	[redacted]	[redacted]	
Las Vegas Block 2 2x1	Las Vegas Block 2 2x1	Small CC	112,000	[redacted]	[redacted]	[redacted]	
Las Vegas Block 3 2x1	Las Vegas Block 3 2x1	Small CC	112,000	[redacted]	[redacted]	[redacted]	
Sunpeak Station				[redacted]	[redacted]	[redacted]	
Sunpeak 3	Sunpeak 3	Peaker	72,000	[redacted]	[redacted]	[redacted]	
Sunpeak 4	Sunpeak 4	Peaker	72,000	[redacted]	[redacted]	[redacted]	
Sunpeak 5	Sunpeak 5	Peaker	72,000	[redacted]	[redacted]	[redacted]	

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

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Unit	Type	Cold Start (Consumables) Single Generator (includes 1x0) Current 2024 $	Cold Start (Consumables) CC: 1x1 to 2x1 Current 2024 $	Cold Start (Consumables) CC: 0 to 2x1 Current 2024 $
Ft Churchill				
Ft. Churchill 1	NG Boiler	[redacted]	[redacted]	[redacted]
Ft. Churchill 2	NG Boiler	[redacted]	[redacted]	[redacted]
Tracy Complex				
Tracy 3	NG Boiler	[redacted]	[redacted]	[redacted]
Tracy 4&5	Small CC	[redacted]	[redacted]	[redacted]
Tracy Combined Cycle 2x1	**Large CC**	[redacted]	[redacted]	[redacted]
Tracy Combined Cycle 1x1	Large CC	[redacted]	[redacted]	[redacted]
Tracy Combined Cycle 1x0	Large CC	[redacted]	[redacted]	[redacted]
Clark Mountain 3	Peaker	[redacted]	[redacted]	[redacted]
Clark Mountain 4	Peaker	[redacted]	[redacted]	[redacted]
Valmy Complex				
Valmy 1	Coal Boiler	[redacted]	[redacted]	[redacted]
Valmy 2	Coal Boiler	[redacted]	[redacted]	[redacted]
Clark Complex				
Clark789 1x0	Small CC	[redacted]	[redacted]	[redacted]
Clark789 1x1	Small CC	[redacted]	[redacted]	[redacted]
Clark789 2x1	Small CC	[redacted]	[redacted]	[redacted]
Clark5610 1x0	Small CC	[redacted]	[redacted]	[redacted]
Clark5610 1x1	Small CC	[redacted]	[redacted]	[redacted]
Clark5610 2x1	Small CC	[redacted]	[redacted]	[redacted]
Clark 4	Peaker	[redacted]	[redacted]	[redacted]
Clark Peakers 11-22	Peaker	[redacted]	[redacted]	[redacted]
Arrow Canyon Complex				
Lenzie Combined Cycle 2x1	**Large CC**	[redacted]	[redacted]	[redacted]
Lenzie Combined Cycle 1x1	Large CC	[redacted]	[redacted]	[redacted]
Lenzie Combined Cycle 1x0	Large CC	[redacted]	[redacted]	[redacted]
Silverhawk Combined Cycle 2x1	**Large CC**	[redacted]	[redacted]	[redacted]
Silverhawk Combined Cycle 1x1	Large CC	[redacted]	[redacted]	[redacted]
Silverhawk Combined Cycle 1x0	Large CC	[redacted]	[redacted]	[redacted]
Silverhawk 3	Peaker	[redacted]	[redacted]	[redacted]
Silverhawk 4	Peaker	[redacted]	[redacted]	[redacted]
Harry Allen Combined Cycle 2x1	**Large CC**	[redacted]	[redacted]	[redacted]
Harry Allen Combined Cycle 1x1	Large CC	[redacted]	[redacted]	[redacted]
Harry Allen Combined Cycle 1x0	Large CC	[redacted]	[redacted]	[redacted]
Harry Allen 3	Peaker	[redacted]	[redacted]	[redacted]
Harry Allen 4	Peaker	[redacted]	[redacted]	[redacted]
Higgins Station				
Higgins Combined Cycle 2x1	**Large CC**	[redacted]	[redacted]	[redacted]
Higgins Combined Cycle 1x1	Large CC	[redacted]	[redacted]	[redacted]
Higgins Combined Cycle 1x0	Large CC	[redacted]	[redacted]	[redacted]
Goodsprings				
Goodsprings	Renewable	[redacted]	[redacted]	[redacted]
Las Vegas Station				
Las Vegas Block 1	Small CC	[redacted]	[redacted]	[redacted]
Las Vegas Block 2 1x0		[redacted]	[redacted]	[redacted]
Las Vegas Block 2 1x1	Small CC	[redacted]	[redacted]	[redacted]
Las Vegas Block 2 2x1	Small CC	[redacted]	[redacted]	[redacted]
Las Vegas Block 3 1x0		[redacted]	[redacted]	[redacted]
Las Vegas Block 3 1x1	Small CC	[redacted]	[redacted]	[redacted]
Las Vegas Block 3 2x1	Small CC	[redacted]	[redacted]	[redacted]
Sunpeak Station				
Sunpeak 3	Peaker	[redacted]	[redacted]	[redacted]
Sunpeak 4	Peaker	[redacted]	[redacted]	[redacted]
Sunpeak 5	Peaker	[redacted]	[redacted]	[redacted]

