

# BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2027-2046 integrated resource plan, 2027-2029 Action Plan and 2027-2029 Energy Supply Plan.

Docket No. 26-05 \_\_\_\_

## VOLUME 41 OF 41

### ENERGY SUPPLY PLAN TESTIMONY, NARRATIVE AND TECHNICAL APPENDIX

DESCRIPTION	PAGE NUMBER
<b>TESTIMONY</b>	
Janet Wells	2
Catalin Adrian Cacuci	22
Michael Holland	40
Charles McCutchen	57
Timothy Pollard	69
Nicolai Schlag	78
Valentic, Matthew	99
Vincent Vitiello	109
Zeljko Vukanovic	118
<b>Narrative – Energy Supply Plan (Redacted)</b>	128
<b>Technical Appendix</b>	
FPP-1 Fuel and Purchased Power (Confidential)	217
ECON-1 NPC SPPC ESP Base Fuel and Purchased Power Costs CONFIDENTIAL	218
ECON-2 2026 Sierra Subsystem Resource Adequacy Assessment (E3) (Confidential)	219
GAS-1 Natural Gas Hedging Update	238
GAS-2 Projected BTER and DEAA Rates	294
RM-1 Risk Management and Control Policy	299
RM-2 Energy Risk Management and Control Policy	314
RM-3 Credit Risk Management and Control Policy	339

**JANET WELLS**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Janet Wells**

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

A. My name is Janet Wells. My current position is Vice President of Integrated Resource Planning for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My primary business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

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

A. I hold a Bachelor of Arts Degree in Geography and a Master of Science Degree in Applied Economics and Statistics. I have 19 years of utility experience within the Rates and Regulatory Affairs, and Integrated Resource Planning departments. Prior to joining the Companies, and during an absence from the Companies, I worked in economic consulting and research. The details of my background and experience are provided in **Exhibit Wells-Direct-1**.

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

3 A. As Vice President of Integrated Resource Planning, my responsibilities include  
4 leading the distribution, integrated grid, transmission, and resource planning  
5 functions, as well as the load forecasting and research, integrated energy services,  
6 and energy efficiency and conservation teams. These teams contribute to multiple  
7 regulatory filings, most significantly the Integrated Resource Plan, including the  
8 Distributed Resource Plan, and the Demand Side Management Plan.

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

13 A. Yes. Most recently in Docket No. 25-10028, the 2024 Joint Integrated Resource  
14 Plan (“IRP”) First Amendment. **Exhibit Wells-Direct-1** provides a full list of  
15 proceedings in which I have testified before the Commission.

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

18 A. As the 2026 Joint Energy Supply Plan (“ESP”) policy witness, I introduce the  
19 Companies’ witnesses, describe the preparation of the ESP and describe and give  
20 an overview of the ESP. I also sponsor or co-sponsor the following sections in the  
21 Companies’ ESP:

- 22 • Section 1 (“Executive Summary”);
- 23 • Section 2.D (“Renewable Energy Planning”);
- 24 • Section 7 (“Determination of Prudence under Nevada Administrative  
25 Code (“NAC”) §§ 704.9508(2) and 704.9494”); and
- 26 • Section 8 (“Commission Directives”).

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6. Q. PLEASE IDENTIFY THE WITNESSES WHO WILL TESTIFY IN THE COMPANIES' DIRECT CASE.

A. In addition to myself, the following witnesses testify in the Companies' direct case:

**Adrian Cacuci, Treasurer.** Mr. Cacuci sponsors Section 6 of the ESP, which relates to the Risk Control organization and strategy. Mr. Cacuci describes the role of the Risk Control organization in managing energy supply risk. In addition, Mr. Cacuci co-sponsors portions of Section 7 of the ESP and also sponsors Technical Appendix RM-1 through RM-3.

**Michael Holland, Vice President of Resource Optimization.** Mr. Holland co-sponsors Section 2.C ("Energy Requirements"); Section 2.G ("Financial Gas Requirements"); Section 3.B ("Regional Market Development"); Section 4 ("Power Procurement Plan"); Section 5.A ("Physical Gas Procurement Plan"); and Section 5.C ("Recommended Gas Hedging Plan"); In addition, Mr. Holland also sponsors Technical Appendix GAS-1.

**Charles McCutchen, Production Cost Modeling Lead.** Mr. McCutchen sponsors Section 2.B ("Capacity Requirements"), Section 2.E ("Gas Transportation Requirements"), Section 2.F ("Physical Gas Requirements"), and co-sponsors Section 2.C ("Energy Requirements"). He also sponsors Technical Appendix ECON-1.

**Timothy Pollard, Director of Load Forecasting.** Mr. Pollard sponsors the load forecast, which is described in Section 2.A of the ESP narrative.

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**Nicolai Schlag**, Partner at Energy and Environmental Economics (“E3”), supports a resource adequacy study of the Sierra subsystem, Technical Appendix ECON-2.

**Matthew Valentic, Regulatory Accounting Manager.** Mr. Valentic sponsors Technical Appendix Item GAS-2, which provides actual and forecasted Base Tariff Energy Rates and Deferred Energy Accounting Adjustment components.

**Vincent Vitiello, Gas Supply Planning Lead.** Mr. Vitiello sponsors Section 5.B (“Gas Transportation Plan”).

**Zeljko Vukanovic, Market Fundamentals Lead.** Mr. Vukanovic sponsors Section 3.A (“Market Fundamentals”), and Section 3.C (“Fuel and Purchased Power Price Forecasts”), and also Technical Appendix FPP-1.

- 7. **Q. PLEASE SUMMARIZE THE COMPANIES’ REQUESTS IN THIS ESP.**
  - A. First, and most generally, the Companies ask that the Commission approve and accept the ESP and, pursuant to the Commission’s regulations, find that the elements of the ESP – the purchased power procurement plan, the fuel procurement plan, and the risk management strategy and the components of those elements are prudent.  
  
Second, and more specifically, the Companies request that the Commission make the following findings:

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- That the ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan.
- That the ESP optimizes the value of the overall supply portfolio of the Companies for the benefit of their bundled retail customers.
- That the ESP does not contain any feature or mechanism that would impair the Companies’ creditworthiness or would lead to a deterioration of the Companies’ creditworthiness.

Third, the Companies request that the Commission make the following findings and issue the following approvals:

**Loads and Resources:** A finding that the load forecast used in this ESP meets the requirements of the NAC and is suitable for making planning decisions during the ESP action plan period (2027-2029). In addition, as described in Section 2.B in the narrative and in the testimony of Mr. McCutchen, the Companies request approval to close the open capacity position in the overnight hours rather than simply the evening hours.

**Power Procurement/Sales Plans:** Acceptance and approval of the power procurement/sales plan, and an affirmative finding consistent with NAC § 704.9494(3) that the power procurement strategy is prudent. The Companies request acceptance and approval of their plan to continue to implement a four-season laddering strategy for physical energy and/or capacity procurement to manage the open capacity position.

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**Fuel Procurement Plans:**

**Physical Gas Procurement Plan:** The Companies request acceptance and approval of the plan to continue to implement their four-season laddering strategy for physical gas supply, and an affirmative finding consistent with NAC § 704.9494(3) that the physical gas procurement strategy is prudent. Additionally, the Companies request the elimination of the premium cap on the procurement of physical gas.

**Gas Transportation Plan:** The Companies request acceptance and approval of the gas transportation plan, and an affirmative finding consistent with NAC § 704.9494(3) that the gas transportation strategy is prudent.

**Gas Hedging Plan:** The Companies request acceptance and approval of the gas hedging plan, which continues the current hedging strategy pursuant to which the Companies will not acquire natural gas hedges during the ESP action plan period, and an affirmative finding consistent with NAC § 704.9494(3) that the gas hedging strategy is prudent.

**Risk Management Strategy:** The Companies request acceptance and approval of the risk management strategy and a finding that the strategy identifies risks inherent in procuring and obtaining a supply portfolio and establishes the means by which the Companies plan to address and balance or hedge the identified risks related to cost, price volatility and reliability. The Companies request an affirmative finding consistent with NAC § 704.9494(3) that the risk management strategy is prudent.

1                    **Directives:** The Companies request a finding that they have satisfied their  
2 obligations to continue to hold bi-annual workshops with the Regulatory  
3 Operations Staff of the Commission (“Staff”) and the Bureau of Consumer  
4 Protection (“BCP”) and provide updates in the form of presentations to review the  
5 implementation of the constituent elements of the ESP and ESP updates, and the  
6 approved hedging strategy as contained in the Commission’s order dated October  
7 17, 2019, in Docket No. 19-08034.

8  
9                    **8.        Q.        HOW DO THE COMPANIES PREPARE AN ESP?**

10                    A.        The ESP is a short-term plan covering the first three years of a triennial IRP. This  
11 2026 ESP covers the 2027-2029 period. The Companies used the load forecast to  
12 project customers’ energy needs, including appropriate planning reserve margins.  
13 Once those needs are known, the Companies then assess the options available to  
14 meet those needs. The process includes an examination of market fundamentals in  
15 the region, including the outlook for change over the planning horizon. The  
16 Companies then identify resource options such as market purchases, including the  
17 type or mix of products, company-owned resources, and long-term power purchase  
18 agreements that are available to meet identified needs. The resource options are  
19 evaluated against three criteria: 1) minimizing the cost of supply, 2) minimizing  
20 retail price volatility, and 3) maximizing the reliability of energy supply over the  
21 term of the ESP. The Companies also consider the need to comply with Nevada’s  
22 Renewable Portfolio Standard (“RPS”), whether the ESP optimizes the value of the  
23 overall supply portfolio for the benefit of customers, and whether the ESP contains  
24 any feature or mechanism that would impair the restoration of the Companies’  
25 creditworthiness or would lead to a deterioration of the Companies’  
26 creditworthiness.

1 9. Q. WHAT PRINCIPLES GUIDED THE COMPANIES IN THE  
2 DEVELOPMENT OF THIS ESP?

3 A. The following principles guide the Companies' preparation of this ESP.

4 1) **Manage Exposure to Volatile Wholesale Energy Markets.** The  
5 Companies' strategies generally include executing longer-term contracts where  
6 appropriate in order to reduce customer exposure to price volatility on the capacity  
7 portion of NV Energy's energy supply costs.

8 2) **Utilize Competitive Procurement Processes.** The Companies use  
9 request for proposals ("RFPs"), or other tools, designed to produce competitive  
10 offers so that the Companies procure necessary resources in a manner that yields  
11 just and reasonable rates. RFPs provide flexibility to adjust the contracted amount  
12 based on the reasonableness of the offers that are received. An experienced team  
13 evaluates the proposals that are received, and determines the contract awards based  
14 upon price, reliability, and other competitive factors. The Companies' procedures  
15 are designed to ensure that customers pay fair market value for the commodities  
16 that the Companies purchase on their behalf.

17 3) **Continuous Evaluation and Monitoring.** The Companies  
18 continuously assess their procurement plans and strategies based upon changing  
19 market conditions and needs. The Risk Committee reviews supply plans  
20 approximately once a month. As a further check on the costs and benefits of the  
21 approved ESP and ESP Updates throughout the implementation process, the Risk  
22 Control organization monitors the energy costs and customer value at risk against  
23 set limits on a monthly basis, and reports variances to the Risk Committee. To the  
24 extent that circumstances dictate a change in strategy, the Resource Planning  
25 organization alerts the Risk Committee, notifies Staff and BCP, and obtains  
26 appropriate approvals of such deviations where applicable.

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1 **10. Q. PLEASE DESCRIBE NEVADA’S RPS.**

2 A. Nevada measures RPS compliance using portfolio credits (“PCs”). In simple terms,  
3 PCs are the accounting units utilities must hold to show they met the required  
4 standard for the year. PCs can come from Company-owned renewable generation,  
5 renewable power purchase agreements (“PPAs”), banked PCs from prior-year  
6 generation, eligible station-use PCs, and grandfathered solar multiplier PCs. In the  
7 most recent annual RPS compliance filing, Docket No. 26-04023, the Companies  
8 exceeded the 2025 RPS credit requirements of 34 percent, achieving an RPS of 47.5  
9 percent.

10  
11 For calendar year 2026, the RPS requirement is 34 percent of retail sales. In  
12 practice, each Company must hold PCs equal to at least 34 percent of its retail sales  
13 for that year. The requirement increases to 42 percent for 2027 through 2029, and  
14 to 50 percent beginning in 2030.

15  
16 Nevada also has an aspirational goal of creating an inventory of greenhouse gas  
17 emissions in the State and planning to reduce greenhouse gas emissions to zero or  
18 near-zero by the year 2050.

19  
20 **11. Q. HOW HAS THE TREATMENT OF ENERGY EFFICIENCY IN RPS**  
21 **COMPLIANCE CHANGED IN 2026?**

22 A. Previously, utilities could use energy efficiency savings to satisfy a limited portion  
23 of the RPS. From 2020 through 2024, up to 10 percent of the annual RPS  
24 requirement could be met with credits from qualifying energy efficiency measures,  
25 with at least half of those savings coming from residential customers. Effective  
26  
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1 January 1, 2025, energy efficiency and demand response program PCs are no longer  
2 allowed for RPS compliance. The Companies' 2026 ESP reflects this change.

3  
4 **12. Q. PLEASE DESCRIBE THE RPS RENEWABLE PLAN DEVELOPED FOR**  
5 **THE ESP.**

6 A. For the ESP, the Companies prepared an RPS renewable plan by forecasting (1)  
7 how many PCs will be required each year (based largely on retail sales) and (2)  
8 how many PCs the Companies are expected to have from existing and planned  
9 renewable resources. Comparing those two forecasts shows whether the Companies  
10 are projected to have enough PCs to comply, and it helps identify when additional  
11 actions may be needed. In this filing, the Companies provide these estimates  
12 through the ESP action plan period (2027–2029).

13  
14 **13. Q. PLEASE EXPLAIN THE ASSUMPTIONS AND METHODOLOGY**  
15 **UNDERLYING THE SHORT-TERM RENEWABLE EXPANSION PLAN.**

16 A. The short-term renewable expansion plan uses a set of assumptions to estimate RPS  
17 compliance under current statutory, regulatory, and market conditions. It starts with  
18 the Companies' Commission-approved renewable portfolio (operating resources  
19 and executed PPAs, plus Company-owned generation). It also assumes PPAs expire  
20 on their stated contract end dates unless the Companies have already executed an  
21 extension.

22  
23 For short-term planning, the plan then adjusts expected PC supply using actual  
24 historical generation—generally two or more years of operating data—so the  
25 forecast reflects how projects have been performing in practice. After coordinating  
26 with internal contract administrators, the Companies updated the forecasts to reflect  
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the most recent operating data and sustained deviations from contractual expectations. For Sierra, this resulted in adjustments to seven contracted renewable projects (three decreases and four increases), reducing total renewable energy by an average of 0.55 percent over 2027–2028. For Nevada Power, this resulted in adjustments to 13 projects (12 decreases and one increase), reducing renewable energy and derived PCs by an average of 2.54 percent over 2027–2028. These adjustments are intended to produce a more realistic short-term view of PC supply.

**14. Q. PLEASE DESCRIBE NEVADA POWER’S RPS OUTLOOK AND ANY POTENTIAL CONCERNS.**

A. Nevada Power is projected to be noncompliant with the RPS in 2027 through 2029 in large part due to the increase in the RPS requirement coupled with projected retail load growth. As retail sales increase, the number of PCs Nevada Power must hold increases, and that requirement steps up to 42 percent in 2027. At the same time, bringing new renewable resources online quickly enough to match the increasing load growth is challenging due to limited developable land, lengthy permitting and interconnection timelines, and near-term transmission constraints (including needed network upgrades and long-lead equipment). Nevada Power’s outlook also worsened due to renewable project attrition, including the cancellation of the Boulder Solar III PPA on March 20, 2026, after the developer did not meet a critical milestone due to cost escalation and permitting delays. These factors increase near-term compliance risk, even as the Companies continue pursuing renewable procurement, self-development, and other mitigation strategies.

1 **15. Q. PLEASE DESCRIBE SIERRA’S RPS OUTLOOK AND ANY POTENTIAL**  
2 **CONCERNS.**

3 A. Sierra is projected to be noncompliant with the RPS in 2027 and compliant in 2028  
4 and 2029. Compliance in 2028 and 2029 is partly attributable to accounting for the  
5 output from Libra in Sierra’s outlook as opposed to Nevada Power’s outlook, absent  
6 an approved allocation. Combined with Nevada Power, the Companies are  
7 projected to be non-compliant in 2027 through 2029. As retail sales increase, the  
8 number of PCs Sierra must acquire likewise increases, and that requirement steps  
9 up to 42 percent in 2027. At the same time, Sierra’s projected PC supply is lower  
10 due to renewable project cancellations and delays, and integrating additional  
11 renewable generation in the near term is challenging due to transmission  
12 constraints. These factors increase near-term compliance risk, even as the  
13 Companies continue pursuing mitigation strategies and monitoring conditions that  
14 may change actual results.

15  
16 Compliance is ultimately determined using actual retail sales and actual renewable  
17 generation for the year. The Companies will continue taking actions to support  
18 long-term RPS compliance while managing near-term constraints that drive risk in  
19 2027 and other near-term years.

20  
21 **16. Q. PLEASE DESCRIBE THE ACTIONS TAKEN TO ADDRESS THE**  
22 **RELIABILITY CONCERNS IDENTIFIED IN THE RESOURCE**  
23 **ADEQUACY STUDY FOR SIERRA.**

24 A. The resource adequacy study for Sierra, supported by Mr. Schlag, identified  
25 reliability risks in 2027 and 2028 that required action by Sierra to mitigate  
26 reliability risks. As described in Section 2.B of the ESP narrative, after revisiting  
27

1 its near-term load forecast, the Companies addressed those risks by (1) modifying  
2 an outage schedule, and (2) securing available firm resources within Sierra's  
3 territory. These steps improve Sierra's supply-demand balance in the study and  
4 mitigate the loss-of-load risk.  
5

6 **17. Q. DID THE COMPANY SECURE AN AVAILABLE FIRM RESOURCE?**

7 A. Yes. Sierra secured an available firm resource within its territory. This incremental  
8 capacity improves Sierra's reliability outlook and supports compliance with a  
9 planning standard of a loss-of-load expectation of one day in ten years. The costs  
10 associated with this resource will be allocated between bundled retail customers  
11 and certain large customers whose service requests necessitated the incremental  
12 capacity.  
13

14 **18. Q. PLEASE FURTHER DESCRIBE THE REVIEW OF THE LOAD  
15 FORECAST.**

16 A. Sierra revisited the large-customer portion of the load forecast for 2027 and 2028  
17 based on updated information. Sierra removed early-phase "study" loads from 2027  
18 and 2028 and applied a one-year delay to certain contracted loads. Stated  
19 differently, some large-customer load is still expected to materialize, but later than  
20 originally forecast. For modeling purposes, the change was represented as an  
21 effective reduction of 83 MW in 2027 and 146 MW in 2028. Sierra revisited and  
22 reaffirmed the magnitude of modeled reduction after recent work with large  
23 customers on energy agreements and continues to support a return to reliability  
24 metrics within standards. Sierra will continue monitoring actual load ramps and  
25 update assumptions as needed.  
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1 19. Q. PLEASE EXPLAIN THE ASSUMPTION DESCRIBED IN THE ESP OF A  
2 GREENLINK WEST DELAY UNTIL DECEMBER 31, 2027.

3 A. NV Energy’s posting on Open Access Same-time Information System (“OASIS”)  
4 indicate that Greenlink West may be delayed and may not be in service by May 31,  
5 2027. Accordingly, and for purposes of this ESP, the Companies adopted a planning  
6 assumption that Greenlink West will be in service on December 31, 2027. This  
7 assumption supports prudent reliability planning by reflecting the potential for  
8 schedule risk.

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10 20. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

11 A. Yes.  
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## **EXHIBIT WELLS-DIRECT-1**

**Janet C. Wells**  
**Vice President of Integrated**  
**Resource Planning**  
NV Energy  
6100 Neil Road  
Reno, Nevada 89511-1137  
(775) 834-4135

Mrs. Wells has been an employee of NV Energy for eighteen years and her time at the company includes her previous positions as Vice President of Regulatory, Regulatory Policy Director, Manager of Load Research, Senior Economist and Staff Economist in the Rates and Regulatory Affairs department and her current position as Vice President of Integrated Resource Planning. Her current responsibilities are focused on the analytical and strategic approaches to the planning functions of NV Energy.

Prior to joining NV Energy, Mrs. Wells had experience in economic consulting and research in both corporate and academic environments, detailed below, as well as other non-profit business experience not specifically detailed below.

**Employment History NV Energy**

October 2011 to Present December 2000 to August 2005

**Vice President of Integrated Resource Planning**

February 2025 to present

- Lead the distribution, integrated grid, transmission and resource planning teams in addition to load forecasting and research analyses, integrated energy services and energy efficiency and conservation teams.

**Vice President of Regulatory**

May 2022 to February 2025

- Oversee the preparation of regulatory filings before the Public Utilities Commission of Nevada and specifically the Load Research, Pricing, and Regulatory Affairs technical teams.

**Regulatory Policy Director, Rates and Regulatory Affairs**

March 2020 to April 2022

- Direct analytical and strategic approaches to regulatory issues and filings as well as corporate deliverables. Conduct research and analysis in support of new regulatory initiatives. Collaborate with regulatory groups in developing analysis and strategic approaches to integrating regulatory, load research, load forecasting, and pricing.
- Continue to support the management and technical production of class loads and other regulatory filings employing load data analyses.

**Manager, Load Research, Rates and Regulatory Affairs**

April 2017 to February 2020

**Supervisor, Load Research, Rates and Regulatory Affairs**

July 2012 to March 2017

- Manage all data and analysis related to producing hourly class loads for all Nevada Power and Sierra Pacific customer classes. Specifically, this process includes verification and estimation of interval data from multiple systems, population identification and validation, statistical sampling from populations, expansion of sample classes to produce class level total loads, and verification of final class loads to historical loads.
- Support all regulatory filings and data requests with load data and analysis ranging from: providing actual data, drafting responses, providing feedback to responses, and documenting completed analysis. Write and support testimony as needed.
- Provide validated load data and analysis to numerous areas within the company including Major Accounts, Load Forecasting, Energy Efficiency, Billing, Contracts, and to specific projects within the company such as the Energy Imbalance Market and Advanced Metering Infrastructure. In addition, provide validated load data where appropriate for external requests.
- Provide expertise and support to other major projects related to load data management and analysis including all work from raw data integrations and management, customer specific deliverables, original programming to produce needed calculations, and both data and statistical support of final analyses and report writing for projects such as the Nevada Dynamic Pricing Trial (NDPT)

**Senior Economist, Advanced Service Delivery Project**

October 2011 to July 2012

- Managed statistical sampling for U.S. Department of Energy reporting on metrics and recruitment
- Contributed to development of statistical design for analysis
- Managed data integrations needed for implementation of project

**Staff Economist, Rates and Regulatory Affairs**

October 2001 to August 2005

- Updated the Nevada Power Cost of Service Study as an input to rate cases
- Updated Customer Weighting Factor Study for Nevada Power and Sierra Pacific as an input to rate cases
- Supported all regulatory filings with testimony review and responses to data requests

**Senior Economist, Rates and Regulatory Affairs**

December 2000 to October 2001

- Developed Nevada Power Cost of Service Study as an input to rate cases
- Developed automated system for completing Customer Weighting Factor Studies

**Other Related Employment**

**University of Nevada, Reno**

May 2005 to August 2006

**Research Associate**

- Developed statistical programs for data management and analysis of 20 years of data to assess the Economic Value of Hiking for publication in a book chapter
- Developed survey instrument, data management from the survey, and econometric analysis related to wild horse adoption

**Triangle Economic Research, Durham, NC**

July 1997 to December 2000

**Senior Economist**, March 2000-December 2000

**Economist**, July 1997-March 2000

- Prepared preliminary estimate of recreational fishing damages from hazardous substance release using revealed preference data in a random utility model
- Estimated random utility models to determine expected catch using multiple methods, including non-parametric estimation and a multinomial logit estimation of catch (presented at American Agricultural Economics Association annual meeting)
- Developed and administered survey of recreational boaters; acquired survey research firm and validated data. Developed analysis plan for probit model of probability of site choice and conditional logit model of recreational benefits from restoration projects. Results were published with estimates of recreational benefits from proposed restoration projects using benefit transfer from other cases in Arizona Law Review
- Completed data collection, data management, econometric modeling and analysis, and report writing to estimate aggregate values of recreational activities using a nested price index, published in Environmental and Resource Economics

**Prior Testimony Before the Public Utilities Commission of Nevada**

**PUCN Docket Nos.:** 15-07041, 15-07042, 16-06006, 17-06003, 17-06014, 17-06015, 18-08007, 18-10034, 19-02002, 19-04002, 19-06002, 20-06003, 21-09031, 21-09032, 22-06014, 22-09002, 22-09006, 22-11032, 23-02010, 23-02011, 23-06007, 23-08019, 24-02026, 24-02027, 24-05022, 24-05023, 24-05041, 24-06011, 24-06012, 24-06014, 25-01018, 25-01019, 25-02016, 25-02033, 25-08027, 25-08029, 25-10003, and 25-10028.

**Education**

**University of Nevada, Reno**

Master of Applied Economics and Statistics, August 1996

**University of Manitoba, Winnipeg, Manitoba**

Bachelor of Arts in Geography, June 1992

**Continuing Education**

NERA Marginal Cost Methodology for Electric Utilities SAS Programming I and II

CORE Leadership Training

Six Sigma Green Belt Certification


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AFFIRMATION

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

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

Date: May 4, 2026

  
Janet Wells

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**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Catalin Adrian Cacuci**

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

A. My name is Catalin Adrian Cacuci. My current position is Treasurer for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I joined the Companies in 2022 as Assistant Treasurer and became Treasurer in 2023. Prior to joining the Companies, I held the position of Treasurer at The Cosmopolitan of Las Vegas since the property opened in 2010. In addition to the Treasurer role, I have held the roles of Vice President of Finance, Executive Director of Finance, Senior Director of Financial Planning and Analysis, and Director of Operational Analysis. Prior to The Cosmopolitan, I worked in Treasury and Financial Planning and Analysis at MGM Resorts International and Caesars’ Entertainment corporate and various properties, respectively. I have undergraduate

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and graduate degrees in business with an emphasis in finance. Additional details regarding my professional background and experience are in my Statement of Qualifications which was provided as **Exhibit Cacuci-Direct-1**.

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

A. As Treasurer, my responsibilities include oversight of the treasury and risk control-related functions. Treasury-related responsibilities include assisting the Chief Financial Officer to ensure adequacy of liquidity and financial stability including long-term financing and short-term debt utilization for the Companies.

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

A. Yes. I have previously prepared testimony in proceedings before the Commission, including in the Joint Energy Supply Plan (“ESP”) Update for 2025 and the Energy Supply Plan filed in 2024, Docket Nos. 25-08027 and 24-05041 respectively.

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

A. I sponsor Section 7 (“Risk Management Strategy”) and portions of Section 8 (“Determination of Prudence”) of the Companies’ 2026 Joint ESP, which covers the three-year period from 2027 through 2029. I sponsor the following Technical Appendices:

- RM-1 Risk Management and Control Policy
- RM-2 Energy Risk Management and Control Policy
- RM-3 Credit Risk Management and Control Policy

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

2 A. I sponsor the following exhibit:

3 Exhibit Cacuci-Direct-1 – Statement of Qualifications

4  
5 7. Q. PLEASE DESCRIBE THE POLICIES THAT GOVERN THE COMPANIES’  
6 RISK CONTROL FUNCTION.

7 A. The Companies’ risk control policies are as follows:

- 8 • RM-1: Risk Management and Control Policy is the Companies’ umbrella  
9 document that defines corporate risks, describes the management of that risk,  
10 and creates a governance structure (including the Risk Committee) to oversee  
11 policy implementation and adherence.
- 12 • RM-2: Energy Risk Management and Control Policy relates specifically to  
13 physical and financial transactions related to energy procurement, sales, and  
14 hedging. This policy establishes governance structures, authorized signatories,  
15 risk control thresholds, and compliance, among other items.
- 16 • RM-3: Credit Risk Management and Control Policy provides an overview of  
17 the Companies’ definition and management of risk created by a counterparty’s  
18 inability or unwillingness to fulfill its contractual obligations.

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20 8. Q. PLEASE DESCRIBE THE COMPANIES’ RISK MANAGEMENT  
21 FUNCTION AND CONTROL STRUCTURE.

22 A. The policies create the framework for managing risk, including four functional  
23 areas that are important components of risk management and control activities.  
24 They are:

- 25 1) **Risk Committee.** The Risk Committee, a formal Company interdepartmental  
26 executive forum organized and governed by NV Energy’s Risk Management  
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and Control Policy, is responsible for the overall policy direction and administration of the risk control efforts, including overall policy compliance. Each department is responsible for the administration of the Company’s risk management and risk mitigation programs and is held accountable to the Risk Committee. The Risk Committee serves as the designated forum through which the Company’s Chief Executive Officer (“CEO”) and executive team members are kept apprised of inherent risks. Risk Committee members are listed in the Risk Management and Control Policy (See RM-1, Section V, subsection B).

- 2) **Risk Control.** The Risk Control function, under the direction of the Vice President, Chief Financial Officer (“CFO”) and the Treasurer, is responsible for monitoring compliance with established policies and associated procedures, including the approved ESP and ESP updates. The Risk Control function is also responsible for evaluating and reporting the energy supply portfolio risk control metrics discussed later in this testimony.
- 3) **Credit Risk Management.** Credit risk is defined as the possibility that a counterparty will be unable or unwilling to fulfill its financial or physical obligations because of the counterparty’s financial condition. The Credit Risk Management function, under the direction of the CFO and The Treasurer, is generally responsible for credit risk management activities as they apply to energy supply.
- 4) **Energy Supply.** The Energy Supply function, under the direction of the Vice President of Generation and the Vice President of Resource Optimization, is responsible for electric generation and the delivery and optimization of fuel and wholesale power transactions.

1 9. Q. **WHAT ARE THE RISK COMMITTEE’S ENERGY SUPPLY RELATED**  
2 **RESPONSIBILITIES?**

3 A. The Risk Committee has several key responsibilities regarding energy supply risks.  
4 These include:

- 5 • Assessing the appropriateness of the Companies’ energy supply risk  
6 management and control activities and making recommendations for  
7 modifications to existing risk policies.
- 8 • Approving changes and exceptions as designated in specific sections of the risk  
9 policies and ensuring the ongoing availability of procedures required to  
10 implement those policies or any changes to them.
- 11 • Assessing the systems required to monitor, record, and report on the risks  
12 inherent in the Companies’ energy supply related activities and making  
13 recommendations for improvements to existing policies.
- 14 • Approving ESPs, ESP updates and any exceptions to these plans.
- 15 • Reviewing all transactions requiring exceptions to the applicable policies and  
16 procedures.
- 17 • Reviewing all energy procurement and sale transactions that are not transacted  
18 in accordance with the ESP or ESP updates prior to the submission for approval  
19 of such transactions to the President.
- 20 • Reviewing all violations of notification thresholds and processes established  
21 under the risk policies, approving or recommending approval remedies of the  
22 violations, and monitoring progress of such remedies.
- 23 • Assigning the completion of any other activities to guide the overall policy  
24 direction of the Companies’ energy risk management and control efforts.

1 10. Q. WHAT TYPES OF FORMAL METRICS HAVE BEEN ESTABLISHED BY  
2 THE RISK COMMITTEE FOR EVALUATING THE COMPANIES'  
3 ENERGY SUPPLY PORTFOLIOS?

4 A. Three types of risk control metrics are utilized: transaction approval metrics,  
5 portfolio risk metrics, and credit risk metrics.  
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7 11. Q. PLEASE DESCRIBE THE TRANSACTION APPROVAL METRICS THAT  
8 ARE USED TO ASSIST THE RISK COMMITTEE IN EVALUATING THE  
9 COMPANIES' PORTFOLIOS.

10 A. The transaction approval metrics control the values of contracts that authorized  
11 personnel are allowed to execute. Total dollar value of the contract is tracked and  
12 reported.  
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14 12. Q. PLEASE DESCRIBE THE PORTFOLIO RISK METRICS THAT ARE  
15 USED TO ASSIST THE RISK COMMITTEE IN EVALUATING THE  
16 COMPANIES' PORTFOLIOS.

17 A. The Energy Risk Management and Control Policy defines the use of the following  
18 two metrics:

19 1) **Test Period Mark-to-Base.** Monthly differences between fuel and purchased  
20 power costs and base tariff energy rate revenues are deferred. Mark-to-base  
21 provides an estimate of such deferrals for the current Deferral Period. Mark-to-  
22 base is determined using actual expenditures to date, committed expenditures  
23 for the balance of the Deferral Period, and expected expenditures for  
24 uncommitted purchases. The policy triggers notifications if significant changes  
25 in mark-to-base are experienced on either a cumulative basis or on a month-to-  
26 month basis.  
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2) **Value-at-Risk.** Value-at-risk serves as a gauge of market exposure, summarizing the total market risk on the Company’s fuel and purchased power costs. As measured by the Company, value-at-risk estimates the increase in fuel and wholesale power costs over the forthcoming rolling 12 months, at a 95 percent confidence interval. Value-at-risk is also a useful tool in determining liquidity requirements and is referred to as cash flow at risk when used in this context. The policy triggers notifications if value-at-risk exceeds certain levels. The Company calculates value-at-risk with the portfolio period limited to the next 12 months and using a 95 percent confidence interval. A 95 percent confidence interval means that there is a 95 percent probability that actual fuel and purchased power expenses will not exceed the value-at-risk value. However, there is still a 5 percent probability that the increased costs will be higher than the value-at-risk projection. The idea is to measure, within a 95 percent degree of probability, the potential increase in cost to customers.

Inputs used to calculate Value-at-Risk include the forward price curves for power and natural gas, as well as the associated forward monthly volatilities of each product. Correlations between the various power and gas trading hubs are calculated based on historical prices at each trading hub. An algorithm then runs a user-specified number of iterations to create a distribution of possible cost increase outcomes. From this distribution, standard statistical methods are applied to give the user the cost increase at various confidence intervals.

1 13. Q. PLEASE DESCRIBE THE CREDIT RISK METRICS THAT ARE USED TO  
2 ASSIST THE RISK COMMITTEE IN EVALUATING THE COMPANIES'  
3 PORTFOLIOS.

4 A. Credit limits help to ensure that the Companies are not overly exposed to any single  
5 counterparty or to a counterparty with unacceptable credit profiles. The Credit Risk  
6 Management and Control Policy identifies four credit limits that are monitored  
7 monthly:

- 8 1) **Portfolio Below Investment Grade.** The percentage of actual mark-to-market  
9 exposure below investment grade for the portfolio as of prior month's end;  
10 2) **Portfolio Weighted Average Credit Rating.** The weighted average of actual  
11 mark-to-market exposure for the portfolio as of prior month's end;  
12 3) **Counterparty Credit Limit On-going Transactions.** The actual mark-to-  
13 market exposure of counterparties at prior month's end; and  
14 4) **Counterparty Credit Limits Large Transactions.** The potential mark-to-  
15 market exposure of counterparties with transactions greater than \$10 million  
16 entered into in the past month.

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18 14. Q. PLEASE DESCRIBE THE RISK CONTROL FUNCTION.

19 A. Risk Control is a distinct organization within the Companies and is responsible for  
20 calculating certain risk control metrics. Representatives of the Risk Control  
21 organization report the results of these analyses to management in a Monthly Risk  
22 Control Report. Risk Control also performs actualization of fuel and power  
23 transactions prior to invoices being paid to counterparties. Additionally, Risk  
24 Control monitors recorded conversations of fuel and power traders via phone,  
25 instant message and other channels to check for any signs of fraud.

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**15. Q. PLEASE DESCRIBE THE MONTHLY RISK CONTROL REPORTS.**

A. The Risk Control organization prepares monthly reports to identify, track and report risk control metrics relating to transaction approval risk, portfolio risk, and credit risk. The reports are presented and discussed at meetings of the Risk Committee or, if not available at the time of the meeting, they are e-mailed to the Committee members upon completion.

**16. Q. PLEASE DEFINE THE TERM ‘NOTIFICATION THRESHOLD’ AS IT IS USED IN THE RISK CONTROL REPORTING PROCESS.**

A. A ‘notification threshold’ triggers reports to management when certain threshold events occur, such as a large increase in the Mark-to-Base. The notification thresholds require management notification and discussion. After notification and discussion, management must decide whether or not to take specific actions in response to the event that triggered the notification.

**17. Q. WHAT HAPPENS WHEN THE RISK CONTROL ORGANIZATION REPORTS AN EVENT THAT TRIGGERS A NOTIFICATION REQUIREMENT?**

A. Several steps are taken upon a triggering event:

- Upon identification of an event triggering a notification requirement, the Treasurer or a designated Risk Control employee will notify the appropriate officer, and, depending upon the nature of the issue, can call for a special Risk Committee meeting;
- Risk Control maintains a log of all notifications and monitors the status of each issue until compliance is achieved; and

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- Risk Control presents all events triggering a notification requirement to the Risk Committee for discussion, including a recommended course of corrective action if deemed necessary.

**18. Q. PLEASE DESCRIBE THE CREDIT RISK MANAGEMENT FUNCTION.**

A. The Credit Risk Management and Control Policy establishes a set of metrics that are monitored by Risk Control on a periodic basis. The purpose of these metrics is to provide transparency of the corporate credit portfolio to the Risk Committee. The metrics include an Arrears Balance Metric and an Uncollected Deposits Metric, each designed to monitor the credit exposure attributable to large retail customers. In addition, a counterparty credit metric for supply chain is used to control the credit exposure attributable to large suppliers.

All potential transactions are reviewed to determine counterparty credit ratings, financial scoring metrics, the current mark-to-market exposure of all current transactions, and whether the potential credit exposure calculations are within the Companies' policy limits. The Credit Risk Management function is responsible for assessing and approving the credit risk of counterparties and is also responsible for data collection and reporting of the creditworthiness of current and potential counterparties on an ongoing basis. A monthly report tracks current counterparties, their credit ratings from Moody's and Standard and Poor's, the outlook of the ratings, the internal credit limit of each counterparty based on the lowest of the two ratings, and the mark-to-market exposure. This credit report is distributed to the Companies' management, and, based upon these reports, stricter counterparty limits will be put in place if appropriate. The Credit Risk Management function is also responsible for providing collateral requirements for fuel and power contracts.

1 19. Q. **WHAT HAPPENS IF A COUNTERPARTY’S CREDIT IS DOWNGRADED**  
2 **AFTER A CONTRACT IS SIGNED?**

3 A. If a counterparty is downgraded after a contract is signed, Credit Risk Management  
4 monitors the performance and the exposure of the contract in relation to the credit  
5 limit. The contracts themselves provide the Companies and customers with  
6 protection in the form of monetary damages in the event of certain credit events  
7 and if the delivery obligation is not fulfilled. Depending on the nature of the credit  
8 event and contract exposure, the counterparty can be deactivated for additional  
9 transactions.

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11 20. Q. **PLEASE SUMMARIZE THE ROLE OF THE ENERGY SUPPLY GROUP**  
12 **IN THE ENERGY RISK MANAGEMENT PROGRAM.**

13 A. The Energy Supply organization manages energy risk by purchasing and selling  
14 financial instruments and physical products in accordance with an approved ESP.  
15 The ESP and ESP updates are reviewed on an ongoing basis and updated at least  
16 annually. Material changes in the data or assumptions underlying the approved  
17 ESP, which may also require a change in strategy, are promptly reported to the Risk  
18 Committee by Resource Planning & Analysis.

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20 21. Q. **WHAT PORTIONS OF SECTION 8 OF THE ESP DO YOU SPONSOR?**

21 A. Section 8 of the 2026 ESP addresses the three criteria set forth in Nevada  
22 Administrative Code, section 704.9494, which are to be applied by the Commission  
23 in making a determination that the ESP is prudent:

- 24 • The ESP balances the objectives of minimizing the cost of supply, minimizing  
25 retail price volatility and maximizing the reliability of supply over the term of  
26 the plan.

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- The ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
- The ESP does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

I address the third criterion, relating to the Companies’ creditworthiness.

**22. Q. PLEASE SUMMARIZE THE COMPANIES’ CURRENT CREDIT RATINGS.**

A. On December 22, 2025, Standard & Poor’s Ratings Services (‘S&P’) affirmed Nevada Power’s and Sierra’s ‘A-’ issuer ratings and stable outlook. S&P noted that because both Nevada Power and Sierra are considered strategically important subsidiaries of Berkshire Hathaway Energy, the issuer rating is two notches above what they would be rated on a stand-alone basis.

On October 7, 2025, Moody’s Investors Service re-affirmed Nevada Power’s ‘Baa1’ Issuer credit rating and on the same date it reaffirmed Sierra’s ‘Baa2’ Issuer credit rating. For both Nevada Power and Sierra, Moody’s recognized that the Companies are undergoing significant capital expenditures and noted that regulatory lag is more pronounced in Nevada due to reliance on a regulatory framework which does not include a forward test year or capital cost recovery mechanism. Moody’s lists several factors that could lead to a downgrade at Sierra including a decrease in the cash flow from operations before changes in working capital (“CFO pre-WC”) to debt ratio to 14% or below on a sustained basis, insufficient parent support, unfavorable regulatory recovery treatment, or if its wildfire risk may materialize into a large liability.

Table Cacuci-Direct-1 below shows each rating for each respective company.

**TABLE CACUCI-DIRECT-1**

Ratings	S&P – STABLE			Moody's – STABLE		
	Issuer	Senior Secured	Junior Subordinated	Issuer	Senior Secured	Junior Subordinated
<b>Nevada Power</b>	A-	A	BBB	Baa1	A2	Baa2
<b>Sierra</b>	A-	A	BBB	Baa2	A3	Baa3

23. Q. DOES THE 2026 ESP CONTAIN ANY FEATURE OR MECHANISM THAT WOULD IMPAIR THE RESTORATION OF THE CREDITWORTHINESS OF THE COMPANIES OR THAT COULD BE REASONABLY EXPECTED TO IMPAIR OR ERODE THE CREDITWORTHINESS OF THE COMPANIES?

A. No, the Companies’ creditworthiness improved materially following the acquisition by Berkshire Hathaway Energy Company in 2013. S&P revised its rating methodology in 2016 which resulted in Nevada Power and Sierra’s credit ratings being raised above the ratings assigned by S&P to these entities at the time of the 2013 acquisition.

Credit quality can be impacted by the funding requirements associated with capital expenditures and by financial commitments created by contracts, such as power purchase agreements (“PPAs”). The impact on credit quality from funding requirements associated with capital expenditures can be estimated using changes in equity and debt capital balances and cash flow amounts. PPAs are also part of the rating agencies’ evaluation process and have the potential to negatively impact credit ratings, depending on the magnitude and terms of a utility’s PPA portfolio, other pending uncertainties, and issuer mitigation strategies.

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**24. Q. THE 2026 ESP PROPOSES A NATURAL GAS HEDGING STRATEGY WHEREBY THE COMPANIES WOULD NOT PROCURE ANY HEDGES DURING THE ESP FORECAST PERIOD. WOULD THIS STRATEGY IMPAIR THE CREDITWORTHINESS OF THE COMPANIES?**

A. The strategy, in and of itself, does not impair the Companies' creditworthiness; significant under collection of fuel and purchase power costs due to increasing natural gas prices and the limitations of the recovery mechanism can create pressure as seen recently with increases in the deferred energy balance. Nevertheless, the Companies do not believe the mechanism itself has a negative impact on creditworthiness. The Companies have historically relied upon internally generated cash flow, existing cash balances, and capacity under their revolving credit facilities to fund fuel and power expenditures.

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

A. Yes.

**EXHIBIT CACUCI-DIRECT-1**

**CATALIN ADRIAN CACUCI**  
**TREASURER**  
NV Energy  
6226 West Sahara Avenue  
Las Vegas, NV 89151

**Summary of Qualifications**

I have been employed at NV Energy since September 2022 with primary responsibilities in Treasury and Risk Control. I have 23 years of experience in Treasury, Corporate Finance, and Financial Planning and Analysis.

**Professional Experience**

***NV Energy – Treasurer (2022-Current)***

Primary responsibilities in Treasury and Risk Control. Other positions held: Interim Treasurer, Assistant Treasurer

***The Cosmopolitan of Las Vegas – Vice President of Finance and Treasurer (2010-2022)***

Oversaw all treasury and payables functions. Other positions held: Executive Director of Finance, Sr. Director Financial Planning and Analysis, Director of Operational Analysis, HOA President, HOA Treasurer

***MGM Resorts International – Treasury Manager (2006-2010)***

Oversaw daily cash management and reporting, bank relationship management, cash liquidity, corporate card programs, merchant services, employee stock compensation plan

***New York, New York Hotel and Casino – Financial Planning and Analysis Manager (2005-2006)***

Managed FP&A functions including annual operational and capital budgets, strategic plans, return on investment analysis, evaluated host and independent agent efficiency, labor standards and productivity, special event proformas and post event analysis

***Caesars' Entertainment – Senior Financial Analyst (2003-2005)***

Prepared and analyzed annual operating and capital budgets, labor standards, gaming host and independent agent productivity, commission reports, individual player activity reports, special event proformas and post event analysis

**Education and Certification**

**University of Nevada, Las Vegas – Master of Business Administration**

Two-year program with a concentration in finance

**University of Nevada, Las Vegas – Bachelor of Science in International Business**

Summa Cum Laude

**Association for Financial Professionals - Certified Treasury Professional (CTP)**

Issued 2012, Active status

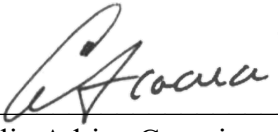
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AFFIRMATION

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

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

Date: May 4, 2026

  
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Catalin Adrian Cacuci

**MICHAEL HOLLAND**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Michael Holland**

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

A. My name is Michael Holland. I am the Vice President, Resource Optimization for Sierra Pacific Power Company d/b/a NV Energy (“Sierra”) and Nevada Power Company d/b/a NV Energy (“Nevada Power” or the “Company” and, together with Sierra, the “Companies”). I work primarily out of Nevada Power’s office at 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. My experience includes more than 18 years in the energy sector with positions in several areas, including power and natural gas trading and the oversight of energy trading activities in multiple markets. I have been in various leadership roles overseeing activities related to energy trading, retail natural gas and electric supply, origination and market operations. My statement of qualifications is attached as **Exhibit Holland-Direct-1.**

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

3 A. My current responsibilities involve the oversight of the Resource Optimization  
4 team. Resource Optimization is responsible for a number of activities, including,  
5 but not limited to, all power and natural gas trading activities, short-term production  
6 cost modeling, the development of trading analytics to support energy marketing  
7 and origination activities, participation in the Western Energy Imbalance Market  
8 (“WEIM”), renewable resource origination, contract management, and wholesale  
9 market design efforts.

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

14 A. Yes. Most recently I prepared testimony in proceedings before the Commission in  
15 Nevada Power and Sierra’s 2026 Deferred Energy Accounting Adjustment  
16 (“DEAA”) filings, Docket Nos. 26-02035, 26-02036 and 26-02037. I also have  
17 prepared testimony in the first amendment to the 2024 Triennial Joint Integrated  
18 Resource Plan filing in Docket No. 25-10028, in Nevada Power and Sierra’s joint  
19 application for an amendment to the 2025-2027 Energy Supply Plan (“ESP”) filing  
20 in Docket No. 25-10025, in Nevada Power’s 2025 General Rate Case filing in  
21 Docket No. 25-02016, and in the Companies’ 2025 DEAA filings, Docket Nos. 25-  
22 02033, 25-02034, and 25-02035.

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

A. The purpose of my testimony is to describe the Companies’ power procurement plan, discuss portfolio optimization, and address a compliance item. I also sponsor or co-sponsor the following sections in the Companies’ 2026 ESP for the action plan period of 2027-2029:

- Section 2.C (“Energy Requirements”);
- Section 2.G (“Financial Gas Requirements”);
- Section 3.B (“Regional Market Development”);
- Section 4 (“Power Procurement Plan”);
- Section 5.A (“Physical Gas Procurement Plan”); and
- Section 5.C (“Recommended Gas Hedging Plan”).

**6. Q. ARE YOU SPONSORING ANY TECHNICAL APPENDIX ITEMS?**

A. Yes, I am sponsoring the following Technical Appendices:

- Technical Appendix GAS-1- Gas Hedging Workshop Presentations.

**7. Q. PLEASE DESCRIBE THE COMPANIES’ POWER PROCUREMENT PLAN.**

A. In 2017, the Commission accepted stipulations resolving all matters in the Companies’ 2017 ESP update applications in Docket Nos. 17-09001 and 17-09002, including the power procurement plan strategies. In compliance with the approved power procurement plan, in January 2018 the Companies issued the first of several requests for proposals (“RFPs”) to procure energy and/or capacity to implement a four-season laddering strategy to close the open position. In this filing, the Companies are requesting approval to continue with the four-season laddering strategy to close the open position.

The four-season power procurement plan for managing the open position will utilize a competitive bidding process scheduled to coordinate with the Companies' physical natural gas procurement plan. The procurement percentages are shown in **Table Holland Direct-1**.

**TABLE HOLLAND DIRECT-1**  
**PERCENTAGE OF OPEN POWER POSITION TO BE CLOSED**  
**IN EACH PROCUREMENT PERIOD**

Incremental transaction	Delivery				
	Summer 2027	Summer 2028	Summer 2029	Summer 2030	Summer 2031
Q3 2025	25%				
Q1 2026	25%				
Q3 2026	25%	25%			
Q1 2027	25%	25%			
Q3 2027		25%	25%		
Q1 2028		25%	25%		
Q3 2028			25%	25%	
Q1 2029			25%	25%	
Q3 2029				25%	25%
<b>Sum</b>	100%	100%	100%	75%	25%

In addition to the RFP process, the Companies propose to continue to work directly with counterparties to solicit non-standard products, which may more cost-effectively address the short-term (two to three hour) jumps in open capacity due to drastic drops in renewable resources in the evening hours. The Companies will evaluate all available products and determine the most prudent transaction plan based on cost and deliverability.

1 8. Q. ARE THE COMPANIES CONCERNED ABOUT THEIR ABILITY TO  
2 OBTAIN SUFFICIENT RELIABLE ENERGY TO FILL ANY  
3 ADDITIONAL OPEN POSITIONS THAT MAY OCCUR DURING THE  
4 ESP FORECAST PERIOD DUE TO UNANTICIPATED INCREASES IN  
5 ENERGY DEMAND AND/OR SHORTAGES IN SUPPLY?

6 A. Yes. Western energy markets are experiencing rapid and significant changes in  
7 climate, weather, resource mix, policy, and energy consumption patterns, requiring  
8 the Companies and stakeholders to reevaluate established practices, in particular,  
9 large reliance on market purchases, to ensure sufficient capacity to meet peak  
10 demands during the summer. Climate-related incidents and record load levels no  
11 longer appear to be isolated incidents but annual occurrences. Both the Western  
12 Electric Coordinating Council (“WECC”) and the North American Electric  
13 Reliability Corporation (“NERC”) have issued resource adequacy and reliability  
14 cautionary statements regarding the uncertain availability and deliverability of  
15 market capacity and energy due to more frequent extreme weather, weather-related  
16 events, and a changing climate that are stressing the system.

17  
18 9 Q. WHAT IS THE STATUS OF THE WESTERN RESOURCE ADEQUACY  
19 PROGRAM (“WRAP”) AND ARE THE COMPANIES STILL MOVING  
20 FORWARD WITH PARTICIPATION?

21 A. In the 2025 ESP update, Docket No. 25-08027, the Companies informed the  
22 Commission of the Companies’ intention to withdraw from the Western Power  
23 Pool’s WRAP. On October 24, 2025, the Companies filed a letter to the Western  
24 Power Pool Board of Directors to formally withdraw from the program prior to the  
25 onset of binding program operations.<sup>1</sup> The Companies have continued to monitor

---

26  
27 <sup>1</sup> [https://www.westernpowerpool.org/private-media/documents/NV\\_Energy\\_WRAP\\_Withdrawal.pdf](https://www.westernpowerpool.org/private-media/documents/NV_Energy_WRAP_Withdrawal.pdf)

1 the program’s development and continue to participate in the non-binding program.  
2 To date, WRAP has not evolved to address the five critical issues identified in the  
3 2025 ESP update.<sup>2</sup> Therefore, the Companies do not have plans to rejoin the  
4 program in September 2026 to be a part of the binding summer 2027 season.  
5

6 **10. Q. WHAT IS THE STATUS OF DAY-AHEAD MARKET DEVELOPMENT?**

7 A. The Companies sought approval from the Commission to join the California  
8 Independent System Operator (“CAISO”) Extended Day Ahead Market (“EDAM”)  
9 on October 22, 2025.<sup>3</sup> The Commission issued its decision on April 3, 2026,  
10 granting the request, subject to specific conditions. The Companies filed a petition  
11 for reconsideration and clarification on April 17, 2026. The Companies  
12 respectfully request reconsideration of Paragraph 130, which designates the day-  
13 ahead Resource Sufficiency Evaluation (“RSE”) surcharges responsibility, and  
14 Paragraph 131, which caps the annual EDAM participation budget at \$16.52  
15 million. The Companies also seek clarification and, to the extent necessary,  
16 reconsideration of (1) the method to obtain prior approval to increase the  
17 implementation budget cap, as outlined in Paragraph 131, and (2) the timing of  
18 the EDAM implementation costs as outlined in Paragraph 134.  
19

20 **11. Q. PLEASE DESCRIBE THE COMPANIES’ PHYSICAL GAS**  
21 **PROCUREMENT PLAN.**

22 A. Section 5.A of the ESP summarizes the Companies’ physical gas procurement plan.  
23 The Companies are requesting acceptance and approval of their plan to continue to  
24 procure physical gas using the four-season laddering strategy originally approved  
25 by the Commission in Docket No. 09-09001, and most recently reaffirmed by the  
26

27 <sup>2</sup> 25-08027 Prepared Direct Testimony of Lindsey Schlekeway

<sup>3</sup> Docket No. 25-10025, October 22, 2025

Commission in Docket Nos. 25-08027 and 24-05041. Pursuant to the four-season laddering strategy, the Companies will procure 25 percent of projected monthly physical gas requirements per season for four seasons, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. Furthermore, targeted physical gas volumes will exclude any potential gas-fired generation to meet forward sales; gas needed to meet forward sales will only be procured in the short-term.

**TABLE HOLLAND DIRECT-2  
PHYSICAL GAS ACQUISITION STRATEGY**

Incremental transaction	Delivery								
	Summer '27	Winter '27-'28	Summer '28	Winter '28-'29	Summer '29	Winter '29-'30	Summer '30	Winter '30-'31	Summer '31
Q1 2025									
Q3 2025	25%								
Q1 2026	25%	25%							
Q3 2026	25%	25%	25%						
Q1 2027	25%	25%	25%	25%					
Q3 2027		25%	25%	25%	25%				
Q1 2028			25%	25%	25%	25%			
Q3 2028				25%	25%	25%	25%		
Q1 2029					25%	25%	25%	25%	
Q3 2029						25%	25%	25%	25%
<b>Sum</b>	100%	100%	100%	100%	100%	100%	75%	50%	25%

**12. Q. PLEASE BRIEFLY DESCRIBE COMPANIES' NATURAL GAS HEDGING PLAN.**

A. The Companies propose to continue the currently approved hedging strategy and acquire no natural gas hedges covering the ESP action plan period at this time. The Companies will continue to monitor the gas markets and propose a revised hedging strategy, if necessary, in a future ESP amendment or ESP update.

1 **13. Q. ARE THE COMPANIES PROPOSING ANY CHANGES TO THE**  
2 **PHYSICAL GAS PROCURMENT PLAN?**

3 A. Yes. The Companies propose to remove the physical premium cap from the  
4 four-season laddering strategy. As currently structured and approved in 2009, the  
5 laddering strategy includes a physical premium cap on executed transactions, which  
6 may be exceeded only with approval from the Company's Risk Committee. The  
7 existing premium cap no longer reflects current market realities or procurement  
8 conditions<sup>4</sup>.

9  
10 **14. Q. IN WHAT WAYS DOES THE PREMIUM CAP NO LONGER REFLECT**  
11 **CURRENT MARKET REALITIES OR PROCUREMENT CONDITIONS?**

12 A. The premium cap has not been adjusted for inflation since 2009, and sellers' risk  
13 preferences and cost structures have evolved over time. As a result, the Companies  
14 rarely receive bids that are at or below the existing premium cap.<sup>5</sup> For example,  
15 for all 2023 deliveries, 101 of 101 seasonal purchases exceeded the premium cap.<sup>6</sup>  
16 Similar outcomes were observed for 2024 deliveries, where 102 of 103 seasonal  
17 purchases exceeded the premium cap.<sup>7</sup>

18  
19 **15. Q. DOES THE REMOVAL OF THE PREMIUM CAP AFFECT THE RESULTS**  
20 **OF THE COMPANIES' LADDERING STRATEGY?**

21 A. No. The Companies execute transactions submitted through the laddering strategy  
22 in least-cost order. Because execution is always based on least cost, the presence of  
23 a physical premium cap does not affect transaction outcomes. This has been true  
24 for past transactions and will remain true for future transactions executed under the

25  
26 <sup>4</sup> Docket Nos. 24-03003 and 24-03004 Prepared Direct Testimony of Kurt Strunk at Q&A 24-29

27 <sup>5</sup> Docket Nos. 24-03003 and 24-04004 Prepared testimony of Kurt Strunk at Q&A 24-29

28 <sup>6</sup> Docket Nos. 24-03003 and 24-04004 Prepared testimony of Kurt Strunk at Q&A 23

<sup>7</sup> Docket Nos. 25-02033 and 25-02034 Prepared testimony of Kurt Strunk at Q&A 24

1 laddering strategy. The same transactions would have been executed even if the  
2 premium cap had not been in place. Removing the premium cap achieves two  
3 primary objectives: (1) it acknowledges that the current premium cap is no longer  
4 consistent with prevailing market conditions, and (2) it eliminates the  
5 administrative burden of seeking Risk Committee approval.  
6

7 **16. Q. DOES SIERRA CURRENTLY HAVE ANY COAL FOR THE ESP ACTION**  
8 **PLAN PERIOD?**

9 A. North Valmy ceased all coal operations in January of 2026. As a result, there will  
10 be no coal procured during the ESP action plan period.  
11

12 **17. Q. WHAT IS PORTFOLIO OPTIMIZATION?**

13 A. Portfolio optimization involves structuring the Companies' portfolio of resources,  
14 including generation resources and assets, purchased power contracts, and natural  
15 gas contracts, based upon reliability considerations, economic factors, and changes  
16 in anticipated load, in a manner that minimizes costs to the Companies' customers  
17 while effectively managing risk.  
18

19 **18. Q. DO THE COMPANIES OPTIMIZE THEIR RESOURCE PORTFOLIOS?**

20 A. Yes. The Companies engage in short-term (*i.e.*, less than one month) and forward  
21 (*i.e.*, greater than one month) purchases of power and natural gas when economic  
22 or as needed to serve native load. The Companies also engage in sales of power and  
23 natural gas to the extent that available resources are not expected to be needed to  
24 serve customer load. They also engage in sales of natural gas transportation  
25 capacity (*i.e.*, capacity release) that is not expected to be needed to serve their gas  
26 requirements. The Companies further optimize their respective power portfolio  
27

1 through participation in the WEIM operated by CAISO. The Companies began  
2 participating in the WEIM on December 1, 2015.

3  
4 **19. Q. HOW DO THE COMPANIES PROPOSE TO OPTIMIZE THEIR**  
5 **PORTFOLIOS FOR THE BENEFIT OF CUSTOMERS DURING THE ESP**  
6 **PERIOD?**

7 A. The Companies propose to continue using a mix of short-term and forward  
8 purchases and sales as part of their portfolio optimization strategy. The Companies  
9 propose to continue to optimize their portfolio through participation in the WEIM.  
10 The Companies propose to commence optimizing their portfolio in the CAISO  
11 EDAM beginning in the fall of 2028. The Companies will continue their existing  
12 practices of making sales of natural gas and natural gas transport capacity to the  
13 extent that resources are not expected to be needed to serve their native load.

14  
15 **20. Q. WILL THE COMPANIES CONTINUALLY REVIEW THE PORTFOLIO**  
16 **OPTIMIZATION STRATEGY IN LIGHT OF CHANGING MARKET**  
17 **CONDITIONS?**

18 A. Yes. The Companies will review and revise the portfolio optimization strategy as  
19 appropriate in response to changing market conditions. However, the Companies  
20 will not deviate from the strategy recommended in this ESP without prior approval  
21 from the Companies' Risk Committee. In addition, if the Companies deviate from  
22 the ESP, they will provide appropriate notice to Staff and the BCP as required by  
23 the Commission's regulations and, if appropriate under Commission regulations or  
24 directive, seek Commission approval to continue to deviate from the ESP.

1 21. Q. PROVIDE A “LOOK BACK” COMPARISON OF THE EXCESS, OR  
2 DUMP, ENERGY REFLECTED IN THE PREVIOUS INTEGRATED  
3 RESOURCE PLAN FILING (DOCKET NO. 24-05041) WITH THAT  
4 SUBSEQUENTLY EXPERIENCED DURING THE ACTION PLAN  
5 PERIOD AS DIRECTED IN DOCKET NOS. 25-02033, 25-02034, AND 25-  
6 02035.

7 A. Below is a look-back comparison of the excess, or dump, energy forecast in the  
8 previous integrated resource plan filing (Docket No. 24-05041) with that  
9 subsequently experienced during the action plan period. The breakout between  
10 Nevada Power and Sierra was done by ownership of the solar photovoltaic  
11 facilities. In 2025, there were no solar curtailments manually initiated by either the  
12 day-ahead or real-time trading teams. All curtailments are for other reasons. For  
13 example, they may be the result of congestion, balancing authority action, or market  
14 mechanics, to name a few.

15  
16 The results of the analysis show that Nevada Power had 6.56 Gigawatts (“GW”)  
17 more excess energy than the IRP forecast. At the same time, Sierra had 20.3 GW  
18 less excess energy than the IRP forecast during 2025. Combined, the volume of  
19 actual excess energy was 13.8 GW less than the IRP forecast.

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**TABLE HOLLAND DIRECT-3  
2025 NEVADA POWER MONTHLY EXCESS ENERGY COMPARISON**

<b>Nevada Power 2025</b>			
<b>Month</b>	<b>IRP (GWh)</b>	<b>Actual (GWh)</b>	<b>Difference (GWh)</b>
<b>January</b>	0.00	0.63	0.63
<b>February</b>	0.00	1.74	1.74
<b>March</b>	0.69	0.46	-0.23
<b>April</b>	1.95	0.79	-1.16
<b>May</b>	0.26	1.18	0.92
<b>June</b>	0.01	0.42	0.41
<b>July</b>	0.00	0.48	0.48
<b>August</b>	0.00	0.56	0.56
<b>September</b>	0.00	1.16	1.16
<b>October</b>	0.00	0.36	0.36
<b>November</b>	0.00	1.67	1.67
<b>December</b>	0.00	0.02	0.02
<b>Totals</b>	2.91	9.47	6.56

**TABLE HOLLAND DIRECT-4  
2025 SIERRA MONTHLY EXCESS ENERGY COMPARISON**

<b>Sierra 2025</b>			
<b>Month</b>	<b>IRP (GWh)</b>	<b>Actual (GWh)</b>	<b>Difference (GWh)</b>
<b>January</b>	0.00	0.01	0.01
<b>February</b>	0.00	0.04	0.04
<b>March</b>	4.58	0.13	-4.45
<b>April</b>	10.67	0.14	-10.53
<b>May</b>	5.67	0.12	-5.55
<b>June</b>	1.09	0.53	-0.56
<b>July</b>	0.00	0.32	0.32
<b>August</b>	0.33	0.37	0.04
<b>September</b>	0.00	0.27	0.27
<b>October</b>	0.11	0.14	0.03
<b>November</b>	0.00	0.01	0.01
<b>December</b>	0.00	0.00	0.00
<b>Totals</b>	22.45	2.09	-20.36

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

A. Yes.

**EXHIBIT HOLLAND-DIRECT-1**

## STATEMENT OF QUALIFICATIONS

### **Michael Holland**

Vice President, Resource Optimization

NV Energy

6226 West Sahara Avenue

Las Vegas, NV 89151

702.321.0796

Michael.Holland@NVEnergy.com

### **Professional Experience**

**NV Energy**, Las Vegas, NV

**Vice President, Resource Optimization, December 2024-Present**

- Responsible for directing the development and execution of strategies to maximize the value of NV Energy's portfolio of energy supply resources through oversight of NV Energy's day ahead and real time operations analytics and trading activities around power, natural gas, carbon credit allowances, and coal
- Oversight of NV Energy's renewable origination activities
- Oversight of the contract management tasks for NV Energy's owned and contracted resources

**BHE Renewables**, Des Moines, IA

**Director, Energy Trading, August 2022-December 2024**

- Managed a team of power traders responsible for a generation portfolio spread across six markets
- Managed a team of natural gas traders responsible for retail and gas generation supply
- Responsible for trading capacity and renewable energy credits in multiple markets across the United States
- Directed teams responsible for onboarding new generation and coordinating market integration
- Provided due diligence expertise in both pricing and transmission for potential acquisitions and projects

**NV Energy, Las Vegas, NV**

**Manager, Power and Gas Trading, July 2021-August 2022**

- Managed a team of power traders responsible for managing both the short and long-term power positions
- Managed a team of gas traders responsible for the procurement of natural gas to supply both power plants and end-use customers
- Responsible for multiple Requests for Proposals (RFPs) yearly to ensure power and natural gas needs are met at the best price

**Senior Power Trader, June 2018-July 2021**

- Optimized NV Energy's generation portfolio and executed day-ahead power transactions consistent with the Company's risk management guidelines
- Administered multiple RFPs to fill seasonal power needs

**Macquarie Energy, Houston, TX**

**Senior Real-Time Trader, November 2010-June 2018**

- Traded hourly physical and virtual power in PJM, MISO, CAISO, SWPP, ERCOT, MIDC, and NYISO markets

**Ameren UE, St. Louis, MO**

**Real-Time Power Trader, May 2008- October 2010**

- Utilized various generation assets, physical trades, and virtual bids and offers to actively manage the real-time position to maximize profits and mitigate risk.

**Education**

**Tulane University, Freeman School of Business, New Orleans, LA**

Master of Business Administration – 2008

**United States Naval Academy, Annapolis, MD**

Bachelor of Science, English - 1999

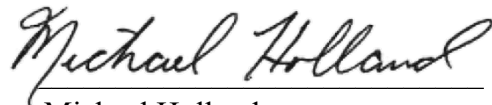
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AFFIRMATION

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

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

Date: May 4, 2026

  
Michael Holland

**CHARLES McCUTCHEN**

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

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

4 2026 Joint Energy Supply Plan  
5 Docket No. 26-05 \_\_\_\_

6 Prepared Direct Testimony of

7 **Charles McCutchen**

8  
9 **1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS**  
10 **ADDRESS AND PARTY FOR WHOM YOU ARE FILING**  
11 **TESTIMONY.**

12 A. My name is Charles McCutchen. My current position is Production Cost  
13 Modeling Lead for Nevada Power Company d/b/a NV Energy (“Nevada  
14 Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and,  
15 together with Nevada Power, the “Companies”). My business address is 6226  
16 West Sahara Avenue, Las Vegas, Nevada, 89146. I am filing testimony on  
17 behalf of the Companies.

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

21 A. My professional experience includes more than seven years in the utility  
22 industry. I have been employed by the Companies since 2018, working in the  
23 Resource Optimization and Resource Planning departments. During this time,  
24 I have held roles including Portfolio Optimization Analyst II, Senior Power  
25 and Gas Trading Specialist, and Production Cost Modeling Lead. I hold a  
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Bachelor of Science degree in Business Administration from Nebraska Wesleyan University and a Master of Science degree in Financial Engineering from the University of Michigan. I also maintain active certifications as a Chartered Alternative Investment Analyst and Certified Financial Risk Manager. The details of my background and experience are provided in **Exhibit McCutchen-Direct-1.**

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS PRODUCTION COST MODELING LEAD.**

A. As Production Cost Modeling Lead, I am responsible for assisting in the development and management of production cost models and tools to provide reports of projected energy production and associated costs. I assess the Companies’ short term energy needs and lead various supply management activities including developing open capacity positions consistent with regulatory requirements and the Companies’ goals and objectives.

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

A. Yes, I have prepared testimony in Docket No. 25-08027, the Companies Joint Energy Supply Plan (“ESP”) Update for 2026-2027.

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

A. I am sponsoring the following exhibit:  
**Exhibit McCutchen-Direct-1** Statement of Qualifications

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I am sponsoring the following Technical Appendix:

**Technical Appendix-ECON-1 – Confidential**

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

A. Yes. ECON-1 is being filed confidentially. This confidential information is commercially sensitive and contains trade secret information that derives independent economic value from not being generally known. Public disclosure of this confidential information would adversely affect the Companies’ ability to obtain favorable terms from their fuel and purchase power suppliers.

**7. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL TREATMENT?**

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

**8. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE REGULATORY OPERATIONS STAFF (“STAFF”) OR THE BUREAU OF CONSUMER PROTECTION (“BCP”) TO FULLY INVESTIGATE THE ESP?**

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

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**9. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?**

- A. I sponsor the following sections in the Companies’ 2026 Joint ESP:
- Section 2.B (“Capacity Requirements”)
  - Section 2.C (“Energy Requirements”) (sponsored jointly with Michael Holland)
  - Section 2.E (“Gas Transportation Requirements”)
  - Section 2.F (“Physical Gas Requirements”)
  - 2027-2029 Estimated Cost to Serve for the Companies in Section 7

**10. Q. PLEASE DESCRIBE THE METHODOLOGY USED TO PERFORM THE ECONOMIC ANALYSIS IN THIS FILING.**

A. The Companies’ analysis of future resource requirements begins with the Loads and Resources Tables (“L&R Tables”). The L&R Tables indicate the capacity resources available to serve forecasted customer load including internal generation and purchases. Purchased power resources include purchases from existing and planned renewable energy projects, internal power contracts (within the Companies’ system) and external power contracts (outside the Companies’ system). External generation purchases require system import transmission capacity. In addition, resources in specific locations within the Companies’ control area consume or reduce import capability.

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Next, the Companies utilize the software tool PLEXOS ST for production cost modeling.<sup>1</sup> PLEXOS ST simulates the operation of the electric system and computes production costs (fuel, purchase power, variable and fixed costs to operate generation) by performing hourly, chronological, economic unit commitment and dispatch of the Companies’ electric production resources and market purchases to satisfy hourly load requirements in a least cost solution over the planning period.

The Companies use PLEXOS ST to calculate the average daily gas requirements as illustrated in Figures ESP-20 and ESP-21 in Section 2.F (“Physical Gas Requirements”).

The Companies also conduct scenario analysis under the low, base, and high fuel and purchased power price forecasts. The Companies then calculate the projected Base Tariff Energy Rates (“BTER”) and Deferred Energy Accounting Adjustment (“DEAA”) rates for 2027-2029 under the low, base, and high fuel and purchased power price forecasts. The projected BTER and DEAA rates are presented in Technical Appendix GAS-2 and sponsored by Matthew Valentic.

An additional production cost model sensitivity is used to evaluate the system reliability and projected firm gas transportation needs for northern and southern generation plants and Sierra’s natural gas local distribution company.

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<sup>1</sup> PLEXOS ST is a proprietary software product that the Companies license from Energy Exemplar.

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The result of this analysis is presented in Section 2.E (“Gas Transportation Requirements”).

**11. Q. HAVE THE COMPANIES MADE ANY CHANGES IN THEIR PLANNING PROCESSES TO IMPROVE RELIABILITY?**

A. Yes. Due to the continuing evolution of the Companies’ system, with a portfolio of continually growing quantities of variable renewable resources, for which availability decreases in the evening hours, but also dramatic increases in quantities of energy-limited storage resources and a flattening load shape, a new paradigm is engaged for evaluation of the hours of greatest need. Recognizing that the overnight hours – hours without solar photovoltaic output – are becoming increasingly worthy of scrutiny in a system in which storage resources are largely 4-hour batteries, the Companies have expanded the assessment of the hour of greatest need to include 5:00 p.m. to 7:00 a.m. Market products are typically offered in multi-hour blocks rather than for individual hours. Storage resources provide the flexibility to flatten the open position across multiple hours, allowing the Companies to more fully benefit from block market purchases. As a result, the *hour of greatest need*, a concept first introduced in the 2021 ESP,<sup>2</sup> is being expanded to the *hours of greatest need* – multiple hours with the same open position. As such, the Companies are requesting approval to close the open capacity position in the overnight hours rather than simply the evening hours as described in Section 2.B of the 2026 Joint ESP narrative. This paradigm shift will increase reliability and

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<sup>2</sup> See Section 2.B. in the Companies’ 2021 Joint ESP for 2022-2024, Docket No. 21-06001.

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reduce risk of being reliant on short-term power markets in the evening and overnight hours.

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

A. Yes, it does.

**EXHIBIT McCUTCHEN-DIRECT-1**

**STATEMENT OF QUALIFICATIONS**  
**CHARLES MCCUTCHEN**  
**6226 W. Sahara Ave.**  
**Las Vegas, Nevada 89146**

**EDUCATION and CERTIFICATIONS**

**Nebraska Wesleyan University**

Bachelor of Science in Business Administration, May 1996

**University of Michigan**

Master of Science in Financial Engineering, May 2008

**Chartered Alternative Investment Analyst (CAIA) Charterholder**

Issued 2018, Active status

**Certified Financial Risk Manager (FRM)**

Issued 2016, Active status

**Microsoft Certified Systems Administrator (MCSA)**

Issued 2003, Inactive status

**PROFESSIONAL EXPERIENCE**

**NV Energy, Las Vegas, NV**

**Production Cost Modeling Lead**, Resource Planning and Analysis (July 2023 – Present)

- Use production cost model PLEXOS to prepare reports of projected energy production and associated costs for fuel and power procurement, as well as for budgeting fuel and purchased power costs.
- Prepare and present the Monthly Energy Supply Plan (ESP) Update to the Risk Committee. Prepare analysis, charts, tables, and language for the ESP and Business Plan.
- Migrated four studies from PCI GenTrader to PLEXOS through extensive model development, calibration, and benchmarking to ensure continuity and accuracy in simulation results.

**Senior Power & Gas Trading Specialist**, Resource Optimization (May 2022 – July 2023)

- Modeled NV Energy's resources in PCI GenTrader to determine unit commitment, economic dispatch, contract pricing, and to support budgetary and operational decision-making.
- Designed and implemented a comprehensive bid evaluation model using Excel VBA and advanced optimization engines to support the procurement of natural gas.
- Developed and executed analytical models for strategic purchasing of power and coal, enhancing cost-efficiency and decision-making.

**Portfolio Optimization Analyst II**, Resource Optimization (October 2018 – May 2022)

- Developed and maintained models in R and Excel to track the accuracy of load, temperature, battery, and solar forecasts from third-party vendors.
- Acted as primary liaison with Hitachi Energy and UL to troubleshoot forecast discrepancies and implement model improvements, enhancing operational reliability and planning accuracy.

**HC Technologies, Chicago, IL****Quantitative Trader/Analyst** (July 2016 – November 2016)

- Independently developed a highly profitable quantitative trading strategy in the energy and grain futures markets.
- Used R extensively to support the trading of dollar index futures and energy futures butterflies and spreads on the Chicago Mercantile Exchange (CME).

**University of California, Berkeley - Haas School of Business, Berkeley, CA****Data Scientist** (January 2013 – June 2016)

- Led Berkeley Trading Teams to top global placements in the Rotman International Trading Competition, the world's largest trading competition (2<sup>nd</sup> in 2015, 3<sup>rd</sup> in 2014), with consecutive wins in the Optiver Options Case and a first-place finish in the BP Commodities Case, achieved through simulation design, strategic planning, risk management guidance, and consistent team training.
- Supported the High Frequency Finance course by explaining the structure and usage of high-frequency data including NYSE TAQ, NASDAQ ITCH, and EBS currency data as well as the use of analytical packages such as OneTick and R.
- Managed the Data Lab servers and data resources through the utilization of Perl, R, and OneTick.
- Served as a principal organizer for two international data science conferences, DataLead 2014 and DataLead 2015.

**Independent Proprietary Trader, Chicago, IL****Self-employed** (October 2009 – December 2012)

- Traded equity options based on extensive fundamental analysis of distressed financial firms and other special situations.
- Traded five major currency pairs based on technical and macroeconomic analysis and utilized risk management techniques.

**Cutler Group, LP, San Francisco, CA****Equity Options Market Maker / Options Analyst** (July 2008 – September 2009)

- Acted as a NYSE Arca Options Market Maker for 80 equities, operating both on the floor of the Pacific Exchange and remotely on the Chicago Board Options Exchange (CBOE).
- Built a modified Black-Scholes model in Excel to evaluate discrete event outcomes, including FDA drug approvals, using fundamental and peer analysis; also modeled mergers and acquisitions arbitrage opportunities to assess market impact and pricing inefficiencies.
- Developed efficient, event-driven trading strategies by quantifying the short-term order flow impact of index rebalances on component stocks, resulting in profitable execution and improved market timing.

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AFFIRMATION

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

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

Date: May 4, 2026

*Charles McCutchen*  
Charles McCutchen

**TIMOTHY POLLARD**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Timothy Pollard**

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

11 A. My name is Tim Pollard. My position is the Director of Load Forecasting, Research  
12 and Analytics for NV Energy, Inc. (“NV Energy”), Nevada Power Company d/b/a  
13 NV Energy (“Nevada Power”), and Sierra Pacific Power Company d/b/a NV  
14 Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business  
15 address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the  
16 Companies.

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

20 A. I have been employed by the Companies since 2007. Until 2022, I worked as a  
21 Technical Lead in the Rates and Regulatory Affairs department where my main  
22 focus was related to regulatory cost of service and rate design items. In my current  
23 position, my primary focus is on long-term load forecasting and load research issues  
24 for the Companies. I was also previously employed by the Companies in 2004 as a  
25 Load Forecasting Economist within the Resource Planning department.

1 I have previously provided expert witness testimony before the Public Utilities  
2 Commission of Nevada (“Commission”) regarding load forecasts, cost of service,  
3 and regulatory pricing issues in support of various Rate & Regulatory Affairs  
4 department proceedings. My educational background, previous positions and  
5 professional experience are summarized in the statement of qualifications attached  
6 as **Exhibit Pollard-Direct-1**.

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

10 A. My current responsibilities include leading and overseeing the Companies’ long-  
11 term load forecasts and historical data load research activities. This includes all  
12 technical aspects of their historical and forecast class load data used for filings with  
13 the Commission.

14  
15 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**  
16 **WITH THE COMMISSION?**

17 A. Yes. Most recently, I provided testimony to the Commission in the Companies’  
18 First Amendment to the 2024 Joint Integrated Resource Plan (Docket No. 25-  
19 10028). A full list of cases in which I have provided testimony before the  
20 Commission can be found in **Exhibit Pollard-Direct-1**.

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

23 A. The purpose of my testimony is to support updates to the short-term load forecast  
24 for the three-year 2027 to 2029 action plan period for the 2026 Energy Supply Plan  
25 (“2026 Joint ESP”), with the corresponding Technical Appendices. Because the  
26 load forecast for this period is the same presented in the 2026 Joint Integrated  
27

1 Resource Plan (“2026 Joint IRP”) filing, the supporting material and workpapers  
2 are identical for both the 2026 Joint ESP forecast and 2026 Joint IRP forecast.  
3 Therefore, these materials are physically located in the Technical Appendices  
4 accompanying the load forecast narrative for the 2026 Joint IRP.  
5

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

7 A. In this proceeding, I am sponsoring the following Exhibit:

- 8 • **Exhibit Pollard-Direct-1** – Summary of Qualifications

9  
10 **7. Q. PLEASE SUMMARIZE THE IMPACT OF THE UPDATES TO THE LOAD**  
11 **FORECAST DURING THE THREE-YEAR ACTION PLAN PERIOD.**

12 A. **Table Pollard-Direct-1** below summarizes the change in forecast annual energy  
13 gigawatt-hour (“GWh”) sales and peak megawatts (“MW”) over the 2027-2029  
14 period for this 2026 Joint ESP load forecast.

15  
16 For the three-year action plan period 2027 through 2029, the Compound Annual  
17 Growth Rate (“CAGR”) of the annual retail energy for the Companies is 11.3  
18 percent (7.4 percent at Nevada Power and 17.6 percent at Sierra). Annual energy  
19 consumption during this period increases approximately 9,500 GWh for the  
20 combined utilities’ system, with 3,800 GWh at Nevada Power and 5,700 GWh at  
21 Sierra. The CAGR of the Companies’ coincident peak is 7.4 percent (4.8 percent at  
22 Nevada Power and 11.7 percent at Sierra). System coincident peak demand is  
23 expected to increase 1,397 MW for the combined system during the three-year  
24 action plan period, with separate system peak growth of 664 MW at Nevada Power  
25 and 644 MW at Sierra.  
26  
27

**TABLE POLLARD-DIRECT-1  
COMPANIES' ENERGY AND PEAK FORECAST COMPARISON**

Year	Native Energy (GWh)			Peak (MW)		
	NVE	NPC	Sierra	NVE	NPC	Sierra
2027	39,896	25,038	14,858	9,114	6,705	2,598
2028	44,329	26,620	17,709	9,629	6,865	2,951
2029	49,402	28,859	20,543	10,511	7,369	3,242
<b>CAGR</b>						
2027-2029	11.3%	7.4%	17.6%	7.4%	4.8%	11.7%

**Table Pollard-Direct-2** summarizes the Annual Peak MW and GWh energy differences between the 2026 ESP forecast to the forecast approved in the 2024 Joint IRP 1<sup>st</sup> Amendment filing (Docket No. 25-10028).

**TABLE POLLARD-DIRECT-1  
ANNUAL PEAK (MW) AND RETAIL SALES (GWH) DIFFERENCES**

		Peak (MW)			Energy (GWh)		
		2027	2028	2029	2027	2028	2029
Nevada Power	2024 IRP	6,674	6,799	6,835	23,161	23,527	23,825
	2026 ESP Update	6,705	6,865	7,369	25,038	26,620	28,859
	Difference	31	66	534	1,877	3,092	5,035
	Percent Difference	0.5%	1.0%	7.8%	8.1%	13.1%	21.1%
Sierra	2024 IRP	2,495	2,657	2,856	13,927	14,844	15,918
	2026 ESP Update	2,598	2,951	3,242	14,858	17,709	20,543
	Difference	103	294	386	932	2,865	4,625
	Percent Difference	4.1%	11.1%	13.5%	6.7%	19.3%	29.1%
NVE	2024 IRP	8,895	9,145	9,405	37,087	38,371	39,742
	2026 ESP Update	9,114	9,629	10,511	39,896	44,329	49,402
	Difference	219	484	1,106	2,809	5,958	9,660
	Percent Difference	2.5%	5.3%	11.8%	7.6%	15.5%	24.3%

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

A. Yes.

**EXHIBIT POLLARD-DIRECT-1**

**TIM POLLARD**  
**DIRECTOR-LOAD FORECASTING, RESEARCH & ANALYTICS**  
**RESOURCE PLANNING & ANALYSIS**

NV Energy  
6100 Neil Road  
Reno, Nevada 89511-1137  
(775) 834-4006

Mr. Pollard has been a current employee of NV Energy since 2007 and is currently the Director of Load Forecasting, Research and Analytics. His responsibilities are focused upon leading the load research and forecasting teams for regulatory filings and special assignments in support of the Resource Planning & Analysis department's responsibilities.

Prior to joining the company in his current position, Mr. Pollard had experience across different industries and was most recently employed at Covance Cardiac Safety Services, a clinical research organization for the pharmaceutical industry, as a Senior Clinical Data Manager.

**Employment History**

**NV Energy**

**Director-Load Forecasting, Research & Analytics**  
**Technical Lead, Regulatory Policy, Strategy & Analysis**  
**Pricing Specialist, Regulatory Pricing & Economic Analysis**  
**Staff Economist, Regulatory Pricing & Economic Analysis**  
**Senior Economist, Regulatory Pricing & Economic Analysis**  
January 2007 to Present

- Leads load forecasting and load research teams for required strategy and regulatory activities
- Supports load research and forecasting results as necessary in regulatory filings
- Guides technical aspects of cost of service and rate design filings and special assignments
- Conducts research and prepares studies for internal and external presentation
- Provides technical support and analyzes data necessary to resolve the complex set of pricing, financial, economic, and regulatory issues for filings in Nevada and California, Gas and Electric case filings
- Applies extensive experience and understanding of the principles and theories of cost of service and rate design as well as the technical mechanics and applications necessary to successfully develop pricing of electric and gas service
- Provides direction and technical assistance to less experienced team members
- Develops educational materials and actively instructs other team members on various technical, economic and cost of service related subjects

**Economist, Resource Planning & Analysis**  
June 2004 to December 2004

- Conduct research and prepare studies for internal and external presentation
- Prepare and assist in preparation of load forecasts
- Assist in technical aspects of market analysis projects as requested

## **Non-Sierra Employment**

### **Covance Cardiac Safety Services**

January 2005 to January 2007

#### **Senior Clinical Data Manager (10/06 to 1/07); Clinical Data Manager (2/06 to 10/06); Data Analyst (1/05 to 2/06), Data Management & Statistics**

- Technical Lead for all department activities within business unit for the development/validation of new systems and processes
- Acted as primary liaison and escalation contact for clients assigned within team to ensure that data presented met or exceeded the agreed upon expectations for accuracy and timeliness
- Developed and implemented internal and external reports, processes and metrics to add value to company through data analysis, management and quality control activities
- Accountable for all department personnel and activities within Clinical Trial Operations Team

### **Nevada State Health Division**

December 2000 to June 2004

#### **Health Resource Analyst II (7/02 to 6/04); Health Resource Analyst I (12/00 to 7/02), Center for Health Data and Research, Bureau of Health Planning & Statistics**

- Development, linkage, management, and analysis of Public Health Data Warehouse (Cancer Registry, HIV/AIDS, Vital Statistics) for program policy and reporting issues relating to public health arena
- Prepared statistical and special topic reports, performed quality assurance measures and evaluated other health related program data
- Management, quality assurance and analysis of Vital Statistics databases for various Division programs, state agencies and requests from the public for health statistics

## **Education**

### **University of Nevada, Reno**

Bachelor of Arts in Economics, August 2000

## **Certifications**

SAS Certified Advanced Programmer

SAS Certified Basic Programmer

## **Prior Testimony before Public Utilities Commissions**

PUCN Dockets: 07-12001, 08-12002, 08-10043, 09-06029, 10-06001, 10-07003, 11-06006, 13-06002, 15-07041, 15-07042, 16-06006, 16-06007, 18-11039, 19-06002, 20-06003, 21-10012, 22-06014, 22-09006, 23-06007, 23-08015, 24-02026, 24-02027, 25-02016, 25-08027, and 25-10028.

CPUC Applications: 08-08-004.


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AFFIRMATION

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

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

Date: May 4, 2026

  
Timothy Pollard

**NICOLAI SCHLAG**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Nicolai Schlag**

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

A. My name is Nicolai Schlag. My current position is Partner at Energy and Environmental Economics (“E3”). My business address is 44 Montgomery Street Suite 1500, San Francisco, California, 94104. I am filing testimony in support of Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”).

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

A. I have 17 years of experience working in the electric utility industry and have worked extensively on issues related to integrated resource planning and resource adequacy. I have worked for utilities and regulators throughout the Western Interconnection and North America to study various aspects of low carbon, highly renewable electricity systems. My expertise is in utility resource planning, with a special emphasis on resource adequacy and reliability studies.

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Before joining E3, I received a Master’s degree in Civil and Environmental Engineering from Stanford University. I also hold a Bachelor of Science degree in Earth Systems, also from Stanford University.

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

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

A. As a partner at E3, my responsibilities include the oversight of projects within E3’s Integrated System Planning practice area. E3 works extensively with utilities and other clients throughout the country to support and engage in integrated resource planning processes. E3’s work in this practice area typically focuses on utility long-term planning, where E3 provides support to its clients in identifying optimized and/or least-cost plans to meet long-term energy needs and environmental goals while maintaining reliability.

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

A. Yes. I have testified before the Commission on four occasions. Most recently, I testified on behalf of the Companies in Docket No. 24-05041 in support of the 2024 Joint System Integrated Resource Plan (“2024 Joint IRP”) on multiple topics, including: (1) a study to update the Companies’ planning reserve margin (“PRM”) and effective load carrying capability (“ELCC”) assumptions, (2) an analysis of the local resource adequacy of the Sierra subsystem, and (3) a study of operating reserve needs at increasing renewable penetrations. Prior to that proceeding, I

1 submitted testimony on the Companies’ behalf on topics related to resource  
2 adequacy and integrated resource planning in Docket No. 20-07023, the  
3 Companies’ Fourth Amendment to the 2018 Joint IRP; in Docket No. 21-0600, the  
4 Companies’ 2021 Joint IRP; and in Docket No. 23-08015, the Companies’ Fifth  
5 Amendment to the 2021 Joint IRP. I have also previously testified before the New  
6 Mexico Public Regulation Commission and the Colorado Public Utilities  
7 Commission on behalf of utilities in matters related to integrated resource planning  
8 and resource adequacy modeling.  
9

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

11 A. My testimony presents and describes results from a study conducted by E3 in  
12 support of the 2026 Joint Energy Supply Plan (“ESP”) to evaluate potential  
13 reliability risks in the Companies’ Sierra subsystem in the years 2027 and 2028.  
14

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

16 A. My statement of qualifications is attached as **Exhibit Schlag-Direct-1**.

17  
18 I am sponsoring the following Technical Appendices:

- 19 • ESP Technical Appendix ECON-2: 2026 Sierra Subsystem Resource Adequacy  
20 Assessment (“2026 Sierra Study”)  
21

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

24 A. Yes. Portions of my testimony and ESP Technical Appendix ECON-2 are  
25 confidential. The information contained in this report could be employed by bad  
26 actors to engineer attacks against the Companies’ critical energy infrastructure. In  
27

1 the wake of the September 11, 2001, tragedy, the Federal Energy Regulatory  
2 Commission ("FERC") removed from easy public access various categories of  
3 documents that could be useful to a person in planning an attack on critical energy  
4 infrastructure. 18 C.F.R. 388.113(c)(1).2 The FERC found that concerns for the  
5 safety of the public and the nation's energy systems compelled it to ensure that  
6 information regarding critical energy infrastructure is not readily available to the  
7 public. 68 Fed. Reg. 9857 at 9858-59. In an abundance of caution, the Companies  
8 believe that the same concerns support confidential treatment of these documents.  
9

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

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

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

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

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

24 A. The remainder of my testimony describes the purpose, methods, and key findings  
25 of the 2026 Sierra Study.  
26  
27

1 11. Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE PREVIOUS  
2 RESOURCE ADEQUACY ASSESSMENT OF THE SIERRA SUBSYSTEM  
3 YOU COMPLETED IN SUPPORT OF THE 2024 JOINT IRP.

4 A. In support of the 2024 Joint IRP, E3 conducted an assessment of the resource  
5 adequacy of the Sierra subsystem to quantify the extent to which the transmission  
6 limit between Nevada Power and Sierra would impact localized resource adequacy  
7 risk (the “2024 Sierra Study”). In this study, E3 used RECAP to conduct Loss of  
8 Load Probability (“LOLP”) modeling, quantifying the expected level of reliability  
9 risk in the Sierra subsystem in 2028 with and without the completion of the  
10 Greenlink transmission projects. The results of this analysis led to two key findings  
11 at the time:

- 12 • Without the completion of the Greenlink transmission projects, the Sierra  
13 subsystem would face elevated reliability risks in 2028 unless additional  
14 generation resources were added in the North. With neither segment completed,  
15 the study calculated a loss-of-load-expectation (“LOLE”) of 2.6 days per year,  
16 over 25 times the target frequency of loss-of-load events under the traditional  
17 one-day-in-ten-year standard.
- 18 • With the completion of the both Greenlink transmission projects, projected risk  
19 levels dropped to negligible levels.

20 These results highlighted the importance of the completion of the Greenlink  
21 projects to local resource adequacy in the Sierra subsystem and provided an early  
22 indication of the potential for near-term local reliability challenges.

1 12. Q. PLEASE DESCRIBE THE SCOPE AND PURPOSE OF THE 2026 SIERRA  
2 STUDY.

3 A. To support the 2026 Joint ESP, the Companies requested that E3 conduct a detailed  
4 assessment of resource adequacy in the Sierra subsystem for the years 2027 and  
5 2028. The purpose of this assessment was twofold: (1) to quantify the level of  
6 reliability risk that the Sierra subsystem would experience based on updated load,  
7 resource, and transmission assumptions, including the 2026 Joint IRP Base load  
8 forecast and the Companies' current resource and transmission plans; and (2) to  
9 explore how any risks identified could be mitigated by potential actions taken by  
10 the Companies.

11  
12 13. Q. HOW WAS THE ANALYSIS FOR THE 2026 SIERRA STUDY  
13 CONDUCTED?

14 A. The analysis was conducted using the same LOLP modeling approach used in the  
15 2024 analysis of the Sierra subsystem: E3 used RECAP to simulate the availability  
16 of various portfolios of resources and transmission to meet loads across a wide  
17 range of weather and outage conditions. For each portfolio analyzed, this approach  
18 was used to quantify the expected frequency of reliability events (measured using  
19 LOLE, expressed in days per year), to identify the likely timing of those events  
20 throughout the year, and to inspect the system conditions during periods of elevated  
21 risks to better understand the contributing factors.

22  
23 14. Q. WHAT UPDATES TO INPUTS AND ASSUMPTIONS HAVE BEEN MADE  
24 FOR THIS SPECIFIC ANALYSIS SINCE THE 2024 SIERRA STUDY?

25 A. Relative to the 2024 Sierra Study, the most important updates to inputs and  
26 assumptions incorporated in this study include:

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- Rescaling of hourly load profiles used in RECAP to align with the Companies’ 2026 Joint IRP Base load forecast for the Sierra subsystem;
- Incorporation of new northern resources approved by the Commission since the 2024 Joint IRP, including the North Valmy Simple-Cycle Capacity Project, the Libra Solar Project with paired Battery Energy Storage System (“BESS”) solar-storage hybrid, and the Dodge Flat BESS addition;
- Incorporation of plant-specific maintenance schedules for thermal units for 2027 and 2028 to the modeling; and
- Updates to the timing that new resource and transmission projects come in service based on the most recent information available to the Companies at the time of the analysis.

**15. Q. WHAT DOES THE 2026 SIERRA STUDY SHOW REGARDING THE ANTICIPATED RELIABILITY RISK IN THE SIERRA SUBSYSTEM?**

A. The 2026 Sierra Study shows that the Sierra subsystem would face elevated reliability risks (significantly higher than 0.1 days per year) in both 2027 and 2028 should the Companies take no additional action. More specifically:

- In 2027, the Sierra Subsystem would experience an LOLE of 2.1 days per year, concentrated primarily [REDACTED] and [REDACTED]
- In 2028, the Sierra Subsystem would experience an LOLE of 1.3 days per year, with most risk occurring [REDACTED]

Figure NS-1 shows the incidence of loss of load events by months across the twenty-four months of the simulation.

**FIGURE NS-1  
MONTHLY RELIABILITY RISK (DAYS PER YEAR) WITHOUT  
CONSIDERATION OF MITIGATION OPTIONS (CONFIDENTIAL)**



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

16. Q. DOES THE ANALYSIS PROVIDE AN INDICATION OF THE TYPES OF CIRCUMSTANCES THAT LEAD TO LOSS OF LOAD?

A. Yes. [REDACTED] most reliability risk observed in the simulations occurs [REDACTED]

[REDACTED] When loss-of-load events occur under these circumstances, they reflect a system that is “energy-constrained” rather than “capacity-constrained” – meaning that the incidence of loss-of-load is the cumulative effect of the portfolio’s inability to meet energy demands across a sustained window of time rather than its inability to meet the highest capacity needs on an instantaneous basis. This, in turn, directly informs what types of solutions would be most effective in mitigating those risks: resources (or resource alternatives) capable of providing both capacity and energy to the system over sustained periods.

1 17. Q. WHAT OPTIONS TO MITIGATE THESE RELIABILITY RISKS DID  
2 YOUR ANALYSIS EVALUATE?

3 A. Based on direction from the Companies, the 2026 Sierra Study explores multiple  
4 potential actions to mitigate the risks described above. These include:

- 5 • Addition of new resources, limited to two potential projects with in-service  
6 dates prior to summer 2028;
- 7 • Contracting with existing generation resources for 100 MW of firm power;
- 8 • An adjustment to a specific thermal plant’s maintenance schedule in 2028;
- 9 • An uprating to an existing geothermal facility; and
- 10 • Adjustments to the load forecast to reflect potential delays in large customer  
11 load development.

12  
13 18. Q. WHAT DOES YOUR ANALYSIS SHOW REGARDING THE  
14 EFFECTIVENESS OF THESE MITIGATION OPTIONS?

15 A. These mitigation options were studied both independently and in combination. The  
16 analysis shows:

- 17 • The most significant improvements in reliability in both years are the result of  
18 (a) contracting for 100 MW of firm power and (b) delaying new large customer  
19 loads (reductions of up to 83 MW and 146 MW in 2027 and 2028, respectively).  
20 The effectiveness of these solutions stems both from their magnitude and their  
21 shape (both are relatively flat throughout the year and therefore effectively  
22 address energy-constrained risks across multiple seasons). In combination,  
23 these two measures would reduce risk levels to 0.2 days per year in 2027 and  
24 0.01 days per year in 2028.
- 25 • The potential adjustment to thermal plant maintenance schedules identified by  
26 the Companies could materially improve reliability to 0.5 days per year in 2028.

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- The few possible options to add new capacity in the very near term (including the geothermal plant uprate) have limited impact on reliability risk within the Sierra subsystem. This is due to various combinations of (a) their scale relative to the need, (b) their in-service dates relative to key risk periods, and (c) their performance characteristics relative to the observed reliability risks.

**19. Q. PLEASE SUMMARIZE THE KEY FINDINGS FROM THIS STUDY.**

A. Based on this analysis, the 2026 Sierra Study reaches three key findings:

1. Without additional action, the Sierra subsystem will face elevated reliability risks in 2027 and 2028.
2. Reliability events may occur [REDACTED]
3. While opportunities to develop new resources are limited in the very near term, multiple alternative options to reduce risk are possible; the most impactful of these are contracting for existing firm generation within the subsystem and a delay in the ramp of new large customer loads.

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

A. Yes.

## **EXHIBIT SCHLAG-DIRECT-1**



44 Montgomery Street, Suite 1250, San Francisco, CA 94104  
[nick@ethree.com](mailto:nick@ethree.com)

**ENERGY AND ENVIRONMENTAL ECONOMICS, INC.**  
*Partner*

San Francisco, CA

Mr. Schlag has seventeen years of experience in energy analysis. He currently leads E3's Integrated System Planning practice area, where his principal areas of expertise are in resource adequacy & reliability, long-term electricity resource planning, and utility strategy. Mr. Schlag has led a number of E3's most prominent electricity system planning studies in the West, including (1) the 2021 study *Resource Adequacy in the Desert Southwest*, a regional resource adequacy assessment conducted by E3 on behalf of six large utilities in Arizona and New Mexico; (2) Salt River Project's 2023 Integrated System Plan, where E3 served as a strategic advisor through the entirety of the study process, conducted capacity expansion modeling, and presented results to stakeholder groups and SRP's Board; and (3) Pasadena Water and Power's Optimized Strategic Plan, where E3 developed a comprehensive roadmap grounded in robust modeling of the power system to support the city's goal to source all electricity from carbon-free sources by 2030. Additionally, Mr. Schlag has provided advisory and technical support to a large number of western utilities and regulators in the integrated resource planning process, including Anaheim Public Utilities, Arizona Public Service, Black Hills Energy, California Public Utilities Commission, NV Energy, Pasadena Water & Power, Public Service Company of Colorado, Public Service Company of New Mexico, Sacramento Municipal Utilities District, Tucson Electric Power, holds a Master of Science in Civil and Environmental Engineering (Atmosphere and Energy) and a Bachelor of Science in Earth Systems, both from Stanford University.

Other previous clients include the Balancing Authority of Northern California, Bonneville Power Administration, the California Independent System Operator, Los Angeles Department of Water and Power, Portland General Electric, Public Generating Pool, Seattle City Light, the Western Electricity Coordinating Council, and the Western Interstate Energy Board. Select E3 projects include:

- **Arizona Public Service, Integrated Resource Planning Support, 2019-present.** Mr. Schlag led an engagement to provide strategic and technical support to APS culminating in the development of its 2020 Integrated Resource Plan. Mr. Schlag oversaw an effort to develop a simplified IRP portfolio model used to facilitate dialog with stakeholders through a series of workshops exploring the impacts of different potential future portfolios and ultimately presented key findings from the effort to the Arizona Corporation Commission. More recently, Mr. Schlag and the E3 team also provided support to APS to assist in the development of its 2023 IRP filing.
- **Salt River Project, Integrated Resource and System Planning Support, 2021-2023, 2025-present.** Mr. Schlag has been closely involved in multiple engagements with SRP to provide support for resource planning and system planning activities. In the inaugural cycle of the Integrated System Plan (2021-2023) – a first-of-its-kind to coordinate planning functions including resource planning, transmission planning, distribution planning, and customer planning – Mr. Schlag led E3's efforts to support SRP in the scoping, development, and execution of an analysis plan; served as a lead liaison with the public advisory group of stakeholders; oversaw capacity expansion modeling conducted by E3 on behalf of SRP; and presented recommended system strategies to SRP's Board.

Mr. Schlag is also currently overseeing an effort to assist SRP's resource planning team in the creation of internal capacity expansion and production cost models using PLEXOS and is currently leading an engagement to support SRP in the development of its 2026 ISP.

- **NV Energy, Integrated Resource Planning Support, 2020-present.** Mr. Schlag has led multiple studies of resource adequacy for NV Energy using a loss-of-load-probability modeling framework. These studies include analyses of the effective load carrying capability of renewables and storage (filed in NV Energy's Fourth Amendment to the 2018 Joint IRP and updated in the 2024 Joint IRP) and a quantification of the Planning Reserve Margin requirement needed to achieve a "one-day-in-ten-years" standard for resource adequacy (filed in NV Energy's 2021 Joint IRP and updated in the 2024 Joint IRP). In support of these studies, Mr. Schlag provided expert testimony before the Public Utilities Commission of Nevada. Mr. Schlag has also overseen several studies examining the challenges NV Energy will face in its pursuit of the state's goal to decarbonize the electricity portfolio, including the development of cost-optimized portfolios to meet a range of levels of carbon reductions using the PLEXOS LT capacity expansion model. Mr. Schlag is currently providing additional expert witness support on resource adequacy to NV Energy in its 2026 Joint IRP.
- **Tucson Electric Power, Resource Adequacy Support, 2022-2023, 2025-2026.** Mr. Schlag has led multiple resource adequacy studies for Tucson Electric Power (TEP) using a loss-of-load-probability modeling framework to quantify the effective load carrying capability of renewables and energy storage resources. These studies have served as direct inputs to TEP's 2023 and 2026 Integrated Resource Plans.
- **Black Hills Energy, Colorado Electricity Resource Plan Support, 2020-present.** Mr. Schlag led multiple engagements to support Black Hills Energy in its 2022 and 2026 Energy Resource Plan and Clean Energy Plan filings in Colorado. In both cycles, E3 conducted (1) resource adequacy studies for BHE to quantify a planning reserve margin and effective load carrying capability values; (2) capacity expansion modeling to identify a least-cost portfolio of resources to meet reliability needs and greenhouse gas reduction goals; and (3) production cost modeling to simulate the hour-to-hour operations of the resulting portfolios. In the 2022 cycle, these analyses were used by BHE to support their preferred plan, which led to the Commission's approval of two new solar power purchase agreements and one new energy storage agreement. Analysis supporting BHE's 2026 filing is ongoing and will continue through multiple phases (including integrated resource planning and bid evaluation) through 2028.
- **Public Service Company of Colorado, Resource Adequacy Study, 2025.** Mr. Schlag oversaw a team that conducted resource adequacy modeling to develop a planning reserve requirement and effective load carrying capability values used in PSCo's 2025 Just Transition Solicitation filing. The results of this analysis were used by PSCo as inputs to capacity expansion modeling used to identify new resources necessary to meet reliability needs and greenhouse gas reduction requirements.
- **Public Service Company of New Mexico, Integrated Resource Planning Support, 2019-2020, 2022-2023, 2025-present.** Mr. Schlag has led E3's team in providing technical and strategic support to PNM through multiple IRP cycles and related processes. In 2020, Mr. Schlag led the development of the IRP report and narrative, which lays out a pathway for the utility to transition to 100% carbon-free energy by 2040. Subsequently, Mr. Schlag provided additional support PNM through a number of regulatory filings related to the IRP Action Plan, which included providing direct testimony regarding the implications of PNM's objective to achieve its goal of 100% carbon-free energy for its ability to maintain resource adequacy. In 2023, Mr. Schlag again led the development of the narrative for PNM's 2023 IRP, focused on identifying resources needed to maintain near-term resource adequacy while positioning PNM for its eventual transition to a

carbon-free electricity system. Mr. Schlag is now overseeing E3's continued support for PNM in the preparation of its 2026 IRP.

- **Pasadena Water & Power, System Planning Support, 2023-2025.** In 2023, under Mr. Schlag's direction, E3 conducted an independent review of PWP's IRP modeling and narrative. Mr. Schlag presented results of this review, which found PWP's IRP to be generally aligned with industry standard practices, to Pasadena City Council at a public meeting. Subsequently, the City of Pasadena hired E3 to work with PWP to develop an Optimized Strategic Plan (OSP) that would allow the city to meet its goal of sourcing all electricity from carbon-free sources by the end of 2030. The resulting OSP, supported by E3's technical studies using loss-of-load-probability and capacity expansion modeling, was approved by Pasadena City Council in 2025.
- **Various utilities, Southwest Resource Adequacy Study, 2021-2022.** Mr. Schlag led a study funded by a coalition of utilities to investigate resource adequacy challenges facing the Desert Southwest region in the coming decade; the study's sponsors included Arizona Public Service, Arizona Electric Power Cooperative, El Paso Electric, Public Service Company of New Mexico, Salt River Project, and Tucson Electric Power. The study used on state-of-the-art loss-of-load-probability modeling to assess reliability risks in light of rapidly growing loads, planned resource retirements, the transition towards renewables and storage, and increasing climatic uncertainty. The analysis highlighted a dire need for new capacity within the region to address a rapidly increasing shortfall and explored the possible roles of renewables, storage, and other resources to satisfy these needs.
- **Arizona Electric Power Cooperative, Resource Adequacy Studies, 2022 & 2026.** In 2022, under Mr. Schlag's direction, E3 conducted a resource adequacy study on behalf of AEPCO, applying LOLP modeling techniques to calculate a planning reserve margin requirement and effective load carrying capability values. E3 also worked closely with AEPCO to devise reasonable methods to apply the results of this analysis to its members in a manner that was both equitable and efficient given differences in load and electric resource portfolios. Mr. Schlag is currently overseeing an update to this analysis based on updated loads and resources.
- **Electric Reliability Council of Texas, Performance Credit Mechanism Implementation, 2023-2024.** Mr. Schlag is currently advising E3's team in assisting ERCOT in efforts to implement a "Performance Credit Mechanism" (PCM) to improve system reliability in Texas. The PCM design, adopted by the Public Utilities Commission of Texas following an extensive market redesign process, represents an innovative market-based construct to provide financial incentives to generators to be available during periods of system scarcity. E3's advisory support in this effort spans all aspects of market design, including both technical and administrative elements of the design.
- **Public Utilities Commission of Texas, Assessment of Market Reform Options to Enhance Reliability of the ERCOT System, 2022-2023.** Mr. Schlag oversaw a study to analyze potential market reforms with the objective of improving the reliability of the ERCOT region. Using loss of load probability modeling, E3's analysis evaluated the impacts of various market reforms upon cost, reliability, and impacts on new investment. The study prompted the PUCT to recommend and ultimately adopt an innovative "Performance Credit Mechanism" (PCM) designed to reward generators for their ability to generate during the highest risk periods of the year, providing an additional economic incentive to encourage investment in the types of resources needed to ensure reliability.
- **California Energy Commission, SB100 Implementation Study, 2020.** Mr. Schlag contributed in an advisory capacity to the development of a study examining the investments needed to achieve a California's 100% goal for carbon-free power in 2050. The analysis builds off Mr. Schlag's prior

experience working with California state agencies to develop an optimization-based approach to resource planning in the state using E3's RESOLVE model.

- **Xcel Energy, Upper Midwest Integrated Resource Plan Technical Support, 2018-2019.** Mr. Schlag led analysis of the impact of deep decarbonization scenarios on Xcel Energy's Upper Midwest System over the 2020-2034 planning period to support Xcel's IRP filing before the Minnesota Public Utilities Commission. Using E3's RESOLVE and RECAP models, Mr. Schlag identified optimal resource investment portfolios that met resource adequacy needs in the context of state and corporate long-term greenhouse gas reduction targets.
- **Sacramento Municipal Utilities District, Integrated Resource Planning Support, 2018-2023.** In a project evaluating long-term clean energy and greenhouse gas reduction goals in the context of vehicle and building electrification, Mr. Schlag customized E3's RESOLVE model to SMUD's system to develop optimal portfolios of renewable, conventional, and energy storage resources to meet SMUD's electric energy and reliability needs while achieving 90-100% carbon emissions reductions by 2040. More recently, Mr. Schlag directed technical analysis exploring various pathways to achieve a net-zero emissions target by 2030 in response to the SMUD Board's Climate Emergency Declaration. The results of this analysis served as the basis for SMUD's recent 2030 Zero Carbon Plan.
- **California Public Utilities Commission, Integrated Resource Planning Implementation Support, 2016-present.** Mr. Schlag has worked closely with the CPUC in its rollout of a framework and process for integrated resource planning. Mr. Schlag helped design the analytical framework currently in use in the 2017 IRP and managed an E3 team working to develop a "Preferred System Plan"—an optimal resource portfolio consistent with the state of California's long-term greenhouse gas reduction goals—using RESOLVE, E3's in-house capacity expansion model designed for use on high-penetration renewable systems. Mr. Schlag continues to advise E3's team in an ongoing engagement to provide technical support to the IRP process.
- **Public Generating Pool, Pacific Northwest Low Carbon Scenario Analysis, 2017.** Mr. Schlag led a study examining the most effective policy mechanisms to facilitate greenhouse gas reductions in the electric sector in the Pacific Northwest. The study relied on E3's RESOLVE model to compare the relative impacts of expanded RPS goals, carbon caps, carbon taxes, and a prohibition on new gas generation, highlighting the different cost and emissions impacts of each on ratepayers in the Northwest.
- **Los Angeles Department of Water and Power, 100% Clean Energy Study, 2017.** Working directly with LADWP staff, Mr. Schlag designed a work plan for LADWP's 100% Clean Energy Study to be executed over a period of several years. This effort included scoping of a public outreach program, development of potential research partnerships, and preliminary data gathering and validation.
- **California Public Utilities Commission, RPS Program Evaluation Support, 2012-2017.** Mr. Schlag managed an E3 team including four subcontractors to provide multiple services to the CPUC over a five-year period. Foremost among these was the redesign, development, and maintenance of an updated RPS Calculator—tailored specifically to highlight renewable integration challenges at high penetrations—which was used as a key source of inputs in both the CAISO's Transmission Planning Process (TPP) and the CPUC's Long-Term Procurement Proceeding (LTPP). Additional support tasks included development and maintenance of a database of the renewable contracts of the three investor-owned utilities and an assessment of renewable cost, potential, and performance in California and throughout the Western U.S.
- **Northwestern Energy, EIM Benefits Analysis, 2016-2017.** Mr. Schlag led E3's study of the benefits to NWE of participating in the Western EIM. The E3 team worked closely NWE staff to model the effect of NWE's EIM participation on system operations using PLEXOS production simulation software, providing a clear illustration of the EIM value proposition.

- **Balancing Authority of Northern California, EIM Benefits Analysis, 2016.** Mr. Schlag led E3's study of the benefits to BANC members of participating in the Western EIM. The E3 team worked closely with representatives from all BANC members to model the operations of their respective electric systems accurately using PLEXOS production simulation software, providing a clear illustration of the EIM value proposition for each BANC member.
- **Seattle City Light, EIM Benefits Analysis, 2016.** Mr. Schlag led the assessment of Seattle City Light's prospective benefits of participation in the Western EIM. E3's analysis for SCL was designed specifically to highlight the value of Seattle's flexible hydroelectric generation fleet in the EIM's 15- and 5-minute markets, using dispatch optimization software and historical market prices to quantify the value of arbitrage opportunities.
- **California Independent System Operator, SB350 Regionalization Study, 2015-2016.** Mr. Schlag contributed to E3's work as part of a consulting team studying the benefits of expanding the CAISO to a broader regional entity in accordance with California's Senate Bill 350. Using RESOLVE, Nick helped to design the alternative portfolios used as the basis for identifying the potential infrastructure impacts (and associated fixed cost savings) of ISO expansion.
- **Western Electricity Coordinating Council & Western Interstate Energy Board, Western Interconnection Flexibility Assessment, 2014-2016.** Working in partnership with the National Renewable Energy Laboratory, an E3 team managed by Mr. Schlag completed a thorough examination of the flexibility of the generation fleet of the Western Interconnection and its ability to integrate high penetrations of renewable generation. The study identified both operational challenges as well as institutional and physical solutions to facilitate renewable integration across the region.
- **Western Interstate Energy Board, Western Gas-Electric Study, 2013-2014.** Mr. Schlag managed a two-phase study of gas-electric coordination in the Western Interconnection to investigate whether the natural gas infrastructure in the West would be sufficient to meet future needs of the electric sector, considering both the anticipated retirements of a sizeable portion of the Western coal fleet as well as the increasing penetrations of intermittent renewable resources.
- **PG&E, SCE, SDG&E, LADWP & SMUD, Investigating a Higher Renewables Portfolio Standard for California, 2013.** As part of the E3 team, Mr. Schlag helped to design and analyze a range of renewable portfolios to meet a 50% Renewables Portfolio Standard, using production simulation to evaluate integration challenges and calculating the corresponding rate impacts for California ratepayers.
- **Portland General Electric, Low Carbon Portfolio Development, 2012.** Mr. Schlag worked with PGE staff and a group of environmental stakeholders to create a low carbon portfolio for analysis in PGE's 2012 Integrated Resource Plan. The portfolio was designed to include higher penetrations of renewable generation and accelerated achievement of efficiency goals.
- **Western Electricity Coordinating Council, Cost and Performance Review of Generation Technologies, 2012.** Mr. Schlag led E3's literature review of the cost and performance of new electric generation technologies, which culminated in a report to WECC staff with recommended assumptions for use in its 10- and 20-year study processes.

**STANFORD UNIVERSITY**  
*Teaching Assistant*

Palo Alto, CA  
2008-2009

- Assisted students with coursework in engineering classes related to energy efficiency, electric power, and meteorology; facilitated students' experiments in the Renewable Energy Laboratory

**ROCKY MOUNTAIN INSTITUTE**

*MAP Sustainable Energy Fellow*

Boulder, CO

Summer 2008

- Awarded three-month MAP Sustainable Energy Fellowship sponsored by MAP Royalty, Inc. to conduct research on the energy efficiency potential in residential, commercial, and industrial sectors of the United States as part of RMI's Next Generation Utilities project

**STOCKHOLM ENVIRONMENT INSTITUTE**

*Donald Kennedy Environmental Fellow*

Stockholm, Sweden

Summer 2007

- Awarded Donald Kennedy Environmental Fellowship through Stanford in Government to study benefits of clean cooking fuels in Sub-Saharan Africa, research that culminated with a working paper on the market barriers to clean cooking fuel adoption

Education

Stanford University

*M.S., Atmosphere and Energy (Civil & Environmental Engineering)*

Palo Alto, CA

2009

Stanford University

*B.A., Earth Systems (Energy Science and Technology)*

Palo Alto, CA

2008

Expert Witness Testimony

1. *Public Utilities Commission of Nevada, 2020, testified on behalf of NV Energy in its Fourth Amendment to 2018 Joint Triennial Integrated Resource Plan proceeding regarding the effective load carrying capability (ELCC) of renewable and energy storage resources and the value of diverse renewable resources in helping NV Energy meet Nevada's goal of 100 percent zero-carbon energy by 2050*
2. *Public Utilities Commission of Nevada, 2021, testified on behalf of NV Energy in its 2021 Joint Triennial Integrated Resource Plan to support an update to NV Energy's Planning Reserve Margin (PRM) requirement based on a loss of load probability analysis to identify the amount of capacity needed to meet a "one-day-in-ten-years" standard*
3. *New Mexico Public Regulation Commission, 2021, testified on behalf of Public Service Company of New Mexico in the company's filing for the abandonment and replacement of leased shares of the Palo Verde Nuclear Generating Station regarding best practices in planning for resource adequacy and the challenges that the company will face in its transition to 100 percent carbon-free energy*
4. *Colorado Public Utilities Commission, 2021-2022, testified on behalf of Black Hills Energy in its Clean Energy Plan (CEP) filing as a technical expert supporting analysis of the utility's future resource adequacy needs and optimization of portfolios to meet the greenhouse gas reduction targets of 80% below 1990 levels by 2030 and 100% clean energy by 2050*
5. *Public Utilities Commission of Nevada, 2023, testified on behalf of NV Energy in the Fifth Amendment to the 2021 Joint IRP supporting NV Energy's continued use of E3's PRM and ELCC*

*analysis and providing commentary on evolving risks related to resource adequacy in the Western Interconnection*

6. *Public Utilities Commission of Nevada, 2024, testified on behalf of NV Energy in its 2024 Joint Triennial Integrated Resource Plan supporting an updated Planning Reserve Margin and Effective Load Carrying Capability study and a detailed analysis of resource adequacy in northern Nevada's Sierra Pacific Power Company subsystem*

## Publications

1. Ming, Z., N. Schlag, D. Delgado, A. Burdick, K. Steinberger, B. Elsey, A. Gold-Parker, A. Au, C. Gulian, & A. Olson (2025). Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets." [https://www.ethree.com/wp-content/uploads/2025/08/E3\\_Critical-Periods-Reliability-Framework\\_White-Paper.pdf](https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf).
2. Burdick, A., **N. Schlag**, A. Au, R. Go, Z. Ming, & A. Olson (2022). "Lighting a Reliable Path to 100% Clean Electricity." IEEE Power and Energy Magazine, 20(4):30-43.
3. Stenlik, D., M. Ahlstrom, S. Awara, J. Bakke, A. Bloom, W. Cole, E. Delaney, A. Dobbie, S. Elsevier, A. Acevedo, B. Frew, E. Hart, W. Henson, E. Ibanez, J. Jin, W. Lamanna, C. Lau, J. Matevosyan, M. Milligan, K. Parks, R. Pungaliya, **N. Schlag**, J. Sharp, E. Smeloff, G. Stephen, A. Tuohy, M. Welch, P. Wong (2023). Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. A Report of the Redefining Resource Adequacy Task Force. Reston, VA. <https://www.esig.energy/new-design-principles-for-capacity-accreditation>.
4. Stenlik, D., A. Bloom, W. Cole, G. Stephen, A. Acevedo, R. Gramlich, C. Dent, **N. Schlag**, & M. Milligan (2021). "Quantifying Risk in an Uncertain Future: The Evolution of Resource Adequacy," IEEE Power and Energy Magazine, 19(6): 29-36.
5. **Schlag, N.**, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, & H. Jiang (2020). "Capacity and Reliability Planning in the Era of Decarbonization." <https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf>.
6. **Schlag, N.**, Z. Ming, & A. Olson (September 2020). "Adding it all up: Counting the capacity contribution of variable and duration limited resources." Utility Dive.

<https://www.utilitydive.com/news/adding-it-all-up-counting-the-capacity-contribution-of-variable-and-durati/584843/>.

7. **Schlag, N.**, D. Mullen, & K. Patel. (April 2019). "Moving beyond 'rules of thumb' for smart, cost-effective storage deployment." Utility Dive. <https://www.utilitydive.com/news/moving-beyond-rules-of-thumb-for-smart-cost-effective-storage-deployment/553674/>.
8. Woo, C.K., Y. Chen, A. Olson, J. Moore, **N. Schlag**, A. Ong, & T. Ho. (2017). "Electricity price behavior and carbon trading: New evidence from California," Applied Energy, Elsevier, vol. 204(C): 531-543.
9. Olson, A., C.K. Woo, **N. Schlag** & A. Ong (2016). "What Happens in California Does Not Always Stay in California: The Effect of California's Cap-and-Trade Program on Wholesale Electricity Prices in the Western Interconnection," The Electricity Journal, 29(7), 18-22.
10. Olson, A., E. Hart, J. Hargreaves, R. Jones, **N. Schlag**, G. Kwok, N. Ryan, R. Orans, & R. Frowd, "Halfway There: Can California Achieve a 50% Renewable Grid?", IEEE Power and Energy Magazine, 13(4): 41-52.
11. Woo, C.K., H. Liu, F. Kahrl, **N. Schlag**, J. Moore, & A. Olson (2012). "Assessing the economic value of transmission in Alberta's restructured electricity market." Electricity Journal, 25(3): 68-80.

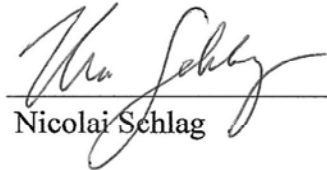
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AFFIRMATION

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

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

Date: May 4, 2026

  
\_\_\_\_\_  
Nicolai Schlag

**MATTHEW VALENTIC**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Matthew Valentic**

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

A. My name is Matthew Valentic. My current position is Regulatory Accounting Manager for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6100 Neil Road in Reno, NV. I am filing testimony on behalf of the Companies.

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

A. I graduated from the University of Nevada, Reno with a Bachelor’s degree in Mathematics and then subsequently obtained Master’s degrees in Accountancy and Business Administration. I have been employed by the Companies since 2017, with most of my time spent in the Revenue Accounting department, where my duties included the preparation of Statement J for both Nevada Power and Sierra, Exhibit G in support of the quarterly Deferred Energy Accounting Adjustment (“DEAA”) filings, and other projects. I assumed the role of Regulatory Accounting Manager

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in May 2024. My statement of qualifications is attached as **Exhibit Valentic-Direct-1**.

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

A. As Regulatory Accounting Manager, my responsibilities include the oversight of the preparation of the fuel and purchased power recovery rates and various deferred energy mechanisms, along with the regulatory earned rate of return and revenue requirement calculations.

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

A. Yes I have. Most recently I testified in the Companies’ 2026 DEAA annual filings, Docket Nos. 26-02035, 26-02036, and 26-02037.

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

A. The purpose of my testimony is to provide background information about the forecasted Base Tariff Energy Rate (“BTER”) and DEAA components and how they were developed for the gas hedging plan for the 2027 - 2029 action plan period.

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

A. I am sponsoring or co-sponsoring the following Exhibits:

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

I am sponsoring the following Technical Appendices:

**Technical Appendix GAS-2**          Summary of Actual and Forecasted BTERs  
and DEAA

7.    **Q.    DID YOU PREPARE FORECASATED BTERS AND DEEAS?**

A.    Yes. The forecasted BTERs and DEEAs, assuming base, low, and high fuel and purchased power costs, for the gas hedging plan were prepared under my direction. As discussed in this filing, the Companies are not proposing any gas hedges.

8.    **Q.    HOW WERE THE FORECASTED BTERS AND DEEAS CALCULATED?**

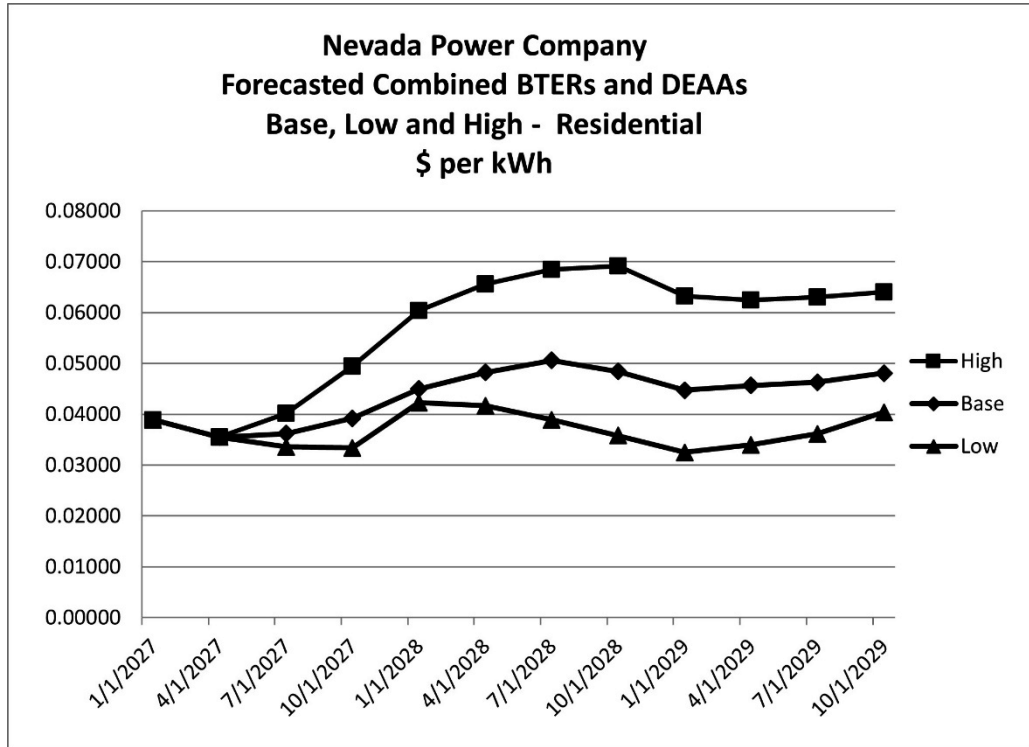
A.    Base, low, and high fuel and purchased power price forecasts for 2027 - 2029 were prepared by the Resource Planning team, as sponsored by Zeljko Vukanovic and are presented in Technical Appendix FPP-1. These forecasts were used in the PLEXOS ST model to estimate the total cost to serve. The estimates generated by PLEXOS ST, which are also sponsored by Mr. Vukanovic, were used to forecast BTERs and DEEAs for 2027 - 2029 under base, low, and high price scenarios. A summary of the actual and forecasted BTERs and DEEAs is provided in Technical Appendix GAS-2, pages 1 and 3 for Nevada Power and Sierra, respectively.

9.    **Q.    PLEASE SUMMARIZE THE POTENTIAL RANGE OF RATE IMPACTS OF THE GAS HEDGING PLAN.**

A.    Figures Valentic-Direct-1 and Valentic-Direct-2 reflect the combined Nevada Power 2027 - 2029 forecasted residential and non-residential BTERs and DEEAs for the plan.

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**FIGURE VALENTIC-DIRECT-1**



**FIGURE VALENTIC-DIRECT-2**

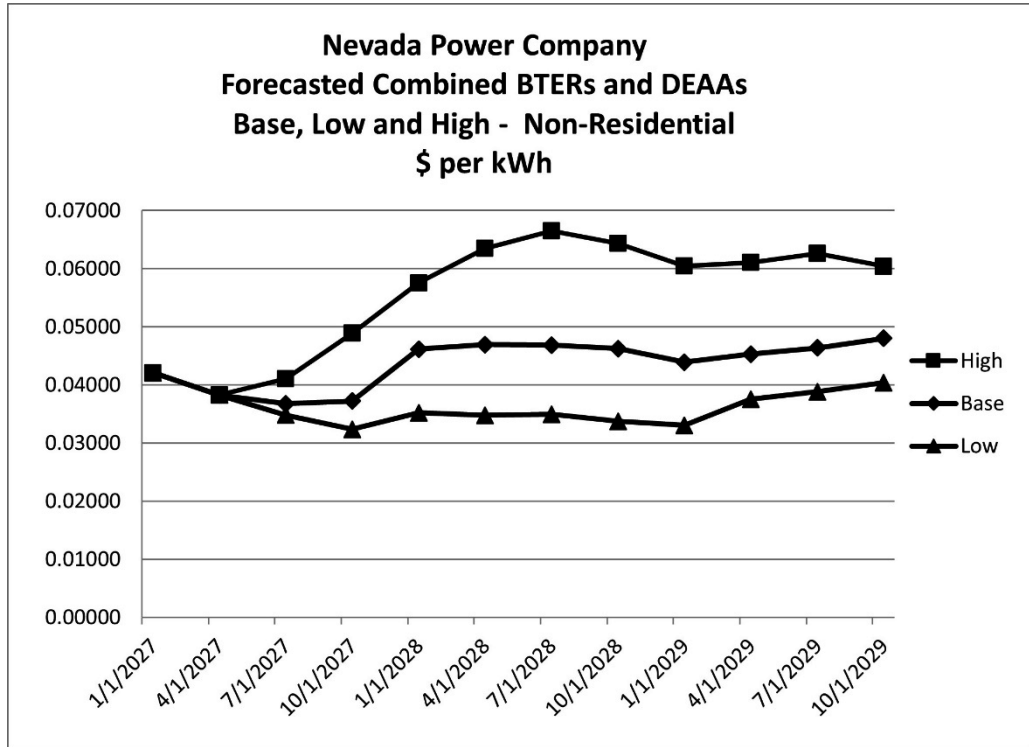
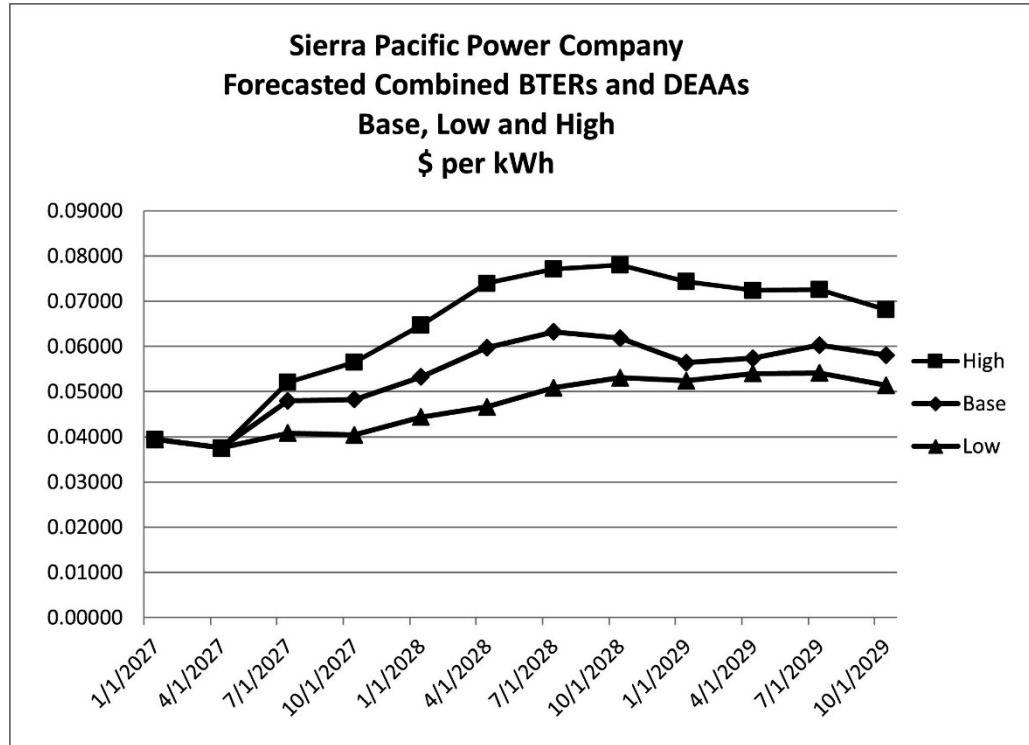


Figure Valentic-Direct-3 shows the combined 2027-2029 forecasted Sierra BTERs and DEAA's for the plan.

**FIGURE VALENTIC-DIRECT-3**



10. Q. WERE CARRYING CHARGES CALCULATED FOR THE GAS HEDGING PLAN?

A. Yes. The estimated carrying charges are provided in Technical Appendix GAS-2, pages 2 and 4 for Nevada Power and Sierra respectively.

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

A. Yes.

**EXHIBIT HUGHEY-DIRECT-1**

**STATEMENT OF QUALIFICATIONS**

**Matthew Valentic**  
**Regulatory Accounting Manager**  
**NV Energy**  
**6100 Neil Rd.**  
**Reno, NV 89511**

Matthew Valentic has been with NV Energy in various capacities since 2017, primarily focused on recording, analyzing, and reporting revenue. Mr. Valentic has prepared statements, reports, and data responses for regulators and interveners.

**EMPLOYMENT HISTORY**

May 2024 to present	<b>NV Energy</b>	<b><i>Regulatory Accounting Manager</i></b>
		Manage the preparation of fuel and purchased power recovery and various deferred energy mechanisms and their required filings. Oversee the preparation of regulatory earned rate of return and revenue requirement calculations in compliance with regulations and Commission directives for state and FERC jurisdictional filings. Responsible for the completion of various state and FERC reporting requirements.
2020 to May 2024	<b>NV Energy</b>	<b><i>Revenue and Regulatory Accounting Manager</i></b>
		Directed staff in the performance of various corporate and regulatory functions, including preparation of regulatory statements, adjustments, and analysis. Directed implementation of appropriate accounting procedures to comply with regulatory orders and developments. Oversaw accounting and reporting for revenue and responsible for preparation of the internal component of tariff and ensuring proper accounting for rate changes.
2019 to 2020	<b>NV Energy</b>	<b><i>Senior Revenue and Regulatory Analyst</i></b>
		Reviewed and analyzed revenue data, recorded journal entries, and identified revenue related issues. Prepared estimates of monthly unbilled revenue and sales. Prepared statements and schedules for reporting to the Public Utilities Commission of Nevada (“PUCN”). Led process improvement for the revenue and regulatory team and responsible for the internal component of tariff.
2017 to 2019	<b>NV Energy</b>	<b><i>Revenue and Regulatory Analyst</i></b>
		Reviewed and analyzed revenue data, recorded journal entries, and identified revenue related issues. Prepared estimates of monthly unbilled revenue and sales. Assisted in the preparation of statements and schedules for reporting to the PUCN.
2010 to 2017	<b>Verizon Wireless</b>	<b><i>Solution Specialist</i></b>
2008 to 2010	<b>Peace Corps</b>	<b><i>Peace Corps Volunteer – Math Teacher</i></b>
2005 to 2008	<b>Enterprise Rent-A-Car</b>	<b><i>Management Assistant</i></b>

**EDUCATION**

*University of Nevada, Reno*

Master of Accountancy – 2017

*University of Phoenix*

Master of Business Administration – 2014

*University of Nevada, Reno*

BA in Mathematics – 2005

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AFFIRMATION

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

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

Date: May 4, 2026

  
Matthew Valentic

**VINCENT VITIELLO**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Vincent Vitiello**

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

11 A. My name is Vincent Vitiello. I am the Gas Supply Planning Lead for Nevada Power  
12 Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company  
13 d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”).  
14 My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing  
15 testimony on behalf of the Companies.  
16

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

19 A. My professional experience includes more than 30 years in the utility and power  
20 generation industries. I have a Bachelor of Engineering degree with a concentration  
21 in mechanical engineering and have worked for the Companies since 2006.  
22

23 Prior to joining the Companies, I was employed for six years by Chevron  
24 Corporation as the Assistant Executive Director at Nevada Cogeneration  
25 Associates #1 and Nevada Cogeneration Associates #2. Prior to that, I worked at  
26 Southwest Gas Corporation for 14 years, in the major accounts and engineering  
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departments. Prior to that, my first career position was as an engineer at Exxon Company, U.S.A., in the refining and oil and natural gas production areas. More details regarding my background and experience are provided in **Exhibit Vitiello-Direct-1.**

**3. Q. WHAT ARE YOUR RESPONSIBILITIES AS GAS SUPPLY PLANNING LEAD?**

A. As the Gas Supply Planning Lead, I am primarily responsible for the short- and long-term planning of the Companies’ natural gas transportation and storage assets necessary to ensure the adequate supply of natural gas to the Companies’ generation plants and to Sierra’s gas distribution system. I am also responsible for reviewing and monitoring pipeline filings, negotiating rate case settlements, and supporting related efforts before the Federal Energy Regulatory Commission and state regulatory commissions.

**4. Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?**

A. Yes, I provided testimony before this Commission most recently in Docket Nos. 26-02035, 26-02036, and 26-02037, the Companies deferred energy accounting adjustment filings.

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

A. In my testimony, I sponsor the following sections in the Companies’ Joint Energy Supply Plan (“ESP”) for the action plan period of 2027-2029 (“Action Plan Period”).

- Section 5.B (“Gas Transportation Plan”)

1 6. Q. PLEASE SUMMARIZE THE COMPANIES' NATURAL GAS  
2 TRANSPORTATION PORTFOLIOS AND STRATEGY.

3 A. Section 5.B of the ESP captures in more detail the Companies' gas transportation  
4 portfolios. The Companies are proposing to maintain their current transportation  
5 portfolios during the Action Plan Period. Section 2.E of the ESP narrative,  
6 sponsored by the Companies' witness Charles McCutchen, discusses the analysis,  
7 which informs the gas transportation requirements. Because Nevada Power's firm  
8 transportation rights are lower than the projected volume of natural gas flowing to  
9 southern Nevada during the summer months, and Sierra's firm transportation rights  
10 during the winter months are at the projected volume of natural gas flowing to  
11 northern Nevada for Sierra's generation and local distribution company, the  
12 Companies feel it is prudent to, at a minimum, maintain their existing transportation  
13 portfolios.

14  
15 7. Q. IS SIERRA SEEKING ADDITIONAL TRANSPORTATION CAPACITY  
16 TO SERVE NEW NATURAL GAS-FIRED GENERATION BEING  
17 PROPOSED IN THE PREFERRED PLAN OF THE IRP?

18 A. Yes. The Companies' Preferred Plan proposes generation additions in Sierra's  
19 service territory of 401 MW of new generation at the Fort Churchill generation site  
20 requiring 85,552 MMBtu per day of natural gas in June 2030, 401 MW of new  
21 generation at Fort Churchill requiring 85,552 MMBtu per day of natural gas in June  
22 2031, and 421 MW of new generation at Forth Churchill requiring 103,681 MMBtu  
23 per day of natural gas in June 2032 for a total need of approximately 275,000  
24 MMBtu/day.

1 8. Q. WHAT STEPS DID SIERRA TAKE TO INVESTIGATE OPTIONS FOR  
2 ADDITIONAL NATURAL GAS TRANSPORTATION CAPACITY TO  
3 MEET THE NEEDS OF THE PREFERRED PLAN?

4 A. Please see Q&As 12 through 23 in my testimony in the Companies' 2026 Joint  
5 Integrated Resource Plan, filed concurrently with their ESP.  
6

7 9. Q. IN REGARD TO INTERSTATE PIPELINE RATE CASES, HAVE ANY  
8 INTERSTATE PIPELINE RATE CASES CONCLUDED OR INITIATED  
9 SINCE THE LAST ESP?

10 A. No.  
11

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

13 A. Yes.  
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**EXHIBIT VITIELLO-DIRECT-1**

Vincent J. Vitiello  
6226 West Sahara Avenue  
Las Vegas, Nevada 89146  
(702) 402-2991

## **Employment History**

### **NV ENERGY**

#### **GAS SUPPLY PLANNING LEAD – RESOURCE OPTIMIZATION – LAS VEGAS, NV**

##### **2019 – Present**

- Responsible for short and long-term planning of the Company's natural gas transportation and storage assets necessary to ensuring adequate gas supply to the Company's generation plants and to Sierra's gas distribution system.
- Responsible for reviewing and monitoring pipeline filings, negotiating rate case settlements, and supporting related efforts before the Federal Energy Regulatory Commission (FERC) and state regulatory commissions.

#### **STAFF ANALYST/ ENGINEER – RESOURCE PLANNING DEPARTMENT – LAS VEGAS, NV**

##### **2007 – 2019**

- Perform technical analysis and evaluation of the capital cost, production cost, and reliability of various transmission, generation, purchase power, and demand side alternatives being considered by the Company.
- Project management of regulatory filings submitted to the Public Utilities Commission of Nevada. Assist in the preparation of testimony and exhibits and respond to data requests.

#### **SENIOR COMPLIANCE CONSULTANT – COMPLIANCE DEPARTMENT – LAS VEGAS, NV**

##### **2006 – 2007**

- Assisted in the establishment, implementation and monitoring of an effective compliance program.
- Audited several departments to insure Sarbanes-Oxley compliance.

### **CHEVRON CORPORATION**

#### **ASSISTANT EXECUTIVE DIRECTOR – NEVADA COGENERATION ASSOCIATES #1 AND #2 LAS VEGAS, NEVADA**

##### **2000 – 2006**

- Responsible for the engineering activities of two 85 MW cogeneration facilities which provided electricity to Nevada Power Company under long-term contracts.
- Coordinated all environmental compliance, including Title V air permits.
- Assisted in the operations and maintenance of the facilities to insure safe operations and optimized plant performance.

## **SOUTHWEST GAS CORPORATION**

**SUPERVISOR – MAJOR ACCOUNTS DEPARTMENT – LAS VEGAS, NV  
1993 – 2000**

- Supervised the activities of Industrial Gas Engineers in Nevada, Arizona and California.
- Coordinated and administered natural gas supplies and interstate transportation service to power generation, large industrial and commercial customers.
- Developed programs to maintain or increase the corporate margin from power generation, large industrial and commercial customers.

**INDUSTRIAL GAS ENGINEER – MAJOR ACCOUNTS DEPARTMENT – PHOENIX, AZ  
1989 – 1993**

- Maintained contact and provided technical assistance for power generation, large industrial and commercial gas customers.
- Negotiated contracts for customers served under transportation and optional fuel rate schedules.
- Promoted natural gas technology including cogeneration, natural gas air-conditioning and compressed natural gas vehicles.

**ENGINEER – ENGINEERING DEPARTMENT – PHOENIX, AZ  
1986 – 1989**

- Designed gas distribution facilities including high pressure and distribution gas piping, regulating stations, meter sets and telemetry.
- Provided work direction and conducted the performance reviews for several Engineering Technicians and Drafters.
- Special projects included an emergency valve isolation plan and over-pressure protection review.

## **EXXON COMPANY, U.S.A.**

**SENIOR PROJECT ENGINEER – PRODUCTION DEPARTMENT – CORPUS CHRISTI, TX  
1982 – 1986**

- Designed oil and gas production facilities including gathering lines, oil storage sites and separation and metering stations. Responsible for the design, material specification, cost estimating and project management necessary during construction.

**MECHANICAL CONTACT ENGINEER – REFINING DEPARTMENT – BAYTOWN, TX  
1980 – 1982**

- Responsible for maintaining the operation of several refinery process units. Duties included solving daily maintenance problems as well as designing and implementing quality and production improvements. This assignment provided extensive experience with heat exchangers, furnaces, pumps and compressors.

## **EDUCATION**

**STEVENS INSTITUTE OF TECHNOLOGY – HOBOKEN, NEW JERSEY**

- Bachelor of Engineering – with Honor, awarded May 1980
- Major: Mechanical Engineering

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AFFIRMATION

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

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

Date: May 4, 2026

  
Vincent Vitiello

**ZELJKO VUKANOVIC**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2026 Joint Energy Supply Plan  
Docket No. 26-05 \_\_\_\_

Prepared Direct Testimony of

**Zeljko Vukanovic**

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

A. My name is Zeljko Vukanovic. I am the Market Fundamentals Lead for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I hold a Masters of Science in Finance and Banking from Boston University and Masters in Business Administration from University of Nevada, Las Vegas. I have been employed by the Companies since June 2006 and have served as the Market Fundamentals Lead since September 2019. Prior to my current role, I served in Resource Planning and Analysis as a Valuation Specialist, where I performed Energy Supply Plan (“ESP”) analyses. I have also held the Consultant Staff position in the Demand Side Management department at the Companies. More details regarding my professional

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background and experience are set forth in my Statement of Qualifications, included as **Exhibit Vukanovic -Direct-1**.

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

A. Yes, I have testified before the Commission in Docket Nos. 12-06051, 13-07002, 13-07005, 14-07007, 14-07008, 21-06001, 22-03024, 22-11032, 23-08015, 24-05041, 25-08027, 25-10003, and 25-10028.

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

A. I sponsor the following sections in the Companies’ 2026 Joint ESP for the action plan period of 2027-2029 (“2026 ESP”):

Section 3.A. (“Market Fundamentals”)

Section 3.C. (“Fuel and Purchased Power Price Forecats”)

I also sponsor Technical Appendix FPP-1, the fuel and purchased power price forecasts.

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

A. Yes. FPP-1 is being filed confidentially. This confidential information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies and their customers by limiting the ability to

1 foster competition among prospective suppliers, compromising the  
2 Companies' negotiating position and reducing their bargaining leverage.  
3 Publication of this information would impair the Companies' ability to achieve  
4 the most favorable pricing and terms and conditions from suppliers on behalf  
5 of its customers.

6  
7 **6. Q. FOR HOW LONG DO THE COMPANIES REQUEST**  
8 **CONFIDENTIAL TREATMENT?**

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

10  
11 **7. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF**  
12 **REGULATORY OPERATIONS STAFF ("STAFF") OR THE BUREAU**  
13 **OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE**  
14 **THE ESP?**

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

18  
19 **8. Q. PLEASE BRIEFLY DESCRIBE THE NATURAL GAS AND**  
20 **PURCHASED POWER PRICE FORECASTS USED IN THE ESP.**

21 A. The base, high and low fuel and purchased power price forecasts used in this  
22 filing have been prepared in a manner consistent with the Companies' previous  
23 ESP and integrated resource plan ("IRP") filings. The methodology used to  
24 prepare the Price Forecasts relies upon near-term observable market-based  
25 price quotes that are blended into a long-term market fundamental price  
26 forecast. The base power and natural gas price forecasts were developed using  
27

1 a 19-day average of market-based price quotes from November 2025. These  
2 quotes reflect observed transactions at the following natural gas trading hubs:  
3 Henry Hub, Alberta NOVA Inventory Transfer (“AECO”), Northwest  
4 Pipeline Rockies (“Rockies”), Malin, and the Southern California Border  
5 (“SoCal”). Similarly, quotes for purchased power are obtained from Argus  
6 Media and reflect observed transactions at power trading hubs the Mead, the  
7 Palo Verde, and the Mid-Columbia (“Mid-C”).

8  
9 The long-term fundamental price forecast is obtained from Wood Mackenzie  
10 (“WoodMac”), which publishes its fundamental price forecast (Long-term  
11 outlook or “LTO”) bi-annually. The price curves in this filing are based on the  
12 H2 Base Case, released in December of 2025. WoodMac performs detailed  
13 modeling of regional natural gas and power markets, taking into account  
14 supply-demand price dynamics. The market fundamentals in this case serve as  
15 the foundation in building the price forecasts included as Technical Appendix  
16 Item FPP-1.

17  
18 **9. Q. PLEASE DESCRIBE THE PROCESS USED TO PREPARE THE**  
19 **NATURAL GAS AND POWER PRICE FORECASTS.**

20 A. The near-term (January 2027 through March 2029) market quotes for power  
21 and gas are based entirely on the average of settlement prices during 19 trading  
22 days in November 2025. The Price Forecasts transition from being entirely  
23 market-based price quotes to entirely long-term fundamental forecast during a  
24 24-month blending period from April 2029 through March 2031. The near-  
25 term market-based quotes are incrementally blended with the long-term  
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fundamental forecast across this transition period.<sup>1</sup> The Companies used the pure fundamental forecast for the April 2031 through December 2050 portion of the price forecast. Thus, the near-term market quotes, blending period, and long-term forecast constitute the forecasted natural gas price curve for each of the relevant Western natural gas trading hubs. The natural gas price forecasts are provided in Technical Appendix FPP-1.

**10. Q. PLEASE BRIEFLY DESCRIBE THE PROCESS USED TO PREPARE THE HIGH AND LOW PRICE FORECASTS USED BY THE COMPANIES IN THE ESP.**

A. The Companies include sensitivity analyses around the base case projections to determine how planning results vary under a range of market price conditions. High- and low-price curves for natural gas were calculated at one standard deviation around the base case forecast (plus and minus). Market quotes of implied volatilities from at-the-money call options from November 2025 were used to calculate the volatility of natural gas futures for the period from January 2027 to December 2050. High- and low-power price forecasts were prepared to reflect Western energy prices that fluctuate with the respective natural gas price forecasts, using the implied market heat rates (Socal hub for southern and Malin hub for northern Nevada).

---

<sup>1</sup> The blending of market quotes and the fundamental forecast occurs across four gas seasons, or 24 months, with a weighting of the fundamental forecast increasing monthly by 4.0 percent per month.

1       **11.    Q.    HOW DO YOU CAPTURE CAPACITY COSTS FOR PURPOSES OF**  
2                   **THE POWER PRICE FORECAST?**

3           A.    WoodMac’s regional power price forecast represents day-ahead firm energy  
4                   prices; it does not explicitly include the full cost of new capacity additions that  
5                   would be required to ensure resource adequacy over the forecast period. The  
6                   regional price forecast is used by the PLEXOS ST model to economically  
7                   dispatch market purchases against internal generation, while the capacity price  
8                   forecast (dollars per kilowatt-month) is multiplied by the Companies’ open  
9                   capacity position, if not filled by external power contract placeholders, as an  
10                  additional fixed fuel and purchased power cost.

11  
12       **12.    Q.    WHAT IS THE SOURCE OF THE COMPANIES’ LONG-TERM**  
13                   **CAPACITY PRICE FORECAST?**

14           A.    The Companies have utilized WoodMac’s capacity price forecast in the  
15                   preparation of the ESP for 2027-2029. As part of its Long-Term Outlook,  
16                   WoodMac prepared an estimate of the levelized cost of new entry (“CONE”)  
17                   for the installed cost of future combined cycle and combustion turbine  
18                   generation. The CONE is an estimate of the annual fixed costs associated with  
19                   owning and operating a new generating facility (*i.e.*, exclusive of variable  
20                   costs such as fuel and emissions). WoodMac then calculates the capacity price  
21                   forecast (in dollars per kW-year) as the difference between the CONE and the  
22                   net energy and ancillary services margins reflected in the wholesale power  
23                   price forecast.

24  
25       **13.    Q.    DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

26           A.    Yes, it does.

**EXHIBIT VUKANOVIC-DIRECT-1**



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AFFIRMATION

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

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

Date: May 4, 2026

  
\_\_\_\_\_  
Zeljko Vukanovic

**NARRATIVE**  
**ENERGY SUPPLY PLAN**

**NEVADA POWER COMPANY d/b/a NV ENERGY  
SIERRA PACIFIC POWER COMPANY d/b/a NV ENERGY  
JOINT ENERGY SUPPLY PLAN FOR 2027-2029**

**TABLE OF CONTENTS**

**SECTION 1 - EXECUTIVE SUMMARY .....2**

A. INTRODUCTION.....2

B. ESP OBJECTIVES & REGULATORY CONTEXT .....2

C. SUMMARY OF REQUESTS FOR COMMISSION APPROVAL .....3

D. OVERVIEW OF THE ENERGY SUPPLY PLAN.....7

**SECTION 2 – POWER AND FUEL REQUIREMENTS .....10**

A. NV ENERGY ELECTRIC LOAD FORECAST..... 10

B. CAPACITY REQUIREMENTS ..... 13

C. ENERGY REQUIREMENTS ..... 17

D. RENEWABLE ENERGY PLANNING..... 17

E. GAS TRANSPORTATION REQUIREMENTS ..... 31

F. PHYSICAL GAS REQUIREMENTS..... 36

G. FINANCIAL GAS REQUIREMENTS..... 39

**SECTION 3 - MARKETS & PRICE FORECASTS .....40**

A. MARKET FUNDAMENTALS..... 40

B. REGIONAL MARKET DEVELOPMENT..... 55

C. FUEL AND PURCHASED POWER PRICE FORECASTS..... 56

**SECTION 4 – POWER PROCUREMENT PLAN.....62**

A. POWER PORTFOLIO AND OPTIMIZATION PROCEDURES ..... 62

B. SUMMARY OF POWER PROCUREMENT PLAN ..... 68

C. OPEN POWER POSITIONS ..... 68

**SECTION 5 – GAS PROCUREMENT PLAN .....73**

A. PHYSICAL GAS PROCUREMENT PLAN ..... 73

B. GAS TRANSPORTATION PLAN ..... 74

C. RECOMMENDED GAS HEDGING PLAN ..... 81

**SECTION 6 – RISK MANAGEMENT STRATEGY .....82**

A. ELEMENTS OF THE STRATEGY ..... 82

B. ELEMENTS OF THE STRATEGY APPLIED TO THE ENERGY SUPPLY PLAN..... 84

C. SELECTION CRITERIA ..... 85

D. EVALUATION CRITERIA..... 85

**SECTION 7 – DETERMINATION OF PRUDENCE .....86**

**SECTION 8 – COMMISSION DIRECTIVES .....88**

GAS HEDGING WORKSHOPS..... 88

## **SECTION 1 - EXECUTIVE SUMMARY**

### **A. INTRODUCTION**

Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”) respectfully submit this joint Energy Supply Plan for 2027-2029 (“ESP”). In accordance with Nevada Administrative Code (“NAC”) §§ 704.9506 and 704.9482, this ESP sets forth the Companies’ power procurement plan, fuel procurement plan, and risk management strategy for calendar years 2027-2029. NRS § 704.751 requires that this ESP be processed within 135 days of filing. The Companies request that the Public Utilities Commission of Nevada (“Commission”) approve this ESP and make the determinations of prudence provided for in NAC § 704.9494 regarding each element of the plan.

### **B. ESP OBJECTIVES & REGULATORY CONTEXT**

Pursuant to NAC § 704.9061, an ESP means a plan that:

1. Establishes the parameters of an energy supply portfolio for a utility for the three-year period covered by its Action Plan and which balances the objectives of:
  - a) Minimizing the cost of supply;
  - b) Minimizing retail price volatility; and
  - c) Maximizing the reliability of energy supply over the term of the ESP supply plan.
2. Is composed of a purchased power procurement plan, fuel procurement plan and risk management strategy.

Pursuant to NAC § 704.9494, the Commission can determine that the ESP is prudent if the following requirements are met:

- The ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.
- The ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.

- The ESP does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

## **C. SUMMARY OF REQUESTS FOR COMMISSION APPROVAL**

The Companies are requesting the Commission:

### **Load Forecast**

- Find that the load forecast used in this ESP (the “2026 ESP Forecast”), as described in Section 2.A. (Electric Load Forecast) and Technical Appendix Item IRP LF-1, meets the requirements of NAC §§ 704.9321(1) (because they are based on substantially accurate data and are adequately documented, justified, demonstrated and defended), NAC § 704.9482 (because the 2026 ESP Forecast uses base load forecast), and NAC § 704.9482(7) and NAC § 704.922 (because the technical appendices provide sufficient detail as to how the 2026 ESP Forecasts were prepared to facilitate the evaluation of the validity of the assumptions and the accuracy of the data used).
- Find that the 2026 ESP Forecast is suitable for making planning decisions during the ESP 2027-2029 action plan period.

### **Power Procurement/Sales Plan**

- Accept and approve the power procurement plan, which includes the following elements:
  - The Companies propose to continue the four-season laddering strategy to fill the remaining open positions in 2027, continue filling the 2028 open positions and begin filling 2029 open positions. This plan is consistent with the laddering strategy for closing the open power position, which was most recently approved in Docket Nos. 25-08027 and 24-05041. The power procurement laddering strategy will be executed in coordination with the physical gas procurement plan.
  - The Companies propose to continue to negotiate and transact directly with counterparties as a supplement to the current request-for-proposal (“RFP”) process. The Companies will evaluate all available products and determine the most prudent transaction plan based on cost and deliverability.
  - A commitment by the Companies to continuously monitor the portfolio and seek to make short-term and forward purchases when economic or needed to serve native load.

Any proposed purchases of greater than three years in duration will be submitted to the Commission for approval in a resource plan filing or amendment in accordance with NAC §§ 704.9113 and 704.9512(1).