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	CONFIDENTIAL - COMPANY USE ONLY		
	Warm Start (Consumables)	Warm Start (Consumables)	Warm Start (Consumables)
	Single Generator	CC: 1x1 to 2x1	CC: 0 to 2x1
	Current	Current	Current
Unit	2024 $	2024 $	2024 $
Ft Churchill	[redacted]		
Ft. Churchill 1			
Ft. Churchill 2			
Tracy Complex			
Tracy 3			
Tracy 4&5			
Tracy Combined Cycle 2x1			
Tracy Combined Cycle 1x1			
Tracy Combined Cycle 1x0			
Clark Mountain 3			
Clark Mountain 4			
Valmy Complex			
Valmy 1			
Valmy 2			
Clark Complex			
Clark789 1x0			
Clark789 1x1			
Clark789 2x1			
Clark5610 1x0			
Clark5610 1x1			
Clark5610 2x1			
Clark 4			
Clark Peakers 11-22			
Arrow Canyon Complex			
Lenzie Combined Cycle 2x1			
Lenzie Combined Cycle 1x1			
Lenzie Combined Cycle 1x0			
Silverhawk Combined Cycle 2x1			
Silverhawk Combined Cycle 1x1			
Silverhawk Combined Cycle 1x0			
~~Silverhawk 3~~			
~~Silverhawk 4~~			
Harry Allen Combined Cycle 2x1			
Harry Allen Combined Cycle 1x1			
Harry Allen Combined Cycle 1x0			
Harry Allen 3			
Harry Allen 4			
Higgins Station			
Higgins Combined Cycle 2x1			
Higgins Combined Cycle 1x1			
Higgins Combined Cycle 1x0			
Goodsprings			
Goodsprings			
Las Vegas Station			
Las Vegas Block 1			
Las Vegas Block 2 1x0			
Las Vegas Block 2 1x1			
Las Vegas Block 2 2x1			
Las Vegas Block 3 1x0			
Las Vegas Block 3 1x1			
Las Vegas Block 3 2x1			
Sunpeak Station			
Sunpeak 3			
Sunpeak 4			
Sunpeak 5			

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

	CONFIDENTIAL - COMPANY USE ONLY			
	Hot Start (Consumables) Single Generator	Hot Start (Consumables) CC: 1x1 to 2x1	Hot Start (Consumables) CC: 0 to 2x1	Change Comments
	Current	Current	Current	
Unit	2024 $	2024 $	2024 $	
Ft Churchill	[redacted]			
Ft. Churchill 1				
Ft. Churchill 2				
Tracy Complex				
Tracy 3				
Tracy 4&5				
Tracy Combined Cycle 2x1				
Tracy Combined Cycle 1x1				
Tracy Combined Cycle 1x0				
Clark Mountain 3				
Clark Mountain 4				
Valmy Complex				
Valmy 1				
Valmy 2				
Clark Complex				
Clark789 1x0				
Clark789 1x1				
Clark789 2x1				
Clark5610 1x0				
Clark5610 1x1				
Clark5610 2x1				
Clark 4				
Clark Peakers 11-22				
Arrow Canyon Complex				
Lenzie Combined Cycle 2x1				
Lenzie Combined Cycle 1x1				
Lenzie Combined Cycle 1x0				
Silverhawk Combined Cycle 2x1				
Silverhawk Combined Cycle 1x1				
Silverhawk Combined Cycle 1x0				
Silverhawk 3				New unit. Estimated performance effective June 1, 2024
Silverhawk 4				New unit. Estimated performance effective June 1, 2024
Harry Allen Combined Cycle 2x1				
Harry Allen Combined Cycle 1x1				
Harry Allen Combined Cycle 1x0				
Harry Allen 3				
Harry Allen 4				
Higgins Station				
Higgins Combined Cycle 2x1				
Higgins Combined Cycle 1x1				
Higgins Combined Cycle 1x0				
Goodsprings				
Goodsprings				
Las Vegas Station				
Las Vegas Block 1				
Las Vegas Block 2 1x0				
Las Vegas Block 2 1x1				
Las Vegas Block 2 2x1				
Las Vegas Block 3 1x0				
Las Vegas Block 3 1x1				
Las Vegas Block 3 2x1				
Sunpeak Station				
Sunpeak 3				
Sunpeak 4				
Sunpeak 5				