- A strategy and plan to make purchases and sales to optimize the value of the overall supply portfolio for the benefit of retail customers.
- An obligation on behalf of the Companies to monitor their renewable portfolios on a continuous basis to ensure that sufficient renewable energy and portfolio energy credits (“PCs”) are maintained to comply with the State of Nevada’s Renewable Portfolio Standard (“RPS”) and undertake cost-effective opportunities to fill any new needs that may arise. Current projections indicate that Nevada Power will be non-compliant in action plan period of the ESP, 2027 through 2029. Sierra is projected to be non-compliant in 2027 and compliant in 2028 and 2029. Combined, the Companies are projected to be non-compliant in the action plan period of the ESP, 2027 through 2029.
- Find, consistent with NAC § 704.9494(3), that the power procurement strategy is prudent.

### **Physical Gas Procurement Plan**<sup>1</sup>

- Accept and approve the Companies’ plan to implement the four-season laddering strategy originally approved by the Commission in Docket No. 09-09001 to procure physical gas. Projected physical gas requirements procured through the laddering strategy will be procured with indexed products. Previously, the procurement of physical gas was subject to a cap on the premium, which could be exceeded with prior approval from the Risk Committee. Consistent with the Stipulation in Docket No. 09-09001, if the Companies exceeded the premium cap, and the procured gas that exceeded the premium cap was not the least cost supply alternative, they would provide written notice to the Commission’s Regulatory Operations Staff (“Staff”) and the Bureau of Consumer Protection (“BCP”). The Companies propose that the physical premium cap be removed. The physical premium cap was originally approved in 2009 and has not been adjusted for inflation. Additionally, sellers’ risk preferences and cost structures have evolved over time. As a result, the Companies rarely receive bids that are at or below the existing premium cap. Removing the premium cap would not affect the results of the Companies’ laddering strategy. Because execution is always based on least cost, the presence of a physical premium cap does not affect transaction outcomes.

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<sup>1</sup> The Companies’ “fuel procurement plan” consists of several distinct elements; namely, the physical gas procurement plan, the gas transportation plan, and the gas hedging plan.

- A strategy and plan to make purchases and sales to optimize the value of the overall supply portfolio for the benefit of retail customers.
- Find, consistent with NAC § 704.9494(3), that the physical gas procurement strategy is prudent.

### **Gas Transportation Plan**

- Accept and approve the gas transportation plan, which includes the following elements:
  - Approval to maintain the Companies' current natural gas transportation portfolios. For Nevada Power, this requires authority to maintain seven existing gas transportation contracts with Kern River Pipeline and three with Southwest Gas Corporation. At Sierra, this requires authority to maintain a total of 35 existing gas transportation and storage contracts with TC Energy – Alberta, TC Energy – Foothills, TC Energy Gas Transmission Northwest (“GTN”), TC Energy Tuscarora Gas Transmission Company (“Tuscarora”), Great Basin Gas Transmission Company (“Great Basin”), Northwest Pipeline LLC (“NWPL”), Ruby Pipeline (“Ruby”) and the Pinyon Pipeline (“Pinyon”) pursuant to rights of first refusal and evergreen rights. The total projected annual costs for firm transportation contracts at both Nevada Power and Sierra are approximately \$117.5 million.
- Find, consistent with NAC § 704.9494(3), that the gas transportation strategy is prudent.

### **Gas Hedging Plan**

- Approval to continue the current hedging strategy and acquire no natural gas hedges covering the ESP period. The Companies will continue to monitor the natural gas market fundamentals and recommend changes to the hedging strategy in a future ESP Update or ESP amendment as necessary.
- The Companies will continue bi-annual workshops with Staff and the BCP to review implementation of the approved no-hedge gas hedging strategy.
- An affirmative finding, consistent with NAC § 704.9494(3), that the Companies' gas hedging strategy is prudent.

## **Risk Management Strategy**

- Acceptance and approval of the Companies' risk management strategy and a finding that the strategy identifies risks inherent in procuring and obtaining a supply portfolio and establishes the means by which the utility plans to address and balance or hedge the identified risks related to cost, price volatility and reliability.
- An affirmative finding consistent with NAC § 704.9494(3) that the risk management strategy is prudent.

## **Commission Directives**

A finding that the Companies have satisfied the following Commission directive:

- The Commission's order approving the stipulation in Docket No. 20-09002 accepting the Companies' plan to continue conducting bi-annual gas hedging workshops with Staff and BCP to review the implementation of the constituent elements of the ESP and the approved gas hedging strategy.

## **Determination of Prudence**

Pursuant to NAC § 704.9494, the Companies request that the Commission determine the elements of the ESP are prudent by finding that the 2026 ESP:

- Balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.
- Optimizes the value of the overall supply portfolio of the utilities for the benefit of their bundled retail customers.
- Does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utilities or would lead to a deterioration of the creditworthiness of the utilities.

Finally, the Companies ask that the Commission grant their request for confidential treatment of information filed under seal, including copyrighted and proprietary data of third parties, natural gas price forecasts, power price forecasts, large customer load information, information related to the safety and security of critical energy infrastructure, and the production cost modeling outputs.

For more information on the Companies' request for a determination of prudence of the ESP see Section 7.

## D. OVERVIEW OF THE ENERGY SUPPLY PLAN

### 1. POWER PROCUREMENT PLAN

Based on the 2026 ESP Forecast, the Companies have open capacity positions in the summers of 2027, 2028, and 2029. Note that any open positions in the spring or fall period of each year are “maintenance-driven,” rather than “load-driven,” and occur during lower system load conditions when wholesale power market supplies are generally available. The Companies propose to close up to the respective anticipated summer open positions with firm products prior to the respective summer.

The Companies propose to implement a four-season laddering strategy to close the remaining open power positions in 2027 with the procurement of physical power and/or capacity acquired through a competitive bidding process. In addition, the Companies propose to negotiate and transact directly with counterparties as a supplement to the current request for proposal process as approved in the 2024 Joint Integrated Resource Plan (“IRP”). This would allow the Companies to seek custom non-standard firm energy products to help address short-term supply challenges during the evening and overnight net demand peak period when solar resources are largely unavailable, given that battery storage is energy-limited. Any proposed purchases of greater than three years in duration will be submitted to the Commission for approval in accordance with NAC §§ 704.9113 and 704.9512(1). Additional information regarding the closing of the open positions in the power procurement plan is provided in Section 4.C.

Additionally, the Companies monitor the portfolio seasonally, monthly, weekly, daily, and hourly, and when economic, seek to make short-term and forward sales of resources not expected to be needed to serve native load. This practice will be continued over the ESP period.

The Companies project Nevada Power will be non-compliant in the action plan period of the ESP, 2027 through 2029. Sierra is projected to be non-compliant in 2027 and compliant in 2028 and 2029. Combined, the Companies are projected to be non-compliant in the action plan period of the ESP, 2027 through 2029. This ESP incorporates the current regulations governing the Companies’ ability to use PCs to meet the RPS and the calculation of the PCs. The plan also contemplates that the Companies may seek Commission approval to revive the credit pooling arrangement in a future filing in order to maintain compliance with the RPS.

For more detail on the purchased power procurement plan, see Section 4. For more detail on the RPS compliance outlook, see Section 2.D.

## 2. FUEL PROCUREMENT PLAN

The fuel procurement plan is made up of three components: (1) a physical gas procurement plan, (2) a gas transportation plan, and (3) a gas hedging plan.

***Physical Gas Procurement Plan.*** The Companies employ a four-season laddering strategy for physical gas purchases, through 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. The Companies will continue to solicit physical gas supplies sourced from geographically diverse gas supply basins.

Additionally, the Companies monitor the natural gas portfolio monthly, weekly, and daily. The Companies will make short-term purchases and sales for balancing and optimization activities for the natural gas portfolio based on the needs of the system. This practice will be continued over the ESP period. Additional information regarding the Companies' physical gas procurement plan is provided in Section 5.A.

***Gas Transportation Plan.*** Nevada Power is connected directly to the interstate pipeline systems 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. The Kern River pipeline connects the Rocky Mountain basin through Nevada into southern California with a design capacity of 2,166,575 million British thermal units ("MMBtu") per day. This pipeline deliverability capacity is large in comparison to Nevada Power's daily needs.

Sierra is well poised to access the dominant supply basins serving the Pacific Northwest with its existing firm gas transportation assets. These gas supply basins are the Rocky Mountain Basin, the San Juan Basin, British Columbia and the Western Canadian Sedimentary Basin. Sierra takes delivery of natural gas from three interstate pipelines, Great Basin, Tuscarora, and Ruby. Great Basin receives gas supplies upstream from 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 GTN, 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 Alberta Energy Company ("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's system at the U.S./Canadian border near Kingsgate, Idaho. Ruby receives supplies from the Rocky Mountain Basin.

The Companies are seeking approval to maintain their current natural gas transportation portfolios. The contracts are listed in Figures ESP-43 and ESP-44. Additional information regarding the Companies' gas transportation plan is provided in Section 5.B.

**Gas Hedging Plan.** The Companies are proposing to continue the current approved hedging strategy and acquire no natural gas hedging products during the ESP period. The Companies will continue to monitor the natural gas market fundamentals and recommend changes to the hedging strategy in a future ESP Update or ESP amendment as necessary.

### 3. RISK MANAGEMENT STRATEGY

The Companies' risk management strategy includes:

- Detailed corporate governance and risk control policies and procedures,
- Compliance with approved supply plans,
- Reduced reliance on volatile wholesale markets,
- Use of competitive procurement processes,
- Gas hedging strategies, and
- Market monitoring.

For more detail on risk management strategy, see Section 6.

### 4. DETERMINATION OF PRUDENCE

Pursuant to NAC §§ 704.9508(2) and 704.9494, the Commission can determine that the elements of an ESP are prudent if:

- The ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.
- The ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
- The ESP does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

This ESP satisfies the prudency requirements of NAC §§ 704.9508(2) and 704.9494 for each of the three elements, as discussed in detail in Section 8. The Companies acknowledge that the prudence of their implementation of an approved ESP will be determined in a future deferred

energy proceeding. In addition, pursuant to NAC § 704.9504, the Companies may deviate 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.”

## **SECTION 2 – POWER AND FUEL REQUIREMENTS**

### **A. NV ENERGY ELECTRIC LOAD FORECAST**

The 2026 ESP Forecast utilizes the same load forecast proposed as part of the 2026 Joint IRP (“2026 Joint IRP”) filing, covering the period beginning with the calendar year 2027 through the 20 years ending 2046. Please see Section 1.A.3 of the 2026 Joint IRP Narrative or Technical Appendix LF-1 in that filing for further details on the development of the load forecast for the three-year action plan period. The sections below provide a brief summary of the load forecast for the 2026 ESP three-year action plan period (2027-2029).

#### **Load Forecast Summary**

In total, for the three-year action plan period 2027 through 2029, the Compound Annual Growth Rate (“CAGR”) of the annual retail energy for the Companies is 11.3 percent (7.4 percent at Nevada Power and 17.6 percent at Sierra). Annual energy consumption during this period increases by approximately 9,500 GWh for the combined NV Energy system, with 3,800 GWh at Nevada Power and 5,700 GWh at Sierra. The CAGR of the Companies’ combined system coincident peak is 7.4 percent (with non-coincident peak CAGR values of 4.8 percent at Nevada Power and 11.7 percent at Sierra). System Peak Demand is expected to increase 1,397 MW for the combined system during the three-year action plan period, with 664 MW at Nevada Power and 644 MW at Sierra.

Figure ESP-1 summarizes the Annual Peak MW and GWh energy differences between the 2026 ESP forecast and the forecast approved in the 2024 IRP filing.<sup>2</sup> Updates for large customer major projects are the driver of incremental load growth during the three-year action plan period.

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<sup>2</sup> Docket No. 24-05041, Order dated December 27, 2024, at ¶¶ 520-530.

**FIGURE ESP-1  
ANNUAL PEAK (MW) AND ENERGY (GWH) DIFFERENCES**

		Peak (MW)			Energy (GWh)		
		2027	2028	2029	2027	2028	2029
Nevada Power	2024 Joint IRP 1A	6,674	6,799	6,835	23,161	23,527	23,825
	2026 ESP	6,705	6,865	7,369	25,038	26,620	28,859
	Difference	31	66	534	1,877	3,092	5,035
	Percent Difference	0.5%	1.0%	7.8%	8.1%	13.1%	21.1%
Sierra	2024 Joint IRP 1A	2,495	2,657	2,856	13,927	14,844	15,918
	2026 ESP	2,598	2,951	3,242	14,858	17,709	20,543
	Difference	103	294	386	932	2,865	4,625
	Percent Difference	4.1%	11.1%	13.5%	6.7%	19.3%	29.1%
NVE	2024 Joint IRP 1A	8,895	9,145	9,405	37,087	38,371	39,742
	2026 ESP	9,114	9,629	10,511	39,896	44,329	49,402
	Difference	219	484	1,106	2,809	5,958	9,660
	Percent Difference	2.5%	5.3%	11.8%	7.6%	15.5%	24.3%

Figure ESP-2 demonstrates the monthly coincident peak load forecast for the three years of the ESP action plan period (2027 - 2029).

**FIGURE ESP-2  
MONTHLY NV ENERGY PEAK LOAD FORECAST (2027 - 2029)**

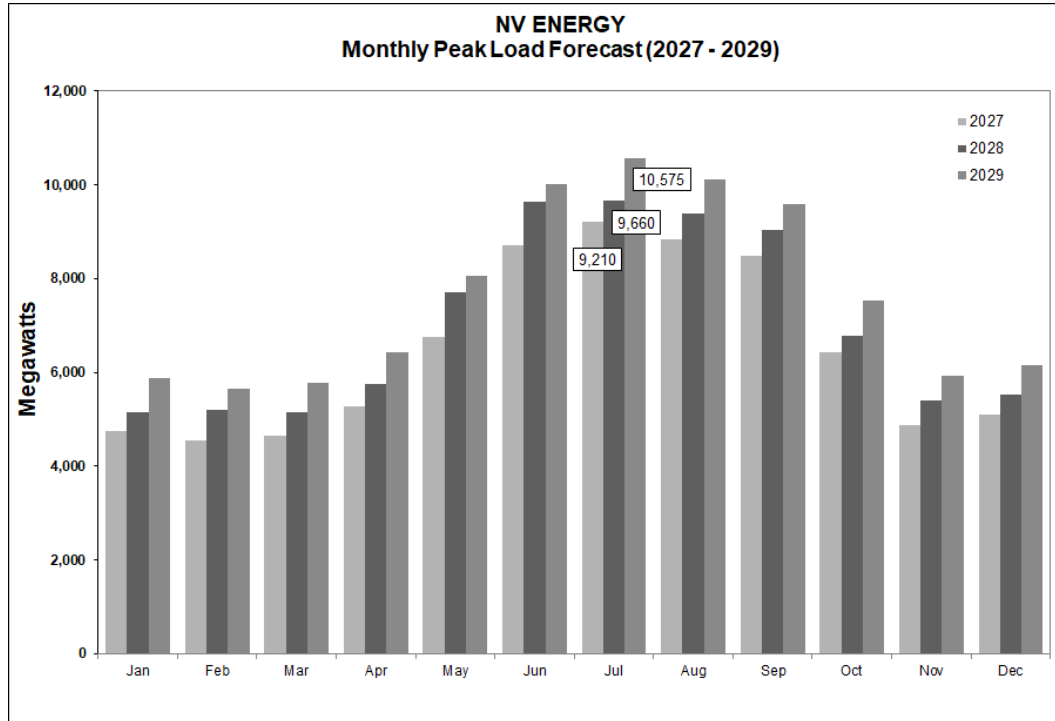


Figure ESP-3 shows the Companies' projected load duration curve for 2027, which is representative of each year in the 2027-2029 action plan period. This is the distribution of load across the number of hours in the year and represents a load factor of 49.4 percent overall.

**FIGURE ESP-3  
NV ENERGY 2027 LOAD DURATION CURVE**

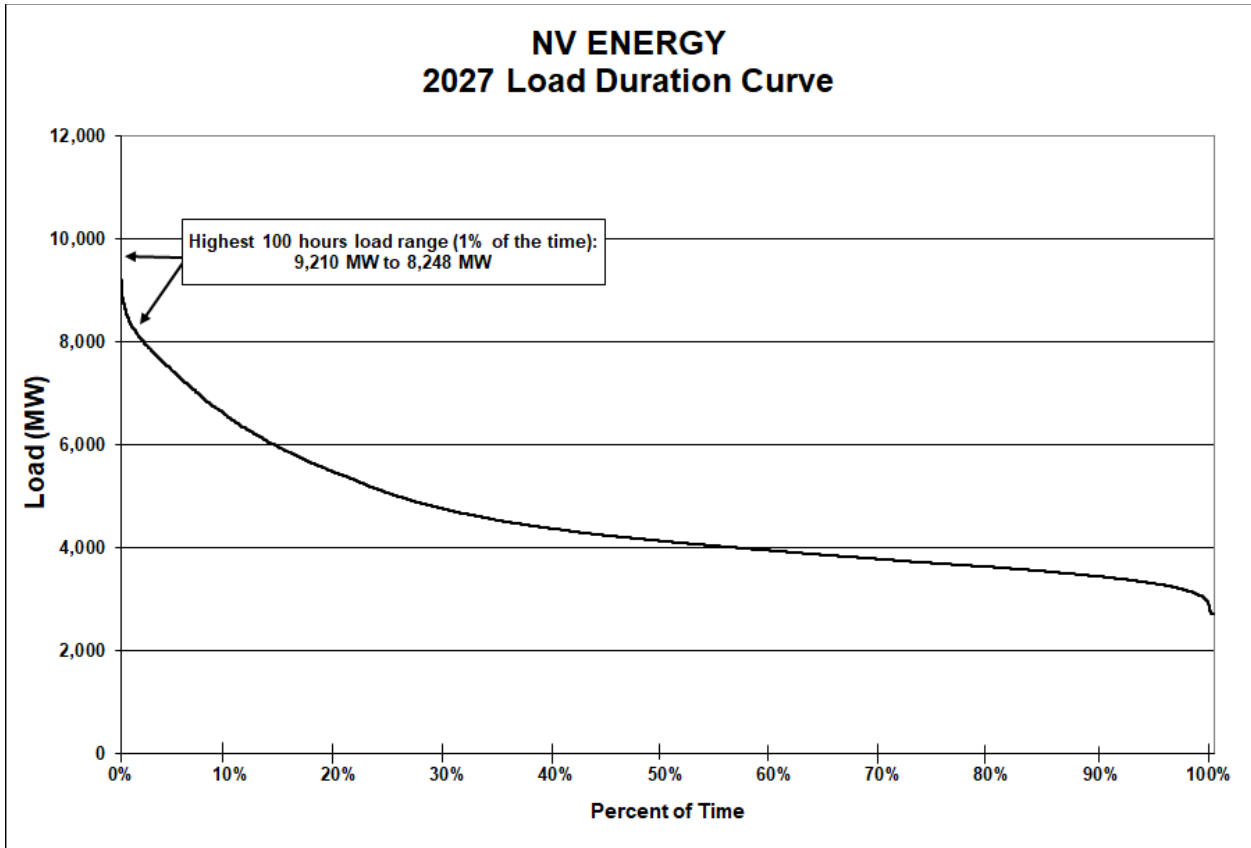
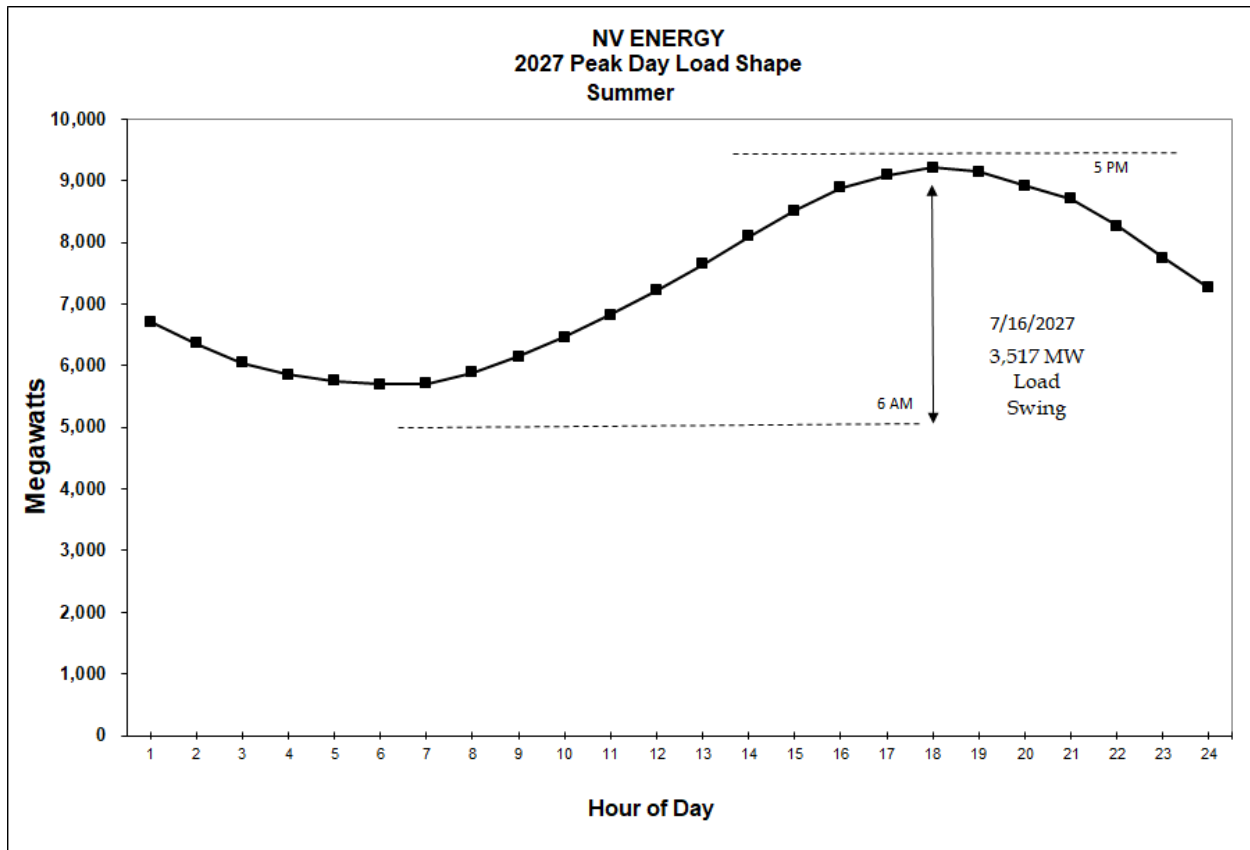


Figure ESP-4 reflects the expected fluctuation in hourly load during the summer peak day in July of 2027, which is expected to experience a range of 3,517 MW, or 38.2 percent of the daily peak, between the minimum and maximum loads. The presented load shape is representative of the near-term summer peak load shape for the Companies over the 2027-2029 action plan period.

**FIGURE ESP-4  
NV ENERGY PEAK DAY LOAD SHAPE FORECAST**



**B. CAPACITY REQUIREMENTS**

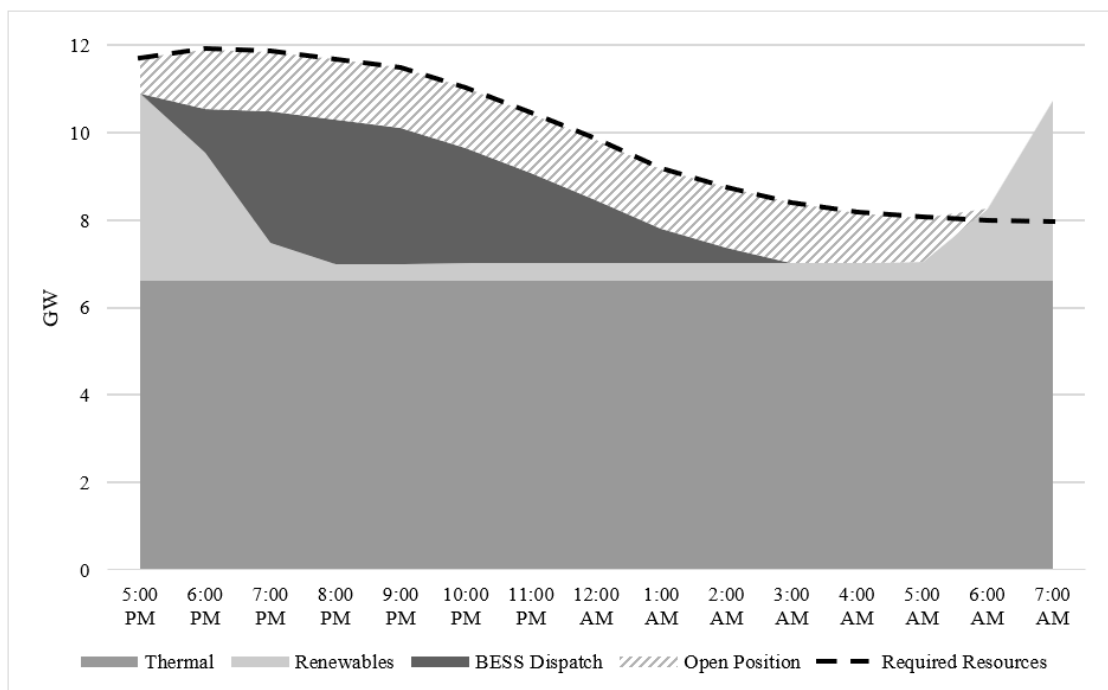
The Companies require enough firm capacity to cover their projected electric load plus their respective planning reserve margin (“PRM”) of 12.5 percent.<sup>3</sup>

In addition, due to the continuing evolution of the Companies’ system, a new paradigm is engaged for evaluation of the hours of greatest need. The new paradigm reflects a portfolio of continually growing quantities of variable renewable resources, for which availability decreases in the evening

<sup>3</sup> See 2024 Joint IRP, Docket No. 24-05041, Volume 8 at 216 of 393.

hours, but also increases in quantities of energy-limited storage resources and a flattening load shape. Recognizing that the overnight hours – hours without solar PV output – are becoming increasingly worthy of scrutiny in a system in which storage resources are largely 4-hour batteries, the Companies have expanded the assessment of the hour of greatest need to include 5:00 p.m. to 7:00 a.m. Market products are typically offered in multi-hour blocks rather than for individual hours. Storage resources provide the flexibility to flatten, or levelized, the open position across multiple hours, allowing the Companies to more fully benefit from block market purchases, as illustrated in Figure ESP-5. This figure illustrates the overnight view in a future summer month before procurement of any market products.

**FIGURE ESP-5  
JOINT SYSTEM OPEN POSITION ANALYSIS**



As a result, the *hour of greatest need*, a concept first introduced in the 2021 ESP,<sup>4</sup> is being expanded to the *hours of greatest need* – multiple hours with the same open position. As such, the Companies are requesting approval to close the open capacity position in the overnight hours rather than simply the evening hours. This paradigm shift will increase reliability and reduce risk of being reliant on short-term power markets in the evening and overnight hours.

The largest open capacity positions under this new methodology are 850 MW in 2027, 638 MW in 2028, and 1,513 MW in 2029.

<sup>4</sup> See Section 2.B. in the Companies’ 2021 Joint ESP for 2022-2024, Docket No. 21-06001.

While the PRM addresses systemwide resource adequacy, the Companies identified concerns for Sierra’s near-term subsystem resource adequacy given the large load growth prior to the full Greenlink commercial operation date projected at the end of 2028. This concern closely mirrors the concern addressed via a Sierra Subsystem Resource Adequacy study in the 2024 IRP, which evaluated resource adequacy concerns for Sierra if the Greenlink Nevada transmission project were not constructed. Therefore, the Companies engaged Energy and Environmental Economics, Inc. (“E3”) to perform a loss-of-load-probability analysis to quantify the likelihood of resource deficiencies in the Sierra subsystem in 2027 and 2028. The results of the study are reported in the Sierra Subsystem Resource Adequacy Analysis in Technical Appendix ECON-2.

The study concluded the Sierra subsystem, without additional resources, experiences a level of reliability in 2027 and 2028 with the 2026 IRP Base Load Forecast that is “far lower than what would be considered acceptable in most modern electricity systems.” The standard referenced by E3 is NV Energy’s systemwide planning standard for a loss-of-load-expectation of 1 day in 10 years, also sometimes referred to as 0.1 days per year. The study assesses various mitigation options including proposed long-term projects in this 2026 Joint IRP as well as short-term solutions. To address resource adequacy concerns identified in the study, the following adjustments and short-term resources are modeled for Sierra in this ESP:

- A load delay resource mimicking a certain amount of delay in large customer load development in 2027 and 2028;
- A 100 MW contract resource for non-contingent firm generation in 2027 and 2028; and
- An adjustment to the seasonal outage schedule for Tracy Unit 3 to allow the unit to remain in service during Tracy combined cycle’s scheduled maintenance outage in 2028.

Figure ESP-6 (“L&R Tables”) illustrates the evolving paradigm and details the resources necessary for the Companies to meet the forecasted customer load, including planning reserve requirements, for summer hours 5:00 p.m. through 8:00 p.m. and continuing into the overnight hours, as appropriate, for 2027 through 2029. As ordered in the Companies’ 2021 ESP, the L&R Tables reflect an increase in the August hourly load forecast and associated planning reserve to match the July hourly loads and planning reserve requirement.<sup>5</sup> The L&R Tables also reflect the unforced capacity accounting methodology used in the Companies’ 2024 ESP and described in the 2024 Joint IRP (Docket No. 24-05041).

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<sup>5</sup> See Docket No. 21-06001, Order dated October 28, 2021, at 8.

## FIGURE ESP-6 2027-2029 LOADS & RESOURCES

2027	June				July				August				September			
	Hour Ending				Hour Ending				Hour Ending				Hour Ending			
	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM
Maximum Coincident System Load	8,447	8,629	8,489	8,268	8,992	9,114	9,059	8,847	8,992	9,114	9,059	8,847	8,337	8,425	8,233	7,902
Planning Reserves (12.5%)	1,056	1,079	1,061	1,034	1,124	1,139	1,132	1,106	1,124	1,139	1,132	1,106	1,042	1,053	1,029	998
Required Resources	9,503	9,707	9,550	9,302	10,116	10,253	10,192	9,952	10,116	10,253	10,192	9,952	9,379	9,478	9,262	8,890
Generation Totals	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206	6,206
Renewables	3,322	2,255	712	389	3,073	2,061	682	386	2,930	1,470	443	397	2,256	664	449	454
Other	101	101	101	100	104	103	103	102	105	104	104	103	101	101	101	100
BESS Dispatch	-	-	1,347	1,422	-	-	1,299	1,357	-	456	1,422	1,229	24	1,562	1,633	1,263
Market Transactions	200	425	425	425	875	1,200	1,200	1,200	950	1,275	1,275	1,275	350	425	425	425
OATT Reserves	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)
Total Available Resources	9,739	8,897	8,701	8,452	10,168	9,480	9,399	9,160	10,100	9,421	9,359	9,120	8,847	8,868	8,723	8,358
Long (Open) - Joint System	237	(810)	(850)	(850)	52	(774)	(792)	(792)	(15)	(832)	(832)	(832)	(532)	(611)	(540)	(532)
	<i>8:00 PM open position continues to 11:00 PM</i>				<i>8:00 PM open position continues to 1:00 AM</i>				<i>8:00 PM open position continues to 1:00 AM</i>				<i>8:00 PM open position continues to 11:00 PM</i>			
2028	June				July				August				September			
	Hour Ending				Hour Ending				Hour Ending				Hour Ending			
	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM
Maximum Coincident System Load	9,377	9,558	9,494	9,250	9,497	9,629	9,491	9,277	9,497	9,629	9,491	9,277	8,840	8,958	8,774	8,429
Planning Reserves (12.5%)	1,172	1,195	1,187	1,156	1,187	1,204	1,186	1,160	1,187	1,204	1,186	1,160	1,105	1,120	1,097	1,054
Required Resources	10,549	10,752	10,680	10,406	10,684	10,833	10,677	10,436	10,684	10,833	10,677	10,436	9,945	10,078	9,870	9,483
Generation Totals	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589	6,589
Renewables	3,852	2,687	832	422	4,036	2,822	856	382	3,784	1,949	479	393	3,050	847	442	448
Other	170	169	168	168	166	166	165	165	170	169	169	168	164	163	163	162
BESS Dispatch	-	659	2,443	2,580	-	787	2,598	2,831	-	1,498	2,813	2,659	321	2,657	2,855	2,462
Market Transactions	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
OATT Reserves	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)
Total Available Resources	10,620	10,114	10,042	9,768	10,801	10,373	10,217	9,976	10,553	10,215	10,059	9,818	10,133	10,265	10,058	9,671
Long (Open) - Joint System	71	(638)	(638)	(638)	118	(460)	(460)	(460)	(131)	(618)	(618)	(618)	188	188	188	188
	<i>8:00 PM open position continues to 12:00 AM</i>				<i>8:00 PM open position continues to 1:00 AM</i>				<i>8:00 PM open position continues to 12:00 AM</i>							
2029	June				July				August				September			
	Hour Ending				Hour Ending				Hour Ending				Hour Ending			
	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM
Maximum Coincident System Load	9,713	9,929	9,915	9,677	10,336	10,511	10,467	10,300	10,336	10,511	10,467	10,300	9,452	9,520	9,313	9,115
Planning Reserves (12.5%)	1,214	1,241	1,239	1,210	1,292	1,314	1,308	1,287	1,292	1,314	1,308	1,287	1,182	1,190	1,164	1,139
Required Resources	10,927	11,170	11,154	10,887	11,628	11,825	11,775	11,587	11,628	11,825	11,775	11,587	10,634	10,710	10,477	10,255
Generation Totals	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
Renewables	4,454	3,167	928	420	4,281	2,948	877	398	3,708	1,929	494	413	3,355	901	465	474
Other	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
BESS Dispatch	-	748	2,971	3,212	-	982	3,002	3,294	-	1,862	3,247	3,141	434	2,964	3,167	2,936
Market Transactions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OATT Reserves	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)
Total Available Resources	10,975	10,436	10,420	10,153	10,802	10,451	10,401	10,213	10,229	10,313	10,262	10,074	10,310	10,385	10,153	9,930
Long (Open) - Joint System	47	(734)	(734)	(734)	(826)	(1,374)	(1,374)	(1,374)	(1,399)	(1,513)	(1,513)	(1,513)	(324)	(324)	(324)	(324)
	<i>8:00 PM open position continues to 4:00 AM</i>				<i>8:00 PM open position continues to 2:00 AM</i>				<i>8:00 PM open position continues to 2:00 AM</i>				<i>8:00 PM open position continues to 2:00 AM</i>			

In the L&R Tables, the capacity resources available to serve forecasted customer load consist of internal generation and purchases. Firm purchased power resources include purchases from existing and planned renewable energy projects, internal power contracts (within the Companies' system) and external power contracts (outside the Companies' system). External generation purchases require system import transmission capacity. In addition, resources in specific locations within the Companies' control area consume or reduce import capability. The north/south allocation of open access transmission tariff ("OATT") reserves was adjusted to align with recent OATT customer loads. Total available resources (generation and purchases) are shown at the bottom section of the L&R Tables, along with any open capacity positions. Open ("short") positions are indicated as negative values.

The Companies continuously assess their procurement plans and strategies based upon changing market conditions and needs. The Risk Committee reviews supply plans approximately once a month. To the extent that circumstances such as delays, shortfalls, and/or cancellations of any

renewable resources occur, Resource Planning would alert the Risk Committee of the changes to the open capacity positions. To the extent that the change in the open capacity position dictates a change in strategy, Staff and the BCP would be notified, and the Companies would obtain appropriate approvals of such deviations where applicable.

### **C. ENERGY REQUIREMENTS**

In the ESP context, the Companies can meet the energy requirements of their retail customers in several ways, including daily and real-time hourly purchases, existing generation, and forward products (such as call options or forward block power). The total open position is the portion of projected energy requirements that is otherwise unmet, either physically or economically, by other sources given operational constraints (*e.g.*, operating reserve requirements, the ramp rates of the units,<sup>6</sup> minimum unit load levels, and must-run requirements).

No modeled unserved energy is observed in the current analysis. The Companies monitor their energy requirements on a continuous basis to determine when and what quantities of additional energy are required to ensure continued reliable electric service and will undertake cost-effective opportunities to fill such needs. This is discussed further in Section 4 – Power Procurement Plan.

### **D. RENEWABLE ENERGY PLANNING**

The Companies 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 must carefully consider several overarching objectives:

- Full compliance with an escalating and compressed RPS schedule: 34 percent through 2026, 42 percent in years 2027-2029, and 50 percent in 2030 and beyond;
- 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 achieving by 2050 an amount of energy

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<sup>6</sup> The ability to shut down or rapidly ramp down a unit each night is a critical feature for determining which units are economic to run. If a unit is able to shutdown (cycle) each night, then the question of whether the unit is “in-the-money” is relatively simple. If the cost of operation is less than the market prices of energy, the unit is economic.

production from zero carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State.”<sup>7</sup>

The Nevada RPS is stated in terms of the number of PCs required for compliance. A PC is equal to one kilowatt-hour (“kWh”) of renewable energy generated. Similarly, one MWh of energy from renewable resources would result in one thousand PCs, or a “kPC.”<sup>8</sup>

In their most recent annual RPS compliance filing, Docket No. 26-04023, Nevada Power and Sierra both exceeded their respective 2025 RPS credit requirements of 34 percent. Nevada Power ended 2025 at 44.6 percent, Sierra at 54.7 percent. Adding to the Companies’ existing renewable capacity, the Companies self-developed the Sierra Solar Battery Energy Storage System (“BESS”) project. The project includes a 400 MW BESS system with a four-hour duration, providing up to 1,600 MWh of BESS capacity to support grid reliability and the integration of renewable generation. The BESS portion of the project declared commercial operation on March 20, 2026. Sierra Solar BESS will enhance the Companies’ ability to serve customer load, manage peak demand, and may increase the PCs available to meet the energy needs of the Companies’ customers.

As of April 30, 2026, Nevada Power had approximately 2,723 MW of contracted and 165 MW of owned renewable generating resources operating and delivering renewable energy to meet the energy needs of its customers. In addition, Nevada Power ended April 2026 with one company owned PV and two solar PV and BESS power purchase agreements (“PPAs”) under development: Sierra Solar PV, Dry Lake East, and Libra – pending final allocation of the Libra PPA between Nevada Power and Sierra. This pipeline reflects the removal of the Boulder Solar III PPA, previously approved in Docket No. 24-05041, as the agreement was terminated on March 20, 2026, as discussed further below.

Figure ESP-7, below, lists Nevada Power’s renewable pipeline of PPAs and Company-owned projects, showing the facility’s name, resource type, approval docket number, projected commercial operation date, nameplate capacity (AC), BESS capacity, and energy and capacity allocation, as approved by the Commission in the approval order.

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<sup>7</sup> NRS § 704.7820(2).

<sup>8</sup> Beginning in 2025, PCs from energy efficiency measures are no longer eligible for RPS compliance, as specified in NRS § 704.7821(2)(a)(4).

**FIGURE ESP-7  
NEVADA POWER PIPELINE PPAS**

Approved, Under Development / Under Construction / Undergoing Commissioning

Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation		
						NPC	SPPC	
1 Sierra Solar <sup>a</sup>	Solar PV+BESS	23-08015	04/01/27	400	400	40	360	
2 Libra <sup>b</sup>	Solar PV+BESS	24-05041	12/01/27	700	700	TBD <sup>b</sup>	TBD <sup>b</sup>	
3 Dry Lake East	Solar PV+BESS	24-05041	12/01/26	200	200	200	0	
<b>1300</b>						<b>1300</b>	<b>240</b>	<b>360</b>

a. Sierra Solar BESS reached commercial operation as of March 20th, 2026. The associated Solar PV facility is anticipated to reach commercial operation by April 2027. 10 percent of the energy and PCs from Sierra Solar are to be assigned to Nevada Power per the order (Docket No. 23-08015).

b. Energy, capacity, and PCs have not been allocated to either NPC or SPPC per Commission Order (Docket No. 24-05041).

As of April 30, 2026, Sierra had approximately 945 MW of renewable contracted generating resources and approximately 20 MW of company-owned generating resources operating and delivering renewable energy to meet the energy needs of its customers. In addition, Sierra ended April 2026 with seven geothermal portfolio PPAs in various stages of development. As discussed above, Sierra’s portfolio also includes BESS, which offers flexibility by allowing 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.

Figure ESP-8, below, lists Sierra’s future renewable PPAs and Company-owned projects, showing the facility name, resource type, approval docket number, projected commercial operation date, nameplate capacity (AC), BESS capacity, and energy and capacity allocation, as approved by the Commission in the approval order; the Libra PPA has not yet been allocated to either Sierra or Nevada Power and is thus listed as TBD.

**FIGURE ESP-8  
SIERRA PACIFIC POWER PIPELINE PPAS**

Approved, Under development / Under Construction / Under Going Commissioning

Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation		
						SPPC	NPC	
1 Ormat Portfolio (OWGP, LLC)								
>Galena 1	Geothermal	22-11032	02/01/27	15		15		
>Desert Peak 2	Geothermal	22-11032	02/01/28	10		10		
>Galena 3	Geothermal	22-11032	01/01/29	15		15		
>Lone Mountain	Geothermal	22-11032	10/01/28	15		15		
>Pinto	Geothermal	22-11032	01/01/27	15		15		
2 Sierra Solar <sup>a</sup>	Solar PV+BESS	23-08015	04/01/27	400	400	<b>360</b>	40	
3 Libra <sup>b</sup>	Solar PV+BESS	24-05041	12/01/27	700	700	<b>TBD<sup>b</sup></b>	TBD <sup>b</sup>	
					1170	1100	<b>430</b>	40

a. Sierra Solar BESS reached commercial operation as of March 20th, 2026. The associated Solar PV facility is anticipated to reach commercial operation by April 2027. 90 percent of the energy and PCs from Sierra Solar are to be assigned to Sierra per the order (Docket No. 23-08015).

b. Energy, capacity, and PCs have not been allocated to either NPC or SPPC per Commission Order (Docket No. 24-05041).

**RPS Compliance Planning**

The expected PC supply was determined starting with the current portfolio of approved PPAs, including 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.<sup>1</sup> 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; the Beowawe, Burdett, Desert Peak 2, and Galena 3 contracts have been renegotiated in the Ormat Western Geothermal Portfolio (“OWGP”), Docket No. 22-11032. A contract extension for the Stillwater Geothermal PPA is under evaluation;
- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2027-2028 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. The adjustment is consistent with the methodology that the Companies used for the past several years in developing their IRPs and ESPs, recognizes that options to address underperformance within a shorter planning window are limited, and aligns the short-term and long-term plans. Adjustments for 2029 were not identified as actual resource performance from 2025 that would inform a 2029 adjustment was unavailable at the time of the analysis;

- 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;
- Solar PV systems placed into service before December 31, 2015, qualify for the solar multiplier; systems placed into service after do not qualify;
- Surplus/Deficit PCs are not being carried forward although the Companies provide a view in Figure ESP-10 and Figure ESP-12 that includes surplus and deficit PCs;
- The plan assumes that generation from both company-owned solar PV systems and PPAs would be degraded 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 Commission approved and existing NV Green Energy Rider (“NGR”) and energy supply agreements (“ESAs”) as of December 31, 2025, where PCs associated with all or a portion of the output from a renewable facility(ies) have been assigned to a customer under the NGR, the Market Price Energy or Large Customer Market Price Energy tariffs, or other energy agreements, and therefore, cannot be used by the Companies in meeting their RPS credit requirements. As of April 2026, the NGR forecast, incorporated into the assessment of need discussed in the Economic Analysis Section of the Supply Plan Narrative in the 2026 Joint IRP, reflects existing commitments through 2027. Beginning in 2030, the forecast assumes the annual limits established in Docket No. 25-03025, with reduced limits for Sierra during the 2028–2029 period as established in Docket No. 26-04021;
- 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 has been adjusted to account for recent cancellations and delays associated with the 120 MW Ormat portfolio, originally consisting of eight geothermal plants with staggered COD dates. Ormat has provided notice to the Companies that two of its portfolio projects, North Valley 2 and Gerlach, have been cancelled, and the Lone Mountain project COD has been delayed from January 2026 to October 2028. 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 PPA 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 NRS § 704.78215(3)(b). Station usage PCs for this facility were estimated at 15 percent of net;
- The plan RPS outlook has been adjusted to account for recent cancellations and delays associated with the 127.9 MW solar and 127.9 MW BESS Boulder Solar III facility approved in Docket No. 24-05041. As discussed above, the agreement for the project that was intended to reach COD on June 1, 2027, has been terminated. Nevada was the sole off taker of the energy and PCs from the terminated agreement. A new PPA with a planned COD of June 1, 2028, is being sought for approval in this filing.
- The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery losses which are site-specific but typically further degrades by less than one percent annually. The adjustment recognized that not all of the energy produced by solar PV arrays paired with BESS 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;
- An adjustment has been added to the model to capture the generation and PCs lost due to curtailment. The curtailed amount is estimated from the excess energy in the PLEXOS ST 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 plan assumes an extension of the Liberty contract through December 31, 2027, reflecting potential delays with Greenlink West<sup>9</sup> that would enable Liberty’s transition to Network Integration Transmission service;
- In the absence of an approved allocation, Libra Solar and BESS is allocated 100 percent to Sierra, in contrast to the proposed allocation of 100 percent to Nevada Power in the 2024 Joint IRP (Docket No. 24-05041);
- The plan includes a modified load forecast that is detailed in Section 2.A; and
- The plan assumes a reduction in previously forecasted PCs due to the Community Solar Program proposed by the Companies in the 2024 Joint IRP (Docket No. 24-05041) not receiving approval in the Commission’s Order.

As previously stated, in forecasting renewable generation for IRP and ESP filings, the Companies account for trends in the operating performance of resources in their existing portfolio. In the long-term, if a renewable facility is failing to meet its contractual energy or credit obligations, the assumption is that the PPA counterparty will be able to initiate necessary actions to rectify the shortfall. This assumption is not necessarily true for short-term planning, where options to address underperformance within a shorter planning horizon are limited. This assumption also holds true in cases of over production as most renewable PPAs are must-take. Therefore, in developing the ESP and IRP, the Companies adjusted the expected amount of energy from certain renewable facilities, where historic generation varied more than five percent from that of the contractual or expected supply table. This adjustment applied to the 2027-2028 planning horizon, adjustments for 2029 were not identified as actual resource performance from 2025 that would inform a 2029 adjustment was unavailable at the time of the analysis.

Figure ESP-9 below is a summary of all PPAs and supply adjustments used in developing Nevada Power’s RPS outlook. Note, the list below only includes PPAs that were approved by the Commission as of April 30, 2026.

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<sup>9</sup> NV Energy’s posting on Open Access Same-time Information System (“OASIS”) indicate that Greenlink West may be delayed and may not be in service by May 31, 2027. Accordingly, and for purposes of this ESP, the Companies adopted a planning assumption that Greenlink West will be in service on December 31, 2027.

**FIGURE ESP-9  
NEVADA POWER SHORT-TERM SUPPLY ADJUSTMENTS**

Facility	Actual/ Projected COD	NamePlate (AC)	Resource	Type	2026 a.	IRP/ESP Action Period			
						2027 a.	2028 a.	2029 e.	
Blue Mountain 1 (Faulkner)	11/20/09	49.5	Geo	PPA	100%	100%	100%	100%	
Desert Peak 2	04/17/07	25.0	Geo	PPA	100%	100%	n/a	n/a	
Jersey Valley	08/30/11	22.5	Geo	PPA	90%	90%	90%	100%	a.
McGinness Hills	06/20/12	96.0	Geo	PPA	100%	100%	100%	100%	
Salt Wells	09/18/09	23.6	Geo	PPA	90%	87%	87%	100%	a.
Stillwater (Geo & PV)	10/10/09	69.2	Geo/PV	PPA	95%	91%	91%	100%	a.
Tuscarora	01/11/12	32.0	Geo	PPA	105%	105%	105%	100%	
ACE Searchlight Solar	12/16/14	17.5	PV	PPA	100%	100%	100%	100%	
Arrowhead Canyon (Moapa) Solar (30%)	12/01/22	60.0	PV	PPA	100%	100%	100%	100%	b.
Boulder Solar I	12/09/16	100.0	PV	PPA	100%	100%	100%	100%	
Copper Mountain V	07/23/21	250.0	PV	PPA	100%	100%	100%	100%	
Dry Lake	03/15/24	150.0	PV	PPA	100%	100%	100%	100%	
Dry Lake East	12/01/26	200.0	PV	PPA	100%	100%	100%	100%	
Eagle Shadow Mountain	05/10/23	300.0	PV	PPA	100%	100%	100%	100%	
FRV Spectrum	09/23/13	30.0	PV	PPA	113%	113%	113%	100%	a.
Gemini Solar	03/25/24	690.0	PV	PPA	100%	100%	100%	100%	c.
Mountain View Solar	01/05/14	20.0	PV	PPA	100%	100%	100%	100%	
Nellis 2	11/23/15	15.0	PV	NVE	100%	100%	100%	100%	
Nevada Solar One NPC	06/27/07	46.9	CSP	PPA	79%	79%	n/a	n/a	a.
RV Apex Solar Power	07/21/12	20.0	PV	PPA	90%	90%	90%	100%	a.
Sierra Solar (10%)	04/01/27	40.0	PV	NVE	n/a	100%	100%	100%	b.
Silver State Solar North	04/25/12	52.0	PV	PPA	91%	91%	91%	100%	a.
Switch Station I	08/08/17	100.0	PV	PPA	88%	88%	88%	100%	d.
Techren 1	03/11/19	100.0	PV	PPA	72%	73%	73%	100%	a.
Techren 3	10/07/20	25.0	PV	PPA	86%	86%	86%	100%	a.
Techren 5	12/31/20	50.0	PV	PPA	90%	91%	91%	100%	a.
Apex Landfill	03/01/12	12.0	LFG	PPA	48%	48%	48%	100%	a.
WMNRE Lockwood	04/01/12	3.2	LFG	PPA	94%	94%	94%	100%	a.
Goodsprings	12/01/10	5.0	Waste Heat	NVE	100%	100%	100%	100%	
Total		2,756.2							

- a. Adjustment applied to the supply table or calculated supply table (if no PPA supply table) based on recent (2 or more years of performance) to determine the expected amount of energy generated by the facility to serve customer load. 100% equals no adjustment
- b. The energy and PCs from these projects will be pooled then split between Nevada Power and Sierra (ref. Docket No. 19-06039)
- c. 40 percent of PCs generated by this project are assigned to Sierra based on the order (Docket No. 19-06039)
- d. The energy is delivered to Nevada Power to serve customer load, but the derived PCs are assigned to a customer and cannot be counted towards the RPS
- e. Short-term adjustments for 2029 were not identified, as actual 2025 resource performance data was unavailable at the time of the analysis

After applying the above supply adjustments, this planning approach resulted in an average 2.54 percent decrease in the total amount of projected net renewable energy for the 2027 to 2028 period as compared to the PPA supply tables assuming no adjustments. The estimated amount of renewable energy available to Nevada Power is shown in Figure ESP-10 below.

**FIGURE ESP-10  
NEVADA POWER PORTFOLIO CREDIT PROJECTIONS (kPCs)<sup>1</sup>**

Nevada Power Company

	2026	Action Period		
		2027	2028	2029
Credit Requirement <sup>1</sup> :				
Nevada RPS Credit Target <sup>2</sup> :	7,206,366	9,737,405	10,339,237	11,482,718
Other non-RPS Credit Obligations (NGR, 704B, etc.) <sup>3</sup> :	1,129,333	1,179,459	1,304,144	787,557
	8,335,698	10,916,864	11,643,381	12,270,275
Expected Credits all Sources - Unadjusted				
Energy / MW hrs <sup>4</sup> :	8,126,489	8,518,925	8,980,992	9,738,903
Station Usage, PC only, Co Owned, & Credit Allocations <sup>5</sup> :	(447,364)	(549,400)	(688,880)	(733,793)
RenewableGenerations <sup>6</sup> :	602,454	597,939	593,457	589,009
Carried Forward <sup>7</sup> :	2,182,857	2,128,737	(220,663)	(2,978,475)
Expected Credits, kPCs (All Sources, Unadjusted)	10,464,435	10,696,200	8,664,906	6,615,644
Projected Credit Surplus/<Deficit>	2,128,737	(220,663)	(2,978,475)	(5,654,631)
Expected Credits all Sources - Adjusted				
Energy / MW hrs <sup>8</sup> :	7,909,557	8,293,582	8,772,759	9,738,903
Station Usage, PC only, Co Owned, & Credit Allocations <sup>5</sup> :	(447,364)	(549,400)	(688,880)	(733,793)
RenewableGenerations <sup>6</sup> :	602,454	597,939	593,457	589,009
Carried Forward <sup>7</sup> :	2,182,857	0	0	0
Expected Credits, kPCs (All Sources, adjusted)	10,247,503	8,342,121	8,677,336	9,594,119
Projected Credit Surplus/<Deficit> w/Adj.	1,911,805	(2,574,743)	(2,966,045)	(2,676,156)

1 1 kWh = 1 PC, 1,000 kWh (1 MWh) = 1 kPC

2 Nevada RPS credit target by year 34%, 2024-2026, 42% 2027

3 Non-RPS credit obligations: Nevada GreenRider (NGR), Energy Supply Agreements (ESA) and Exit Obligations (704B)

4 Total renewable energy delivered to Nevada Power's system and available to meet Nevada Power's retail load

5 Credits from station usage, small NVE owned systems, credit only agreements, settlement agreements, Gemini credits allocated to Sierra and credits assigned to NGR Customers

6 Credits incentive programs pursuant to NRS Chapter 701B

7 Excess credits carried forward for future compliance (note the plan assumes no excess credit sales)

8 Adjusted energy supply outlook after adjusting for historical performance

Figure ESP-11 below is a summary of all PPAs and supply adjustments used in developing Sierra's RPS outlook. After applying the above supply adjustments, this planning approach resulted in an average 0.55 percent decrease in the total amount of projected net renewable energy for the 2027 to 2028 period as compared to the PPA supply tables assuming no adjustments. The estimated amount of renewable energy available to Sierra is shown in Figure ESP-12 below.

**FIGURE ESP-11  
SIERRA’S SHORT-TERM SUPPLY ADJUSTMENTS**

Facility	Actual / Projected COD	NamePlate (AC)	Resource	Type	2026 a.	IRP/ESP Action Period			
						2027 a.	2028 a.	2029 d.	
Galena 3	02/21/08	26.5	Geo	PPA	100%	100%	100%	n/a	
North Valley Geo	04/26/23	25.0	Geo	PPA	100%	100%	100%	100%	
USG San Emidio	05/25/12	11.8	Geo	PPA	100%	100%	100%	100%	
Battle Mountain	06/23/21	101.0	PV	PPA	100%	100%	100%	100%	
Dodge Flat	03/02/22	200.0	PV	PPA	100%	100%	100%	100%	
Fish Springs Ranch	03/15/22	100.0	PV	PPA	100%	100%	100%	100%	
Nevada Solar One SPPC	06/27/07	22.1	CPS	PPA	79%	79%	n/a	n/a	a.
Arrowhead Canyon (Moapa) Solar (70%)	12/01/22	140.0	PV	PPA	100%	100%	100%	100%	b.
Ft. Churchill PV	08/05/15	19.5	PV	PPA	100%	100%	100%	100%	
Boulder Solar II Apple	01/27/17	50.0	PV	PPA	94%	94%	94%	100%	a.
Libra	12/01/27	700.0	PV	PPA	n/a	100%	100%	100%	
Sierra Solar (90%)	04/01/27	360.0	PV	NVE	n/a	100%	100%	100%	b.
Switch Station 2	10/11/17	51.3	PV	PPA	91%	91%	92%	100%	c.
Techren Solar II	10/04/19	200.0	PV	PPA	100%	100%	100%	100%	
Techren Solar IV	10/07/20	25.0	PV	PPA	85%	85%	85%	100%	a.
Turquoise	12/04/20	50.0	PV	PPA	100%	100%	100%	100%	
Frank Hooper	06/23/86	0.8	Hydro	PPA	100%	100%	100%	100%	
TMWA Fleish	05/16/08	2.3	Hydro	PPA	121%	121%	121%	n/a	a.
TMWA Verdi	05/15/09	2.2	Hydro	PPA	125%	125%	125%	100%	a.
TMWA Washoe	07/25/08	2.2	Hydro	PPA	231%	231%	175%	n/a	a.
Ormat Portfolio:									
> Beowawe Bundled	01/01/25	20.0	Geo	PPA	100%	100%	100%	100%	
> Desert Peak 2 Bundled	02/07/28	10.0	Geo	PPA	n/a	n/a	n/a	n/a	
> Galena 1 Bundled	02/01/27	15.0	Geo	PPA	n/a	n/a	n/a	n/a	
> Galena 3 Bundled	01/01/29	15.0	Geo	PPA	n/a	n/a	n/a	n/a	
> Lone Mountain Bundled	10/01/28	15.0	Geo	PPA	n/a	n/a	n/a	n/a	
> Pinto Bundled	01/01/27	15.0	Geo	PPA	n/a	n/a	n/a	n/a	
					2,179.6				

- a. Adjustment applied to the supply table or calculated supply table (if no PPA supply table) based on recent (2 or more years of performance) to determine the expected amount of energy generated by the facility to serve customer load. 100% equals no adjustment
- b. The energy and PCs from these projects will be pooled then split between NPC and SPPC (ref. Docket No 19-06039)
- c. The energy is delivered to Nevada Power to serve customer load, but the derived PCs are assigned to a customer and cannot be counted towards the RPS
- d. Short-term adjustments for 2029 were not identified, as actual 2025 resource performance data was unavailable at the time of the analysis.

**FIGURE ESP-12**  
**SIERRA PORTFOLIO CREDIT PROJECTIONS (kPCs)<sup>1</sup>**  
**Sierra Pacific Power**

	2026	Action Period		
		2027	2028	2029
Credit Requirement <sup>1.</sup>				
Nevada RPS Credit Target <sup>2.</sup>	3,245,617	5,199,191	6,647,928	7,747,137
Other non-RPS Credit Obligations (NGR, 704B, etc.) <sup>3.</sup>	972,433	928,035	915,103	1,084,023
	4,218,050	6,127,225	7,563,031	8,831,160
Expected Credits all Sources - Unadjusted				
Energy / MW hrs <sup>4.</sup>	3,390,650	4,624,213	6,890,334	8,083,239
Station Usage, PC only, Co Owned, & Credit Allocations <sup>5.</sup>	658,152	625,044	800,715	759,193
Renewable Generations <sup>7.</sup>	110,485	109,659	108,839	108,025
Carried Forward <sup>8.</sup>	1,645,303	1,586,541	818,232	1,055,090
Expected Credits, kPCs (All Sources, Unadjusted)	5,804,591	6,945,457	8,618,120	10,005,547
Projected Credit Surplus/<Deficit>	1,586,541	818,232	1,055,090	1,174,387
Expected Credits all Sources - Adjusted				
Energy / MW hrs <sup>8.</sup>	3,358,332	4,593,499	6,861,249	8,083,239
Station Usage, PC only, Co Owned, & Credit Allocations <sup>5.</sup>	658,152	625,044	800,715	759,193
Renewable Generations <sup>6.</sup>	110,485	109,659	108,839	108,025
Carried Forward <sup>7.</sup>	1,645,303	0	0	0
Expected Credits, kPCs (All Sources, adjusted)	5,772,273	5,328,202	7,770,803	8,950,457
Projected Credit Surplus/<Deficit> w/Adj.	1,554,223	(799,023)	207,772	119,297

- 1 1 kWh = 1 PC, 1,000 kWh (1 MWh) = 1 kPC
- 2 Nevada RPS credit target by year 34%, 2024-2026, 42% 2027
- 3 Non-RPS credit obligations: Nevada GreenRider (NGR), Energy Supply Agreements (ESA) and Exit Obligations (704B), and Sleeved Projects associated with Customer Energy Agreements
- 4 Total renewable energy delivered to Sierra's system and available to meet Sierra's retail load
- 5 Credits from station usage, small NVE owned systems, credit only agreements, settlement agreements, Gemini credits allocated to Sierra and credits assigned to NGR Customers
- 6 Credits incentive programs pursuant to NRS Chapter 701B
- 7 Excess credits carried forward for future compliance (note the plan assumes no excess credit sales)
- 8 Adjusted energy supply outlook after adjusting for historical performance

**Compliance Outlook**

**NEVADA POWER**

With the approval of the proposed projects in this filing Nevada Power's RPS compliance outlook is forecasted to be non-compliant in 2027-2029. This is different from the 2024 IRP's outlook in Docket No. 24-05041 as well as the Portfolio Standard Annual Report for Compliance Year 2025 filed on April 15, 2026, for several reasons. First, increased projected load growth coupled with the RPS step increase in 2027 to 42 percent. As illustrated in Figure ESP-14 below, Nevada Power's current retail load outlook in this IRP filing is higher than that of the previously approved

plan from the 2024 Joint IRP and in the year when the RPS increases to 42 percent. Because the RPS credit requirement is tied directly to retail sales, the combined change increases Nevada Power’s forecasted RPS credit requirement. The limited available land for development, multiyear project permitting timelines, and lack of available transmission capacity are key constraints in the renewable project pipeline.<sup>10</sup> 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. For example, the Boulder Solar III project approved in Docket No. 24-05041 has experienced challenges in its development due to increased costs, driven primarily by external factors and permitting delays. The developer missed a critical project milestone and subsequently on March 20, 2026, the PPA was terminated. Figure ESP-13 below shows the PCs Nevada has recently lost due to canceled PPAs.

**FIGURE ESP-13**

<b>Lost Projects, Lost Generation</b>				
<b>Projects <sup>a</sup></b>	<b>Docket No.</b>	<b>Original COD</b>	<b>Date Terminated</b>	<b>MW AC</b>
Iron Point (56% NPC)	21-06001	12/31/2023	6/22/2023	250
Hot Pot (56% NPC)	21-06001	12/31/2024	6/22/2023	350
Southern Bighorn (60% NPC)	19-06039	9/1/2023	11/13/2023	300
Chuckwalla	20-07023	12/1/2023	11/17/2023	200
Boulder Solar III	20-07023	12/31/2023	4/29/2024	128
Boulder Solar III	24-05041	6/1/2027	3/20/2026	128
				2,411
<b>Table Notes:</b>				
<b>a. The energy/credits of the project as allocated between Nevada Power and Sierra per the order.</b>				

**SIERRA**

With the approval of the proposed projects in this filing, Sierra’s RPS compliance outlook is forecasted to be non-compliant in 2027 and compliant in 2028 and 2029. Compliance in 2028 and 2029 is partly attributable to accounting for the output from Libra in Sierra’s outlook as opposed to Nevada Power’s outlook. Combined with Nevada Power, NV Energy is projected to be non-compliant in 2027 through 2029. This is different from the 2024 IRP’s outlook in Docket No. 24-05041 as well as the Portfolio Standard Annual Report for Compliance Year 2025 filed on April 15, 2026, for several reasons. First, increased projected load growth coupled with the RPS step increase in 2027 to 42 percent. As illustrated in Figure ESP-14, Sierra’s current retail load outlook

<sup>10</sup> Note the available credits from the approved project, Libra, are allocated to Sierra in this outlook.

is higher than that of the previously approved plan from the 2024 Joint IRP and in the year when the RPS increases to 42 percent. Because the RPS credit requirement is tied directly to retail sales, the combined change increases Sierra’s forecasted RPS credit requirement. Included in the increased forecast of Sierra’s load is the planned extension of the Liberty contract through December 31, 2027, which also provides PCs to the utility. Finally, the Sierra Utility Owned Community Solar and Solar for all projects proposed in Docket No. 24-05041 were not approved, resulting in the loss of a planned 6,312 PCs.

**FIGURE ESP-14**

	Sierra (MW hours)			NPC (MW hours)		
	2024 IRP 1st Amendment*	2026 ESP	Difference	2024 IRP 1st Amendment*	2026 ESP	Difference
2026	12,010,964	10,518,365	-12.43%	22,237,202	22,324,526	0.39%
2027	12,843,346	13,307,060	3.61%	22,237,202	24,363,756	9.56%
2028	13,988,213	16,743,503	19.70%	22,516,659	25,921,375	15.12%
2029	15,022,507	19,529,588	30.00%	22,875,648	28,127,361	22.96%
2030	16,788,241	22,203,847	32.26%	23,166,115	30,637,482	32.25%
	Increase/ (Decrease)	RPS%	Credit Impact	Increase/ (Decrease)	RPS%	Credit Impact
2026	-1,492,599	34%	(507,484)	87,324	34%	29,690
2027	463,714	42%	194,760	2,126,554	42%	893,153
2028	2,755,290	42%	1,157,222	3,404,716	42%	1,429,981
2029	4,507,081	42%	1,892,974	5,251,713	42%	2,205,719
2030	5,415,606	50%	2,707,803	7,471,367	50%	3,735,684
	*Docket No. 25-10028					

Compliance challenges are also a result of cancelled PPAs by developers. Figure ESP-15 below shows the PCs Sierra has recently lost due to canceled PPAs. As discussed in the First Amendment to the 2024 Joint IRP,<sup>4</sup> Ormat has provided notice to the Companies that two of its portfolio PPAs, North Valley 2 and Gerlach, have been cancelled, and the Lone Mountain PPA COD has been delayed from January 2026 to October 2028. Additionally, Liberty Utilities has notified the Companies that it has placed the Luning Expansion PPA on hold indefinitely, which would have provided Liberty with PCs and therefore reduced Sierra’s PC transfer obligation to Liberty under the requirements of the Service Agreement. The energy and credits from these facilities were to be assigned to Sierra, thus, the loss impacts Sierra’s RPS compliance and capacity. While every PPA is entered into with the expectation of success, events can and do happen that make once-viable PPAs unviable. The primary driver for the latest wave of cancelations was cost. Supply chain disruptions, fluctuating tariffs, and related increases in component and labor costs made the PPAs too costly to move forward.

## FIGURE ESP-15

### Lost Projects, Lost Generation

Projects <sup>a</sup>	Docket No.	Original	Date	MW AC
		COD	Terminated	
Iron Point (44% SPPC)	21-06001	12/31/2023	6/22/2023	250
Hot Pot (44% SPPC)	21-06001	12/1/2024	6/22/2023	350
Southern Bighorn (40% SPPC)	19-06039	9/1/2023	11/13/2023	300
North Valmy Eavor Loop	22-11032	12/31/2026	6/22/2024	20
North Valley II (OWGP)	22-11032	1/1/2026	4/25/2025	15
Gerlach (OWGP)	22-11032	1/1/2028	4/25/2025	15
Lone Mountain (OWGP) <sup>b</sup>	22-11032	1/1/2026	04/29/25 <sup>b</sup>	15
				965

Table Notes:

- a. The energy/credits of the projects as allocated between Nevada Power and Sierra per the order
- b. The Lone Mountain project has been delayed until 10/01/2028, not cancelled. The date shown reflects when NV Energy was notified of the delay. The Companies are still in discussions with the counterparty to explore all remedial options.

Finally, the compliance outlook is challenged by transmission constraints for Sierra. Currently there is limited ability to move energy from generation to load in Sierra’s 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.

To mitigate risk on non-compliance, Nevada Power and Sierra will continue to explore near-term options, including evaluating available proposals received from renewable energy RFPs, self-developing projects, discussions with counterparties to amend existing PPAs to facilitate acquisition of additional PCs, 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 BESS resources needed to continue meeting its RPS requirement.

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.

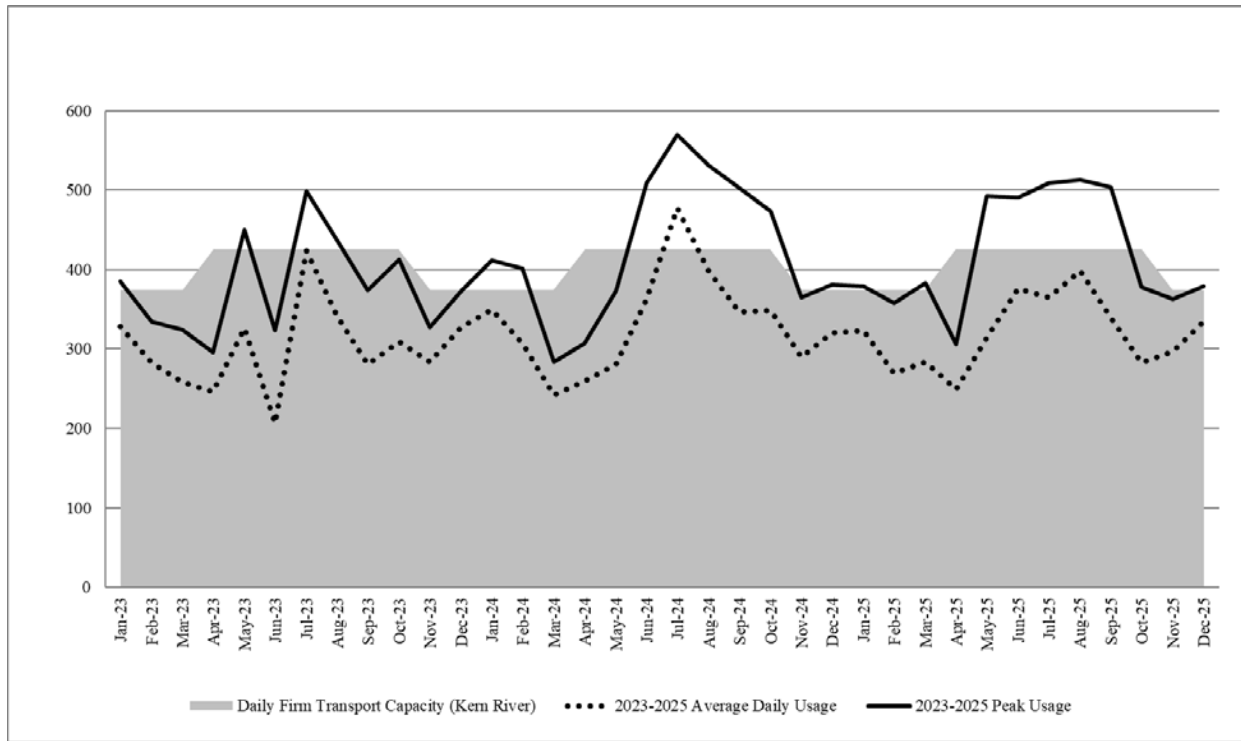
## **E. GAS TRANSPORTATION REQUIREMENTS**

The Companies' portfolio of gas transportation assets serves their generation units and Sierra's local distribution company ("LDC"). The existing firm gas transportation assets for Nevada Power and Sierra are listed in Figures ESP-43 and ESP-44 respectively. The Companies rely on rights of first refusal and annual evergreen rights to keep existing gas transport capacity rights in place. As of the date of this filing, the Companies have expanded their existing gas transport portfolio. Sierra added transportation capacity from the Ruby Pipeline ("Ruby") and the Pinyon Pipeline ("Pinyon") effective January 2026 to supply natural gas to the North Valmy Generating Station ("Valmy"). Valmy Units 1 and 2 are being converted to operate on natural gas. As of the date of this filing, Valmy Unit 1 has returned to service following completion of its gas conversion and is operating on natural gas. Valmy Unit 2 remains on outage due to gas conversion and is expected to commence operation on natural gas in mid-May 2026.

For the ESP, the Companies utilized PLEXOS ST, a chronological unit commitment and economic dispatch model, to evaluate the system reliability and projected firm gas transportation needs for Nevada Power and Sierra generating plants and the LDC with the One Nevada Transmission Line ("ON Line") in service, and with the Greenlink Nevada and Southwest Intertie Project North ("SWIP-N") transmission projects projected to be in service at the start of 2029.

For the previous three years, Nevada Power's firm transportation capacity was fully utilized 24 days in 2023, 72 days in 2024, and 31 days in 2025, leaving open positions for firm interstate gas transportation in each year, as seen in Figure ESP-16.

**FIGURE ESP-16  
HISTORICAL NATURAL GAS USAGE VS. TRANSPORT CAPACITY  
(000s MMBTU/DAY) NEVADA POWER**



Historically, Nevada Power’s firm interstate gas transportation open positions have been reliably met by purchasing firm delivered gas.

For Nevada Power, PLEXOS ST was used to further evaluate projected firm gas transportation needs for the generation fleet. The time period of the analysis was January 2027 through December 2029.

Two scenarios were evaluated:

1. Normal weather conditions and existing firm gas transportation contracts; and
2. Hot summer/cold winter weather conditions<sup>11</sup> (based on 1 in 10 peak Cooling Degree Days (“CDD”) and Heating Degree Days (“HDD”)) and existing firm gas transportation contracts.

Based on this modeling, the projected number of days Nevada Power will require deliveries in excess of the existing firm rights for natural gas transportation capacity under normal weather

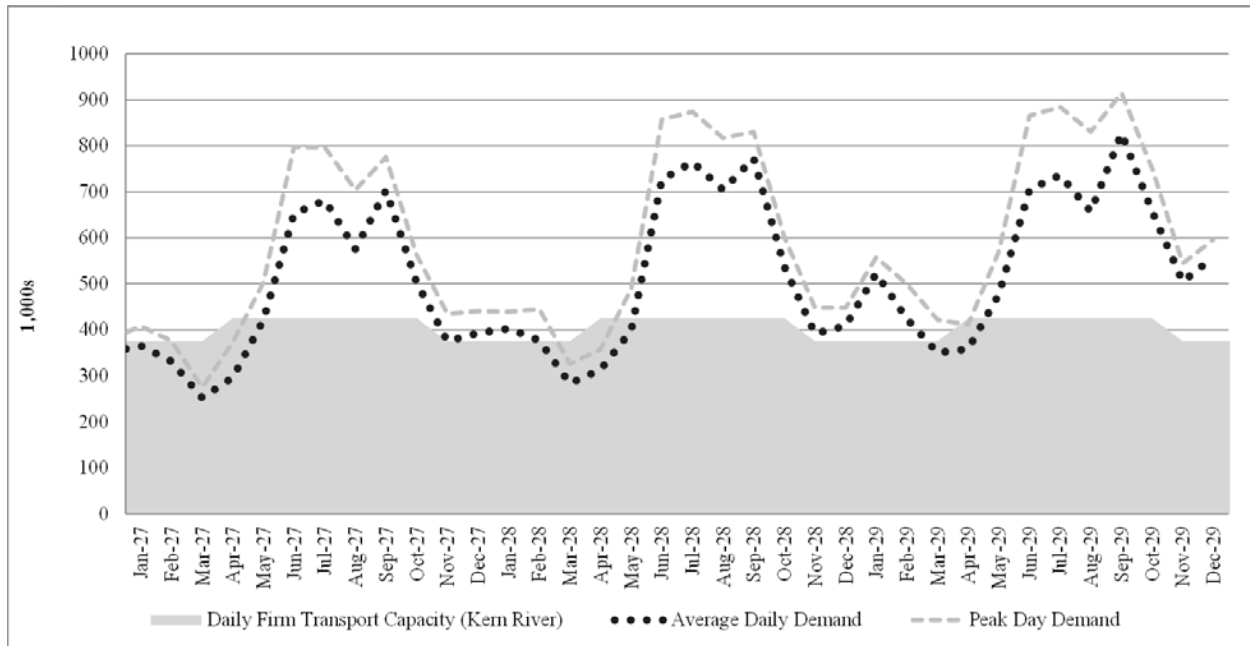
<sup>11</sup> See Technical Appendix LF-1, Section VIII – Weather Scenario Forecast for Gas Transportation Analysis, provided in support of the Third Amendment and approved in the March 24, 2023, Order in Docket No. 22-09006, for more details.

conditions are 113 days for 2027, 202 for 2028, and 244 for 2029. Similarly, under hot summer/cold winter weather conditions, the projected number of days Nevada Power will require deliveries in excess of the existing firm rights for natural gas transportation capacity are 220 days for 2027, 258 for 2028, and 308 for 2029. Figure ESP-17 and Figure ESP-18 show the projected daily natural gas requirements at Nevada Power with the firm natural gas transportation available for both the normal and hot summer/cold winter weather scenarios for the generation fleet.

**FIGURE ESP-17  
NORMAL WEATHER NATURAL GAS USAGE VS. TRANSPORT CAPACITY  
(MMBTU/DAY) NEVADA POWER**



**FIGURE ESP-18  
HOT SUMMER/COLD WINTER WEATHER - NATURAL GAS USAGE VS.  
TRANSPORT CAPACITY (MMBTU/DAY) NEVADA POWER**



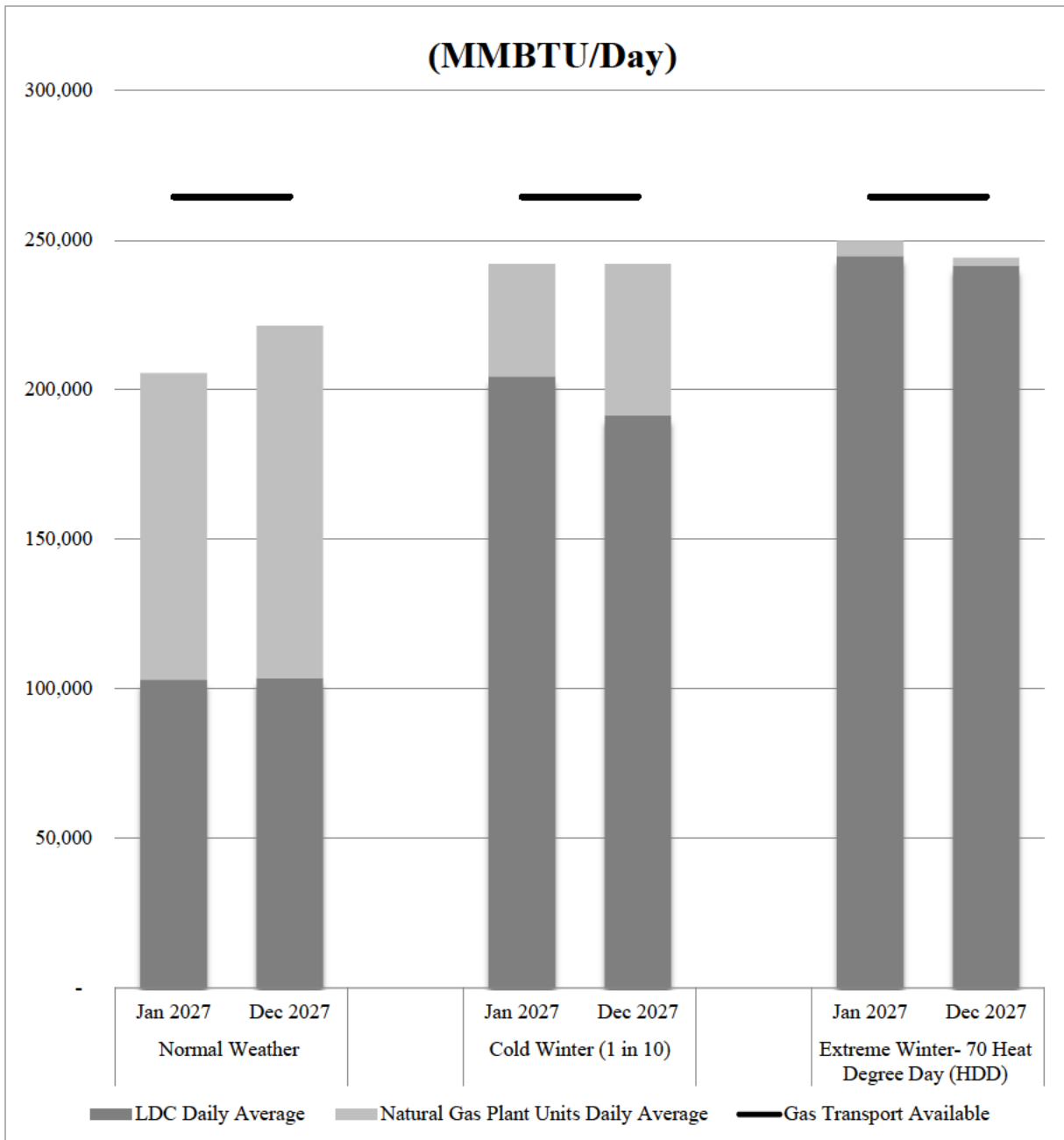
PLEXOS ST was used to evaluate Sierra’s electric system reliability, as quantified by modeled Loss of Load Hours (“LOLH”), as well as projected firm gas transportation needs for both the plants and the LDC with ON Line, Greenlink Nevada, and SWIP-N in service as appropriate.

LDC natural gas requirements were prioritized ahead of electric generation requirements for three reasons: (1) human safety, (2) no alternative fuels, (3) and the significant cost of a re-light. For the LDC, the analysis period was limited to December and January (for the years 2027-2029), as the LDC’s recorded peaks have predominantly occurred in those two months. Three scenarios were evaluated:

1. Normal weather conditions and existing natural gas transportation contracts;
2. Cold winter weather conditions (based on 1 in 10 peak HDD) and existing natural gas transportation contracts; and
3. Extreme weather conditions (based on 70 HDDs) and existing natural gas transportation contracts.

Figure ESP-19 shows the daily natural gas requirements projected for December/January along with the firm natural gas transportation available for the three scenarios for both the LDC and electric generating plants in western Nevada.

**FIGURE ESP-19  
SIERRA DAILY NATURAL GAS REQUIREMENT  
FOR DECEMBER/JANUARY**



The key finding from this analysis is that Sierra has sufficient firm transportation/storage resources under contract to meet the average daily gas supply required on a winter day under normal weather conditions, so long as generation is available from the southern system via ON Line as well as Greenlink Nevada and power from Mid-C is available via SWIP-N (the latter two starting in January 2029). However, during a cold winter (1 in 10) or extreme winter weather scenario, Sierra's western Nevada firm gas transport capacity<sup>12</sup> is heavily utilized, approximately 82 percent and 97 percent, respectively, to meet LDC peak day requirements, limiting availability of Sierra's western Nevada natural gas-fired generation plants. In the extreme weather case, the majority of the electric requirements would need to be met with a combination of purchased power, renewable energy, or inter-company exchange from the southern system. It is noteworthy that Valmy Units 1 and 2 operating on natural gas, because of their location, do not compete for natural gas with Sierra's local gas distribution system. However, in the extreme weather case, the analysis shows modeled LOLH were observed on the Sierra electric system in the majority of hours in January 2027, December 2027, and January 2028; in fewer than 40 percent of the hours in December 2028; and were not observed in January or December 2029.

Historically, on a combined basis (LDC plus natural gas for Sierra's electric generation), Sierra is long on natural gas transportation capacity in the months of March through November but close to capacity in the months of December through February during normal weather conditions.

Nevada Power and Sierra will continue to evaluate opportunities to release capacity during the months in which capacity is greater than projected requirements based on economics and reliability. The Companies will continue to purchase firm delivered gas to reliably meet open positions with respect to firm interstate gas transportation.

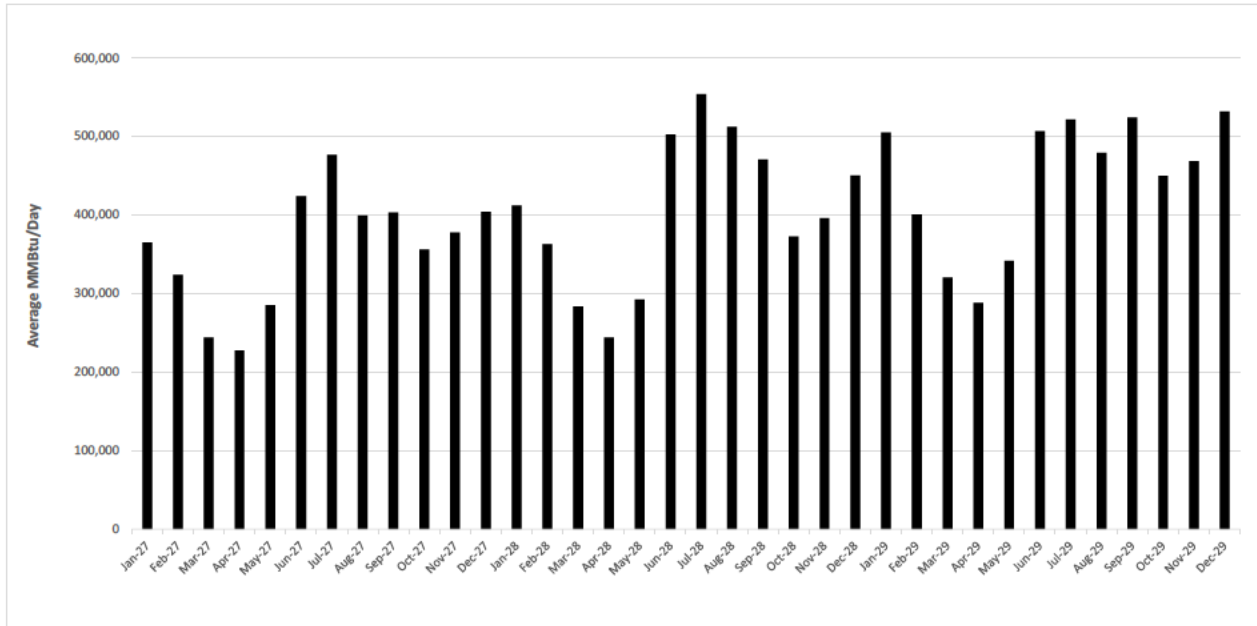
## **F. PHYSICAL GAS REQUIREMENTS**

The Companies used PLEXOS ST to calculate the average daily gas requirements as illustrated in Figures ESP-20 and ESP-21.

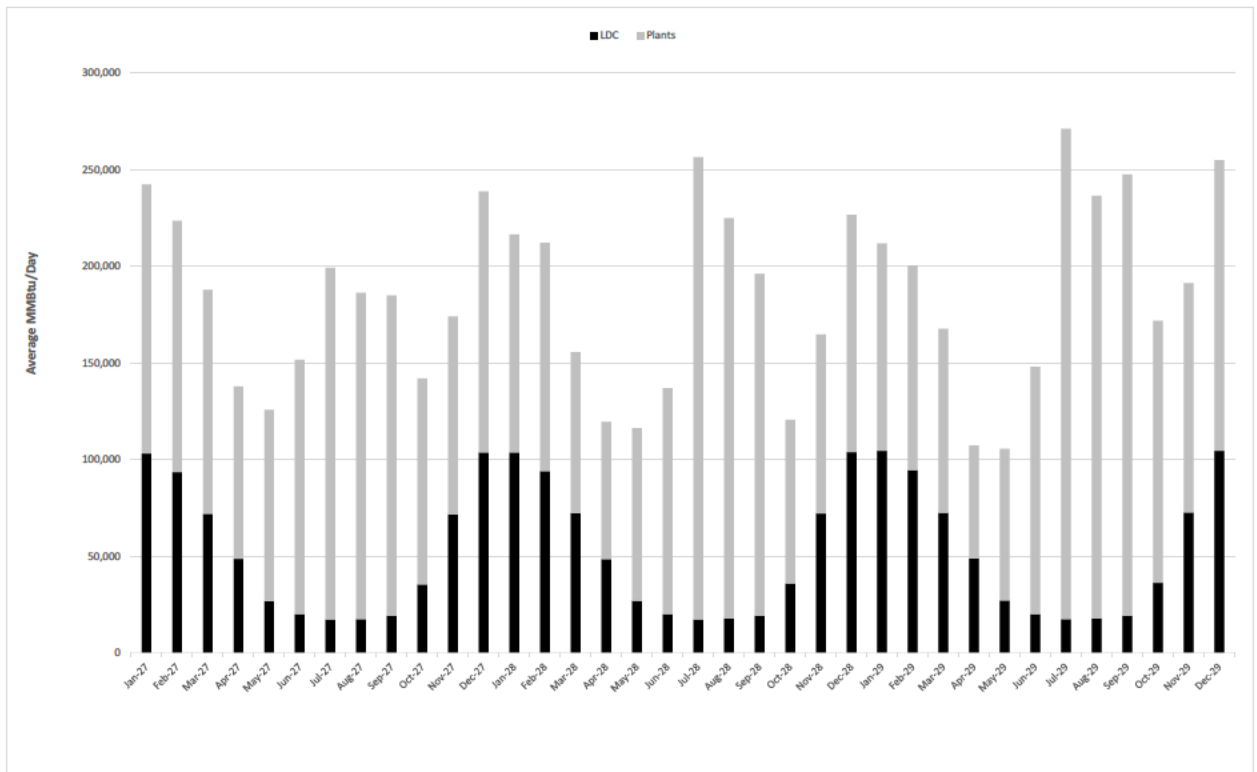
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<sup>12</sup> Sierra holds long-term firm gas transportation contracts on both the Tuscarora and Great Basin pipelines, which collectively serve as the primary sources of firm natural gas delivery into western Nevada.

**FIGURE ESP-20  
NEVADA POWER AVERAGE DAILY GAS REQUIREMENTS**



**FIGURE ESP-21  
SIERRA AVERAGE DAILY GAS REQUIREMENTS**



The Companies employ a four-season laddering strategy for physical gas purchases through which 25 percent of projected monthly gas requirements per season is procured, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. Figure ESP-22 shows the current approved physical gas volumes and future targets for the Companies.

**FIGURE ESP-22  
PHYSICAL GAS SUPPLY UNDER CONTRACT (MMBTU/DAY)**

Monthly NPC	Current Approved Volumes	Volumes Procured as of 3/1/2026	Current Target Procurement Level	Estimated Volumes to Be Procured in 2026 Q3 RFP	Estimated Total Volumes Procured After 2026 Q3 RFP	Estimated Pct of Approved Volumes Closed Following 2026 Q3 RFP
Jan-2027	366,000	274,500	75%	91,500	366,000	100%
Feb-2027	336,000	252,000	75%	84,000	336,000	100%
Mar-2027	288,000	215,500	75%	72,500	288,000	100%
Apr-2027	257,000	128,000	50%	65,000	193,000	75%
May-2027	344,000	171,500	50%	87,000	258,500	75%
Jun-2027	426,000	212,500	50%	107,000	319,500	75%
Jul-2027	498,000	248,500	50%	125,000	373,500	75%
Aug-2027	444,000	222,000	50%	111,000	333,000	75%
Sep-2027	419,000	209,000	50%	105,000	314,000	75%
Oct-2027	355,000	177,000	50%	89,000	266,000	75%
Nov-2027	372,000	93,000	25%	93,000	186,000	50%
Dec-2027	401,000	100,000	25%	101,000	201,000	50%
Jan-2028	431,000	107,500	25%	108,000	215,500	50%
Feb-2028	394,000	98,500	25%	99,000	197,500	50%
Mar-2028	359,000	89,500	25%	90,000	179,500	50%

Monthly SPPC	Current Approved Volumes	Volumes Procured as of 3/1/2026	Current Target Procurement Level	Estimated Volumes to Be Procured in 2026 Q3 RFP	Estimated Total Volumes Procured After 2026 Q3 RFP	Estimated Pct of Approved Volumes Closed Following 2026 Q3 RFP
Jan-2027	269,000	201,500	75%	68,000	269,500	100%
Feb-2027	251,000	188,000	75%	63,000	251,000	100%
Mar-2027	224,000	168,000	75%	56,000	224,000	100%
Apr-2027	171,000	85,000	50%	43,000	128,000	75%
May-2027	151,000	75,500	50%	38,000	113,500	75%
Jun-2027	161,000	80,500	50%	40,000	120,500	75%
Jul-2027	197,000	98,000	50%	50,000	148,000	75%
Aug-2027	188,000	93,500	50%	48,000	141,500	75%
Sep-2027	174,000	86,500	50%	44,000	130,500	75%
Oct-2027	163,000	81,000	50%	41,000	122,000	75%
Nov-2027	192,000	48,000	25%	48,000	96,000	50%
Dec-2027	257,000	64,000	25%	65,000	129,000	50%
Jan-2028	257,000	64,000	25%	65,000	129,000	50%
Feb-2028	256,000	63,500	25%	65,000	128,500	50%
Mar-2028	197,000	49,000	25%	50,000	99,000	50%

The natural gas volumes shown in Figure ESP-22 are subject to the following explanations:

- Procured volumes in the table above do not include an adjustment for pipeline retainage or losses. To account for pipeline retainage or losses, the actual volume procured must be greater than the volume that will be delivered at the burner tip. As a point of reference, the NWPL system is estimated to have a two percent fuel retainage factor. This means that for every 1,000 MMBtu burned at the burner tip, there must be 1,020 MMBtu entering the

pipeline from its various gas supply basins. The Companies procure amounts necessary to address pipeline retainage factors as part of their daily balancing and portfolio optimization activities.

- The volumes offered by bidders cannot be precisely matched to the procurement targets for each month. Therefore, the total volume of the transacted bid responses may deviate from a specific month's target volume. Specific gas transactions were entered into after all gas supply offers were input into an internally developed linear programming optimization model that sought to minimize costs subject to constraints, such as credit and incremental pipeline delivery charges. The aforementioned model calculates the lowest total gas supply portfolio cost.
- The Companies avoid acquiring volumes of less than 1,000 MMBtu per day because such purchases typically carry "odd lot size" premiums.
- All gas quantities will be delivered to Nevada Power via Kern River and to Sierra via Great Basin, Tuscarora and Ruby, subject to meeting any gas transport contractual obligations, such as operational flow orders issued by upstream and/or downstream pipelines.

## **G. FINANCIAL GAS REQUIREMENTS**

The Companies are not proposing to acquire financial hedges during the ESP action period. This proposal is outlined in Section 5.C.

## SECTION 3 - MARKETS & PRICE FORECASTS

### A. MARKET FUNDAMENTALS

#### 1. ELECTRICITY

**Regional Profile.** The Companies are members of the Western Electricity Coordinating Council (“WECC”). WECC is the Regional Entity (“RE”) responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC bylaws. There are six REs given authority by the North American Electric Reliability Corporation (“NERC”) and the Federal Energy Regulatory Commission (“FERC”). Of those six entities, WECC oversees the largest and most geographically diverse region, known as the Western Interconnection (“WI”). WECC’s footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.<sup>13</sup> Figure ESP-23 depicts the various NERC regions and sub-regions, including the WECC. This level of granularity allows NERC to better evaluate resource adequacy and ensure deliverability constraints between and among assessment areas are accounted for.

The WECC assessment area is divided into eight sub-regions: California, Mexico, Northwest, Alberta, British Columbia, Basin, Rocky Mountain and the Southwest. The Southwest area includes Nevada, Arizona and parts of New Mexico. These subregional divisions are used for this assessment as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

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<sup>13</sup> Western Electric Coordinating Council, About WECC, available at <https://www.wecc.org/Pages/AboutWECC.aspx>.

**FIGURE ESP-23  
NERC REGIONS AND SUB-REGIONS**

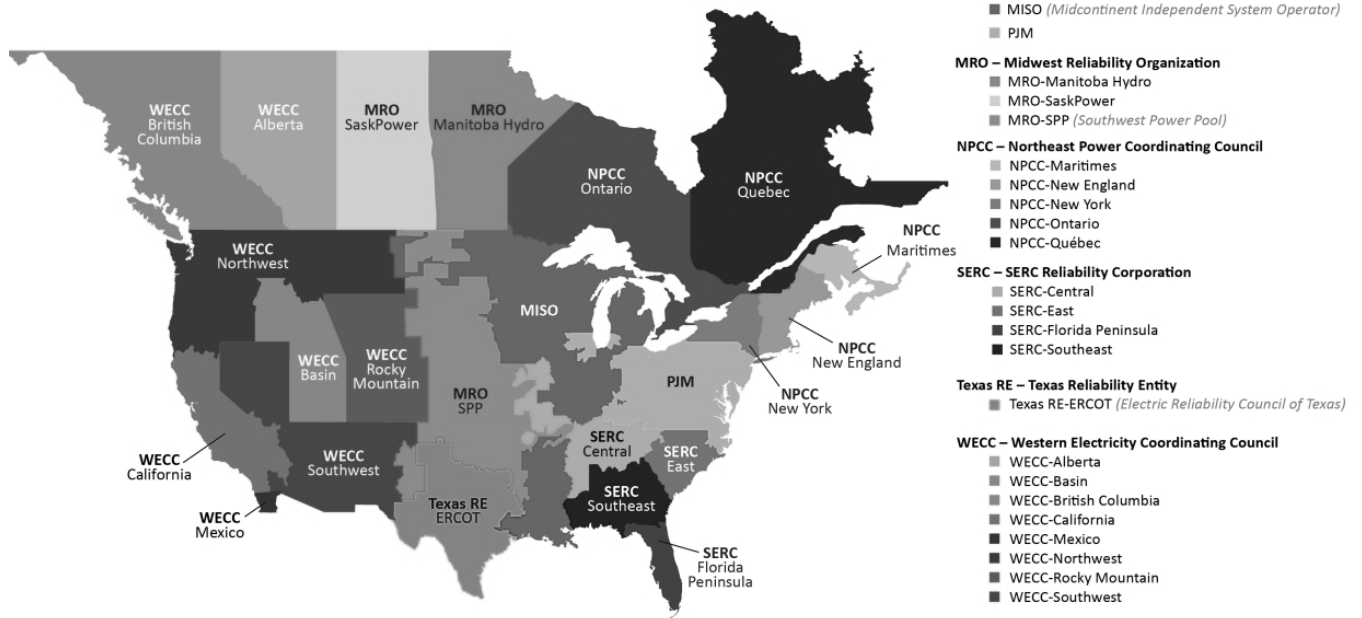


Figure ESP-24 shows the capacity composition in the Southwest sub-region and the prevalence of natural gas-fired generation.<sup>14</sup>

**FIGURE ESP-24  
WECC-SOUTHWEST CAPACITY BY FUEL TYPE (MW)**

WECC-Southwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	4,121	4,116	3,749	3,754	3,754
Coal*	3,761	4,116	3,749	3,754	2,576
Petroleum	341	340	340	336	336
Natural Gas	24,978	24,887	24,817	24,837	24,750
Biomass	46	46	46	46	46
Solar	6,867	6,349	6,503	7,474	7,804
Wind	1,059	1,055	1,055	1,059	1,050
Geothermal	1,555	1,555	1,607	1,572	1,454
Conventional Hydro	1,984	1,989	1,989	1,982	1,981
Pumped Storage	113	113	113	113	113
Nuclear	3,641	3,640	3,640	3,641	3,641
Battery	6,824	7,325	7,657	7,671	7,671
Total MW	51,530	51,414	51,516	52,484	52,598
Total MW*	51,170	51,414	51,516	52,484	51,421

\*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

<sup>14</sup> NERC, Long-Term Reliability Assessment, Jan. 2026, available at [https://www.nerc.com/globalassets/our-work/assessments/nerc\\_ltra\\_2025.pdf](https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf).

### ***Energy Imbalance Market (“EIM”).***

The California Independent System Operator’s (“CAISO”) EIM is a real-time energy market, the first of its kind in the western United States. The EIM’s advanced market system automatically finds low-cost energy to serve real-time consumer demand across the West. Since its launch, the EIM has enhanced grid reliability and generated cost savings for its participants. In addition to its economic advantages, the EIM improves the integration of renewable energy, leading to a cleaner, “greener” grid.<sup>15</sup> The EIM began financially binding operation on November 1, 2014, by optimizing resources across the CAISO and PacifiCorp Balancing Authority Areas (“BAAs”). NV Energy began participating in December 2015. The EIM uses a sophisticated system to automatically balance demand every five minutes with the lowest cost energy available across the combined grid.

The first quarter 2026 EIM Benefits Report published by the CAISO estimates that the EIM has yielded more than \$8.62 billion in total benefits for all participants since the market was launched in 2014. The measured benefits of participation in the EIM include cost savings, increased integration of renewable energy, and improved operational efficiencies including the reduction of the need for real-time flexible reserves. The estimated gross economic benefits for the Companies exceeded \$1 billion as of the first quarter of 2026.<sup>16</sup> Sharing resources across a larger geographic area reduces greenhouse gas emissions by utilizing renewable generation that otherwise would have been turned off. A map of the active and pending EIM participants is provided in Figure ESP-25.

#### *Participants*

- Imperial Irrigation District – planned entry 2028
- Black Hills – planned entry 2026
- PowerWatch (formerly BHE Montana) – planned entry 2026
- Avangrid – entered 2023
- El Paso Electric – entered 2023
- WAPA Desert Southwest Region – entered 2023
- Bonneville Power Administration – entered 2022
- Tucson Electric Power (“TEP”) – entered 2022
- Avista – entered 2022
- Tacoma Power – entered 2022
- NorthWestern Energy – entered 2021
- Los Angeles Department of Water & Power – entered 2021

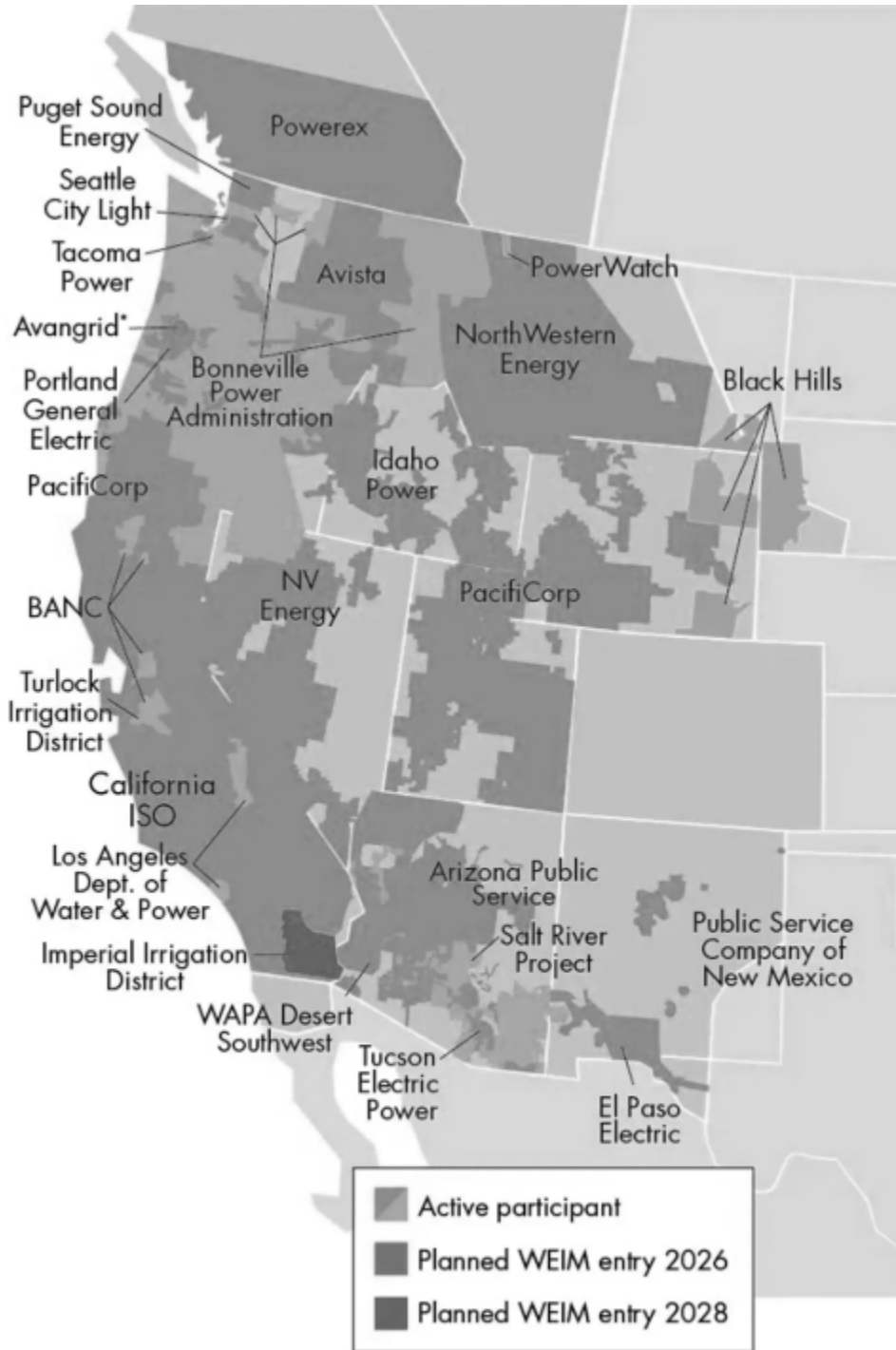
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<sup>15</sup> CAISO, Western Energy Imbalance Market (WEIM), available at <https://www.westerneim.com/Pages/About/default.aspx>.

<sup>16</sup> CAISO, WEIM benefits, available at <https://www.westernenergymarkets.com/western-energy-imbalance-market-weim/benefits>.

- Public Service Company of New Mexico – entered 2021
- Turlock Irrigation District – entered 2021
- Salt River Project (“SRP”) – entered 2020
- Seattle City Light – entered 2020
- Balancing Authority of Northern California – entered 2019
- Idaho Power Company – entered 2018
- Powerex – entered 2018
- Portland General Electric – entered 2017
- Puget Sound – entered 2016
- Arizona Public Service – entered 2016
- NV Energy – entered 2015
- PacifiCorp – entered 2014
- California ISO – entered 2014

**FIGURE ESP-25  
WESTERN EIM ACTIVE PARTICIPANTS**



*\*Avangrid office; generation only BAA with distribution across multiple states. Map boundaries are approximate and for illustrative purposes only. Copyright © 2025 California ISO*

### ***Extended Day-Ahead Market (“EDAM”)***

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. With the order issued on April 3, 2026, the Commission approved the Companies’ participation in EDAM with an anticipated start date in the Fall of 2028. Additional information about EDAM is provided in the Day-Ahead Markets and Regional Transmission Organization Section.

### ***Resource Adequacy***

To ensure reliability during the transition to greater reliance on renewable resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term resource adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy assured. To evaluate the projected resource adequacy (generation resource reserve margins), NERC prepares the Long-Term Reliability Assessment (“LTRA”) - an annual assessment of anticipated resource reserve margins.

Anticipated Reserve Margin (“ARM”) <sup>17</sup> and PRM <sup>18</sup> are calculated and reported for each of the WECC sub-regions and provide an indication of the ability of those sub-regions to meet their load requirements with internal generation and imports from other sub-regions or zones under the specified conditions. Planning Reserve Margins (anticipated or prospective) are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand.

NERC assesses resource adequacy by evaluating each assessment area’s PRM relative to its Reference Margin Level<sup>19</sup> (“RML”) - a “target” or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load (“LOL”) analysis.

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<sup>17</sup> This is the amount of anticipated resources (includes only Tier 1 resources) less net internal demand calculated as a percentage of net internal demand.

<sup>18</sup> This is the amount of prospective resources (includes also Tier 2 resources) less net internal demand calculated as a percentage of net internal demand.

<sup>19</sup> The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/ RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of the assessment period or may be different for the summer and winter seasons.

The most recent forecast of these reserve margins from the NERC 2025 LTRA published in January of 2026 is shown in Figure ESP-26.<sup>20</sup>

**FIGURE ESP-26  
WECC-SOUTHWEST POWER SUPPLY ASSESSMENT**

Demand, Resources, and Reserve Margins										
Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	37,407	38,911	40,429	41,887	43,551	44,772	45,664	46,317	47,226	47,988
Demand Response	237	258	264	272	282	237	258	264	272	282
Net Internal Demand	37,169	38,653	40,165	41,615	43,269	44,535	45,405	46,053	46,953	47,706
Additions: Tier 1	6,639	7,501	8,155	8,562	8,914	8,914	8,914	8,396	8,852	8,852
Additions: Tier 2	1,771	5,410	6,994	9,369	9,872	11,263	11,286	10,468	11,286	11,252
Additions: Tier 3	2,502	3,899	5,242	7,562	9,710	12,409	14,804	14,801	24,521	24,571
Net Capacity Transfers (WECC Model)	902	2,544	4,162	5,101	6,301	5,895	5,570	4,880	5,030	4,715
Existing-Certain and Net Transfers	45,794	46,457	47,523	49,023	49,986	49,308	47,432	44,294	44,948	43,944
Anticipated Reserve Margin (%)	41.1%	39.6%	38.6%	38.4%	36.1%	30.7%	24.1%	14.4%	14.6%	10.7%
Prospective Reserve Margin (%)	45.8%	53.6%	56.0%	60.9%	58.9%	56.0%	49.0%	37.1%	38.6%	34.3%
Reference Margin Level (%)	13.3%	13.7%	13.6%	12.6%	12.2%	12.0%	11.7%	12.3%	11.3%	11.1%

Southwest sub-region is assessed as adequate by NERC until summer of 2034. The ARM falls below the RML starting in Summer 2034. With the addition of Prospective Resources, the PRM stays above the RML for all years in the LTRA time horizon.

The Companies’ BAA is included in the Southwest sub-region within the WECC. The BAA is integrated with the other sub-regions by way of transmission interconnections within the electric grid. The Companies routinely engage in purchase and sales transactions with neighboring utilities belonging to other WECC sub-regions and reserve margins in those sub-regions have the ability to impact operations in Nevada. Consequently, reserve margins in BAAs located in the other sub-regions can affect operations and capacity availability in the system as well.

The traditional methods of assessing resource adequacy at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural gas-fired generation, unprecedented proportions of nonsynchronous resources, including renewables and battery storage, demand response, smart and micro-grids and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

<sup>20</sup> NERC, Long-Term Reliability Assessment, Jan. 2026, available at [https://www.nerc.com/globalassets/our-work/assessments/nerc\\_ltra\\_2025.pdf](https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf).

Therefore, WECC also performs energy-based probabilistic assessments (“ProbA”) looking at all hours of the year. The difference between the LTRA and the ProbA results is that the ProbA captures the expected equivalent forced outage rate for baseload resources whereas the LTRA does not. Another difference is that the ProbA looks at all hours of the year, and the LTRA looks at the peak hour only. WECC uses the Multi-Area Variable Resource Integration Convolution model (“MAVRIC”). The model is a convolution-based probabilistic model and is WECC’s chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. LOLH and expected unserved energy (“EUE”) are not anticipated in 2027 and 2029. Results of the 2027 ProbA shown in the Figure ESP-25 table below indicate negligible unserved energy and load-loss risk.

**FIGURE ESP-27  
WECC-NW SUMMARY OF ASSESSMENTS**

<b>Base-Case Summary of Results</b>			
	<b>2026*</b>	<b>2027</b>	<b>2029</b>
<b>EUE (MWh)</b>	N/A	0	0
<b>NEUE (ppm)</b>	N/A	0.00	0.00
<b>LOLH (hours per Year)</b>	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

**Demand in WECC-Southwest.** The average annual demand growth rate for WECC-Southwest is 3.9 percent. The primary drivers are data centers, industrial electrification, residential electrification, and residential customer growth. Large-load additions in the forecast are 9,422 MW through 2035.

**Generation in WECC-Southwest.** A year-round concern for this subregion is an aging thermal resource fleet. Hundreds of MW of capacity in this region have been operational for over 60 years. During the winter, certain thermal resources are unable to cycle below 40 Fahrenheit due to freezing issues. Older sites also require extensive overhauls such as generator rewinds that can keep resources out of service for extended periods of time and potentially longer than planned as discovery work manifests into additional maintenance. To reduce the risk of age-related forced outages, plant staff adhere to a strict maintenance schedule with frequent inspections, and unit performance is routinely monitored. Solar output variability is a concern year-round for this subregion. It is a primary concern on summer evenings as solar output rapidly declines whereas load increases or remains elevated. Activation of demand response (“DR”) programs, peaking/flexible power plants, and maintaining sufficient BESS charge are all potential strategies to mitigate this issue. Large changes in solar output can also cause extreme area control error (“ACE”) fluctuations, which are addressed using BESS.

**Renewable Portfolio, Clean Electricity and Emissions Standards in WECC-Southwest.** In the Southwest region, Arizona has an RPS mandate for its electric supply to be 15 percent renewable by 2025. Separately, APS has committed to ending the use of coal-fired generation after 2031, and the company set a 100 percent carbon free by 2050 goal. SRP has goals to reduce CO2 emissions per MWh by 62 percent from 2005 levels by 2035 and 90 percent by 2050; TEP will stop using coal by 2032 and plans to reduce carbon emissions by 80 percent by 2035. New Mexico has set more aggressive mandates, requiring 50 percent renewable by 2030, percent by 2040, and 100 percent by 2045.

## 2. NATURAL GAS

As North American power markets continue to transition to cleaner energy sources (*e.g.*, natural gas and renewables), natural gas will be the driving determinant of market power prices as well. Natural gas is widely considered to be a critical energy source for the future, with fossil fuels remaining the dominant source of energy powering the world economy. In particular, the abundance of natural gas, coupled with its relative environmental attributes and multiple applications across all sectors, means that it will continue to play an important role in meeting demand for energy in the United States.

Market fundamentals indicate the availability and reliability of physical gas supplies to be adequate for satisfying natural gas demand for the foreseeable future. Prices for gas will fluctuate depending upon demand (often weather-related), economics of drilling, and finally federal and state decarbonization efforts. On a short-term basis, demand for natural gas has traditionally been seasonal. As a general matter, demand is highest during the winter, the primary driver being residential and commercial heating. Natural gas in storage typically declines in the winter as it is consumed during peak usage, then is injected back into storage in the spring and summer months in order to rebuild storage levels for the next winter's drawdown. Besides weather, the general state of the economy can have a considerable effect on the demand for natural gas in the short term, particularly for industrial consumers. When the economy is expanding, output from industrial sectors generally increases at a similar rate. When the economy is in recession, output from industrial sectors drops.

The Companies currently purchase most of the natural gas supply burned in their power plants from the Rockies region, principally the states of Wyoming, Colorado, and Utah. The Companies also access natural gas supplies from the Western Canadian Sedimentary Basin in Alberta and British Columbia, Canada. In 2025, most production growth came from the Permian region in Texas and New Mexico, where most natural gas production is associated natural gas, meaning producers' oil-drilling activities in the region determine natural gas production levels. Natural gas production regions are presented in Figure ESP-28 below.

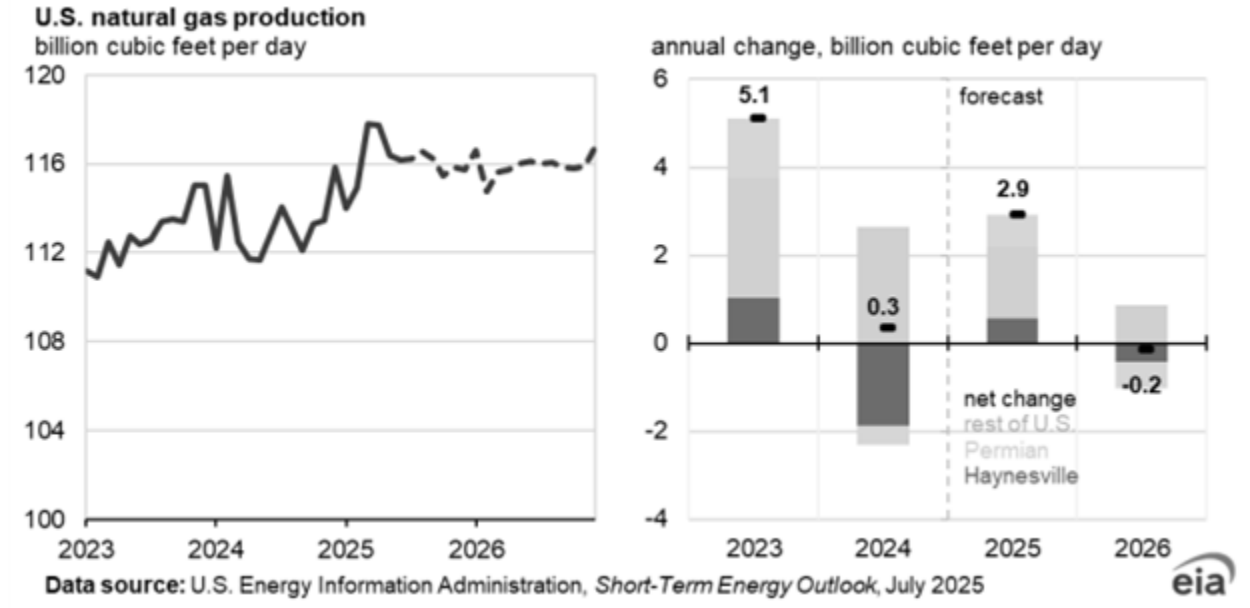
**FIGURE ESP-28  
U.S. NATURAL GAS PRODUCTION REGIONS**



**Natural gas production.** Marketed natural gas production in the Lower 48 states reached a record high in November of 2025 at 118.5 billion cubic feet per day (Bcf/d), and the estimated production will average 117.8 Bcf/d winter 2025-2026, (November—March). The increased production is stemming primarily from increased associated gas production from the Permian and the rest of the U.S. Lower 48 states regions. The U.S. Energy Information Administration (“EIA”) expects<sup>21</sup> marketed natural gas production to rise, averaging 118 Bcf/d in 2026 and 121 Bcf/d in 2027, relative to 116 Bcf/d in 2025. The growth is primarily expected in natural gas production to originate from the Haynesville, Permian, and Appalachia regions. Elevated oil prices will drive more oil-directed drilling in the Permian, which will contribute to greater volumes of associated natural gas production. U.S. Natural Gas production is presented in Figure ESP-29 below.

<sup>21</sup> U.S. Energy Information Administration, Short-Term Energy Outlook, March 2026, available at <https://www.eia.gov/outlooks/steo/archives/Mar26.pdf>.

**FIGURE ESP-29  
U.S. NATURAL GAS PRODUCTION**

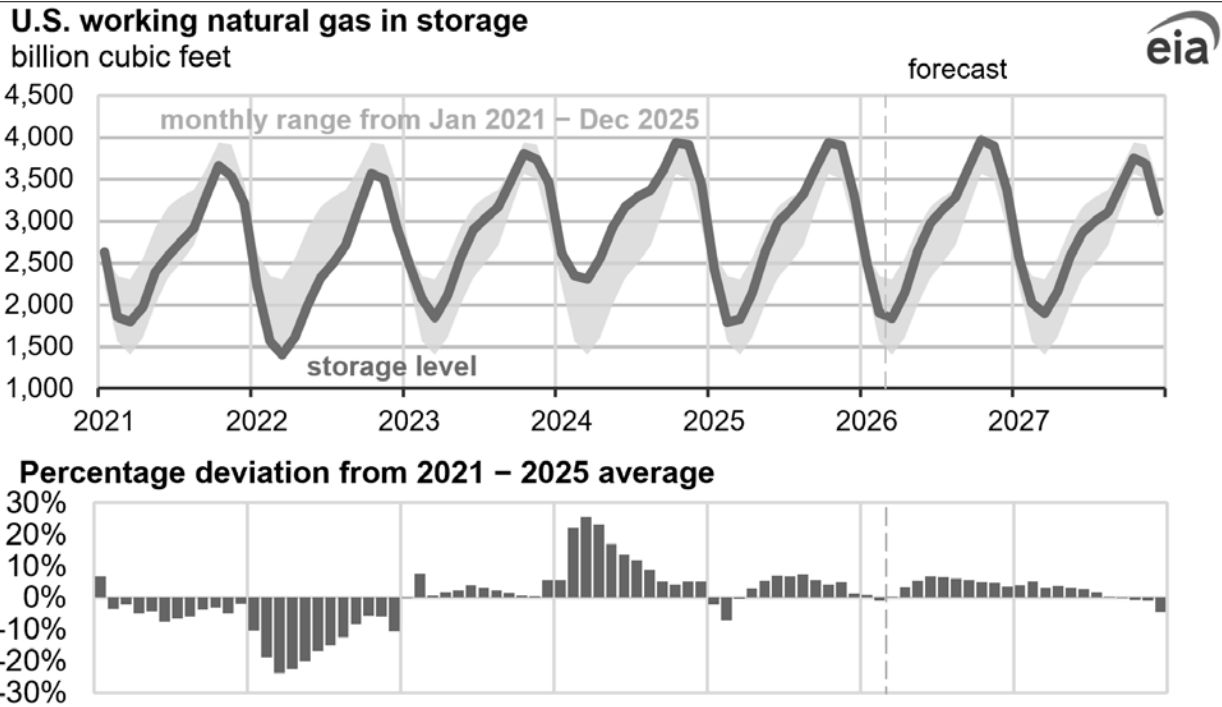


**Natural gas storage.** Based on data from the National Oceanic and Atmospheric Administration, the 2025–2026 winter season (November–March) will have more than 2 percent HDDs than the 10-year average.<sup>22</sup> Although we have had colder weather that has contributed to record high spot prices, production was higher than expected throughout the winter, which helped dampen the effect of January’s large storage withdrawals, keeping storage levels close to or above average through the winter. Natural gas inventories are expected to end the withdrawal season in the U.S. near the five-year average. Also regional inventories are expected to be above-average inventories in the Pacific region (48 percent) and the Mountain region (50 percent) as we head into summer of 2026.<sup>23</sup> Working gas storage levels for the United States in 2021-2025, with the forecast for the remainder of 2026 and 2027 are illustrated in Figure ESP-30.

<sup>22</sup> *Id.*

<sup>23</sup> *Id.*

**FIGURE ESP-30  
U.S. NATURAL GAS STORAGE**



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2026

Movement in natural gas prices can be partly attributable to natural gas storage levels. Relative shortages or excesses of storage capacity during heavy load periods (typically November through March) can either create or hinder the daily volatility of natural gas prices. The consuming West region has the smallest share of gas storage, both in terms of the number of sites, as well as gas capacity/deliverability.

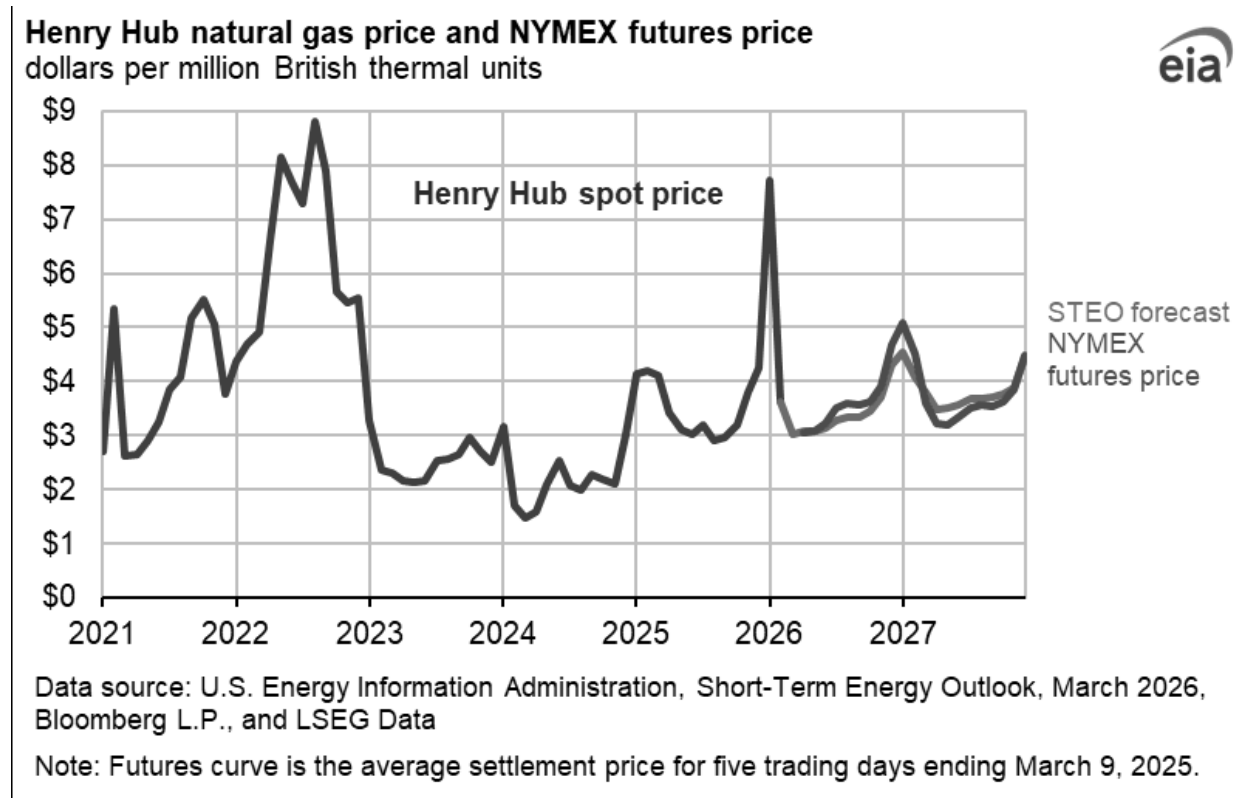
Arizona, Idaho and Nevada do not have any underground storage sites within their borders. Approximately 63 percent of total storage capacity in the West is located in California and Montana. Moreover, the bulk of the region’s working gas capacity is located in California’s 14 underground natural gas storage sites, seven of which are owned by the two principal gas distributors in the State: Southern California Edison (“SoCal”) and Pacific Gas & Electric (“PG&E”). Most of their storage capacity is used for system balancing and as a way of maintaining a steady and high utilization of contracted pipeline capacity from Canada, the Rocky Mountains, and the Southwest.

The seven independent storage facilities in California (not owned by either SoCal or PG&E) are used primarily as depositories for gas produced within the State that is not immediately marketable. In addition, these sites are connected to (and deliver their withdrawals to) the SoCal and/or PG&E

systems. Storage facilities in Washington and Oregon are used primarily to provide seasonal backup to several local distribution companies located in the Northwest and are crucial in maintaining their operational flexibility and system integrity. These storage facilities are also used by some Canadian shippers/customers to support their marketing and operational needs. The import/export facilities of NWPL at Sumas, Washington, are used to move natural gas in either direction to storage, depending on marketing conditions.

**Natural gas prices.** In EIA’s March forecast,<sup>24</sup> the Henry Hub spot price averages almost \$3.80/MMBtu in 2026, and about \$3.90/MMBtu on average next year in 2027. Historical and forecasted natural gas Henry Hub monthly average spot prices for period 2021-2027 are illustrated in figure ESP-31.

**FIGURE ESP-31  
HENRY HUB MONTHLY SPOT PRICES**



<sup>24</sup> *Id.*

EIA expects natural gas consumption to grow in all sectors in 2026 and 2027 except the industrial sector, where the consumption is expected to decrease slightly. Sectoral changes in natural gas consumption depend mostly on the weather. Natural gas-fired power plants provide about 40 percent of U.S. electricity generation annually, so electricity demand from heating and air-conditioning equipment influences how much natural gas the electric power sector consumes.

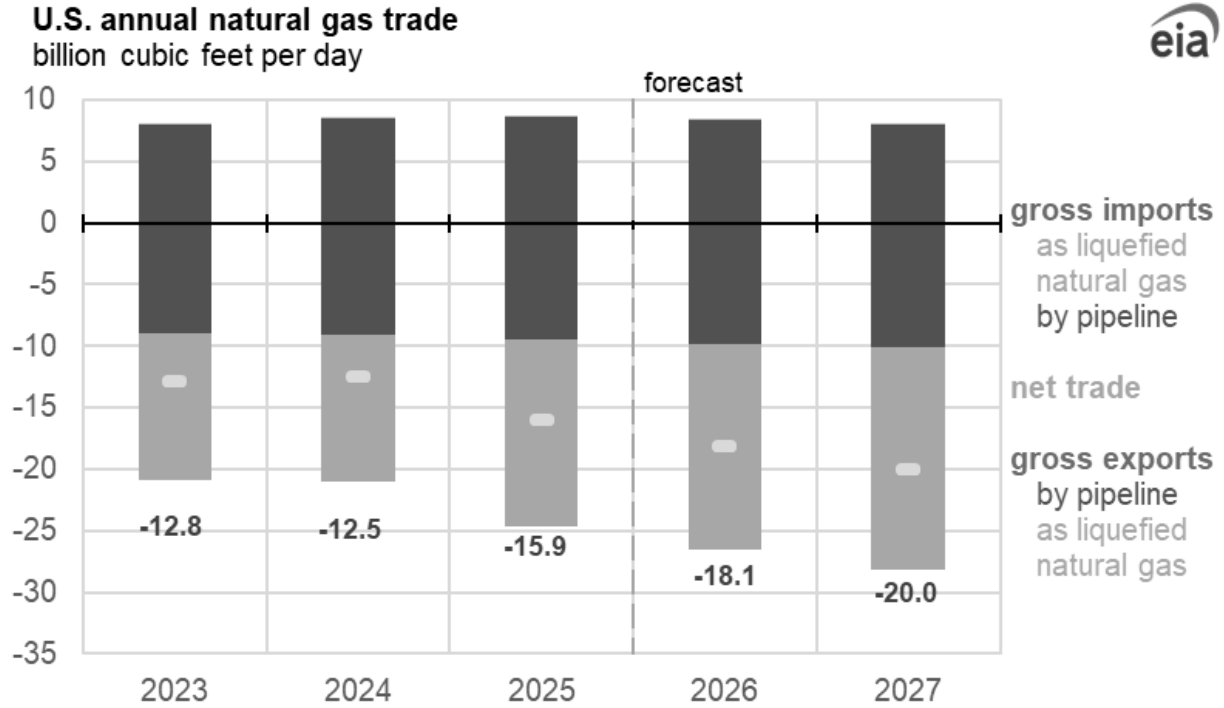
In the residential and commercial sectors, colder temperatures in the winter also affect direct natural gas consumption by heating equipment. The mix of energy sources and technologies used to generate electricity also affects natural gas consumption in the electric power sector. As developers add more generating capacity from solar- and wind-powered generators, those generators' incremental generation may reduce the need to dispatch natural gas-fired power plants. Changes in the timing and magnitude of new solar and wind capacity would also affect the forecast for natural gas consumption in the electric power sector.

Reductions in the flow of liquified natural gas ("LNG") through the Strait of Hormuz have caused natural gas prices in Europe and Asia to increase. However, U.S. natural gas prices are expected to be relatively unaffected by this development, as LNG export facilities were already operating at a high level of utilization prior to the Middle East conflict, limiting the ability to export additional volumes in the near term. Most of the flexibility in exports will be in the ramp-up at Corpus Christi State 3 (Train 5), which was completed in February of 2026 and at Golden Pass Train 1, which is set to come online in March of 2026.<sup>25</sup> LNG demand and natural gas production will be two key drivers of price in the coming years. Historical and forecasted U.S. natural gas trade and LNG exports are illustrated in Figure ESP-32.

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<sup>25</sup> U.S. Energy Information Administration, Short-Term Energy Outlook, April 2026, available at [https://www.eia.gov/outlooks/steo/pdf/steo\\_full.pdf](https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf).

**FIGURE ESP-32**  
**U.S. GAS TRADE AND LNG EXPORTS**



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2026

## **B. REGIONAL MARKET DEVELOPMENT**

In the 2025 ESP Update, Docket No. 25-08027, the Companies informed the Commission of NV Energy's intention to withdraw from WRAP. On October 24, 2025, the Companies filed a letter to the Western Power Pool Board of Directors to formally withdraw from the program prior to the onset of binding program operations.<sup>26</sup> The Companies have continued to monitor the program's development and continue to participate in the non-binding program. To date, WRAP has not evolved to address the five critical issues identified in the 2025 ESP Update. Therefore, the Companies do not have plans to rejoin the program in September 2026 to be a part of the binding Winter 2027-2028 season.

In addition to the Companies' efforts in WRAP, the Companies are also participating in discussions with others that are interested in developing a new resource adequacy program for the Extended Day-Ahead Market ("EDAM"). Members from the group provided a public briefing at the Regional Issues Forum on March 16, 2026, on some of the progress made to date and laid out next steps.<sup>27</sup> Currently, the group is working on a Straw proposal to kick off the stakeholder process which includes various consensus driven program design elements. The paper is anticipated to be released in April 2026.

The Companies have been an active participant in the development of the two day-ahead market options in the West and have worked with other utilities on several studies evaluating potential benefits associated with the different market designs and possible footprints. Two day-ahead markets were under consideration by the Companies: CAISO's EDAM and SPP's Markets+. The decision to join a day-ahead market is a significant event that will require quantitative and qualitative showings in a future filing. And while it is not impossible to exit a market, it is far better to get the decision correct the first time. It is for that reason the Companies have taken a methodical approach and performed due diligence on both day-ahead market options.

Based on a holistic view of these qualitative and quantitative factors, the Companies requested authorization from the Commission to participate in the CAISO EDAM in Docket No. 25-10025. The request was granted, subject to specific conditions in April 2026. The Companies filed a petition for reconsideration and clarification on April 17, 2026. The Companies respectfully request reconsideration of Paragraph 130, which designates the day-ahead Resource Sufficiency Evaluation ("RSE") surcharges responsibility, and Paragraph 131, which caps the annual EDAM participation budget at \$16.52 million. The Companies also seek clarification and, to the extent necessary, reconsideration of (1) the method to obtain prior approval to increase the implementation budget cap, as outlined in Paragraph 131, of the order and (2) the timing of the EDAM implementation costs as outlined in Paragraph 134 of the order.

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<sup>26</sup> [https://www.westernpowerpool.org/private-media/documents/NV\\_Energy\\_WRAP\\_Withdrawal.pdf](https://www.westernpowerpool.org/private-media/documents/NV_Energy_WRAP_Withdrawal.pdf).

<sup>27</sup> <https://www.westernenergymarkets.com/governance/regional-issues-forum>.

## C. FUEL AND PURCHASED POWER PRICE FORECASTS

The Companies' forecasting process for fuels and regional power prices encompasses an assessment of historic and forecast information and related industry data that is obtained from professional services or is publicly available. The outlook on future price trends is reviewed from several sources including forward markets, the results of RFPs, and reputable independent market forecasting services, such as Argus Media ("Argus"), Wood Mackenzie ("WoodMac"), and the EIA.

The methodology used to prepare the base case forecasts for power and natural gas prices relies upon observable market quotes in the near-term forecast years, which are gradually blended into long-term price forecasts obtained from an external consulting firm specializing in market fundamentals and fundamental price forecasting. The price forecast curves for power and natural gas are important to the economic evaluation of alternative electric resource plans.

***Market quotes used for short-term forecast.*** Market quotes consist of observed trades in the relevant trading hubs: for natural gas, the Henry Hub, Alberta NOVA Inventory Transfer ("AB-NIT" or "AECO"), Northwest Pipeline Rockies ("Rockies"), Malin, and South California Border ("SoCal"); and for power, the Mead, the Palo Verde and the Mid-Columbia ("Mid-C") trading hubs. The source of market quotes is Argus for natural gas prices and for western regional power prices. The market quotes for the ESP forecast were prepared as an average of settlement prices for a 19-day trading period from November 1, 2025, through November 30, 2025.

***Fundamental (long-term) forecast.*** The fundamental forecasts of power and natural gas prices are provided through a subscription service with WoodMac, a global energy, metals and mining consultancy service. WoodMac maintains an international reputation for supplying comprehensive data, written analysis and consultancy advice. It performs detailed fundamental modeling of regional electric and natural gas systems, taking into account structural supply-demand price dynamics. For internal consistency, WoodMac's projections of natural gas and power prices are taken from a single integrated forecast, the long-term outlook (2025 H2 Base Case, released in December of 2025.)

1. NATURAL GAS PRICE FORECAST

**Base natural gas price forecast.** The monthly gas price forecast by regional hub begins with the 19-day average trading period of market quotes from November of 2025. The natural gas price monthly forecast for January 2027 - March 2029 was prepared utilizing pure market quotes from the Argus trading settlements for Henry Hub plus western regional basis quotes.<sup>28</sup> For the intermediate-term months, April 2029 through December 2029, a blending process is used to gradually transition from the 19-day average quotes to the long-term fundamental natural gas price forecast from WoodMac.

The base fuel monthly natural gas price forecast, used for the dispatching purposes, SoCal and Malin natural gas hubs, is shown in Figure ESP-33

**FIGURE ESP-33  
NATURAL GAS PRICE FORECASTS  
(CONFIDENTIAL)**



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<sup>28</sup> The prices at western delivery hubs are commonly quoted as a basis to the Henry Hub.

***High and low gas prices.*** The Companies also prepared high and low sensitivities around the base case market price forecasts. An assumption of plus-and-minus one standard deviation around the base gas price forecast was computed for the high and low cases. Market quotes of implied volatilities from at-the-money call options from November 2025 were used to calculate the the high and low natural gas prices.

The base, high and low-price projections, that result from applying the volatility curve and used for the fuel costs, Rockies and Alberta or (AECO) natural gas hubs, are illustrated in Figures ESP-34 and ESP-35.

**FIGURE ESP-34  
NATURAL GAS PRICE FORECAST (ROCKIES)  
(CONFIDENTIAL)**



**FIGURE ESP-35  
NATURAL GAS PRICE FORECAST (ALBERTA OR AECO)  
(CONFIDENTIAL)**



## 2. POWER PRICE FORECAST

Prices for western wholesale power markets are forecasted monthly for both on-peak and off-peak periods.<sup>29</sup> The power price forecast is almost exclusively based on prices at Mead hub. The natural gas price monthly forecast for January 2027 - March 2029 was prepared utilizing pure market quotes from the Argus trading settlements for Mead hub. The Mead prices are based on an average of 19 trading days in November of 2025. For the intermediate-term months, April 2029 through December 2029, a blending process is used to gradually transition from the 19-day average quotes to the long-term fundamental power price forecast from WoodMac.

Also, as with the natural gas price forecast, high and low power price sensitivities were developed for describing potential retail price volatility. The high and low power price forecasts were prepared to reflect western energy prices that fluctuate with the respective high and low natural gas price forecasts. For both on-peak and off-peak periods, the power prices are calculated by first multiplying the high and low natural gas prices with the corresponding market-based heat rates. Figure ESP-36 shows the monthly forecast of on-peak power prices for Mead power hub for 2027-2029 for base, high and low fuel cases.

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<sup>29</sup> On-peak in the WECC region is the 16-hour period, from 6 a.m. to 10 p.m., Monday through Saturday. Off-peak is the balance of hours in the week.

**FIGURE ESP-36  
POWER PRICE FORECAST (MEAD -ON-PEAK)  
(CONFIDENTIAL)**



## **SECTION 4 – POWER PROCUREMENT PLAN**

This section explains how the Companies’ power procurement plan meets the requirements of NAC § 704.9494. See also NAC § 704.9153, which defines “purchased power procurement plan” as “a plan which establishes the parameters of a purchased power portfolio for a utility and which balances the objectives of:

1. Minimizing the cost of purchased power;
2. Minimizing retail price volatility; and
3. Maximizing the reliability of purchased power over the term of the energy supply plan.”

### **A. POWER PORTFOLIO AND OPTIMIZATION PROCEDURES**

The Companies meet the energy demand of their customers through a combination of the Companies’ generating units, long-term PPAs, and short-term transactions.

The Companies meet the requirements of Nevada’s RPS through a combination of Commission-approved long-term PPAs with renewable energy resources and agreements for purchase of PCs. The Companies also sell PCs under the NGR program.

Figures ESP-37 and ESP-38 list all of the Companies’ renewable and non-renewable PPAs, and sales agreements.

**FIGURE ESP-37  
NEVADA POWER LONG-TERM PPAs**

Contract Name	Contract Type	Capacity (MW)	Commercial		BESS Termination Date
			Operation Date	Termination Date	
<b>Renewable Purchase Agreements</b>					
<b>PPAs (Commercial)</b>					
ACE Searchlight <sup>QF</sup>	Solar <sup>S</sup>	17.5	12/16/14	12/31/2034	
APEX Landfill <sup>QF</sup>	Methane	12.0	03/01/12	12/31/2032	
Boulder Solar I <sup>EWG</sup>	Solar <sup>S</sup>	100.0	12/09/16	12/31/2036	
Colorado River Commission-Hoover	Hydro	237.6	10/01/17	09/30/2067	
Copper Mountain 5 <sup>EWG</sup>	Solar <sup>S</sup>	250.0	07/23/21	12/31/2046	
Desert Peak 2 <sup>QF</sup>	Geothermal	25.0	04/17/07	12/31/2027	
Eagle Shadow Mountain <sup>EWG</sup>	Solar <sup>S</sup>	300.0	05/10/23	12/31/2048	
FRV Spectrum <sup>QF</sup>	Solar <sup>S</sup>	30.0	09/23/13	12/31/2038	
Gemini Solar <sup>EWG</sup>	Solar <sup>S,X=380 (3.7 hrs)</sup> 3	690.0	03/25/24	12/31/2049	12/31/2049
Jersey Valley <sup>QF</sup>	Geothermal	22.5	08/30/11	12/31/2031	
McGinness Hills <sup>QF</sup>	Geothermal	96.0	06/20/12	12/31/2032	
Moapa (Arrow Canyon) Solar <sup>EWG</sup>	Solar <sup>S,X=74 (5 hrs)</sup> 3	200.0	12/08/23	12/31/2048	12/31/2048
Mountain View <sup>EWG</sup>	Solar <sup>S</sup>	20.0	01/05/14	12/31/2039	
Nevada Solar One (NPC) <sup>QF</sup>	Solar <sup>T,X</sup>	46.9	06/27/07	12/31/2027	
NGP Blue Mountain <sup>QF</sup>	Geothermal	49.5	11/20/09	12/31/2029	
RV Apex <sup>QF</sup>	Solar <sup>S</sup>	20.0	07/21/12	12/31/2037	
Salt Wells <sup>QF</sup>	Geothermal	23.6	09/18/09	12/31/2029	
Silver State <sup>EWG</sup>	Solar <sup>F</sup>	52.0	04/25/12	12/31/2037	
Spring Valley <sup>EWG</sup>	Wind	151.8	08/16/12	12/31/2032	
Stillwater Geothermal <sup>1,QF</sup>	Geothermal	47.2	10/10/09	12/31/2029 <sup>4</sup>	
Stillwater PV <sup>1,QF</sup>	Solar <sup>F</sup>	22.0	03/05/12	12/31/2029 <sup>4</sup>	
Switch Station 1 <sup>EWG</sup>	Solar <sup>S</sup>	100.0	08/08/17	12/31/2037	
Switch Station 2 (NPC) <sup>EWG</sup>	Solar <sup>S</sup>	0.0	10/11/17	12/31/2037	
Techren I <sup>EWG</sup>	Solar <sup>S</sup>	100.0	03/11/19	12/31/2044	
Techren III <sup>QF</sup>	Solar <sup>S</sup>	25.0	10/07/20	12/31/2045	
Techren V <sup>EWG</sup>	Solar <sup>S</sup>	50.0	12/31/20	12/31/2045	
Tuscarora <sup>QF</sup>	Geothermal	32.0	01/11/12	12/31/2032	
WM Renewable Energy-Lockwood <sup>QF</sup>	Methane	3.2	04/01/12	12/31/2032	
<b>Total</b>		<b>2723.8</b>			
<b>PC Purchase Agreements</b>					
Sierra Pacific Power	Geothermal	2.3	10/30/09	12/31/2028	
Nellis I (Solar Star) <sup>QF</sup>	Solar	13.2	12/15/07	12/31/2027	
SunPower (LVVWD)	Solar	3.0	04/20/06	12/31/2026	
<b>Total</b>		<b>18.5</b>			
<b>PPAs (Pre-Commercial)<sup>2</sup></b>					
			<b>Estimated COD</b>	<b>Termination Date</b>	<b>BESS Termination Date</b>
Dry Lake East	Solar <sup>S,X=200(4hrs)</sup>	200.0	12/01/26	12/31/2051	12/31/2046
Libra Solar	Solar <sup>S,X=700(4hrs)</sup>	700.0	12/01/27	12/31/2052	12/31/2047
<b>Total</b>		<b>900.0</b>			
<b>Non-Renewable Purchase Agreements</b>					
<b>Renewable and Non-Renewable Sales</b>					
Switch NGR (Switch Station 1)	NGR Agreement (Sale of PCs)	100.0	08/08/17	12/31/2037	
Switch NGR-NPC (Switch Station 2)	NGR Agreement (Sale of PCs)	0.0	10/11/17	12/31/2037	
Notes:					
1. The geothermal and solar facilities are combined into <u>one</u> PPA.					
2. Facilities are either under development or construction (the dates shown are expected dates).					
3. Storage reflects current MW based on annual storage capacity test.					
4. NPC has an option to extend the Stillwater Geothermal/Solar PPA for a period of 3, 4 or 5 years upon the termination date.					
QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage					

**FIGURE ESP-38**  
**SIERRA LONG-TERM PPAs**

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date	BESS Termination Date
<b>Renewable Energy PPAs (Commercial)</b>					
Battle Mountain <sup>EWG</sup>	Solar <sup>S,X=24.2MW (4 hrs) 6</sup>	101.0	6/23/2021	12/31/2046	12/31/2031
Boulder Solar II <sup>EWG</sup>	Solar <sup>S</sup>	50.0	1/27/2017	12/31/2037	
Burdette <sup>QF</sup>	Geothermal	26.0	2/28/2006	12/31/2026	
Dodge Flat <sup>EWG</sup>	Solar <sup>S,X=50MW (4 hrs) 6</sup>	200.0	3/2/2022	12/31/2047	12/31/2037
Fish Springs Ranch <sup>EWG</sup>	Solar <sup>S,X=24.91MW (4 hrs) 6</sup>	100.0	3/15/2022	12/31/2047	12/31/2037
Galena 3 <sup>QF</sup>	Geothermal	26.5	2/21/2008	12/31/2028	
Hoope <sup>1,QF</sup>	Hydro	0.75	6/23/2016	12/31/2040	
Kingston <sup>1</sup>	Hydro	0.175	9/19/2011	12/31/2040	
Mill Creek <sup>1</sup>	Hydro	0.037	9/1/2011	12/31/2040	
Nevada Solar One (SPPC) <sup>QF</sup>	Solar <sup>T</sup>	22.1	6/27/2007	12/31/2027	
North Valley <sup>QF</sup>	Geothermal	25	4/26/2023	12/31/2048	
OWGP Beowawe <sup>QF</sup>	Geothermal	20.0	1/10/2025	12/31/2053	
RO Ranch <sup>1,2</sup>	Hydro	0	3/15/2011	12/31/2040	
Switch Station 2 (SPPC) <sup>EWG</sup>	Solar <sup>S</sup>	79.0	10/11/2017	12/31/2037	
Techren II <sup>EWG</sup>	Solar <sup>S</sup>	200.0	10/4/2019	12/31/2044	
Techren IV <sup>QF</sup>	Solar <sup>S</sup>	25.0	10/7/2020	12/31/2045	
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	
Turquoise <sup>EWG</sup>	Solar <sup>F</sup>	50.0	12/4/2020	12/31/2045	
USG San Emidio <sup>QF</sup>	Geothermal	11.75	5/25/2012	12/31/2037	
	<b>Total</b>	<b>944.6</b>			
<b>PC Purchase Agreement</b>					
TMWRF	Methane	0.8	9/9/2005	9/1/2026	
<b>PPAs (Pre-Commercial)<sup>3</sup></b>					
			<b>Estimated COD</b>	<b>Termination Date</b>	
<b>Ormat Western Geothermal Portfolio (OWGP)<sup>5</sup></b>					
OWGP Pinto <sup>QF</sup>	Geothermal	15.0	1/1/2027	12/31/2053	
OWGP Galena 1 <sup>QF</sup>	Geothermal	15.0	2/1/2027	12/31/2053	
OWGP Desert Peak 2 <sup>QF</sup>	Geothermal	10.0	2/1/2028	12/31/2053	
OWGP Lone Mountain <sup>QF</sup>	Geothermal	15.0	10/1/2028	12/31/2053	
OWGP Galena 3 <sup>QF</sup>	Geothermal	15.0	1/1/2029	12/31/2053	
OWGP TBD	Geothermal	30.0	TBD	12/31/2053	
Corsac Generating Station 2 LLC	Geothermal	115.0	2/1/2030	12/31/2045	
	<b>Total</b>	<b>215.0</b>			
<b>Storage Only (Pre-Commercial)<sup>3</sup></b>					
Dodge Flat Energy Storage	Solar & Grid Tied BESS <sup>150MW (4 hrs)</sup>	0.0	7/1/2027		12/31/2047
	<b>Total</b>	<b>0.0</b>			
<b>Non-Renewable Purchase Agreements</b>					
Liberty (CalPeco) EBSA <sup>7</sup>	Diesel	12.0	1/1/2011	12/31/2031	
	<b>Total</b>	<b>12.0</b>			
<b>Renewable &amp; Non-Renewable Sales Agreements</b>					
Liberty (CalPeco)	Full Requirements (Capacity/Energy/PCs)	See Note 4	12/30/2020	5/31/2027	
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. Portfolio consists of multiple facilities under one Power Purchase Agreement.					
6. Storage reflects current MW based on annual storage capacity test.					
7. Emergency backup service agreement for King's Beach Diesels.					
QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage					

## 1. RENEWABLE POWER PURCHASE AGREEMENTS

Nevada Power has executed 27 long-term renewable PPAs (see Nevada Power Figure ESP-34A above) representing a total nameplate capacity of approximately 2,723.8 MW.

Nevada Power has also executed three long-term PC only purchase agreements representing a total nameplate capacity of approximately 18.5 MW. Nevada Power's renewable purchase agreements secure a mix of solar, geothermal, hydro, methane, and wind resources.

Sierra has executed 21 long-term renewable PPAs representing a total nameplate capacity of approximately 944.6 MW (see Sierra Figure ESP-34B above). The latest commercial addition to the portfolio was OWGP Beowawe (20 MW), which achieved commercial operation in January 2025. Also, in June 2025, TCID New Lahontan terminated (-4 MW).

Sierra has executed one long-term PC only purchase agreement representing a nameplate capacity of 0.8 MW. Sierra's renewable PPAs secure a mix of solar, geothermal, and hydro resources.

## 2. NON-RENEWABLE POWER PURCHASE AGREEMENTS

Sierra has executed one long-term non-renewable PPA with Liberty, 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

Nevada Power has executed two long-term agreements under the NGR program for the sale of PCs to Switch Ltd. (associated with the output of the Switch Station 1 solar facility).

Sierra has executed five 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 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 May 31, 2027.

#### 4. CURRENT PORTFOLIO OPTIMIZATION PROCEDURES

The Companies' resource portfolio is adjusted continuously based upon many factors, including changes in expected load, changes in system conditions, system reliability needs, and changes in market conditions. The Companies continuously monitor the resources available to meet load obligations, recognizing the uncertainty not only in system conditions but also in regional energy markets organized across different commodities, locations, and trading timeframes. Forward prices are continuously monitored for comparison with the internal generation costs. As conditions change and new information becomes available, the Companies optimize their portfolio to account for changes in load, cost, volatility, reliability, and other commercial or technical factors.

Each month, the Companies assess their capacity and energy positions for the upcoming month by taking into account planned unit outages, available resources, forecasted system loads and forecasted reserve requirements. If the assessment shows that the Companies are expected to be short in terms of meeting system load and reserve requirements in the upcoming month, the Companies may purchase energy or capacity. The Companies utilize both RFP processes and direct negotiations with approved counterparties to fill short capacity and energy positions.

Short-term energy transactions may be made either for economic reasons or in order to maintain the reliability of the transmission grid. The circumstances in which adjustments may be made for reliability purposes include unexpected loss of generation due to forced outages or capacity constraints, imbalances between supply and demand of non-native load customers, actual loads being higher than the amount forecasted, and transmission constraints due to forced outages or other unanticipated contingencies impacting transmission facilities inside or outside the Companies' transmission network. In any of these circumstances, the transmission system may enter a condition under which, absent an adjustment to short-term transactions, one or more of the requirements of the applicable reliability standards will be violated. Operation in violation of the requirements of the applicable reliability standards poses undue risk to the reliable and secure operation of the bulk electric system and can also result in monetary sanctions for non-compliance. In addition to participation in the EIM as described above, the remedy for a negative imbalance between load and resources is the procurement of emergency resources to regain such balance and restore the required reserve margins.

The Companies also prepare day-ahead plans. On a daily basis, the Companies forecast their energy position and generation costs for the scheduling day using a production cost simulation model. Internal generation costs are compared to actual energy market prices to identify opportunities to sell into the market and mitigate customer costs. The Companies' traders determine actual energy market prices by communicating with other traders and by monitoring the Intercontinental Exchange ("ICE"), a trading platform for global commodity and financial

products marketplaces, including electronic energy markets. Purchase or sales opportunities are evaluated on the basis of economic and reliability considerations.

On the day of delivery, the Companies continue to compare hourly generation costs to hourly energy market prices, monitor hourly weather patterns and actual generation and transmission availability and costs, and assess hourly energy market conditions in order to balance loads and resources across the day. The Companies' traders ascertain real-time market conditions by conducting market surveys through communications with other counterparties. Again, purchase or sales opportunities are evaluated on the basis of economic and reliability considerations.

In the delivery operating hour, the power portfolio is further optimized through participation in the EIM operated by the CAISO. The EIM utilizes a security constrained economic dispatch model to dispatch resources in five-minute intervals in the participating balancing authority areas. Subject to state and federal regulatory approvals, the Companies began participating in the EIM on December 1, 2015. The Companies' traders determine which resources are available for participation in the EIM and voluntarily submit bids to the market operator for EIM purchases or sales. Participation in the EIM does not absolve the Companies from compliance with reliability standards or the obligation to meet customer demand.

## 5. CONTINUOUS MONITORING AND OPTIMIZATION OF THE POWER PORTFOLIO

As opportunities present themselves, the Companies can make forward power sales by entering direct negotiations with counterparties. Forward sales transactions can be pursued if there is confidence that a long capacity and/or energy position will exist and the transaction will yield positive economic benefits for bundled retail customers. The products to be sold on a forward basis may include heat rate call options, indexed power, fixed-price power, ancillary services products, or other products as approved. Also, forward power sales may be accompanied by forward gas procurement. The Companies will not make forward sales for delivery more than three seasons in advance (including the current gas season), unless authorized by the Commission.

Day-ahead or day-of power purchases and sales also continue to be made. If there is an open position or if system costs of decremental energy exceed the additional cost of market purchases, a purchase may be made. Similarly, if system costs of incremental energy are less than the market price, day-ahead or day-of power may be offered for sale.

## **B. SUMMARY OF POWER PROCUREMENT PLAN**

The Companies' proposed power procurement plan includes the following elements:

- The Companies propose to continue the four-season laddering strategy to fill the remaining open positions in summers of 2027, 2028, and 2029 .
- In addition to the request for proposal process, the Companies propose to negotiate and transact directly with counterparties. The Companies will evaluate all available products and determine the most prudent transaction plan based on cost and deliverability.
- The Companies will continue to monitor the portfolio on an on-going basis. If they determine that there is a need for additional capacity and/or energy, the Companies will procure any needed firm products through direct negotiations with counterparties or a competitive procurement process.
- Any proposed purchases of a duration greater than three years would be submitted to the Commission for approval in an IRP filing or Amendment.
- The Companies will continue to make purchases and sales to optimize the value of the overall supply portfolio for the benefit of their bundled retail customers.
- The Companies will monitor their renewable portfolio on a continuous basis to determine whether any additional renewable energy and PCs are required to ensure compliance with the RPS.

Each element of the proposed power procurement plan is discussed below.

## **C. OPEN POWER POSITIONS**

### **1. CAPACITY AND ENERGY POSITIONS**

As discussed in Section 2.B (Capacity Requirement), the Companies have a 850 MW open capacity position in 2027, 638 MW in 2028 and 1,513 in 2029. Therefore, the Companies plan to continue the four-season laddering strategy for the procurement of capacity to close the open position. This is similar to the strategy used for the procurement of physical natural gas. Specifically, and for example, the Companies plan to close up to the 2027 summer open position, a portion of the 2028 summer open position, and a portion of 2029 in the first and third quarters of 2027 through purchases of energy and/or capacity executed through a competitive procurement process, subject to the availability of conforming bids and the willingness of suppliers to accept

reasonable commercial terms. A schedule of procurement activity under the four-season laddering strategy is set forth in Figure ESP-39 below.