REDACTED PUBLIC VERSION

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

CONFIDENTIAL - COMPANY USE ONLY

Unit	Type	Variable Maintenance $ per MWh (includes Variable Coal Yard Maintenace) Capital- Costs associated with Dispach of the units Current 2024 $	Variable Maintenance $ per Operating Hour (includes Variable Coal Yard Maintenace) Capital- Costs associated with Dispach of the units Current 2024 $	Variable Maintenance $ per Start (Normal Start) Capital- Costs associated with Dispach of the units Current 2024 $
Ft Churchill		[redacted]		
Ft. Churchill 1	NG Boiler			
Ft. Churchill 2	NG Boiler			
Tracy Complex				
Tracy 3	NG Boiler			
Tracy 4&5	Small CC			
Tracy Combined Cycle 2x1	Large CC			
Tracy Combined Cycle 2x1 (Peak Fire)	Large CC			
Tracy Combined Cycle 2x1 (with Duct Burners)	Large CC			
Tracy Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC			
Tracy Combined Cycle 1x1	Large CC			
Tracy Combined Cycle 1x1 (with Duct Burners)	Large CC			
Tracy Combined Cycle 1x0	Large CC			
Clark Mountain 3	Peaker			
Clark Mountain 4	Peaker			
Clark Mountain 3-4 (Power Augmentation)	Peaker			
Valmy Complex				
Valmy 1	Coal Boiler			
Valmy 2	Coal Boiler			
Clark Complex				
Clark789 1x0	Small CC			
Clark789 1x1	Small CC			
Clark789 2x1	Small CC			
Clark5610 1x0	Small CC			
Clark5610 1x1	Small CC			
Clark5610 2x1	Small CC			
Clark 4	Peaker			
Clark Peakers 11-22	Peaker			
Clark Peakers 11-22 (Peak)	Peaker			
Clark Peakers 11-22 (Peak + Wet Compression)	Peaker			
Arrow Canyon Complex				
Lenzie Combined Cycle 2x1	Large CC			
Lenzie Combined Cycle 2x1 (with Duct Burners)	Large CC			
Lenzie Combined Cycle 1x1	Large CC			
Lenzie Combined Cycle 1x1 (with Duct Burners)	Large CC			
Lenzie Combined Cycle 1x0	Large CC			
Silverhawk Combined Cycle 2x1	Large CC			
Silverhawk Combined Cycle 2x1 (Peak Fire)	Large CC			
Silverhawk Combined Cycle 2x1 (with Duct Burners)	Large CC			
Silverhawk Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC			
Silverhawk Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)	Large CC			
Silverhawk Combined Cycle 1x1	Large CC			
Silverhawk Combined Cycle 1x1 (with Duct Burners)	Large CC			
Silverhawk Combined Cycle 1x0	Large CC			
Silverhawk 3	Peaker			
Silverhawk 4	Peaker			
Silverhawk 3-4 (Wet Compression)	Peaker			
Harry Allen Combined Cycle 2x1	Large CC			
Harry Allen Combined Cycle 2x1 (Peak Fire)	Large CC			
Harry Allen Combined Cycle 2x1 (with Duct Burners)	Large CC			
Harry Allen Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC			
Harry Allen Combined Cycle 1x1	Large CC			
Harry Allen Combined Cycle 1x1 (with Duct Burners)	Large CC			
Harry Allen Combined Cycle 1x0	Large CC			
Harry Allen 3	Peaker			
Harry Allen 4	Peaker			
Harry Allen 3-4 (Wet Compression)	Peaker			
Higgins Station				
Higgins Combined Cycle 2x1	Large CC			
Higgins Combined Cycle 2x1 (Peak Fire)	Large CC			
Higgins Combined Cycle 2x1 (with Duct Burners)	Large CC			
Higgins Combined Cycle 2x1 (Peak Fire with Duct Burners)	Large CC			
Higgins Combined Cycle 2x1 (Peak Fire + Wet Compression with Duct Burners)	Large CC			
Higgins Combined Cycle 1x1	Large CC			
Higgins Combined Cycle 1x1 (with Duct Burners)	Large CC			
Higgins Combined Cycle 1x0	Large CC			
Goodsprings				
Goodsprings	Renewable			
Las Vegas Station				
Las Vegas Block 1	Small CC			
Las Vegas Block 2 1x0				
Las Vegas Block 2 1x1	Small CC			
Las Vegas Block 2 2x1	Small CC			
Las Vegas Block 3 1x0				
Las Vegas Block 3 1x1	Small CC			
Las Vegas Block 3 2x1	Small CC			
Sunpeak Station				
Sunpeak 3	Peaker			
Sunpeak 4	Peaker			
Sunpeak 5	Peaker			
Sunpeak 3-5 (Wet Compression)	Peaker			