**FIGURE ESP-39  
PERCENTAGE OF REMAINING OPEN POSITION THAT IS CLOSED IN EACH  
TRANSACTION PERIOD**

Incremental transaction	Delivery				
	Summer 2026	Summer 2027	Summer 2028	Summer 2029	Summer 2030
Q3 2024	25%				
Q1 2025	25%				
Q3 2025	25%	25%			
Q1 2026	25%	25%			
Q3 2026		25%	25%		
Q1 2027		25%	25%		
Q3 2027			25%	25%	
Q1 2028			25%	25%	
Q3 2028				25%	25%
Sum	100%	100%	100%	75%	25%

The seasons in the four-season laddering strategy align the closure of the open power position with the seasonal procurement of physical natural gas. The magnitude of the open power position will be determined prior to each transaction cycle using the latest approved forecasts and energy supply availability schedules. For a given initial open position, procurement quantities should be approximately equal in each of the four seasons.

As discussed in Section 2.C (Energy Requirements), the Companies will continue to seek to execute short-term and forward purchases when economic or needed to serve native load. The Companies can meet the energy requirements of their customers with existing generation, forward products (such as call options or forward block power), and daily and/or real-time purchases.

The Companies' short-term energy requirements can vary due to factors such as: 1) changes in fuel and purchased power prices; 2) frequency and duration of planned and forced outages; and 3) changes in expected weather and load requirements. Shifts in gas and market energy prices may cause the Companies to run their generation facilities more or less often than projected (*i.e.*, it may become more economic to self-generate at a greater level than was expected or to buy more power in the open market than was anticipated). Unscheduled plant outages impact plant availability, and real-time changes in weather can impact the Companies' loads. These factors may significantly change electric generation requirements, resulting in unanticipated changes in natural gas usage.

As in the past, the Companies will monitor and continuously adjust their power portfolio in order to optimize the value of their assets for the benefit of bundled retail customers. If the Companies determine a need for additional capacity and/or energy above what is being projected in this ESP filing, they will procure required firm products using direct negotiations with counterparties as well as competitive procurement processes. Any proposed power purchases of greater than three years' duration will be submitted to the Commission for approval in an IRP filing or an IRP amendment. To the extent the Companies have a long position, they will survey the market to identify sales opportunities.

Load requirements and system parameters may change subsequent to preparation and filing of this ESP. Consequently, it is possible the requirement for firm products may also change sometime during the forecast period. As a general policy, should firm power products be required (or subsequently change), the Companies may issue RFPs to fill those short positions. The selection of products to fill open capacity and energy requirements will be based on a detailed evaluation of actual bids received. All responses will be evaluated at the time of the RFP process to ensure an appropriate portfolio is selected based on the then-current availability and price of products being offered. This evaluation will ensure that any contracts executed provide the least-cost option for necessary capacity and energy requirements, while minimizing price volatility and maintaining required system reliability.

## 2. POTENTIAL PRODUCTS

The products typically available to fill any short capacity and energy positions are as follows:

- *Call Options (Fixed or Heat Rate)* – Options have the advantage of flexibility. The buyer of the option has the right, but not the obligation, to buy an agreed-upon quantity of energy at a certain time in the future and at a specified price. In exchange for this flexibility to exercise or not exercise the option, a premium is paid to the seller up front. This payment only covers the right to exercise the option. An additional payment is paid to the seller each time the option is exercised. If the option is exercised, the buyer pays the seller the “strike price.” Generally, the strike price is either a fixed price or it is calculated by multiplying a fixed heat rate by a designated gas index for the day of delivery. Out-of-the-money options are likely not to be exercised due to their high strike price but serve as additional available capacity that can be called upon if necessary.

Typically, the Companies schedule energy deliveries in accordance with WECC scheduling procedures. These procedures call for the buyer of the option to exercise its right to the energy on a day-ahead basis for delivery the next scheduling day.

When exercised, the purchase is for the full capacity amount and for the time of day that was contracted e.g., on-peak, super-peak, etc.

- *Standard Firm Energy* – The price and quantity of these products are mutually agreed to between buyer and seller in advance, and the energy is “must take” over the period for which the contract is executed. In the western U.S., standard firm energy is typically transacted under WSPP Service Schedule C.
- *Unit Contingent Products* – The price and quantity of these products are mutually agreed to between buyer and seller in advance, and subject to generator availability the energy is “must take” over the period for which the contract is executed. In the event of a failure to perform due to forced outage from the sourcing generator, the seller is not subject to financial damages. Unit contingent power transactions are often executed under WSPP Service Schedule B.

The Companies issue RFPs or negotiate directly with counterparties to fill requirements and also monitor the products and prices that are available on trading platforms. Products are modeled using an electric system production simulation model to determine which supply options best fit with the load requirements and available resources in a least-cost manner.

### 3. RETAIL PRICE VOLATILITY

The Companies have controlled their exposure to the capacity component of market price volatility by building and contracting for efficient generation. The Companies will have firm generation and purchased power resources that total between 8,328 MW and 10,501 MW for the summer of 2026, and between 8,382 MW and 10,199 MW for the summer of 2027 (for more details see figure ESP 5.) Open position exposure to the wholesale purchase power market presents the greatest risk of retail price volatility. The Companies’ proposed power procurement strategy is intended to mitigate that risk.

### 4. RELIABILITY

The degree of reliability of a portfolio is directly proportional to the level of a secured commodity under the portfolio. In general, as the percentage of the portfolio that is open increases, reliability declines. Conversely, as the percentage of the portfolio that is closed increases, reliability improves.

As described in Section 2.B, the Companies developed a 12.5 percent PRM in the 2024 Joint IRP. The Companies’ 12.5 percent PRM provides a prudent level of assurance that reliable supplies will

be available in the event of currently unanticipated conditions, such as extreme weather conditions and forced outages on generation.

## 5. COMMERCIAL VIABILITY

As noted in recent filings, changes in climate, weather, resource variability, and market condition are impacting the western energy markets, requiring the Companies and stakeholders to reevaluate established practices to ensure sufficient capacity to meet peak demands during the summer. While the Companies have taken great strides in recent years to address the variability of renewable resources and their contribution to resource adequacy by enacting a new method of evaluating the hour with the largest open position in the ESP, updating the Effective Load Carrying Capability in the IRP, and updating the PRM, addressing changes in weather through the use of new trended weather load forecasts, as well as taking steps to reduce the open position in the IRP in response to concerns about market availability, the concern and focus remain on the uncertain availability and deliverability of market capacity and energy.

As discussed generally in part C.1 of this Section, the Companies will continue to monitor and continuously adjust their power portfolio in order to optimize the value of their assets for the benefit of bundled retail customers. In addition, the Companies will continue to evaluate supply options for potential IRP filings that will mitigate the risk associated with this growing market uncertainty.

## SECTION 5 – GAS PROCUREMENT PLAN

The Companies’ gas procurement plan includes a physical gas procurement plan, a gas transportation plan, and a gas hedging plan.

### A. PHYSICAL GAS PROCUREMENT PLAN

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. As described in this ESP filing, the Companies are proposing to continue to follow the physical gas procurement strategy reviewed and approved in Docket No. 09-07003.

Figure ESP-40 reflects the historic and planned implementation of the physical gas acquisition strategy.

**FIGURE ESP-40  
PHYSICAL GAS ACQUISITION STRATEGY**

Incremental Transaction	Delivery								
	Winter '25 '26	Summer '26	Winter '26 '27	Summer '27	Winter '27 '28	Summer '28	Winter '28 '29	Summer '29	Winter '29 '30
Q3 '25	25%	25%	25%	25%					
Q1 '26		25%	25%	25%	25%				
Q3 '26			25%	25%	25%	25%			
Q1 '27				25%	25%	25%	25%		
Q3 '27					25%	25%	25%	25%	
Q1 '28						25%	25%	25%	25%
Sum	100%	100%	100%	100%	100%	100%	75%	50%	25%

Additionally, the Companies monitor the natural gas portfolio monthly, weekly, and daily. The Companies will make short-term purchases and sales for balancing and optimization activities for the natural gas portfolio based on the needs of the system. This practice will continue over the ESP period.

The Companies continually evaluate their list of approved gas supplier counterparties and adjust as necessary to balance the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply. As the Companies go out for longer term gas supplies, there may be two identifiable issues which continue to require monitoring. The two items, already part of the Companies’ risk management processes, are:

- *Counterparty performance risk:* Given that the natural gas commodity industry is in constant change with gas marketers, gas producers, and commodity trading companies

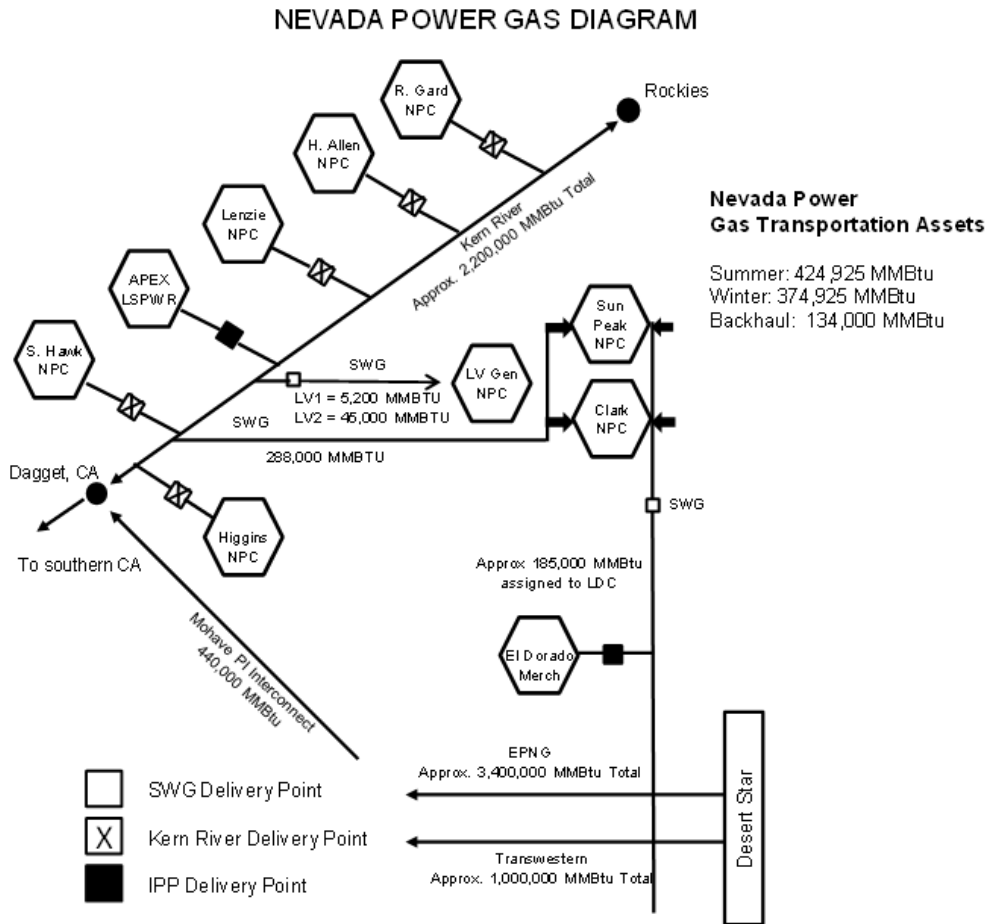
entering into, merging, and exiting the physical gas transaction marketplace, the Companies will continue to monitor counterparty activity in order to have adequate assurance that the business entity with the obligation to provide the physical commodity is able to perform per the terms and conditions of the agreement.

- *Credit Management:* The Companies recognize a need to be able to manage both credit exposure from any one specific counterparty, as well as potential collateral provided to any one counterparty. While utilization of index-priced transactions should serve to minimize both potential counterparty exposure and potential counterparty collateral requirements, these exposures are continually monitored to prevent any future contract performance misunderstandings. The Companies continue to monitor such exposure risks through existing policies and procedures.

## **B. GAS TRANSPORTATION PLAN**

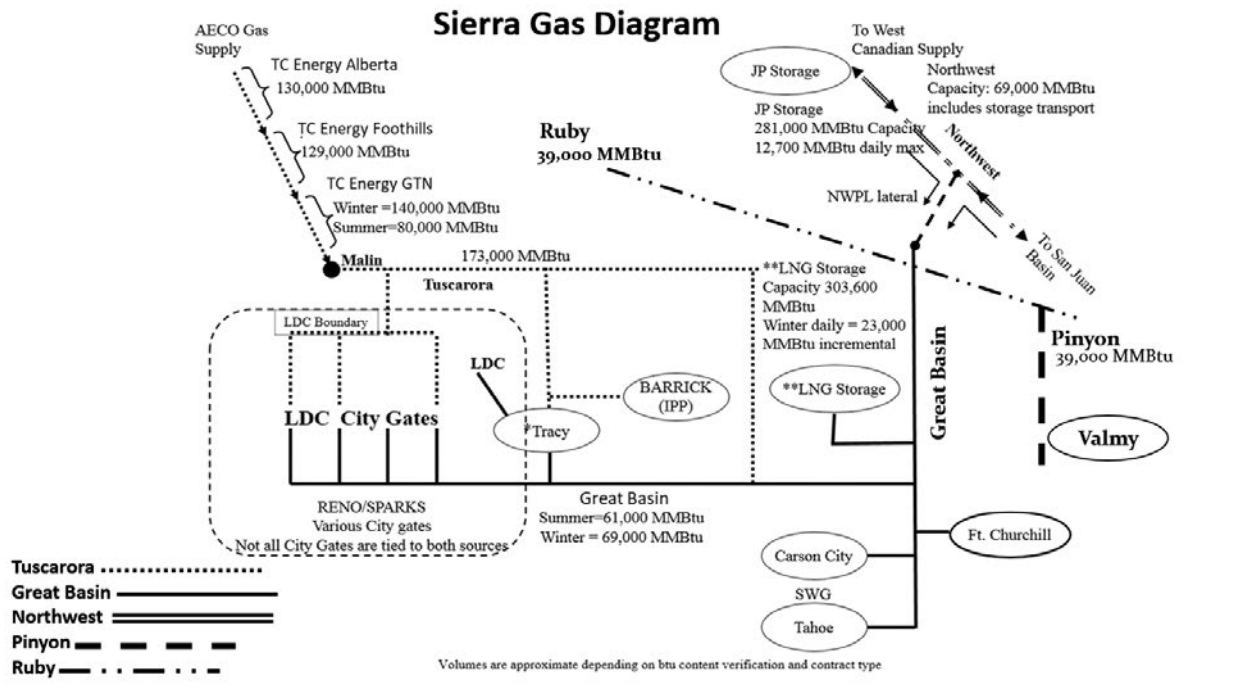
The Companies have access to the dominant supply basins serving the Pacific Northwest and the Desert Southwest per their existing firm gas transportation service agreements. These gas supply basins are the Rocky Mountain Basin, the Permian Basin, the San Juan Basin, British Columbia, Western Canada Sedimentary Basins, as well as California gas supply. The gas transportation facilities that are available to move gas from the supply basins to Nevada Power's and Sierra's service territories are shown in Figures ESP-41 and ESP-42, respectively.

**FIGURE ESP-41  
NEVADA POWER UPSTREAM PIPELINE SUPPLY**



Nevada Power takes delivery of natural gas from interstate pipeline Kern River, which connects 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.

**FIGURE ESP-42  
SIERRA UPSTREAM PIPELINE SUPPLY**



Sierra takes delivery of natural gas from three interstate pipelines, Great Basin, Tuscarora, and Ruby Pipeline (Ruby). Great Basin receives gas supplies upstream and downstream from Northwest Pipeline, 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 GTN, near Malin, Oregon, which is connected to the gas producing regions of Western Canada Sedimentary Basin Alberta through TC Energy’s pipeline 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 of Canada to the Alberta/British Columbia border. There, TC Energy’s Alberta system interconnects with TC Energy’s Foothills system, which transports gas to TC Energy’s GTN system at the U.S./Canadian border near Kingsgate, Idaho. GTN interconnects with Tuscarora near Malin. Sierra also takes natural gas delivery from Ruby to supply Valmy. The gas supply source for Ruby is the Rocky Mountain.

Figure ESP-43 lists Nevada Power’s existing gas transportation service agreements.

**FIGURE ESP-43  
NEVADA POWER NATURAL GAS TRANSPORTATION SERVICE AGREEMENTS**

**Nevada Power Company d/b/a NV Energy  
Gas Transportation Agreements**

Contract		Contract #	Termination Date (as of 7/1/2025)	Maximum Daily Quantity (MMBTUs)			Comments
Type	Counterparty			Annual	Winter	Summer	
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	7/31/2026	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 large portion 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 Gas 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 (Las Vegas Station Unit 1 - 5,200 MMBtu/day and Las Vegas Station Unit 2 45,000 MMBtu/day) with Southwest.

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 proposes to maintain its current natural gas transportation portfolio. As detailed in Section 2.E, Nevada Power's daily gas usage requirements during the summer exceed the current contracted capacity with Kern River. Nevada Power has adequately closed prior firm gas transportation open positions by purchasing delivered natural gas (the gas commodity bundled with gas transport) 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 future filings. 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 ESP-44 lists Sierra's existing gas transportation service agreements.

**FIGURE ESP-44  
SIERRA NATURAL GAS TRANSPORTATION SERVICE AGREEMENTS**

Contract Type	Counterparty	Contract #	Termination Date (as of 4/1/2026)	Units	Maximum Daily Quantity			
					Annual	Winter	Summer	
TSA	TC Energy - Alberta System	2010-447962	10/31/2027	GJ/Day	18,583			
		2010-447963	10/31/2027	GJ/Day	92,918			
		2010-447964	10/31/2027	GJ/Day	25,993			
						137,494		
	TC Energy - Foothills System	SIER - 9976	10/31/2027	GJ/Day	32,444			
		SIER - 9987	10/31/2027	GJ/Day	2,143			
		SIER - 9988	10/31/2027	GJ/Day	5,572			
		SIER - 9994	10/31/2027	GJ/Day	16,220			
		SIER - 9999	10/31/2027	GJ/Day	10,920			
		SIER - 10009	10/31/2027	GJ/Day	866			
		SIER - 9991	10/31/2027	GJ/Day	26,233			
		SIER - 10000	10/31/2027	GJ/Day	10,000			
		SIER - 10001	10/31/2027	GJ/Day	15,826			
		SIER - 10002	10/31/2027	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	6/30/2026	MMBTU/Day	59,696			
		10061	3/31/2027	MMBTU/Day	9,000			
					68,696			
	Great Basin Gas Transmission	F-29	11/30/2029	MMBTU/Day		68,696	61,044	
		F-32	3/31/2030	MMBTU/Day		23,000		
						91,696	61,044	
	Tallgrass Energy - Ruby Pipeline	961921	12/31/2049	MMBTU/Day	39,000			
	Tallgrass Energy - Pinyon Pipeline	962402	12/31/2049	MMBTU/Day	39,000			
	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	3/31/2030	MMBTU	303,604			
		S-6 LNG Daily Del Cap	3/31/2030	MMBTU/Day		23,000		

**Gas Transportation into Tuscarora.** In Canada, Sierra currently holds year-round firm transportation contracts on TC Energy’s Alberta system totaling 137,494 GJ/day. Downstream from TC Energy Alberta, Sierra holds year-round firm transportation contracts on TC Energy’s Foothills system totaling 136,031 GJ/day. Downstream from TC Energy Foothills, Sierra holds both year-round and seasonal firm transportation contracts on TC Energy’s GTN pipeline for 80,000 MMBtu/day and 140,000 MMBtu/day, respectively. Sierra holds 173,583 MMBtu/day of year-round firm transportation contracts on TC Energy – Tuscarora.

**Gas Transportation into Great Basin.** Sierra holds year-round firm transportation contracts on Northwest Pipeline totaling 68,696 MMBtu/day. On Great Basin, Sierra holds seasonal firm transportation contracts. The winter totals 91,696 MMBtu/day and the summer totals 61,044 MMBtu/day.

**Gas Transportation to Valmy.** Sierra holds a year-round firm transportation contract on Ruby Pipeline with a maximum daily quantity of 39,000 MMBtu/day. Sierra also holds a year-round firm transportation contract on Pinyon Pipeline with a maximum daily quantity of 39,000 MMBtu/day. Both contracts became effective January 7, 2026.

**Other Transportation and Storage.** Sierra also has storage assets along both Northwest Pipeline and Great Basin. The Northwest Pipeline 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. Each year Sierra evaluates opportunities to enter into an asset management agreement to further optimize these assets. The Great Basin storage is located at the H.G. Laub LNG plant and allows for 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 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.

The Companies’ natural gas transportation strategy is designed to maintain reliable fuel supply for existing operations while supporting future generation needs under the Preferred Plan. Nevada Power seeks approval to maintain its current transportation portfolio and continue relying on delivered natural gas transactions to manage periodic capacity shortfalls, particularly during peak summer periods. Sierra similarly seeks to maintain its existing portfolio, which has historically

been sufficient under normal conditions, while recognizing that load growth and extreme weather scenarios may result in the system running at or near maximum capacity.

Sierra proposes to maintain its current natural gas transportation portfolio. Many of Sierra's contracts have evergreen clauses and can be renewed for successive one-year extension periods. Given the results of the analysis detailed in Section 2.E, sponsored by the Companies' witness Mr. Charles McCutchen, the need to ensure reliability remains a critical focus of the LDC. Additionally, with the requirement in NAC § 704.9099(3) to maximize the reliability of fuel supply over the term of the ESP, Sierra proposes to continue to renew these contracts on an annual basis to ensure firm deliveries of gas supplies.

Additionally, in the IRP, Sierra is seeking approval for a pipeline expansion and additional transport capacity to support the Companies' Preferred Plan. The Preferred Plan includes the addition of approximately 1,223 MW of new natural gas generation at the Fort Churchill Generating Station ("Fort Churchill") between 2030 and 2032, requiring approximately 275,000 MMBtu per day of incremental natural gas supply. Sierra determined that existing pipeline capacity is fully subscribed and insufficient to meet these needs, necessitating a new pipeline expansion to Fort Churchill. Sierra engaged the three interstate pipelines in closest proximity to Fort Churchill - Great Basin, TC Energy, and Tallgrass Energy to evaluate pipeline expansion options. Great Basin currently owns Great Basin Pipeline that serves the Fort Churchill generation site and Sierra's LDC. TC Energy owns the Tuscarora Pipeline, which currently serves Sierra's Tracy Generating Station ("Tracy"), Fort Churchill, and Sierra's LDC. Tallgrass Energy owns the Ruby Pipeline and Pinyon Pipeline, which currently serves Valmy. All three pipelines proposed similar solutions involving new pipeline infrastructure interconnecting to the Ruby Pipeline, which has access to gas supply in the Rocky Mountains. Following a formal solicitation and evaluation process, which requested the three pipelines provide proposals on a pipeline expansion and requested that Tallgrass provide pricing on upstream capacity on the Ruby Pipeline, Sierra selected Great Basin for the pipeline expansion based on its ability to meet all technical and commercial requirements at the lowest overall transportation cost.

### **C. RECOMMENDED GAS HEDGING PLAN**

The Companies are seeking Commission approval of a hedging strategy for gas seasons 2027-2029 that uses no financial or fixed physical products to hedge their natural gas price exposure. If a change in strategy is warranted or necessary, the Companies will bring forward an ESP amendment or future ESP update for Commission approval.

## SECTION 6 – RISK MANAGEMENT STRATEGY

### A. ELEMENTS OF THE STRATEGY

Energy risk management involves the development and implementation of strategies to appropriately balance cost, risk, and reliability concerns. The Companies' energy supply risk management activities are the responsibility of the Resource Planning & Analysis Organization, which is described in the direct testimony of Ms. Janet Wells, the Risk Control Organization, which is described in the direct testimony of Mr. Adrian Cacuci, and the Resource Optimization Organization which is described in the direct testimony of Mr. Michael Holland.

Four areas are involved in the Companies' risk management and control processes:

1) **Risk Committee.** The Risk Committee, a formal Company interdepartmental executive forum organized and governed by NV Energy's Risk Management and Control Policy, is responsible for overall policy direction of the Companies' risk control activities and serves as the mechanism through which the Chief Executive Officer and senior management are kept apprised of inherent company-wide risks. The Risk Management and Control Policy (Technical Appendix RM-1) details the membership and specific responsibilities of the Risk Committee.

2) **Energy Supply.** Energy Supply, under direction of the Vice President of Generation and the Vice President of Resource Optimization, are responsible for the generation production, delivery and optimization of fuel and wholesale power transactions.

3) **Risk Control.** The Risk Control function, under the direction of the Vice President, Chief Financial Officer ("CFO") and the Treasurer, is responsible for monitoring compliance with established risk policies and associated procedures. All omissions and exceptions will be reported promptly to the Risk Committee.

4) **Credit Risk Management.** Credit risk is defined as the possibility that a counterparty will be unable or unwilling to timely fulfill its financial or physical obligations to the Companies because of the counterparty's financial condition. Credit Risk Management, under the direction of the CFO and The Treasurer, is responsible for managing and mitigating the Companies' credit risk exposures associated with energy and service delivery transactions. The Credit Risk Management and Control Policy is included as Technical Appendix RM-3.

The Risk Committee has several key responsibilities, including:

- Assessing the appropriateness of the Companies' energy supply risk management and control activities and making recommendations for modifications to existing risk policies;

- Approving changes and exceptions as designated in specific sections of the risk policies and ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Assessing the systems required to monitor, record, and report on the risks inherent in the Companies' energy supply related activities and making recommendations for improvements to existing risk policies;
- Approving ESPs, ESP updates and any exceptions to these plans;
- Reviewing all transactions requiring exceptions to the applicable policies and procedures;
- Reviewing all energy procurement and sale transactions that are not transacted in accordance with the ESP prior to the submission for approval of such transaction to the President;
- Reviewing all violations of notification thresholds and processes established under the risk policies, approving or recommending for approval remedies of the violations, and monitoring progress of such remedies; and
- Assigning the completion of any other activities to guide the overall policy direction of the Companies' energy risk management and control efforts.

Resource Planning & Analysis develops and maintains ongoing energy supply and risk management plans to systematically evaluate supply portfolio alternatives against a set of specific criteria monitored and reported by Risk Control. These criteria include transaction approval limits, test period mark-to-base, value at risk, and credit risk limits. This risk management approach includes: (1) the IRP covering the long-term resource and infrastructure needs and the plans to meet those needs; and (2) the ESP covering in detail the intermediate-term resource requirements and the plans to fulfill those requirements. Resource Optimization executes transactions that are consistent with the approved IRPs and ESPs. Material transactions that deviate from the approved plans are not executed without the prior approval of the Risk Committee.

Risk Control measures the Companies' energy portfolio exposures and compares measurements to the approved exposure notification thresholds. Reports are prepared to identify, track, and report compliance with the Companies' risk policies.

Credit Risk Management mitigates risk of the organization by reviewing potential transactions with counterparties to make sure they comply with credit limits. All potential transactions are reviewed to determine the counterparty's credit ratings, policy limits based on credit ratings, the

current mark-to-market exposure of all current transactions, and whether the potential credit exposure calculations are within the company policy limits.

## **B. ELEMENTS OF THE STRATEGY APPLIED TO THE ENERGY SUPPLY PLAN**

This ESP was prepared by the Resource Planning & Analysis Department, with additional input from the Rates & Regulatory, Renewable Energy & Origination, Generation, Resource Optimization, Revenue Requirements, Risk Control and Treasury groups.

The ESP is designed to achieve the objectives set forth in NAC § 704.9061 – minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of energy supply over the term of the ESP. However, it is not generally possible to minimize both cost and risk. For example, a completely open position may yield the lowest expected cost under certain assumptions, but it may carry significant risks associated with unforeseen events. Option contracts may eliminate the potential for retail price volatility, but the Companies may be required to incur a cost to compensate its counterparties for the price risk that has been shifted from the utility's customers to them. Thus, option contracts may not yield the lowest expected cost in all cases. The recommended strategies are designed to mitigate risk in the following respects:

**Evaluation of Options.** Risk minimization activities start with the planning process and the decisions for demand or supply options that are examined and eventually integrated into the Companies' IRP and ESP. Starting with the load forecast, the Companies establish customers' needs, including appropriate reserve margins. Once those needs are known, the options available to meet those needs are assessed. A part of that process is an examination of market fundamentals in the region, including the outlook for change over the planning horizon.

**Reduce Reliance on Volatile Wholesale Energy Markets.** As part of its longer-term risk management strategy and with a goal of reducing its exposure to volatility of the capacity portion (scarcity premiums) of the energy supply costs, the Companies pursue a strategy that relies on longer term power purchase contracts, and a multi-year laddering strategy.

**Use of Competitive Procurement Processes.** While the Companies have significantly reduced their open positions compared to previous years, they may issue a request for proposal if warranted to cover unanticipated needs at competitive costs. As part of the risk management plan, an economic analysis of the bid responses will be conducted, and the selected options will be referred to the Resource Optimization Department and Renewable Energy and Origination for negotiation and contracting as appropriate.

### **C. SELECTION CRITERIA**

The criteria used to select the Companies' risk management strategy are set forth in NAC § 704.9061 and include: cost of supply, retail price volatility, and reliability of energy supply.

### **D. EVALUATION CRITERIA**

The Risk Committee reviews the Companies' forward power and gas positions on a regular basis. To the extent that circumstances dictate a change in the Companies' procurement strategies, the Risk Committee would review and approve the changes, as appropriate.

In general, the criteria used to evaluate the effectiveness of the risk management strategy include the criteria set forth in NAC § 704.9061 and the metrics that are monitored by the Risk Control organization, which include:

- Test period Mark-to-Base
- Value-at-Risk
- Portfolio below investment grade
- Portfolio weighted-average credit rating
- Counterparty credit limit on-going transactions
- Counterparty credit limit large transactions

The Companies acknowledge that they may deviate from an approved ESP or ESP update in accordance with NAC § 704.9504 and accept the obligation to modify the strategy as conditions warrant.

**SECTION 7 – DETERMINATION OF PRUDENCE**

Pursuant to NAC §§ 704.9508(2) and 704.9494, the Commission can determine that the elements of an ESP are prudent if:

- The plan balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.
- The plan optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
- The plan does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

*This ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.* Based on results of the PLEXOS ST production cost forecasting model, Figure ESP-45 shows the estimated cost-to-serve for the recommended unhedged scenario under base, high, and low fuel and purchased power pricing scenarios.

**FIGURE ESP-45  
ESTIMATED COST TO SERVE (IN \$000)**

TOTAL FUEL AND PURCHASED POWER (F&PP) COSTS, EXCLUDING FIXED & VARIABLE OPERATIONS AND MAINTENANCE			
Year	Cost to Serve Assuming Low F&PP Prices (1,000s) (A)	Cost to Serve Assuming Base F&PP Prices (1,000s) (B)	Cost to Serve Assuming High F&PP Prices (1,000s) (C)
2027	\$1,631,995	\$1,920,909	\$2,360,460
2028	\$1,835,971	\$2,143,071	\$2,627,658
2029	\$2,257,163	\$2,675,708	\$3,357,285

The Companies also calculated the projected Base Tariff Energy Rates (“BTER”) and Deferred Energy Accounting Adjustment (“DEAA”) rates for 2027-2029 under the low, base, and high fuel

and purchased power price forecasts. The projected BTER and DEAA rates, along with estimated carrying charges, are presented in Technical Appendix GAS-2.

The expected cost-to-serve and BTER remain within a reasonable band under the Companies' proposed procurement strategies. The ESP provides for the procurement of sufficient firm resources to ensure reliable service to retail customers.

The production cost, BTER, and DEAA calculations and analysis, show that this ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of this plan.

***This ESP optimizes the value of the overall supply portfolio of the utilities for the benefit of their bundled retail customers.*** The Companies will continue to monitor and adjust the power portfolio in order to identify and account for changes in load, cost, volatility, reliability, and other commercial or technical factors. Day-ahead, day-of, or month-ahead power purchases are expected to be made if there is an open position, or if system costs of decremental energy exceed the additional cost of market purchases. Similarly, day-ahead or day-of power sales are expected to be made as opportunities arise, including spot, fixed price, indexed agreements, or ancillary services products, as specified in the Energy Risk Management and Control Policy (Technical Appendix RM-2). The Companies also intend to continue to seek opportunities for forward sales of heat rate ("HR") call options and/or other products through direct negotiations with counterparties or the issuance of reverse RFPs.

***This ESP does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utilities or would lead to a deterioration of the creditworthiness of the utilities.*** The Companies are able to finance this ESP without impairing their creditworthiness, assuming timely recovery under the Commission's current rate recovery mechanisms.

## **SECTION 8 – COMMISSION DIRECTIVES**

### **GAS HEDGING WORKSHOPS**

The Companies continue to conduct workshops bi-annually with the Staff and BCP and provide updates in the form of presentations for the remaining two quarters. Several topics are addressed, including energy market fundamentals, a monitoring matrix for potential gas hedging strategies, forward sales activity, gas procurement, and the most recent management decision on hedging.

Copies of the meeting presentations for the Gas Hedging Workshop held during the last three quarters of 2025 and the first quarter of 2026 are included as Technical Appendix GAS-1.

**ESP FPP-1**

**FILED UNDER CONFIDENTIAL SEAL**

**ESP ECON-1**

**FILED UNDER CONFIDENTIAL SEAL**

## **ESP ECON-2**



**Energy+Environmental Economics**

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# 2026 Sierra Subsystem Resource Adequacy Assessment

**Prepared for NV Energy, April 2026**

This document provides a brief description of E3’s 2026 Sierra Subsystem Resource Adequacy Assessment, conducted by E3 as in support of NV Energy’s 2026 Integrated Resource Plan (“2026 Joint IRP”). In this analysis, E3 applies loss-of-load-probability modeling to quantify the likelihood of resource deficiencies in NV Energy’s Sierra subsystem in 2027 and 2028, providing insight into potential near-term local reliability challenges and examining potential options available to NV Energy to mitigate any shortfalls that may exist.

## **Study Highlights**

**The Sierra subsystem is currently facing elevated reliability risks in 2027 and 2028.** The near-term growth projected in the 2026 Joint IRP load forecast will exceed the capabilities of resources and transmission that are currently existing and in development. The projected frequency of loss-of-load events, measured using loss-of-load-expectation (“LOLE”), is 2.1 days per year in 2027 and 1.3 days per year in 2028. Both values are significantly higher than the traditional “one-day-in-ten-year” standard of 0.1 days per year.

### **Reliability events may occur**

In both periods, loss-of-load events are most likely to occur

**While opportunities to develop new resources are limited in the very near term, multiple alternative options to reduce risk are possible;** the most impactful of potential solutions are contracting for existing firm generation in the region and a delay in the ramp of new large customer loads. Both are effective in their ability to mitigate reliability risks because of their relatively flat hourly profile, which allows them to meet both energy and capacity needs across critical risk periods.

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## Study Purpose

In support of NV Energy’s 2024 Joint Triennial Integrated Resource Plan (“2024 Joint IRP”), E3 conducted an analysis of the potential resource adequacy risks facing the Sierra subsystem in 2028 (“2024 Sierra Study”). This analysis, focused on evaluating the relative impacts of different transmission configurations (with and without the Greenlink Nevada projects), highlighted a potential near-term reliability risk in the Sierra subsystem; namely, with NV Energy’s load forecast and current resource portfolio at the time, the Sierra subsystem would face an elevated risk of resource deficiencies prior to the completion of the Greenlink Nevada projects if no additional resources in the north were developed.

Through the 2024 Joint IRP and First Amendment, NV Energy secured Commission approval to develop multiple new generation projects in the Sierra subsystem, including the natural gas-fired North Valmy Simple-Cycle Capacity Project (“Valmy CTs”) (400 MW), the Libra Solar Project with paired Battery Energy Storage System (“BESS”) (700 MW solar with 700 MW storage), and Dodge Flat BESS Addition (150 MW). Despite the addition of these new resources to the portfolio, multiple factors continue to pose challenges to near-term resource adequacy:

- Upward revisions to NV Energy’s load forecast since the 2024 Joint IRP, reflecting expectations of accelerating growth of large customers in the Sierra subsystem;
- Limited ability to import electricity from the south until the completion of Greenlink West and North; and
- Few potential options to develop new generation capacity in the north in the very near term given project development timelines.

Facing these constraints, NV Energy requested that E3 conduct an updated analysis of the near-term resource adequacy risks facing the Sierra subsystem. By applying the same loss-of-load-probability (“LOLP”) modeling techniques used in E3’s 2024 Resource Adequacy Study and the 2024 Sierra Study, this analysis seeks to answer two specific questions:

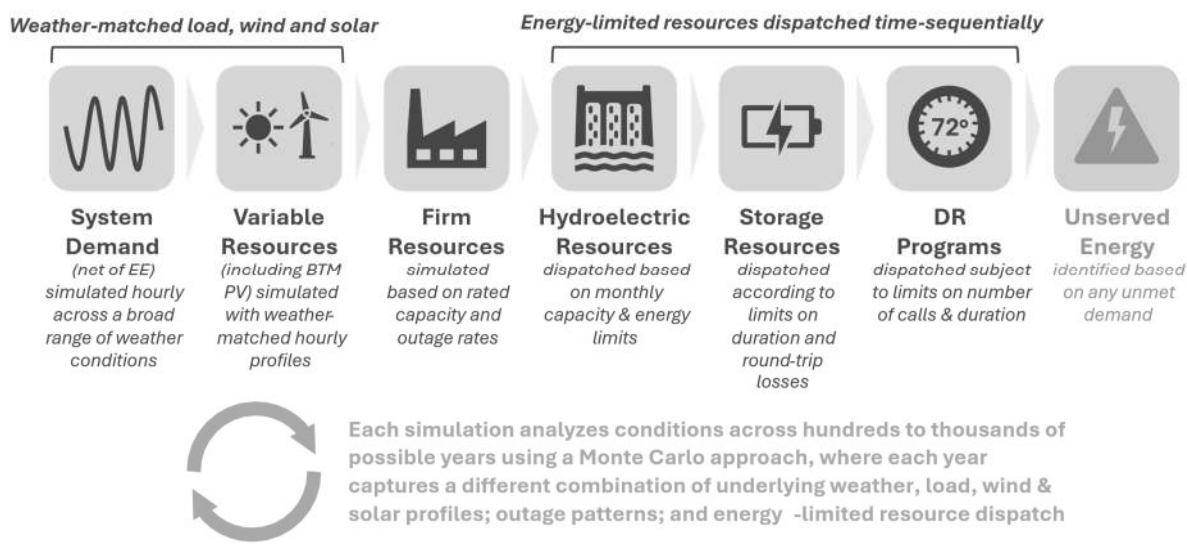
1. What level of reliability risk will the Sierra subsystem experience in 2027 and 2028 based on the current load forecast with existing and approved resources?
2. How can the risk of potential shortfalls be mitigated through measures – including new generation development, contracting for existing resources, rescheduling maintenance, and load mitigation?

## Modeling Approach

This analysis relies upon the same general methods as E3’s 2024 Sierra Study. Specifically, E3 utilizes RECAP to conduct LOLP analysis of the Sierra subsystem in 2027 and 2028, following the procedures outlined in Figure 1. Inputs and assumptions used in the modeling have been updated and refined since the 2024 Joint IRP to reflect planning assumptions used in NV Energy’s 2026 Joint IRP filing. Subsequent sections provide details on the specific assumptions used to characterize future loads, operating reserve needs, resource availability, and transmission in this analysis.

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Figure 1. General overview of Monte Carlo simulation methodology used in RECAP<sup>1</sup>



The primary outputs of relevance produced in this analysis are statistical measures of the likelihood, magnitude, and duration of potential resource deficiencies that may occur in the Sierra subsystem. This report focuses on **loss of load expectation (“LOLE”)**, a measure of the expected number of days per year on which reliability events would likely occur, as this can be easily compared to the traditional planning standard of “one day in ten years” (an LOLE of 0.1 days per year) to measure adequacy. The relative reliability is also expressed in terms of a “capacity shortfall” or (“surplus”) representing the amount of additional (or decremental) capacity that would be needed to achieve that standard.

**Comparison to E3’s System-Level Resource Adequacy Studies**

In addition to the and Sierra subsystem studies, E3 has conducted a number of system-level resource adequacy studies to support NV Energy’s IRP filings. While both types of studies utilize LOLP modeling, the outputs produced by the two types of studies differ due to their respective functions in NV Energy’s planning process. The purpose of the system-level studies is to establish planning reserve margin (“PRM”) and effective load carrying capability (“ELCC”) assumptions, which serve as direct inputs into NV Energy’s planning models and inform the creation of resource portfolios to satisfy system resource adequacy needs across the 20-year IRP time horizon. The Sierra studies, in contrast, seek to quantify the absolute level of reliability of the Sierra subsystem, assessing whether or not specific portfolios of resources are sufficient to meet loads with an acceptable level of reliability. To do so, these studies use LOLP modeling to quantify the frequency, size, duration, and timing of reliability risks, providing a concrete assessment of the reliability risks the subsystem may face under specified load and resource assumptions.

<sup>1</sup> This figure shows the general RECAP modeling methodology. Hydroelectric and demand response functionality are not used in this analysis.

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## Scenario Framework

E3 calculates statistical measures of reliability risk for a “Base Case,” reflecting NV Energy’s 2026 Joint IRP load forecast, existing resources, and future resources approved by the Commission; as well as a number of alternative “Mitigation” scenarios, which evaluate the impacts of a range of potential strategies to mitigate risks identified in the Base Case. The potential mitigation measures, identified by NV Energy, include:

- Procuring new solar and battery storage resources with in-service dates prior to 2029, including Fish Springs Energy Storage Addition (BESS) and Jersey Valley (PV and BESS);
- Contracting with existing generation resources located in the North for 100 MW of non-contingent firm generation;
- Adjusting the outage schedule for Tracy 3 during key risk periods in 2028;
- Upgrading the Cyrq Blue Mountain (“Cyrq”) geothermal facility;.
- Adding a resource that mimics a certain amount of delay in large customer load development.

Seven mitigation scenarios are evaluated in this analysis, each including one or more of these measures to evaluate their impacts on the reliability risk in the Sierra subsystem.

**Table 1. Elements included in each of the mitigation scenarios studied**

Mitigation Scenario ID	New Solar and Storage	100 MW Firm Contract	Tracy 3 Outage Adjustment	Cyrq Capacity Uprate	Large Customer Load Delay
1	●				
2		●			
3			●		
4	●	●	●		
5	●	●	●	●	
6					●
7		●			●

Finally, E3 conducted sensitivity analysis on the load forecast, evaluating reliability metrics for the Sierra subsystem under an alternate load forecast provided by NV Energy – the Base Minus Load Forecast. This alternative load forecast excludes many of the new large customers that result in the large expected increase in load in the Sierra subsystem.

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## Modeling Assumptions

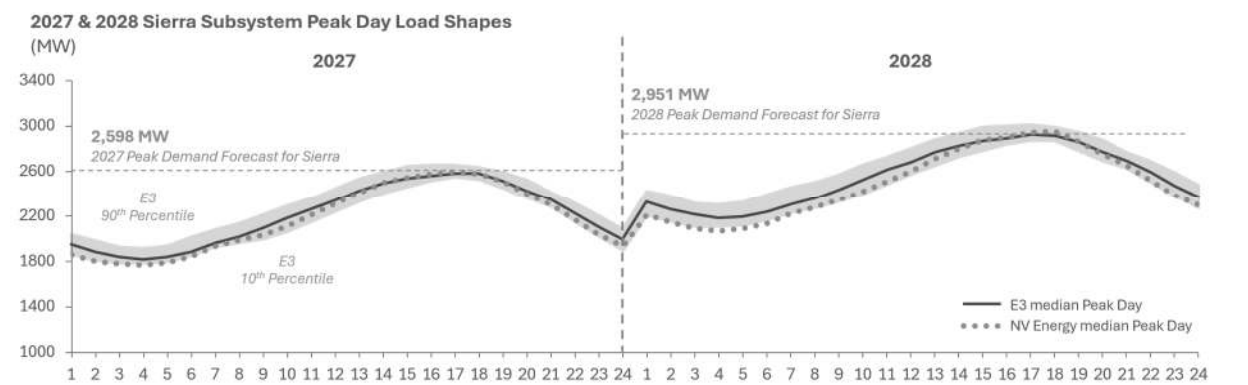
### Load Forecast

For this analysis, E3 repeated the load shape simulation and calibration process described in the 2024 Resource Adequacy Study to develop an hourly load shape consistent with NV Energy’s forecast for the Sierra subsystem that reflects conditions observed across the same 32-year weather record (1990-2021). At a high level, this process entails:

1. Collection of hourly historical load data (2015-2021, exclusive of 2020 due to load impacts of COVID) and hourly weather data (1990-2021);
2. Development of an artificial neural network model used to simulate hourly loads under today’s economic and demographic conditions across the full 32-year weather record (i.e. 32 years of distinct hourly load profiles, each representing a different underlying weather realization); and
3. Scaling and calibration of the resulting profile to align with forecasted annual energy, peak demand, and seasonal shape of NV Energy’s demand forecast for the Sierra subsystem in 2028.

Figure 2 compares NV Energy’s 2027 and 2028 peak demand forecast for Sierra against the range of forecasts developed by E3 representing the 32-year weather record from 1990-2021.

**Figure 2. Benchmarking of Sierra subsystem peak day load shape, E3 simulations across 32 weather years and NV Energy demand forecast (2027 and 2028)**



“E3 Median Peak Day” represents 50<sup>th</sup> percentile of peak day hourly demands across 32 weather years simulated (1990-2021). Shaded range represents 10<sup>th</sup> and 90<sup>th</sup> percentile of simulated peak day hourly demands across the same weather record.

### Operating Reserve Requirements

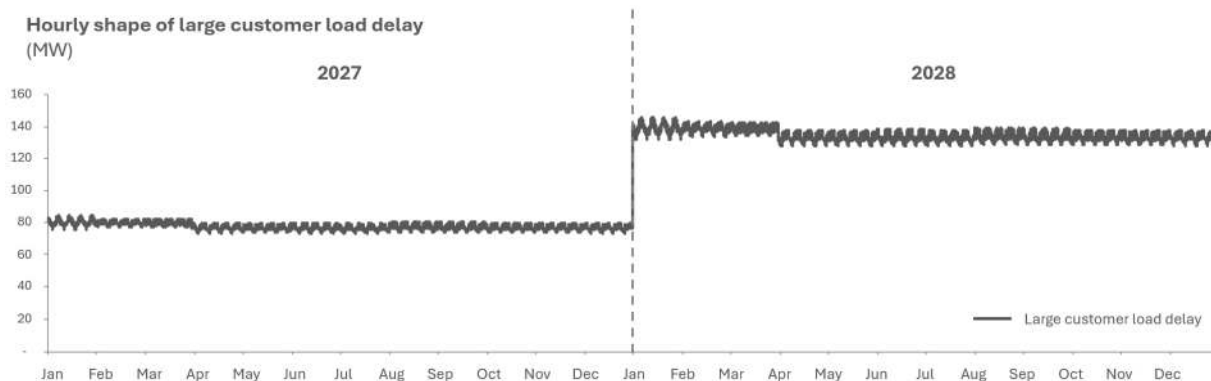
This analysis includes an operating reserve requirement equal to 3 percent of load plus 51 MW of static reserve – reserves held for Open Access Transmission Tariff customers – based on input provided by NV Energy.

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**Mitigation Options**

Mitigation scenarios 6 and 7 include a reduction in load that is intended to reflect the potential for a delay in the interconnection of large customers included in the Base load forecast. This reduces load in 2027 by a maximum of 83 MW and in 2028 by a maximum of 146 MW. The shape of the load deducted from the Base load forecast is relatively flat, reflecting the characteristic high load factor of new large customers in the North. The hourly profile for this load is shown in Figure 3.

**Figure 3. Hourly shape used to represent load impact of large customer load delay**



**Sensitivity Analysis**

In addition to NV Energy’s Base load forecast, this study also evaluates the near-term reliability risk levels in the Sierra subsystem under NV Energy’s Base Minus load forecast.

**Resource Portfolio**

The Base Case in this analysis focuses on NV Energy’s current portfolio of resources physically located in the Sierra subsystem, including both existing resources and future resources that have been approved by the Commission. This portfolio comprises a diverse mix of natural gas, geothermal, wind, solar, and battery storage resources. The composition of this portfolio by technology is shown in Table 2.

Each resource’s availability in RECAP on an hour-to-hour basis is represented using the same methods and assumptions described in depth in the 2024 Resource Adequacy Study:

- Availability of natural gas resources are simulated stochastically based on their rated capacities and assumed outage rates;
- Solar, wind, and geothermal resources are modeled with hourly profiles, developed from NREL’s WIND Toolkit, NREL’s System Advisor Model, and historical data provided by NV Energy, respectively; and

Energy storage resources are dispatched on an hour-to-hour basis subject to constraints on state of charge and accounting for round-trip losses.

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**Table 2. Rated capacity by resource (existing and under development)**

Resource Type	Plant Name	Rated Capacity (MW)	In-Service Date	Retirement Date
<b>Natural Gas</b>	Tracy 3	92	10/1/1974	12/31/2038
	Tracy 4/5	104	12/1/1996	12/31/2049
	Tracy 8/9/10	580	7/1/2008	12/31/2049
	Valmy 1	127	1/1/2026	12/31/2049
	Valmy 2	134	5/16/2026	12/31/2049
	Valmy 3	208	6/1/2028	6/1/2058
	Valmy 4	208	6/1/2028	6/1/2058
	Clark MT 3	69	7/1/1994	12/31/2044
	Clark MT 4	69	7/1/1994	12/31/2044
	Ft. Churchill 1	98	9/1/1968	12/31/2038
	Ft. Churchill 2	98	9/1/1971	12/31/2038
<b>Geothermal</b>	Stillwater	14	10/10/2009	12/31/2029
	Blue Mountain	24	11/20/2009	12/31/2029
	Desert Peak 2	11	4/17/2007	12/31/2027
	Galena 3	11	2/21/2008	12/31/2028
	Jersey Valley	9	8/30/2011	12/31/2031
	McGinness Hills	85	6/20/2012	12/31/2032
	North Valley	26	4/1/2022	12/31/2048
	Ormat-Beowawe	24	1/1/2025	12/31/2053
	Ormat-Desert Peak 2	11	2/1/2028	12/31/2053
	Ormat-Galena 1	16	2/1/2027	12/31/2053
	Ormat-Lone Mountain	20	10/1/2028	12/31/2053
	Ormat-Pinto	17	1/1/2027	12/31/2053
	Salt Wells	11	9/18/2009	12/31/2029
	San Emidio	10	5/25/2012	12/31/2037
	Tuscarora	15	1/11/2012	12/31/2032
<b>Solar</b>	Ft. Churchill	10	8/5/2015	8/4/2041
	Stillwater PV	16	3/5/2012	12/31/2029
	Turquoise	48	12/4/2020	12/31/2045
	Battle Mountain	97	6/23/2021	12/31/2046
	Dodge Flat	185	3/2/2022	12/31/2047

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Resource Type	Plant Name	Rated Capacity (MW)	In-Service Date	Retirement Date
	Fish Springs Ranch	92	3/14/2025	12/31/2047
	Sierra Solar	447	4/1/2027	3/31/2057
	Libra PV	695	12/1/2027	12/1/2052
	Liberty Luning PV	50	1/1/2021	12/31/2027
	Liberty Turquoise PV	8	1/1/2021	12/31/2027
<b>Storage</b>	Chukar 1	10	6/1/2021	12/31/2046
	Battle Mountain	23	6/23/2021	12/31/2031
	Dodge Flat	50	3/2/2022	12/31/2037
	Fish Springs Ranch	25	3/14/2025	12/31/2037
	Sierra Solar	400	7/1/2026	6/30/2046
	Libra BESS	700	12/1/2027	12/1/2052
	Dodge Flat BESS Addition	150	12/1/2027	6/30/2047
<b>Wind</b>	Spring Valley	152	8/16/2012	12/31/2032

**Mitigation Options**

Several additional potential resource opportunities are included in select Mitigation scenarios. These resources include:

- Contracting with an existing generation facility in the North for 100 MW of firm, non-contingent generation in 2027 and 2028
- Fish Springs, a BESS with 75 MW of capacity
- Jersey Valley, a PV-BESS hybrid with 67.2 MW of solar and 67 MW of BESS capacity
- Upgrading the Blue Mountain geothermal facility, increasing its maximum capacity output by 5 MW

***Planned Outage Schedules***

Planned outage schedules for thermal resources for 2027 and 2028 were provided by NV Energy. Planned outages generally reflect routine annual scheduled maintenance – [REDACTED] – and seasonal operational schedules. The periods during which thermal resources are on planned outages are shown in the table below:

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**Table 3. Planned outage schedules for thermal plants**

**Mitigation Options**

*Transmission*

Import capability from the Nevada Power subsystem changes over time with the completion of the Greenlink Nevada transmission projects. For this analysis, import capability from the South is assumed to be:

- 600 MW from 1/1/2027 to 12/31/2027 (prior to the completion of Greenlink West)
- 644 MW from 1/1/2028 to 12/31/2028 (following the completion of Greenlink West, prior to the completion of Greenlink North).

The end of the time horizon considered in this analysis (through 12/31/2028) coincides with the current planned in-service date for Greenlink North, when import capability would increase to a total of 2,255 MW due to a combination of factors.

Within the LOLP simulation, the import capacity is represented as a perfectly available resource. This approach is not intended to suggest that resources necessarily will be available to fill transmission lines at all times, but instead provides a means of conditional loss-of-load-probability analysis: if resources are available within the NV Energy joint system, to what extent can they be delivered to Sierra’s loads? This approach provides a useful means of understanding the degree to which the import limit will impact the reliability of the Sierra subsystem.

## Results

### Base Case Reliability Metrics

In both years, NV Energy’s current portfolio of resources are insufficient to meet the one-day-in-ten-year standard, and the Sierra subsystem experiences a level of reliability that is far lower than what would be considered acceptable in most modern electricity systems. In 2027, the observed loss of load expectation is **2.1 days per year**, implying that loss-of-load events would occur with over twenty times the frequency as in a system planned to a traditional one-day-in-ten-year standard. In 2028, the LOLE is **1.3 days per year**, still thirteen times greater than the traditional standard. These results, along with the corresponding “capacity shortfall” – the amount of additional perfect generation capacity needed to restore the system to an LOLE of 0.1 days per year – are reported in Table 4.

**Table 4. Reliability metrics for the Sierra subsystem under Base Case assumptions**

ID	Scenario	2027 System		2028 System	
		Capacity Shortfall (MW)	Loss of Load Expectation (days/yr)	Capacity Shortfall (MW)	Loss of Load Expectation (days/yr)
0	Base Case	229	2.08	146	1.28

The incidence of this elevated loss-of-load risk – along with a timeline of key events that impact the risk profile across these twenty-four months – is shown in Figure 4. Four key periods are notable in this diagram:



- Summer 2028:** despite continued load growth, the addition of new resources (including Libra PV/BESS and the Valmy CTs) and the increase in import capability resulting from the completion of Greenlink West are sufficient to reduce risk significantly relative to summer 2027.

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Figure 4. Monthly loss of load expectation (days per year) and timeline of key events, 2027-2028

Loss of Load Risk by Month (days per year)



Figure 5 shows what times of day reliability events are most likely to occur. [REDACTED]  
[REDACTED]  
[REDACTED]  
[REDACTED]  
[REDACTED]  
[REDACTED]

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**Figure 5. Month-hour incidence of loss-of-load risk in 2027 and 2028**



Figure 6 shows the timing and relative level of reliability risk throughout the year along and how those periods coincide with the two key drivers of risk: [REDACTED]

[REDACTED]

[REDACTED] This unique risk profile is the result of several factors:

[REDACTED]

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[Redacted text block]

**Figure 6. Daily peak demand, natural gas generation availability, and expected unserved energy**



Figure 7 shows an example of one of the more severe risk periods simulated across the full sample of events, [Redacted text]

[Redacted text block]



[Redacted text block]

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Figure 7. [Redacted]



*Impacts of Risk Mitigation Measures*

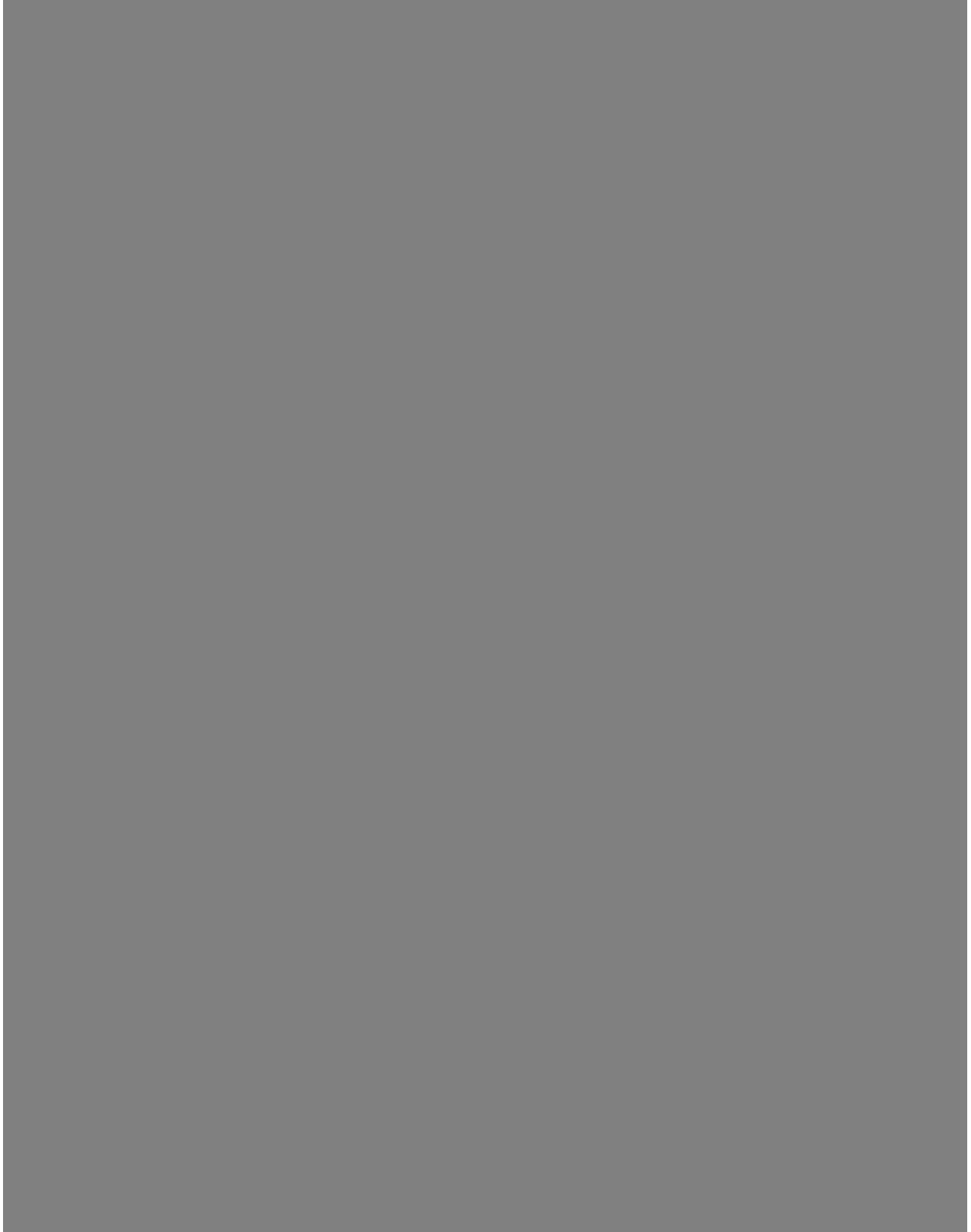
Based on direction from NV Energy, E3 evaluated how risk levels would be impacted by a variety of measures. The impacts of the seven mitigation scenarios are shown in Table 5. Table 6 provides short descriptions of the key changes implemented in each mitigation scenario and the resulting impacts on the reliability of the system in 2027 and 2028.

**Table 5. Reliability statistics for the Base Case and seven Mitigation scenarios evaluated**

ID	Scenario	2027 System		2028 System	
		Capacity Shortfall (MW)	Loss of Load Expectation (days/yr)	Capacity Shortfall (MW)	Loss of Load Expectation (days/yr)
<b>0</b>	<b>Base Case</b>	<b>229</b>	<b>2.08</b>	<b>146</b>	<b>1.28</b>
<b>1</b>	New PV/BESS Resources	n/a	n/a	140	1.13
<b>2</b>	100 MW Firm Contract	133	0.61	48	0.26
<b>3</b>	Tracy 3 Outage Adjustment	n/a	n/a	81	0.47
<b>4</b>	New PV/BESS Resources, 100 MW Firm Contract and Tracy 3 Outage Adjustment	133	0.61	-33	0.04
<b>5</b>	New PV/BESS Resources, 100 MW Firm Contract, Tracy 3 Outage Adjustment and Cyrq Capacity Uprate	124	0.60	-34	0.04
<b>6</b>	Large Customer Load Delay	156	0.81	9	0.11
<b>7</b>	100 MW Firm Contract and Large Customer Load Delay	58	0.2	-89	0.01

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**Table 6. Explanation of impacts observed in Mitigation scenarios**

A large, solid gray rectangular area covers the majority of the page, indicating that the content of Table 6 has been redacted. The table's structure, including its columns and rows, is not visible.

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### ***Sensitivity Analysis Results***

The Base Minus load forecast evaluated as a sensitivity is a significantly lower level of demand than the Base load forecast. Under this lower forecast, NV Energy's current resource portfolio is sufficient to make reliability risk very low in 2027 (an LOLE of 0.01 days per year) and negligible in 2028 (no loss of load events observed across all simulations).

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Table 7. Reliability statistics for the Base Case and Base Minus sensitivity

ID	Scenario	2027 System		2028 System	
		Peak Demand (MW)	Loss of Load Expectation (days/yr)	Peak Demand (MW)	Loss of Load Expectation (days/yr)
0	Base Case	2,598	2.08	2,951	1.28
8	Base Minus Load Forecast Sensitivity	2,248	0.01	2,240	0.00

## Conclusions

The results of this analysis highlight the potential for the emergence of near-term resource deficiencies in the Sierra subsystem and serve to identify near-term actions that would effectively mitigate those risks:

- Without additional action, the Sierra subsystem will face elevated reliability risks in 2027 and 2028.** The expected frequency of reliability events, measured using loss of load expectation, is 2.1 days per year in 2027, meaning that reliability events would be over twenty times more likely to occur than in a system planned to the traditional standard of 0.1 days per year. In 2028, the frequency decreases to 1.3 days per year (thirteen times greater than the traditional standard), reflecting anticipated changes in loads and resources.
- Reliability events may occur in both traditional and non-traditional risk periods.** In 2027, the highest risks are observed [REDACTED]
- While opportunities to develop new resources to address potential shortfalls are limited in the near term, multiple alternative options to reduce risk are possible.** Among the options evaluated to mitigate reliability risks, the three that are most effective are (1) a 100 MW contract for existing firm generation (2027 and 2028); (2) a delay in large customer load development (2027 and 2028); and (3) an adjustment to the Tracy Unit 3 outage schedule (2028 only). In combination, these measures reduce the frequency of reliability events to levels that approach the traditional one-day-in-ten-year standard in 2027 and exceed it in 2028. Other mitigation options explored, including the addition of solar and storage resources and uprating of existing geothermal capacity, showed limited impact.

Additionally, the results of this study – in conjunction with E3’s previous evaluations of resource adequacy in the Sierra subsystem – have important implications for NV Energy’s longer-term operations, planning and procurement efforts. Namely:

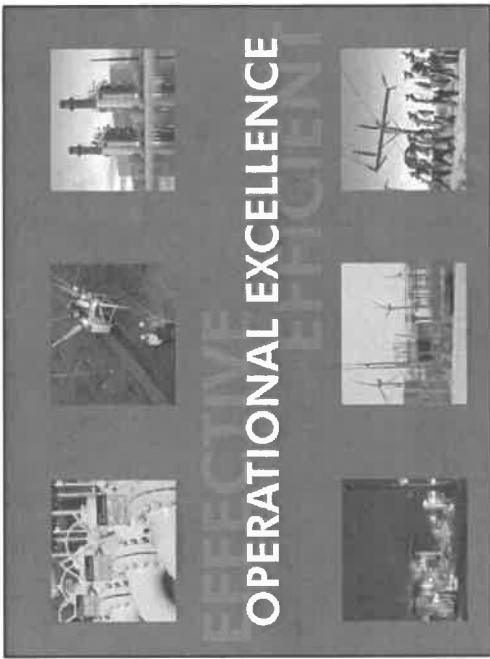
- Beyond 2028, depending on load growth, the Sierra subsystem may require local resource additions to maintain local resource adequacy.** In 2029, the reliability risk facing the Sierra subsystem is expected to subside relative to 2028 due to (1) the presence of the Valmy CTs, and (2) the completion of Greenlink North and the Southwest Intertie Project -

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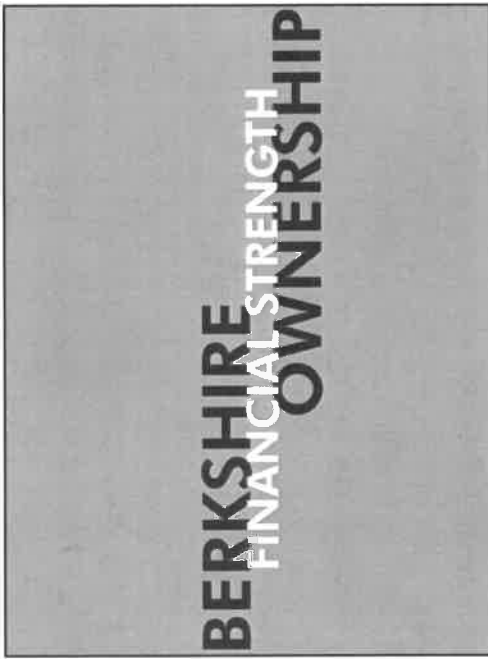
North (constructed by others), which jointly increase the import capability of the Sierra subsystem to 2,255 MW. However, NV Energy's current load forecast for the Northern system continues to grow at roughly 300 MW per year beyond 2028, which would quickly erode the headroom that is present in 2029. Under these circumstances, additional resources or investments in additional transmission to increase import capability would be needed to avoid elevated reliability risks due to local constraints.

- **Because the risk profile for the Sierra subsystem is distinct from NV Energy's joint system, the comparative effectiveness of potential solutions in addressing local resource shortfalls may also differ from their value to the system.** The types of reliability events observed in the Sierra subsystem – events that result from storage insufficiency, extended plant outages, and periods of low renewable output – tend to reflect a system that is often “energy-constrained,” rather than “capacity-constrained.” As the expected growth within the Sierra subsystem is predominantly from large customers with high load factors, the diurnal and seasonal shape of Sierra's load is expected to become increasingly flat, exacerbating the potential for reliability risks driven by energy insufficiency. Under such circumstances, firm resources (e.g. natural gas, geothermal) that are able to sustain output at or near maximum capacity address the local reliability needs more effectively than variable or energy-limited resources.

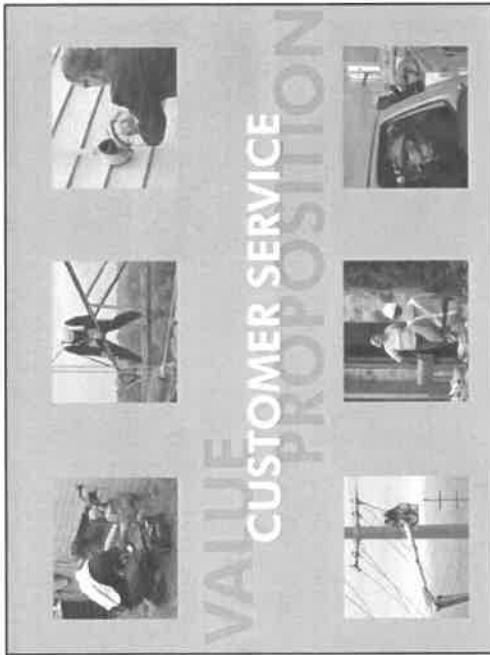
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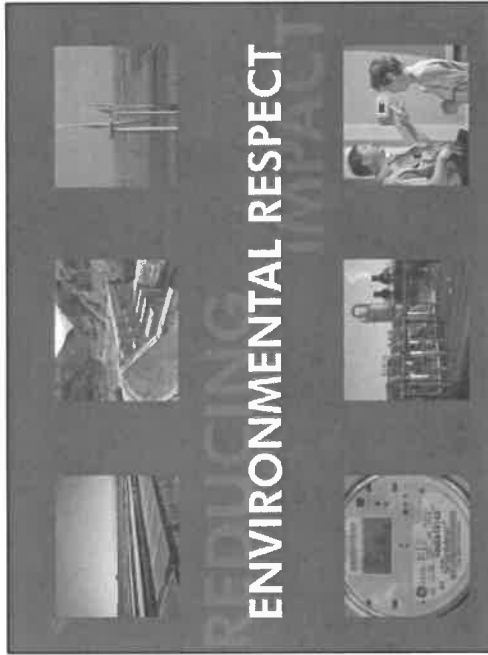
**OPERATIONAL EXCELLENCE**



**BERKSHIRE**  
FINANCIAL STRENGTH  
OWNERSHIP



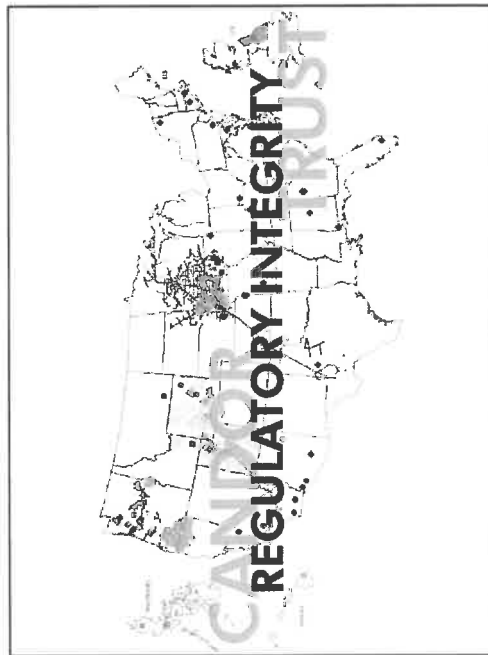
**CUSTOMER SERVICE**



**ENVIRONMENTAL RESPECT**



**EMPLOYEE COMMITMENT**



**REGULATORY INTEGRITY**

# Q2 2025 Natural Gas Hedging Workshop

June 27, 2025

## Market Fundamentals Overview

- ✓ U.S. Natural gas consumption in the U.S. electric power sector is the primary source of natural gas consumption in the summer, as electricity is used to meet demand for air conditioning during warmer weather months. EIA forecasts natural gas consumed to generate electricity in the U.S. in June, will be up 26% from May. Weather forecast at the same time assumes 3% more cooling degree days (CDDs) than the 10-year average across the U.S. from June through September and about the same number of CDDs as last year during those months [EIA, Short-Term Energy Outlook, June 2024].
- ✓ EIA in its June Outlook expects the price of natural gas delivered to the power sector to average about \$3.84 per million British thermal units (MMBtu) from June through September (see slides on pages 5 and 6), or \$1.39/MMBtu more than that period in 2024 [EIA, Short-Term Energy Outlook, June 2024].

## Market Fundamentals Overview

- ✓ Net injections into storage totaled 96 billion cubic feet (Bcf) for the week ending June 20, compared with the five-year (2020–24) average net injections of 79 Bcf and last year's net injections of 59 Bcf during the same week. Working natural gas stocks totaled 2,898 Bcf, which is 179 Bcf (7%) more than the five-year average and 196 Bcf (6%) lower than last year at this time. The average rate of injections into storage is 28% higher than the five-year average so far in the refill season (April through October). If the rate of injections into storage matched the five-year average of 7.8 Bcf/d for the remainder of the refill season, the total inventory would be 3,932 Bcf on October 31, (see slide on pg. 7) which is 179 Bcf higher than the five-year average of 3,753 Bcf for that time of year. [EIA, Natural Gas weekly Update, June 26, 2025].

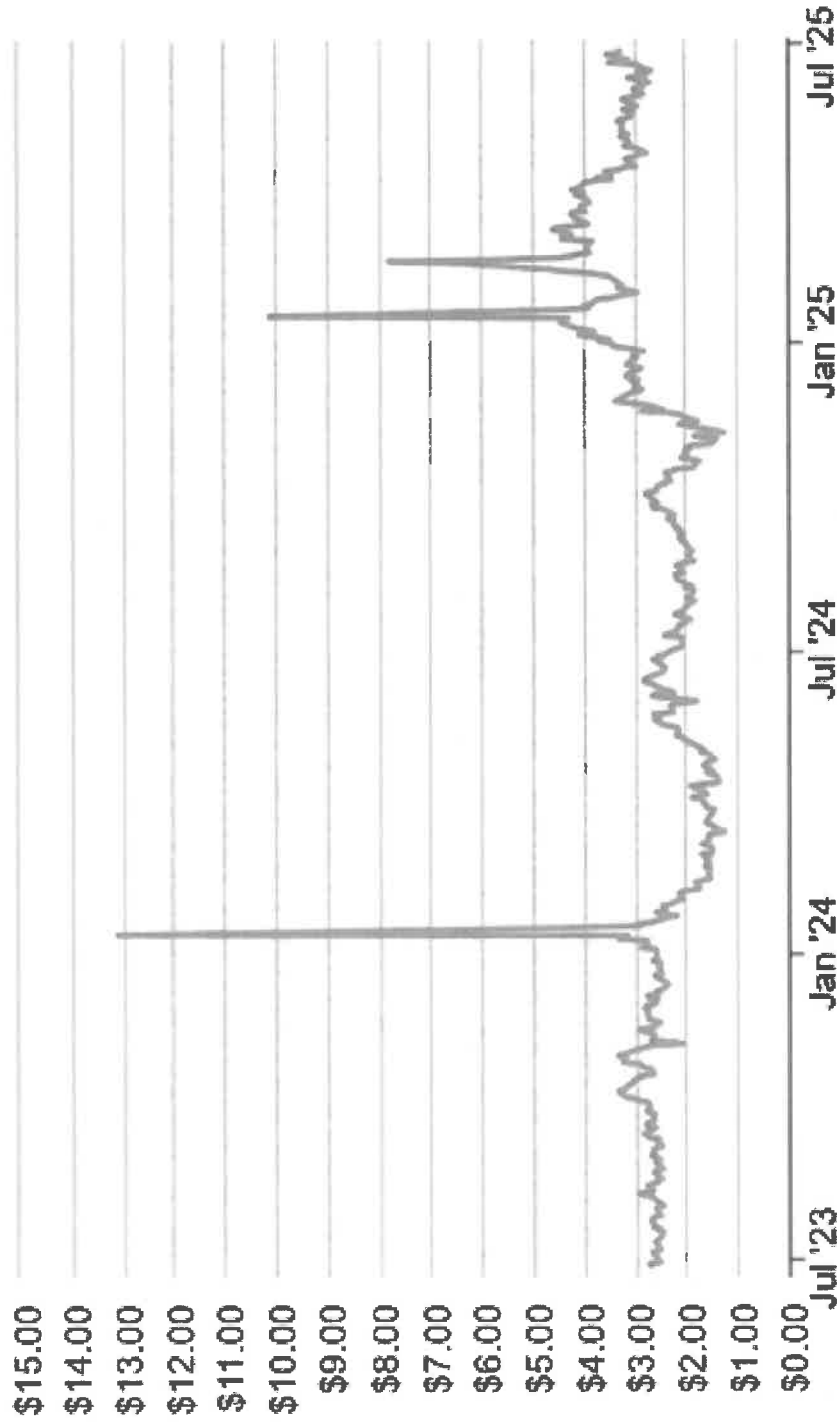
## Market Fundamentals Overview

- ✓ Natural gas exports are the main driver of growth in U.S. natural gas demand in EIA forecast. Two liquefied natural gas (LNG) export facilities—Plaquemines LNG Phase 1 and Corpus Christi Stage 3—started production in December 2024. Two additional LNG developments—Golden Pass and Plaquemines LNG Phase 2—are expected to come online over the next two years. As a result, LNG exports are forecasted to increase 22% in 2025 and 10% in 2026. Additional growth in natural gas demand comes from pipeline exports, which are forecasted to increase by 8% in 2025 and 7% in 2026. In total, natural gas exports are expected to increase by 3.4 Bcf/d in 2025 and 2.1 Bcf/d in 2026. Plaquemines LNG has ramped up production and exports of LNG faster than anticipated earlier this year, highlighting the uncertainty that project timelines can have on natural gas balances. [EIA, Short-Term Energy Outlook, June 2025].

# U.S. Natural Gas Prices



**Natural gas spot prices (Henry Hub)**  
dollars per million British thermal units



Data source: Natural Gas Intelligence

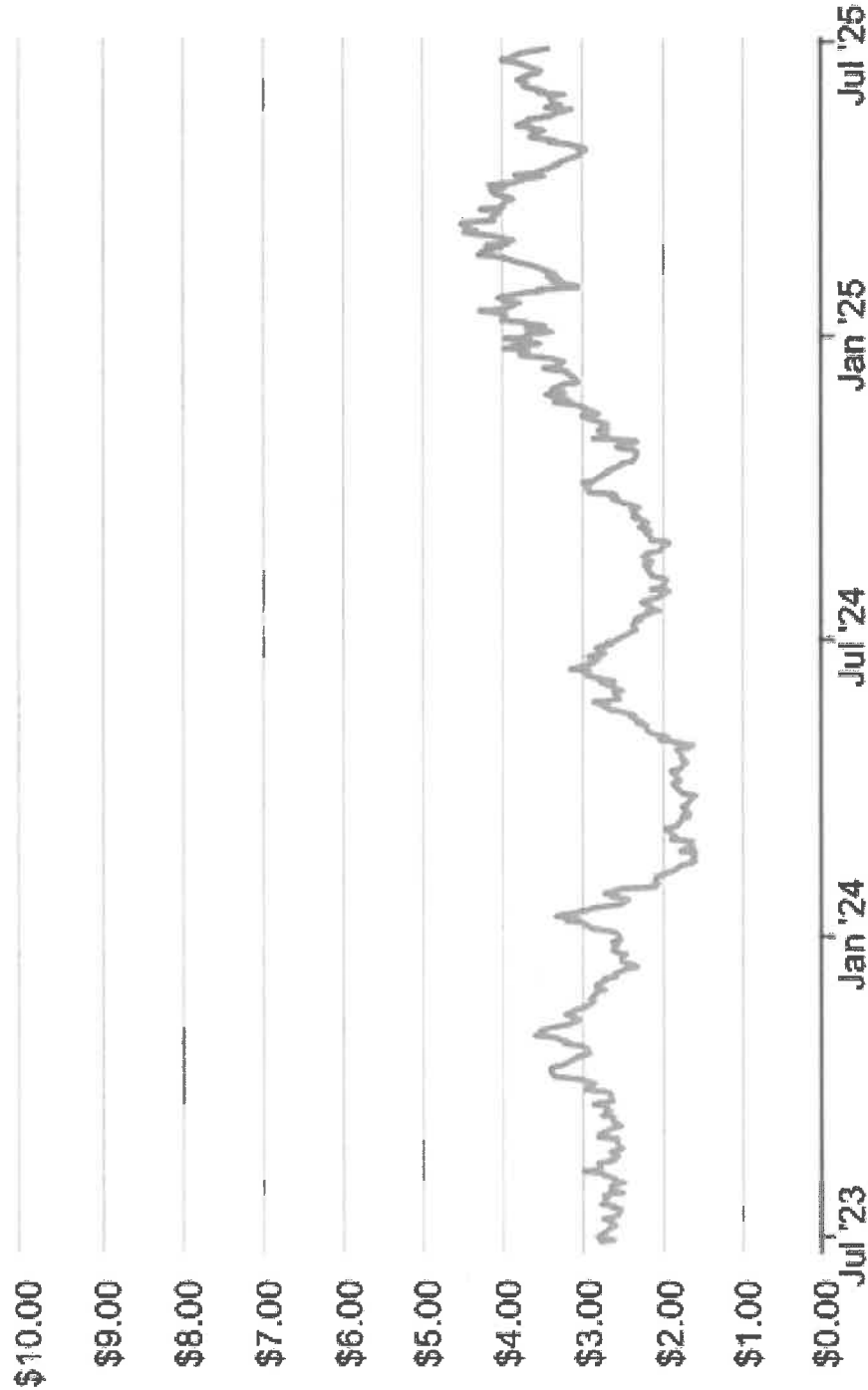


# U.S. Natural Prices



## Near-month natural gas futures prices (NYMEX)

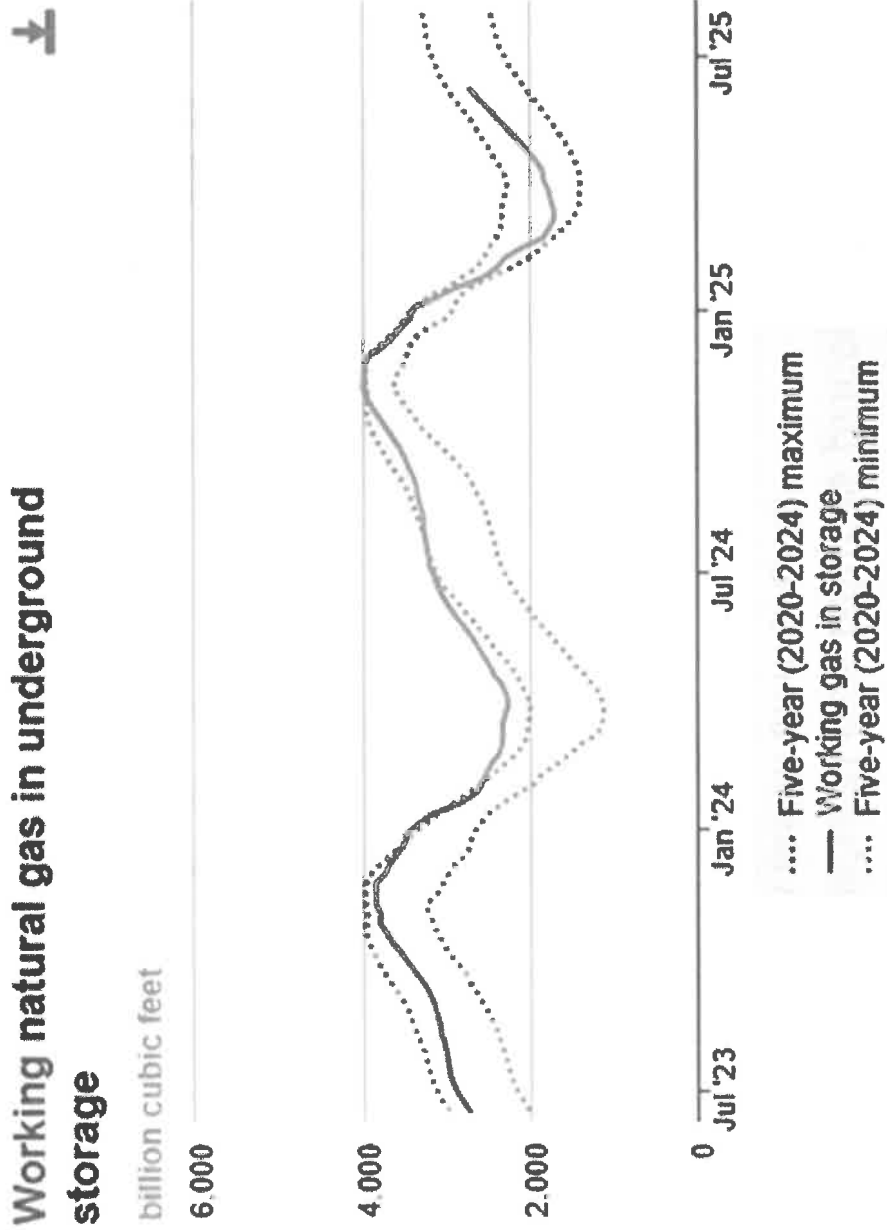
dollars per million British thermal units



Data source: CME Group as compiled by Bloomberg, L.P.



# U.S. Gas Storage (Lower 48)



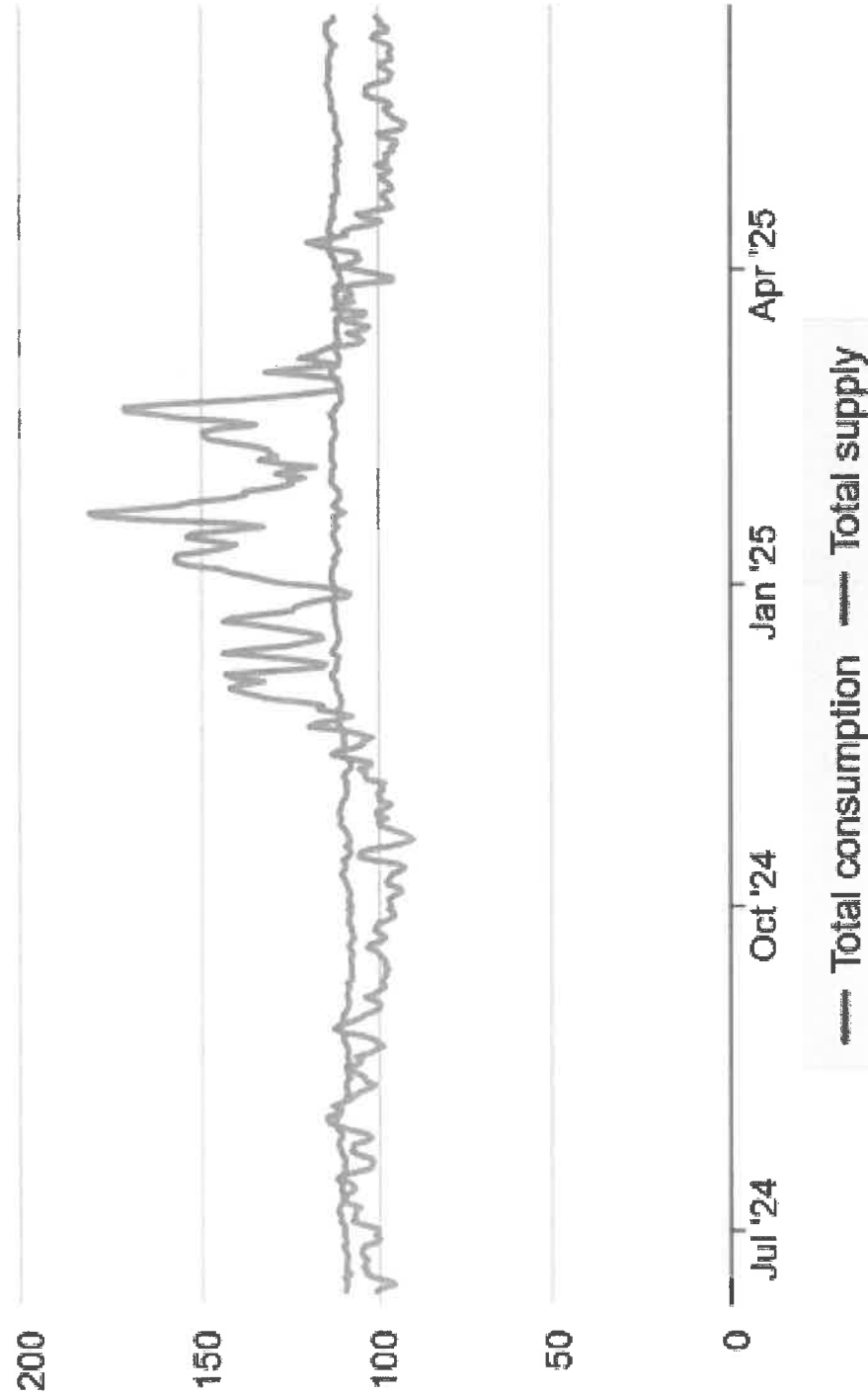
 Data source: U.S. Energy Information Administration Form EIA-912, *Weekly Underground Natural Gas Storage Report*



# U.S. Natural Gas Balance



**Total supply/demand balance (last 365 days)**  
billion cubic feet per day



Data source: S&P Global Commodity Insights



## Natural Gas Pipeline Activities

- ✓ Construction on the Pinyon Pipeline, the lateral from Ruby Pipeline which will serve the Valmy Power Plant, will begin on July 7. Commercial operation of the first unit at Valmy being converted to natural gas is anticipated no later than November 1.

# Gas Risk Evaluation Matrix (NVE South)

	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	2,903,806	2,744,155	2,189,357	1,556,166	1,433,024	1,669,162	1,648,294	1,383,456	1,404,228	1,433,663	1,872,804	2,497,634	22,735,749
Previous Quarter [2]	2,907,550	2,748,544	2,193,110	1,558,672	1,434,307	1,672,468	1,643,124	1,378,873	1,396,687	1,426,035	1,869,532	2,492,969	22,721,871
Current Outlook [3]	2,907,550	2,748,544	2,193,110	1,558,672	1,434,307	1,672,468	1,643,124	1,378,873	1,396,687	1,426,035	1,869,532	2,492,969	22,721,871
Change from Filed ESP	3,744	4,389	3,753	2,506	1,283	3,306	(5,170)	(4,583)	(7,541)	(7,628)	(3,272)	(4,665)	(13,878)
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	(0)	(0)	(0)	(0)
<b>SoCal Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	4.73	4.78	4.63	3.62	4.84	6.59	6.45	5.90	4.13	3.22	3.19	3.35	4.62
Previous Quarter [2]	4.02	4.31	3.99	3.72	4.24	5.79	6.09	5.15	3.42	2.98	2.97	3.10	4.15
Current Outlook [3]	3.37	3.81	3.58	3.06	4.53	6.08	6.31	5.72	4.15	3.40	3.33	3.59	4.24
Change from Filed ESP	(1.36)	(0.97)	(1.06)	(0.56)	(0.31)	(0.51)	(0.13)	(0.18)	0.02	0.18	0.13	0.24	(0.37)
Change from Previous Quarter	(0.64)	(0.50)	(0.41)	(0.66)	0.29	0.28	0.22	0.57	0.74	0.42	0.35	0.48	0.10
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	135.35	148.44	118.51	54.61	61.27	90.77	86.50	63.07	47.66	41.93	37.72	53.94	78.31
Previous Quarter [2]	79.44	95.40	69.95	47.16	44.47	57.42	65.93	49.93	29.87	27.01	26.28	43.89	53.06
Current Outlook [3]	72.78	88.22	70.49	53.32	56.11	72.29	82.92	67.28	44.62	37.14	37.21	54.88	61.44
Change from Filed ESP	(62.57)	(60.22)	(48.02)	(1.29)	(5.16)	(18.48)	(3.58)	(4.21)	(3.04)	(4.79)	(0.50)	0.94	(16.87)
Change from Previous Quarter	(6.66)	(7.18)	0.55	6.15	11.65	14.87	17.00	17.35	14.75	10.13	10.93	10.99	8.38
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	404,098
Previous Quarter [2] [4]	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	404,098
Current Outlook [3] [4]	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	11,064,292	9,795,002	8,953,530	9,201,631	9,677,752	11,836,196	11,222,884	9,213,911	8,827,500	7,450,596	10,149,085	9,999,516	117,391,895
Previous Quarter [2]	12,277,547	10,761,131	10,562,169	9,381,639	9,898,590	12,278,990	11,458,887	9,115,743	8,419,410	8,520,637	10,640,061	10,308,668	123,623,473
Current Outlook [3]	12,558,093	10,933,227	10,046,313	9,544,803	9,646,771	12,288,727	11,773,035	9,045,953	7,913,184	8,626,383	10,709,751	10,596,032	123,682,272
Change from Filed ESP	1,493,801	1,138,225	1,092,783	343,172	(30,980)	452,531	550,151	(167,958)	(914,316)	1,175,788	560,665	596,516	6,290,377
Change from Previous Quarter	280,546	172,096	(515,856)	163,164	(251,819)	9,737	314,148	(69,790)	(506,227)	105,747	69,690	287,364	58,799
<b>Base Tariff Energy Rate - Residential (\$/kWh):</b>													
ESP [5]	0.05838	0.05838	0.05838	0.05727	0.05727	0.05727	0.05781	0.05781	0.05781	0.05772	0.05772	0.05772	0.05780
Previous Quarter [6]	0.05315	0.05315	0.05315	0.05392	0.05392	0.05392	0.05565	0.05565	0.05565	0.05604	0.05604	0.05604	0.05469
Current Outlook [7]	0.05344	0.05344	0.05344	0.05341	0.05341	0.05341	0.05439	0.05439	0.05439	0.05450	0.05450	0.05450	0.05394
Change from Filed ESP	(0.00494)	(0.00494)	(0.00494)	(0.00386)	(0.00386)	(0.00386)	(0.00342)	(0.00342)	(0.00342)	(0.00322)	(0.00322)	(0.00322)	(0.00386)
Change from Previous Quarter	0.00029	0.00029	0.00029	(0.00051)	(0.00051)	(0.00051)	(0.00126)	(0.00126)	(0.00126)	(0.00154)	(0.00154)	(0.00154)	(0.00076)

[7] June 2025 forecasts

[4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity)

[5] Joint ESP filed 6/1/2024 (Docket No. 24-060001) for 2025-2027

[6] March 2025 forecasts

# Gas Risk Evaluation Matrix (NVE North)

Page 1 of 2

	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	1,195,572	1,154,279	1,023,049	970,184	993,628	1,072,088	1,062,967	950,309	1,025,364	985,644	1,022,839	1,062,529	12,518,452
Previous Quarter [2]	1,204,038	1,162,748	1,029,502	975,626	997,958	1,077,254	1,064,445	952,241	1,027,419	988,633	1,028,366	1,069,555	12,577,785
Current Outlook [3]	1,204,038	1,162,748	1,029,502	975,626	997,958	1,077,254	1,128,247	1,009,765	1,083,003	1,034,960	1,062,177	1,103,642	12,868,919
Change from Filled ESP	8,466	8,469	6,453	5,442	4,330	5,166	65,280	59,456	57,639	49,316	39,338	41,113	350,467
Change from Previous Quarter	0	0	0	0	0	0	63,802	57,524	55,584	46,327	33,811	34,087	291,134
<b>Malin Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	3.45	3.49	3.46	3.38	4.53	6.09	5.93	5.84	4.29	3.16	3.14	3.27	4.17
Previous Quarter [2]	3.75	3.87	3.89	3.63	4.31	5.45	5.42	5.11	3.78	2.90	2.78	2.98	3.99
Current Outlook [3]	3.00	3.28	3.04	2.99	4.30	5.57	5.73	5.35	3.86	3.19	3.04	3.32	3.89
Change from Filled ESP	(0.45)	(0.20)	(0.42)	(0.39)	(0.22)	(0.53)	(0.21)	(0.50)	(0.43)	0.04	(0.10)	0.05	(0.28)
Change from Previous Quarter	(0.75)	(0.59)	(0.85)	(0.65)	(0.01)	0.12	0.30	0.23	0.09	0.29	0.26	0.34	(0.10)
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	135.35	148.44	118.51	54.61	61.27	90.77	86.50	63.07	47.66	41.93	37.72	53.94	78.31
Previous Quarter [2]	79.44	95.40	69.95	47.16	44.47	57.42	65.93	49.93	29.87	27.01	26.28	43.89	53.06
Current Outlook [3]	72.78	88.22	70.49	53.32	56.11	72.29	82.92	67.28	44.62	37.14	37.21	54.88	61.44
Change from Filled ESP	(62.57)	(60.22)	(48.02)	(1.29)	(5.16)	(18.48)	(3.58)	4.21	(3.04)	(4.79)	(0.50)	0.94	(16.87)
Change from Previous Quarter	(6.66)	(7.18)	0.55	6.15	11.65	14.87	17.00	17.35	14.75	10.13	10.93	10.99	8.38
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	234,627	234,627	234,627	234,627	265,279	265,279	304,279	304,279	304,279	273,627	273,627	312,627	270,149
Previous Quarter [2] [4]	234,627	234,627	234,627	234,627	265,279	265,279	304,279	304,279	304,279	273,627	273,627	312,627	270,149
Current Outlook [3] [4]	234,627	234,627	234,627	234,627	265,279	265,279	304,279	304,279	304,279	273,627	273,627	312,627	270,149
Change from Filled ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>LDC Consumption Forecast (MMBtu):</b>													
ESP [1]	516,767	527,649	562,354	1,188,141	2,186,194	3,452,041	3,237,040	2,549,377	2,164,361	1,379,248	838,429	585,331	19,186,932
Previous Quarter [2]	516,767	527,649	562,354	1,188,141	2,186,194	3,452,041	3,237,040	2,549,377	2,164,361	1,379,248	838,429	585,331	19,186,932
Current Outlook [3]	533,784	535,904	563,869	1,098,131	2,123,556	3,175,693	3,182,828	2,605,950	2,213,875	1,447,546	823,607	593,435	18,898,178
Change from Filled ESP	17,017	8,256	1,515	(90,009)	(62,637)	(276,348)	(54,211)	56,573	49,515	68,297	(14,823)	8,104	(288,753)
Change from Previous Quarter	17,017	8,256	1,515	(90,009)	(62,637)	(276,348)	(54,211)	56,573	49,515	68,297	(14,823)	8,104	(288,753)
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	4,926,980	4,650,008	3,842,754	3,110,745	2,887,565	3,432,078	3,764,763	2,867,841	2,269,953	3,309,657	3,239,951	3,639,711	41,941,933
Previous Quarter [2]	3,714,339	3,425,640	2,656,989	2,481,860	2,391,328	2,688,856	3,152,650	2,718,422	2,515,519	2,223,904	2,800,880	3,652,525	34,422,911
Current Outlook [3]	3,988,316	3,770,613	3,289,880	2,786,928	3,000,022	2,981,761	2,870,941	2,835,986	2,922,262	1,931,107	2,454,070	3,209,883	36,021,721
Change from Filled ESP	(958,614)	(879,395)	(552,874)	(323,817)	112,457	(450,316)	(893,821)	(31,905)	652,309	(1,378,550)	(785,861)	(429,827)	(5,920,213)
Change from Previous Quarter	253,977	344,973	632,891	305,067	608,694	292,906	(281,708)	117,513	406,743	(292,796)	(346,810)	(442,642)	1,598,809

[4] Combined Great Basin, Tuscarora, and Ruby/Pinyon transportation contracts

[1] Joint ESP filed 6/1/2024 (Docket No. 24-06001) for 2025-2027

[2] March 2025 Risk Run

[3] June 2025 Risk Run

# Gas Risk Evaluation Matrix (NVE North)

Page 2 of 2

	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	12 Mos.
<b>Base Tariff Energy Rate (\$/kWh):</b>													
ESP [5]	0.05215	0.05215	0.05215	0.05121	0.05121	0.05121	0.05240	0.05240	0.05240	0.05197	0.05197	0.05197	0.05193
Previous Quarter [6]	0.04788	0.04788	0.04788	0.04700	0.04700	0.04700	0.05258	0.05258	0.05258	0.05384	0.05384	0.05384	0.05033
Current Outlook [7]	0.04821	0.04821	0.04821	0.04824	0.04824	0.04824	0.05457	0.05457	0.05457	0.05639	0.05639	0.05639	0.05185
Change from Filed ESP	(0.00394)	(0.00394)	(0.00394)	(0.00297)	(0.00297)	(0.00297)	0.00217	0.00217	0.00217	0.00442	0.00442	0.00442	(0.00008)
Change from Previous Quarter	0.00033	0.00033	0.00033	0.00124	0.00124	0.00124	0.00199	0.00199	0.00199	0.00255	0.00255	0.00255	0.00153

[5] Joint ESP filed 6/1/2024 (Docket No. 24-06001) for 2025-2027

[6] March 2025 forecasts

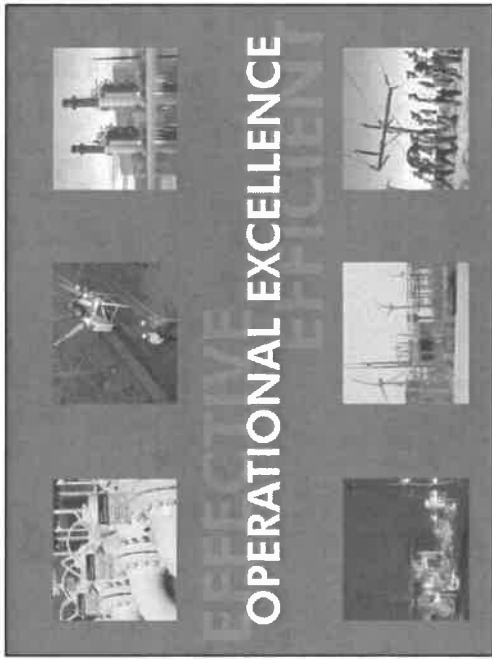
[7] June 2025 forecasts

## NV Energy Course of Action

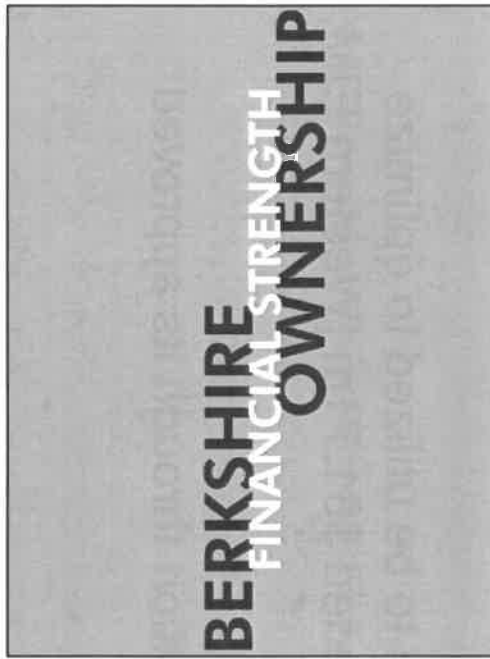
- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.

## Electric Power Activities

- ✓ No forward sales were executed in Q1.
- ✓ The Company will continue to evaluate forward transaction opportunities as appropriate.
- ✓ The Western Energy Imbalance Market (“EIM”) continued to be utilized to optimize system resources. The Company Q1 benefits have exceeded \$81.71m [Western EIM, Benefits Report - First Quarter 2025].
- ✓ The Company continues to fill its 2026 open capacity position through its approved laddering strategy.
- ✓ Coal – the 2024/2025 winter coal supply procurement has been completed and contracts fully executed.



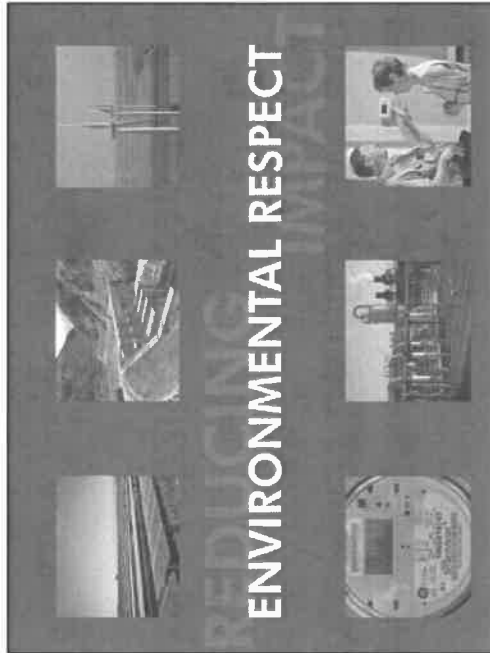
**OPERATIONAL EXCELLENCE**



**BERKSHIRE  
FINANCIAL STRENGTH  
OWNERSHIP**



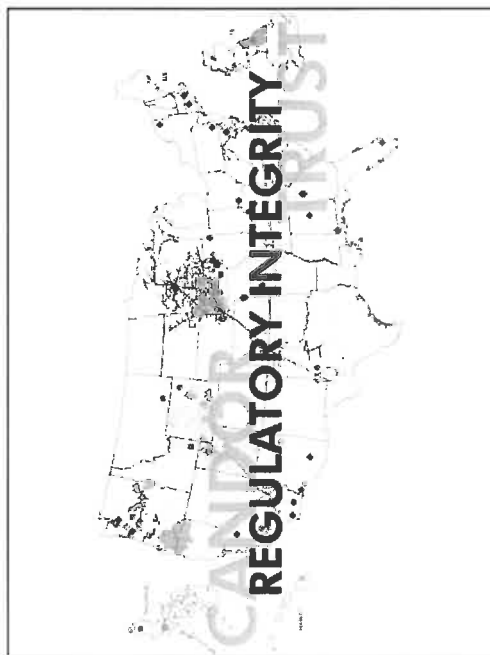
**CUSTOMER SERVICE**



**ENVIRONMENTAL RESPECT**



**EMPLOYEE COMMITMENT**



**REGULATORY INTEGRITY**

# Q3 2025 Natural Gas Hedging Update

September 25, 2025

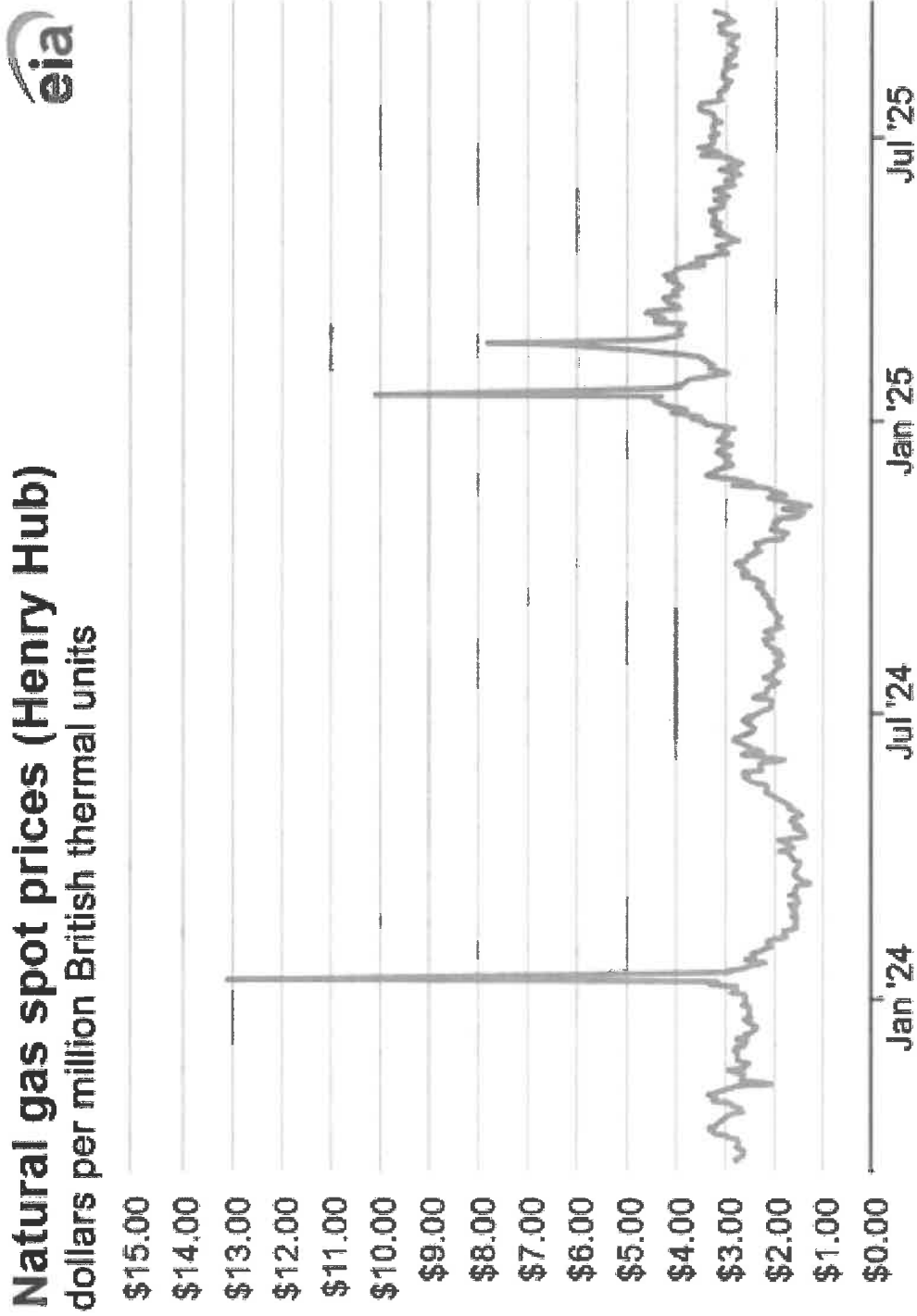
# Market Fundamentals Overview

- ✓ The Henry Hub spot price averaged \$2.91 per million British thermal units (\$/MMBtu) in August. Lower prices over this summer have been driven by robust production and reduced natural gas consumption in the electric power sector. Energy Information Administration (EIA) expects the Henry Hub spot price to average about \$3.00/MMBtu for the third quarter of 2025 (see slides on pages 4 and 5). In the September forecast, the Henry Hub price reaches its winter peak in January at \$4.60/MMBtu. [EIA, Short-Term Energy Outlook, September 2025].
- ✓ Historically, average annual prices for gas and oil change in tandem. This year will be the first time they move in the opposite direction since 2014 (see slide on page 6). The West Texas Intermediate (WTI) crude oil price is expected to fall 38%, leading to the lowest crude oil-to-natural gas price premium since 2005 at just over \$4.00/MMBtu. With these price movements, it is expected that decreases in natural gas produced as a byproduct of oil directed drilling will offset increases in that produced by natural gas-directed drilling. Overall, U.S. marketed natural gas production is expected to average around 117 billion cubic feet per day (Bcf/d) in 2025 and in 2026 (see slide on page 7). [EIA, Short-Term Energy Outlook, September 2025].

## Market Fundamentals Overview

- ✓ Net injections into storage totaled 90 billion cubic feet (Bcf) for the week ending September 12, compared with the five-year (2020–24) average net injections of 79 Bcf and last year's net injections of 56 Bcf during the same week. Working natural gas stocks totaled 3,433 Bcf, which is 204 Bcf (6%) more than the five-year average and 4 Bcf (less than 1%) lower than last year at this time. The average rate of injections into storage is 19% higher than the five-year average so far in the refill season (April through October). If the rate of injections into storage matched the five-year average of 10.7 Bcf/d for the remainder of the refill season, the total inventory would be 3,957 Bcf on October 31, (see slide on pg. 8) which is 204 Bcf higher than the five-year average of 3,753 Bcf for that time of year. [EIA, Natural Gas weekly Update, September 18, 2025].

# U.S. Natural Gas Prices

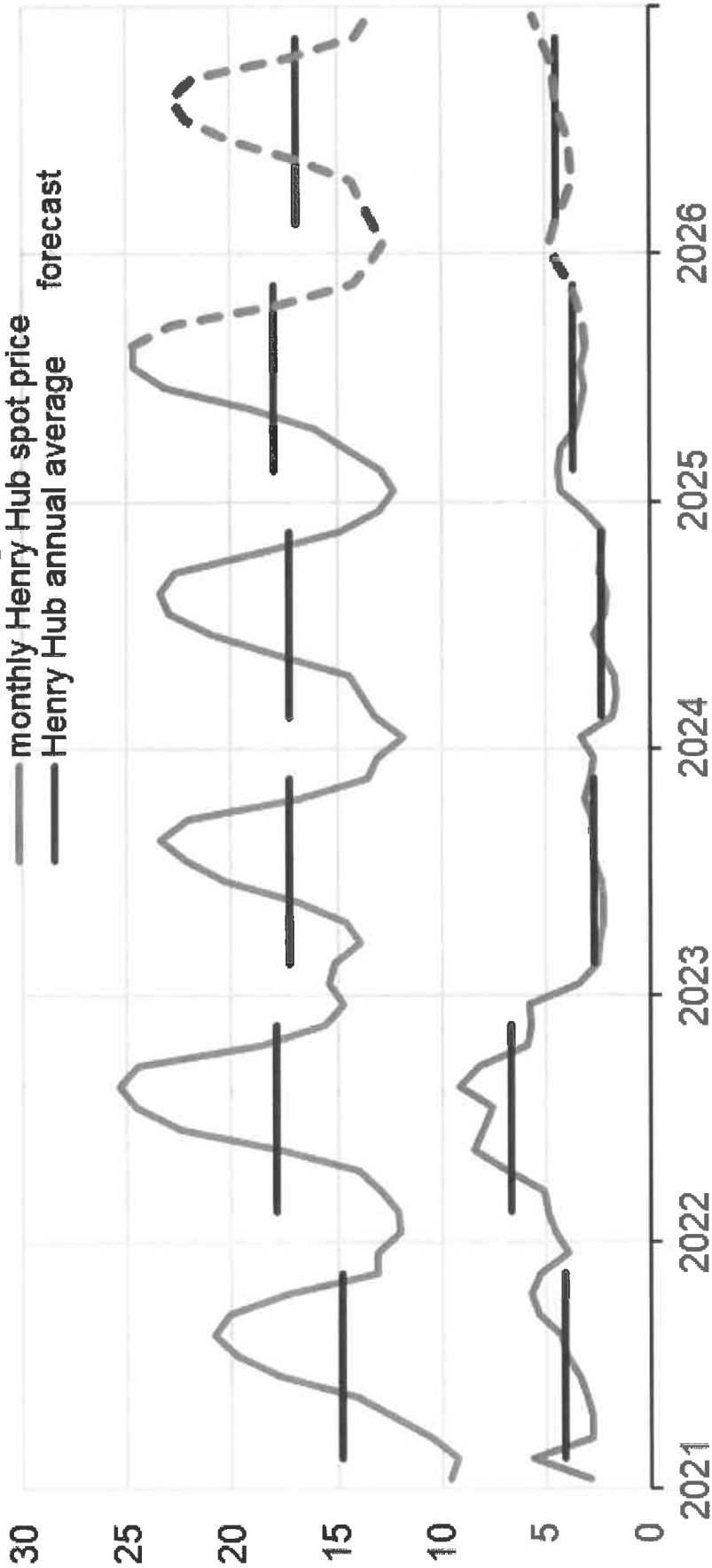


Data source: Natural Gas Intelligence



# U.S. Natural Gas Prices

U.S. natural gas prices  
dollars per thousand cubic feet

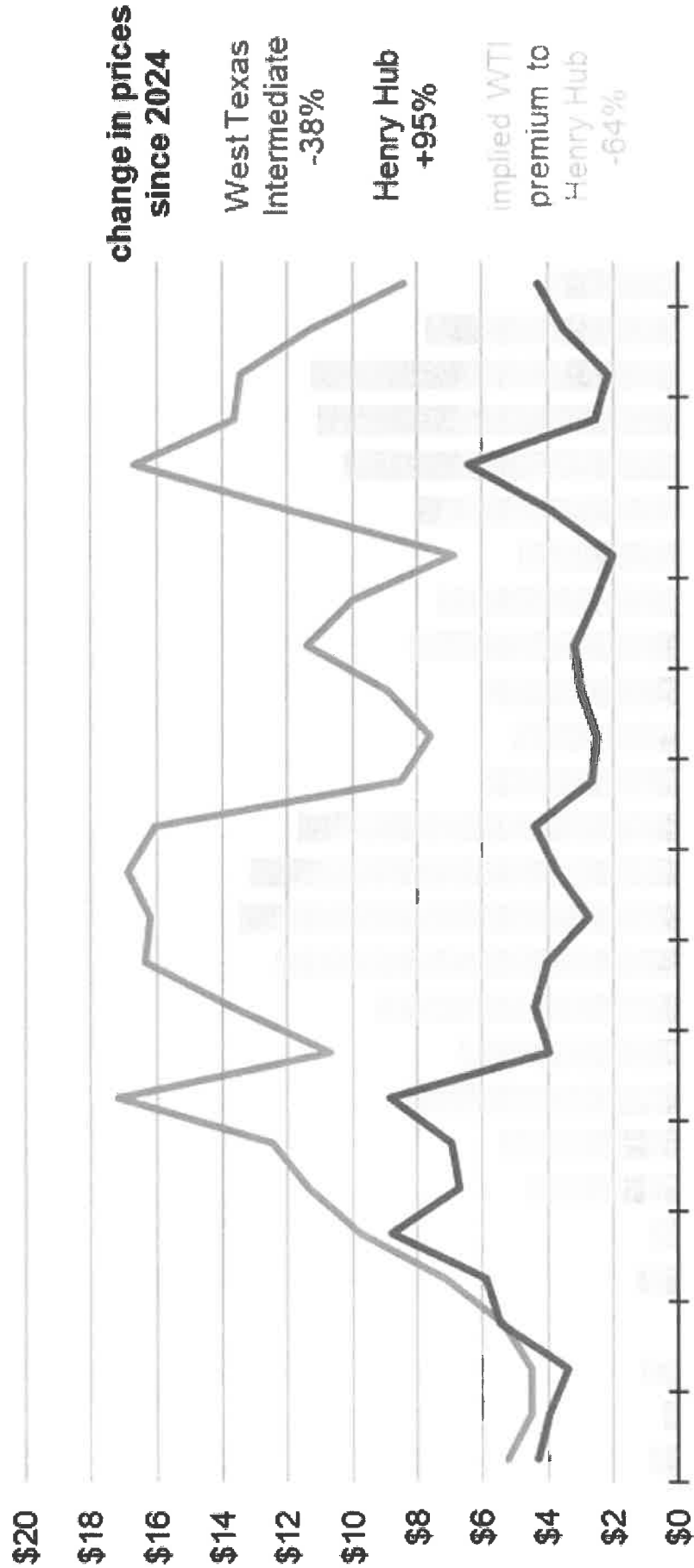


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2025, and Refinitiv an LSEG Business



# Henry Hub vs. WTI Spot Price

Henry Hub and West Texas Intermediate (WTI) spot price dollars per million British thermal units



**change in prices since 2024**

- West Texas Intermediate -38%
- Henry Hub +95%
- implied WTI premium to Henry Hub -64%

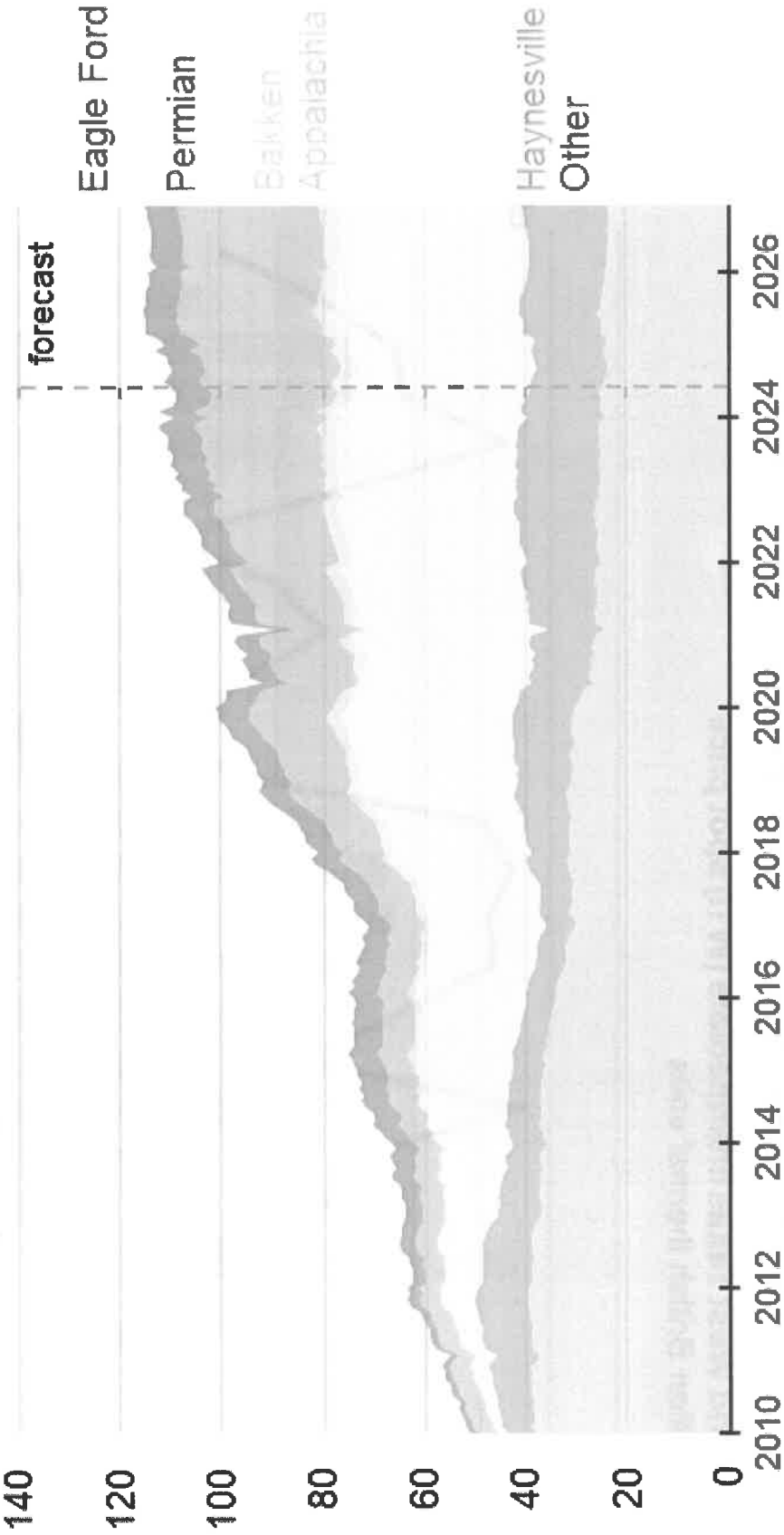


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2025



# U.S. Natural Gas Production

Monthly Lower 48 natural gas production by region  
billion cubic feet per day

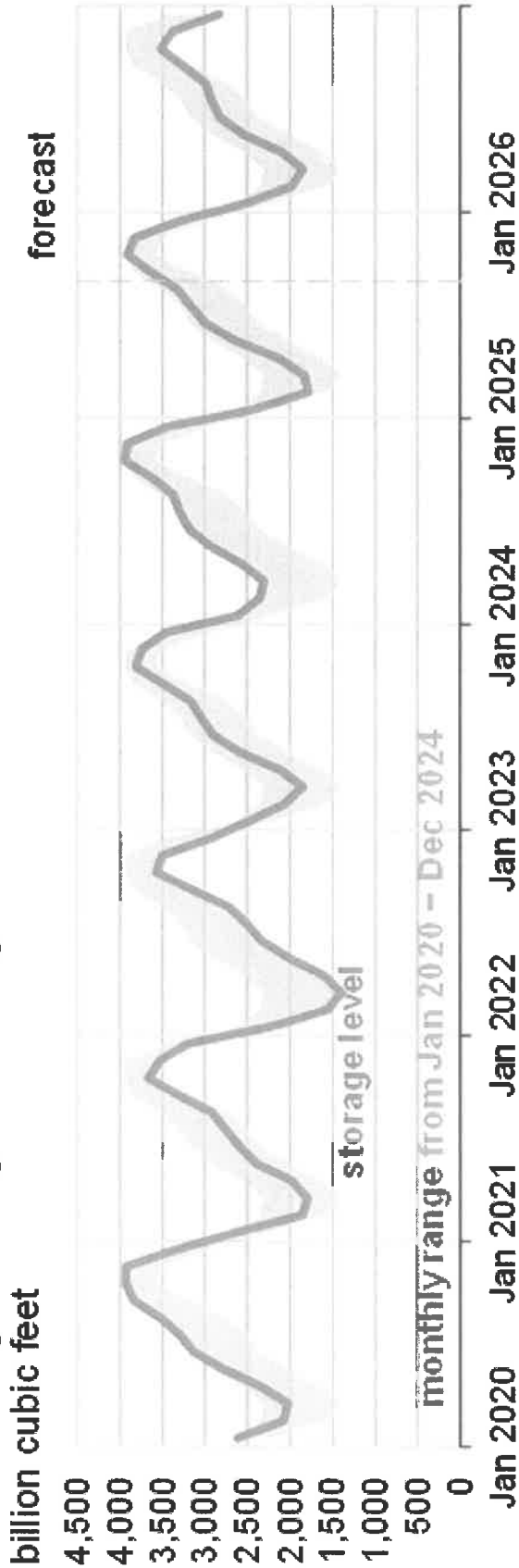


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, September

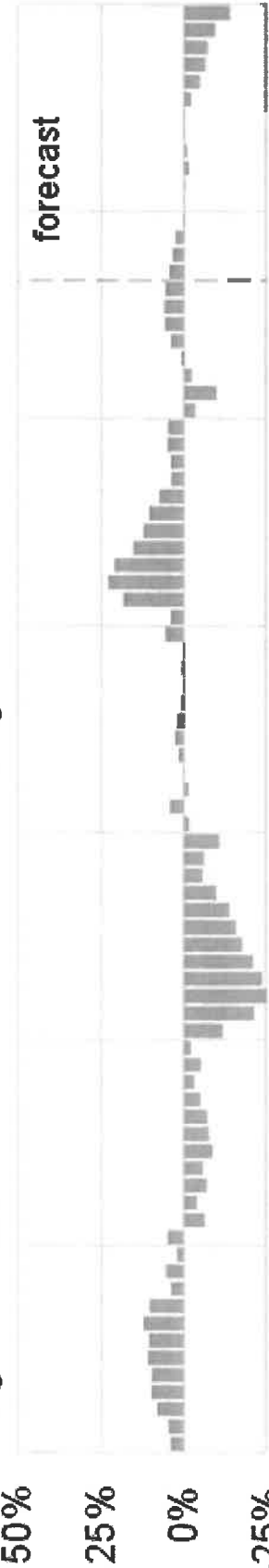


# U.S. Gas Storage (Lower 48)

U.S. working natural gas in storage



Percentage deviation from 2020 - 2024 average



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2025



## Natural Gas Pipeline Activities

- ✓ Construction of Pinyon Pipeline, the lateral from Ruby Pipeline which will serve the Valmy Power Plant, is approximately 70 percent complete. It is anticipated that during December the first unit at Valmy being converted to natural gas will be commercially operational.

# Gas Risk Evaluation Matrix (NVE South)

	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	1,556,166	1,433,024	1,669,162	1,648,294	1,383,456	1,404,228	1,433,663	1,872,804	2,497,634	2,930,529	2,776,338	2,224,000	22,829,298
Previous Quarter [2]	1,558,672	1,434,307	1,672,468	1,643,124	1,378,873	1,396,687	1,426,035	1,869,532	2,492,969	2,927,907	2,774,019	2,220,941	22,795,534
Current Outlook [3]	1,558,672	1,434,307	1,672,468	1,643,124	1,378,873	1,396,687	1,426,035	1,869,532	2,492,969	2,927,907	2,774,019	2,220,941	22,795,533
Change from Filed ESP	2,506	1,283	3,306	(5,170)	(4,583)	(7,541)	(7,628)	(3,272)	(4,665)	(2,622)	(2,319)	(3,059)	(33,765)
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	(1)
<b>SoCal Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	3.62	4.84	6.59	6.45	5.90	4.13	3.22	3.19	3.35	4.77	4.82	4.68	4.63
Previous Quarter [2]	3.72	4.24	5.79	6.09	5.15	3.42	2.98	2.97	3.10	4.32	4.36	4.21	4.20
Current Outlook [3]	3.06	4.53	6.08	6.31	5.72	4.15	3.40	3.33	3.59	5.10	5.15	4.98	4.62
Change from Filed ESP	(0.56)	(0.31)	(0.51)	(0.13)	(0.18)	0.02	0.18	0.13	0.24	0.33	0.33	0.30	(0.01)
Change from Previous Quarter	(0.66)	0.29	0.28	0.22	0.57	0.74	0.42	0.35	0.48	0.78	0.79	0.77	0.42
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	54.61	61.27	90.77	86.50	63.07	47.66	41.93	37.72	53.94	138.28	155.23	124.06	79.59
Previous Quarter [2]	47.16	44.47	57.42	65.93	49.93	29.87	27.01	26.28	43.89	85.02	100.13	71.66	54.06
Current Outlook [3]	53.32	56.11	72.29	82.92	67.28	44.62	37.14	37.21	54.88	91.21	101.84	84.79	65.30
Change from Filed ESP	(1.29)	(5.16)	(18.48)	(3.58)	4.21	(3.04)	(4.79)	(0.50)	0.94	(47.06)	(53.40)	(39.27)	(14.28)
Change from Previous Quarter	6.15	11.65	14.87	17.00	17.35	14.75	10.13	10.93	10.99	6.19	1.71	13.13	11.24
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	424,935	374,925	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	404,098
Previous Quarter [2] [4]	424,935	374,925	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	404,098
Current Outlook [3] [4]	424,935	374,925	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	9,201,631	9,677,752	11,836,196	11,222,884	9,213,911	8,827,500	7,450,596	10,149,085	9,999,516	12,324,604	11,036,037	9,757,558	120,697,271
Previous Quarter [2]	9,381,639	9,898,590	12,278,990	11,458,887	9,115,743	8,419,410	8,520,637	10,640,061	10,308,668	12,201,672	10,914,655	10,015,969	123,154,922
Current Outlook [3]	9,544,803	9,646,771	12,288,727	11,773,035	9,045,953	7,913,184	8,626,383	10,709,751	10,596,032	12,754,019	11,293,301	10,036,945	124,228,904
Change from Filed ESP	343,172	(30,980)	452,531	550,151	(167,958)	(914,316)	1,175,788	560,665	596,516	429,415	257,263	279,386	3,531,633
Change from Previous Quarter	163,164	(251,819)	9,737	314,148	(69,790)	(506,227)	105,747	69,690	287,364	552,347	378,646	20,976	1,073,982
<b>Base Tariff Energy Rate - Residential (\$/kWh):</b>													
ESP [5]	0.05727	0.05727	0.05727	0.05781	0.05781	0.05781	0.05772	0.05772	0.05772	0.05747	0.05747	0.05747	0.05757
Previous Quarter [6]	0.05341	0.05341	0.05341	0.05439	0.05439	0.05439	0.05450	0.05450	0.05450	0.05375	0.05375	0.05375	0.05401
Current Outlook [7]	0.05327	0.05327	0.05327	0.05522	0.05522	0.05522	0.05465	0.05465	0.05465	0.05346	0.05346	0.05346	0.05415
Change from Filed ESP	(0.00400)	(0.00400)	(0.00400)	(0.00259)	(0.00259)	(0.00259)	(0.00307)	(0.00307)	(0.00307)	(0.00401)	(0.00401)	(0.00401)	(0.0342)
Change from Previous Quarter	(0.00014)	(0.00014)	(0.00014)	0.00083	0.00083	0.00083	0.00015	0.00015	0.00015	(0.00029)	(0.00029)	(0.00029)	0.00014

[1] Joint ESP filed 6/1/2024 (Docket No. 24-06001) for 2025-2027

[2] June 2025 Risk Run

[3] September 2025 Risk Run

[4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity)

[5] Joint ESP filed 6/1/2024 (Docket No. 24-06001) for 2025-2027

[6] June 2025 forecasts

[7] September 2025 forecasts

# Gas Risk Evaluation Matrix (NVE North)

Page 1 of 2

	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	970,184	993,628	1,072,088	1,062,967	950,309	1,025,364	985,644	1,022,839	1,062,529	1,235,493	1,198,570	1,057,601	12,637,216
Previous Quarter [2]	975,626	997,958	1,077,254	1,064,445	952,241	1,027,419	988,633	1,028,366	1,069,555	1,244,510	1,207,333	1,063,111	12,696,451
Current Outlook [3]	975,626	997,958	1,077,254	1,128,247	1,009,765	1,083,003	1,034,960	1,062,177	1,103,642	1,286,398	1,245,079	1,097,825	13,101,933
Change from Filed ESP	5,442	4,330	5,166	65,280	59,456	57,639	49,316	39,338	41,113	50,905	46,509	40,224	464,717
Change from Previous Quarter	0	0	0	63,802	57,524	55,584	46,327	33,811	34,087	41,888	37,746	34,714	405,482
<b>Main Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	3.38	4.53	6.09	5.93	5.84	4.29	3.16	3.14	3.27	3.54	3.58	3.55	4.19
Previous Quarter [2]	3.63	4.31	5.45	5.42	5.11	3.78	2.90	2.78	2.98	3.28	3.35	3.29	3.86
Current Outlook [3]	2.99	4.30	5.57	5.73	5.35	3.86	3.19	3.04	3.32	3.81	3.89	3.80	4.07
Change from Filed ESP	(0.39)	(0.22)	(0.53)	(0.21)	(0.50)	(0.43)	0.04	(0.10)	0.05	0.27	0.31	0.25	(0.12)
Change from Previous Quarter	(0.65)	(0.01)	0.12	0.30	0.23	0.09	0.29	0.26	0.34	0.54	0.55	0.51	0.21
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	54.61	61.27	90.77	86.50	63.07	47.66	41.93	37.72	53.94	138.28	155.23	124.06	79.59
Previous Quarter [2]	47.16	44.47	57.42	65.93	49.93	29.87	27.01	26.28	43.89	85.02	100.13	71.66	54.06
Current Outlook [3]	53.32	56.11	72.29	82.92	67.28	44.62	37.14	37.21	54.88	91.21	101.84	84.79	65.30
Change from Filed ESP	(1.29)	(5.16)	(18.48)	(3.58)	4.21	(3.04)	(4.79)	(0.50)	0.94	(47.06)	(53.40)	(39.27)	(14.28)
Change from Previous Quarter	6.15	11.65	14.87	17.00	17.35	14.75	10.13	10.93	10.99	6.19	1.71	13.13	11.24
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	234,627	265,279	265,279	265,279	265,279	265,279	273,627	273,627	273,627	273,627	273,627	312,627	270,149
Previous Quarter [2] [4]	234,627	265,279	265,279	265,279	265,279	265,279	273,627	273,627	273,627	273,627	273,627	312,627	270,149
Current Outlook [3] [4]	234,627	265,279	265,279	265,279	265,279	265,279	273,627	273,627	273,627	273,627	273,627	312,627	270,149
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>LDC Consumption Forecast (MMBtu):</b>													
ESP [1]	1,188,141	2,186,194	3,452,041	3,237,040	2,549,377	2,164,361	1,379,248	838,429	585,331	520,519	530,967	567,186	19,198,834
Previous Quarter [2]	1,188,141	2,186,194	3,452,041	3,237,040	2,549,377	2,164,361	1,379,248	838,429	585,331	520,519	530,967	567,186	19,198,834
Current Outlook [3]	1,098,131	2,123,556	3,175,693	3,182,828	2,605,950	2,213,875	1,447,546	823,607	593,435	535,454	537,185	566,790	18,904,051
Change from Filed ESP	(90,009)	(62,637)	(276,348)	(54,211)	56,573	49,515	68,297	(14,823)	8,104	14,935	6,218	(396)	(294,783)
Change from Previous Quarter	(90,009)	(62,637)	(276,348)	(54,211)	56,573	49,515	68,297	(14,823)	8,104	14,935	6,218	(396)	(294,783)
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	3,110,745	2,887,565	3,432,078	3,764,763	2,867,841	2,269,953	3,309,657	3,239,931	3,639,711	6,201,661	6,019,254	5,087,986	45,831,142
Previous Quarter [2]	2,481,860	2,391,328	2,688,856	3,152,650	2,718,422	2,515,519	2,223,904	2,800,880	3,652,525	5,786,160	5,390,306	4,523,606	40,326,015
Current Outlook [3]	2,786,928	3,000,022	2,981,761	2,870,941	2,895,936	2,922,262	1,931,107	2,454,070	3,209,883	4,403,698	4,269,995	3,565,096	37,231,700
Change from Filed ESP	(323,817)	112,457	(450,316)	(893,821)	(31,905)	652,309	(1,378,550)	(785,861)	(429,827)	(1,797,963)	(1,749,259)	(1,522,889)	(8,599,442)
Change from Previous Quarter	305,067	608,694	292,906	(284,708)	117,513	406,743	(292,796)	(346,810)	(442,642)	(1,382,463)	(1,120,310)	(958,509)	(3,094,315)

[4] Combined Great Basin, Tuscarora, and Ruby/Pinyon transportation contracts

[1] Joint-ESP filed 6/1/2024 (Docket No. 24-06001) for 2025-2027

[2] June 2025 Risk Run

[3] September 2025 Risk Run

# Gas Risk Evaluation Matrix (NVE North)

Page 2 of 2

	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	12 Mos.
<b>Base Tariff Energy Rate (\$/kWh):</b>													
ESP [5]	0.05121	0.05121	0.05121	0.05240	0.05240	0.05240	0.05197	0.05197	0.05197	0.05150	0.05150	0.05150	0.05177
Previous Quarter [6]	0.04824	0.04824	0.04824	0.05457	0.05457	0.05457	0.05639	0.05639	0.05639	0.05837	0.05837	0.05837	0.05439
Current Outlook [7]	0.04770	0.04770	0.04770	0.05040	0.05040	0.05040	0.05121	0.05121	0.05121	0.05244	0.05244	0.05244	0.05044
Change from Filed ESP	(0.00351)	(0.00351)	(0.00351)	(0.00200)	(0.00200)	(0.00200)	(0.00076)	(0.00076)	(0.00076)	0.00094	0.00094	0.00094	(0.00133)
Change from Previous Quarter	(0.00054)	(0.00054)	(0.00054)	(0.00417)	(0.00417)	(0.00417)	(0.00518)	(0.00518)	(0.00518)	(0.00593)	(0.00593)	(0.00593)	(0.00396)

[5] Joint ESP filed 6/1/2024 (Docket No. 24-06001) for 2025-2027

[6] June 2025 forecasts

[7] September 2025 forecasts

## NV Energy Course of Action

- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.

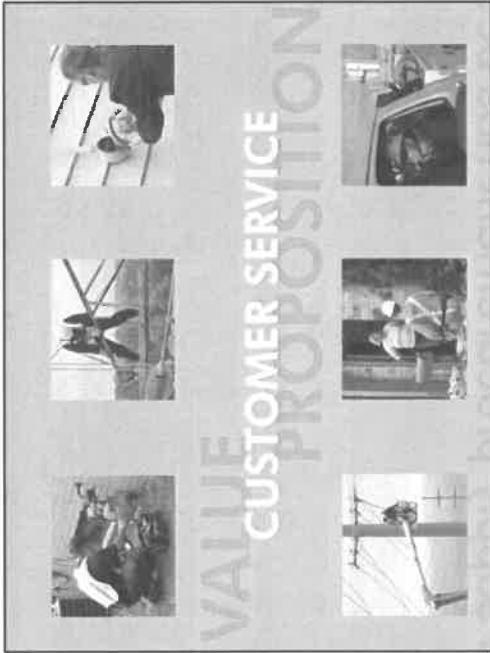
## Electric Power Activities

- ✓ No forward sales were executed in Q2.
- ✓ The Company will continue to evaluate forward transaction opportunities as appropriate.
- ✓ The Western Energy Imbalance Market (“EIM”) continued to be utilized to optimize system resources. The Company Q1 benefits have exceeded \$84.12m [Western EIM, Benefits Report - Second Quarter 2025].
- ✓ The Company continues to fill its 2026 and 2027 open capacity positions through its approved laddering strategy.
- ✓ Coal – the 2025 winter coal supply procurement has been completed and contracts fully executed.

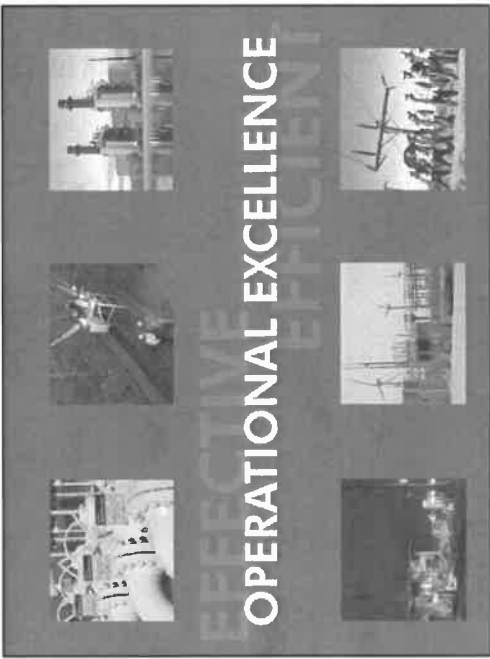
**EMPLOYEE COMMITMENT**



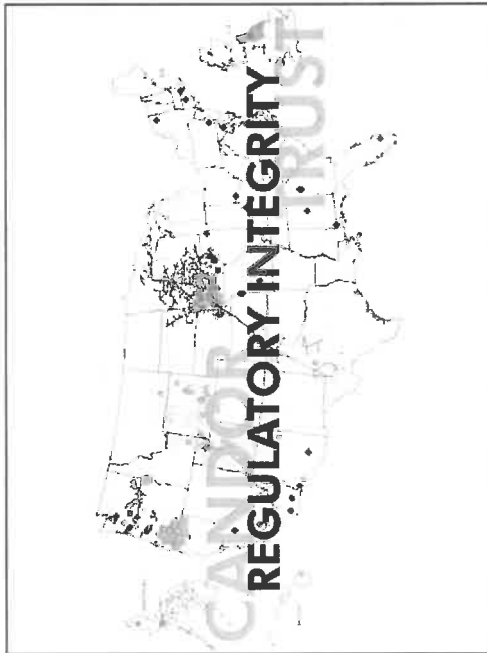
**CUSTOMER SERVICE**



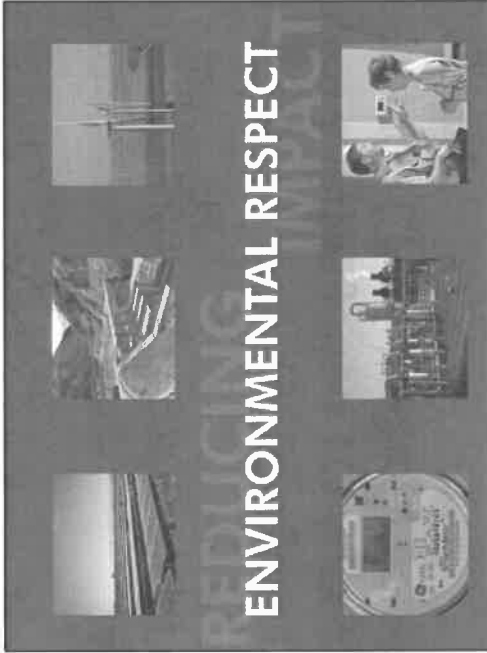
**OPERATIONAL EXCELLENCE**



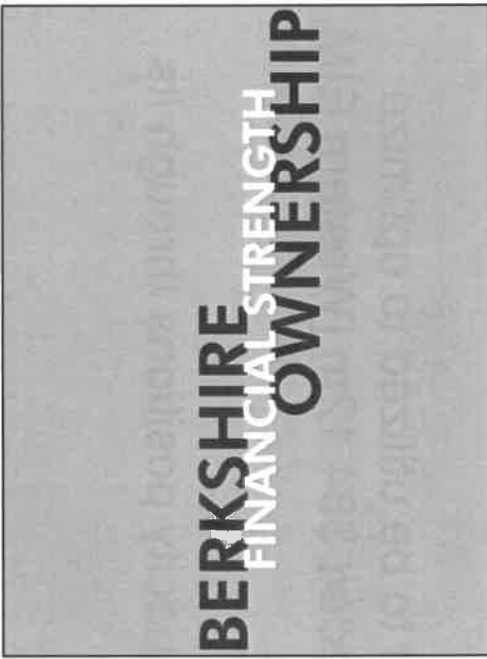
**REGULATORY INTEGRITY**



**ENVIRONMENTAL RESPECT**



**BERKSHIRE FINANCIAL STRENGTH OWNERSHIP**



# Q4 2025 Natural Gas Hedging Workshop

December 19, 2025

## Market Fundamentals Overview

- ✓ Although an early December cold snap has put temporary upward pressure on natural gas prices, the Energy Information Administration (EIA,) in its most recent forecast, expects milder-than-normal weather in early 2026 and rising production which helps moderate natural gas prices following the winter, with the Henry Hub price averaging about \$4.00/million British thermal units (\$/MMBtu) next year. (see slide on page 5). [EIA, Short-Term Energy Outlook, December 2025].
- ✓ The United States entered the winter heating season with 4% more working natural gas in storage than the previous five-year (2020–2024) average. EIA forecasts U.S. natural gas stocks will end the winter at 2,000 billion cubic feet (Bcf), or 9% above the five-year average (see slide on page 6). [EIA, Natural Gas weekly Update, December 11, 2025].

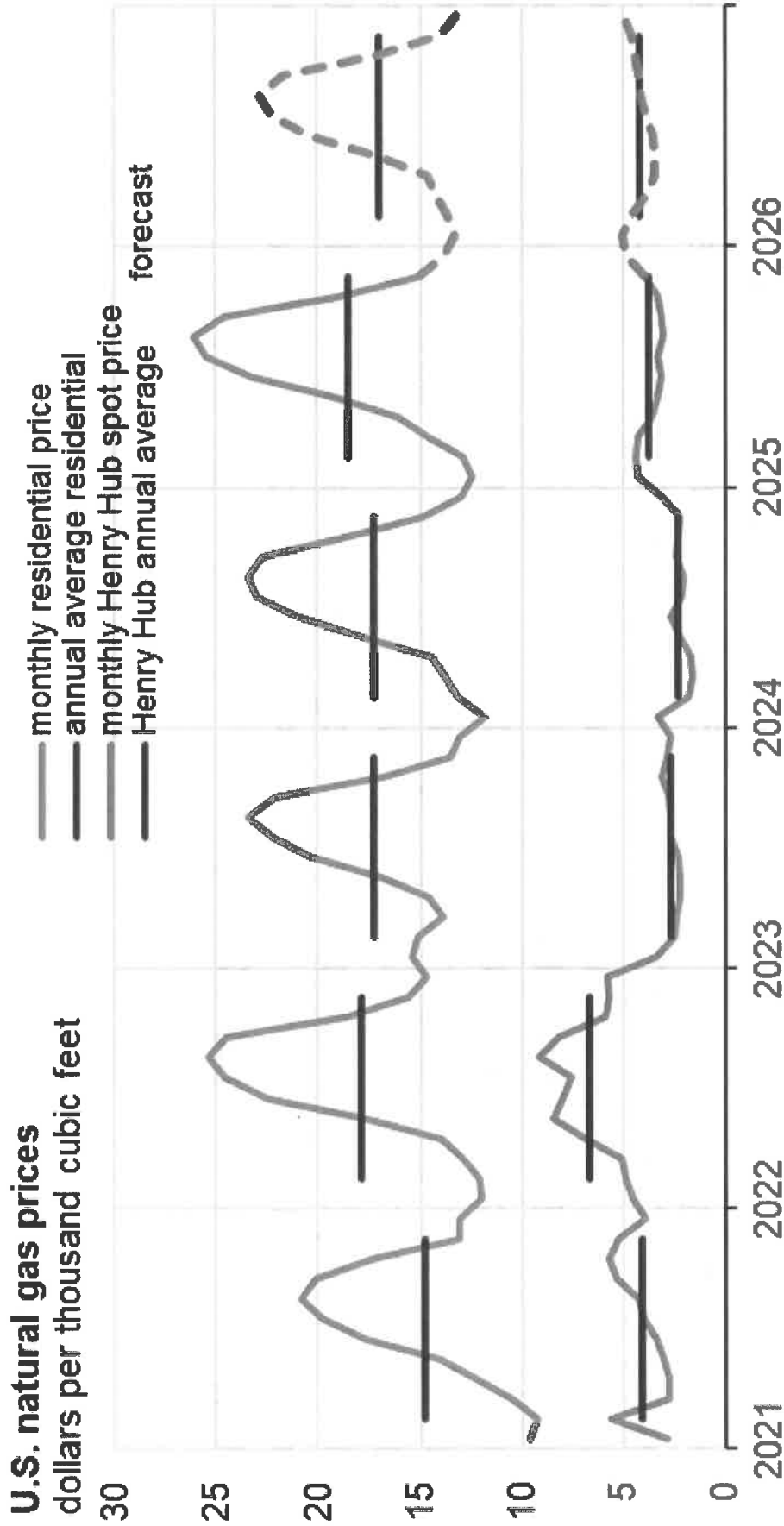
## Market Fundamentals Overview

✓ In 2026, the combined production from the Appalachia, Permian, and Haynesville regions is forecasted to account for 69% of overall U.S. production (see slide on page 6). Haynesville region is expected to grow by 2% in 2026 as higher natural gas prices has led to an increase in drilling activity in the region. In the past, production in the Appalachia region has been constrained by limited takeaway capacity. But recently with the addition of the Mountain Valley Pipeline and demand growth from additional data centers production in Appalachia is also expected to grow by 2% in 2026. The Permian Basin has been the most prolific natural gas growth area in the past, and it is expected the Permian region production to rise 9% (2.3 Bcf/d) for 2025. In the Permian region, growth in natural gas production is primarily the result of associated natural gas produced during oil production. As West Texas Intermediate (WTI) crude oil prices fall in 2026, Permian natural gas production growth is expected to slow to 1% next year. The forecast decline in WTI prices also reduces associated natural gas production from other regions such as the Eagle Ford, Anadarko, and Niobrara regions. [EIA, Short-Term Energy Outlook, December 2025].

## LNG Export Capacity

- ✓ The U.S. is scheduled to add more than 5 Bcf/d in liquefied natural gas (LNG) export capacity combined over 2025 and 2026. The forecast is that Plaquemines LNG (adding 2.6 Bcf/d of nominal LNG export capacity and 3.2 Bcf/d of peak export capacity), Corpus Christi LNG Stage 3 (bringing an estimated 0.8 Bcf/d of nominal capacity 0.9 Bcf/d peak capacity) and Golden Pass LNG will begin exports, (adding 1.4 Bcf/d of nominal LNG export capacity and 1.6 Bcf/d of peak export capacity), and drive most of the increase in LNG exports compared with 2024. EIA expects these capacity increases will raise U.S. LNG exports to an annual average of more than 16 Bcf/d in 2026, compared with less than 12 Bcf/d in 2024 (see slide on pg. 9). [EIA, Short-Term Energy Outlook, December 2025].