REDACTED PUBLIC VERSION

Technical Appendix GEN-1 - NVE Gen Unit Characteristics Table - 2024 Update (01152024) - Confidential - Redacted.xlsx

Variable Maintenance $ per Start (Fast Start)	Change Comments
Capital- Costs associated with Dispach of the units	
Current	
2024 $	
[redacted]	
	New configuration: Estimated performance effective May 1, 2024.
	New configuration: Estimated performance effective May 1, 2024.
	New unit. Estimated performance effective June 1, 2024
	New unit. Estimated performance effective June 1, 2024
	New unit. Estimated performance effective June 1, 2024
	New configuration: Estimated performance effective May 1, 2024.
	New configuration: Estimated performance effective May 1, 2024.

GEN-2

2023 PLANT EMISSION RATES [1]

Revised January 24, 2024

UNIT	FUEL	SO_2	NO_X	CO	PM	VOC	CO_2	Hg
		lbs/mmbtu	lbs/mmbtu	lbs/mmbtu	lbs/mmbtu	lbs/mmbtu	lbs/mmbtu	lbs/Tbtu
Fort Churchill 1	Natural Gas	0.0006	0.1406	0.0010	0.0026	0.00021	118.86	NA
Fort Churchill 2	Natural Gas	0.0006	0.1241	0.0010	0.0025	0.00013	118.86	NA
Tracy 3	Natural Gas	0.0006	0.1201	0.0049	0.0060	0.00012	118.86	NA
Tracy 4 (CM3)	Natural Gas	0.0006	0.0371	0.0317	0.0022	0.0003	118.86	NA
Tracy 5 (CM4)	Natural Gas	0.0006	0.0287	0.0252	0.0000	0.0001	118.86	NA
Tracy 6 (Pinon)	Natural Gas	0.0006	0.1523	0.0025	0.0031	0.00001	118.86	NA
Tracy 8	Natural Gas	0.0006	0.0059	0.0010	0.0002	0.0002	118.86	NA
Tracy 9	Natural Gas	0.0006	0.0060	0.0020	0.00276	0.0004	118.86	NA
Clark 4	Natural Gas	0.0006	0.4400	0.1100	0.0420	0.0240	118.86	NA
Clark 5	Natural Gas	0.0006	0.0350	0.0750	0.0226	0.0046	118.86	NA
Clark 6	Natural Gas	0.0006	0.0200	0.0550	0.0226	0.0046	118.86	NA
Clark 7	Natural Gas	0.0006	0.0300	0.1040	0.0226	0.0046	118.86	NA
Clark 8	Natural Gas	0.0006	0.0340	0.0760	0.0226	0.0046	118.86	NA
Clark Unit 11	Natural Gas	0.0006	0.0636	0.0110	0.0080	0.0025	118.86	NA
Clark Unit 12	Natural Gas	0.0006	0.0531	0.0090	0.0080	0.0025	118.86	NA
Clark Unit 13	Natural Gas	0.0006	0.0623	0.0070	0.0080	0.0025	118.86	NA
Clark Unit 14	Natural Gas	0.0006	0.0658	0.0070	0.0080	0.0025	118.86	NA
Clark Unit 15	Natural Gas	0.0006	0.0420	0.0050	0.0080	0.0025	118.86	NA
Clark Unit 16	Natural Gas	0.0006	0.0367	0.0040	0.0080	0.0025	118.86	NA
Clark Unit 17	Natural Gas	0.0006	0.0406	0.0060	0.0080	0.0025	118.86	NA
Clark Unit 18	Natural Gas	0.0006	0.0433	0.0040	0.0080	0.0025	118.86	NA