# U.S. Natural Gas Prices

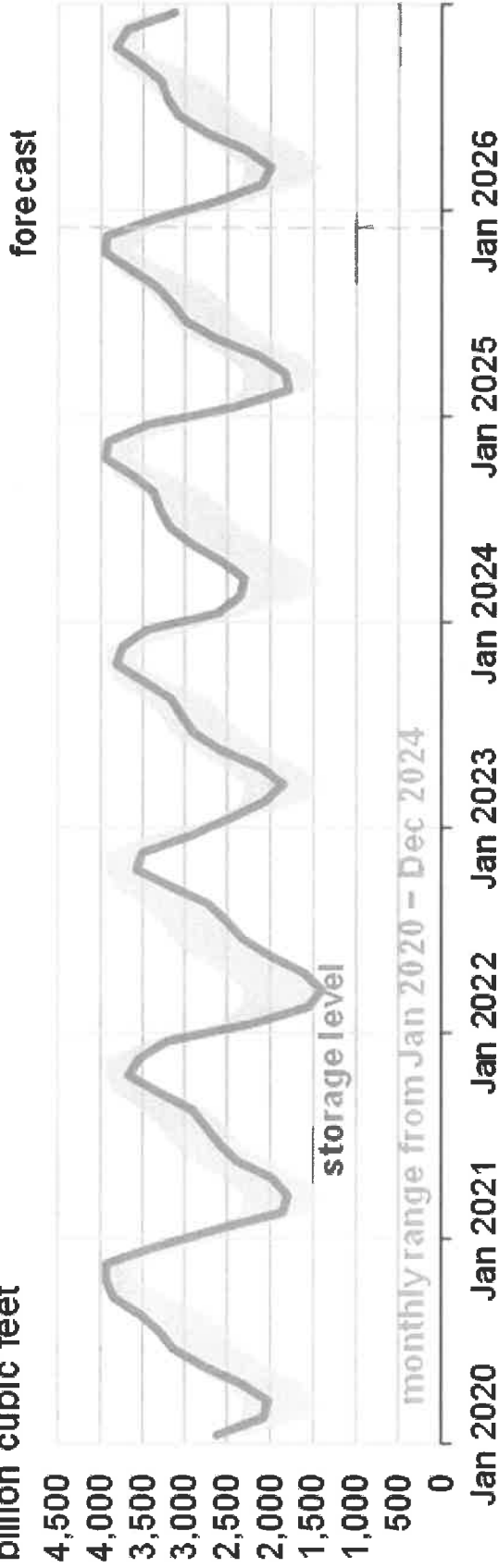


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025, and Refinitiv an LSEG Business

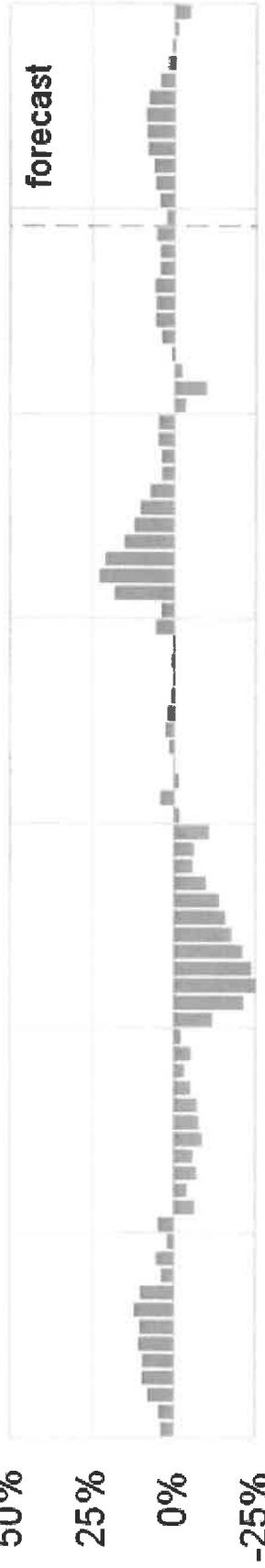


# U.S. Gas Storage (Lower 48)

U.S. working natural gas in storage  
billion cubic feet



Percentage deviation from 2020 - 2024 average

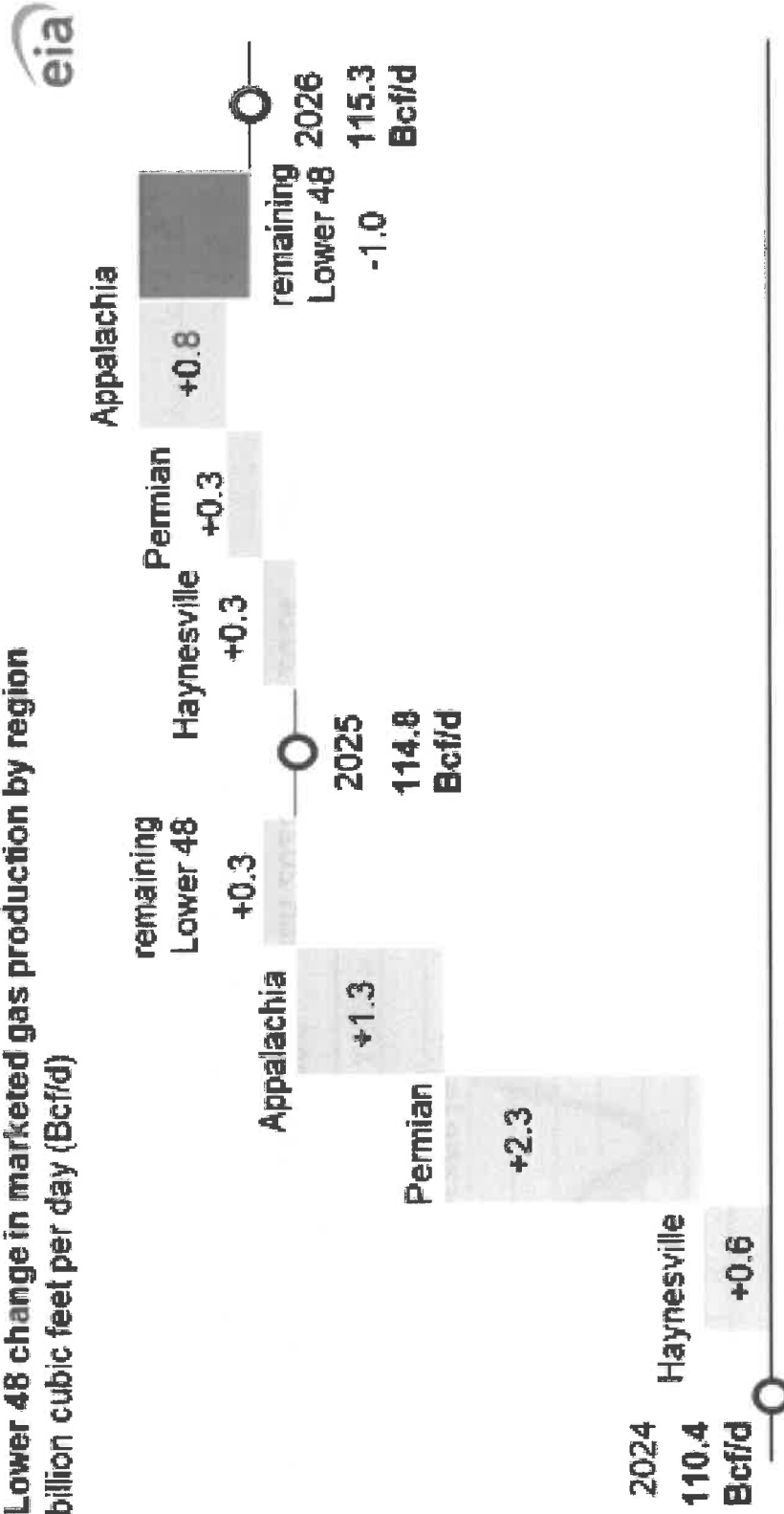


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025



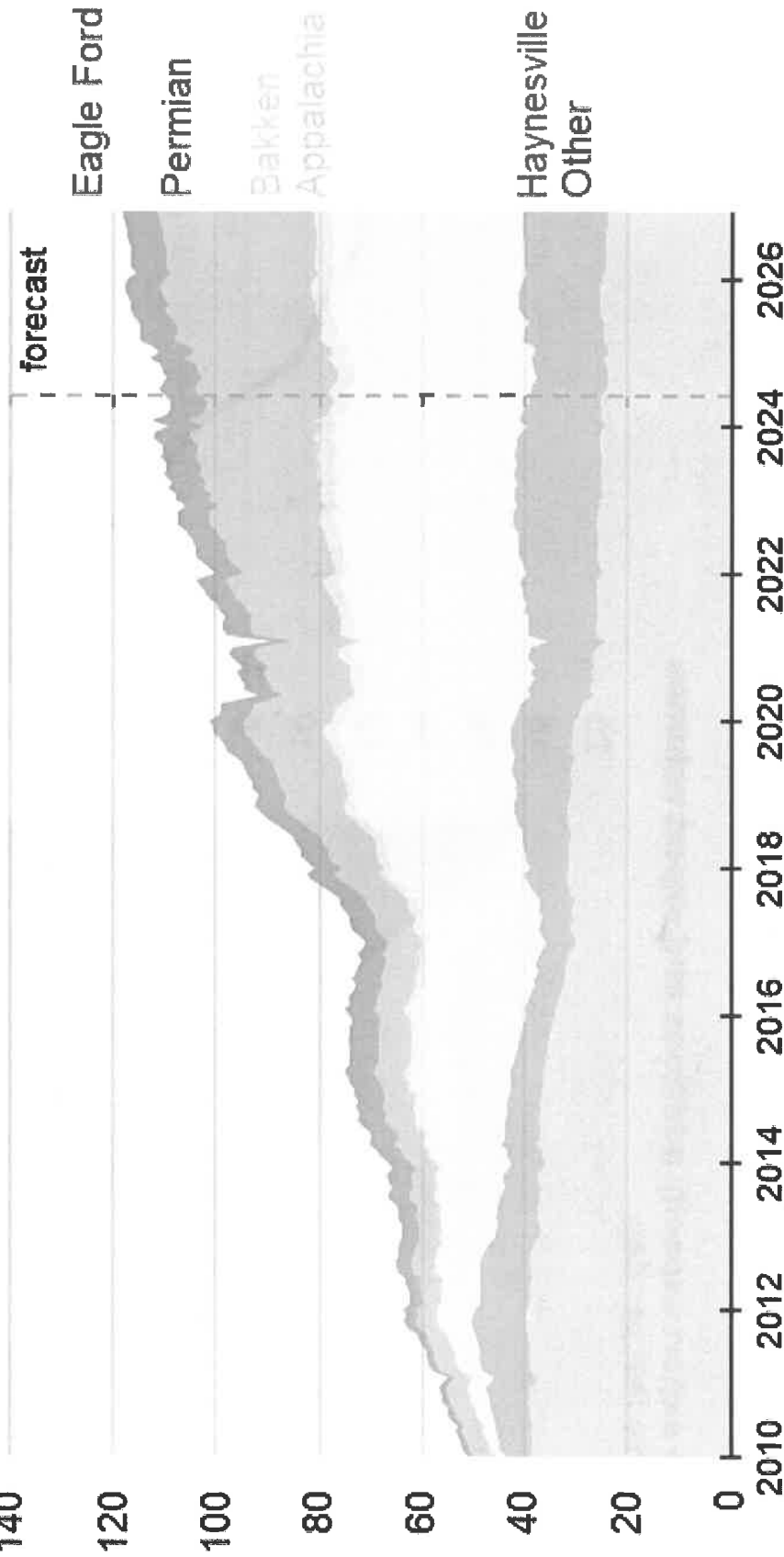
# U.S. Natural Gas Production

Lower 48 change in marketed gas production by region  
billion cubic feet per day (Bcfd/d)



# U.S. Natural Gas Production

Monthly Lower 48 natural gas production by region  
billion cubic feet per day

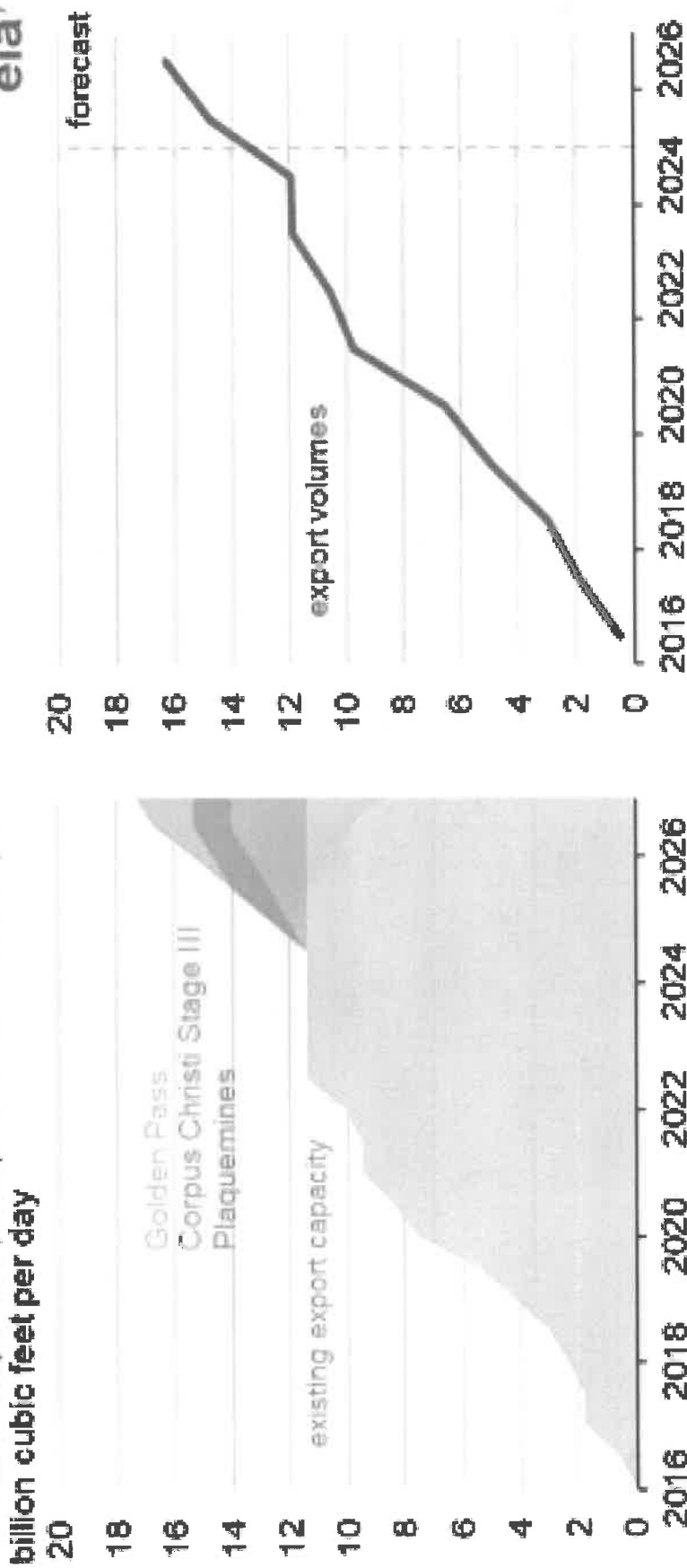


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025



# U.S. LNG Export

U.S. LNG export capacity additions and export volumes



## Natural Gas Pipeline Activities

- ✓ Valmy Unit 1 began taking natural gas for testing purposes from Pinyon Pipeline, the lateral from Ruby Pipeline on December 11. Unit 1 is expected to be declared commercially operational by the end of December.

# Gas Risk Evaluation Matrix (NVE South)

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	1,750,859	1,475,152	1,503,466	1,528,576	1,974,946	2,594,499	3,031,957	2,877,800	2,320,875	1,683,925	1,560,554	1,804,945	24,107,554
Previous Quarter [2]	1,750,859	1,475,152	1,503,466	1,528,576	1,974,946	2,594,499	3,031,957	2,877,800	2,320,875	1,683,925	1,560,554	1,804,945	24,107,554
Current Outlook [3]	1,540,344	1,322,142	1,410,919	1,380,104	1,878,398	2,585,540	3,072,362	2,858,463	2,327,430	1,610,352	1,396,064	1,585,103	22,967,220
Change from Filed ESP	(210,515)	(153,010)	(92,546)	(148,472)	(96,549)	(8,959)	40,405	(19,337)	6,555	(73,573)	(164,490)	(219,842)	(1,140,334)
Change from Previous Quarter	(210,515)	(153,010)	(92,546)	(148,472)	(96,549)	(8,959)	40,405	(19,337)	6,555	(73,573)	(164,490)	(219,842)	(1,140,334)
<b>SoCal Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	6.27	5.65	4.10	3.48	3.40	3.65	5.01	5.05	4.89	4.06	4.80	6.69	4.75
Previous Quarter [2]	5.17	4.87	3.28	2.92	2.81	3.10	4.57	4.62	4.48	3.71	4.26	6.08	4.16
Current Outlook [3]	4.74	4.29	2.99	2.78	2.66	2.88	4.10	4.20	3.96	3.50	4.12	5.84	3.84
Change from Filed ESP	(1.53)	(1.36)	(1.11)	(0.70)	(0.75)	(0.77)	(0.91)	(0.85)	(0.93)	(0.57)	(0.68)	(0.86)	(0.92)
Change from Previous Quarter	(0.42)	(0.58)	(0.29)	(0.14)	(0.16)	(0.22)	(0.47)	(0.43)	(0.52)	(0.21)	(0.14)	(0.24)	(0.32)
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	81.54	65.96	43.53	36.29	36.43	54.16	91.69	102.45	84.79	53.79	62.91	79.09	66.05
Previous Quarter [2]	60.04	53.32	35.81	31.83	36.72	51.64	74.88	78.42	71.90	57.40	55.79	74.90	56.89
Current Outlook [3]	65.88	58.07	40.58	31.32	30.82	43.62	69.30	75.12	66.44	46.43	44.54	60.53	52.72
Change from Filed ESP	(15.66)	(7.89)	(2.94)	(4.96)	(5.61)	(10.54)	(22.39)	(27.33)	(18.36)	(7.36)	(18.38)	(18.57)	(13.33)
Change from Previous Quarter	5.84	4.75	4.77	(0.50)	(5.90)	(8.03)	(5.59)	(3.31)	(5.46)	(10.97)	(11.25)	(14.38)	(4.17)
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	404,098
Previous Quarter [2] [4]	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	404,098
Current Outlook [3] [4]	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	11,559,024	9,095,676	7,218,767	8,210,626	9,892,707	10,424,496	12,339,814	10,991,738	10,152,530	9,739,935	10,479,097	11,824,233	121,868,644
Previous Quarter [2]	11,700,884	8,912,562	8,084,627	9,255,026	10,818,371	10,527,333	12,384,403	11,187,025	10,240,018	9,713,249	10,568,789	11,858,709	125,250,997
Current Outlook [3]	9,870,222	7,565,509	7,469,648	7,766,080	9,562,793	11,385,056	14,416,259	12,704,485	11,215,814	9,123,742	9,458,370	10,753,377	121,291,354
Change from Filed ESP	(1,688,801)	(1,530,167)	(250,882)	(444,546)	(329,914)	960,560	2,076,444	1,772,746	1,063,283	(616,193)	(1,020,727)	(1,070,857)	(577,290)
Change from Previous Quarter	(1,830,661)	(1,347,054)	(614,979)	(1,488,946)	(1,255,578)	857,723	2,031,855	1,517,460	975,796	(589,508)	(1,110,419)	(1,105,332)	(3,959,643)
<b>Base Tariff Energy Rate - Residential (\$/kWh):</b>													
ESP [5]	0.05596	0.05522	0.05596	0.05640	0.05640	0.05640	0.05564	0.05564	0.05564	0.05639	0.05639	0.05639	0.05610
Previous Quarter [6]	0.05522	0.05522	0.05522	0.05465	0.05465	0.05465	0.05346	0.05346	0.05346	0.05337	0.05337	0.05337	0.05418
Current Outlook [7]	0.05493	0.05493	0.05493	0.05516	0.05516	0.05516	0.05398	0.05398	0.05398	0.05391	0.05391	0.05391	0.05450
Change from Filed ESP	(0.00103)	(0.00103)	(0.00103)	(0.00103)	(0.00124)	(0.00124)	(0.00166)	(0.00166)	(0.00166)	(0.00248)	(0.00248)	(0.00248)	(0.00160)
Change from Previous Quarter	(0.00029)	(0.00029)	(0.00029)	0.00051	0.00051	0.00051	0.00052	0.00052	0.00052	0.00054	0.00054	0.00054	0.00032

[1] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027 [4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity) [7] December 2025 forecasts  
 [2] September 2025 Risk Run [5] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027  
 [3] December 2025 Risk Run [6] September 2025 forecasts

# Gas Risk Evaluation Matrix (NVE North)

## Page 1 of 2

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	1,057,473	941,877	996,710	933,610	949,840	995,863	1,161,708	1,142,381	1,020,717	985,326	1,014,940	1,114,694	12,315,138
Previous Quarter [2]	1,057,473	941,877	996,710	933,610	949,840	995,863	1,161,708	1,142,381	1,020,717	985,326	1,014,940	1,114,694	12,315,138
Current Outlook [3]	1,014,325	901,059	947,181	883,241	914,302	975,675	1,215,208	1,166,254	987,450	953,042	976,370	1,083,503	12,017,609
Change from Filed ESP	(43,148)	(40,818)	(49,529)	(50,369)	(35,539)	(20,188)	53,500	23,873	(33,267)	(32,284)	(38,570)	(31,191)	(297,529)
Change from Previous Quarter	(43,148)	(40,818)	(49,529)	(50,369)	(35,539)	(20,188)	53,500	23,873	(33,267)	(32,284)	(38,570)	(31,191)	(297,529)
<b>Malin Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	5.72	5.37	3.88	3.19	3.06	3.32	3.73	3.81	3.72	3.88	4.87	5.57	4.18
Previous Quarter [2]	4.86	4.60	3.23	2.75	2.63	2.85	3.46	3.60	3.46	3.63	4.36	5.20	3.72
Current Outlook [3]	4.52	4.22	3.01	2.76	2.70	2.87	3.46	3.62	3.47	3.43	4.25	5.19	3.63
Change from Filed ESP	(1.19)	(1.15)	(0.87)	(0.43)	(0.36)	(0.45)	(0.27)	(0.19)	(0.25)	(0.45)	(0.62)	(0.38)	(0.55)
Change from Previous Quarter	(0.34)	(0.38)	(0.22)	0.01	0.06	0.02	0.00	0.02	0.01	(0.20)	(0.10)	(0.01)	(0.09)
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	81.54	65.96	43.53	36.29	36.43	54.16	91.69	102.45	84.79	53.79	62.91	79.09	66.05
Previous Quarter [2]	60.04	53.32	35.81	31.83	36.72	51.64	74.88	78.42	71.90	57.40	55.79	74.90	56.89
Current Outlook [3]	65.88	58.07	40.58	31.32	30.82	43.62	69.30	75.12	66.44	46.43	44.54	60.53	52.72
Change from Filed ESP	(15.66)	(7.89)	(2.94)	(4.96)	(5.61)	(10.54)	(22.39)	(27.33)	(18.36)	(7.36)	(18.38)	(18.57)	(13.33)
Change from Previous Quarter	5.84	4.75	4.77	(0.50)	(5.90)	(8.03)	(5.59)	(3.31)	(5.46)	(10.97)	(11.25)	(14.38)	(4.17)
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	304,279	304,279	304,279	273,627	273,627	312,627	312,627	312,627	312,627	312,627	343,279	343,279	309,149
Previous Quarter [2] [4]	304,279	304,279	304,279	273,627	273,627	312,627	312,627	312,627	312,627	312,627	343,279	343,279	309,149
Current Outlook [3] [4]	304,279	304,279	304,279	273,627	273,627	312,627	312,627	312,627	312,627	312,627	343,279	343,279	309,149
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>LDC Consumption Forecast (MMBtu):</b>													
ESP [1]	3,182,828	2,605,950	2,213,875	1,447,546	823,607	593,435	535,454	537,185	566,790	1,097,945	2,132,842	3,192,297	18,929,754
Previous Quarter [2]	3,182,828	2,605,950	2,213,875	1,447,546	823,607	593,435	535,454	537,185	566,790	1,097,945	2,132,842	3,192,297	18,929,754
Current Outlook [3]	3,182,828	2,605,950	2,213,875	1,447,546	823,607	593,435	535,454	537,185	566,790	1,097,945	2,132,842	3,192,297	18,929,754
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	4,316,169	3,842,222	3,626,129	1,897,226	3,099,442	4,300,704	6,194,625	6,018,192	5,286,706	3,993,500	3,597,824	5,152,021	51,324,760
Previous Quarter [2]	4,136,721	4,170,404	3,735,845	1,832,022	3,043,498	4,277,274	6,128,450	5,740,149	5,176,472	4,057,411	3,485,184	5,117,496	50,902,925
Current Outlook [3]	3,797,210	3,688,486	2,978,522	1,212,577	2,395,534	4,082,415	5,999,543	5,350,911	4,640,631	4,000,649	3,466,190	4,515,180	46,127,849
Change from Filed ESP	(518,959)	(153,736)	(647,607)	(684,650)	(703,908)	(218,288)	(195,082)	(667,281)	(646,075)	7,149	(131,633)	(636,841)	(5,196,910)
Change from Previous Quarter	(341,510)	(481,918)	(757,323)	(619,445)	(647,963)	(194,859)	(128,907)	(389,238)	(535,842)	(56,761)	(18,994)	(602,316)	(4,775,076)

[1] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027

[2] September 2025 Risk Run

[3] December 2025 Risk Run

[4] Combined Great Basin, Tuscarora, and Ruby/Pinyon transportation contracts

# Gas Risk Evaluation Matrix (NVE North)

Page 2 of 2

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	12 Mos.
<b>Base Tariff Energy Rate (\$/kWh):</b>													
ESP [5]	0.05119	0.05119	0.05119	0.05316	0.05316	0.05316	0.05511	0.05511	0.05511	0.05459	0.05459	0.05459	0.05351
Previous Quarter [6]	0.05040	0.05040	0.05040	0.05121	0.05121	0.05121	0.05244	0.05244	0.05244	0.05129	0.05129	0.05129	0.05134
Current Outlook [7]	0.04956	0.04956	0.04956	0.05080	0.05080	0.05080	0.05303	0.05303	0.05303	0.05322	0.05322	0.05322	0.05165
Change from Filed ESP	(0.00163)	(0.00163)	(0.00163)	(0.00236)	(0.00236)	(0.00236)	(0.00208)	(0.00208)	(0.00208)	(0.00137)	(0.00137)	(0.00137)	(0.00186)
Change from Previous Quarter	(0.00084)	(0.00084)	(0.00084)	(0.00041)	(0.00041)	(0.00041)	0.00059	0.00059	0.00059	0.00193	0.00193	0.00193	0.00032

[7] December 2025 forecasts

[5] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027

[6] September 2025 forecasts

## NV Energy Course of Action

- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.

## Electric Power Activities

- ✓ No forward sales were executed in Q3.
- ✓ The Company will continue to evaluate forward transaction opportunities as appropriate.
- ✓ The Western Energy Imbalance Market (“EIM”) continued to be utilized to optimize system resources. The Company Q3 benefits have exceeded \$103.81m [Western EIM, Benefits Report - Third Quarter 2025].
- ✓ The Company continues to fill its 2026 and 2027 open capacity positions through its approved laddering strategy.
- ✓ Coal – on the track to fully utilize the existing coal supply by the end of this year.

**EMPLOYEE COMMITMENT**



EMPLOYEE COMMITMENT

**CUSTOMER SERVICE**



CUSTOMER SERVICE

**OPERATIONAL EXCELLENCE**



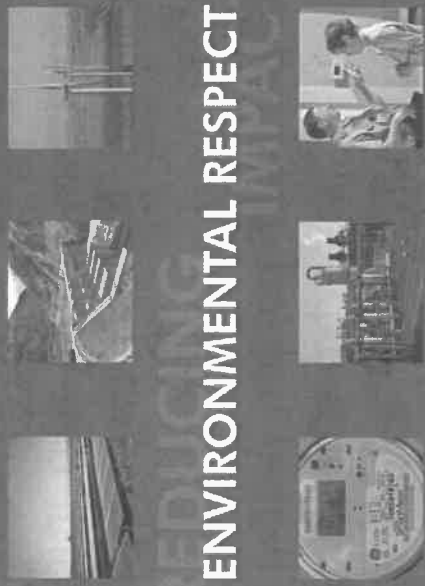
OPERATIONAL EXCELLENCE

**REGULATORY INTEGRITY**




REGULATORY INTEGRITY

**ENVIRONMENTAL RESPECT**



ENVIRONMENTAL RESPECT

**BERKSHIRE FINANCIAL STRENGTH OWNERSHIP**



BERKSHIRE FINANCIAL STRENGTH OWNERSHIP

# Q1 2026 Natural Gas Hedging Update

March 26, 2026

# Market Fundamentals Overview

- ✓ In Energy Information Administration (EIA) March forecast, the Henry Hub spot price averages almost \$3.80 per million British thermal units (MMBtu) in 2026, significantly less than in previous monthly forecasts. Reduced forecast for prices this year is largely because of milder-than-expected weather in February, and March which led to more natural gas in storage in the coming months in the forecast. Prices are expected to rise to about \$3.90/MMBtu on average next year despite higher natural gas production (see slide on page 5). [EIA, Short-Term Energy Outlook, March 2026].
- ✓ Reductions in the flow of liquified natural gas (LNG) through the Strait of Hormuz have caused natural gas prices in Europe and Asia to significantly increase. However, EIA expects U.S. natural gas prices to be relatively unaffected by this development, as LNG export facilities were already operating at a high level of utilization prior to the Middle East conflict, limiting the ability to export additional volumes in the near term. Most of the flexibility in exports will be in the ramp-up at Corpus Christi State 3, which was completed in February and at Golden Pass Train 1, which is set to come online this month. [EIA, Short-Term Energy Outlook, March 2026].

## Market Fundamentals Overview

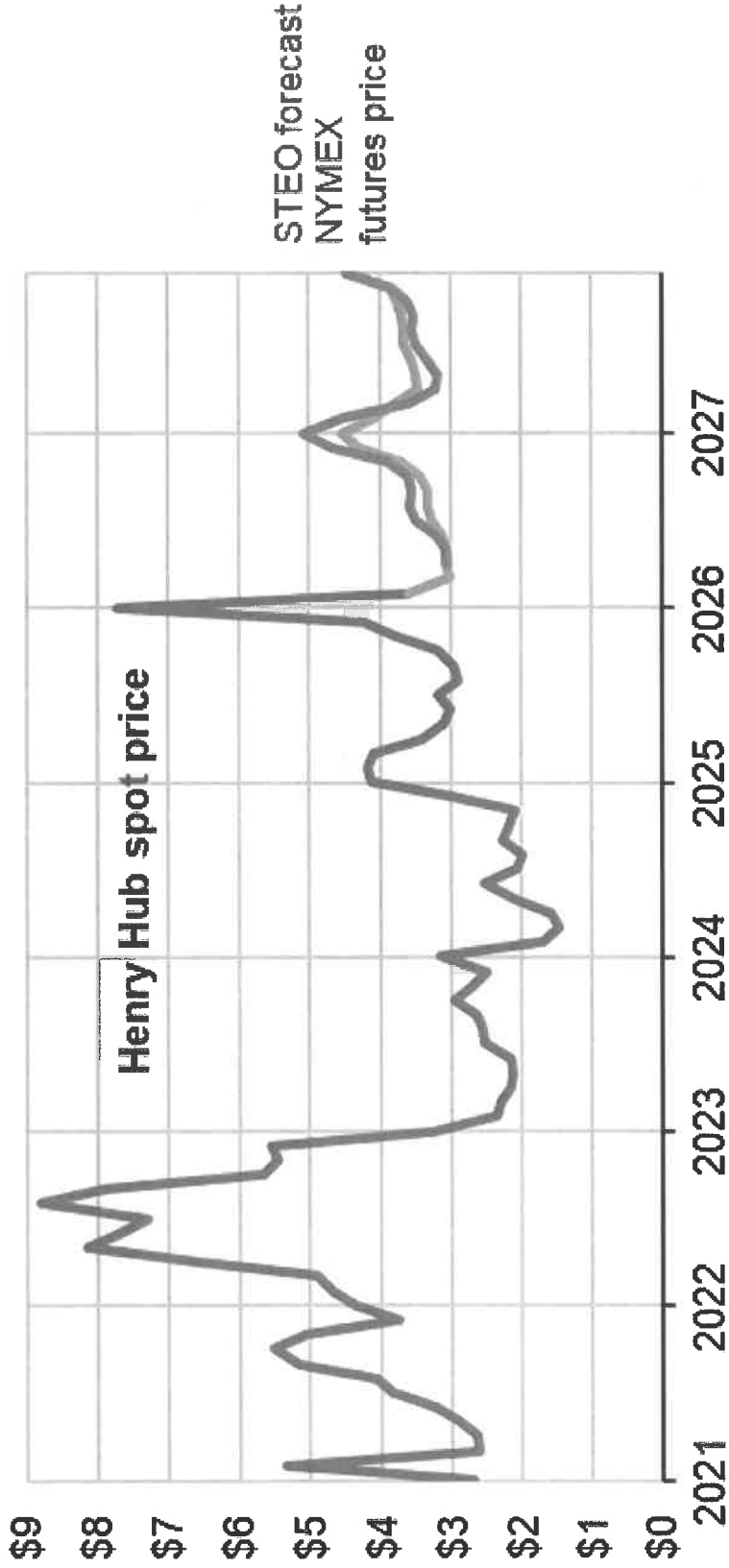
- ✓ Marketed natural gas production in the Lower 48 states reached a record high in November at 118.5 billion cubic feet per day (Bcf/d), and the estimate is that production will average 117.8 Bcf/d this winter (November—March), which is 2% higher than 2025 fall forecasts. The increased production, stemming primarily from increased associated gas production from the Permian and the rest of the U.S. Lower 48 states regions, offset the temporary drop in production during Winter Storm Fern. In February, production nearly recovered after the 3.6 Bcf/d decrease in January, which was concentrated in the Appalachia region (-1.3 Bcf/d) and Permian region (-1.3 Bcf/d). Expectation is for marketed natural gas production to rise averaging 118 Bcf/d in 2026 and 121 Bcf/d in 2027, relative to 116 Bcf/d in 2025. The growth in natural gas production is forecasted to originate from the Haynesville, Permian, and Appalachia regions. Elevated oil prices will drive more oil-directed drilling in the Permian, which will contribute to greater volumes of associated natural gas production (see slide on page 6). [EIA, Short-Term Energy Outlook, March 2026].

## Market Fundamentals Overview

- ✓ U.S. natural gas inventories are expected to end the winter season at 1,840 Bcf, similar to the five-year (2021–2025) average. In January, natural gas stocks dropped to 2,493 Bcf, reflecting the historic withdrawals in response to Winter Storm Fern. Based on data from the National Oceanic and Atmospheric Administration, the 2025–2026 winter season (November–March) will have 2% more heating degree days (HDDs) than the 10-year average. Although we have had colder weather that has contributed to record high spot prices, production was higher than expected throughout the winter, which helped dampen the effect of January’s large storage withdrawals, keeping storage levels close to or above average through the winter. EIA expects natural gas inventories will end the withdrawal season near the five-year average (see slide on pg. 7). Above-average inventories in the Pacific region (48%) and the Mountain region (50%) are expected as we head into summer. [EIA, Short-Term Energy Outlook, March 2026].

# U.S. Natural Gas Prices

Henry Hub natural gas price and NYMEX futures price  
dollars per million British thermal units

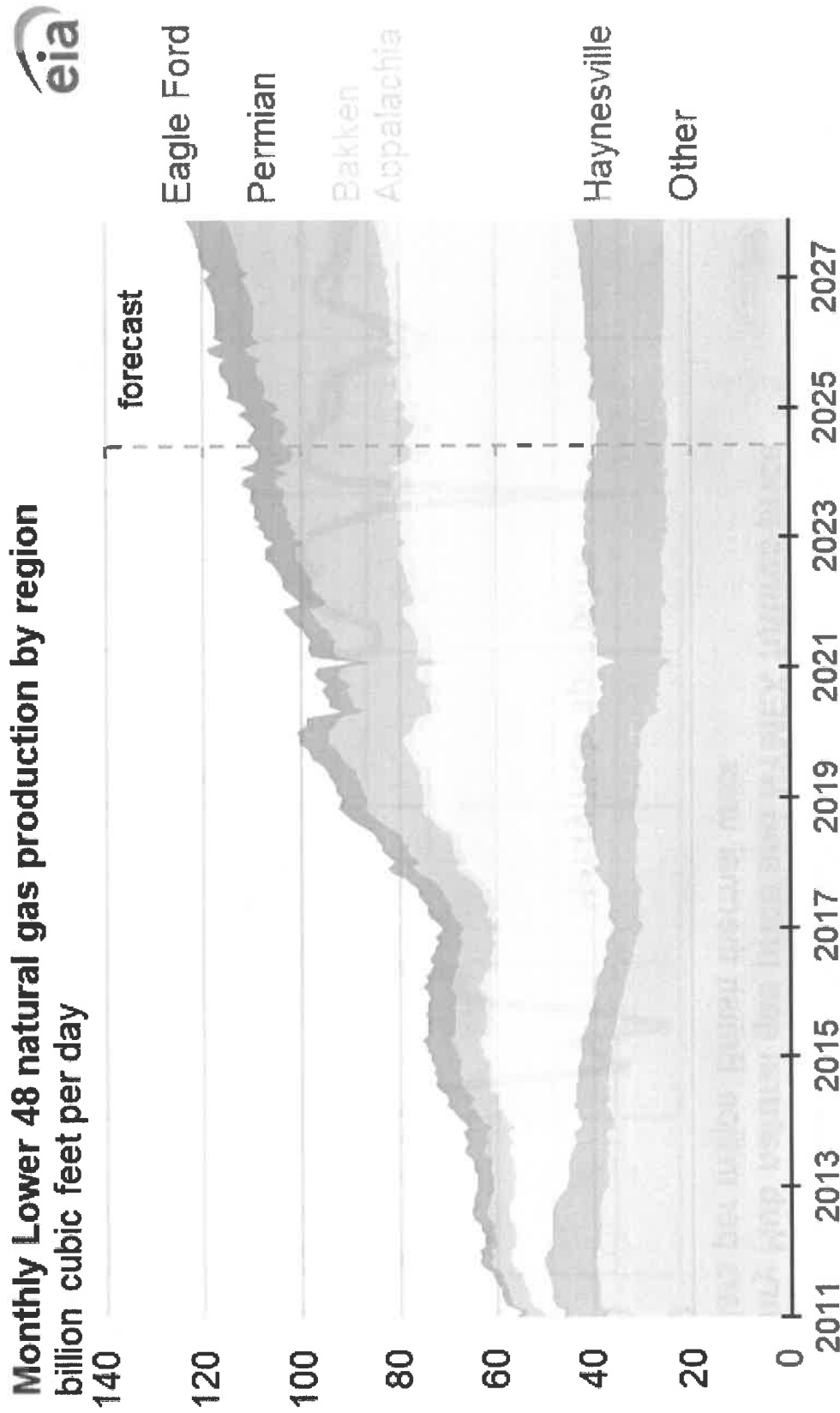


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2026, Bloomberg L.P., and LSEG Data

Note: Futures curve is the average settlement price for five trading days ending March 9, 2025.



# U.S. Natural Gas Production

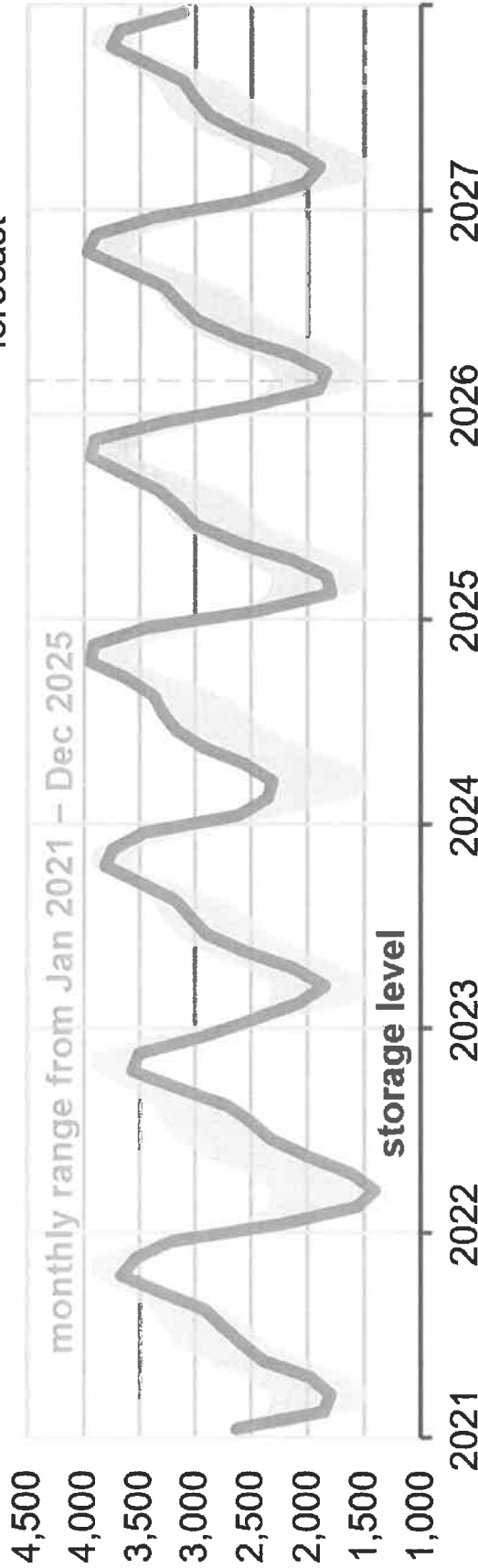


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2026

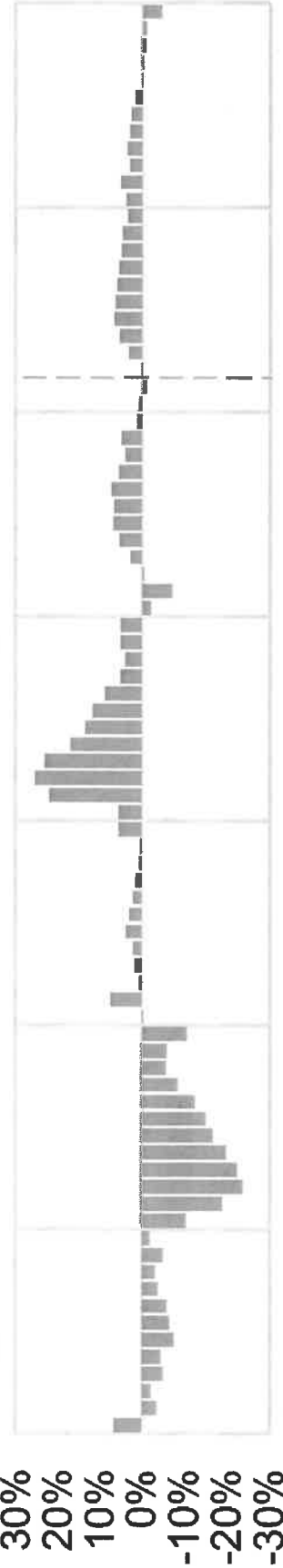


# U.S. Gas Storage (Lower 48)

**U.S. working natural gas in storage**  
billion cubic feet



**Percentage deviation from 2021 - 2025 average**



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2026



## Natural Gas Pipeline Activities

- ✓ Valmy Unit 1 became commercially operational burning natural gas on January 7, 2026.
- ✓ Gas Transmission Northwest (GTN) Pipeline is required to file a Section 4 rate case at FERC by September 30, 2026. Sierra participated in pre-filing rate settlement discussions with GTN on February 25.

# Gas Risk Evaluation Matrix (NVE South)

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	1,528,576	1,974,946	2,594,499	3,031,957	2,877,800	2,320,875	1,683,925	1,560,554	1,804,945	1,902,387	1,615,391	1,649,024	24,544,879
Previous Quarter [2]	1,380,104	1,878,398	2,585,540	3,072,362	2,858,463	2,327,430	1,610,352	1,396,064	1,585,103	1,673,534	1,449,711	1,563,972	23,381,032
Current Outlook [3]	1,380,104	1,878,398	2,585,540	3,072,362	2,858,463	2,327,430	1,610,352	1,396,064	1,585,103	1,673,534	1,449,711	1,563,972	23,381,032
Change from Filed ESP	(148,472)	(96,549)	(8,959)	40,405	(19,337)	6,555	(73,573)	(164,490)	(219,842)	(228,853)	(165,680)	(85,052)	(1,163,847)
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>SoCal Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	3.48	3.40	3.65	5.01	5.05	4.89	4.06	4.80	6.69	6.75	5.72	3.50	4.75
Previous Quarter [2]	2.78	2.66	2.88	4.10	4.20	3.96	3.50	4.12	5.84	5.91	5.34	3.48	4.06
Current Outlook [3]	1.37	1.25	1.42	2.41	2.85	2.63	2.18	3.02	4.48	4.80	4.37	2.63	2.78
Change from Filed ESP	(2.11)	(2.15)	(2.23)	(2.60)	(2.20)	(2.25)	(1.88)	(1.79)	(2.21)	(1.96)	(1.36)	(0.86)	(1.97)
Change from Previous Quarter	(1.41)	(1.40)	(1.46)	(1.69)	(1.35)	(1.32)	(1.31)	(1.10)	(1.35)	(1.12)	(0.97)	(0.84)	(1.28)
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	36.29	36.43	54.16	91.69	102.45	84.79	53.79	62.91	79.09	87.89	67.07	33.86	65.87
Previous Quarter [2]	31.32	30.82	43.62	69.30	75.12	66.44	46.43	44.54	60.53	71.12	59.60	36.08	52.91
Current Outlook [3]	20.66	22.61	33.39	52.41	59.85	51.43	39.56	36.86	45.34	57.42	48.09	27.38	41.25
Change from Filed ESP	(15.63)	(13.82)	(20.77)	(39.28)	(42.60)	(33.36)	(14.23)	(26.06)	(33.75)	(30.46)	(18.97)	(6.47)	(24.62)
Change from Previous Quarter	(10.66)	(8.21)	(10.23)	(16.89)	(15.27)	(15.01)	(6.87)	(7.68)	(15.18)	(13.70)	(11.51)	(8.70)	(11.66)
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	404,098
Previous Quarter [2] [4]	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	404,098
Current Outlook [3] [4]	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	8,210,626	9,892,707	10,424,496	12,339,814	10,931,738	10,152,530	9,739,935	10,479,097	11,824,233	12,941,841	10,521,861	6,458,347	123,917,227
Previous Quarter [2]	7,766,080	9,562,793	11,385,056	14,416,259	12,704,485	11,215,814	9,123,742	9,458,370	10,753,377	11,398,183	9,455,874	9,077,524	126,317,555
Current Outlook [3]	7,909,745	9,280,618	11,862,174	14,775,586	12,634,265	11,122,495	9,296,816	9,402,031	10,899,742	11,400,294	9,325,964	8,867,286	126,777,016
Change from Filed ESP	(300,881)	(612,089)	(1,437,678)	(2,435,771)	(1,702,526)	(969,965)	(443,119)	(1,077,066)	(924,491)	(1,541,548)	(1,195,897)	2,408,939	2,859,789
Change from Previous Quarter	143,666	(282,175)	477,118	359,327	(70,220)	(93,318)	173,074	(56,339)	146,366	2,111	(129,910)	(210,238)	459,460
<b>Base Tariff Energy Rate - Residential (\$/kWh):</b>													
ESP [5]	0.05640	0.05640	0.05640	0.05640	0.05640	0.05640	0.05639	0.05659	0.05639	0.05639	0.05309	0.05309	0.05538
Previous Quarter [6]	0.05516	0.05516	0.05516	0.05398	0.05398	0.05398	0.05391	0.05391	0.05391	0.04756	0.04756	0.04756	0.05265
Current Outlook [7]	0.05535	0.05535	0.05535	0.05432	0.05432	0.05432	0.05279	0.05279	0.05279	0.04387	0.04387	0.04387	0.05158
Change from Filed ESP	(0.00105)	(0.00105)	(0.00105)	(0.00132)	(0.00132)	(0.00132)	(0.00360)	(0.00360)	(0.00360)	(0.00922)	(0.00922)	(0.00922)	(0.0380)
Change from Previous Quarter	0.00019	0.00019	0.00034	0.00034	0.00034	0.00034	(0.00112)	(0.00112)	(0.00112)	(0.00369)	(0.00369)	(0.00369)	(0.08107)

[1] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027  
 [2] December 2025 Risk Run  
 [3] March 2026 Risk Run  
 [4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity)  
 [5] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027  
 [6] December 2025 forecasts  
 [7] March 2026 forecasts

# Gas Risk Evaluation Matrix (NVE North)

## Page 1 of 2

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	12 Mos.
<b>Load Forecast (MWh):</b>													
ESP [1]	933,610	949,840	995,863	1,161,708	1,142,381	1,020,717	985,326	1,014,940	1,114,694	1,235,148	1,110,054	1,198,855	12,863,136
Previous Quarter [2]	883,241	914,302	975,675	1,215,208	1,166,254	987,450	953,042	976,370	1,083,503	1,205,073	1,082,400	1,160,414	12,602,933
Current Outlook [3]	883,241	914,302	975,675	1,215,208	1,166,254	987,450	953,042	976,370	1,083,503	1,205,073	1,082,400	1,160,414	12,602,933
Change from Filled ESP	(50,369)	(35,539)	(20,188)	53,500	23,873	(33,267)	(32,284)	(38,570)	(31,191)	(30,075)	(27,653)	(38,441)	(260,203)
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Malin Gas Price Forecast (\$/MMBtu):</b>													
ESP [1]	3.19	3.06	3.32	3.73	3.81	3.72	3.88	4.87	5.57	6.00	5.36	3.76	4.19
Previous Quarter [2]	2.76	2.70	2.87	3.46	3.62	3.47	3.43	4.25	5.19	5.52	4.99	3.55	3.82
Current Outlook [3]	1.36	1.32	1.37	2.15	2.35	2.21	2.18	3.00	4.03	4.29	3.84	2.43	2.54
Change from Filled ESP	(1.83)	(1.74)	(1.95)	(1.58)	(1.46)	(1.51)	(1.70)	(1.87)	(1.54)	(1.70)	(1.52)	(1.32)	(1.64)
Change from Previous Quarter	(1.40)	(1.37)	(1.50)	(1.31)	(1.27)	(1.26)	(1.25)	(1.25)	(1.16)	(1.23)	(1.15)	(1.12)	(1.27)
<b>Purch Power Price Fcst (\$/MWh):</b>													
ESP [1]	36.29	36.43	54.16	91.69	102.45	84.79	53.79	62.91	79.09	87.89	67.07	33.86	65.87
Previous Quarter [2]	31.32	30.82	43.62	69.30	75.12	66.44	46.43	44.54	60.53	71.12	59.60	36.08	52.91
Current Outlook [3]	20.66	22.61	33.39	52.41	59.85	51.43	39.56	36.86	45.34	57.42	48.09	27.38	41.25
Change from Filled ESP	(15.63)	(13.82)	(20.77)	(39.28)	(42.60)	(33.36)	(14.23)	(26.06)	(33.75)	(30.46)	(18.97)	(6.47)	(24.62)
Change from Previous Quarter	(10.66)	(8.21)	(10.23)	(16.89)	(15.27)	(15.01)	(6.87)	(7.68)	(15.18)	(13.70)	(11.51)	(8.70)	(11.66)
<b>Gas Pipeline Capacity (Dth/Day):</b>													
ESP [1] [4]	304,279	304,279	304,279	273,627	273,627	312,627	312,627	312,627	312,627	312,627	343,279	343,279	309,149
Previous Quarter [2] [4]	304,279	304,279	304,279	273,627	273,627	312,627	312,627	312,627	312,627	312,627	343,279	343,279	309,149
Current Outlook [3] [4]	304,279	304,279	304,279	273,627	273,627	312,627	312,627	312,627	312,627	312,627	343,279	343,279	309,149
Change from Filled ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>LDC Consumption Forecast (MMBtu):</b>													
ESP [1]	1,447,546	823,607	593,435	535,454	537,185	566,790	1,097,945	2,132,842	3,192,297	3,194,572	2,617,795	2,229,747	18,969,214
Previous Quarter [2]	1,447,546	823,607	593,435	535,454	537,185	566,790	1,097,945	2,132,842	3,192,297	3,194,572	2,617,795	2,229,747	18,969,214
Current Outlook [3]	1,447,546	823,607	593,435	535,454	537,185	566,790	1,097,945	2,132,842	3,192,297	3,194,572	2,617,795	2,229,747	18,969,214
Change from Filled ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Power Plant Gas Burn (MMBtu):</b>													
ESP [1]	1,897,226	3,099,442	4,300,704	6,194,625	6,018,192	5,286,706	3,993,500	3,597,824	5,152,021	5,529,936	4,483,237	3,722,409	53,275,823
Previous Quarter [2]	1,212,577	2,395,534	4,082,415	5,995,543	5,350,911	4,640,631	4,000,649	3,466,190	4,515,180	5,085,838	4,312,446	4,517,699	49,579,614
Current Outlook [3]	1,430,893	2,944,977	4,923,799	5,756,978	5,570,479	4,864,798	3,868,155	3,443,912	4,341,056	5,124,380	4,532,067	4,868,511	51,670,006
Change from Filled ESP	(466,334)	(154,464)	623,096	(437,647)	(447,713)	(421,908)	(125,345)	(153,912)	(810,965)	(405,556)	48,829	1,146,102	(1,605,817)
Change from Previous Quarter	218,316	549,443	841,384	(242,565)	219,568	224,168	(132,494)	(22,279)	(174,124)	38,542	219,621	350,812	2,090,392

[4] Combined Great Basin, Tuscarora, and Ruby/Pinyon transportation contracts

[1] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027

[2] December 2025 Risk Run

[3] March 2026 Risk Run

# Gas Risk Evaluation Matrix (NVE North)

Page 2 of 2

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	12 Mos.
<b>Base Tariff Energy Rate (\$/kWh):</b>													
ESP [5]	0.05316	0.05316	0.05316	0.05511	0.05511	0.05511	0.05459	0.05459	0.05459	0.05134	0.05134	0.05134	0.05355
Previous Quarter [6]	0.05080	0.05080	0.05080	0.05303	0.05303	0.05303	0.05322	0.05322	0.05322	0.04989	0.04989	0.04989	0.05174
Current Outlook [7]	0.05088	0.05088	0.05088	0.05084	0.05084	0.05084	0.04927	0.04927	0.04927	0.04411	0.04411	0.04411	0.04878
Change from Filed ESP	(0.00228)	(0.00228)	(0.00228)	(0.00427)	(0.00427)	(0.00427)	(0.00532)	(0.00532)	(0.00532)	(0.00723)	(0.00723)	(0.00723)	(0.00478)
Change from Previous Quarter	0.00008	0.00008	0.00008	(0.00219)	(0.00219)	(0.00219)	(0.00395)	(0.00395)	(0.00395)	(0.00578)	(0.00578)	(0.00578)	(0.00296)

[7] March 2026 forecasts

[5] Joint ESP Update filed 8/27/2025 (Docket No. 25-08027) for 2026-2027

[6] December 2025 forecasts

## NV Energy Course of Action

- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.

## **ESP GAS-2**

**Nevada Power Company  
d/b/a NV Energy  
Summary of Actual and Forecasted BTERs and DEAA  
(\$ per kWh)**

Ln	Residential	BTER				DEAA				Ln
		Projected				Projected				
		1/1/2027	4/1/2027	7/1/2027	10/1/2027	1/1/2027	4/1/2027	7/1/2027	10/1/2027	
1	Base	0.04387	0.04301	0.04349	0.04501	(0.00500)	(0.00750)	(0.00733)	(0.00582)	1
2	Low	0.04387	0.04301	0.04220	0.04213	(0.00500)	(0.00750)	(0.00862)	(0.00874)	2
3	High	0.04387	0.04301	0.04548	0.04939	(0.00500)	(0.00750)	(0.00531)	0.00000	3
4										4
5		<b>1/1/2028</b>	<b>4/1/2028</b>	<b>7/1/2028</b>	<b>10/1/2028</b>	<b>1/1/2028</b>	<b>4/1/2028</b>	<b>7/1/2028</b>	<b>10/1/2028</b>	5
6	Base	0.04830	0.04902	0.04891	0.04839	(0.00332)	(0.00082)	0.00168	0.00000	6
7	Low	0.04225	0.04165	0.04138	0.04078	0.00000	0.00000	(0.00250)	(0.00500)	7
8	High	0.05789	0.06063	0.06091	0.06064	0.00250	0.00500	0.00750	0.00850	8
9										9
10		<b>1/1/2029</b>	<b>4/1/2029</b>	<b>7/1/2029</b>	<b>10/1/2029</b>	<b>1/1/2029</b>	<b>4/1/2029</b>	<b>7/1/2029</b>	<b>10/1/2029</b>	10
11	Base	0.04470	0.04566	0.04628	0.04808	0.00000	0.00000	0.00000	0.00000	11
12	Low	0.03693	0.03788	0.03866	0.04036	(0.00444)	(0.00393)	(0.00251)	0.00000	12
13	High	0.05718	0.05822	0.05855	0.06067	0.00600	0.00421	0.00443	0.00334	13
14										14
15										15
16										16
17										17
18	Non-Residential	BTER				DEAA				18
19		Projected				Projected				19
20		1/1/2027	4/1/2027	7/1/2027	10/1/2027	1/1/2027	4/1/2027	7/1/2027	10/1/2027	20
21	Base	0.04240	0.04104	0.04203	0.04357	(0.00028)	(0.00278)	(0.00528)	(0.00636)	21
22	Low	0.04240	0.04104	0.04008	0.04011	(0.00028)	(0.00278)	(0.00528)	(0.00778)	22
23	High	0.04240	0.04104	0.04507	0.04887	(0.00028)	(0.00278)	(0.00403)	0.00000	23
24										24
25		<b>1/1/2028</b>	<b>4/1/2028</b>	<b>7/1/2028</b>	<b>10/1/2028</b>	<b>1/1/2028</b>	<b>4/1/2028</b>	<b>7/1/2028</b>	<b>10/1/2028</b>	25
26	Base	0.04613	0.04694	0.04685	0.04625	0.00000	0.00000	0.00000	0.00000	26
27	Low	0.04046	0.03957	0.03923	0.03860	(0.00528)	(0.00480)	(0.00432)	(0.00485)	27
28	High	0.05506	0.05846	0.05898	0.05857	0.00250	0.00500	0.00750	0.00577	28
29										29
30		<b>1/1/2029</b>	<b>4/1/2029</b>	<b>7/1/2029</b>	<b>10/1/2029</b>	<b>1/1/2029</b>	<b>4/1/2029</b>	<b>7/1/2029</b>	<b>10/1/2029</b>	30
31	Base	0.04389	0.04529	0.04638	0.04799	0.00000	0.00000	0.00000	0.00000	31
	Low	0.03615	0.03754	0.03881	0.04035	(0.00312)	0.00000	0.00000	0.00000	
	High	0.05635	0.05787	0.05857	0.06041	0.00409	0.00315	0.00402	0.00000	

**Nevada Power Company  
d/b/a NV Energy  
Summary of Forecasted Carrying Charges  
(In Thousands)**

Ln		2027	2028	2029	Ln
1	<b>Residential</b>				1
2	Base	\$ (2,081)	\$ 1,505	\$ 3,147	2
3	Low	(4,161)	(2,624)	603	3
4	High	1,160	6,172	4,976	4
5					5
6	<b>Non-Residential</b>				6
7	Base	\$ (3,745)	\$ (40)	\$ 3,682	7
8	Low	(6,940)	(3,976)	2,346	8
9	High	972	6,597	6,306	9

**Sierra Pacific Power Company  
d/b/a NV Energy  
Summary of Actual and Forecasted BTERs and DEAA  
(\$ per kWh)**

Ln		BTER				DEAA				Ln
		Projected				Projected				
		1/1/2027	4/1/2027	7/1/2027	10/1/2027	1/1/2027	4/1/2027	7/1/2027	10/1/2027	
1	Base	0.04411	0.04382	0.04794	0.04823	(0.00470)	(0.00628)	0.00000	0.00000	1
2	Low	0.04411	0.04382	0.04527	0.04439	(0.00470)	(0.00628)	(0.00446)	(0.00397)	2
3	High	0.04411	0.04382	0.05206	0.05402	(0.00470)	(0.00628)	0.00000	0.00250	3
4										4
5		<b>1/1/2028</b>	<b>4/1/2028</b>	<b>7/1/2028</b>	<b>10/1/2028</b>	<b>1/1/2028</b>	<b>4/1/2028</b>	<b>7/1/2028</b>	<b>10/1/2028</b>	5
6	Base	0.05073	0.05473	0.05597	0.05707	0.00250	0.00500	0.00726	0.00476	6
7	Low	0.04436	0.04662	0.04837	0.04991	0.00000	0.00000	0.00250	0.00319	7
8	High	0.05972	0.06645	0.06710	0.06757	0.00500	0.00750	0.01000	0.01044	8
9										9
10		<b>1/1/2029</b>	<b>4/1/2029</b>	<b>7/1/2029</b>	<b>10/1/2029</b>	<b>1/1/2029</b>	<b>4/1/2029</b>	<b>7/1/2029</b>	<b>10/1/2029</b>	10
11	Base	0.05642	0.05739	0.05779	0.05805	0.00000	0.00000	0.00250	0.00000	11
12	Low	0.04973	0.05100	0.05123	0.05141	0.00268	0.00301	0.00293	0.00000	12
13	High	0.06638	0.06697	0.06765	0.06816	0.00794	0.00544	0.00490	0.00000	13

**Sierra Pacific Power Company  
d/b/a NV Energy  
Summary of Forecasted Carrying Charges  
(In Thousands)**

<u>Ln</u>		<u>2027</u>		<u>2028</u>		<u>2029</u>	<u>Ln</u>
1	Base	\$ 565	\$	4,583	\$	4,395	1
2	Low	(2,193)		3,017		2,949	2
3	High	5,272		10,955		6,074	3

## **ESP RM-1**

**NV Energy, Risk Management and Control Policy**

**NV Energy, Inc.**  
**Risk Management and Control Policy**

**Risk Committee Approval**

**October 22, 2025**

**This policy should only be distributed to the employees of NV Energy (and its subsidiaries) who need access to the document during the performance of their assigned duties. This policy should not be provided to anyone outside the Company without the prior approval of the Risk Control Department.**

NV Energy, Risk Management and Control Policy

**TABLE OF CONTENTS**

**I. BACKGROUND ..... 3**

**II. OBJECTIVES..... 3**

**III. ENTERPRISE RISK TYPES..... 4**

    A. ACCIDENTAL LOSS RISK ..... 4

    B. CREDIT RISK ..... 4

    C. ENERGY SUPPLY RISK ..... 4

    D. FACILITIES RISK ..... 5

    E. ENVIRONMENTAL RISK..... 5

    F. FINANCIAL RISK ..... 5

    G. INFORMATION AND CONTROL SYSTEMS RISK..... 5

    H. OTHER OPERATING RISK..... 5

**IV. RISK MANAGEMENT AND CONTROL FRAMEWORK ..... 6**

    A. ORGANIZATION AND GOVERNANCE ..... 6

    B. RISK MANAGEMENT PROGRAMS..... 6

    C. RISK CONTROL PRACTICES ..... 6

**V. ORGANIZATION AND GOVERNANCE..... 6**

    A. PRESIDENT & CHIEF EXECUTIVE OFFICER ..... 6

    B. RISK COMMITTEE..... 7

    C. GENERAL COUNSEL ..... 9

    D. RISK CONTROL..... 9

**VI. RISK MANAGEMENT PROGRAMS ..... 9**

    A. ACCIDENTAL RISK..... 9

    B. CREDIT RISK MANAGEMENT PROGRAM ..... 10

    C. ENERGY SUPPLY RISK MANAGEMENT PROGRAM ..... 10

    D. ENVIRONMENTAL RISK ..... 10

    E. FACILITIES RISK ..... 10

    F. FINANCIAL RISK ..... 10

    G. INFORMATION AND CONTROL SYSTEMS RISK ..... 10

    H. OTHER OPERATING RISK ..... 11

**VII. RISK REPORTING ..... 11**

    REPORTING PROCESS ..... 11

**APPENDIX A: POLICY REVISION LOG.....11**

**NV Energy, Risk Management and Control Policy**

**I. Background**

NV Energy, Inc. (the Company) has two wholly owned utility subsidiaries, Nevada Power Company (d/b/a NV Energy) and Sierra Pacific Power Company (d/b/a NV Energy) (and together with NV Energy, the ‘Companies’) who are engaged in the generation, transmission and distribution of electric energy and in the distribution of natural gas in Nevada. The Companies are exposed to a variety of risks inherent in their commercial operations. Those risks include accidental loss risk, credit risk, energy supply risk, environmental risk, facilities risk, financial risk, information and control systems risk, and other operating risk. In aggregate, these risks constitute the Companies’ enterprise risk.

The Companies manage risk in a variety of ways. For example, commitments to generation and transmission and to longer-term energy supply contracts are managed through the resource planning process (including distributed energy resource plans) and culminating with Public Utilities Commission of Nevada (“PUCN”) approval of the resource plans. Other multiyear risks are managed, in part, through the Companies’ strategic planning exercises. Shorter-term risks are managed through annual Energy Supply Plans, budgets, key performance indicators and prioritized objectives by departments or functional area<sup>1</sup>.

**II. Objectives**

This policy establishes standards for monitoring and managing enterprise risk.

The primary objectives of the Companies’ risk management and control efforts will be:

- The identification of risks;
- The qualitative or quantitative assessment of risks;
- The evaluation of the costs and merits of risk mitigation options;
- The identification of risks to be retained by the Companies; and,
- The identification of risks to be shifted to other entities and the means to do so.

Continuous oversight of the Companies’ risk management programs is essential for effective risk control. The Risk Committee will be responsible for the overall policy direction and administration of the Companies’ risk control efforts.

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<sup>1</sup> Because organizations change names, responsibilities, and reporting relationships, references in this policy to ‘department’ or ‘departments’ is effectively referencing the executive or senior vice president responsible for that department or functional area,

**NV Energy, Risk Management and Control Policy**

The Treasurer will assist the Risk Committee in monitoring the operations of the Companies to ensure compliance with risk related policies and procedures. All material omissions and exceptions will be promptly reported to the Risk Committee. The Treasurer will also be responsible for assisting with modifications to those policies and procedures dictated by changing conditions, new technologies and other factors affecting the risks faced by the Companies. The executive leader of each functional area will be responsible for maintaining an inventory of the three biggest risks faced by their organization. Appraisals of those risks will be reported to the Risk Committee on a semi-annual basis along with mitigation plans/tracking/variances.

**III. Enterprise Risk Types**

The Companies encounter several types of risk in their day-to-day operations. For the purposes of this policy, such risks have been categorized as:

- A. Accidental loss risk
- B. Credit risk
- C. Energy supply risk
- D. Environmental risk
- E. Facilities risk
- F. Financial risk
- G. Information and control systems risk
- H. Other risk (e.g., regulatory, reputational, legal, etc.)

***A. Accidental Loss Risk***

Accidental loss risk is defined as the possibility that the Companies will experience financial losses or detrimental operating effects because of accidents and other unanticipated occurrences for which insurance may be acquired. Financial losses can result from damage to the Companies' property, increased operating costs, liability for injury to employees and others, and liability for damage to the property of others.

***B. Credit Risk***

The Companies contract with numerous entities in the normal course of business. Credit risk is defined as the possibility that a counterparty to one or more contracts will be unwilling or unable to fulfill its financial or physical obligations to the Companies because of the counterparty's financial condition.

***C. Energy Supply Risk***

The Companies buy and sell coal, natural gas, oil, wholesale power, carbon allowances, and other products (e.g. Renewable Energy Credit's or Portfolio Energy Credit's) to meet the energy requirements of their customers. They also operate generating plants that produce electric energy for their customers. Those

**NV Energy, Risk Management and Control Policy**

activities expose the Companies to energy risk which causes uncertainty as to the Companies' cash flow requirements for fuel and wholesale power, the expense the Companies incur as a result of their energy procurement efforts, and the Companies' recovery of these costs in customer rates. Energy risk also encompasses reliability risk which is the prospect that energy supplies will not be sufficient to fulfill customer requirements.

***D. Facilities Risk***

The Companies lease or own numerous facilities that are used to provide services to their customers. Facilities risk is defined as the uncertainty introduced by the threat of vandalism, sabotage and other willful acts that could result in injury or death to the Companies' personnel and the general public while they are at the Companies facilities and damage to those facilities. Facilities risk will also include the prospective loss of revenue through theft of service and misappropriation of the Companies' assets through burglaries and other wrongful acts.

***E. Environmental Risk***

The Companies operate generating facilities, electric transmission and distribution lines and substations, gas pipelines and other facilities with the potential to adversely affect the environment. Environmental risk is defined as the possibility that the Companies will experience financial losses or adverse operating conditions because of an emission or release to the environment in excess of that which is currently allowed by law.

***F. Financial Risk***

The primary constituents of financial risk are earnings and liquidity risk. Earnings risk constitutes the uncertainty inherent in the Companies' efforts to earn acceptable levels of revenue. Liquidity risk addresses the uncertainty inherent in the Companies' efforts to have sufficient cash and credit facilities to cover their needs.

***G. Information and Control Systems Risk***

The Companies operate and maintain electronic systems for the accumulation and dissemination of data, the preparation of documents, the distribution of information and the monitoring and control of facilities used in the provision of service to their customers. Information and control systems risk is defined as the uncertainty introduced by the threat of disruption to business activities and to the services provided that could be caused by the wrongful infiltration or manipulation of those information and control systems.

***H. Other Operating Risk***

The preceding description of certain types of operating risk is not intended to be exhaustive. The Companies are currently exposed to other risks and will continue to be exposed to new risks because of the changing business environments in which they operate. This policy will be modified to address any areas of significant risk that have not been specifically cited.

NV Energy, Risk Management and Control Policy

**IV. Risk Management and Control Framework**

The Companies will systematically manage and control each of the types of risk identified above through three primary vehicles.

***A. Organization and Governance***

This policy defines certain risk parameters and exposure management techniques that the departments and employees are expected to use in managing the risk faced by the Companies. The Risk Committee will be responsible for the risk policies of the Company. Each department will be responsible for administration of the Companies' risk management and risk mitigation programs and will be accountable to the Risk Committee.

***B. Risk Management Programs***

The Companies' personnel, who are responsible for managing each type of risk, will maintain risk management programs that provide for the assessment and quantification of the magnitude of each type of risk on an ongoing basis by the development of risk policies; the creation and maintenance of risk mitigation plans; and the implementation of these plans and policies in a manner consistent with this policy.

***C. Risk Control Practices***

The Companies personnel, who are responsible for risk control, will monitor compliance with approved risk management policies and procedures through the use of specific notification thresholds and processes.

**V. Organization and Governance**

***A. Chief Executive Officer***

The Chief Executive Officer will be responsible for assuring that the Risk Committee follows its charter.

To preclude interruptions in the performance of the Risk Committee's assigned duties, the Chief Executive Officer may replace members of the committee who leave the organization or are otherwise assigned within the organization with other members.

The Chief Executive Officer will also have the authority to designate authorized representatives for the members of the Risk Committee and its committees. Authorized representatives will have the same rights and obligations as the members.

**NV Energy, Risk Management and Control Policy**

***B. Risk Committee***

The Risk Committee will be responsible for the overall policy direction and administration of the Companies' risk control activities.

The Risk Committee will be responsible for ensuring that the Chief Executive Officer is kept apprised of Risk Committee activities and required notifications and approvals as stated in the Company's Energy Risk Management and Control Policy.

The Risk Committee will provide a forum for the discussion and evaluation of all of the risks faced by the Companies to achieve an integrated view of overall risk.

The Risk Committee will be responsible for ensuring that adequate risk assessment and control policies and procedures are in place and followed. The Risk Committee will have full authority to approve risk policies and risk mitigation programs of the Company.

The Risk Committee will pursue its objective through and as a complement to the Companies' existing organizational structures.

The Risk Committee is comprised of the following individuals:

- Vice President, General Counsel, Chief Compliance Officer and Government Relations (Chairperson)
- Senior Vice President, Energy Delivery
- Senior Vice President, Regulatory & Resource Planning
- Vice President, Chief Financial Officer
- Vice President, Customer Operations
- Vice President, Customer Solutions
- Vice President, Electric Delivery
- Vice President, Energy Management Systems
- Vice President, Engineering and Project Management
- Vice President, Environmental Services & Land Management
- Vice President, Gas Delivery
- Vice President, Generation
- Vice President, Integrated Resource Planning
- Vice President, Major Projects
- Vice President, Regulatory
- Vice President, Regulatory & Business Policy
- Vice President, Resource Optimization
- Vice President, Transmission
- Treasurer

**NV Energy, Risk Management and Control Policy**

A quorum of the committee will consist of ten of the members. Any action taken by the Risk Committee will require a majority of affirmative votes. The Risk Committee will meet at least once each quarter, or more frequently if requested by the Chairman of the committee. Meetings may be conducted in person, via telephone, video conference, or email. The purpose of the meetings will be to perform the duties set forth in this policy and any additional duties assigned to the committee by the Chief Executive Officer.

Minutes of the Risk Committee meetings will be kept in accordance with Company's Records Retention Policy. Those minutes will include, as attachments, all of the documents presented to the committee during the associated meetings.

The Risk Committee will be responsible for:

- Monitoring the current and expected future economic conditions, assessing their effect on the general business environment and on the Companies, and disseminating the information obtained through such monitoring to the management of the Companies;
- Initiating the preparation of new risk control policies when or where appropriate and the modification of risk control policies already in place;
- Ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Resolving any disputes regarding the appropriate application of those policies and procedures;
- Ensuring the availability of the systems required to monitor, record and report on the risks inherent in the Companies' operations;
- Reviewing and approving the Companies' resource plans, energy supply plans prior to Chief Executive Officer approval;
- Assuring integration of energy procurement or sale risk, credit risk, cash flow risk and ratepayer risk;
- Reviewing and approving all transactions requiring exceptions to the approved plans for acquiring or selling fuel and wholesale power prior to implementation;
- Reviewing all energy procurement or sale transactions requiring the approval of the Chief Executive Officer<sup>2</sup> prior to the presentation of such transactions to the Chief Executive Officer; and
- Assessing the appropriateness of the Companies' risk control activities and modifying this policy, whenever modifications are required to ensure the ongoing viability of the Companies' risk management and control programs and the continued fulfillment of the Companies' obligations.

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<sup>2</sup> The review by the Risk Committee prior to the presentation to the Chief Executive Officer is not required if such transactions are being done in accordance with an Energy Supply Plan already approved by the Chief Executive Officer.

**NV Energy, Risk Management and Control Policy**

The Risk Committee will have the right to delegate portions of its assigned duties to one or more committees. The Risk Committee will establish the charter of each Committee when it is established and modify the charter if necessary. Committees will keep minutes in the same manner as the Risk Committee. Committees will also make periodic reports of their activities to the Risk Committee in the manner designated by the Risk Committee.

***C. General Counsel***

The officers and managers of the Companies will be responsible for enforcing the Companies' risk control policies and procedures applicable to the areas for which they are responsible. The General Counsel will serve as the independent compliance officer responsible for monitoring the operations of the Companies to ensure compliance with policies and procedures as identified in Section VI and VII. All material omissions and exceptions identified by any department will be promptly reported to the General Counsel.

***D. Risk Control***

Each department will be responsible for developing policies, procedures and risk mitigation plans dictated by changing conditions, new technologies, and other factors affecting the risk faced by the department.

Each department will be responsible for maintaining an inventory of the risks faced by that department and providing integrated appraisals of those risks to the Risk Committee at least once each year. Each department will take steps to ensure that the Risk Committee has adequate descriptions of possible future conditions as a setting for risk analysis, evaluation and policy direction. Each department subject to general oversight will monitor compliance with this policy and any additional policies approved by the Risk Committee.

**VI. Risk Management Programs**

Each of the previously identified types of enterprise risk will be managed through the Companies' risk management programs. Primary responsibility for risk management execution will be through these programs and company management as distinct from the risk integration and control function of the Risk Committee.

***A. Accidental Loss Risk***

The Companies will attempt to avoid financial losses through the identification, assessment, prevention, monitoring, and financing of insurable risks. The program will have provisions for the timely evaluation of alternatives for minimizing the frequency and severity of losses and for the mitigation of losses. Financing alternatives such as self-insurance and various forms of commercially available insurance will be routinely evaluated. The program will also have provisions for

**NV Energy, Risk Management and Control Policy**

the preparation of periodic reports to document the Companies' efforts and to comply with legal and regulatory requirements.

***B. Credit Risk Management***

See the Credit Risk Management and Control Policy

***C. Energy Supply Risk Management Program***

See the Energy Risk Management and Control Policy

***D. Environmental Risk***

The Companies will attempt to avoid financial losses through the identification, evaluation, prevention, and monitoring of environmental risks. The program will rely heavily upon the training of personnel to help to ensure compliance with environmental laws and regulations. The program will also have provisions for ongoing communication and cooperation with environmental agencies and other groups.

***E. Facilities Risk***

The Companies, through a program of identification and evaluation of threats, monitoring of facilities, and training of personnel, will attempt to preclude injury, damage, and losses to its facilities. The program will also have provisions for the ongoing communication and cooperation with law enforcement agencies and for the preparation of periodic reports to document the Companies' efforts and to comply with legal and regulatory requirements. Additionally, the program will have provisions to ensure adequate preparation for prompt recovery if any of the Companies' facilities are damaged by willful acts or natural disasters.

***F. Financial Risk***

The Companies have numerous processes like their budgetary processes for the control of expenditures and the management of cash flow as well as the annual financing plan. Financial risk will be addressed through the management processes in place for that purpose.

***G. Information and Control Systems Risk***

The Companies, through a program of identification and evaluation of threats, monitoring of systems, installation of safeguards, and training of personnel, will attempt to preclude infiltration or manipulation of their electronic information and electronic control systems. The program will also have provisions for the preparation of periodic reports to document the Companies' efforts and to comply with legal and regulatory requirements. Additionally, the program will have provisions to ensure adequate preparation for prompt recovery if any of the Companies' information and control systems are adversely affected by such wrongful acts or natural disasters.

NV Energy, Risk Management and Control Policy

***H. Other Operating Risk***

The Companies will address other operating risk through management processes in place for that purpose.

**VII. Risk Reporting**

The Companies' risk control policies will contain practices, which will incorporate risk identification, reporting and risk management.

***Reporting Process***

As directed by the Risk Committee, departments will report on identified risks and the plan to mitigate such risks on a semi-annual basis.

**Note: All those individuals identified as being impacted by the Risk Policies, e.g., Credit Risk Management and Control Policy, Risk Management and Control Policy and Energy Risk Management and Control Policy are required to review the policies each calendar year.**

NV Energy, Risk Management and Control Policy

Appendix A: Policy Revision Log

Date	Revision(s)
August 28, 2014	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Replaced the title of “President” with the title of “Chief Executive Officer”. <ul style="list-style-type: none"> <li>• Although Paul Caudill is the President and Chief Executive Officer, we are using his highest title in the Policy</li> <li>• Change is applied throughout the document</li> </ul> </li> <li>2. Added carbon allowances as instruments that the Companies buy and sell. <ul style="list-style-type: none"> <li>• This recommended change is a result of the change made to Appendix D (Approved financial instruments and physical products) of the Energy Risk Management and Control Policy</li> </ul> </li> <li>3. Replaced “Senior Officer in Charge of General Counsel” with “General Counsel”</li> <li>4. Changed the quorum of the Committee <u>from six to seven</u> members of the twelve member committee. Thus any action to be taken by the committee requires a majority vote of the committee.</li> <li>5. Modified language regarding the Risk Committee’s reviewing and approving Energy Supply Plans and any exceptions to the Energy Supply Plans.</li> <li>6. Added a policy revision log.</li> </ol>
December 16, 2014	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Replaced the acronyms RECs and PECs with their full wording.</li> <li>2. Corrected the appendix reference in the policy revision log.</li> </ol>
May 20, 2015	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Updated the members of the Risk Committee by replacing the Executive, Ethics and Corporate Compliance and the Director, Corporate Insurance with the Senior Officer in Charge of Compliance and Standards and the Manager, Corporate Insurance.</li> </ol>
July 27, 2016	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Removed the Chief Executive Officer, the senior officer in charge of Compliance and Standards and the Manager of Corporate Insurance from the Risk Committee.</li> <li>2. Added the senior officer in charge of Customer Operations and the senior officer in charge of Resource Planning &amp; Analysis to the Risk Committee.</li> <li>3. Updated Risk Committee members’ titles where appropriate.</li> <li>4. A quorum of the Committee will now consist of 6 of the 10 members.</li> <li>5. Added that the Risk Committee will be responsible for ensuring that the Chief Executive Officer is kept apprised of Risk Committee activities and required approvals and notifications as stated in the Company’s Energy Risk Management and Control Policy. Added how meetings can be conducted; in person, via telephone, videoconference, or via email.</li> </ol>
July 26, 2017	<p>Modified Existing Policy:</p>

**NV Energy, Risk Management and Control Policy**

	<ol style="list-style-type: none"> <li>1. Organizational changes necessitated a title change from Senior Vice-President Renewable Energy, Origination and Strategy, to Senior Vice-President Renewable Energy and Smart Infrastructure.</li> <li>2. Organizational changes necessitated updating Jim Doubek’s title to Vice President, Energy Delivery.</li> <li>3. Added the Director, Resource Planning and Analysis as a member of the Risk Committee.</li> </ol>
January 24, 2018	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Removed the Vice President Energy Delivery and Senior Vice President, Renewable Energy and Smart Infrastructure from the Risk Committee</li> <li>2. Replaced the title of “Senior Vice President, Energy Supply” with the title of “Executive Vice President, Chief Operations Officer” and replaced the title of “Senior Vice President, Regulation &amp; Strategic Planning” with “Senior Vice President, Business Planning, Regulation &amp; Legal Strategy”.</li> </ol>
May 7, 2018	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Replaced Chief Executive Officer with President</li> <li>2. Replaced Director, Risk Control with Treasurer</li> <li>3. Updated titles</li> </ol>
December 19, 2018	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Replaced “President” with “Chief Executive Officer”</li> <li>2. Replaced the title of “Senior Vice President, Chief Financial Officer” with the title of “Vice President, Chief Financial Officer</li> <li>3. Replaced the title of “Senior Vice President, Customer Operations” with the title of Vice President, Customer Operations”</li> <li>4. Added footnote on page 3 referencing the “executive or senior vice president”</li> </ol>
December 4, 2019	<p>Modified Existing Policy</p> <ol style="list-style-type: none"> <li>1. Added Senior Vice President Renewable &amp; Origination as voting member to Risk Committee</li> <li>2. Changed member title from Senior Vice President, Business Planning, Regulation &amp; Legal Strategy to Vice President, Regulatory</li> </ol>
September 17, 2020	<p>Modified Existing Policy</p> <ol style="list-style-type: none"> <li>1. Added Assistant along side Treasurer</li> <li>2. Added Vice President, Electric Delivery to Risk Committee</li> <li>3. Added Vice President, Transmission to Risk Committee</li> <li>4. Added Vice President, Generation to Risk Committee</li> <li>5. Added Assistant Treasurer to Risk Committee</li> <li>6. Deleted Senior Vice President, Operations from Risk Committee</li> <li>7. Added &amp; Treasurer to Vice President, Chief Financial Officer title</li> </ol>
November 16, 2021	<p>Modified Existing Policy</p> <ol style="list-style-type: none"> <li>1. Deleted Vice President, Resource Optimization</li> </ol>
December 14, 2022	<ol style="list-style-type: none"> <li>1. Deleted Senior Vice President, Energy Supply</li> <li>2. Added Vice President, Renewables</li> <li>3. Added Vice President, Generation</li> <li>4. Added Vice President, Resource Optimization</li> </ol>
April 19, 2023	<p>Modify Existing Policy</p> <ol style="list-style-type: none"> <li>1. Change Senior Vice President, Chief Financial Officer &amp; Treasurer to Vice President, Chief Financial Officer</li> <li>2. Change Assistant Treasurer to Treasurer</li> </ol>
November 15, 2023	<p>Modify Existing Policy</p> <ol style="list-style-type: none"> <li>1. Replaced Assistant Treasurer with Treasurer</li> </ol>

**NV Energy, Risk Management and Control Policy**

	2. Removed Appendix B (Employee acknowledgement)
November 20, 2024	Modify Existing Policy 1. Changed section VI to reflect the table of contents
January 22, 2025	Modify Existing Policy Revised the voting members of the Risk Committee as follows: 1. Replaced VP Electric Delivery & Natural Disaster Protection with SVP Energy Delivery 2. Added - VP Electric Delivery 3. Replaced VP Integrated Energy Services with VP Energy Mgmt Sys 4. Added - VP Customer Solutions 5. Added - VP Major Projects 6. Added - VP Regulatory & Business Policy 7. Removed Director, Resource & Planning Analysis 8. Added – VP Integrated Resource Planning
April 26, 2025	Modify Existing Policy Added Senior Vice President, Regulatory & Resource Planning as a voting member.
October 22, 2025	Modify Existing Policy 1. Changed Chairman of Risk Committee title SVP, General Counsel, Corporate Secretary & Chief Compliance Officer to VP General Counsel, Chief Compliance Officer and Government Relations 2. Removed the title VP Renewables as a voting member of the Risk Committee (old title) 3. Changed the Risk Committee quorum from 11-10

## **ESP RM-2**

**NV Energy, Inc.**  
**Energy Risk Management and Control Policy**

**Risk Committee Approval**

**October 22, 2025**

**This policy should only be distributed to the employees of NV Energy (and its subsidiaries) who need access to the document during the performance of their assigned duties. This policy should not be provided outside the Company without the prior approval of the Risk Committee Chairperson.**

## TABLE OF CONTENTS

<b>I.</b>	<b>BACKGROUND</b> .....	<b>3</b>
<b>II.</b>	<b>APPLICATION AND PURPOSE</b> .....	<b>3</b>
<b>III.</b>	<b>POLICY OBJECTIVES</b> .....	<b>3</b>
<b>IV.</b>	<b>ENERGY RISK DEFINITION</b> .....	<b>4</b>
<b>V.</b>	<b>ENERGY RISK MANAGEMENT AND CONTROL FRAMEWORK</b> .....	<b>4</b>
	A. ORGANIZATION AND GOVERNANCE .....	4
	B. ENERGY RISK MANAGEMENT PROGRAM .....	5
	C. DOCUMENTING TRANSACTIONS AND AUTHORIZED SIGNATORIES .....	6
	D. RISK CONTROL PRACTICES .....	7
<b>VI.</b>	<b>COMPLIANCE</b> .....	<b>9</b>
	<b>APPENDIX A: DEFINITIONS</b> .....	<b>10</b>
	<b>APPENDIX B: AREAS OF RESPONSIBILITY - COMMITTEE</b> .....	<b>13</b>
	<b>APPENDIX C: AREAS OF RESPONSIBILITY – DEPARTMENTS</b> .....	<b>13</b>
	<b>APPENDIX D: RESOURCE PROCUREMENT AND SALE CONSTRAINTS</b> .....	<b>17</b>
	<b>APPENDIX E: RISK CONTROL NOTIFICATION THRESHOLD</b> .....	<b>20</b>
	<b>APPENDIX F: POLICY REVISION LOG</b> .....	<b>21</b>

## **I. Background**

NV Energy, Inc. (the Company) has two wholly owned utility subsidiaries, Nevada Power Company (d/b/a NV Energy) and Sierra Pacific Power Company (d/b/a NV Energy) (and together with NV Energy, the ‘Companies’) who are engaged in the generation, transmission and distribution of electric energy and in the distribution of natural gas in Nevada.

This policy addresses energy risks of the Companies. The officers and management of the Companies are responsible for enforcing this policy and the associated procedures in the areas for which they are responsible. The Companies are exposed to a variety of risks inherent in their commercial operations. Those risks include accidental loss risk, credit risk, energy supply risk, environmental risk, facilities risk, financial risk, information and control systems risk, and other operating risk. In aggregate, these risks constitute the Companies’ enterprise risk.

The Companies manage risk in a variety of ways. For example, commitments to generation and transmission and to longer-term energy supply contracts are managed through the resource planning process (including distributed energy resource plans) and culminating with Public Utilities Commission of Nevada (PUCN) approval of the resource plans. Other multiyear risks are managed, in part, through the Companies’ strategic planning exercises. Shorter-term risks are managed through annual Energy Supply Plans, budgets, key performance indicators and prioritized objectives by departments or functional area<sup>1</sup>.

## **II. Application and Purpose**

This policy will be applied to all physical and financial transactions related to energy procurement, energy sales, and energy hedging in accordance with Energy Supply Plans or Integrated Resource Plans approved by the PUCN as applicable. Any variances from the approved Energy Supply Plans or Integrated Resource Plans must be approved in accordance with Section V.D.2.

## **III. Policy Objectives**

1. Provide preset notification thresholds for transactions entered into pursuant to this policy;
2. Establish sound principles for entering into and managing such transactions; and,

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<sup>1</sup> Because organizations change names, responsibilities, and reporting relationships, references in this policy to ‘department’ or ‘departments’ is effectively referencing the executive or vice president responsible for that department or functional area.

3. Define the responsibilities for managing and monitoring those risks.

#### IV. **Energy Risk Definition**

The Companies are engaged in the generation, transmission and distribution of electricity, and in the distribution of natural gas in Nevada. The Companies deal in the coal, natural gas, oil and wholesale power markets (including renewable) to meet the energy requirements of their customers. They also acquire, develop and operate generating plants that produce electric energy for their customers. In so doing, the Companies are exposed to a variety of risks inherent in their energy supply efforts, including among others: price, volumetric, credit, and operational risk.

#### V. **Energy Risk Management and Control Framework**

The Companies will systematically manage price, volumetric and credit risks through three primary vehicles: (i) organization and governance; (ii) energy risk management programs; and (iii) energy risk control practices. Credit risk is addressed by a separate Credit Risk Management and Control Policy.

##### A. ***Organization and Governance***

1. **Risk Committee:** The Risk Committee will be responsible for overall policy direction of the Companies' energy risk management and control efforts. Specific activities for which the Risk Committee will be responsible are set forth in Appendix B, Section A. The Risk Committee has the right to delegate portions of its assigned duties to one or more committees.
2. **Risk Control:** Risk Control, under the direction of the Vice President, Chief Financial Officer and the Treasurer, will monitor the operations of the Companies to ensure compliance with this policy and the associated procedures. All omissions and exceptions will be reported promptly to the Risk Committee by Risk Control. Risk Control will be responsible for the activities set forth in Appendix C, Section A.
  1. **Credit Risk Management:** Credit Risk Management, under the direction of the Vice President, Chief Financial Officer and the Treasurer, will be responsible for managing and mitigating the Companies' credit risk exposures associated with energy and service delivery transactions. Credit Risk Management will be responsible for the activities set forth in Appendix C, Section B.
3. **Resource Optimization:** Resource Optimization, under direction of the Vice President of Resource Optimization, will be responsible for the resource

NV Energy, Energy Risk Management and Control Policy

optimization, balancing, forward trading, and contract negotiation related to fuel and short-term wholesale power. Specific activities for which Resource Optimization will be responsible are set forth in Appendix C, Section C.

4. **Origination:** Origination, under the direction of the Vice President of Resource Optimization will be responsible for the origination functions related to long-term (i.e., three year or greater term) wholesale power. Specific activities for which Origination will be responsible are set forth in Appendix C, Section D.
5. **Resource Planning and Analysis:** Resource Planning and Analysis, under direction from the Vice President, Resource Optimization will be responsible for preparation of forecasts of: customer energy requirements; energy and fuel prices; production costs; and fuel requirements. Additionally, Resource Planning and Analysis will develop Integrated Resource Plans and Energy Supply Plans in accordance with the Public Utilities Commission of Nevada resource planning regulations. Specific activities for which Resource Planning and Analysis will be responsible are set forth in Appendix C, Section E.
6. **Fuel and Purchased Power Accounting:** Fuel and Purchased Power Accounting, under direction from the, Chief Financial Officer and the Treasurer, will be responsible for ensuring transactions are accurately recorded in the financial system of record. Specific activities for which Fuel and Purchased Power Accounting will be responsible are set forth in Appendix C, Section F.

**B. Energy Risk Management Program**

1. **Portfolio Optimization:** The Companies, through the purchase and sale of the financial instruments and physical products set forth in Appendix D, Section A, will manage the energy risks inherent in the Companies' operations and prepare periodic reports to document the Companies' efforts and comply with legal and regulatory requirements. The Companies' will enter into transactions to balance and optimize their portfolios. However, speculative transactions are not permitted. Bookouts In Lieu of Liquidated Damages are permitted. Bookout transactions for the sole purpose of financial gain or of transactions that were not originally intended for physical delivery are not permitted.
2. **Energy Supply Plans.** The Companies will seek the PUCN approval of Energy Supply Plans to govern the purchase and sale of fuel and wholesale power and the associated transmission and transportation services. The process will include assessments of projected loads and resources, assessments of expected market prices, evaluations of relevant options available to the Companies for the purchase, sale, or optimization of resources, and evaluations of the risk attributable to those portfolio options. The Energy Supply Plans will include recommended courses of action to be followed during the three-year period covered by each plan.

Any energy transactions that deviate from the PUCN approved Energy Supply Plans may only be entered into in accordance with Section V.D.2. The Energy

## NV Energy, Energy Risk Management and Control Policy

Supply Plans will be reviewed on an ongoing basis and updated at least once a year. Changes in the data and assumptions underlying the approved Energy Supply Plans will be promptly reported to the Risk Committee.

- 3. Authorized Products and Authority of Personnel.** The personnel listed in Appendix D, Section B are authorized to originate transactions for the commodities and services indicated.

**C. Documenting Transactions and Authorized Signatories**

The Companies will not enter into any transaction for the purchase or sale of fuel and wholesale power without a written contract delineating the associated terms and conditions. The contract may be an agreement for a specific transaction, a standard agreement, or a master agreement. Transactions entered into for Energy Supply typically fall into two types: (i) transactions entered into for specific transactions under standard contract practices (“Non-Standard Transactions”), and (ii) transactions entered into orally pursuant to master agreements (“Standard Transactions”). These two types of transactions require different execution and risk control practices.

- 1. Non-Standard Transactions.** Non-Standard Transactions are all contracts executed pursuant to this policy that are not Standard Transactions or Online Exchange Transactions. Non-Standard Transactions may be executed by the individuals identified in Appendix D, Section B and Section C in accordance with the Signature Authority Levels in Appendix D, Section F.
- 2. Standard Transactions.** Standard Transactions are transactions that are entered into pursuant to a master trading agreement (as further discussed below) and subsequently confirmed, in the case of term transactions (one month or more), in writing. Gas transactions of less than one month are not required to be confirmed in writing. Power transactions of less than seven days are not required to be confirmed in writing. Standard transactions will be entered into or confirmed on recorded phone lines (for transactions entered into via brokers, transactions can be confirmed via written methods such as the Intercontinental Exchange (“ICE”) Chat feature or other industry acceptable methods). The Companies will maintain telephone systems capable of recording trader transactions. Notices are provided pursuant to the Commitment Notification Thresholds for Oral Transactions as indicated in Appendix E Section A. The individuals indicated in Appendix D, Section D are authorized to enter into oral transactions.
- 3. Online Exchange Transactions.** Online Exchange Transactions are transactions that are entered into via an online commodities exchange platform, such as ICE. These transactions do not require oral confirmation over a recorded phone line. Online Exchange Transactions are subject to the same notification limits as Oral Transactions. The individuals identified in Appendix D; Section D are authorized to enter into Online Exchange Transactions.
- 4. Master Agreements.** Master agreements include, but are not limited to, the

## NV Energy, Energy Risk Management and Control Policy

International Swap and Derivatives Association (“ISDA”) Agreement for financial and physical gas transactions (where a physical annex exists), WSPP Inc. Agreement for physical power, and the North America Energy Standard Board (“NAESB”) Agreement for physical gas. Master agreements will be executed by the Vice President of Resource Optimization. When a master agreement is in place, a transaction may be entered into orally or through exchange transactions in accordance with the terms of the relevant master agreement and subsequently confirmed, in the case of gas transactions (one month or more) and power transactions (seven days or more), in writing. Risk Control shall notify the appropriate personnel if the Dollar Threshold is exceeded in the Table in Appendix E, Section A. Confirmations will be executed by the Director, Gas Trading or the Director, Power Trading.

5. **Authorized Signatories.** The individuals listed in Appendix D, Section E are authorized to execute transactions and confirmations for approved financial and physical instruments on behalf of the Companies provided that such transactions conform to the Energy Supply Plan approved by the Public Utilities Commission of Nevada or as otherwise approved by Risk Committee. Invoices shall be approved in accordance with the signature authority limits of the Corporate Governance and Approvals Policy.

**D. Risk Control Practices**

Risk Control Practices are established to monitor and manage the risks inherent in the efforts to secure reliable supplies of fuel and wholesale power, and to optimize the portfolio through sales. Risk Control Notification Thresholds have been established to monitor and report risk metrics for transactions entered into by the Companies.

1. **Notification Thresholds:** The Companies will adhere to the notification thresholds set forth in this policy. The notification thresholds fall into three categories: Transaction Approval Notification thresholds, Portfolio Risk Notification thresholds, and Credit Risk Notification thresholds.
2. **Transaction Notification Thresholds.** The transaction notification thresholds relate to the values of contracts to which authorized personnel of the Companies obligate the Companies. Risk Control will report any transactions that exceed the transaction notification thresholds (Appendix E, Section A) monthly to the voting members of the Risk Committee.
3. **Portfolio Risk Control Notification Thresholds:** Value-at-Risk notification thresholds and Mark-to-Base change notification thresholds will be applied to the Companies’ energy procurement and sales activities. Risk Control will report any instances where the Value-at-Risk and Mark-to-Base metrics exceed the portfolio risk control notification thresholds (Appendix E, Sections B and C) monthly to the members of the Risk Committee as they occur.
  - i. **Value-at-Risk Notification Thresholds:** The Value-at-Risk (also referred to as Cash-Flow-at-Risk when used in analyzing liquidity requirements) notification thresholds set forth in Appendix E, Section B will be the

NV Energy, Energy Risk Management and Control Policy

notification threshold for the expected maximum increase in fuel and wholesale power costs. The Companies will use methodologies, consistent with industry standards, for calculating the Value-at-Risk for their energy portfolios. Those calculations will incorporate the level of confidence, length of term and holding period set forth in Appendix E, Section B.

- ii. **Mark-to-Base Notification Thresholds:** Base Tariff Energy Rates (BTER) are set at levels that anticipate the Companies' expenditures for fuel and wholesale power. During any period, recovery of expenditures in excess of the revenue produced by those base rates is first offset against sales for the same period. To the extent that expenditures for fuel and wholesale power exceed BTER revenues and offsets for sales, the excess will be deferred. Mark-to-Base will provide an estimate of such deferrals for the current deferral period. It will reflect actual expenditures to date, committed expenditures for the balance of the deferral period, and expected expenditures for uncommitted purchases. The Mark-to-Base Notification thresholds set forth in Appendix E, Section C will trigger notifications if changes in Mark-to-Base Thresholds occur on both a cumulative basis and a month-to-month basis. Mark-to-Base for each deferral period will begin to be assessed three months before the beginning of each deferral period and continue to be assessed until the end of each deferral period.

- 4. **Energy Credit Risk Notification Thresholds:** All Energy Credit Risk Notifications shall be made in accordance with the Credit Risk Management and Control Policy.
- 5. **Exception Management Process:** The Risk Committee may approve exceptions to this policy and to the plans and procedures developed in accordance with this policy. Transactions which are not contemplated by an Integrated Resource Plan or Energy Supply Plan may only be entered into if approved by the Risk Committee and the President.
- 6. **Procedures:** The Companies will maintain procedures for reporting exceptions and notifications pursuant to this policy and the plans and procedures developed in accordance with this policy. The procedures will have provisions for the prompt notification of the Treasurer, who will, in turn, be responsible for notifying the Companies' personnel responsible for resolution of the exception, and the Risk Committee. Presentations to the Risk Committee will include descriptions of the exceptions, proposed courses of action to resolve the exceptions, and schedules for resolving the exceptions.

## VI. Compliance

All personnel who are or may become involved in any energy procurement or sale activities or otherwise influence the energy procurement or sale decisions covered by this policy will be provided a copy of this policy and any associated procedures. Company personnel are prohibited from buying and selling any approved commodity for their own account or for the benefit of any entity other than the Companies. Additionally, Company personnel are required to disclose any significant direct interest<sup>2</sup> in any of the Companies' counterparties for transactions covered by this policy. To facilitate that disclosure, a listing of the Companies' counterparties and their parent organizations will be made available upon request.

Personnel who are or may become involved in any energy procurement or sale activities covered by this policy will be familiar with this policy and any associated procedures and solicit clarification of any areas that they do not understand.

1. Each employee will have an affirmative duty to alert management immediately upon learning of any potential violations of this policy.
2. Each employee also will have an affirmative duty to alert management immediately upon learning of any risks not adequately covered by this policy and the associated procedures, methodologies, and systems.

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<sup>2</sup> For the purposes of this policy, a direct interest will be defined as the direct ownership of shares in a publicly traded entity or an ownership interest in a privately held entity. A significant direct interest will be one with a current value greater than one thousand dollars. The ownership of shares via a mutual fund will not be deemed a direct interest.

## Appendix A: Definitions

Aggregate Exposure	An estimate of the current cost of replacing all of the contracts with a counterparty.
Approved Commodity	Electricity, natural gas, propane, coal, oil, and portfolio energy credits together with derivatives that are linked to those commodities and transmission or transportation services for those commodities. Renewable energy credits that fall outside the definition of portfolio energy credits.
Bookouts	An agreement entered into subsequent to an agreement for the physical delivery of a commodity to cancel an outstanding agreement by the parties involved, through cash settlement of the difference between the price specified in the agreement and an acceptable reference price. A Bookout must be memorialized in a subsequent agreement in writing between the parties involved to comply with Dodd-Frank regulations.
Bookouts In Lieu of Liquidated Damages	An agreement entered into to cancel an outstanding delivery obligation or portion thereof in lieu of the payment of liquidated damages by the parties involved, through cash settlement of the difference between the price specified in the agreement and an acceptable reference price.
Counterparty	An entity that has entered into a contract with one of the Companies.
Energy Supply Plans	Plans that the Companies will develop to govern the purchase and sale of fuel and wholesale power and the associated transmission and transportation services. Energy Supply Plans will cover three-year periods.
Financial Instruments	Swaps, options, futures, and options on futures entered into to hedge risks.
Fixed Price Agreement	A contract in which the price of the commodity or service is set at a particular level when the contract is executed.
Forwards	Agreements to buy or sell a quantity of a product, at an agreed price, for delivery at a specific location and for a future period and traded over the counter directly with counterparties.
Indexed Agreement	A contract in which the price of the commodity or service is tied to one or more published indices.

NV Energy, Energy Risk Management and Control Policy

Liquid Market	A market characterized by narrow bid/offer spreads, easy access to reliable price data, and small movements in prices as a result of sizable transactions.
Mark-to-Base	An estimate of costs that may be deferred through deferred energy or purchased gas adjustment accounting.
Mark-to-Market	The value of a financial or physical instrument, or an aggregation of such instruments, at the Companies' best estimate of current market prices.
Options	Instruments which give the holder the right, but not the obligation, to sell or buy the underlying commodity at specified prices, times, and locations.
Physical Instrument	A contract for a commodity under which the Companies expect to take delivery of the specified commodity.
Portfolio Energy Credit	A credit that is earned through energy produced or saved from a renewable energy system or energy efficiency measure. These credits are issued to any eligible renewable energy producer as defined in Nevada Revised Statute 704.7811. These credits may be purchased and sold to meet the Renewable Portfolio Standard.
Products	Commodities with specific characteristics like electricity delivered during predefined periods.
Renewable Energy Benefits	Represents the property rights to the environmental, societal, and other nonpower qualities of renewable electricity generation. A Portfolio Energy Credit and its associated attributes and benefits can be sold separately from the underlying physical electricity associated with a renewable-based generation source.
Swaps	Agreements to exchange net future cash flows or physical positions.
Transaction	A contract obligating the Companies to buy or sell physical commodities and services. Transactions will also include monetary obligations incurred through financial instruments.
Transmission Agreement	A contract to move electricity from one point to another. Such contracts are frequently referred to as "wheeling" agreements.
Transportation Agreement	A contract to move coal, natural gas, or oil from one point to another.

NV Energy, Energy Risk Management and Control Policy

Value-at-Risk (also referred to as Cash-Flow-at-Risk when used in analyzing liquidity requirements)	The expected maximum increase in fuel and wholesale power costs over a target horizon within a given confidence interval and holding period. Value-at-Risk serves as a gauge of market exposure, summarizing the total market risk in a portfolio of assets.
Western North America Coal Sources	Coal mines in the States of Arizona, Colorado, New Mexico, Utah, and Wyoming that produce coal that can be burned efficiently and effectively in the Companies' generating units.
Western North America Natural Gas Hubs	Locations in the western half of the United States and Canada at which natural gas is traded in quantities sufficiently large to ensure liquid markets.
WSPP Regional Power Markets	Locations in the western half of the United States and Canada at which electricity is traded in quantities sufficiently large to ensure liquid markets. Such electricity is often traded under the provisions of the WSPP agreement.

## Appendix B: Areas of Responsibility - Committee

**Risk Committee:** The Risk Committee will be responsible for:

- Assessing the appropriateness of the Companies' energy supply risk management and control activities and making recommendations for modifications to existing policies;
- Approving changes and exceptions as designated in specific sections of this Policy and ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Assessing the systems required to monitor, record, and report on the risks inherent in the Companies' energy supply related activities and making recommendations for improvements to existing risk policies;
- Approving Energy Supply Plans;
- Reviewing all transactions requiring exceptions to the applicable policies and procedures;
- Reviewing and approving all energy procurement and sale transactions that are Transactions not transacted in accordance with the Energy Supply Plan, requiring the approval of the President;
- Reviewing all violations of notification thresholds and processes established under this policy, approving, or recommending for approval remedies of the violations, and monitoring progress of such remedies;
- Assigning the completion of any other activities to guide the overall policy direction of the Companies' energy risk management and control efforts; and,
- Approving any exceptions to the Energy Supply Plan.

## Appendix C: Areas of Responsibility – Departments

**A. Risk Control:** Risk Control is responsible for:

- Monitoring compliance with the Energy Risk Management and Control Policy and reporting exceptions;
- Disseminating this policy to the Companies' personnel who will be affected by this policy;
- Measuring the Companies' energy portfolio exposures and comparing the measurements against approved exposure notification thresholds;
- Accumulating risk control information for the Companies;
- Creating monthly risk control reports;
- Assessing proposed modifications to risk control policies and notification thresholds based on changing business or market conditions;
- Recommending the appropriate level of risk - within approved notification thresholds - to be accepted on behalf of the Companies;
- Each business day, review sample of 1 - 5 trades by listening to phone recordings or ICE Chat (gas/power) and verifying that transactions are in the trader log and TRM for natural gas or Allegro and OATI for power; and,
- Notifying Executive Management per the Energy Supply Commitment Threshold Notification levels set forth in Appendix E, Section A.
  - a) Credit Risk Management: Credit Risk Management is responsible for:
    - Assessing the creditworthiness of counterparties;

NV Energy, Energy Risk Management and Control Policy

- Approving counterparties and establishing credit ratings for them before the Companies enter into energy-related transactions with them;
- Maintaining the Companies' lists of approved bidders;
- Monitoring and reporting on the creditworthiness of wholesale fuel and power counterparties;
- Reviewing and reporting on all contractual credit terms;
- Reviewing and reporting on information requested by counterparties for collateral or other credit support;
- Notifying Resource Optimization leadership when credit exposure limits have been exceeded and assisting Risk Control in developing the strategy to mitigate risk;
- Resolving credit issues with counterparties;
- Calculating collateral requirements to be posted by counterparties and overseeing the receipt of that collateral;
- Maintaining records of the collateral posted by counterparties;
  - Calculating collateral requirements and managing collateral posted by the Companies; and,
    - i. Managing margining requirements

**B. Resource Optimization: Resource Optimization is responsible for:**

- Negotiating, developing, and executing transaction plans consistent with the approved Energy Supply Plans and the associated notification thresholds;
- Identifying prospective counterparties and presenting viable entities to Credit Risk Management for approval;
- Facilitating Requests For Proposals (“RFPs”) for standard power, natural gas, coal, propane, and oil;
- Verifying the accuracy of financial/physical gas, carbon allowances, and spot power invoices received by the Companies related to short-term power, transmission, and California Independent System Operator market transactions;
- Leading the negotiation process for certain natural gas transportation contracts and gas storage;
- Recording transactions for accounting and contract management purposes, distributing the records, and adjusting the records as a result of actualization activities;
- Reviewing confirmations for accuracy prior to approval; and,
- Coordinating with Risk Control and Credit Risk Management to manage or mitigate any risk exposure.

**C. Renewables and Origination: Renewables and Origination is responsible for:**

- Negotiating, developing, and executing transaction plans consistent with the approved Energy Supply Plans and the associated notification thresholds;
- Facilitating Requests For Proposals (“RFPs”) for non-standard transactions, portfolio energy credits, other renewable energy credits, and qualifying facilities;

NV Energy, Energy Risk Management and Control Policy

- Managing customer programs and executing associated commercial transactions;
- Performing due diligence and all associated tasks for asset acquisitions and specific asset developments to meet customer or resource planning needs;
- Coordinating with Risk Control and Credit Risk Management to manage or mitigate any risk exposure;
- Leading the negotiation process for non-standard power contract amendments; and
- Providing contract support to Resource Optimization, Credit Risk Management, Contract Management, Legal, Resource Planning and Analysis, Fuel & Purchased Power Accounting, etc.

**D. Resource Planning and Analysis:** Resource Planning and Analysis is responsible for:

- Developing forecasts of energy and fuel prices;
- Estimating the Companies fuel and the associated costs;
- Developing Integrated Resource Plans;
- Developing Energy Supply Plans and associated risk management strategies;
- Analyzing energy resources available to the Companies to help to ensure the optimal use of those resources; and,
- Preparing or assisting with the preparation of periodic reports.

**E. Fuel and Purchased Power Accounting:** Fuel and Purchased Power Accounting is responsible for:

- Verifying the accuracy of financial/physical gas, carbon allowances, and spot power invoices received by the Companies;
- Resolving issues regarding financial/physical gas, carbon allowances, and spot power invoices received by the Companies;
- Submitting final invoices to authorized personnel for approval;
- Preparing and issuing invoices for sales to counterparties;
- Verifying the settlement amounts from financial transactions;
- Accounting for all transactions;
- Reconciling the accounts to confirm the accuracy of the energy accounting;
- Ensuring the timely collection of receivables attributable to sales of energy and fuel;
- Supervising the payment and receipt of all settlements from financial transactions; and,
- Preparing designated reports.

**F Energy Supply Contract Management:** Energy Supply Contract Management is responsible for:

- Managing pre-commercial and commercial energy supply contracts per their terms and conditions, including but not limited to; certifying completion of contractually required milestones, acceptance of commercial operation, and the invoice settlement function for long-term power and certain natural gas contracts;
- Maintaining counterparty contract and trading status information in the systems of record;
- Managing the confirmation process for term physical/financial gas and power transactions;

NV Energy, Energy Risk Management and Control Policy

- Maintaining energy supply contracts in accordance with the Corporate Records Retention Schedule; and,
- Providing contract support to Resource Optimization, Credit Risk Management, Contract Management, Legal, Resource Planning and Analysis, Fuel & Purchased Power Accounting, etc.
- Leading the negotiation process of Master Agreements for power and carbon;

NV Energy, Energy Risk Management and Control Policy

**Appendix D : Resource Procurement and Sale Constraints**

***A. Approved Financial Instruments and Physical Products***

Instrument	Commodity											
	Power		Natural Gas		Coal		Oil, Diesel, Propane		SO2 Allowances		Carbon Allowances	
	Buy	Sell	Buy	Sell	Buy	Sell	Buy	Sell	Buy	Sell	Buy	Sell
<b>Financial Instruments</b>												
Forwards	X	X	X	X			X				X	X
Options	X	X	X	X			X					
Swaps	X	X	X	X			X					
<b>Physical Products and Instruments</b>												
Spot Agreements	X	X	X	X	X	X	X	X			X	X
Fixed Price Agreements	X	X	X	X	X	X	X	X	X	X	X	X
Indexed Agreements	X	X	X	X	X	X	X	X			X	X
Ancillary Services	X	X										
Options (includes capacity contracts)	X	X	X									
Transmission Agreements	X	X										
Transportation Agreements			X	X	X	X	X					
Storage Agreements			X	X								

Underlying Markets: All Western North America Natural Gas Hubs  
The Henry Natural Gas Hub in Louisiana  
All WSPP Regional Power Markets  
All Western North America Coal Sources

The Risk Committee may approve changes to the Approved Financial Instruments and Physical Products or Underlying Markets as deemed necessary.

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**B. Authorization to Originate Standard and Non-Standard Transactions Under Approved Energy Supply Plans**

	Power		Natural Gas			Oil, Diesel, Propane		Coal		Financial <sup>3</sup>		SO2	Carbon
	Commodity	Transmission	Commodity	Transportation	Storage	Commodity	Freight	Commodity	Freight	Swaps	Options	Allowances	Allowances
Director, Gas Trading	X	X	X	X	X	X	X	X	X	X	X	X	X
Director, Power Trading	X	X	X	X	X	X	X	X	X	X	X	X	X
	X	X	X	X	X	X	X	X	X	X	X	X	X
Director, Real Time Operations	X	X	X	X	X	X	X	X	X	X	X	X	X
Power Traders	X	X	X	X				X	X	X			X
Gas Traders	X	X	X	X		X	X	X	X	X	X		X
Power Trader - Gendesk	X	X	X	X				X	X				X
Resource Optimization Manager								X	X				

The Risk Committee may approve additions and changes to the Authorization to Originate Transactions prior to the origination of the transaction.

**C. Authorization to Originate or Amend Renewables and Non-Standard Transactions Under Approved Energy Supply Plans**

	Renewable Power and QFs		Portfolio Energy Credits/Renewable Energy Credits		Power	
	Buy	Sell	Buy	Sell	Buy	Sell
Vice President, Resource Optimization	X		X	X	X	
Director, Renewable Energy & Origination	X	X	X	X	X	X
Director, Contract Management and Special	X		X			

<sup>3</sup> Financial transactions related to energy commodities only.

NV Energy, Energy Risk Management and Control Policy

Programs (Amendments/Settling disputes only)					X	
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The Risk Committee may approve additions and changes to the Authorization to Originate Transactions prior to the origination of the transaction.

**D. Individuals Authorized to Enter Into Oral Transactions**

- Director, Gas Trading
- Director, Power Trading
- Director, Real Time Operations
- Gas Traders
- Power Traders

**E. Authorized Signatories – Power and Fuel Contracts and Confirmations**

- Chief Executive Officer
- Vice President, Chief Financial Officer
- Vice President, Resource Optimization
- Director, Gas Trading
- Director, Power Trading

Personnel may not execute contracts or confirmations for transactions they originated.

Signature authority may not be delegated.

**F. Authorization Approval Levels for the Execution of Fuel and Purchased Power Transactions and Daily Trades (\$ up to and including)**

<b>Title</b>	<b>Limit – RFPs and Daily Trades*</b>	
<i>Chief Executive Officer, Berkshire Hathaway Energy Company</i>	<i>Unlimited</i>	
<i>Chief Executive Officer</i>	<i>\$100,000,000</i>	
<i>Vice President, Chief Financial Officer</i>	<i>\$12,500,000</i>	
<i>Vice President, Resource Optimization<sup>11,12</sup></i>	<i>\$12,500,000</i>	
<i>Director, Trading Analytics &amp; Operations<sup>13</sup></i>	<i>\$7,500,000</i>	
<i>Director, Contract Management and Special Programs (Amendments/Settling disputes only)</i>	<i>\$7,500,000</i>	
<i>Director, Gas Trading</i>	<i>\$7,500,000</i>	
<i>Director, Power Trading</i>	<i>\$7,500,000</i>	

NV Energy, Energy Risk Management and Control Policy

<i>Director, Real Time Operations</i>	<i>\$7,500,000</i>	
<i>Manager, Power Trading</i>	<i>\$5,000,000</i>	
<i>Resource Optimization Manager</i>	<i>\$5,000,000</i>	
<i>Traders</i>	<i>\$1,000,000</i>	

***Approval of invoices are subject to dollar thresholds in the Corporate Governance and Approvals Policy.***

***\* To ensure reliability, approvals of daily trades may happen after trade execution.***

<sup>[1]</sup> Applies to transactions longer than one month

<sup>[2]</sup> Applies to transactions pertaining to the table in Appendix D, Section C

<sup>[3]</sup> Applies to transactions pertaining to the table in Appendix D, Section B

***Note: All those individuals identified as being impacted by the Risk Policies, e.g., Credit Risk Management and Control Policy, Risk Management and Control Policy and Energy Risk Management and Control Policy are required to review the policies each calendar year.***

***Appendix E: Risk Control Notification Thresholds***

***A. Commitment Threshold Notification for fuel and purchase power – Per Transaction<sup>4</sup>***

<i>Title</i>	<i>Dollar Threshold</i>
<i>Chief Executive Officer</i>	<i>\$100,000,000</i>
<i>Vice President, Chief Financial Officer</i>	<i>\$12,500,000</i>
<i>Vice President, Resource Optimization</i>	<i>\$12,500,000</i>

The maximum total commitment attributable to a transaction at index will be based on the Companies’ best estimate of the index at the time of the transaction.

***B. Value-at-Risk Commitment:***

Company	Level of Confidence	Length of Term	Holding Period	Amount
Nevada Power	95% or higher	Rolling twelve Months	1 year	\$100 million

<sup>4</sup> Applies to transactions longer than one month

NV Energy, Energy Risk Management and Control Policy

Sierra Pacific Power	95% or higher	Rolling twelve Months	1 year	\$60 million
Local Distribution Company	95% or higher	Rolling twelve Months	1 year	\$20 million

**C. Mark-to-Base Commitment Threshold Notification – Cumulative/Monthly:**

Company	Base	Cumulative Change	Notify
Nevada Power	BTER	\$80 million	President
Sierra Pacific Power	BTER	\$50 million	President
Local Distribution Company	BTER	\$10 million	President

**Appendix F: Policy Revision Log**

Date	Revision(s)
August 28, 2014	<p>Modified Existing Policy.</p> <ol style="list-style-type: none"> <li>1. Updated titles of personnel. Replaced “Mid-American Energy Holdings Company” with “Berkshire Hathaway Energy Company”.</li> <li>2. Modified language regarding the Risk Committee’s reviewing and approving Energy Supply Plans and any exceptions to the Energy Supply Plans.</li> <li>3. Added the definition of “Bookout” and language clarifying which types of “Bookout” transactions are permitted. Made a distinction between standard and non-standard transactions.</li> <li>4. Clarified when power transactions must be confirmed in writing.</li> <li>5. Added clarifying language that the Risk Committee is responsible for approving any exceptions to the Energy Supply Plan.</li> <li>6. Added the management of margining requirements as a Credit Risk Management responsibility.</li> <li>7. Moved the responsibility for leading the negotiation process of Master Agreements for physical/financial gas, power and carbon from Resource Optimization to Renewable Energy &amp; Origination.</li> <li>8. Added the responsibility for leading the negotiation process for gas storage to Resource Optimization.</li> <li>9. Added the responsibility for facilitating Requests for Proposals for propane and oil to Resource Optimization.</li> <li>10. Modified the responsibilities of Renewable Energy &amp; Origination as follows:</li> </ol>

NV Energy, Energy Risk Management and Control Policy

	<ul style="list-style-type: none"> <li>• Negotiating, developing and executing transaction plans consistent with the approved Energy Supply Plans and the associated notification thresholds</li> <li>• Leading the negotiation process of Master Agreements for physical/financial gas, power and carbon</li> <li>• Facilitating Requests For Proposals (“RFPs”) for non-standard power, and portfolio credits</li> <li>• Coordinating with Risk Control and Credit Risk Management to manage or mitigate any risk exposure.</li> </ul> <ol style="list-style-type: none"> <li>11. Added oil, diesel, and propane freight and commodity as transactions that gas traders are authorized to originate.</li> <li>12. Added carbon allowances invoices to Fuel and Purchase Power Accounting’s responsibilities, added gas storage and gas transportation as origination transactions the Manager, Market Operations and Trading is authorized to originate (Buying and Selling).</li> <li>13. Added gas storage and gas transportation as origination transactions the Manager, Commercial and Trading Strategy is authorized to originate (Buying only).</li> <li>14. Added the Chief Executive Officer, Director of Renewable Energy and Origination (marketing function employee designated position), Project Manager, Power Origination (Confirms only) as authorized signatories to Power and Fuel Contracts and confirmations.</li> <li>15. Added a policy revision log.</li> </ol>
December 16, 2014	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Changes were made throughout the document to fix references to the appendices.</li> <li>2. Replaced the acronyms, RECs, PECs, PUCN, WSPP, and CAISO with their full wording.</li> <li>3. Added Renewable Energy Credit and Portfolio Energy Credit to the terms defined in Appendix A (Definitions).</li> <li>4. Removed the Company’s Procurement function from the table indicating who is authorized to originate transactions under the Public Utilities Commission of Nevada approved Energy Supply Plans.</li> <li>5. Removed the Chief Executive Officer of Berkshire Hathaway Energy Company as the top level commitment threshold notification for fuel and purchase power transactions.</li> <li>6. Changed the Employee Acknowledgement section to read “A list of the Companies counterparties for transactions covered by the policy and their parent organizations will be provided upon request.”</li> </ol>
June 3, 2015	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Added the position of Power Marketer, Origination to Appendix D, Section C, (Authorization to Originate or Amend Renewables and Origination Transactions Under Approved Energy Supply Plans).</li> </ol>
June 17, 2015	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Updated titles of personnel.</li> <li>2. Modified the existing table in Appendix D, section B to pertain to Standard and Non-standard transactions under approved Energy Supply Plans.</li> <li>3. Modified the existing table in Appendix D, section C to pertain to Non-standard transactions under approved Energy Supply Plans.</li> </ol>

NV Energy, Energy Risk Management and Control Policy

	<p>4. Transferred the responsibility for notifying Executive Management per the Energy Supply Commitment Threshold notification levels (Appendix E, section A) from Energy Supply Contract Management to Risk Control. Notification will be made to Executive Management via Risk Committee Meetings instead of via email as was previously done.</p>
July 26, 2017	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Updated the Energy Risk Management and Control Policy to include organizational changes made since the policy was last approved on June 17, 2015.</li> <li>2. Added propane and portfolio energy credits to the definition of approved commodity.</li> <li>3. Modified the definition of Portfolio Energy Credit.</li> <li>4. Changed Renewable Energy Credit to Renewable Energy Benefit.</li> <li>5. Moved the footnotes reference (3, 4, and 5) to the appropriate page.</li> </ol>
May 7, 2018	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Updated titles of personnel</li> <li>2. Replaced CEO with President</li> </ol>
December 19, 2018	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Added footnote on page 3 defining functional area</li> <li>2. Replace “Chief Accounting Officer” with “Chief Financial Officer”</li> <li>3. Removed President line item from Authorization Approval Level and Risk Control Notification Threshold charts</li> <li>4. Removed “Senior” from Senior Vice President, Chief Financial Officer title</li> </ol>
December 4, 2019	<ol style="list-style-type: none"> <li>1. Modified Appendix A – Approved Commodity; added; Renewable energy credits that fall outside the definition of portfolio energy credits.</li> <li>2. Modified Renewable and Origination responsibilities <ul style="list-style-type: none"> <li>• 3<sup>rd</sup> bullet to read: Facilitating Request for Proposal (RFPs) for non-standard transactions, portfolio energy credits, other renewable energy credits and qualifying facilities</li> <li>• 7<sup>th</sup> bullet to read; Managing pre-commercial and commercial energy supply contracts per their terms and conditions, including but not limited to; certifying completion of contractually required milestones, acceptance of commercial operation, and the invoice settlement function for long-term power and certain natural gas contracts</li> </ul> </li> </ol>
Dec 17, 2020	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Deleted Senior Vice President, Operations throughout policy</li> <li>2. Change page 24 to 25 on table on content</li> <li>3. Added “in accordance with section V.D.2” and deleted by the Risk Committee and President (page 3)</li> <li>4. Added “PUCN and may only be entered into in accordance with Section V.D.2”v deleted without the prior approval of Risk Committee and The Companies will not execute) (page 6)</li> <li>5. Added Transactions which are not contemplated by an Integrated Resource Plan or Energy Supply Plan may only be entered into if approved by the Risk and the President and added Assistant Treasurer (pg+ 8)</li> <li>6. Removed “A” in front of Risk Committee (pg 13)</li> </ol>
July 21, 2021	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Replaced Manager, Market Operations and Trading with Manager, Power &amp; Gas Trading</li> </ol>

NV Energy, Energy Risk Management and Control Policy

	<ol style="list-style-type: none"> <li>2. Replaced Project Manager, Forward Trading with Power Trader</li> <li>3. Replaced Manager, Coal Operations and Procurement with Resource Optimization Manager</li> <li>4. Replaced Vice President, Resource Optimization with Director, Trading Analytics &amp; Operations</li> <li>5. Added a dollar limit in Section F for Director, Trading Analytics &amp; Operations to \$7, 500.000</li> <li>6. Added Section D Power and Natural Gas Trading Limits to Appendix E</li> <li>7. Updated the CEO and CFO dollar thresholds</li> <li>8. Added Resource Optimization Manager and Traders to Section F with \$5M and \$1M dollar limits respectfully</li> </ol>
November 17, 2021	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Updated title of Manager, Contract Management with Director, Contract Management and updated dollar limits for RFP and daily trades</li> <li>2. Revised a Risk Control responsibility to be consistent with the corresponding SOX control</li> </ol>
December 14, 2022	<ol style="list-style-type: none"> <li>1. Updated titles</li> <li>2. Moved several responsibilities from the Renewables section to Contract Management's section</li> </ol>
August 1, 2023	<ol style="list-style-type: none"> <li>1. Changed titles to allow for either Director or Manager of Power and/or Gas Trading consistent with the reorganization and leadership title changes in Resource Optimization.</li> </ol>
November 15, 2023	<ol style="list-style-type: none"> <li>1. Replaced Senior Vice President, Chief Financial Officer and Treasurer with Vice President, Chief Financial Officer</li> <li>2. Removed Appendix G – Employee acknowledgement statement</li> </ol>
November 20, 2024	<ol style="list-style-type: none"> <li>1. Deleted Assistant Treasurer</li> </ol>
October 22, 2025	<p>Modified Existing Policy</p> <ol style="list-style-type: none"> <li>1. Placed Credit Risk Management as a sub bullet under Risk Control</li> <li>2. Removed Renewables from Renewable and Origination</li> <li>3. Deleted the title Manager, Gas Trading and relaced it with Director, Gas Trading</li> <li>4. Replaced the title Manager, Power Trading with Director, Real time Operations</li> <li>5. Deleted the title Vice President, Renewables</li> <li>6. Updated the authorization levels to reflect those of the Corporate Governance and Approval Policy</li> </ol>

**ESP RM-3**

NV Energy Credit Risk Management and Control Policy

**NV Energy, Inc.**

**Credit Risk Management and Control Policy**

**Risk Committee Approval**

**October 22, 2025**

**This policy should only be distributed to the employees of NV Energy (and its subsidiaries) who need access to the document during the performance of their assigned duties. This policy should not be provided to anyone outside the Company without the prior approval of the Risk Control Department.**

NV Energy Credit Risk Management and Control Policy

**TABLE OF CONTENTS**

<b><u>I.</u></b>	<b><u>BACKGROUND</u></b>	<b>3</b>
<b><u>II.</u></b>	<b><u>APPLICATION AND PURPOSE</u></b>	<b>3</b>
<b><u>III.</u></b>	<b><u>CREDIT RISK DEFINITION</u></b>	<b>4</b>
<b><u>IV.</u></b>	<b><u>CREDIT RISK MANAGEMENT AND CONTROL FRAMEWORK</u></b>	<b>4</b>
	<u>A. Organization and Governance</u>	4
	<u>B. Credit Risk Management Program</u>	6
	<u>C. Credit Risk Control Practices</u>	8
<b><u>V.</u></b>	<b><u>COMPLIANCE</u></b>	<b>10</b>
	<b><u>APPENDIX A: DEFINITIONS</u></b>	<b>11</b>
	<b><u>APPENDIX B: AREAS OF RESPONSIBILITY – COMMITTEES</u></b>	<b>13</b>
	<b><u>APPENDIX C: AREAS OF RESPONSIBILITY – RISK CONTROL</u></b>	<b>14</b>
	<b><u>APPENDIX D: AREAS OF RESPONSIBILITY – CREDIT RISK MANAGEMENT</u></b>	<b>14</b>
	<b><u>APPENDIX E: RISK CONTROL METRICS</u></b>	<b>17</b>
	<b><u>APPENDIX F: CREDIT LIMITS</u></b>	<b>18</b>
<b><u>A.</u></b>	<b><u>COUNTERPARTY AND CUSTOMER CREDIT LIMITS</u></b>	<b>18</b>
<b><u>B.</u></b>	<b><u>SUB-INVESTMENT GRADE NOTIFICATION THRESHOLDS</u></b>	<b>19</b>
<b><u>C.</u></b>	<b><u>WEIGHTED AVERAGE PORTFOLIO CREDIT NOTIFICATION THRESHOLDS</u></b>	<b>19</b>
	<b><u>APPENDIX G: COLLATERAL RELEASE PROCEDURE</u></b>	<b>19</b>
	<b><u>APPENDIX H: POLICY REVISION LOG</u></b> .....	<b>20</b>

NV Energy Credit Risk Management and Control Policy

**I. Background**

NV Energy, Inc. (the “Company”) has two wholly owned utility subsidiaries, Nevada Power Company (d/b/a NV Energy) and Sierra Pacific Power Company (d/b/a NV Energy) (and together with NV Energy, the ”Companies”) who are engaged in the generation, transmission, and distribution of electric energy and in the distribution of natural gas in Nevada.

NV Energy’s Risk Committee approved the Risk Management and Control Policy dated January 5, 2021. That policy outlines NV Energy’s philosophy toward the management and control of the risk inherent in the Companies’ business operations. That policy also created the Risk Committee and made that committee responsible for overall policy direction of the Companies’ risk management and control efforts. That policy further instructed the Risk Committee to oversee the development of appropriate risk management and control policies including this Credit Risk Management and Control Policy.

**II. Application and Purpose**

The Credit Risk Management and Control Policy outlines NV Energy’s philosophy toward the management and control of the credit risk inherent in the Companies’ normal business operations.

The primary purpose of the policy is to:

- Provide guidelines for employees that are authorized to legally bind the Companies for procurement, sales, and service delivery transactions;
- Establish sound guidelines for the management and control of risks attributable to those transactions; and,
- Define the responsibilities for managing and monitoring those risks.

This policy will be applied to all physical and financial transactions related to the Companies’ procurement, sales, and service delivery activities. Five principal areas of credit risk are addressed in this policy:

- Energy supply
- Large customer accounts<sup>1</sup>
- Procurement (non-fuel)
- Transmission
- Rule 9

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<sup>1</sup> Credit risk of Mid-to-Small customers is managed by Credit and Billing Department

### III. Credit Risk Definition

Credit risk is the possibility that because of a counterparty's financial condition the counterparty's financial or physical obligations may not be timely performed. Credit exposure is the dollar amount that would be at risk in the event that the counterparty fails to perform. Credit loss is the actual dollar amount loss incurred due to the default. An evaluation of credit risk should measure exposure, and the possibility of failure to perform and recovery on defaults.

### IV. Credit Risk Management and Control Framework

The Companies will systematically manage and control credit risk through three primary vehicles - organization and governance, credit risk management program, and credit risk control practices.

#### *A. Organization and Governance*

**1. Risk Committee:** The Risk Committee is responsible for overall policy direction of the Companies' risk management and control efforts, including credit risk management and risk control efforts. Specific activities for which the Risk Committee is responsible are set forth in Section A of Appendix B. The Risk Committee has the right to delegate portions of its assigned duties to one or more committees.

**2. Vice President, Chief Financial Officer and Treasurer:** The Companies' management is responsible for enforcing this policy and the associated procedures in the areas for which they are responsible. The Vice President, Chief Financial Officer and the Treasurer and are responsible for monitoring compliance with this policy and those procedures. All material omissions and exceptions will be promptly reported to the Risk Committee.

**3. Risk Control:** The Risk Control organization monitors compliance with this credit policy and the associated procedures. Risk Control, under direction from the Vice President, Chief Financial Officer and the Treasurer are responsible for the activities set forth in Section A of Appendix C.

**a) Energy Credit Risk Management:** The Companies enter into contracts with numerous counterparties while buying and selling energy including fuel, purchased power, and coal. Credit Risk Management, under direction from the Treasurer, is responsible for the Companies' credit risk management activities as they apply to energy supply. Specific activities for which Energy

NV Energy Credit Risk Management and Control Policy

Credit Risk Management will be responsible are set forth in Section A of Appendix D.

**b) Large Customer Credit Risk Management:** The Companies provide power services to large customers. The credit risk associated with these customers results from the possibility that they will be unable or unwilling to remit payment to the Companies after services have been received. Large Customer Credit Risk Management under the direction of the Companies' Risk Control and Credit & Billing organizations will be responsible for the Companies' credit risk management activities as they relate to large customers. Specific activities for which Large Customer Credit Risk Management will be responsible are set forth in Section B of Appendix D.

**c) Business Unit Credit Risk Management:** The Companies enter into non-fuel contracts with numerous suppliers of materials used in the development and maintenance of the electric and gas infrastructure. Contracts for the new construction, repair or reconstruction of any public building or other public work or public improvement in excess of \$100,000 require performance bonds. These contracts are approved per the Corporate Governance and Approvals Policy. Contracts more than \$1,000,000 require a risk assessment to be performed by Risk Control. Credit risk associated with these suppliers is the possibility that they will be unable or unwilling to provide materials in time or fail to provide materials altogether. Any exceptions to collateral requirements must be approved by the authorized contract signatory, in line with the limits specified in the Corporate Governance and Approval Policy. The CFO should be notified and provided justification of any requests for collateral waivers over \$1 million at the same time the VP receives that request for approval and before they are routed to the President/CEO for final approval. Specific activities for which Business Unit Credit Risk Management will be responsible are set forth in Section C of Appendix D.

**d) Transmission Credit Risk Management:** The Companies enter into contracts with numerous counterparties and customers for long term point-to-point transmission, large and small generator interconnection, and short-term point-to-point transmission. Specific activities for which Energy Credit Risk Management will be responsible are set forth in Section D of Appendix D.

**e) Rule 9 Credit Risk Management:** The Companies enter into contracts with numerous customers for large projects that the

## NV Energy Credit Risk Management and Control Policy

Company has a reasonable basis for believing that circumstances particular to an applicant's project would subject the Company to a substantial risk of not recovering its investment in the applicant's project. Abnormal Risk projects are defined as: project costs will not be fully collected from project developers and new loads enabled by line extensions will be reduced or terminated. Consequently, these will not generate the required rate revenue to pay for the allowance or refund cost of the project over its life. Specific activities for which Energy Credit Risk Management will be responsible are set forth in Section E of Appendix D.

***B. Credit Risk Management Program***

**1. Energy Credit Risk:** The Companies will maintain an ongoing energy credit risk program with the objective of avoiding material increase in operating and capital costs attributable to failures to perform by counterparties. The program will address these three key components: i) counterparty credit risk mitigation through arrangements such as credit support, netting, mark-to-market margin collateral, termination clauses, etc.; ii) evaluation and potential use of credit risk transfer instruments such as credit insurance, credit derivatives and clearinghouse transactions; and iii) the implementation of appropriate procedures such as transaction credit approval, exception management, etc. The program will have provisions for the systematic identification, quantification, evaluation, and management of the credit risk inherent in the Companies' operations and for the preparation of periodic reports to document the Companies' efforts. All counterparties will be pre-approved by the Credit Risk Management group of the Risk Control department.

**2. Large Customer Credit Risk:** The Companies will maintain an ongoing large customer credit risk management program that focuses both on preventing the occurrence of adverse credit outcomes at an account level, and on recovering any material increase in operating and capital costs attributable to failures to pay by customers. As part of the prevention mechanisms, the credit risk management program will implement measures such as, but not limited to, an assessment of customer credit based on payment history with the Companies, third party credit analysis, tighter billing cycles, late fee assessment, and deposit requirements. All risk management and risk mitigation measures used will be in compliance with the governing legal and regulatory statutes (e.g., the Consumer Bill of Rights, tariff filings, and other applicable regulations). As part of the regulatory recovery mechanisms, the credit risk management program will thoroughly document working capital charges resulting from delayed

## NV Energy Credit Risk Management and Control Policy

payments and capture any write-offs. The credit risk management program will ensure appropriate regulatory recovery of all such additional costs incurred by the Companies and will have provisions for the preparation of periodic reports to document the Companies' efforts.

**3. Business Unit Procurement Credit Risk:** The Companies will maintain an ongoing business unit credit risk program focused on avoiding material interruption and costs attributable to failures by counterparties to perform or pay. The program will include four key components: (i) periodic vendor credit evaluation, (ii) critical vendor status determination, (iii) on-going critical vendor credit status assessment, and (iv) risk mitigation activities. Critical material vendors will be identified by Procurement based on, but not limited to, total contract value outstanding, estimated annual spend, product replacement options, services provided, frequency of transactions, and alliance partners. After a critical vendor has been identified, a credit rating will be given based on external credit ratings services, independent debt rating by major investment banks, or internal evaluation of a vendor's financial condition. The credit status and credit exposure of critical material vendors will be monitored and assessed no less than annually and prior to the awarding of major new contracts. Risk mitigation techniques will be utilized for all vendors when available. Such activities will include, but are not limited to, requiring credit support, including provisions for liquidated damages, diversifying vendor portfolio, actively seeking creditworthy vendors, and identifying replacement vendors.

**4. Transmission Credit Risk:** The Companies will maintain an ongoing transmission credit risk program with the objective of avoiding a material increase in operating and capital costs attributable to failures to perform by counterparties and customers. The program will address these key components: i) counterparty and customer credit risk mitigation through arrangements such as credit support, netting, termination clauses, etc.; and ii) the program will have provisions for the systematic identification, quantification, evaluation, and management of the credit risk inherent in the Companies' operations and for the preparation of periodic reports to document the Companies' efforts. All counterparties and customers will be pre-approved by the Credit Risk Management group of the Risk Control department.

**5. Rule 9 Credit Risk:** The Companies will maintain an ongoing Rule 9 customer credit risk management program that focuses both on preventing the occurrence of project costs not fully being collected from project developers, new load enabled by line extensions will be reduced or terminated, will not generate the required rate revenue to pay the allowance

NV Energy Credit Risk Management and Control Policy

or refund cost of the project over its life or project 1MW or more or total project cost of \$400,000 or more. The program will have provisions for the systematic identification, quantification, evaluation, and management of the credit risk inherent in the Companies’ operations and for the preparation of periodic reports to document the Companies’ efforts. All counterparties and customers will be pre-approved by the Credit Risk Management group of the Risk Control department. The credit risk management program will ensure appropriate regulatory recovery of all such additional costs incurred by the Companies and will have provisions for the preparation of periodic reports to document the Companies’ efforts.

**C. Credit Risk Control Practices**

The Companies’ risk control practices will incorporate limits, metrics, and exception management.

1. **Limits:** The Companies will adhere to the energy credit risk limits set forth in this policy. The purpose of these limits is to balance the need to secure reliable supplies of fuel and wholesale power with the need to control the risks inherent in the process. Energy Credit Risk Limits are set forth in Appendix F.

**2. Standards for Credit and Financial Assessment of Counterparties:**

Creditworthiness assessment for rated counterparties with publicly filed financials is to be updated every quarter with availability of new financials.

Creditworthiness assessment for unrated or privately held counterparties without publicly filed financials is to be performed after receipt of audited financials. The highest exposure power/gas and supply chain private counterparties will be evaluated on an annual basis.

If a counterparty is a subsidiary of a parent company, a guarantee may be required from the parent to support the transactions that are entered into with the subsidiary. The credit limit assigned to this counterparty will be limited to lesser of the amount of the parent guarantee, the unsecured limit the parent qualifies for or the netted credit limit (buys and sells).

The scoring module uses a multi variable scorecard to establish credit limits for counterparties. The scorecard methodology factors in agency ratings, performance, liquidity, leverage ratios, and assigns credit limits based on a percentage of tangible net worth. The assigned credit limits are further adjusted downward to the NV Energy defined ratings matrix set forth in Section A of Appendix F. The components of the credit exposure calculation include cash flow, mark-to-market nominal value and the assigned credit limit or collateral.

NV Energy Credit Risk Management and Control Policy

Counterparties with higher exposures will be evaluated on an annual basis and monitored daily. Qualitative risk acceptance criteria will be incorporated into the evaluation of the highest exposure counterparties.

Under Rule 9, large customers (projects >1MW or project costs > \$400,000) including mining, data centers, master plan development, renewables and new industry type businesses that are sent to Risk Control for determination of ‘Abnormal Risk’ will be underwritten using the same scoring methodology and tools that are used to evaluate counterparties.

3. **Metrics:** In addition to the above formal limits, Risk Control will monitor a set of metrics on a periodic basis. The purpose of these metrics is to provide transparency of the corporate credit portfolio to the Risk Committee.

- **Large Customer Credit Metrics:** The Companies have established the Arrears Balance Metric and the Uncollected Deposits Metric to monitor the credit exposure attributable to large customers. Large customers are defined by the Companies based on rate class, total yearly summary bill, or total yearly revenue.
  - i. **Arrears Balance Metric:** The Companies will monitor the balance of large customers’ accounts receivable in arrears as a percentage of total quarterly revenue due from large customers.
  - ii. **Uncollected Deposit Metric:** The Companies will monitor the allowable deposits uncollected as a percentage of total allowable deposits. Total allowable deposits based on prevailing regulations pertaining to maximum allowable deposit assessment.
- **Business Unit Procurement Metrics:** The Companies have established the Supplier Credit Metric to control the credit exposure attributable to procurement.
  - i. **Supplier Credit Metric:** The Companies will not enter into transactions with a material supplier for the purchase of goods or services over the amount of \$1,000,000, until Credit Risk Management has analyzed the supplier’s financial stability. Contracts with numerous suppliers of materials and services used in the development and maintenance of the electric and gas infrastructure for the new construction, repair or

reconstruction of any public building or other public work or public improvement in excess of \$100,000 require performance bonds. Any exceptions to collateral requirements must be approved by the authorized contract signatory, in line with the limits specified in the Corporate Governance and Approval Policy. The CFO should be notified of any requests for collateral waivers over \$1 million at the same time the VP receives that request for approval and before they are routed to the President/CEO for final approval.

**Exception Management Process:**

- i. **Limits:** The Risk Committee may approve waivers to this policy and to the plans and procedures developed in accordance with this policy. The Companies will develop and maintain procedures for reporting material exceptions to the limits established under this policy if those exceptions were not approved by the Risk Committee. The procedures will have provisions for prompt notification to the Treasurer who will, in turn, be responsible for notifying the personnel responsible for resolution of the exception and, if necessary, the Risk Committee. Presentations to the Risk Committee will include descriptions of the exceptions, proposed courses of action to resolve the exceptions, and schedules for resolving the exceptions.
  
- ii. **Metrics:** The relevant business unit may approve exceptions to the stated practices associated with the Large Customer Credit Metrics and Procurement Metrics. The business function will develop procedures and necessary documentation for deviation. Since a formal limit is not associated with the metrics, notification of non-compliance with standard procedures is not required beyond the relevant business unit.
  
- iii. **Reporting Process:** The Companies will monitor credit limits and metrics through a formal reporting process driven by the Treasurer. On a monthly basis, Risk Control, with the assistance of Energy Credit Risk Management, Large Customer Credit Risk Management, and Business Unit and Supply Chain Credit Risk Management, will calculate and compile the limits and metrics outlined in this policy into a report. The report will be disseminated monthly to each member of the Risk Committee. Material adverse findings will be discussed at the meetings, and exceptions will be raised to the appropriate business function.

## **V. Compliance**

Each employee will have an affirmative duty to alert their reporting management immediately upon learning of any apparent violations of this policy.

Each employee will also have an affirmative duty to alert management immediately upon learning of any risks not adequately covered by this policy and the associated procedures, methodologies, and systems.

NV Energy Credit Risk Management and Control Policy

**Appendix A: Definitions**

Aggregate Exposure	An estimate of the current cost of replacing all of the contracts with a counterparty.
Clearinghouse	An entity that clears the total transactions (buys with sales) for the period.
Consumer Bill of Rights	Provisions under Nevada Revised Statutes 704.210 governing billing procedures and processes for residential and small commercial gas and electric customers.
Counterparty	The entity that has entered a contract with one of the Companies.
Credit Derivatives	A financial instrument whose characteristics and value depend upon the characteristics and value of an underlying instrument or asset, typically a commodity, bond, equity, or currency.
Credit Insurance	Insurance on the counterparty portfolio which is used to mitigate the risk of one or more of the counterparties in the portfolio defaulting on its obligations.
Critical material suppliers	As defined by the Business Unit(s)
Fixed Price Agreement	A contract in which the price of the commodity or service is set at a particular level when the contract is executed.
Futures	Agreements to buy or sell a quantity of a product, at an agreed price, on a given date, traded on an exchange, and cleared by a clearinghouse.
Indexed Agreement	A contract in which the price of the commodity or service is tied to one or more published indices.
Large Customer	At Nevada Power, an LGS-2 (or larger) customer, along with any additional meters associated with that customer. At Sierra Pacific Power, a GS3 (or larger) customer, along with any additional meters associated with that customer.
Mark-to-Market	The value of a financial or physical instrument, or an aggregation of such instruments, at the Companies' best estimate of current market prices.
Mark-to-Market Margin Collateral	Collateral posted based on the current market value of a financial or physical instrument.

NV Energy Credit Risk Management and Control Policy

Netting	The act of offsetting purchases with sales.
Options	Instruments which give the holder the right, but not the obligation, to sell or buy the underlying commodity at specified prices, times, and locations.
Physical Instrument	A contract for a commodity under which the Companies expect to take delivery of the specified commodity.
Products	Commodities with specific characteristics like electricity delivered during predefined periods.
Swaps	Agreements to exchange net future cash flows or physical positions.
Transaction	A contract obligating the Companies to buy or sell physical commodities and services. Transactions will also include monetary obligations incurred through financial instruments.

**Appendix B: Areas of Responsibility – Committees**

**Risk Committee:** The Risk Committee will be responsible for:

- Monitoring the current and expected future economic conditions, assessing their effect on the general business environment and on the Companies, and disseminating the information obtained through such monitoring to the management of the Companies;
- Initiating the preparation of new risk control policies when or where appropriate and the modification of risk control policies already in place;
- Ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Resolving any disputes regarding the appropriate application of those policies and procedures;
- Ensuring the availability of the systems required to monitor, record and report on the risks inherent in the Companies’ operations;
- Reviewing and approving the Companies’ resource plans, energy supply plans, and the financing of the plans prior to Chief Executive Officer approval;
- Assuring integration of energy procurement or sale risk, credit risk, cash flow risk and customers' risk;
- Reviewing and approving all transactions requiring exceptions to the approved plans for acquiring or selling fuel and wholesale power prior to implementation;
- Reviewing all energy procurement or sale transactions requiring the approval of the Chief Executive Officer<sup>2</sup> prior to the presentation of such transactions to the Chief Executive Officer; and,
- Assessing the appropriateness of the Companies’ risk control activities and

NV Energy Credit Risk Management and Control Policy

modifying this policy, whenever modifications are required to ensure the ongoing viability of the Companies' risk management and control programs and the continued fulfillment of the Companies' obligations.

The Risk Committee will have the right to delegate portions of its assigned duties to one or more committees. The Risk Committee will establish the charter of each Committee when it is established and modify the charter if necessary. Committees will keep minutes in the same manner as the Risk Committee. Committees will also make periodic reports of their activities to the Risk Committee in the manner designated by the Risk Committee.

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<sup>2</sup> The review by the Risk Committee prior to the presentation to the Chief Executive Officer is not required if such transactions are being done in accordance with an Energy Supply Plan already approved by the Chief Executive Officer.

## **Appendix C: Areas of Responsibility – Risk Control**

***Risk Control:*** Risk Control will be responsible for:

- Disseminating this policy to the Companies’ personnel who will be affected by this policy;
- Measuring the Companies’ energy portfolio exposures and comparing the measurements against approved exposure limits;
- Accumulating risk control information for the Companies;
- Creating monthly risk control reports;
- Assessing proposed modifications to risk control policies and limits based on changing business or market conditions; and,
- Training employees on this policy.

## **Appendix D: Areas of Responsibility – Credit Risk Management**

***A. Energy Credit Risk Management: Credit Risk Management will be responsible for:***

- Assessing the financial and credit worthiness of current and potential counterparties;
- Assessing the current market and industry conditions affecting the credit of counterparties through updates and research;
- Providing a forward-looking perspective on counterparty credit, input of qualitative remarks for our major counterparties in our scoring tool;
- Approving counterparties and establishing credit ratings for them before the Companies enter into energy-related transactions with them;
- Assigning internal credit ratings for counterparties based on rating of parent company when parental guarantees are utilized or the lower of credit rating services, independent debt ratings by major investment banks, and internal evaluations of the entities’ financial condition;
- Accumulating credit risk management and control information from our system of record;
- Managing and mitigating credit risks associated with energy supply optimization;
- Monitoring current credit of major counterparties on an on-going basis;
- Following processes and procedures outlined by the Credit Policy;
- Providing Risk Control with necessary counterparty credit information on a periodic basis through our system of records and the monthly Credit Report;
- Monitoring and reporting on the creditworthiness of current counterparties;
- Monitoring credit exposures at the counterparty and portfolio level on an on-going basis;
- Evaluating credit impact on counterparty and portfolio credit of large transactions;
- Reviewing and reporting on all contractual credit terms;
- Ensuring credit terms in contracts are in accordance with standard business practices;
- Reviewing and reporting on information requested by counterparties for collateral or other credit support;

NV Energy Credit Risk Management and Control Policy

- Evaluating costs and benefits associated with risk transfer and reduction methods;
- Resolving credit issues with counterparties;
- Calculating collateral requirements to be posted by counterparties and overseeing the receipt of that collateral; all letters of credit submitted are kept in the Legal Department and tracked;
- Notifying the Manager of Market Operations and Trading when credit exposure limits have been exceeded and assist Risk Control in developing the strategy to mitigate risk; and,
- Maintaining records and tracking collateral posted by counterparties. Calculating collateral requirements and managing collateral posted by the Companies.

***B. Large and Mid-to-Small Customer Credit Risk Management:*** Risk Control along with Credit & Billing will be responsible for managing the credit risk associated with large and mid-to-small customers and frequently reporting on the status of such risks. Responsibilities of Risk Control include:

- Managing and mitigating credit risks associated with the customer payment of large non-residential customers;
- Monitoring on-going credit of large non-residential customers and disseminating relevant credit information to Credit & Billing and Major Accounts;

Responsibilities of Credit & Billing include:

- Periodically provide Risk Control with a list of large customers;
- Managing and mitigating credit risks associated with the customer payment of large and mid-to-small non-residential customers;
- Reviewing and tracking occasions of deposits and late fees waivers;
- Monitoring changes in regulations regarding large customer credit;
- Monitoring current credit and payment history of the Companies of customers;
- Collecting and disseminating relevant credit information to managing account executives;
- Following processes and procedures outlined by the Credit Policy and/or applicable regulations;
- Provide information for metrics referenced in Appendix E - Large Customer Credit Metrics;
- Providing Risk Control with necessary customer credit information on a periodic basis; and
- Ensure timely posting of write-offs to accounts for regulatory recovery.

In case of disagreements on the risk assessment of and credit mitigations for customers, Risk Control and Credit & Billing are encouraged to present their recommendations to members of the Risk Committee for further determination.

***C. Business Unit Credit Risk Management:*** Risk Control along with Procurement will be responsible for managing the credit risk associated with material vendors and procurement customers.

Responsibilities of Risk Control include:

- Managing and mitigating credit risks associated with material procurement;
- Monitoring current credit of critical material procurement vendors, based on, but not limited to, third party credit rating and company financials;
- Following processes and procedures outlined by the Credit Policy; and,
- Ensuring credit terms in material contracts are in accordance with standard business arrangements.

Responsibilities of Business Unit include:

- Identify critical material procurement vendors;
- Identify contracts in excess of \$100,000 requiring performance bonds and contracts in excess of \$1,000,000 requiring risk assessment by Risk Control;
- Provide information for metrics referenced in Appendix E – Risk Control Metrics.
- Determine if service-only contracts are exempt and do not require collateral based on their low-risk classification in the insurance risk matrix, no electric or gas infrastructure involvement, no prepayments, and vendor does not process payments on behalf of the Company.

**D. Transmission Credit Risk Management: Credit Risk Management will be responsible for:**

- Assessing the financial and credit worthiness of current and potential counterparties and customers;
- Assessing the current market and industry conditions affecting the credit of counterparties and customers through updates and research;
- Providing a forward-looking perspective on counterparty and customer credit;
- Approving counterparties and customers and establishing credit ratings for them before the Companies enter into transmission-related transactions with them;
- Assigning internal credit ratings for counterparties and customers based on rating of parent company when parental guarantees are utilized or the lower of credit rating services, independent debt ratings by major investment banks, and internal evaluations of the entities' financial condition;
- Accumulating credit risk management and control information from our system of record;
- Monitoring current credit of counterparties and customers on an on-going basis;
- Monitoring and reporting on the creditworthiness of current counterparties and customers;
- Reviewing and reporting on information requested by counterparties and customers for collateral or other credit support;
- Resolving credit issues with counterparties and customers;
- Reporting on accounts receivable aging information on counterparties and customers;
- Calculating collateral requirements to be posted by counterparties and customers

NV Energy Credit Risk Management and Control Policy

and overseeing the receipt of that collateral; all letters of credit submitted are kept in the Legal Department and tracked;

- Maintaining records and tracking collateral posted by counterparties and customers.

**E. Rule 9 Credit Risk Management: Credit Risk Management will be responsible for:**

- Assessing the financial and credit worthiness of current and potential new customers;
- Assessing the current market and industry conditions affecting the credit of customers through updates and research;
- Providing a forward-looking perspective on customer credit;
- Approving customers and establishing credit ratings for them before the Companies enter into transmission-related transactions with them;
- Assigning internal credit ratings for customers based on rating of parent company when parental guarantees are utilized or the lower of credit rating services, independent debt ratings by major investment banks, and internal evaluations of the entities' financial condition;
- Accumulating credit risk management and control information from our system of record;
- Monitoring current credit of customers on an on-going basis;
- Monitoring and reporting on the creditworthiness of current customers;
- Reviewing and reporting on information requested by customers for collateral or other credit support;
- Resolving credit issues with customers;
- Reporting on accounts receivable aging information on customers
- Calculating collateral requirements to be posted by customers and overseeing the receipt of that collateral; all letters of credit submitted are kept in the Legal Department and tracked; and
- Maintaining records and tracking collateral posted by customers.

**Appendix E: Risk Control Metrics**

**A. Large Customer Credit Metrics**

**i. Arrears Balance Metric – Monthly**

Total dollar value of current accounts receivable in arrears divided by total dollar value of accounts receivable due or received in a given month

- Arrears balances will be determined as balances outstanding for 30 days or more past the due date
- Individual account balances under summary accounts will not be considered in arrears until 30 days after the summary account billing date

*ii Uncollected Deposit Metric – Quarterly*

Sum of total allowable deposits uncollected divided by total allowable deposits for unsatisfactory customers in a given quarter

- Allowable deposits uncollected to be determined as the maximum allowable deposit uncollected or the difference between maximum allowable deposit and the deposit collected by the Companies
- Non-Residential
  - Maximum allowable deposit based on 200% of average monthly bill
  - Unsatisfactory customers are defined as customers who pay after their due date even once in a 24-month period, or are subject to disconnect/termination of services
- Residential:
  - Maximum allowable deposit based on 150% of average monthly bill
  - Unsatisfactory customers are defined as customers who pay after their due date more than three times in a twelve-month period, or are subject to disconnect/termination of services
- New customers are unsatisfactory at time of initial service agreement if adequate credit is not available in the form of satisfactory past payment history with a utility/municipal agency or guarantor with satisfactory credit

***B. Business Unit Procurement Credit Risk***

*i. Counterparty Credit Metric – Annual*

Total contract value outstanding with a critical material supplier determined on a semi-annual basis

- Total contract value is determined as the greater of maximum payment for goods and services or market replace costs associated with goods and services provided to the Companies by critical material suppliers.

**Critical material supplier’s status based on, but not limited to, alliance membership, aggregate contract value with NVE and its Subsidiaries, and availability of substitute goods or product**

**NOTE: All those individuals identified as being impacted by the Risk Policies, e.g., Credit Risk Management and Control Policy, Risk Management and Control Policy and Energy Risk Management and Control Policy are required to review the policies each calendar year.**

**Appendix F: Credit Limits**

**A. Counterparty and Customer Credit Limits**

<b>Counter-party Credit Notification Thresholds- All Transactions</b>	
<b>Credit Rating</b>	<b>Maximum Aggregate Exposure per Counter- party</b>
AAA+ to AA- or equivalent	\$20,000,000
A+ to A- or equivalent	\$15,000,000
BBB+ to BBB- or equivalent	\$10,000,000
BB+ to BB- or equivalent	\$6,000,000
B+ to B- or equivalent	\$0
Less than B-	\$0

**B. Sub-investment Grade Notification Thresholds**

Maximum portion of the portfolio below investment grade based on actual Mark-to-Market exposure may not exceed 40% without prior approval from the Risk Committee.

**C. Weighted Average Portfolio Credit Notification Thresholds**

**Weighted average credit rating of portfolio based on actual Mark-to-Market exposure must be ‘BBB- ‘or better.**

**Appendix G: Collateral Release Procedure:**

The Department contacts Credit Risk to have the collateral released that is being held for a specific contract or project. This includes but is not limited to energy credit risk, large customer credit risk, business unit credit risk, supply chain credit risk, transmission credit risk, Rule 9 credit risk, developer credit risk.

- The email that is sent to Credit Risk will include the approval by the Director of the Department. In the absence of a Director, the next level of management over the Department.
- A release of collateral letter, located on MyNVE, is created by Credit Risk, attached to the original letter of credit or bond and sent via Fed Ex to the issuing bank or Surety for cancellation.

**NV Energy Credit Risk Management and Control Policy**

- Signature of Authority for the collateral release letter:
  - Business Risk Control Specialist – up to \$5M
  - Treasurer – up to \$30M
  - Vice President, CFO – over \$30M

NV Energy Credit Risk Management and Control Policy

**Appendix H: Policy Revision Log**

<b>Date</b>	<b>Revision(s)</b>
December 17, 2014	<p>Modified Existing Policy.</p> <ol style="list-style-type: none"> <li>1. Updated risk committee name. Replaced “Enterprise Risk Oversight Committee” with “The Risk Committee.”</li> <li>2. Reassigned responsibility by replacing “Board of Directors” by “Risk Committee” and “Chief Risk Officer” by “Chief Financial Officer.”</li> <li>3. Added language related to Rule 9 and the methodology of customer scoring and evaluation.</li> <li>4. Replaced the Credit Notification Thresholds table with the new approved version.</li> <li>5. Replaced Risk Committee’s area-of-responsibility description by language in Risk Management and Control Policy for consistency.</li> <li>6. Removed language related to Energy Risk Committee since it was dissolved.</li> <li>7. Added a policy revision log.</li> </ol>
December 28, 2016	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Updated sub-section A.ii regarding maximum allowable deposit amounts to be consistent with Electric Rules 1 and 13 for both North and South.</li> </ol>
July 26, 2017	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Updated the approval date of the Risk Management and Control Policy in the Background section.</li> <li>2. Updated the approval date of the Credit Risk Management and Control Policy in Appendix H, the Employee Acknowledgement section.</li> <li>3. Made formatting changes to make the document consistent with the Risk Management and Control Policy and the Energy Risk Management and Control Policy.</li> </ol>
May 7, 2018	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Replaced Chief Executive Officer with President</li> <li>2. Replaced Director, Risk Control with Treasurer</li> </ol>

NV Energy Credit Risk Management and Control Policy

	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Replaced Chief Executive Officer with President</li> <li>2. Replaced Director, Risk Control with Treasurer</li> <li>3. Updated titles</li> </ol>
December 19, 2018	<p>Modified Existing Policy:</p> <ol style="list-style-type: none"> <li>1. Removed “Senior” from “Vice President, Chief Financial Officer”</li> <li>2. Replaced “President” with Chief Executive Officer</li> </ol>
December 4, 2019	<p>Modified Existing Policy</p> <p>Replaced ratepayer with customers</p>
November 17, 2021	<p>Modified Existing Policy</p> <ol style="list-style-type: none"> <li>1. Add Assistant Treasurer to specified locations throughout document</li> <li>2. Removed “A” from Risk Committee on page 12</li> <li>3. Added existing procedures for Transmission and Rule 9</li> </ol>
November 15, 2023	<p>Modified Existing Policy</p> <ol style="list-style-type: none"> <li>1. Replaced Assistant Treasurer with Treasurer</li> <li>2. Replaced Senior Vice President, CFO &amp; Treasurer with Vice President, CFO</li> <li>3. Removed Appendix I: Employee Acknowledgement</li> </ol>
November 20, 2024	<p>Modified Existing Policy</p> <ol style="list-style-type: none"> <li>1. Replaced Procurement with Business Procurement Credit Risk</li> <li>2. Deleted Assistant Treasurer title</li> <li>3. Clarified the requirement for performance bonds</li> </ol>
January 25, 2025	<p>Modified Existing Policy</p> <p>Added existing clarification on collateral requirements, emphasizing that the CFO should be notified of any requests for collateral waivers over \$1M and at the same time the VP receives the request for approval before being routed to the President/CEO for final approval</p>
February 26, 2025	<p>Modified Existing Policy</p> <p>Added language to address collateral waivers for service-only contracts</p>
October 22, 2025	<p>Modified existing Policy</p> <ol style="list-style-type: none"> <li>1. Minor language clarifications were implemented throughout the policy</li> <li>2. Removed duplicate schedule for “Large Transactions”</li> </ol>