Clark Unit 19	Natural Gas	0.0006	0.0517	0.0060	0.0080	0.0025	118.86	NA
Clark Unit 20	Natural Gas	0.0006	0.0555	0.0100	0.0080	0.0025	118.86	NA
Clark Unit 21	Natural Gas	0.0006	0.0477	0.0070	0.0080	0.0025	118.86	NA
Clark Unit 22	Natural Gas	0.0006	0.0350	0.0060	0.0080	0.0025	118.86	NA
Higgins 1	Natural Gas	0.0006	0.0105	0.0200	0.0018	0.00023	118.86	NA
Higgins 2	Natural Gas	0.0006	0.0107	0.0140	0.0021	0.00031	118.86	NA
Harry Allen 3	Natural Gas	0.0006	0.0457	2.7640	0.0083	0.00024	118.86	NA
Harry Allen 4	Natural Gas	0.0006	0.0349	0.8610	0.0083	0.00024	118.86	NA
Harry Allen 5	Natural Gas	0.0006	0.0152	1.0494	0.0024	0.000043	118.86	NA
Harry Allen 6	Natural Gas	0.0006	0.0126	1.1607	0.0020	0.000018	118.86	NA
Chuck Lenzie 1	Natural Gas	0.0006	0.0121	0.0006	0.00408	0.00013	118.86	NA
Chuck Lenzie 2	Natural Gas	0.0006	0.0132	0.0050	0.00408	0.00013	118.86	NA
Chuck Lenzie 3	Natural Gas	0.0006	0.0125	0.0060	0.00408	0.00013	118.86	NA
Chuck Lenzie 4	Natural Gas	0.0006	0.0112	0.0090	0.00408	0.00013	118.86	NA
Silverhawk 1	Natural Gas	0.0006	0.0151	0.0380	0.0070	0.0012	118.86	NA
Silverhawk 3	Natural Gas	0.0006	0.0142	0.0420	0.0053	0.0010	118.86	NA
Las Vegas 1	Natural Gas	0.0006	0.0326	0.0270	0.0060	0.0040	118.86	NA
Las Vegas 2	Natural Gas	0.0006	0.0163	0.0040	0.0050	0.0040	118.86	NA
Las Vegas 3	Natural Gas	0.0006	0.0185	0.0030	0.0050	0.0040	118.86	NA
Las Vegas 4	Natural Gas	0.0006	0.0174	0.0030	0.0050	0.0040	118.86	NA
Las Vegas 5	Natural Gas	0.0006	0.0177	0.0030	0.0050	0.0040	118.86	NA
Sun Peak 3	Natural Gas	0.0006	0.1437	0.1520	0.0059	0.0021	118.86	NA
Sun Peak 4	Natural Gas	0.0006	0.1370	0.1980	0.0059	0.0021	118.86	NA
Sun Peak 5	Natural Gas	0.0006	0.1416	0.2380	0.0059	0.0021	118.86	NA
Valmy 1	Coal	0.750	0.2511	0.0730	0.01101	0.0000	209.76	6.78E-01
Valmy 2	Coal	0.148	0.2611	0.2160	0.00784	0.0010	209.76	7.60E-05

[1] The basis of the rates shown is 2023 CEMS data, Acid Rain data for NOx, most recent emissions compliance testing, default emission factors, and, if no other source of data is available, permit limits or AP-42.

The Brunswick units have been removed from the table. However, they are now dispatchable up to 50 hours/unit. No emissions information is available for these units.

The following units have been retired and therefore removed from the table: Clark 1-3, Sunrise 1-2, Tracy 1-2, Reid Gardner 1-4, and Gabbs.

GEN-3

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